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PacifiCorp / Scottish Power

DOCKET# 98-2035-04	**In the Matter of:**.The Application of PacifiCorp and Scottish Power plc for an Order Approving the Issuance of PacifiCorp Common Stock 18177	Vol. III of IV 20484
Date	**Description**	**SS#**

February 1, 2002	Scottish Power/PacifiCorp Merger Commitments	NEC
February 20, 2002	Appendix A: Paul I. Nippes	NEC
February 21, 2002	Comments from DPU	28356 28357
February 26, 2002	PacifiCorp's Third Quarter Outage Detail Report	NEC
February 26, 2002	Comments from DPU	28409
March 6, 2002	Major Events Letter from Commission	28545
June 3, 2002	Scottish Power/PacifiCorp Merger Commitments	papervision
August 12, 2002	Comments from DPU	papervision
September 30, 2002	PacifiCorp's Update to the First Quarter Report for the Period April 2002 through June 2002	papervision
November 1, 2002	Pacificorp's Semi-annual Report for July 2002 Through September 2002	papervision

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PacifiCorp / Scottish Power

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Date	**Description**	**SS#**
June 1, 2001	ScottishPower / PacifiCorp Merger Commitments Re: PacifiCorp's Annual Report for the Period April 2000 Through March 2001 Detailing Company's Performance in Meeting the Customer Guarantees and Performance Standards	NEC
June 8, 2001	Comments from DPU	25185
June 11, 2001	Notice of Summary of Cash Flows for the Year Ended March 31, 2001	PaperVision
July 13, 2001	PacifiCorp Major Event Report, No. 2	PaperVision
August 1, 2001	ScottishPower/PacifiCorp Merger Commitments Re: PacifiCorp's Quarterly Report for the Period April 2001 through June 2001	PaperVision
September 18, 2001	Comments from DPU Re: Major Even Reports	26481
October 16, 2001	Petition of PacifiCorp for Modification of Order	26860
October 25, 2001	Action Request: Due ASAP	26908
November 1, 2001	ScottishPower / PacifiCorp Merger Commitments: Semi-Annual Report for Period April 2001 thru September 2001	NEC
November 21, 2001	Comments from DPU	27259
November 23, 2001	Comments from CCS	27294
December 17, 2001	Order Modifying Call Answering Rate	27496
December 21, 2001	ScottishPower / PacifiCorp Merger Commitments: Addendum to Semi-Annual Report for Period April 2001 thru September 2001	NEC
December 21, 2001	Exhibit A: David A. Schlisser, and Paul I. Nippes	NEC

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Date	**Description**	**SS#**

March 1, 2000	Correspondence from PacifiCorp/ScottishPower to the Commission, Re: Completion of Condition #20	NEC
April 21, 2000	PacifiCorp's March 2000 Report	NEC
May 2, 2000	Revised March 2000 Report Re: Detailing The Company's Performance in Meeting The Customer Guarantees	NEC
May 22, 2000	Summary of Cash Flows for the 11 Months Ended February 19, 2000	NEC
May 23, 2000	Letter from DPU/Lowell Alt RE: Audit	NEC
May 25, 2000	Informational Filing - Merger Commitment Condition 13 [EXHIBIT FILE]	NEC
June 29, 2000	Pacificorp's Consolidated Statement of Cash Flows	NEC
August 2, 2000	Scottish Power / Pacificorp Merger Commitments	NEC
September 29, 2000	PacifiCorp's Summary of Cash Flows for the Year Ended June 30, 2000	NEC
October 3, 2000	PacifiCorp's Summary of Cash Flows for the Year Ended June 30, 2000 CORRECTION	NEC
November 1, 2000	ScottishPower / PacifiCorp Merger Commitments	NEC
November 1, 2000	Schedule 70 - New Wind, Geothermal and Solar Power Rider Annual Report	NEC
January 31, 2001	APPENDIX A Re: Helmuth W. Schultz, Hugh Larkin Jr., Donna DeRonne	NEC
January 31, 2001	ScottishPower / PacifiCorp Merger Commitments	NEC

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PacifiCorp / Scottish Power

DOCKET# 98-2035-04	**In the Matter of:**.The Application of PacifiCorp and Scottish Power plc for an Order Approving the Issuance of PacifiCorp Common Stock 18177	Vol. III of III 20484
Date	**Description**	**SS#**
September 3, 1999	Opening Brief of Deseret Generation and Transmission Co-Operative and Member Co-Ops	18050
September 3, 1999	Post-Hearing Brief of Applications Scottish Power and PacifiCorp	18052
September 7, 1999	Letter to the Commission from Mr. Kyle Polychronis, Re: Merger	NEC
September 17, 1999	Letter to the Commission from John & Cher Zirker	NEC
September 17, 1999	Reply Brief of Intervenor Megnesium Corporation of America on the Proposed Merger of Scottish Power PLC and PacifiCorp	18142
September 17, 1999	Reply Brief of Nucor Steel, A Division of Nucor Corporation	18144
September 17, 1999	PacifiCorp/ScottishPower's Confidential Reply Brief [PROPRIETARY FILE]	NEC
September 17, 2000	Large Customer Group's Reply Brief	18170
September 17, 1999	Reply Brief of Applicants Scottish Power PLC and PacifiCorp	18160
September 17, 1999	UIEC'S Post Hearing Reply Brief	18158
October 4, 1999	Joint Reply Memmorandum of the Division of Public Utilities and the Committee of Consumer Services	18310
November 23, 1999	Report and Order * Appendices 1-5	18771
December 14, 1999	Memo from the Division, Re: Tariff Revisions Specified in the Above-Mentioned Order (Tariff Approved Jan. 3, 2000 - Also see **Docket No. 99-035-T03)**	18922

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SERVICE COMMISSION

AGREEMENT BETWEEN PACIFICORP AND UTAH DIVISION OF PUBLIC UTILITIES ON ESTABLISHING BASELINES FOR PACIFICORP'S PERFORMANCE STANDARDS 1 and 2
APRIL 2003

APPROVED BY COMMISSIONERS
STEPHEN F. MECHAM
CONSTANCE B. WHITE CBW 4/9
RICHARD M. CAMPBELL

PacifiCorp (the Company) and the Utah Division of Public Utilities (Division) have entered into an agreement, as described below, concerning the 10% improvement in performance regarding Performance Standards 1 and 2, two of the performance standards that were implemented by PacifiCorp in the merger with ScottishPower, Docket No. 98-2035-04. Performance Standard 1 pertains to duration of outages, or System Average Interruption Duration Index (SAIDI). Performance Standard 2 pertains to frequency of outages, or System Average Interruption Frequency Index (SAIFI).

1. Background

As part of the merger between ScottishPower and PacifiCorp, performance standards were developed which included specific network performance improvements. Key to achieving these improvements was the need to better document outages as well as the need to implement a new outage management system. These two actions would ensure greater accuracy of the customer minutes lost for each outage event, as well as the frequency of outages, and would give the Company greater capabilities in targeting facility and operational improvements in delivering reliability.

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Within the Joint Motion for Approval of Stipulation in Docket No. 98-2035-04, it was recognized that the planned system changes would capture outage minutes that had not been previously captured. Therefore a "baseline adjustment" process was introduced into both witness testimony and stipulation documents (Stipulation Condition No. 30). Since the approval of the merger, substantial efforts have been undertaken to improve the accuracy of the Company's outage reporting process and better track the customer reported outages compared to the outages reported in the Company's outage reporting system. Since the merger the Company has also been working with the Division to determine the appropriate baseline adjustment and ensure establishment of a merger commitment target reflective of the planned 10% improvement over the five-year measurement period as described in Performance Standards 1 and 2. Submission by the Division of outage baselines within 18 months after approval of the merger, as outlined in Stipulation Condition 30 (b) was delayed to accommodate this work.

The Company has prepared calculations that demonstrate what it believes to be correct adjustments to earlier under-reported outage data sets. The Division does not feel that using these calculations to correct for earlier under-reporting is the best approach, since no direct measurements of the uplift can be prepared. As a result, the Company and Division have agreed upon the process discussed below that they believe will achieve at least a 10% improvement in reliability over the five-year measurement period described in Performance Standards 1 and 2.

2. Agreement Between PacifiCorp and Utah Division of Public Utilities

The Company and the Division have agreed to establish a target from which to measure improvements based on a timeframe from which the Company can assure quality outage management data to prepare its target, then effect an outage management data quality audit process. The Company and the Division are submitting this agreement to the Commission for approval.

The proposal developed by the Company and the Division has as its keys components:

1) Development of the merger commitment target beginning point
2) Methodology by which exclusions from the data-set will be conducted
3) Identification of a methodology to assess accuracy of the data in the future.

Merger Commitment Target

In order to match to the Company's fiscal calendar, the Company proposes that fiscal year 2005 (April 1, 2004 through March 31, 2005) be used as the period of record. The Company and the Division believe the outage management reporting discipline and customer connectivity data for fiscal year 2002 (April 1, 2001 through March 31, 2002) are of adequate quality to set fiscal year 2002 as a starting point. The pertinent performance criteria are listed below:

FY 2002 Total Performance			**Major Event Performance**			**Normalized Performance**		
Sustained Outages	SAIDI	SAIFI	Sustained Outages	SAIDI	SAIFI	Sustained Outages	SAIDI	SAIFI
13,788	369.291	2.851	2,750	134.1	0.48	11,038	235.192	2.365
2% Annual Reduction							221	2.2
Proposed Merger Commitment Target							**217**	**2.2**

After the merger, the Company implemented numerous process and system changes to improve performance reporting and also implemented network improvements to increase reliability. These changes create difficulty in comparing current performance to pre-merger performance. As a result, the Company and the Division have agreed to evaluate reliability improvements from a beginning base of fiscal year 2002 (April 1, 2001 through March 31, 2002), and increment accordingly. The Division and the Company agree that reducing the SAIDI and SAIFI target by 2% a year from the 2002 performance (April 1, 2001 through March 31, 2002) until 2005 (April 1, 2004 through

March 31, 2005) would be a reasonable approach. Based on this methodology, the target for 2005 (April 1, 2004 through March 31, 2005) would be 221 for SAIDI and 2.2 for SAIFI. After further negotiations between the Company and the Division, a revised SAIDI target for 2005 of 217 and SAIFI of 2.2 was agreed upon by the Company and the Division.

In addition to this reduction in the SAIDI and SAIFI target of 2% per year from 2002 until 2005, the Company's analysis shows that a significant outage reduction was achieved in fiscal 2002 compared to 2001 performance. To estimate the percentage of reduction already achieved, the Company performed an analysis to identify the improvement in reliability that occurred after a substantial investment in the heavily growing Salt Lake City area. The Company's analysis used the occurrence of outages. In fiscal 2001 (April 1, 2000 through March 31, 2001), the Company experienced 12,997 outages, and in fiscal 2002 (April 1, 2001 through March 31, 2002) only 11,038 outages, for an outage reduction of 15.1%. The Company has determined that since the introduction of its new outage reporting system there is a high correlation between outage incidents and SAIDI. Therefore the Company estimates that in fiscal 2002 (April 1, 2001 through March 31, 2002) it delivered a 15.1% improvement in performance over 2001 (April 1, 2000 through March 31, 2001).

Based on the Company's analysis, the Company and Division believe delivery of the targets above will provide reliability improvements to customers that at least meet the original merger commitment goal of 10% improvement over a five-year period.

Exclusion Process

The Division and the Company agree that "major events" should be excluded from the outage data. A major event is defined as:

> "An event which exceeds reasonable design or operational limits of the electric power system, and during which at least 10% of the customers within an operating area experience a sustained interruption during a 24-hour period."

The Division and the Company also agree that performance results delivered will be normalized to exclude all events where the above conditions apply, and that have been approved by the Commission.

Data Quality Indicators

Since the introduction of PacifiCorp's CADOPS (Computer-Aided Distribution Operations System) and Prosper/US, and its integration with the Trouble Up (fault-recording) System, the Company looks to several metrics to assess the quality of the outage management system.

1) Evaluation of quantity of "orphan trouble calls": when a customer calls who is not associated with a transformer an "orphan trouble call" is generated. (They may be new customers whose meters have not yet been associated to a transformer, individuals who are reporting a line down or calling the wrong utility.) These calls are unable to generate an outage incident automatically (from Trouble Up) within CADOPS. The Company monitors this data on a regular basis and ensures the proper resolution to these entries.

2) Evaluation of "untied customers": when new customers are added to the Company's delivery system, a record is created in the Customer Service System (CSS) that establishes basic account information, including a site-service record. On a regular basis CADOPS is updated with these new accounts. An association between the customer's site service record and the upstream transformer ensures that if that device is without power the associated customer-minutes-lost will be reported. If no association exists in

> CADOPS, the effect of those untied customers' outage minutes would not be included in the reliability metrics.

The Company will prepare a calculation of "unreported untied customer minutes lost." This calculation will be the result of a statistical correlation between the Trouble Up and CADOPS systems' untied and tied customer calls. A 90% confidence interval will be used to establish the error rate used to calculate the unreported untied customer minutes lost. The Company will evaluate this effect on its SAIDI and SAIFI targets routinely, and report the results on an annual basis. The Company will cooperate with the Division to audit the results of these calculations.

3. Summary of Agreement

To summarize, PacifiCorp and the Division have agreed to measure the improvements in system reliability based on the establishment of a system performance baseline using fiscal year 2002 (April 1, 2001 through March 31, 2002) data. The reliability target the Company needs to deliver during fiscal year 2005 (April 1, 2004 through March 31, 2005) will be a normalized SAIDI of 217 and SAIFI of 2.2. This target delivers a greater than 2% improvement per year, over a three-year measurement period. This target builds upon the Company's estimate of the 15% improvement in performance already achieved from fiscal 2001 (April 1, 2000 through March 31, 2001) to fiscal 2002 (April 1, 2001 through March 31, 2002). The Company will exclude from performance measurements those events that meet the definition for a major event and have been approved by the Commission. The Company will also develop a data quality indicator using orphan trouble calls, untied customer percentages, and calculate an estimate of untied unreported customer minutes lost. The Company will cooperate with the Division to audit the results of these calculations.

By using the proposed targets, exclusion processes and accuracy measures the Company and the Division believe the Company will deliver reliability improvements at least equivalent to that agreed to in Docket No. 98-2035-04 with regard to Performance Standards 1 and 2.

Signed ______________________ Date 4/8/2003
Heidi Caswell, Manager
PacifiCorp

Signed ______________________ Date 4-9-03
Lowell Alt Jr., Director
Utah Division of Public Utilities

Appendix

SAIDI: System Average Interruption Duration Index = Customer Minutes Lost (for the Period in Question)/Frozen Customer Count (for the Period in Question)

SAIFI: System Average Interruption Frequency Index = Customers Interrupted (for the Period in Question)/Frozen Customer Count (for the Period in Question)

Customer Minutes Lost (CML): Customer Minutes Lost is the sum of all sustained outage's outage duration for the period in question. This value is reported using the Prosper/US database.

Frozen Customer Count: For the period in question, the Company develops a "frozen customer count". This value is the beginning number of customers' site service locations within the area. This value is stored within the Prosper/US database.

Sustained Outage (or sustained interruption): an outage event that exceeds 5 minutes in duration.

Major Event: an event which exceeds reasonable design or operational limits of the electric power system, and during which at least 10% of the customers within an operating area experience a sustained interruption during a 24-hour period.

Fiscal Year: from April 1, of the year through March 31 of the following year. The fiscal year number is the calendar year number of the last 3 months of the fiscal year. For instance, April 1, 2000 through March 31, 2001 is the fiscal year 2001.

2001 Major Events

Date	Description	SAIDI	SAIFI	MAIFI
1) 5/2-5/5/2001	Wind Storm	23.302	0.141	0.056
2) 6/12-6/14/2001	Wind Storm	60.425	0.215	0.025
3) 11/22-11/27/2001	Snow Storm	62.751	0.221	0.128

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Portland, Oregon 97201

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REVIEWED BY COMMISSIONERS
STEPHEN F. MECHAM
CONSTANCE B. WHITE CBW 11/4
RICHARD M. CAMPBELL RC

VIA OVERNIGHT MAIL

October 30, 2002

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Julie Orchard
Commission Secretary

RE: Docket No. 98-2035-04 Scottish Power/PacifiCorp Merger Commitments

Please find enclosed PacifiCorp's semi-annual report for the period July 2002 through September 2002 detailing the Company's performance in meeting the Customer Guarantees which were agreed upon as a result of the merger between ScottishPower and PacifiCorp. Year-to-date information is provided as well.

If you have any questions or require further information, please call me at (503) 813-7408.

Sincerely,

Carole Rockney

Carole Rockney, Director
Customer and Regulatory Liaison

Enclosures

c: Mark Flandro- Utah Division of Public Utilities
Rea Petersen- Utah Division of Public Utilities
Matthew Wright - Executive Vice President, Power Delivery

		July-September 2002 (FY2003)				Fiscal YTD 2003				Fiscal YTD 2002			
	Description	Events	Failures	% Success	Paid	Events	Failures	% Success	Paid	Events	Failures	% Success	Paid
CG1	Restoring Supply	510,263	22	99.99%	$1,675	1,113,594	23	99.99%	$2,050	963,056	9	99.99%	$725
CG2	Appointments	1,770	10	99.4%	$500	3,514	21	99.4%	$1,050	3,362	6	99.8%	$300
CG3	Switching on Power	8,395	35	99.6%	$4,150	16,178	49	99.7%	$5,650	17,274	27	99.8%	$3,775
CG4	Estimates	1,621	72	95.6%	$3,600	3,581	110	96.9%	$5,500	3,876	70	98.2%	$3,500
CG5	Respond to Billing Inquiries	3,681	30	99.2%	$1,500	6,051	43	99.3%	$2,150	4,661	17	99.6%	$850
CG6	Respond to Meter Problems	193	3	98.4%	$150	319	4	98.7%	$200	238	3	98.7%	$150
CG7	Notification of Planned Interruptions	7,569	14	99.8%	$850	21,921	25	99.9%	$1,400	15,035	23	99.8%	$1,200
CG8	Power Quality Complaints	9	0	100.0%	$0	26	0	100.0%	$0	410	6	98.5%	$300
		533,501	**186**	**99.97%**	**$12,425**	**1,165,184**	**275**	**99.98%**	**$18,000**	**1,007,912**	**161**	**99.98%**	**$10,800**

General Comments: On-going internal audits continue to improve employee adherence to guarantee procedures. As a result, the number of paid failures has continued to increase, especially in CG4. However, PacifiCorp's overall success rate remains high.

CG3 - Switching on Power - The increase in failures occurred partially due to incorrect future turn-on dates being set.

CG7 - Planned Interruptions - Although Utah has seen a significant increase in the number of planned interruptions, the number of failures has remained very low.

Excludes major events

Description	Baseline	Performance at Sept 2002	Goal
• SAIDI (System availability in minutes per customer)	Revised baselines under development[1]	177.6	Reduce SAIDI by 10% from revised baseline
• SAIFI (System reliability in interruptions per customer)		1.6	Reduce SAIFI by 10% from revised baseline
• MAIFI (Momentary interruptions per customer)		0.2	Reduce MAIFI by 5% from revised baseline
• Worst Performing Circuits - Circuit Performance Indicator (CPI)[2]			Reduce CPI's by 20% from revised baseline
Fiscal Year 2001:		New CPI will be reported in May 2005	
Coalville 12	288		
Lewiston 11	377		
Pioneer 11	425		
Pioneer 13	529		
Pioneer 14	393		
Fiscal Year 2002:		New CPI will be reported in May 2006	
Woods Cross 11	311		
Eden 11	339		
Rattlesnake 22	308		
Lark 11	419		
Bothwell 11	323		
Fiscal Year 2003:		New CPI will be reported in May 2007	
University 1	107		
West Cedar	613		
Parowan Valley 25	1563		
Eureka 12	90		
Coleman 15	110		
• Power supply restored within 3 hours	Not applicable	86%	80%
• Calls answered			
• Within 20 seconds[3]	Not applicable	80%	80%
• Respond to commission complaints within 3 days	Not applicable	100%	100%
• Respond to commission complaints regarding service disconnects within 4 hours	Not applicable	100%	100%
• Commission complaints resolved within 30 days[4]	Not applicable	99%	95%

1 Baseline uplift methodology developed and analysis submitted and reviewed by Commission Staff. Staff to provide feedback during Fall 2002. If uplift factors cannot be jointly developed, Commission Staff may recommend other measures to ensure operational improvements in alignment with this merger commitment.

2 Baseline CPI figures are based on 3-years ended data as of December 31, 1998 for FY 2001 circuits; 3-years ended data as of December 31, 2000 for FY 2002 circuits; 3-years ended December 31, 2001 for FY 2003 circuits. Improvement period is 2 years after identification year, followed by a 3-year period to recalculate CPI.

3 Reflects system-wide performance for improved accuracy.

4 The target in Utah for complaint resolution is 5 days.

Note: Performance figures exclude impacts of major events.

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Portland, Oregon 97201

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CONSTANCE B. WHITE CBW10/3
RICHARD M. CAMPBELL

VIA OVERNIGHT MAIL

September 27, 2002

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City UT 84114

Attention: Julie P. Orchard
Commission Secretary

RE: Docket No. 98-2035-04 ScottishPower/PacifiCorp Merger Commitments

Please find enclosed PacifiCorp's update to the first quarter report for the period April 2002 through June 2002 detailing the Company's performance in meeting the Customer Guarantees which were agreed upon as a result of the merger between ScottishPower and PacifiCorp. A comparison of performance for this quarter compared to performance for last year is included as well.

If you have any questions or require further information, please call me at (503) 813-7408.

Sincerely,

Carole Rockney / by Kms

Carole Rockney, Director
Customer and Regulatory Liaison

c: Mark Flandro - Utah Division of Public Utilities
Rea Petersen - Utah Division of Public Utilities
Matthew Wright - Executive Vice President, Power Delivery

Enclosures

customer*guarantees*

PACIFICORP

April-June 2002 (2nd Filing)

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Note: The five reports that were delayed at July 31, 2002 are included in this filing. Also included is a Customer Guarantees Summary report which has been updated for CG1 outage events.

		April-June 2002 (FY 2003)				April-June 2001			
	Description	Events	Failures	% Success	Paid	Events	Failures	% Success	Paid
CG1	Restoring Supply	603,331	1	99.99%	$375	383,690	0	100.0%	$0
CG2	Appointments	1,744	11	99.4%	$550	1,689	3	99.8%	$150
CG3	Switching on Power	7,783	14	99.8%	$1,500	8,749	12	99.9%	$1,300
CG4	Estimates	1,960	38	98.1%	$1,900	2,147	30	98.6%	$1,500
CG5	Respond to Billing Inquiries	2,370	13	99.5%	$650	1,761	4	99.8%	$200
CG6	Respond to Meter Problems	126	1	99.2%	$50	93	0	100.0%	$0
CG7	Notification of Planned Interruptions	14,352	11	99.9%	$550	8,405	11	99.9%	$600
CG8	Power Quality Complaints	17	0	100.0%	$0	309	0	100.0%	$0
		631,683	**89**	**99.98%**	**$5,575**	**406,843**	**60**	**99.99%**	**$3,750**

Summary analysis:

General Comments: Recent internal audits have demonstrated that certain program steps have been missed and procedures not followed to the letter. The end result has been a notable increase in the number of failures paid during the quarter as we took another look at completed work. We are developing a corrective action plan which will include additional training and program oversight, as well as targeted internal communications. Even with the increased failures, PacifiCorp's success rate continues to portray the company's premium level of customer service.

CG1 - Restoring Supply: The increase in event counts is primarily due to the number of severe storms.

CG5 - Billing Inquiries: Failures have increased due to increased events and the continuing implementation of new systems and procedures.

CG8 - Power Quality Complaints: Events have been reduced significantly due to process refinement efforts and training efforts to help employees better understand the definition of this guarantee.

Excludes major events

Utah - Failures and Events

1st Quarter - Fiscal Year 2003
April-June 2002

Filter the table by District and/or Guarantee to see individual District performance or Guarantee performance

			1st Qtr			
District	CG	Description	Failures	Events	Paid	Success
American Fork	CG1	Restoring Supply		12,560		100.0%
American Fork	CG2.3	CG3 Appointments		40		100.0%
American Fork	CG2.4	CG4 Appointments		103		100.0%
American Fork	CG2.5	CG5 Appointments		2		100.0%
American Fork	CG2a	All Other RCMS Appointmts	2	186	$100	98.9%
American Fork	CG3	Switching on Power		817		100.0%
American Fork	CG4a	Contact Customer - 2 days	5	122	$250	95.9%
American Fork	CG4b	5-day, Non-Net / Ballpark		11		100.0%
American Fork	CG4c	15-days, Network Changes	6	65	$300	90.8%
American Fork	CG5	Respond to Bill Inquiries	1	32	$50	96.9%
American Fork	CG6	Respond to Meter Problems		2		100.0%
American Fork	CG7	Planned Interruptions	3	581	$150	99.5%
Cedar City	CG1	Restoring Supply		14,131		100.0%
Cedar City	CG2.3	CG3 Appointments		41		100.0%
Cedar City	CG2.4	CG4 Appointments		81		100.0%
Cedar City	CG2.5	CG5 Appointments		2		100.0%
Cedar City	CG2a	All Other RCMS Appointmts		13		100.0%
Cedar City	CG3	Switching on Power		309		100.0%
Cedar City	CG4a	Contact Customer - 2 days	3	135	$150	97.8%
Cedar City	CG4b	5-day, Non-Net / Ballpark		67		100.0%
Cedar City	CG4c	15-days, Network Changes	1	72	$50	98.6%
Cedar City	CG5	Respond to Bill Inquiries		28		100.0%
Cedar City	CG7	Planned Interruptions		49		100.0%
Jordan Valley	CG1	Restoring Supply		74,830		100.0%
Jordan Valley	CG2.3	CG3 Appointments		68		100.0%
Jordan Valley	CG2.4	CG4 Appointments		55		100.0%
Jordan Valley	CG2.5	CG5 Appointments	1	10	$50	90.0%
Jordan Valley	CG2a	All Other RCMS Appointmts		84		100.0%
Jordan Valley	CG3	Switching on Power	2	1,764	$225	99.9%
Jordan Valley	CG4a	Contact Customer - 2 days	4	147	$200	97.3%
Jordan Valley	CG4b	5-day, Non-Net / Ballpark		52		100.0%

Excludes major events

Utah - Failures and Events

1st Quarter - Fiscal Year 2003
April-June 2002

Filter the table by District and/or Guarantee to see individual District performance or Guarantee performance

			1st Qtr			
District	CG	Description	Failures	Events	Paid	Success
Jordan Valley	CG4c	15-days, Network Changes	2	61	$100	96.7%
Jordan Valley	CG5	Respond to Bill Inquiries	2	93	$100	97.8%
Jordan Valley	CG6	Respond to Meter Problems		1		100.0%
Jordan Valley	CG7	Planned Interruptions	1	2,826	$50	100.0%
Laketown/Woodruff	CG2.3	CG3 Appointments		1		100.0%
Laketown/Woodruff	CG2.4	CG4 Appointments		15		100.0%
Laketown/Woodruff	CG3	Switching on Power		35		100.0%
Laketown/Woodruff	CG4a	Contact Customer - 2 days		17		100.0%
Laketown/Woodruff	CG4b	5-day, Non-Net / Ballpark		5		100.0%
Laketown/Woodruff	CG4c	15-days, Network Changes		9		100.0%
Laketown/Woodruff	CG5	Respond to Bill Inquiries		6		100.0%
Layton	CG1	Restoring Supply		61,917		100.0%
Layton	CG2.3	CG3 Appointments		7		100.0%
Layton	CG2.4	CG4 Appointments		15		100.0%
Layton	CG2a	All Other RCMS Appointmts		19		100.0%
Layton	CG3	Switching on Power		252		100.0%
Layton	CG4a	Contact Customer - 2 days		27		100.0%
Layton	CG4b	5-day, Non-Net / Ballpark		13		100.0%
Layton	CG4c	15-days, Network Changes		16		100.0%
Layton	CG5	Respond to Bill Inquiries		21		100.0%
Layton	CG7	Planned Interruptions	1	596	$50	99.8%
Moab	CG1	Restoring Supply		7,552		100.0%
Moab	CG2.3	CG3 Appointments		2		100.0%
Moab	CG2.4	CG4 Appointments	1	22	$50	95.5%
Moab	CG2.5	CG5 Appointments		1		100.0%
Moab	CG2a	All Other RCMS Appointmts		11		100.0%
Moab	CG3	Switching on Power		106		100.0%
Moab	CG4a	Contact Customer - 2 days	2	32	$100	93.8%
Moab	CG4b	5-day, Non-Net / Ballpark		8		100.0%
Moab	CG4c	15-days, Network Changes		18		100.0%
Moab	CG5	Respond to Bill Inquiries		12		100.0%

Excludes major events

Utah - Failures and Events

1st Quarter - Fiscal Year 2003
April-June 2002

Filter the table by District and/or Guarantee to see individual District performance or Guarantee performance

			1st Qtr			
District	CG	Description	Failures	Events	Paid	Success
Ogden	CG1	Restoring Supply		201,879		100.0%
Ogden	CG2.3	CG3 Appointments		138		100.0%
Ogden	CG2.4	CG4 Appointments		59		100.0%
Ogden	CG2.5	CG5 Appointments		3		100.0%
Ogden	CG2.6	CG6 Appointments		1		100.0%
Ogden	CG2a	All Other RCMS Appointmts	2	75	$100	97.3%
Ogden	CG3	Switching on Power	1	823	$50	99.9%
Ogden	CG4a	Contact Customer - 2 days		95		100.0%
Ogden	CG4b	5-day, Non-Net / Ballpark		18		100.0%
Ogden	CG4c	15-days, Network Changes	1	53	$50	98.1%
Ogden	CG5	Respond to Bill Inquiries		78		100.0%
Ogden	CG7	Planned Interruptions	4	6,796	$200	99.9%
Park City	CG1	Restoring Supply		9,689		100.0%
Park City	CG2.3	CG3 Appointments		7		100.0%
Park City	CG2.4	CG4 Appointments		48		100.0%
Park City	CG2a	All Other RCMS Appointmts		11		100.0%
Park City	CG3	Switching on Power		136		100.0%
Park City	CG4a	Contact Customer - 2 days		70		100.0%
Park City	CG4b	5-day, Non-Net / Ballpark		9		100.0%
Park City	CG4c	15-days, Network Changes		39		100.0%
Park City	CG5	Respond to Bill Inquiries	2	29	$100	93.1%
Park City	CG6	Respond to Meter Problems		1		100.0%
Park City	CG7	Planned Interruptions		1,219		100.0%
Price	CG1	Restoring Supply		10,392		100.0%
Price	CG2.3	CG3 Appointments		15		100.0%
Price	CG2.4	CG4 Appointments		38		100.0%
Price	CG2a	All Other RCMS Appointmts		6		100.0%
Price	CG3	Switching on Power	1	60	$100	98.3%
Price	CG4a	Contact Customer - 2 days		38		100.0%
Price	CG4b	5-day, Non-Net / Ballpark		15		100.0%
Price	CG4c	15-days, Network Changes		32		100.0%

Excludes major events

Utah - Failures and Events

1st Quarter - Fiscal Year 2003
April-June 2002

Filter the table by District and/or Guarantee to see individual District performance or Guarantee performance

			1st Qtr			
District	CG	Description	Failures	Events	Paid	Success
Price	CG5	Respond to Bill Inquiries		6		100.0%
Price	CG7	Planned Interruptions	1	33	$50	97.0%
Richfield	CG1	Restoring Supply		12,716		100.0%
Richfield	CG2.3	CG3 Appointments		9		100.0%
Richfield	CG2.4	CG4 Appointments	2	49	$100	95.9%
Richfield	CG2a	All Other RCMS Appointmts		14		100.0%
Richfield	CG3	Switching on Power	1	150	$50	99.3%
Richfield	CG4a	Contact Customer - 2 days	9	80	$450	88.8%
Richfield	CG4b	5-day, Non-Net / Ballpark		27		100.0%
Richfield	CG4c	15-days, Network Changes	2	43	$100	95.3%
Richfield	CG5	Respond to Bill Inquiries	2	11	$100	81.8%
Richfield	CG6	Respond to Meter Problems	1	1	$50	0.0%
SLC Metro	CG1	Restoring Supply	1	121,276	$375	100.0%
SLC Metro	CG2.3	CG3 Appointments		123		100.0%
SLC Metro	CG2.4	CG4 Appointments		56		100.0%
SLC Metro	CG2.5	CG5 Appointments		1		100.0%
SLC Metro	CG2a	All Other RCMS Appointmts		102		100.0%
SLC Metro	CG3	Switching on Power	7	2,818	$800	99.8%
SLC Metro	CG4a	Contact Customer - 2 days		119		100.0%
SLC Metro	CG4b	5-day, Non-Net / Ballpark		49		100.0%
SLC Metro	CG4c	15-days, Network Changes		43		100.0%
SLC Metro	CG5	Respond to Bill Inquiries	4	139	$200	97.1%
SLC Metro	CG7	Planned Interruptions	1	2,172	$50	100.0%
Smithfield	CG1	Restoring Supply		22,726		100.0%
Smithfield	CG2.3	CG3 Appointments		16		100.0%
Smithfield	CG2.4	CG4 Appointments		27		100.0%
Smithfield	CG2.5	CG5 Appointments		1		100.0%
Smithfield	CG2a	All Other RCMS Appointmts	1	14	$50	92.9%
Smithfield	CG3	Switching on Power	1	134	$75	99.3%
Smithfield	CG4a	Contact Customer - 2 days	1	74	$50	98.6%
Smithfield	CG4b	5-day, Non-Net / Ballpark		18		100.0%

Excludes major events

Utah - Failures and Events

1st Quarter - Fiscal Year 2003
April-June 2002

Filter the table by District and/or Guarantee to see individual District performance or Guarantee performance

			1st Qtr			
District	CG	Description	Failures	Events	Paid	Success
Smithfield	CG4c	15-days, Network Changes		30		100.0%
Smithfield	CG5	Respond to Bill Inquiries	1	15	$50	93.3%
Smithfield	CG7	Planned Interruptions		39		100.0%
Tooele	CG1	Restoring Supply		33,560		100.0%
Tooele	CG2.3	CG3 Appointments	1	9	$50	88.9%
Tooele	CG2.4	CG4 Appointments		26		100.0%
Tooele	CG2a	All Other RCMS Appointmts	1	28	$50	96.4%
Tooele	CG3	Switching on Power	1	228	$200	99.6%
Tooele	CG4a	Contact Customer - 2 days		58		100.0%
Tooele	CG4b	5-day, Non-Net / Ballpark		22		100.0%
Tooele	CG4c	15-days, Network Changes		28		100.0%
Tooele	CG5	Respond to Bill Inquiries		6		100.0%
Tooele	CG7	Planned Interruptions		41		100.0%
Tremonton	CG1	Restoring Supply		18,260		100.0%
Tremonton	CG2.3	CG3 Appointments		2		100.0%
Tremonton	CG2.4	CG4 Appointments		31		100.0%
Tremonton	CG2a	All Other RCMS Appointmts		10		100.0%
Tremonton	CG3	Switching on Power		40		100.0%
Tremonton	CG4a	Contact Customer - 2 days	1	34	$50	97.1%
Tremonton	CG4b	5-day, Non-Net / Ballpark		5		100.0%
Tremonton	CG4c	15-days, Network Changes	1	23	$50	95.7%
Tremonton	CG5	Respond to Bill Inquiries	1	3	$50	66.7%
Vernal	CG1	Restoring Supply		1,843		100.0%
Vernal	CG2.3	CG3 Appointments		14		100.0%
Vernal	CG2.4	CG4 Appointments		28		100.0%
Vernal	CG2.5	CG5 Appointments		1		100.0%
Vernal	CG3	Switching on Power		107		100.0%
Vernal	CG4a	Contact Customer - 2 days		30		100.0%
Vernal	CG4b	5-day, Non-Net / Ballpark		9		100.0%
Vernal	CG4c	15-days, Network Changes		19		100.0%
Vernal	CG5	Respond to Bill Inquiries		8		100.0%

Excludes major events

Utah - Failures and Events

1st Quarter - Fiscal Year 2003
April-June 2002

Filter the table by District and/or Guarantee to see individual District performance or Guarantee performance

			1st Qtr			
District	**CG**	**Description**	**Failures**	**Events**	**Paid**	**Success**
Wasatch Collection Center	CG4a	Contact Customer - 2 days		1		100.0%
Wasatch Collection Center	CG5	Respond to Bill Inquiries		1,883		100.0%
Wasatch Collection Center	CG6	Respond to Meter Problems		121		100.0%
Wasatch Collection Center	CG8a	Respond in 5 days		7		100.0%
Wasatch Collection Center	CG8b	Respond in 7 days		10		100.0%
			89	**631,673**	**$5,575**	**100.0%**

Excludes major events

Utah - Outage Restoration Performance

1st Quarter - Fiscal Year 2003
April-June 2002

District	# Customers Interrupted > 5 minutes 1st Qtr	% Restored Within 3 hours 1st Qtr
American Fork	12,560	86%
Cedar City [1]	14,131	75%
Jordan Valley	74,830	85%
Layton	61,917	90%
Moab	7,552	93%
Ogden	201,879	95%
Park City	9,689	88%
Price	10,392	96%
Richfield	12,716	83%
SLC Metro [2]	121,276	74%
Smithfield [2]	22,726	75%
Tooele	33,560	98%
Tremonton	18,260	95%
Vernal	1,843	96%
All Districts	603,331	

[1] Performance in the Cedar City area was low due to large coverage areas and one outage requiring a circuit breaker replacement in a substation.

[2] The Smithfield and SLC Metro districts were heavily impacted by the June 1-2 storm where a significant number of individual outages affected performance.

UTAH RESIDENTIAL/SMALL COMMERCIAL METER SETS - REPORT BY DISTRICT

FISCAL YEAR TO DATE - 1ST QUARTER 2003

NORTHERN UTAH

LOCATION	April 2002			May 2002			June 2002			FYD - 1st Quarter			Notes
	Within 5 Days	%	Total	Within 5 Days	%	Total	Within 5 Days	%	Total	Total Within 5 Days	1st Quarter %	Total	
Jordan Valley	334	99%	336	327	99%	331	394	100%	395	1055	99%	1062	
Layton/Davis				157	99%	158	143	100%	143	300	100%	301	
Metro	165	98%	168	168	99%	169	243	100%	243	576	99%	580	
Ogden	145	99%	146	235	100%	235	237	100%	237	617	100%	618	
Park City	46	98%	47	54	93%	58	45	68%	66	145	85%	171	
Smithfield	32	91%	35	39	98%	40	41	98%	42	112	96%	117	
Tooele	46	96%	48	46	98%	47	70	99%	71	162	98%	166	
Tremonton	8	100%	8	6	86%	7	6	100%	6	20	95%	21	
TOTAL	776	98%	788	1032	99%	1045	1179	98%	1203	2987	98%	3036	

SOUTHERN UTAH

LOCATION	April 2002			May 2002			June 2002			FYD - 1st Quarter			Notes
	Within 5 days	%	Total	Within 5 days	%	Total	Within 5 days	%	Total	Total Within 5 Days	1st Quarter %	Total	
American Fork	137	99%	139	106	98%	108	152	99%	154	395	99%	401	
Cedar City	46	90%	51	87	99%	88	63	93%	68	196	95%	207	
Moab	18	100%	18	32	100%	32	49	100%	49	99	100%	99	
Price	9	100%	9	12	100%	12	15	100%	15	36	100%	36	
Richfield	32	94%	34	22	92%	24	40	98%	41	94	95%	99	
Vernal	18	100%	18	21	100%	21	12	100%	12	51	100%	51	
TOTAL	260	97%	269	280	98%	285	331	98%	339	871	98%	893	

TOTAL UTAH

LOCATION	APRIL			MAY			JUNE			FYD - 1st Quarter			Notes
	Within 5 days	%	Total	Within 5 days	%	Total	Within 5 days	%	Total	Total Within 5 Days	1st Quarter %	Total	
TOTAL UTAH	1036	98%	1057	1312	99%	1330	1510	98%	1542	3858	98%	3929	

UTAH TEMPORARY METER SETS - REPORT BY DISTRICT

FISCAL YEAR TO DATE - 1st QUARTER 2003

NORTHERN UTAH

LOCATION	April 2002			May 2002			June 2002			FYD - 1st Quarter			Notes
	Within 10 Days	%	Total	Within 10 Days	%	Total	Within 10 Days	%	Total	Total Within 10 Days	1st Quarter %	Total	
Jordan Valley	208	100%	208	221	98%	226	187	100%	187	616	99%	621	
Layton/Davis				170	100%	170	127	99%	128	297	100%	298	
Metro	72	100%	72	92	100%	92	76	100%	76	240	100%	240	
Ogden	100	100%	100	103	100%	103	93	100%	93	296	100%	296	
Park City	20	100%	20	41	100%	41	42	95%	44	103	98%	105	
Smithfield	24	96%	25	24	96%	25	31	100%	31	79	98%	81	
Tooele	39	100%	39	32	100%	32	52	100%	52	123	100%	123	
Tremonton	9	100%	9	5	100%	5	5	100%	5	19	100%	19	
TOTAL	472	100%	473	688	99%	694	613	100%	616	1773	99%	1783	

SOUTHERN UTAH

LOCATION	April 2002			May 2002			June 2002			FYD - 1st Quarter			Notes
	Within 10 days	%	Total	Within 10 days	%	Total	Within 10 days	%	Total	Total Within 10 Days	1st Quarter %	Total	
American Fork	107	100%	107	99	98%	101	113	100%	113	319	99%	321	
Cedar City	50	100%	50	40	100%	40	47	100%	47	137	100%	137	
Moab	0	-	0	1	100%	1	2	100%	2	3	100%	3	
Price	0	-	0	2	100%	2	2	100%	2	4	100%	4	
Richfield	6	100%	6	4	100%	4	12	100%	12	22	100%	22	
Vernal	5	100%	5	4	100%	4	8	100%	8	17	100%	17	
TOTAL	168	100%	168	150	99%	152	184	100%	184	502	100%	504	

TOTAL UTAH

LOCATION	APRIL			MAY			JUNE			FYD - 1st Quarter			Notes
	Within 10 days	%	Total	Within 10 days	%	Total	Within 10 days	%	Total	Total Within 10 Days	1st Quarter %	Total	
TOTAL UTAH	640	100%	641	838	99%	846	797	100%	800	2275	99%	2287	

Operating Area Naming Changes for Outage Reporting 19-Sep-02

Utah

Previous	***New***
SOUTH VALLEY	JORDAN VALLEY
CANYONLANDS	MOAB
CARBON	PRICE
DELTA	RICHFIELD (DELTA)
SALINA	RICHFIELD (SALINA)
METRO	SLC METRO
UINTA	*removed*
ASHLEY	VERNAL

Note: These name changes apply only to the detail report by district and brings that report more in line with the other district level reports.

1ST Quarter Fiscal Year 2003 04/01/2002 to 06/30/2002

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off	Number of Occurrences	Customer Minutes Lost	Customers in Incident Momentary	Customers in Incident Momentary Eve	MC 33 Customers Exceeding State SAIFI	MC 38 Customers Affected by Transmission
Unplanned	Utah			98.678	0.878	0.126	0.098	112.356	686,759	603,152	2,848	67,768,000	86,694	67,339		
Planned	Utah			3.688	0.021	0.000	0.000	176.484	686,759	14,352	270	2,532,898	117	117		
Customer Requested	Utah			0.009	0.000	0.000	0.000	59.407	686,759	108	3	6,416	0	0		
Unplanned	AMERICAN FORK			21.961	0.211	0.031	0.031	104	58,283	12,560	183	1,307,476	1,874.000	1874	2560	0
Planned	AMERICAN FORK			1.137	0.010	0.000	0.000	116.482	58,283	581	7	67,676	18	18		
Customer Requested	AMERICAN FORK			0.001	0.000	0.000	0.000	61	58,283	1	1	61	0.000	0		
High SAIDI	AMERICAN FORK	SAN12	SANTAQUIN #12	97.508	0.853	0.000	0.000	114.316	1,850	1,578	14	180,390	0	0		
Low SAIDI	AMERICAN FORK	24	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0		
High SAIFI	AMERICAN FORK	WAL12	WALLSBURG #12	573.963	6.107	1.000	1.000	94	187	1,142	8	107,331	187.000	187		
Low SAIFI	AMERICAN FORK	24	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High MAIFI	AMERICAN FORK	SAR11	SARATOGA #11	1.919	0.028	1.278	1.278	68	284	8	6	545	363.000	363		
Low MAIFI	AMERICAN FORK	62	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High MAIFI(e)	AMERICAN FORK	SAR11	SARATOGA #11	1.919	0.028	1.278	1.278	68	679	8	6	545	363.000	363		
Low MAIFI(e)	AMERICAN FORK	62	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0		
High Customer Minutes Lost	AMERICAN FORK	AMF12	AMERICAN FORK #12	0.919	0.004	0.000	0.000	249	1,373	4	4	995	0.000	0		
Low Customer Minutes Lost	AMERICAN FORK	22	***** Circuits with a Low Customer Minutes Los	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0		
Unplanned	CEDAR CITY			28.275	0.365	0.015	0.015	77	22,518	8,810	74	681,913	351.000	351	790	0
Planned	CEDAR CITY			0.451	0.002	0.000	0.000	222	22,518	49	4	10,876	0.000	0		
Customer Requested	CEDAR CITY			0.007	0.000	0.000	0.000	173	22,518	1	1	173	0.000	0		
High SAIDI	CEDAR CITY	MDD25	MIDDLETON #25	78.448	0.621	0.000	0.000	126	29	18	4	2,275	0.000	0		
Low SAIDI	CEDAR CITY	41	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High SAIFI	CEDAR CITY	TOQ32	TOQUERVILLE #32	718.147	8.988	0.000	0.000	79.899	170	1,528	6	122,085	0	0		
Low SAIFI	CEDAR CITY	41	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High MAIFI	CEDAR CITY	ENV11	ENTERPRISE #11	0.138	0.007	2.543	2.543	19	138	1	1	19	351.000	351		
Low MAIFI	CEDAR CITY	60	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High MAIFI(e)	CEDAR CITY	ENV11	ENTERPRISE #11	0.138	0.007	2.543	2.543	19	679	1	1	19	351.000	351		
Low MAIFI(e)	CEDAR CITY	60	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High Customer Minutes Lost	CEDAR CITY	CLM12	COLEMAN #12	38.938	0.816	0.000	0.000	48	2,355	1,921	8	91,700	0.000	0		
Low Customer Minutes Lost	CEDAR CITY	37	***** Circuits with a Low Customer Minutes Los	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0		
Unplanned	CEDAR CITY (MILFORD)			753.642	2.416	0.000	0.000	311.998	2,148	5,319	44	1,659,520	0	0	2,110	0
Planned	CEDAR CITY (MILFORD)			0.000	0.000	0.000	0.000	0	2,148	0	0	0	0.000	0		
Customer Requested	CEDAR CITY (MILFORD)			0.000	0.000	0.000	0.000	0	2,148	0	0	0	0.000	0		
High SAIDI	CEDAR CITY (MILFORD)	MNV11	MINERSVILLE #11	802.374	3.119	0.000	0.000	257	345	1,076	5	276,819	0.000	0		
Low SAIDI	CEDAR CITY (MILFORD)	5	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High SAIFI	CEDAR CITY (MILFORD)	BKL12	BROOKLAWN #12	1,351.807	4.007	0.000	0.000	337	140	561	5	189,253	0.000	0		
Low SAIFI	CEDAR CITY (MILFORD)	5	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High MAIFI	CEDAR CITY (MILFORD)	16	***** Circuits with a High MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
Low MAIFI	CEDAR CITY (MILFORD)	16	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High MAIFI(e)	CEDAR CITY (MILFORD)	16	***** Circuits with a High MAIFI(e) of 0.0000 ***	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
Low MAIFI(e)	CEDAR CITY (MILFORD)	16	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High Customer Minutes Lost	CEDAR CITY (MILFORD)	MLF13	MILFORD #13	335.389	1.071	0.000	0.000	313	280	300	7	93,909	0.000	0		
Low Customer Minutes Lost	CEDAR CITY (MILFORD)	5	***** Circuits with a Low Customer Minutes Los	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
Unplanned	JORDAN VALLEY			64.989	0.421	0.026	0.025	154	173,773	74,830	536	11,551,284	4,552.000	4454	25875	0
Planned	JORDAN VALLEY			0.707	0.016	0.000	0.000	44	173,773	2,826	44	125,752	0.000	0		
Customer Requested	JORDAN VALLEY			0.000	0.000	0.000	0.000	0.000	173,773	0	0	0	0	0		
High SAIDI	JORDAN VALLEY	CAS11	CASTO #11	98.255	1.158	0.000	0.000	85	1,805	2,090	20	177,350	0.000	0		
Low SAIDI	JORDAN VALLEY	45	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High SAIFI	JORDAN VALLEY	BLF11	BLUFFDALE #11	662.642	9.069	0.945	0.945	73	433	3,927	4	286,924	409.000	409		
Low SAIFI	JORDAN VALLEY	45	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High MAIFI	JORDAN VALLEY	DUM16	DUMAS #16	780.278	22.886	6.335	6.335	34	158	3,616	2	123,284	1,001.000	1001		
Low MAIFI	JORDAN VALLEY	104	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0		
High MAIFI(e)	JORDAN VALLEY	DUM16	DUMAS #16	780.278	22.886	6.335	6.335	34	679	3,616	2	123,284	1,001.000	1001		
Low MAIFI(e)	JORDAN VALLEY	104	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High Customer Minutes Lost	JORDAN VALLEY	BTL12	BUTLERVILLE #12	38.001	0.108	0.000	0.000	353.327	2,529	272	8	96,105	0	0		
Low Customer Minutes Lost	JORDAN VALLEY	31	***** Circuits with a Low Customer Minutes Los	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
Unplanned	LAYTON			139.090	1.319	0.068	0.068	105	46,947	61,917	181	6,530,696	3,170.000	3170	22540	0
Planned	LAYTON			0.455	0.013	0.000	0.000	36	46,947	596	7	21,365	0.000	0		
Customer Requested	LAYTON			0.000	0.000	0.000	0.000	0.000	46,947	0	0	0	0	0		

1ST Quarter **Fiscal Year 2003** **04/01/2002 to 06/30/2002**

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off	Number of Occurrences	Customer Minutes Lost	Customers in Incident Momentary	Customers in Incident Momentary Eve	MC 33 Customers Exceeding State SAIFI	MC 38 Customers Affected by Transmission
High SAIDI	LAYTON	LAY16	LAYTON #16	92.017	0.797	0.000	0.000	115	1,935	1,542	9	178,053	0.000	0		
Low SAIDI	LAYTON	9	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High SAIFI	LAYTON	ANG12	ANGEL #12	367.715	6.222	0.000	0.000	59	1,075	6,689	6	395,294	0.000	0		
Low SAIFI	LAYTON	9	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High MAIFI	LAYTON	ELA12	EAST LAYTON #12	113.972	1.632	1.282	1.282	70	2,473	4,037	15	281,853	3,170.000	3170		
Low MAIFI	LAYTON	32	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High MAIFI(e)	LAYTON	ELA12	EAST LAYTON #12	113.972	1.632	1.282	1.282	70	679	4,037	15	281,853	3,170.000	3170		
Low MAIFI(e)	LAYTON	32	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High Customer Minutes Lost	LAYTON	LAY13	LAYTON #13	6.109	0.063	0.000	0.000	97	1,564	99	3	9,555	0.000	0		
Low Customer Minutes Lost	LAYTON	4	***** Circuits with a Low Customer Minutes Los	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
Unplanned	MOAB			46.431	0.697	0.000	0.000	67	9,936	7,552	59	503,084	0.000	0	5215	0
Planned	MOAB			0.000	0.000	0.000	0.000	0.000	9,936	0	0	0	0	0		
Customer Requested	MOAB			0.000	0.000	0.000	0.000	0	9,936	0	0	0	0.000	0		
High SAIDI	MOAB	SVN11	SEVEN MILE #11	912.029	5.000	0.000	0.000	182	35	175	5	31,921	0.000	0		
Low SAIDI	MOAB	17	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High SAIFI	MOAB	SVN11	SEVEN MILE #11	912.029	5.000	0.000	0.000	182.406	35	175	5	31,921	0	0		
Low SAIFI	MOAB	17	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High MAIFI	MOAB	34	***** Circuits with a High MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
Low MAIFI	MOAB	34	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High MAIFI(e)	MOAB	34	***** Circuits with a High MAIFI(e) of 0.0000 ***	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
Low MAIFI(e)	MOAB	34	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0		
High Customer Minutes Lost	MOAB	SPA12	SPANISH VALLEY #12	23.673	0.933	0.000	0.000	25	388	362	2	9,185	0.000	0		
Low Customer Minutes Lost	MOAB	17	***** Circuits with a Low Customer Minutes Los	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
Unplanned	OGDEN			198.156	2.279	0.353	0.349	86.955	87,448	201,879	486	17,554,406	31,256	30,890	50,457	0
Planned	OGDEN			20.080	0.077	0.001	0.001	262	87,448	6,796	136	1,778,888	52.000	52		
Customer Requested	OGDEN			0.000	0.000	0.000	0.000	0	87,448	0	0	0	0.000	0		
High SAIDI	OGDEN	PIO13	PIONEER #13	95.452	0.697	0.000	0.000	136.887	1,001	698	4	95,547	0	0		
Low SAIDI	OGDEN	25	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High SAIFI	OGDEN	NEW12	NEWGATE #12	1,058.108	9.495	0.000	0.000	111	186	1,766	3	196,808	0.000	0		
Low SAIFI	OGDEN	25	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High MAIFI	OGDEN	WCO11	WEST COMMERCIAL #11	1,423.708	27.876	5.664	5.664	51	137	3,819	5	195,048	776.000	776		
Low MAIFI	OGDEN	74	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0		
High MAIFI(e)	OGDEN	WCO11	WEST COMMERCIAL #11	1,423.708	27.876	5.664	5.664	51	679	3,819	5	195,048	776.000	776		
Low MAIFI(e)	OGDEN	74	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High Customer Minutes Lost	OGDEN	BOX12	BOX ELDER #12	624.639	4.069	0.000	0.000	153	1,570	6,389	12	980,683	0.000	0		
Low Customer Minutes Lost	OGDEN	16	***** Circuits with a Low Customer Minutes Los	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0		
Unplanned	PARK CITY			42.095	0.429	0.002	0.002	98	22,275	9,688	90	951,311	36.000	36	4318	0
Planned	PARK CITY			1.495	0.054	0.002	0.002	28	22,275	1,219	4	33,785	37.000	37		
Customer Requested	PARK CITY			0.000	0.000	0.000	0.000	0.000	22,275	0	0	0	0	0		
High SAIDI	PARK CITY	THF22	THIEF CREEK #22	9.029	0.088	0.000	0.000	102.333	68	6	4	614	0	0		
Low SAIDI	PARK CITY	13	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0		
High SAIFI	PARK CITY	HEN11	HENEFER #11	135.106	1.976	0.000	0.000	68	451	891	5	60,933	0.000	0		
Low SAIFI	PARK CITY	13	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High MAIFI	PARK CITY	COA21	COALVILLE #21	0.481	0.007	0.148	0.148	65	135	1	1	65	20.000	20		
Low MAIFI	PARK CITY	32	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High MAIFI(e)	PARK CITY	COA21	COALVILLE #21	0.481	0.007	0.148	0.148	65	679	1	1	65	20.000	20		
Low MAIFI(e)	PARK CITY	32	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0		
High Customer Minutes Lost	PARK CITY	PKC11	PARK CITY #11	0.657	0.007	0.000	0.000	93	1,417	10	2	931	0.000	0		
Low Customer Minutes Lost	PARK CITY	11	***** Circuits with a Low Customer Minutes Los	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0		
Unplanned	PRICE			69.854	1.125	0.001	0.001	62	9,118	10,392	60	645,315	5.000	5	4983	0
Planned	PRICE			0.383	0.004	0.000	0.000	107	9,118	33	4	3,537	0.000	0		
Customer Requested	PRICE			0.669	0.011	0.000	0.000	58.321	9,118	106	1	6,182	0	0		
High SAIDI	PRICE	MOO12	MOORE #12	99.111	1.000	0.000	0.000	99	18	18	1	1,784	0.000	0		
Low SAIDI	PRICE	28	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0		
High SAIFI	PRICE	MAT11	MATHIS #11	175.460	4.227	0.000	0.000	42	963	4,071	12	168,968	0.000	0		
Low SAIFI	PRICE	28	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High MAIFI	PRICE	ORN12	ORANGEVILLE #12	2.120	0.008	0.010	0.010	278	525	4	2	1,113	5.000	5		
Low MAIFI	PRICE	41	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High MAIFI(e)	PRICE	ORN12	ORANGEVILLE #12	2.120	0.008	0.010	0.010	278	679	4	2	1,113	5.000	5		

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Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off	Number of Occurrences	Customer Minutes Lost	Customers in Incident Momentary	Customers in Incident Momentary Eve	MC 33 Customers Exceeding State SAIFI	MC 38 Customers Affected by Transmission
Low MAIFI(e)	PRICE	41	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High Customer Minutes Lost	PRICE	HPM11	HELPER MARTIN #11	1.329	0.011	0.000	0.000	125.857	663	7	3	881	0	0		
Low Customer Minutes Lost	PRICE	27	***** Circuits with a Low Customer Minutes Los	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
Unplanned	RICHFIELD			100.189	0.740	0.042	0.042	135.351	12,405	10,605	88	1,435,401	598	598	8,363	0
Planned	RICHFIELD			0.000	0.000	0.000	0.000	0	12,405	0	0	0	0.000	0		
Customer Requested	RICHFIELD			0.000	0.000	0.000	0.000	0.000	12,405	0	0	0	0	0		
High SAIDI	RICHFIELD	GUN12	GUNNISON #12	91.231	1.502	0.000	0.000	61	649	975	6	59,209	0.000	0		
Low SAIDI	RICHFIELD	14	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High SAIFI	RICHFIELD	SCI11	SCIPIO #11	428.601	2.000	0.000	0.000	214.301	178	356	2	76,291	0	0		
Low SAIFI	RICHFIELD	14	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High MAIFI	RICHFIELD	ELS11	ELSINORE #11	122.305	1.002	0.990	0.990	122.102	604	605	4	73,872	598	598		
Low MAIFI	RICHFIELD	43	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0		
High MAIFI(e)	RICHFIELD	ELS11	ELSINORE #11	122.305	1.002	0.990	0.990	122	679	605	4	73,872	598.000	598		
Low MAIFI(e)	RICHFIELD	43	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High Customer Minutes Lost	RICHFIELD	FTG12	FOUNTAIN GREEN #12	588.970	0.994	0.000	0.000	593	165	164	2	97,180	0.000	0		
Low Customer Minutes Lost	RICHFIELD	14	***** Circuits with a Low Customer Minutes Los	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
Unplanned	RICHFIELD (DELTA)			54.433	0.398	0.001	0.001	136.663	3,158	2,111	31	288,496	3	3	1,025	0
Planned	RICHFIELD (DELTA)			0.000	0.000	0.000	0.000	0	3,158	0	0	0	0.000	0		
Customer Requested	RICHFIELD (DELTA)			0.000	0.000	0.000	0.000	0	3,158	0	0	0	0.000	0		
High SAIDI	RICHFIELD (DELTA)	MDW11	MEADOW #11	49.167	0.333	0.000	0.000	148	6	2	2	295	0.000	0		
Low SAIDI	RICHFIELD (DELTA)	5	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0		
High SAIFI	RICHFIELD (DELTA)	STH21	SUTHERLAND #21	317.652	3.438	0.007	0.007	92	422	1,451	14	134,049	3.000	3		
Low SAIFI	RICHFIELD (DELTA)	5	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High MAIFI	RICHFIELD (DELTA)	STH21	SUTHERLAND #21	317.652	3.438	0.007	0.007	92	422	1,451	14	134,049	3.000	3		
Low MAIFI	RICHFIELD (DELTA)	14	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0		
High MAIFI(e)	RICHFIELD (DELTA)	STH21	SUTHERLAND #21	317.652	3.438	0.007	0.007	92	679	1,451	14	134,049	3.000	3		
Low MAIFI(e)	RICHFIELD (DELTA)	14	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High Customer Minutes Lost	RICHFIELD (DELTA)	LYN11	LYNNDYL #11	377.717	0.969	0.000	0.000	390	191	185	2	72,144	0.000	0		
Low Customer Minutes Lost	RICHFIELD (DELTA)	5	***** Circuits with a Low Customer Minutes Los	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
Unplanned	SLC METRO			96.492	0.626	0.085	0.085	154	191,843	121,276	699	18,680,188	16,438.000	16438	37557	0
Planned	SLC METRO			2.483	0.011	0.000	0.000	221.328	191,843	2,172	58	480,725	0	0		
Customer Requested	SLC METRO			0.000	0.000	0.000	0.000	0	191,843	0	0	0	0.000	0		
High SAIDI	SLC METRO	GRO18	GROW #18	95.143	1.000	0.000	0.000	95	7	7	1	666	0.000	0		
Low SAIDI	SLC METRO	120	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0		
High SAIFI	SLC METRO	WDS11	WOODS CROSS #11	1,451.804	6.984	0.815	0.815	208	547	3,820	6	794,137	446.000	446		
Low SAIFI	SLC METRO	120	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High MAIFI	SLC METRO	CAN11	CANNON #11	480.917	5.167	4.917	4.917	93.081	24	124	1	11,542	118	118		
Low MAIFI	SLC METRO	226	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High MAIFI(e)	SLC METRO	CAN11	CANNON #11	480.917	5.167	4.917	4.917	93	679	124	1	11,542	118.000	118		
Low MAIFI(e)	SLC METRO	226	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High Customer Minutes Lost	SLC METRO	EMI11	EMIGRATION #11	32.808	0.460	0.995	0.995	71	3,028	1,393	11	99,342	3,014.000	3014		
Low Customer Minutes Lost	SLC METRO	117	***** Circuits with a Low Customer Minutes Los	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
Unplanned	SMITHFIELD			175.665	1.284	0.019	0.019	137	17,554	22,550	139	3,084,325	330.000	330	11117	0
Planned	SMITHFIELD			0.197	0.002	0.001	0.001	89	17,554	39	3	3,466	10.000	10		
Customer Requested	SMITHFIELD			0.000	0.000	0.000	0.000	0.000	17,554	0	0	0	0	0		
High SAIDI	SMITHFIELD	NIB21	NIBLEY #21	749.684	4.899	0.000	0.000	153	1,916	9,386	35	1,436,395	0.000	0		
Low SAIDI	SMITHFIELD	3	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0		
High SAIFI	SMITHFIELD	NIB21	NIBLEY #21	749.684	4.899	0.000	0.000	153	1,916	9,386	35	1,436,395	0.000	0		
Low SAIFI	SMITHFIELD	3	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High MAIFI	SMITHFIELD	LEW11	LEWISTON #11	284.224	0.756	0.736	0.736	376	402	304	7	114,258	296.000	296		
Low MAIFI	SMITHFIELD	20	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High MAIFI(e)	SMITHFIELD	LEW11	LEWISTON #11	284.224	0.756	0.736	0.736	376	679	304	7	114,258	296.000	296		
Low MAIFI(e)	SMITHFIELD	20	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High Customer Minutes Lost	SMITHFIELD	NOL11	NORTH LOGAN #11	13.064	0.237	0.000	0.000	55	735	174	1	9,602	0.000	0		
Low Customer Minutes Lost	SMITHFIELD	LOG1	LOGAN CANYON CKT#1	0.000	0.000	0.000	0.000	0	1,105	0	0	0	0.000	0		
Unplanned	TOOELE			143.973	2.442	2.008	0.633	59	13,742	33,560	77	1,978,766	27,592.000	8701	4949	0
Planned	TOOELE			0.497	0.003	0.000	0.000	167	13,742	41	3	6,828	0.000	0		
Customer Requested	TOOELE			0.000	0.000	0.000	0.000	0.000	13,742	0	0	0	0	0		
High SAIDI	TOOELE	BLK11	BLACK MOUNTAIN #11	621.579	1.000	0.000	0.000	622	19	19	1	11,810	0.000	0		

1ST Quarter Fiscal Year 2003 04/01/2002 to 06/30/2002

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off	Number of Occurrences	Customer Minutes Lost	Customers in Incident Momentary	Customers in Incident Momentary Eve	MC 33 Customers Exceeding State SAIFI	MC 38 Customers Affected by Transmission
Low SAIDI	TOOELE	12	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High SAIFI	TOOELE	TOO11	TOOELE #11	347.957	6.272	1.000	1.000	55	2,097	13,152	6	729,666	2,097.000	2097		
Low SAIFI	TOOELE	12	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0		
High MAIFI	TOOELE	TOO12	TOOELE #12	41.675	1.416	2.324	1.162	29.433	2,106	2,982	4	87,768	4,894	2,447		
Low MAIFI	TOOELE	21	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High MAIFI(e)	TOOELE	TOO12	TOOELE #12	41.675	1.416	2.324	1.162	29.433	679	2,982	4	87,768	4,894	2,447		
Low MAIFI(e)	TOOELE	21	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0		
High Customer Minutes Lost	TOOELE	TOO12	TOOELE #12	41.675	1.416	2.324	1.162	29	2,106	2,982	4	87,768	4,894.000	2447		
Low Customer Minutes Lost	TOOELE	11	***** Circuits with a Low Customer Minutes Los	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
Unplanned	TREMONTON			102.297	2.438	0.064	0.064	42	7,482	18,260	78	766,103	477.000	477	6543	0
Planned	TREMONTON			0.000	0.000	0.000	0.000	0	7,482	0	0	0	0.000	0		
Customer Requested	TREMONTON			0.000	0.000	0.000	0.000	0	7,482	0	0	0	0.000	0		
High SAIDI	TREMONTON	PRM11	PROMONTORY #11	79.781	2.581	0.000	0.000	31	105	271	9	8,377	0.000	0		
Low SAIDI	TREMONTON	2	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High SAIFI	TREMONTON	BRR11	BEAR RIVER #11	108.687	6.309	0.000	0.000	17.227	854	5,388	5	92,819	0	0		
Low SAIFI	TREMONTON	2	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High MAIFI	TREMONTON	BRR14	BEAR RIVER #14	40.556	1.616	0.979	0.979	25.097	487	787	4	19,751	477	477		
Low MAIFI	TREMONTON	16	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High MAIFI(e)	TREMONTON	BRR14	BEAR RIVER #14	40.556	1.616	0.979	0.979	25	679	787	4	19,751	477.000	477		
Low MAIFI(e)	TREMONTON	16	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High Customer Minutes Lost	TREMONTON	BRR11	BEAR RIVER #11	108.687	6.309	0.000	0.000	17.227	854	5,388	5	92,819	0	0		
Low Customer Minutes Lost	TREMONTON	2	***** Circuits with a Low Customer Minutes Los	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0		
Unplanned	VERNAL			18.408	0.227	0.001	0.001	81	8,127	1,843	23	149,716	12.000	12	1105	0
Planned	VERNAL			0.000	0.000	0.000	0.000	0	8,127	0	0	0	0.000	0		
Customer Requested	VERNAL			0.000	0.000	0.000	0.000	0	8,127	0	0	0	0.000	0		
High SAIDI	VERNAL	MAE12	MAESER #12	63.821	1.024	0.011	0.011	62	1,105	1,131	6	70,522	12.000	12		
Low SAIDI	VERNAL	2	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High SAIFI	VERNAL	MAE12	MAESER #12	63.821	1.024	0.011	0.011	62.354	1,105	1,131	6	70,522	12	12		
Low SAIFI	VERNAL	2	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High MAIFI	VERNAL	MAE12	MAESER #12	63.821	1.024	0.011	0.011	62	1,105	1,131	6	70,522	12.000	12		
Low MAIFI	VERNAL	8	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		
High MAIFI(e)	VERNAL	MAE12	MAESER #12	63.821	1.024	0.011	0.011	62	679	1,131	6	70,522	12.000	12		
Low MAIFI(e)	VERNAL	8	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0		
High Customer Minutes Lost	VERNAL	VER13	VERNAL #13	13.844	0.197	0.000	0.000	70	679	134	2	9,400	0.000	0		
Low Customer Minutes Lost	VERNAL	2	***** Circuits with a Low Customer Minutes Los	0.000	0.000	0.000	0.000	0	0	0	0	0	0.000	0		

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UTAH PUBLIC SERVICE COMMISSION

Michael O. Leavitt
Governor

Ted Boyer
Executive Director

Lowell E. Alt Jr.
Division Director

DIVISION OF PUBLIC UTILITIES
www.publicutilities.utah.gov
Heber M. Wells Building 4th Floor
160 East 300 South / S.M. Box 146751
Salt Lake City, Utah 84114-6751
Telephone: (801) 530-6651
Fax (801) 530-6512 or (801) 530-6650

98-2035-04

To: Public Service Commission of Utah and Committee of Consumer Services

From: Lowell Alt, Director, Utah Division of Public Utilities
Judith Johnson, Manager, Energy Section
Bob Maloney, Management Analyst

Subject: Recommendation to Approve PacifiCorp's Fourth Claimed Major Event Exclusion for April 15 through April 18, 2002

Date: Monday, August 12, 2002

We recommend that the Commission approve PacifiCorp's claimed major event exclusion for April 15 through April 18, 2002.

PacifiCorp has submitted data showing that significantly more than 10% of the customers in thirteen Utah operations areas experienced a sustained outage of more than five minutes duration during the major event.

ScottishPower/PacifiCorp merger condition #31 indicates that the Company may use the IEEE criteria to determine major events. IEEE criteria include:

1. Exceeds the design limits of the power system
2. Causes extensive damage to the power system
3. Results in more than 10% of the customers in an operations area experiencing a sustained outage.

We recommend approval based upon criterion #3. We do so because significantly more than 10% of PacifiCorp's Utah customers in thirteen operations areas experienced sustained outages.

1900 S.W. Fourth Avenue
Portland, Oregon 97201

PACIFICORP
Pacific Power Utah Power

VIA OVERNIGHT MAIL

REVIEWED BY COMMISSIONERS
STEPHEN F. MECHAM
CONSTANCE B. WHITE CBW 6/3
RICHARD M. CAMPBELL

May 31, 2002

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City UT 84114

Attention: Julie P. Orchard, Commission Secretary

RE: Docket No. 98-2035-04 ScottishPower/PacifiCorp Merger Commitments

Please find enclosed PacifiCorp's annual report for the period April 2001 through March 2002 detailing the Company's performance in meeting the Customer Guarantees and Performance Standards which were agreed to as a result of the merger between ScottishPower and PacifiCorp. Quarterly information for the last quarter of the fiscal year is provided as well. Also enclosed is a report card on our progress with the program, which is being sent to our customers in June's bill as an insert.

The Outage Detail Report will be delayed until mid June 2002 to allow for an update of customer counts by circuit.

If you have any questions or require further information, please call me at (503) 813-7408.

Sincerely,

Carole Rockney /skk

Carole Rockney, Director,
Customer and Regulatory Liaison

c: Mark Flandro - Utah Division of Public Utilities
Bob Maloney - Utah Division of Public Utilities
Rea Petersen - Utah Division of Public Utilities
Matthew Wright - Executive Vice President, Power Delivery

Enclosures

customer*guarantees*

PACIFICORP

January - March 2002

Table of Contents

Note: The Utah Connects/Reconnects report has been merged with the new Utah Failures & Events - Performance report.

customer*guarantees*

PACIFICORP

Utah – Annual Report – Fiscal Year 2002

Customer Guarantees

Utah's total failures were down by over 50% compared to FY 2001 primarily due to ongoing training, improved processes and customer focus. The results of the second year of the Customer Guarantee (CG) program are a strong indicator that the guarantees have become an integral part of each employee's day. As further evidence of the success of the program, EAQA USA, an ISO registrar, presented the company with its official ISO 9001:2000 quality certificate in a special ceremony on May 11, 2001. EAQA USA has also conducted two follow-up audits during FY 2002 in which the company was successful in maintaining its certification. Earning the ISO certificate has helped to set a tone of consistency and continual improvement across the company.

CG program procedures were updated twice during FY 2002, with all involved employees receiving training regarding the updated procedures. Additional 'refresher' training has been provided throughout the year for several roles to ensure understanding of the processes where failures have occurred in the past. Employees are involved in developing and sharing 'best practices' and improvement suggestions. Also, a comprehensive study of the CG7-Planned Interruption processes was completed during FY 2002, which resulted in the streamlining and simplification of procedures for employees. Training for employees involved with CG7 will continue through the first quarter of FY 2003.

CG1 – Restoring Supply

Failure counts increased only slightly during FY 2002, although event counts were up significantly over last year primarily due to severe weather.

CG4 – Estimates

Total events decreased 23% compared to the prior year, and combined with increased employee focus on the guarantees, failure counts were 55% lower.

CG5 – Billing Inquiries

The increase in failure counts is attributable to the higher number of bill inquiries received during the year and the implementation of new systems and procedures.

CG6 – Meter Inquiries

A new effort was introduced in the second half of FY 2001 focused on resolving customers' energy usage concerns before it became necessary to dispatch an employee to the customer's site. The success of this effort is evident and results in customer concerns being resolved while reducing the total number of meter inquiries.

CG7– Notification of Planned Interruptions

The increased level of construction in the summer of 2001 led to an increased number of customers being taken off supply so work could proceed safely. That overall failure counts actually dropped is an indicator of the extra attention to detail employed during the construction period.

CG8 – Power Quality

Failures were down significantly due to process refinements and focused training that helped employees better understand this guarantee. Inquiries regarding outages with no power quality or voltage component had been incorrectly classified as CG8 events in FY 2001. In FY 2002 only power quality/voltage related inquiries are reported as CG8 events.

The figures for other guarantees were not significant.

Performance Standards

The Computer Aided Distribution Operations System (CADOPS) has been operating in Southern Utah since November 2000 and in Northern Utah since February 2001. This implementation, combined with an increased focus on outage reporting as influenced by ScottishPower, has led to an "uplift" in SAIDI and SAIFI figures. A preliminary analysis of the baseline uplift was submitted in the 4th quarter. Analysis continues and will be presented before the end of the 3rd quarter of FY 2003 to finalize the baselines.

The five worst circuits identified for fiscal years 2001, 2002 and 2003 are reported along with their baseline Circuit Performance Indicator (CPI). For each annual set of worst performing circuits, we plan and implement improvements over a 2-year period, then recalculate a new CPI over the following 3-year period. After the 5th year from the year we identified the circuits, we will compare the new CPI to the baseline CPI to determine whether we've achieved 20% improvement. We will report the baseline CPI, the new CPI and the percent improvement at the completion of each 5-year cycle going forward for all circuits so identified.

In Performance Standard 5, the Company committed to restore power to 80% of customers within 3 hours. During the year, we restored 86% of our customers within the targeted timeframe.

The target for Performance Standard 6 is a service level of 80 percent of calls answered within 20 seconds. The Company met this target with 81 percent of calls answered within 20 seconds.

Performance Standard 7 was implemented to ensure that customers receive a timely response and resolution of complaints received from State Commissions. For a non-disconnect-related complaint the Company will respond directly to the customer or the Commission within three business days and for a disconnect-related complaint the Company will respond within 4 business hours. The Company strives to meet this target 100% of the time although this is not always possible with complex issues. In the second year under this standard we responded to more than 99% of Commission complaints within the targeted response time.

The Company also committed to resolving Commission complaints within 30 calendar days 95% of the time. We exceeded this target with 97% of complaints being resolved within the 5-day target for this reporting period.

Description	Baseline	Performance at March 2001	Performance at March 2002	Goal
• SAIDI (System availability in minutes per customer)	Revised baselines under development[1]	141.9	201.8	Reduce SAIDI by 10% from revised baseline
• SAIFI (System reliability in interruptions per customer)		1.5	2.0	Reduce SAIFI by 10% from revised baseline
• MAIFI (Momentary interruptions per customer)		5.6	0.3	Reduce MAIFI by 5% from revised baseline
• Worst Performing Circuits - Circuit Performance Indicator (CPI)[2]				Reduce CPI's by 20% from revised baseline
Fiscal Year 2001:				
Coalville 12	288	New CPI will be reported in May 2005		
Lewiston 11	377			
Pioneer 11	425			
Pioneer 13	529			
Pioneer 14	393			
Fiscal Year 2002:				
Woods Cross 11	311	New CPI will be reported in May 2006		
Eden 11	339			
Rattlesnake 22	308			
Lark 11	419			
Bothwell 11	323			
Fiscal Year 2003:				
University 1	107	New CPI will be reported in May 2007		
West Cedar	613			
Parowan Valley 25	1563			
Eureka 12	90			
Coleman 15	110			
• Power supply restored within 3 hours	Not applicable	86%	86%	80%
• Calls answered				
• Within 20 seconds[3]	Not applicable	81%	81%	80%
• Respond to commission complaints within 3 days	Not applicable	100%	99%	100%
• Respond to commission complaints regarding service disconnects within 4 hours	Not applicable	99%	100%	100%
• Commission complaints resolved within 30 days[4]	Not applicable	100%	97%	95%

1 Baseline uplift preliminary analysis submitted during the quarter. Further analysis is ongoing and will be presented during 2002 to finalize the baselines.

2 Baseline CPI figures are based on 3-years ended data as of December 31, 1998 for FY 2001 circuits; 3-years ended data as of December 31, 2000 for FY 2002 circuits; 3-years ended December 31, 2001 for FY 2003 circuits. Improvement period is 2 years after identification year, followed by a 3-year period to recalculate CPI..

3 Reflects system-wide performance for improved accuracy.

4 For this reporting period the target in Utah for complaint resolution is 5 days.

Note: Performance figures exlude impacts of major events.

	Description	January-March 2002				Year End - FY 2002				Year End - FY 2001			
		Events	Failures	% Success	Paid	Events	Failures	% Success	Paid	Events	Failures	% Success	Paid
CG1	Restoring Supply	282,324	0	100.0%	$0	1,594,973	11	100.0%	$875	940,581	9	100.0%	$575
CG2	Appointments	1,221	1	99.9%	$50	5,891	10	99.8%	$500	6,337	22	99.7%	$1,100
CG3	Switching on Power	3,900	11	99.7%	$1,600	25,201	53	99.8%	$7,700	22,929	61	99.7%	$10,150
CG4	Estimates	1,515	16	98.9%	$800	6,962	116	98.3%	$5,800	9,059	208	97.7%	$10,400
CG5	Respond to Billing Inquiries	2,990	15	99.5%	$750	9,888	49	99.5%	$2,450	7,684	26	99.7%	$1,300
CG6	Respond to Meter Problems	160	2	98.8%	$100	545	6	98.9%	$300	1,174	6	99.5%	$300
CG7	Notification of Planned Interruptions	2,964	6	99.8%	$300	22,308	37	99.8%	$1,900	10,515	50	99.5%	$2,600
CG8	Power Quality Complaints	39	0	100.0%	$0	468	7	98.5%	$350	2,317	199	91.4%	$9,950
		295,113	**51**	**100.0%**	**$3,600**	**1,666,236**	**289**	**100.0%**	**$19,875**	**1,000,596**	**581**	**99.9%**	**$36,375**

Summary analysis:

General Comments: Failure counts have been reduced significantly primarily due to ongoing training and improving customer focus. At the conclusion of the ISO 9001 follow-up audit in October 2001, the external auditors commented that in their experience with many ISO audits in other industries, they "never see this high of a success rate in delivery of services. There is no comparison."

CG1 - Restoring Supply: Increase in event counts are due to the number of severe storms outside of districts where major events were declared.

CG4 - Estimates: The decreased number of failures reported during the last year (55% lower) is partially related to the 23% reduction in reported events. Additional employee emphasis on the guarantees has also reduced failures.

CG5 - Billing Inquiries: Failures have nearly doubled, partly due to increased events but primarily due to implementation of new systems and procedures.

CG6 - Metering Inquiries: Events have dropped significantly due to additional efforts to resolve as many customer billing inquiries over the phone as possible, before it is deemed necessary to dispatch an employee to the customer's site.

CG7 - Planned Interruptions: Overall event counts have increased due to aggressive project schedule during summer 2001.

CG8 - Power Quality Complaints: Failures have been reduced significantly due to process refinement efforts and training efforts to help employees better understand the definition of this guarantee. Inquiries regarding outages with no power quality or voltage component had been incorrectly classified as CG8 events in FY 2001. In FY 2002 only power quality/voltage related inquiries are reported as CG8 events.

customerguarantees

PACIFICORP

Utah - Failures and Events

Filter the table by District and/or Guarantee to see individual District performance or Guarantee performance

4th Quarter - Fiscal Year 2002

January - March 2002

			Current Quarter				Year To Date			
American Fork	CG1	Restoring Supply		35,655		100.0%		121,119		100.0%
Cedar City	CG1	Restoring Supply		10,572		100.0%		71,576		100.0%
Jordan Valley	CG1	Restoring Supply		43,123		100.0%	6	346,329	$350	100.0%
Layton	CG1	Restoring Supply		36,929		100.0%		132,252		100.0%
Moab	CG1	Restoring Supply		658		100.0%		7,843		100.0%
Ogden	CG1	Restoring Supply		54,935		100.0%		319,341		100.0%
Park City	CG1	Restoring Supply		11,274		100.0%		80,728		100.0%
Price	CG1	Restoring Supply		4,496		100.0%	1	20,075	$50	100.0%
Richfield	CG1	Restoring Supply		6,276		100.0%	1	24,379	$100	100.0%
SLC Metro	CG1	Restoring Supply		51,933		100.0%	2	303,336	$175	100.0%
Smithfield	CG1	Restoring Supply		9,140		100.0%	1	56,831	$200	100.0%
Tooele	CG1	Restoring Supply		14,977		100.0%		83,596		100.0%
Tremonton	CG1	Restoring Supply		1,587		100.0%		13,588		100.0%
Vernal	CG1	Restoring Supply		769		100.0%		13,980		100.0%
American Fork	CG2.3	CG3 Appointments		48		100.0%		169		100.0%
Cedar City	CG2.3	CG3 Appointments		19		100.0%		73		100.0%
Jordan Valley	CG2.3	CG3 Appointments		45		100.0%	2	242	$100	99.2%
Laketown/Woodruff	CG2.3	CG3 Appointments		1		100.0%		5		100.0%
Layton	CG2.3	CG3 Appointments		7		100.0%	1	109	$50	99.1%
Moab	CG2.3	CG3 Appointments		5		100.0%		33		100.0%
Ogden	CG2.3	CG3 Appointments		92		100.0%		361		100.0%
Park City	CG2.3	CG3 Appointments		6		100.0%		50		100.0%
Price	CG2.3	CG3 Appointments		7		100.0%		49		100.0%
Richfield	CG2.3	CG3 Appointments		12		100.0%		33		100.0%
SLC Metro	CG2.3	CG3 Appointments		48		100.0%		334		100.0%
Smithfield	CG2.3	CG3 Appointments		5		100.0%		29		100.0%
Tooele	CG2.3	CG3 Appointments		12		100.0%	1	47	$50	97.9%
Tremonton	CG2.3	CG3 Appointments		5		100.0%		13		100.0%
Vernal	CG2.3	CG3 Appointments		9		100.0%		41		100.0%
American Fork	CG2.4	CG4 Appointments		72		100.0%	1	325	$50	99.7%
Cedar City	CG2.4	CG4 Appointments		56		100.0%		254		100.0%
Jordan Valley	CG2.4	CG4 Appointments	1	30	$50	96.7%	1	232	$50	99.6%
Laketown/Woodruff	CG2.4	CG4 Appointments		3		100.0%		36		100.0%
Layton	CG2.4	CG4 Appointments		24		100.0%		58		100.0%
Moab	CG2.4	CG4 Appointments		17		100.0%	1	84	$50	98.8%
Ogden	CG2.4	CG4 Appointments		47		100.0%		223		100.0%
Park City	CG2.4	CG4 Appointments		28		100.0%		200		100.0%
Price	CG2.4	CG4 Appointments		36		100.0%		101		100.0%

CG1 events exclude major events

Utah - Failures and Events

Filter the table by District and/or Guarantee to see individual District performance or Guarantee performance
4th Quarter - Fiscal Year 2002
January - March 2002

			Current Quarter			Year To Date		
Richfield	CG2.4	CG4 Appointments	35	100.0%		177		100.0%
SLC Metro	CG2.4	CG4 Appointments	39	100.0%		201		100.0%
Smithfield	CG2.4	CG4 Appointments	2	100.0%		23		100.0%
Tooele	CG2.4	CG4 Appointments	18	100.0%		69		100.0%
Tremonton	CG2.4	CG4 Appointments	15	100.0%		74		100.0%
Vernal	CG2.4	CG4 Appointments	24	100.0%		122		100.0%
American Fork	CG2.5	CG5 Appointments	3	100.0%		9		100.0%
Cedar City	CG2.5	CG5 Appointments	2	100.0%		5		100.0%
Jordan Valley	CG2.5	CG5 Appointments	13	100.0%		63		100.0%
Layton	CG2.5	CG5 Appointments	1	100.0%	1	5	$50	80.0%
Moab	CG2.5	CG5 Appointments	0	N/A		1		100.0%
Ogden	CG2.5	CG5 Appointments	6	100.0%		15		100.0%
Park City	CG2.5	CG5 Appointments	1	100.0%		9		100.0%
Price	CG2.5	CG5 Appointments	2	100.0%		3		100.0%
Richfield	CG2.5	CG5 Appointments	2	100.0%		4		100.0%
SLC Metro	CG2.5	CG5 Appointments	2	100.0%		9		100.0%
Vernal	CG2.5	CG5 Appointments	2	100.0%		4		100.0%
American Fork	CG2.6	CG6 Appointments	0	N/A		2		100.0%
Layton	CG2.6	CG6 Appointments	0	N/A		2		100.0%
Ogden	CG2.6	CG6 Appointments	1	100.0%		4		100.0%
Price	CG2.6	CG6 Appointments	0	N/A		1		100.0%
Vernal	CG2.6	CG6 Appointments	0	N/A		1		100.0%
American Fork	CG2a	All Other RCMS Appointmts	162	100.0%		643		100.0%
Cedar City	CG2a	All Other RCMS Appointmts	6	100.0%		23		100.0%
Jordan Valley	CG2a	All Other RCMS Appointmts	45	100.0%		239		100.0%
Laketown/Woodruff	CG2a	All Other RCMS Appointmts	0	N/A		2		100.0%
Layton	CG2a	All Other RCMS Appointmts	12	100.0%		44		100.0%
Moab	CG2a	All Other RCMS Appointmts	8	100.0%		27		100.0%
Ogden	CG2a	All Other RCMS Appointmts	65	100.0%		331		100.0%
Park City	CG2a	All Other RCMS Appointmts	1	100.0%		36		100.0%
Price	CG2a	All Other RCMS Appointmts	7	100.0%		15		100.0%
Richfield	CG2a	All Other RCMS Appointmts	10	100.0%	1	50	$50	98.0%
SLC Metro	CG2a	All Other RCMS Appointmts	78	100.0%	1	456	$50	99.8%
Smithfield	CG2a	All Other RCMS Appointmts	0	N/A		1		100.0%
Tooele	CG2a	All Other RCMS Appointmts	15	100.0%		72		100.0%
Tremonton	CG2a	All Other RCMS Appointmts	8	100.0%		35		100.0%
Vernal	CG2a	All Other RCMS Appointmts	2	100.0%		11		100.0%
American Fork	CG3	Switching on Power	355	100.0%	3	2,291	$325	99.9%

CG1 events exclude major events

Utah - Failures and Events

Filter the table by District and/or Guarantee to see individual District performance or Guarantee performance
4th Quarter - Fiscal Year 2002
January - March 2002

			Current Quarter				Year To Date			
Cedar City	CG3	Switching on Power		155		100.0%	5	780	$375	99.4%
Jordan Valley	CG3	Switching on Power	2	635	$750	99.7%	7	4,440	$1,450	99.8%
Laketown/Woodruff	CG3	Switching on Power		7		100.0%		63		100.0%
Layton	CG3	Switching on Power		123		100.0%	5	1,388	$1,300	99.6%
Moab	CG3	Switching on Power		61		100.0%		297		100.0%
Ogden	CG3	Switching on Power	1	378	$50	99.7%	5	3,727	$325	99.9%
Park City	CG3	Switching on Power		34		100.0%		315		100.0%
Price	CG3	Switching on Power	2	40	$125	95.0%	3	330	$400	99.1%
Richfield	CG3	Switching on Power		60		100.0%		412		100.0%
SLC Metro	CG3	Switching on Power	5	1,801	$625	99.7%	21	9,476	$3,250	99.8%
Smithfield	CG3	Switching on Power		37		100.0%	1	385	$125	99.7%
Tooele	CG3	Switching on Power	1	142	$50	99.3%	3	759	$150	99.6%
Tremonton	CG3	Switching on Power		22		100.0%		258		100.0%
Vernal	CG3	Switching on Power		50		100.0%		276		100.0%
Wasatch Collection Center	CG3	Switching on Power		0		N/A		1		100.0%
American Fork	CG4a	Estimates - Contact within 2 days	3	72	$150	95.8%	13	329	$650	96.0%
Cedar City	CG4a	Estimates - Contact within 2 days	2	110	$100	98.2%	6	446	$300	98.7%
Jordan Valley	CG4a	Estimates - Contact within 2 days		78		100.0%	4	477	$200	99.2%
Laketown/Woodruff	CG4a	Estimates - Contact within 2 days		3		100.0%	1	36	$50	97.2%
Layton	CG4a	Estimates - Contact within 2 days		42		100.0%	2	139	$100	98.6%
Moab	CG4a	Estimates - Contact within 2 days	1	27	$50	96.3%	3	125	$150	97.6%
Ogden	CG4a	Estimates - Contact within 2 days		63		100.0%	5	326	$250	98.5%
Park City	CG4a	Estimates - Contact within 2 days		45		100.0%	1	242	$50	99.6%
Price	CG4a	Estimates - Contact within 2 days		41		100.0%	1	103	$50	99.0%
Richfield	CG4a	Estimates - Contact within 2 days	1	71	$50	98.6%	7	245	$350	97.1%
SLC Metro	CG4a	Estimates - Contact within 2 days		73		100.0%	3	351	$150	99.1%
Smithfield	CG4a	Estimates - Contact within 2 days		25		100.0%	3	176	$150	98.3%
Tooele	CG4a	Estimates - Contact within 2 days	3	31	$150	90.3%	7	108	$350	93.5%
Tremonton	CG4a	Estimates - Contact within 2 days	3	18	$150	83.3%	9	112	$450	92.0%
Vernal	CG4a	Estimates - Contact within 2 days		24		100.0%		115		100.0%
American Fork	CG4b	Estimates - 5 days		11		100.0%		47		100.0%
Cedar City	CG4b	Estimates - 5 days		56		100.0%		216		100.0%
Jordan Valley	CG4b	Estimates - 5 days		30		100.0%		181		100.0%
Laketown/Woodruff	CG4b	Estimates - 5 days		0		N/A		7		100.0%
Layton	CG4b	Estimates - 5 days		18		100.0%		46		100.0%
Moab	CG4b	Estimates - 5 days		7		100.0%		34		100.0%
Ogden	CG4b	Estimates - 5 days		13		100.0%		81		100.0%
Park City	CG4b	Estimates - 5 days		5		100.0%		19		100.0%

CG1 events exclude major events

customerguarantees

PACIFICORP

Utah - Failures and Events

Filter the table by District and/or Guarantee to see individual District performance or Guarantee performance
4th Quarter - Fiscal Year 2002
January - March 2002

			Current Quarter				Year To Date			
Price	CG4b	Estimates - 5 days		17		100.0%		29		100.0%
Richfield	CG4b	Estimates - 5 days		21		100.0%		78		100.0%
SLC Metro	CG4b	Estimates - 5 days		32		100.0%		102		100.0%
Smithfield	CG4b	Estimates - 5 days		8		100.0%		31		100.0%
Tooele	CG4b	Estimates - 5 days		16		100.0%		42		100.0%
Tremonton	CG4b	Estimates - 5 days		18		100.0%	1	36	$50	97.2%
Vernal	CG4b	Estimates - 5 days		9		100.0%		26		100.0%
American Fork	CG4c	Estimates - 15 days	2	18	$100	88.9%	21	222	$1,050	90.5%
Cedar City	CG4c	Estimates - 15 days		47		100.0%		221		100.0%
Jordan Valley	CG4c	Estimates - 15 days		27		100.0%	9	270	$450	96.7%
Laketown/Woodruff	CG4c	Estimates - 15 days		5		100.0%		31		100.0%
Layton	CG4c	Estimates - 15 days		13		100.0%	2	78	$100	97.4%
Moab	CG4c	Estimates - 15 days		15		100.0%	1	73	$50	98.6%
Ogden	CG4c	Estimates - 15 days	1	36	$50	97.2%	3	252	$150	98.8%
Park City	CG4c	Estimates - 15 days		35		100.0%		204		100.0%
Price	CG4c	Estimates - 15 days		19		100.0%		84		100.0%
Richfield	CG4c	Estimates - 15 days		20		100.0%	8	147	$400	94.6%
SLC Metro	CG4c	Estimates - 15 days		35		100.0%	1	231	$50	99.6%
Smithfield	CG4c	Estimates - 15 days		21		100.0%		138		100.0%
Tooele	CG4c	Estimates - 15 days		4		100.0%		69		100.0%
Tremonton	CG4c	Estimates - 15 days		15		100.0%	5	89	$250	94.4%
Vernal	CG4c	Estimates - 15 days		17		100.0%		93		100.0%
American Fork	CG5	Responding to Bill Inquiries within	1	165	$50	99.4%	11	595	$550	98.2%
Cedar City	CG5	Responding to Bill Inquiries within	1	139	$50	99.3%	1	379	$50	99.7%
Jordan Valley	CG5	Responding to Bill Inquiries within	3	617	$150	99.5%	10	2,306	$500	99.6%
Laketown/Woodruff	CG5	Responding to Bill Inquiries within		16		100.0%		56		100.0%
Layton	CG5	Responding to Bill Inquiries within	1	187	$50	99.5%	3	579	$150	99.5%
Moab	CG5	Responding to Bill Inquiries within		37		100.0%		139		100.0%
Ogden	CG5	Responding to Bill Inquiries within	1	497	$50	99.8%	2	1,187	$100	99.8%
Park City	CG5	Responding to Bill Inquiries within	1	70	$50	98.6%	2	324	$100	99.4%
Price	CG5	Responding to Bill Inquiries within		28		100.0%		115		100.0%
Richfield	CG5	Responding to Bill Inquiries within	1	57	$50	98.2%	1	167	$50	99.4%
SLC Metro	CG5	Responding to Bill Inquiries within	6	945	$300	99.4%	18	3,659	$900	99.5%
Smithfield	CG5	Responding to Bill Inquiries within		71		100.0%		190		100.0%
Tooele	CG5	Responding to Bill Inquiries within		33		100.0%		109		100.0%
Tremonton	CG5	Responding to Bill Inquiries within		42		100.0%	1	123	$50	99.2%
Vernal	CG5	Responding to Bill Inquiries within		41		100.0%		80		100.0%
American Fork	CG6	Responding to Meter Problems		16		100.0%		47		100.0%

CG1 events exclude major events

Utah - Failures and Events

Filter the table by District and/or Guarantee to see individual District performance or Guarantee performance
4th Quarter - Fiscal Year 2002
January - March 2002

			Current Quarter				Year To Date			
Cedar City	CG6	Responding to Meter Problems		6		100.0%		26		100.0%
Jordan Valley	CG6	Responding to Meter Problems		28		100.0%		112		100.0%
Layton	CG6	Responding to Meter Problems	1	9	$50	88.9%	4	52	$200	92.3%
Moab	CG6	Responding to Meter Problems		1		100.0%		3		100.0%
Ogden	CG6	Responding to Meter Problems		23		100.0%		66		100.0%
Park City	CG6	Responding to Meter Problems		3		100.0%		15		100.0%
Price	CG6	Responding to Meter Problems		1		100.0%		10		100.0%
Richfield	CG6	Responding to Meter Problems		2		100.0%		13		100.0%
SLC Metro	CG6	Responding to Meter Problems	1	47	$50	97.9%	2	155	$100	98.7%
Smithfield	CG6	Responding to Meter Problems		1		100.0%		8		100.0%
Tooele	CG6	Responding to Meter Problems		3		100.0%		12		100.0%
Tremonton	CG6	Responding to Meter Problems		1		100.0%		3		100.0%
Vernal	CG6	Responding to Meter Problems		4		100.0%		8		100.0%
American Fork	CG7	Planned Interruptions		589		100.0%	1	2,361	$50	100.0%
Cedar City	CG7	Planned Interruptions	1	1	$50	0.0%	3	741	$150	99.6%
Jordan Valley	CG7	Planned Interruptions	4	234	$200	98.3%	19	4,814	$950	99.6%
Layton	CG7	Planned Interruptions		129		100.0%		4,774		100.0%
Moab	CG7	Planned Interruptions		1		100.0%		23		100.0%
Ogden	CG7	Planned Interruptions	1	1,292	$50	99.9%	3	3,925	$150	99.9%
Park City	CG7	Planned Interruptions		3		100.0%		969		100.0%
Price	CG7	Planned Interruptions		33		100.0%		187		100.0%
Richfield	CG7	Planned Interruptions		162		100.0%		186		100.0%
SLC Metro	CG7	Planned Interruptions		162		100.0%	10	3,621	$500	99.7%
Smithfield	CG7	Planned Interruptions		124		100.0%		173		100.0%
Tooele	CG7	Planned Interruptions		77		100.0%		277		100.0%
Tremonton	CG7	Planned Interruptions		0		N/A		100		100.0%
Vernal	CG7	Planned Interruptions		157		100.0%	1	157	$100	99.4%
Jordan Valley	CG8a	Respond in 5 days		0		N/A	2	0	$100	0.0%
SLC Metro	CG8a	Respond in 5 days		0		N/A	3	0	$150	0.0%
Wasatch Collection Center	CG8a	Respond in 5 days		22		100.0%		303		100.0%
SLC Metro	CG8b	Respond in 7 days		0		N/A	2	0	$100	0.0%
Wasatch Collection Center	CG8b	Respond in 7 days		17		100.0%		165		100.0%
			51	**294,849**	**$3,600**	**100.0%**	**289**	**1,665,881**	**$19,875**	**100.0%**

CG1 events exclude major events

customer*guarantees*

PACIFICORP

Utah - Guarantee Field Response Performance

Sort the table by District or Guarantee to see individual District performance or overall Guarantee performance
4th Quarter - Fiscal Year 2002
January - March 2002

American Fork	CG4a	Estimates - Contact within 2 days	72	2	329	2
Cedar City	CG4a	Estimates - Contact within 2 days	110	1	446	1
Jordan Valley	CG4a	Estimates - Contact within 2 days	78	1	477	1
Laketown/Woodruff	CG4a	Estimates - Contact within 2 days	3	1	36	1
Layton	CG4a	Estimates - Contact within 2 days	42	<1	139	1
Moab [1]	CG4a	Estimates - Contact within 2 days	27	<1	125	3
Ogden	CG4a	Estimates - Contact within 2 days	63	1	326	1
Park City	CG4a	Estimates - Contact within 2 days	45	<1	242	1
Price	CG4a	Estimates - Contact within 2 days	41	<1	103	<1
Richfield	CG4a	Estimates - Contact within 2 days	71	1	245	1
SLC Metro	CG4a	Estimates - Contact within 2 days	73	1	351	1
Smithfield [2]	CG4a	Estimates - Contact within 2 days	25	8	176	2
Tooele	CG4a	Estimates - Contact within 2 days	31	<1	108	1
Tremonton	CG4a	Estimates - Contact within 2 days	18	<1	112	1
Vernal	CG4a	Estimates - Contact within 2 days	24	<1	115	<1
American Fork	CG4b	Estimates - 5 days	11	<1	47	<1
Cedar City	CG4b	Estimates - 5 days	56	<1	216	<1
Jordan Valley	CG4b	Estimates - 5 days	30	1	181	1
Laketown/Woodruff	CG4b	Estimates - 5 days	0	<1	7	<1
Layton	CG4b	Estimates - 5 days	18	1	46	1
Moab	CG4b	Estimates - 5 days	7	<1	34	<1
Ogden	CG4b	Estimates - 5 days	13	<1	81	<1
Park City	CG4b	Estimates - 5 days	5	1	19	1
Price	CG4b	Estimates - 5 days	17	0	29	<1
Richfield	CG4b	Estimates - 5 days	21	1	78	1
SLC Metro	CG4b	Estimates - 5 days	32	<1	102	<1
Smithfield	CG4b	Estimates - 5 days	8	1	31	1
Tooele	CG4b	Estimates - 5 days	16	1	42	1
Tremonton	CG4b	Estimates - 5 days	18	<1	36	<1
Vernal	CG4b	Estimates - 5 days	9	<1	26	<1
American Fork	CG4c	Estimates - 15 days	18	10	222	10
Cedar City	CG4c	Estimates - 15 days	47	3	221	3
Jordan Valley	CG4c	Estimates - 15 days	27	<1	270	7
Laketown/Woodruff	CG4c	Estimates - 15 days	5	3	31	3
Layton	CG4c	Estimates - 15 days	13	1	78	6
Moab	CG4c	Estimates - 15 days	15	8	73	8
Ogden	CG4c	Estimates - 15 days	36	4	252	4
Park City	CG4c	Estimates - 15 days	35	4	204	4
Price	CG4c	Estimates - 15 days	19	<1	84	1
Richfield	CG4c	Estimates - 15 days	20	<1	147	5
SLC Metro	CG4c	Estimates - 15 days	35	6	231	6
Smithfield	CG4c	Estimates - 15 days	21	3	138	3
Tooele	CG4c	Estimates - 15 days	4	7	69	7
Tremonton	CG4c	Estimates - 15 days	15	2	89	7
Vernal	CG4c	Estimates - 15 days	17	<1	93	<1
American Fork	CG5	Responding to Bill Inquiries within 10 days	165	6	595	6
Cedar City	CG5	Responding to Bill Inquiries within 10 days	139	5	379	5
Jordan Valley	CG5	Responding to Bill Inquiries within 10 days	617	2	2306	5
Laketown/Woodruff	CG5	Responding to Bill Inquiries within 10 days	16	6	56	6
Layton	CG5	Responding to Bill Inquiries within 10 days	187	5	579	5

Utah - Guarantee Field Response Performance

Sort the table by District or Guarantee to see individual District performance or overall Guarantee performance
4th Quarter - Fiscal Year 2002
January - March 2002

Moab	CG5	Responding to Bill Inquiries within 10 days	37	8	139	5
Ogden	CG5	Responding to Bill Inquiries within 10 days	497	4	1187	5
Park City	CG5	Responding to Bill Inquiries within 10 days	70	6	324	6
Price	CG5	Responding to Bill Inquiries within 10 days	28	5	115	5
Richfield	CG5	Responding to Bill Inquiries within 10 days	57	6	167	6
SLC Metro	CG5	Responding to Bill Inquiries within 10 days	945	5	3659	5
Smithfield	CG5	Responding to Bill Inquiries within 10 days	71	4	190	4
Tooele	CG5	Responding to Bill Inquiries within 10 days	33	3	109	5
Tremonton	CG5	Responding to Bill Inquiries within 10 days	42	6	123	6
Vernal	CG5	Responding to Bill Inquiries within 10 days	41	5	80	5
American Fork	CG6	Responding to Meter Problems within 15 days	16	8	47	8
Cedar City	CG6	Responding to Meter Problems within 15 days	6	5	26	5
Jordan Valley	CG6	Responding to Meter Problems within 15 days	28	7	112	7
Layton	CG6	Responding to Meter Problems within 15 days	9	9	52	9
Moab	CG6	Responding to Meter Problems within 15 days	1	3	3	5
Ogden	CG6	Responding to Meter Problems within 15 days	23	9	66	9
Park City[3]	CG6	Responding to Meter Problems within 15 days	3	17	15	9
Price	CG6	Responding to Meter Problems within 15 days	1	12	10	12
Richfield	CG6	Responding to Meter Problems within 15 days	2	8	13	8
SLC Metro	CG6	Responding to Meter Problems within 15 days	47	7	155	7
Smithfield	CG6	Responding to Meter Problems within 15 days	1	6	8	6
Tooele	CG6	Responding to Meter Problems within 15 days	3	9	12	9
Tremonton	CG6	Responding to Meter Problems within 15 days	1	9	3	9
Vernal	CG6	Responding to Meter Problems within 15 days	4	10	8	12

[1] During the previous quarter in Moab, one request with a response periods of 15 days and five requests with responses of 2 - 5 days were the result of waiting for customers to call back despite PacifiCorp's multiple attempts to make contact.

[2] Several attempts were made to contact a Smithfield customer within two days, then after 4 months passed, the customer finally returned our calls.

[3] An incorrect request type was created at the initial call that does not require timely customer response. Field personnel did not discover the request until after the several days had already passed.

Utah - Outage Restoration Performance

4th Quarter - Fiscal Year 2002
January - March 2002

American Fork	35,655	121,119	93%	92%
Cedar City	10,572	71,576	39%	73%
Jordan Valley	43,123	346,329	90%	87%
Layton	36,929	132,252	91%	89%
Moab	658	7,843	99%	88%
Ogden	54,935	319,341	87%	88%
Park City	11,274	80,728	56%	74%
Price	4,496	20,075	85%	84%
Richfield	6,276	24,379	76%	76%
SLC Metro	51,933	303,336	95%	88%
Smithfield	9,140	56,831	89%	88%
Tooele	14,977	83,596	96%	88%
Tremonton	1,587	13,588	100%	81%
Vernal	769	13,980	100%	77%
All Districts	282,324	1,594,973	88%	86%

[1] During the quarter, Cedar City experienced multiple concurrent pole fires related to storms requiring pole replacement. Vehicle accidents and high winds blowing conductor and poles down accounted for a number of additional extended outages.

[2] Park City's low 4th quarter performance resulted from hit and run damage to switch gear, several concurrent storm related pole fires in locations across the district and one instance of Olympic support equipment malfunction.

[3] In Richfield, performance was impacted in the 4th quarter by a single 4.5 hour outage affecting over 1100 customers. The outage was caused by a structure fire in the 138 KV line supplying the area.

[4] Performance earlier in the year in Vernal was low due to large coverage areas, difficult terrain and the nature of the outages requiring pole replacements. No significant outages have been encountered in the last two quarters.

Utah - Non-Guarantee Field Response Performance

FIELD Orders

4th Quarter - Fiscal Year 2002

January - March 2002

	3rd Quarter (Restated) [1]		4th Quarter			
American Fork	61	5	57	3	249	3
Cedar City	62	9	40	5	343	5
Jordan Valley [1]	202	7	189	13	1082	8
Laketown/Woodruff [1]	5	3	1	2	13	2
Layton [1]	299	2	284	2	1196	2
Moab	13	12	7	<1	60	7
Ogden	222	15	182	3	1108	13
Park City	27	7	8	5	96	5
Price	21	28	14	<1	69	9
Richfield	22	1	28	21	120	8
SLC Metro [2]	334	14	323	36	1402	16
Smithfield	31	7	15	7	163	7
Tooele	38	4	16	<1	172	3
Tremonton [3]	20	8	14	32	88	16
Vernal	17	27	9	<1	48	8
	1374		1187		6209	

* Average response measured in working days.

[1] Restated 3rd Quarter event totals due to incorrect district names associated with reported totals.

[2] Valley West District was combined into Salt Lake City Metro totals. Also, SLC Metro personnel closed a large number of FLD orders in March where the work had been completed and not entered in the system or where repeated attempts to contact the customer for more information went unanswered for more than 30 days.

[3] Tremonton closed 4 old FLD orders in March where the work had been completed and not entered in the system. One job was closed where repeated attempts to contact the customer for more information went unanswered for more than 30 days.

Utah - Non-Guarantee Field Response Performance

Tree Trimming Orders

4th Quarter - Fiscal Year 2002

January - March 2002

American Fork	Resolved by Customer Contact	1	6	1	6
American Fork	Site Inspection Required	21	5	95	4
Cedar City	Resolved by Customer Contact	2	1	2	1
Cedar City	Site Inspection Required	5	27	23	11
Jordan Valley	Resolved by Customer Contact	1	<1	5	<1
Jordan Valley	Site Inspection Required	78	5	462	5
Layton	Resolved by Customer Contact	1	<1	2	1
Layton	Site Inspection Required	22	2	90	2
Moab [1]	Site Inspection Required	7	24	14	31
Ogden	Site Inspection Required	51	2	326	2
Ogden	Resolved by Customer Contact	0	--	3	2
Park City	Site Inspection Required	1	7	18	5
Park City	Resolved by Customer Contact	1	<1	2	<1
Price [1]	Site Inspection Required	7	22	41	17
Price	Resolved by Customer Contact	0	--	1	8
Richfield [1]	Site Inspection Required	4	34	18	18
Richfield	Resolved by Customer Contact	1	7	3	3
SLC Metro	Site Inspection Required	187	4	1137	4
SLC Metro	Resolved by Customer Contact	2	2	11	1
Smithfield	Site Inspection Required	5	16	26	11
Smithfield	Resolved by Customer Contact	0	--	2	8
Tooele [1]	Site Inspection Required	3	55	33	14
Tooele	Resolved by Customer Contact	0	--	1	1
Tremonton	Site Inspection Required	1	2	18	3
Vernal	Site Inspection Required	5	6	21	7
		406		2355	

* Average = Average working days from customer call to resolution by contact only, or where necessary, average working days from customer call to site inspection.

[1] Emergency work is always inspected and completed as soon as possible. For non-emergency requests, customers are contacted within ten days, and where necessary, the customer is informed the work will be inspected on the next scheduled visit to the district. For these four districts, such visits may be several weeks in the future.

UTAH RESIDENTIAL/SMALL COMMERCIAL METER SETS - REPORT BY DISTRICT

FISCAL YEAR TO DATE - 4th QUARTER 2001-2002

NORTHERN UTAH

LOCATION	1st Quarter			2nd Quarter			3rd Quarter			4th Quarter			Fiscal YTD		
	Total Within 5 Days	%	Total	Total Within 5 Days	%	Total	Total Within 5 Days	%	Total	Total Within 5 Days	%	Total	Total Within 5 Days	%	Total
Jordan Valley	1104	98%	1124	1374	99%	1388	1464	99%	1486	889	98%	906	4831	99%	4904
Layton	376	96%	393	411	99%	415	505	97%	518	432	98%	439	1724	98%	1765
Metro	769	99%	777	862	99%	872	1303	98%	1327	683	100%	685	3617	99%	3661
Ogden	372	100%	373	506	99%	512	688	98%	705	385	100%	385	1951	99%	1975
Park City	146	96%	152	230	88%	261	415	78%	531	184	86%	214	975	84%	1158
Smithfield	99	99%	100	149	99%	150	149	100%	149	64	100%	64	461	100%	463
Tooele	148	98%	151	234	100%	234	236	98%	242	158	98%	161	776	98%	788
Tremonton	36	100%	36	30	100%	30	51	93%	55	37	97%	38	154	97%	159
TOTAL	3050	98%	3106	3796	98%	3862	4811	96%	5013	2832	98%	2892	14489	97%	14873

SOUTHERN UTAH

LOCATION	1st Quarter			2nd Quarter			3rd Quarter			4th Quarter			Fiscal YTD		
	Total Within 5 Days	%	Total	Total Within 5 Days	%	Total	Total Within 5 Days	%	Total	Total Within 5 Days	%	Total	Total Within 5 Days	%	Total
American Fork	492	100%	493	567	99%	574	652	99%	661	459	100%	460	2170	99%	2188
Cedar City	142	99%	143	188	90%	208	232	89%	260	173	95%	183	735	93%	794
Moab	53	100%	53	65	98%	66	50	100%	50	51	96%	53	219	99%	222
Price	30	94%	32	66	100%	66	28	100%	28	18	100%	18	142	99%	144
Richfield	103	100%	103	135	99%	136	121	100%	121	78	100%	78	437	100%	438
Vernal	41	100%	41	35	100%	35	53	95%	56	30	100%	30	159	98%	162
TOTAL	861	100%	865	1056	97%	1085	1136	97%	1176	809	98%	822	3862	98%	3948

TOTAL UTAH

LOCATION	1st Quarter			2nd Quarter			3rd Quarter			4th Quarter			Fiscal YTD		
	Total Within 5 Days	%	Total	Total Within 5 Days	%	Total	Total Within 5 Days	%	Total	Total Within 5 Days	%	Total	Total Within 5 Days	%	Total
TOTAL UTAH	3911	98%	3971	4852	98%	4947	5947	96%	6189	3641	98%	3714	18351	98%	18821

UTAH TEMPORARY METER SETS - REPORT BY DISTRICT

FISCAL YEAR TO DATE - 4th QUARTER 2001-2002

NORTHERN UTAH

LOCATION	1st Quarter			2nd Quarter			3rd Quarter			4th Quarter			Fiscal YTD		
	Total Within 10 Days	%	Total	Total Within 10 Days	%	Total	Total Within 10 Days	%	Total	Total Within 10 Days	%	Total	Total Within 10 Days	%	Total
Jordan Valley	601	99%	608	504	99%	509	476	100%	476	436	98%	443	2017	99%	2036
Layton	295	97%	303	367	98%	374	291	99%	294	368	100%	368	1321	99%	1339
Metro	236	100%	236	240	100%	240	215	100%	216	205	100%	205	896	100%	897
Ogden	342	90%	380	304	100%	304	235	100%	235	247	100%	247	1128	97%	1166
Park City	96	100%	96	79	95%	83	69	97%	71	63	90%	70	307	96%	320
Smithfield	82	100%	82	82	100%	82	59	100%	59	31	100%	31	254	100%	254
Tooele	110	100%	110	141	100%	141	86	100%	86	92	100%	92	429	100%	429
Tremonton	24	100%	24	29	100%	29	17	100%	17	8	100%	8	78	100%	78
TOTAL	1824	99%	1839	1746	99%	1762	1448	100%	1454	1407	99%	1421	6425	99%	6476

SOUTHERN UTAH

LOCATION	1st Quarter			2nd Quarter			3rd Quarter			4th Quarter			Fiscal YTD		
	Total Within 10 Days	%	Total	Total Within 10 Days	%	Total	Total Within 10 Days	%	Total	Total Within 10 Days	%	Total	Total Within 10 Days	%	Total
American Fork	382	100%	383	379	99%	383	353	100%	353	321	97%	331	1435	99%	1450
Cedar City	104	100%	104	86	100%	86	72	99%	73	93	99%	94	355	99%	357
Moab	2	100%	2	2	100%	2	8	100%	8	4	100%	4	16	100%	16
Price	5	100%	5	7	100%	7	9	100%	9	1	100%	1	22	100%	22
Richfield	17	100%	17	25	100%	25	21	100%	21	34	100%	34	97	100%	97
Vernal	7	100%	7	21	100%	21	12	100%	12	10	100%	10	50	100%	50
TOTAL	517	100%	518	520	99%	524	475	100%	476	463	98%	474	1975	99%	1992

TOTAL UTAH

LOCATION	1st Quarter			2nd Quarter			3rd Quarter			4th Quarter			Fiscal YTD		
	Total Within 10 Days	%	Total	Total Within 10 Days	%	Total	Total Within 10 Days	%	Total	Total Within 10 Days	%	Total	Total Within 10 Days	%	Total
TOTAL UTAH	2341	99%	2357	2266	99%	2286	1923	100%	1930	1870	99%	1895	8400	99%	8468

State of Utah
PUBLIC SERVICE COMMISSION OF UTAH

Michael O. Leavitt
Governor

Heber M. Wells Building
160 East 300 South
Box 45585
Salt Lake City, Utah 84145-0585
(801) 530-6716 (801) 530-6796 Fax

Commissioners
Stephen F. Mecham
Chairman
Constance B. White
Richard M. Campbell

Douglas C. W. Kirk
Executive Staff Director
Sandy Mooy
Legal Counsel
Julie Orchard
Commission Secretary

March 6, 2002

Carole Rockney, Director
PacifiCorp
1900 S.W. Fourth Avenue
Portland, Oregon 97201

Re: 98-2035-04 In the Matter of the Application of PacifiCorp and Scottish Power plc for an Order Approving the Issuance of PacifiCorp Common Stock

The Public Service Commission received recommendations from the Division of Public Utilities to approve PacifiCorp's claimed major event exclusions for May 2nd through May 5th, 2001, June 12th through June 14th, 2001, and November 22nd through November 27th, 2001.

There being no apparent dispute to resolve under merger condition 31, the Commission will take no further action.

If you have further questions or comments, I can be reached by phone at (801) 530-6713 or email at jorchard@utah.gov

Sincerely,

Julie Orchard

Julie Orchard
Commission Secretary

JPO/ab

cc: D. Douglas Larson, Vice President

APPROVED BY COMMISSIONERS
STEPHEN F. MECHAM
CONSTANCE B. WHITE CBW 3/21
RICHARD M. CAMPBELL RC

RECEIVED
FEB 26 11 27 AM '02
SERVICE COMMISSION

Michael O. Leavitt
Governor

Ted Boyer
Executive Director

Lowell E. Alt Jr.
Division Director

DIVISION OF PUBLIC UTILITIES
www.publicutilities.utah.gov
Heber M. Wells Building 4th Floor
160 East 300 South / S.M. Box 146751
Salt Lake City, Utah 84114-6751
Telephone: (801) 530-6651
Fax (801) 530-6512 or (801) 530-6650

To: Utah State Public Service Commission and Committee of Consumer Services

From: Lowell Alt, Director, Division of Public Utilities
Judith Johnson, Manager, Energy Section
Bob Maloney, Management Analyst

98-2035-04

Subject: Recommendation to Approve PacifiCorp's Claimed Major Event Exclusions for November 22 through November 27, 2001.

Date: Tuesday, February 26, 2002

We recommend that the Commission approve PacifiCorp's claimed major event exclusion for November 22 through November 27, 2001.

PacifiCorp has submitted data showing that significantly more than 10% of the customers in nine affected Utah operations areas experienced a sustained outage of more than five minutes duration during the major event.

ScottishPower/PacifiCorp merger condition #31 indicates that the Company may use the IEEE criteria to determine major events. IEEE criteria include:

1. Exceeds the design limits of the power system
2. Causes extensive damage to the power system
3. Results in more than 10% of the customers in an operations area experiencing a sustained outage.

We recommend approval based upon criterion #3. We do so because significantly more than 10% of PacifiCorp's Utah customers in nine affected operations areas experienced sustained outages.

1900 S.W. Fourth Avenue
Portland, Oregon 97201

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SERVICE COMMISSION

PACIFICORP
Pacific Power Utah Power

February 15, 2002

REVIEWED BY COMMISSIONERS
STEPHEN F. MECHAM
CONSTANCE B. WHITE CBW 2/27
RICHARD M. CAMPBELL RC

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Julie P. Orchard
Commission Secretary

RE: Docket No. 98-2035-04 ScottishPower/PacifiCorp Merger Commitments

Please find enclosed PacifiCorp's third quarter Outage Detail Report for the period October 2001 through December 2001. Year-to-date information is provided as well.

This report was previously delayed to allow for an update of customer counts by circuit. During the update process, it was discovered that customer counts by circuit were fluctuating from period to period in CADOPS. Further study confirmed that the customer count related to a particular outage is correctly reported based on the "as operated" model of the circuit at the time of the outage. CADOPS models a circuit as it is operated, not as the circuit is "normally operated" nor as it was originally built. Under the "as operated" model, a given circuit may be reconfigured to pick up the partial or complete load of second circuit. Such "as operated" models of a circuit can change from period to period due to normal load growth, unplanned and planned outages, special service requirements (such as Olympic venues), etc.

When an outage occurs on a reconfigured circuit, the outage data captured for the given circuit includes the affected customers of both former "normally operated" circuits. Such reconfigurations are often left "as is" and thus become the new "normally operated " model. Since these circuit reconfigurations occur on a regular basis to meet operating requirements, a consistent base for counting customers is currently not available. Further, the fluctuation of customer counts at the circuit level result in outage metric calculations (SAIDI, SAIFI, MAIFI, CAIDI, etc.) which are not meaningful nor comparable from period to period. However, because most circuit reconfigurations occur within the boundaries of a district, the customer counts become more stable at the *district* level, thus producing more meaningful outage metrics.

Based on the above, we are submitting the Outage Detail Report at a district level only, excluding the high and low circuit metrics. In the next few weeks, we will conduct a review to determine if there are any other reasonable reporting options and will submit our recommendations along with the year-end reports.

If you have any questions or require further information, please call me at (503) 813-7408.

Sincerely,

Carole Rockney / by Kms

Carole Rockney, Director
Customer and Regulatory Liaison

c: Mark Flandro - Utah Division of Public Utilities
Bob Maloney - Utah Division of Public Utilities
Rea Petersen - Utah Division of Public Utilities
Matthew Wright - Executive Vice President, Power Delivery

Enclosure

3rd Quarter Fiscal Year 2002 10/01/2001 to12/31/2001

Measure	Operating Area	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off *	Number of Occurrences	Customer Minutes Lost	Customers in Incident Momentary	Customers in Incident Momentary Eve	MC 33 Customers Exceeding State SAIFI	MC 38 Customers Affected by Transmission
Unplanned	**Utah**	49.807	0.475	0.090	0.090	104.783	798,900	379,748	2,478	39,791,080	71,899	71,899		
Planned	**Utah**	0.649	0.005	0.000	0.000	120.699	798,900	4,295	126	518,404	27	27		
Customer Requested	**Utah**	0.004	0.000	0.000	0.000	63.585	798,900	53	4	3,370	0	0		
Unplanned	AMERICAN FORK	18.466	0.253	0.042	0.042	72.855	73,862	18,721	204	1,363,915	3,116	3,116	10,490	0
Planned	AMERICAN FORK	0.186	0.002	0.000	0.000	83.176	73,862	165	15	13,724	0	0		
Customer Requested	AMERICAN FORK	0.000	0.000	0.000	0.000	0.000	73,862	0	0	0	0	0		
Unplanned	ASHLEY	5.356	0.044	0.000	0.000	122.976	9,620	419	30	51,527	2	2	0	0
Planned	ASHLEY	0.000	0.000	0.000	0.000	0.000	9,620	0	0	0	0	0		
Customer Requested	ASHLEY	0.000	0.000	0.000	0.000	0.000	9,620	0	0	0	0	0		
Unplanned	CANYONLANDS	3.557	0.118	0.014	0.014	30.270	14,483	1,702	28	51,520	210	210	1,700	1,364
Planned	CANYONLANDS	0.000	0.000	0.000	0.000	0.000	14,483	0	0	0	0	0		
Customer Requested	CANYONLANDS	0.000	0.000	0.000	0.000	0.000	14,483	0	0	0	0	0		
Unplanned	CARBON	5.838	0.075	0.000	0.000	77.711	11,089	833	30	64,733	0	0	210	0
Planned	CARBON	0.138	0.002	0.000	0.000	69.636	11,089	22	3	1,532	0	0		
Customer Requested	CARBON	0.000	0.000	0.000	0.000	0.000	11,089	0	0	0	0	0		
Unplanned	CEDAR CITY	30.334	0.314	0.063	0.063	96.684	23,953	7,515	57	726,582	1,508	1,508	2,287	0
Planned	CEDAR CITY	0.091	0.001	0.000	0.000	128.176	23,953	17	3	2,179	0	0		
Customer Requested	CEDAR CITY	0.000	0.000	0.000	0.000	0.000	23,953	0	0	0	0	0		
Unplanned	COTTONWOOD	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0	0	0
Planned	COTTONWOOD	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0		
Customer Requested	COTTONWOOD	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0		
Unplanned	DELTA	8.421	0.139	0.000	0.000	60.749	5,771	800	33	48,599	0	0	603	0
Planned	DELTA	0.000	0.000	0.000	0.000	0.000	5,771	0	0	0	0	0		
Customer Requested	DELTA	0.000	0.000	0.000	0.000	0.000	5,771	0	0	0	0	0		
Unplanned	LAYTON	103.585	0.848	0.200	0.200	122.112	47,897	40,630	162	4,961,422	9,580	9,580	30,544	0
Planned	LAYTON	0.173	0.004	0.000	0.000	44.310	47,897	187	5	8,286	0	0		
Customer Requested	LAYTON	0.000	0.000	0.000	0.000	0.000	47,897	0	0	0	0	0		
Unplanned	METRO	18.604	0.143	0.126	0.126	130.155	228,204	32,619	539	4,245,510	28,796	28,796	14,226	4
Planned	METRO	0.140	0.002	0.000	0.000	75.934	228,204	422	16	32,044	0	0		
Customer Requested	METRO	0.000	0.000	0.000	0.000	0.000	228,204	0	0	0	0	0		
Unplanned	MILFORD	141.349	0.861	0.059	0.059	164.078	2,440	2,102	32	344,892	143	143	961	0
Planned	MILFORD	0.000	0.000	0.000	0.000	0.000	2,440	0	0	0	0	0		
Customer Requested	MILFORD	0.000	0.000	0.000	0.000	0.000	2,440	0	0	0	0	0		
Unplanned	OGDEN	142.341	1.363	0.028	0.028	104.405	101,377	138,213	395	14,430,062	2,872	2,872	79,462	0
Planned	OGDEN	1.046	0.005	0.000	0.000	197.847	101,377	536	28	106,046	1	1		
Customer Requested	OGDEN	0.000	0.000	0.000	0.000	0.000	101,377	0	0	0	0	0		
Unplanned	PARK CITY	181.201	1.739	0.228	0.228	104.228	26,127	45,422	122	4,734,242	5,960	5,960	19,349	2
Planned	PARK CITY	6.063	0.030	0.000	0.000	200.783	26,127	789	7	158,418	0	0		
Customer Requested	PARK CITY	0.000	0.000	0.000	0.000	0.000	26,127	0	0	0	0	0		
Unplanned	SALINA	37.783	0.254	0.000	0.000	148.602	15,630	3,974	79	590,545	0	0	3,155	130
Planned	SALINA	0.000	0.000	0.000	0.000	0.000	15,630	0	0	0	0	0		
Customer Requested	SALINA	0.000	0.000	0.000	0.000	0.000	15,630	0	0	0	0	0		
Unplanned	SMITHFIELD	84.729	0.537	0.002	0.002	157.865	19,621	10,531	118	1,662,477	34	34	3,145	0
Planned	SMITHFIELD	0.052	0.000	0.001	0.001	112.667	19,621	9	1	1,014	26	26		
Customer Requested	SMITHFIELD	0.000	0.000	0.000	0.000	0.000	19,621	0	0	0	0	0		
Unplanned	SOUTH VALLEY	20.414	0.274	0.100	0.100	74.439	196,759	53,959	514	4,016,629	19,674	19,674	31,225	32
Planned	SOUTH VALLEY	0.937	0.010	0.000	0.000	89.313	196,759	2,064	44	184,342	0	0		
Customer Requested	SOUTH VALLEY	0.003	0.000	0.000	0.000	187.000	196,759	3	3	561	0	0		
Unplanned	TOOELE	152.130	1.399	0.000	0.000	108.743	14,018	19,611	65	2,132,560	4	4	7,932	0
Planned	TOOELE	0.000	0.000	0.000	0.000	0.000	14,018	0	0	0	0	0		
Customer Requested	TOOELE	0.200	0.004	0.000	0.000	56.180	14,018	50	1	2,809	0	0		
Unplanned	TREMONTON	45.466	0.335	0.000	0.000	135.656	8,047	2,697	70	365,865	0	0	3,187	0
Planned	TREMONTON	1.344	0.010	0.000	0.000	128.798	8,047	84	4	10,819	0	0		
Customer Requested	TREMONTON	0.000	0.000	0.000	0.000	0.000	8,047	0	0	0	0	0		
Unplanned	UINTA	0.000	0.000	0.000	0.000	0.000	2	0	0	0	0	0	0	0
Planned	UINTA	0.000	0.000	0.000	0.000	0.000	2	0	0	0	0	0		
Customer Requested	UINTA	0.000	0.000	0.000	0.000	0.000	2	0	0	0	0	0		

* The Customers Off count in this report is higher than reported in the previously submitted Customer Guarantees Summary. The difference is under investigation.

Fiscal Y-T-D | Fiscal Year 2002 | 04/01/00 to 12/31/01

Measure	Operating Area	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off *	Number of Occurrences	Customer Minutes Lost	Customers in Incident Momentary	Customers in Incident Momentary Eve	MC 33 Customers Exceeding State SAIFI	MC 38 Customers Affected by Transmission
Unplanned	Utah	169.571	1.679	0.232	0.231	100.998	798,900	1,341,308	9,095	135,469,922	185,328	184,831		
Planned	Utah	2.673	0.024	0.000	0.000	110.469	798,900	19,330	296	2,135,370	190	190		
Customer Requested	Utah	0.028	0.000	0.000	0.000	160.314	798,900	140	13	22,444	0	0		
Unplanned	AMERICAN FORK	92.130	1.158	0.212	0.212	79.572	73,862	85,519	705	6,804,928	15,623	15,623	13,867	2,001
Planned	AMERICAN FORK	1.311	0.024	0.000	0.000	54.638	73,862	1,772	25	96,819	0	0		
Customer Requested	AMERICAN FORK	0.003	0.000	0.000	0.000	245.000	73,862	1	1	245	0	0		
Unplanned	ASHLEY	199.165	1.374	0.102	0.102	144.995	9,620	13,214	143	1,915,970	985	985	1,187	0
Planned	ASHLEY	0.000	0.000	0.000	0.000	0.000	9,620	0	0	0	0	0		
Customer Requested	ASHLEY	0.000	0.000	0.000	0.000	0.000	9,620	0	0	0	0	0		
Unplanned	CANYONLANDS	48.554	0.512	0.234	0.234	94.772	14,483	7,420	161	703,206	3,383	3,383	835	1,364
Planned	CANYONLANDS	0.307	0.002	0.000	0.000	202.000	14,483	22	3	4,444	0	0		
Customer Requested	CANYONLANDS	0.000	0.000	0.000	0.000	0.000	14,483	0	0	0	0	0		
Unplanned	CARBON	159.570	1.405	0.008	0.008	113.580	11,089	15,579	192	1,769,467	92	92	4,293	2,340
Planned	CARBON	1.806	0.014	0.000	0.000	130.071	11,089	154	6	20,031	0	0		
Customer Requested	CARBON	0.000	0.000	0.000	0.000	0.000	11,089	0	0	0	0	0		
Unplanned	CEDAR CITY	288.259	2.287	0.102	0.102	126.064	23,953	54,771	374	6,904,673	2,432	2,432	7,087	4,584
Planned	CEDAR CITY	4.725	0.031	0.000	0.000	152.949	23,953	740	13	113,182	0	0		
Customer Requested	CEDAR CITY	0.004	0.000	0.000	0.000	106.000	23,953	1	1	106	0	0		
Unplanned	COTTONWOOD	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0	0	0
Planned	COTTONWOOD	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0		
Customer Requested	COTTONWOOD	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0		
Unplanned	DELTA	110.014	0.899	0.989	0.989	122.423	5,771	5,186	126	634,888	5,707	5,707	603	0
Planned	DELTA	0.000	0.000	0.000	0.000	0.000	5,771	0	0	0	0	0		
Customer Requested	DELTA	0.000	0.000	0.000	0.000	0.000	5,771	0	0	0	0	0		
Unplanned	LAYTON	210.399	2.264	0.331	0.331	92.931	47,897	108,440	512	10,077,459	15,838	15,838	18,825	0
Planned	LAYTON	2.219	0.097	0.000	0.000	22.881	47,897	4,645	18	106,283	0	0		
Customer Requested	LAYTON	0.000	0.000	0.000	0.000	0.000	47,897	0	0	0	0	0		
Unplanned	METRO	106.395	1.099	0.330	0.330	96.792	228,204	250,845	2,032	24,279,725	75,340	75,340	46,398	4
Planned	METRO	2.414	0.015	0.000	0.000	159.927	228,204	3,445	53	550,947	26	26		
Customer Requested	METRO	0.060	0.000	0.000	0.000	405.706	228,204	34	2	13,794	0	0		
Unplanned	MILFORD	338.938	2.572	0.140	0.140	131.794	2,440	6,275	120	827,008	342	342	1,344	495
Planned	MILFORD	0.000	0.000	0.000	0.000	0.000	2,440	0	0	0	0	0		
Customer Requested	MILFORD	0.000	0.000	0.000	0.000	0.000	2,440	0	0	0	0	0		
Unplanned	OGDEN	303.805	2.772	0.098	0.098	109.613	101,377	280,978	1,196	30,798,794	9,924	9,924	55,588	0
Planned	OGDEN	5.673	0.026	0.001	0.001	218.427	101,377	2,633	57	575,119	138	138		
Customer Requested	OGDEN	0.004	0.000	0.000	0.000	43.667	101,377	9	2	393	0	0		
Unplanned	PARK CITY	319.834	2.662	0.236	0.236	120.152	26,127	69,548	402	8,356,315	6,174	6,174	15,602	541
Planned	PARK CITY	7.340	0.037	0.000	0.000	198.523	26,127	966	9	191,773	0	0		
Customer Requested	PARK CITY	0.000	0.000	0.000	0.000	0.000	26,127	0	0	0	0	0		
Unplanned	SALINA	105.941	0.830	0.013	0.013	127.639	15,630	12,973	267	1,655,857	202	202	2,361	337
Planned	SALINA	0.227	0.002	0.000	0.000	148.000	15,630	24	1	3,552	0	0		
Customer Requested	SALINA	0.000	0.000	0.000	0.000	0.000	15,630	0	0	0	0	0		
Unplanned	SMITHFIELD	236.935	2.381	0.048	0.048	99.495	19,621	46,725	427	4,648,903	946	946	12,950	0
Planned	SMITHFIELD	0.192	0.002	0.001	0.001	76.898	19,621	49	4	3,768	26	26		
Customer Requested	SMITHFIELD	0.008	0.000	0.000	0.000	159.000	19,621	1	1	159	0	0		
Unplanned	SOUTH VALLEY	138.160	1.541	0.188	0.186	89.653	196,759	303,215	1,926	27,184,159	37,026	36,529	62,358	1,935
Planned	SOUTH VALLEY	2.248	0.023	0.000	0.000	96.579	196,759	4,580	98	442,331	0	0		
Customer Requested	SOUTH VALLEY	0.025	0.000	0.000	0.000	112.227	196,759	44	5	4,938	0	0		
Unplanned	TOOELE	530.757	4.895	0.758	0.758	108.427	14,018	68,619	277	7,440,148	10,626	10,626	13,648	1,088
Planned	TOOELE	1.069	0.014	0.000	0.000	74.915	14,018	200	3	14,983	0	0		
Customer Requested	TOOELE	0.200	0.004	0.000	0.000	56.180	14,018	50	1	2,809	0	0		
Unplanned	TREMONTON	182.481	1.491	0.085	0.085	122.358	8,047	12,001	234	1,468,422	688	688	3,147	0
Planned	TREMONTON	1.508	0.012	0.000	0.000	121.380	8,047	100	6	12,138	0	0		
Customer Requested	TREMONTON	0.000	0.000	0.000	0.000	0.000	8,047	0	0	0	0	0		
Unplanned	UINTA	0.000	0.000	0.000	0.000	0.000	2	0	1	0	0	0	0	0
Planned	UINTA	0.000	0.000	0.000	0.000	0.000	2	0	0	0	0	0		
Customer Requested	UINTA	0.000	0.000	0.000	0.000	0.000	2	0	0	0	0	0		

* The Customers Off count in this report is higher than reported in the previously submitted Customer Guarantees Summary. The difference is under investigation.

283506

State of Utah

DEPARTMENT OF COMMERCE

RECEIVED
FEB 21 6 23 PM '02
SERVICE COMMISSION

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Lowell E. Alt Jr.
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REVIEWED BY COMMISSIONERS
STEPHEN F. MECHAM SFM 2/26/02
CONSTANCE B. WHITE CBW 2/25
RICHARD M. CAMPBELL RC

MEMORANDUM

February 15, 2002

TO: **Mr. D. Douglas Larson**
Vice President, Regulation
PacifiCorp
201 South Main Street, Suite 2300
Salt Lake City, Utah 84140

FROM: UTAH DIVISION OF PUBLIC UTILITIES
Lowell E. Alt, Director
Judith Johnson, Manager - Energy Section
Mark V. Flandro, Utility Analyst

RE: **SCOTTISH POWER/PACIFICORP MERGER DOCKET NO. 98-2035-04, DIVISION OF PUBLIC UTILITIES REQUEST FOR STATUS OF COMPLIANCE WITH MERGER CONDITIONS AGREED TO AND ORDERED BY THE UTAH PUBLIC SERVICE COMMISSION'S ORDER OF NOVEMBER 23, 1999**

Dear Doug:

It has been over two years since the approval in Utah of the corporate merger between Scottish Power and PacifiCorp. The Division has spent some time attempting to determine whether specific Merger Conditions have been met that PacifiCorp and Scottish Power agreed to as part of the merger. As we have reviewed each of the merger conditions, we find that we have some compliance status information on some of the specific conditions and we find that we need more information on others. This letter is written to request that PacifiCorp provide the Division the current status of compliance with each of the merger conditions and stipulations Ordered in the Utah Public Service Commission's November 23, 1999 Order in Docket No. 99-2035-04. The Division is very interested in this information and will make a report to the Commission after evaluating PacifiCorp's status response.

To assist PacifiCorp in complying with this request, the attached file lists all of the

Ordered specific merger conditions and second party stipulations/letter agreements individually, each followed by a "*Compliance Status*" section where the compliance status for each condition or stipulation can be provided. On many of the conditions/stipulations/letter agreements, we have indicated our current understanding of the status and we ask you to verify our understanding statements and correct or add to the information as necessary. On other conditions/stipulations, we do not know or cannot confirm the compliance status and thus are relying on PacifiCorp to provide the accurate status information statement.

Condition 1, an extensive condition running about 19 pages in our attachment, stems from Mr. Alan Richardson's Supplemental Testimony Exhibit AVR-1 some of which is somewhat repeated in subsequently numbered Conditions, so rather than answering the same condition twice, compliance status statements can be or are cross referenced from one condition to the other as appropriate. (Please note that the information on Condition 1 is lengthy and that Conditions 2, 3, etc really do follow-on starting on about page 19).

We realize that there is a great amount of work on other Dockets underway, but we request that PacifiCorp take the time to provide this merger condition compliance data to Utah regulators in a timely manner. We would hope to have your data response by the end of March 2002 so the Division can provide its report to the Commission by the end of April 2002.

Please direct any questions regarding this request to Mark Flandro, 801-530-6788 or Judith Johnson, 801-530-6649.

Attachment: DPU Review of Merger Conditions Compliance, February 2002 View

C: Ted Boyer, Executive Director
Utah Public Service Commission
Michael Ginsberg, Utah AG Office
Roger Ball, CCS
Dan Gimble, CCS
Wes Huntsman, DPU Customer Service

28357

SCOTTISH POWER/PACIFICORP MERGER
Utah PSC Docket No. 98-2035-04
DPU Review of Merger Conditions Compliance
February 2002 View

This Division of Public Utilities compliance status review of the Scottish Power/PacifiCorp Merger Conditions and Second-Party Stipulations looks at the 51 conditions stipulated to by most parties in the merger case, a 52nd condition Ordered by the Commission, and four second-party stipulations also in the Commission's November 23, 1999 merger Order.

Condition 1

ScottishPower and PacifiCorp shall agree to all commitments and conditions as included in Witness Alan Richardson's Supplemental Testimony Exhibit AVR-1 (a copy of which is attached as Attachment 1 *[to the Order]*). In the event of any conflict between Attachment 1 and this Stipulation, the terms of this Stipulation shall govern.

Compliance Status:

The commitments and conditions included in Alan Richardson's Supplemental Testimony Exhibit AVR-1 consists of 12 pages of detailed information. This information is shown below as part of "Compliance Status" for Condition 1. The status of PacifiCorp's compliance with each of these individual items will be shown after each sub-section of Mr. Richardson's 12 page Exhibit which is Condition 1.

[Scottish Power, Richardson (Supplemental Testimony)]

BENEFITS TO CUSTOMERS FROM THE TRANSACTION

I. CUSTOMER SERVICE

A. Network Performance

1. System Availability. On the five-year anniversary of the completion of the transaction, the underlying System Average Interruption Duration Index (SAIDI) for PacifiCorp customers in the State of Utah will have been reduced by 10%.

Compliance Status:

PacifiCorp, please provide compliance status. *During the 2000 through 2001 period, PacifiCorp spent approximately $44.6 million to upgrade the distribution system along the Wasatch Front.*

PacifiCorp estimates that in doing so it reduced the # of outage incidents by approximately 24%. The Division is working with PacifiCorp to determine the extent reducing the # of outage incidents may have also reduced SAIDI. At the time of the merger, PacifiCorp estimated that reducing SAIDI by 10% and MAIFI by 5% would enable Utah customers to save approximately $20 million annually. The estimated savings are attributable to reductions in economic losses attributable to outages. By 5/15/02, PacifiCorp plans to estimate the 1994 through 1998 average SAIDI baseline, against which the Company plans to measure its targeted 10% reduction in SAIDI during 2005. Also, see the status report on merger condition 27.

2. <u>System Reliability.</u> On the five-year anniversary of the completion of the transaction, the underlying System Average Interruption Frequency Index (SAIFI) for PacifiCorp customers in the State of Utah will have been reduced by 10%.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>. During the 2000 through 2001 period, PacifiCorp spent approximately $44.6 million to upgrade the distribution system along the Wasatch Front. PacifiCorp estimates that in doing so it reduced the # of outage incidents by approximately 24%. The Division is working with PacifiCorp to determine the extent reducing the # of outage incidents may have also reduced SAIFI. (At the time of the merger, PacifiCorp estimated that reducing SAIDI - - <u>which correlates with SAIFI</u> – by 10% and MAIFI by 5% enabled Utah customers to save approximately $20 million annually. The estimated savings are attributable to reductions in economic losses attributable to outages. By 5/15/02, PacifiCorp plans to estimate the 1994 through 1998 average SAIFI baseline, against which the Company plans to measure its targeted 10% reduction in SAIFI during 2005. Also, see the status report on merger condition 27.

3. <u>Momentary Interruptions.</u> On the five-year anniversary of the completion of the transaction, the Momentary Average Interruption Frequency Index (MAIFI) for PacifiCorp customers in the State of Utah will have been reduced by 5%.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>. By January 2003, PacifiCorp plans to report on its progress in more accurately reporting MAIFI. During early 2005, the Company plans to recommend a MAIFI uplift factor for the 1994 through 1998 average MAIFI baseline. The Company will then determine whether it has achieved a targeted 5% reduction against this baseline.

4. <u>Worst Performing Circuits.</u> The 5 worst performing circuits in the State of Utah will be selected annually on the basis of the Circuit Performance Indicator (CPI), as calculated over a three-year average excluding extreme events. Corrective measures will be taken within 2 years of implementation of the performance targets to reduce the CPI by 20%.

Compliance Status:

PacifiCorp, please provide compliance status. PacifiCorp has identified the five worst performing circuits for the three years ending 12/31/98 as Fiscal Year 2001 circuits. The Company identified the five worst performing circuits for the three years ending 12/3100 as Fiscal Year 2002 circuits. PacifiCorp considers 1999 a transition year.

PacifiCorp uses a Circuit Performance Indicator (CPI) to identify the five worst performing circuits in Utah. PacifiCorp's CPI is a weighted composite index based upon SAIDI, SAIFI, MAIFI, and the # of lockouts. After two-year improvement periods, the Company will determine whether it has met its commitment to reduce the CPIs by 20%.

5. Supply Restoration. For power outages because of a fault or damage on PacifiCorp's system, PacifiCorp will restore supplies on average to 80% of customers within 3 hours.

Compliance Status:

PacifiCorp, please provide compliance status. Review of PacifiCorp's Customer Guarantee and Performance Standards reports indicate that PacifiCorp has been consistently restoring, on a statewide basis, more than 80% of all outages within 3 hours.

6. Penalties. For each of the standards not achieved in the State of Utah at the end of the five-year period, ScottishPower will pay a financial penalty equal to $1.00 for every customer served by PacifiCorp in Utah.

Compliance Status:

PacifiCorp, please provide compliance status. The Division understands that PacifiCorp plans to measure its performance during fiscal year 2005 (ending 3/31/06) for each of the five standards. Then, for each standard it fails to meet, PacifiCorp then plans to pay a $1.00 penalty for every customer in PacifiCorp Utah.

7. Implementation. Specific terms and conditions relating to the implementation of the Network Performance Standards are set forth in Appendix A.(3)

B. Customer Service Performance

1. Telephone Service Levels. Within 120 days after completion of the transaction, 80% of calls to PacifiCorp's Business Centers will be answered within 30 seconds. This target will be increased to 80% in 20 seconds by January 1, 2001 and 80% in 10 seconds by January 1, 2002.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>. PacifiCorp has been answering telephone calls within required time intervals. See the status report on merger conditions # 27 and #35 for more information regarding PacifiCorp's performance in answering telephones. The PSC has allowed the Company to retain the 80% in 20 seconds beyond January 1, 2002 by Order after application from PacifiCorp.

2. <u>Complaint Resolution.</u>

a. <u>Non-Disconnect Complaints.</u> Within 90 days after completion of the transaction, PacifiCorp will investigate and provide a response to all complaints referred by the Commission within 3 business days. [business days are defined as Monday thru Friday excluding company holidays].

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>. PacifiCorp's end of September 2001 Customer Guarantee Report indicates that 99% of PSC complaints were responded to within 3 days. No similar data was made available by PacifiCorp for the 90 day period ending February 21, 2000 from the November 23, 1999 merger approval date (completion of transaction date).

b. <u>Disconnect Complaints.</u> Within 90 days after completion of the transaction, complaints related to service disconnection will be responded to within 4 business hours. [business hours are defined as 8:00 a.m. to 5:00 p.m.]. [though not specifically stated here, the target performance level for this measurement is <u>all</u> calls, 100%].

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>. PacifiCorp's end of September 2001 Customer Guarantee Report indicates that 100% of PSC complaints regarding disconnects were responded to within 4 hours. No similar data was made available by PacifiCorp for the 90 day period ending February 21, 2000 from the November 23, 1999 merger approval date (completion of transaction date).

c. <u>Commission Complaints.</u> Within 90 days after completion of the transaction, ninety percent of complaints referred to PacifiCorp by the Commission will be resolved within 30 days. This percentage will be increased to 95 percent by 2001.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>. (This target was changed from 90% to 95% in 2001). PacifiCorp's end of September 2001 Customer Guarantee Report indicates that 97% of PSC complaints were resolved within 30 days. No similar data was made available by

PacifiCorp for the 90 day period ending February 21, 2000 from the November 23, 1999 merger approval date (completion of transaction date).

3. Implementation. Specific terms and conditions relating to the implementation of the Customer Service Performance Standards are set forth in Appendix A.

C. Customer Service Guarantees *(Please see summary compliance status for Customer Service Guarantees section after item C9 below).*

1. Restoring the Customer's Supply.

a. Guarantee. If the customer loses electricity supply because of a fault in PacifiCorp's system, PacifiCorp will restore the customer's supply as soon as possible.

b. Penalty. If power is not restored in 24 hours, customers can claim $50 for residential customers and $100 for commercial and industrial customers. For each extra period of 12 hours the customer's supply has not been activated, the customer can claim $25.

2. Appointments.

a. Guarantee. PacifiCorp will keep all mutually agreed appointments with the customer, whether over the phone or in writing. Beginning in the year 2001, PacifiCorp will offer the customer a morning appointment, between 8 AM and 1 PM, or an afternoon appointment, between 12 Noon and 5 PM.

b. Penalty. If PacifiCorp fails to meet its guarantee, PacifiCorp will automatically pay the customer $50.

3. Switching On the Customer's Power.

a. Guarantee. Upon customer request, PacifiCorp will activate the power supply within 24 hours provided no construction is required and all government requirements are met.

b. Penalty. If PacifiCorp fails to meet its guarantee, it will automatically pay the customer $50. In addition, for each extra period of 12 hours the customers power supply has not been activated, PacifiCorp will automatically pay-out $25 to the customer.

4. <u>Estimates for Providing a New Supply.</u>

a. <u>Guarantee.</u> Upon request by a customer for new power supply, PacifiCorp will call the customer back within 2 business days of the customer's initial call and schedule a mutually agreed appointment with an estimator. If PacifiCorp needs to change its network, it will provide a written estimate to the customer within 15 business days of the customer's initial meeting with the estimator. If PacifiCorp does not need to change its network, it will provide an estimate to the customer within 5 business days of the customer's initial meeting with the estimator.

b. <u>Penalty.</u> If PacifiCorp fails to meet its guarantee, PacifiCorp will automatically pay the customer $50 for each failure.

5. <u>Response to Bill Inquiry.</u>

a. <u>Guarantee.</u> PacifiCorp will investigate and respond within 15 business days of a customer's inquiry about its electric bill.

b. <u>Penalty.</u> If PacifiCorp fails to meet its guarantee, PacifiCorp will automatically pay the customer $50 for each failure.

6. <u>Problems with the Customer's Meter.</u>

a. <u>Guarantee.</u> PacifiCorp will investigate and report back to the customer within 15 business days if the customer suspects a problem with its meter.

b. <u>Penalty.</u> If PacifiCorp fails to meet its guarantee, PacifiCorp will automatically pay the customer $50 for each failure.

7. <u>Planned Interruptions.</u>

a. <u>Guarantee.</u> PacifiCorp will give the customer at least 2 days notice if it is necessary to turn the customer's power supply off for planned maintenance work or testing.

b. <u>Penalty.</u> If PacifiCorp fails to meet its guarantee, customers can claim $50 for residential customers and $100 for commercial and industrial customers.

8. <u>Power Quality Complaints.</u>

a. <u>Guarantee.</u> Upon notification from a customer about a problem with the quality of electric supply, PacifiCorp will either initiate an investigation within 7 days or explain the problem in writing within 5 business days.

b. Penalty. If PacifiCorp fails to meet its guarantee, it will automatically pay the customer $50.

9. Implementation. Specific terms and conditions relating to the implementation of the Customer Service Guarantees are set forth in Appendix B. Data calculations to measure performance will be audited by the company and an outside auditor.

Compliance Status:

PacifiCorp, please provide compliance status. On May 5, 2000, PacifiCorp filed a new Electric Service Regulation No. 25, General Rules and Regulations Customer Guarantees, which became effective July 1, 2000. This Regulation incorporated all of the merger Richardson testimony items C1 through C9 above with even an improvement in item C5 (15 to 10 days). This Regulation is in force and PacifiCorp is offering all of these guarantees to its Utah customers.

PacifiCorp has been meeting its commitment to provide $50 service credits for its failures to meet performance requirements specified for eight types of field service. On 5/31/01, the Company reported that its Guarantee Program was awarded the ISO 9001:2000 quality certification for performance during January through March of 2001. The certification focuses on how well the program is implemented and managed. PacifiCorp indicates it conducts internal and external audits to maintain this status.

The Company has also been meeting its commitment to report its performance in implementing the Guarantee Program. For example, each quarter PacifiCorp reports the # of service guarantee failures on a district basis. However, in the near future, the Company plans to add to the report the # of failures as a percentage of the total # of events. Reporting ratios will provide a performance focus. See the status report for merger condition #34 for more information on PacifiCorp's field response reporting.

10. Reporting.

a. To Customers. PacifiCorp will issue a report to the customer by June 30 of each year regarding its record in improving Performance Standards and how well it has performed against its Customer Guarantees. Each report will contain an overview of standards, targets and guarantees and describe the performance results for that year. The report will also discuss any new targets PacifiCorp will be applying in the coming year.

Compliance Status:

PacifiCorp, please provide compliance status. The Customer Guarantee Regulation became effective on July 1, 2000, the June annual report to customers was due by June 30, 2001. Was such a report made? Please provide the DPU a copy of this report. Is a June 30, 2002 report to customers to be prepared. What method does PacifiCorp utilize to physically give this *information to customers?*

b. To Commission. PacifiCorp will provide an annual report to the Commission by May 31 of each year that will discuss implementation of ScottishPower's programs and procedures for providing improved performance. The report will provide a general summary of how PacifiCorp performed according to the standards, targets and guarantees. The report will: (i) provide performance results for each standard, target or guarantee; (ii) identify excluded exceptions; (iii) explain any historical and anticipated trends and events that affected or will affect the measure in the future; (iv) describe any technological advancements in data collection that will significantly change any performance indicator; (v) discuss any "phase in" of new standards, targets or guarantees; and (vi) include the name and telephone numbers of contacts at PacifiCorp to whom inquiries should be addressed. If the company is not meeting a standard, target or guarantee, the report will: (i) provide an analysis of relevant patterns and trends; (ii) describe the cause or causes of the unacceptable performance; (iii) describe the corrective measures undertaken by the company; (iv) set a target date for completion of the corrective measures; and (v) provide details of any penalty payments due.

Compliance Status:

PacifiCorp, please provide compliance status. PacifiCorp provided its first annual report to the PSC on May 31, 2001. Also, see the status of merger conditions 27, 33, 34, and 36 for more information regarding the Company's performance in reporting service results.

II. REGULATORY OVERSIGHT

A. Access to Books and Records

1. PacifiCorp will maintain its own accounting system, separate from ScottishPower's accounting system. All PacifiCorp financial books and records will be kept in Portland, Oregon, and will continue to be available to the Commission upon request at PacifiCorp's offices in Portland, Salt Lake City, Utah, and elsewhere in accordance with current practice.

Compliance Status:

PacifiCorp, please provide compliance status. Based upon audits of PacifiCorp's semi-annual reports, the DPU observes that PacifiCorp is in compliance with this merger condition.

B. Cost Allocation, Affiliated Interest Transactions

1. By the end of the third year following the completion of the transaction, ScottishPower will have achieved a net reduction of $10 million annually in PacifiCorp's corporate costs ($15 million of annual cost savings in corporate costs which, when offset by $5 million of cost increases, will produce a net reduction of $10 million annually in corporate costs). ScottishPower will commit to reflecting this reduction in PacifiCorp's results of operations filed with the Commission.

Compliance Status:

PacifiCorp, please provide compliance status. *Please indicate where and how PacifiCorp has reflected this type of reduction in results of operations filed with the PSC.*

2. ScottishPower will provide an analysis of its proposed allocation of corporate costs within ninety days after completion of the transaction.

Compliance Status:

PacifiCorp, please provide compliance status. *The DPU recalls that PacifiCorp made an initial attempt to provide this proposed allocation of corporate costs and then withdrew it. What is the status of this item?*

3. To determine the reasonableness of allocation factors used by ScottishPower to assign costs to PacifiCorp and amounts subject to allocation or direct charges, the Commission or its agents may audit the records of ScottishPower which are the bases for charges to PacifiCorp. ScottishPower will cooperate fully with such Commission audits.

Compliance Status:

PacifiCorp, please provide compliance status. *The DPU is not aware of any situations where there has been any need for the DPU or others to directly audit the records of Scottish Power.*

4. ScottishPower and PacifiCorp will provide the Commission access to all books of account, as well as all documents, data and records of their affiliated interest, which pertain to any transactions between PacifiCorp and its affiliated interests.

Compliance Status:

PacifiCorp, please provide compliance status. *The DPU observes that PacifiCorp is generally in compliance with this merger condition.*

5. ScottishPower and PacifiCorp agree to comply with all existing Commission

statutes and regulations regarding affiliated interest transactions, including timely filing of applications and reports.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>. The DPU recalls it received March 2000 information in September 2000 but has not seen any information since that time.

6. ScottishPower will not subsidize its activities by allocating to or directly charging PacifiCorp expenses not authorized by the Commission to be so allocated or directly charged.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>. The DPU has no specific compliance information regarding this condition. Audits have not indicated lack of compliance.

7. Neither ScottishPower nor PacifiCorp will assert in any future Commission proceeding that the provisions of the Public Utility Holding Company Act of 1935 preempt the Commission's jurisdiction over affiliated interest transactions.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>. The DPU is not aware of any such claims being made to date.

C. Transaction Costs

1. ScottishPower and PacifiCorp will exclude all costs of the transaction from PacifiCorp's utility accounts.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>.

D. Financial Issues

1. ScottishPower intends to achieve an actual capital structure equivalent to that of comparable, A-rated electric utilities in the U.S., with a common equity ratio for PacifiCorp of not less than 47%.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>. The DPU is interested in PacifiCorp's actual capital structure following its internal restructuring as reported in the December 31, 2001 10Q.

2. PacifiCorp will maintain separate debt and, if outstanding, preferred stock ratings.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>.

3. ScottishPower and PacifiCorp will provide the Commission with unrestricted access to all written information provided to common stock, bond, or bond rating analysts, which directly or indirectly pertains to PacifiCorp.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>. It appears to the DPU that PacifiCorp is generally in compliance with this condition.

III. COMMITMENT TO THE ENVIRONMENT

A. Renewable Resources

1. PacifiCorp will develop an additional 50 MW of renewable resources (wind, solar and/or geothermal) at an anticipated cost of approximately $60 million within five years after completion of the transaction.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>. The DPU is aware that PacifiCorp recently (end of 2001) began operation of a new 50 MW Wyoming wind farm at Foote Creek Rim. PacifiCorp has a 20 year agreement to purchase the entire output of the project which is made up of 50, 1 MW wind turbines. Recent newspaper articles indicate that "The project fulfills a commitment PacifiCorp made at the time of its merger with Scottish Power to bring significant new renewable resources online for its customers". Please confirm if this new contract is related to this merger condition and provide the details as well as costs.

2. Within 60 days after completion of the transaction, PacifiCorp will file applications in each state for a "green resource" tariff.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>. PacifiCorp filed on January 28, 2000 for approval of a green resource tariff in Utah, to be called the "Blue Sky" program, Electric Service Schedule No. 70 - New Wind, Geothermal and Solar Power Rider - Optional. This rate schedule was approved by the PSC on April 17, 2000. PacifiCorp is in compliance with this merger condition.

3. PacifiCorp will contribute $100,000 to the Bonneville Environmental Foundation for use in the development of new renewable resources and fish mitigation projects.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>. PacifiCorp, did this contribution take place? Please provide the details.

B. Environmental Management

1. PacifiCorp will have environmental management systems in place that are self-certified to ISO 14001 standards at all PacifiCorp operated thermal generation by the end of 2000.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>. DPU has no information on PacifiCorp's actions (if any) regarding this condition.

2. ScottishPower will include PacifiCorp operations in ScottishPower's comprehensive annual environmental report with appropriate specific goals.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>. DPU has no information on PacifiCorp's actions (if any) regarding this condition.

3. ScottishPower will include a PacifiCorp officer on the Environmental Policy Advisory Committee.

Compliance Status:

PacifiCorp, please provide compliance status. DPU has no information on PacifiCorp's actions (if any) regarding this condition.

4. ScottishPower will develop a process to gather outside input on environmental matters, such as the establishment of an Environmental Forum.

Compliance Status:

PacifiCorp, please provide compliance status. DPU has no information on PacifiCorp's actions (if any) regarding this condition.

IV. COMMITMENT TO COMMUNITIES

A. Financial Contribution

1. ScottishPower will contribute $5 million to the PacifiCorp Foundation upon completion of the transaction.

Compliance Status:

PacifiCorp, please provide compliance status. It is the opinion of some on the DPU staff that this merger condition contribution was made. Please provide the history and details of this contribution. Was it made above or below the line? Please provide the location of reporting in company reports such as semi-annual, etc.

2. ScottishPower will maintain the existing level of PacifiCorp's other community-related contributions, both in terms of monetary and in-kind contributions.

Compliance Status:

PacifiCorp, please provide compliance status. DPU has no specific information on PacifiCorp's actions (if any) regarding this condition. What was the base line level of contributions? Is PacifiCorp complying? How is this measured and reported? Please help the DPU understand and be able to determine compliance with this condition.

B. Programs

1. ScottishPower will develop, in consultation with the appropriate Utah state

educational authorities and the local business community, a "School to Work" initiative. Skill development opportunities will be made available through the Open Learning Centers, work experience mentoring, and work shadowing.

Compliance Status:

PacifiCorp, please provide compliance status. DPU has no information on PacifiCorp's actions (if any) regarding this condition.

2. ScottishPower will maintain the existing Regional Advisory Boards.

Compliance Status:

PacifiCorp, please provide compliance status. DPU has no specific information on PacifiCorp's actions (if any) regarding this condition. Please help us understand where the Regional Advisory Board structure and utilization presently stands.

C. Low-Income Customers

1. ScottishPower will commit $1.5 million per year (in addition to PacifiCorp's existing commitment of $1.5 million annually) to programs that encourage the economic well-being of communities, including the following:

Compliance Status:

PacifiCorp, please provide compliance status.

a. ScottishPower will double the number of customers assisted by the heat assistance funding program for those customers who qualify under the Federal Low Income Energy Assistance Program and will reintroduce the matching concept with PacifiCorp matching customer donations to heat assistance programs annually.

Compliance Status:

PacifiCorp, please provide compliance status.

b. ScottishPower will establish a debt counseling service for those customers who have difficulty in paying their monthly electric bills.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>.

c. ScottishPower will expand the commitment to educate customers regarding energy efficiency in order to help customers with payment difficulties, and to promote electricity safety for all customers.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>.

V. COMMITMENT TO EMPLOYEES

A. Existing Labor Agreements

1. ScottishPower will honor existing labor contracts with all levels of staff.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>. DPU has no information on PacifiCorp's actions (if any) regarding this condition.

B. New Programs

1. ScottishPower will introduce the following programs in the PacifiCorp service territory, upon completion of the transaction, at a start-up cost of approximately $3 million and estimated annual expenditures of approximately $1 million:

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>. DPU assumes that "following programs" refers to B.1.a, B.1.b and B.1.c below. DPU has no information on PacifiCorp's actions (if any) regarding this condition. Please report on the status of the start up $3 million and annual expenditures around $1 million for these items.

a. ScottishPower will develop one "best-in-class" training center in each of Oregon and Utah. These centers will provide employees with opportunities to improve their work-related skills.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>. DPU has no information on PacifiCorp's actions (if any) regarding this condition.

b. ScottishPower will phase in the introduction of the ScottishPower Open Learning centers. At these Open Learning centers, employees will be able to supplement their work-related skills with other skills designed to enhance their overall knowledge.

Compliance Status:

PacifiCorp, please provide compliance status. DPU has no information on PacifiCorp's actions (if any) regarding this condition.

c. ScottishPower will establish partnerships with local colleges and universities to develop management training programs.

Compliance Status:

PacifiCorp, please provide compliance status. DPU has no information on PacifiCorp's actions (if any) regarding this condition.

C. Occupational Health

1. ScottishPower will examine the appropriateness of introducing for PacifiCorp employees its successful programs already adopted in the U.K. to encourage a healthy lifestyle for employees.

Compliance Status:

PacifiCorp, please provide compliance status. DPU has no information on PacifiCorp's actions (if any) regarding this condition.

[THE FOLLOWING TABLE INFORMATION IS PART OF THE QUOTED MATERIAL FROM MR. RICHARDSON'S SUPPLEMENTAL TESTIMONY, BUT CONTAINS NO COMPLIANCE STATUS INFORMATION FOR THE DPU'S REPORT. THE READER CAN PROCEED TO MERGER CONDITION NO. 2 ON ABOUT PAGE 19]

July 28, 1999 Stipulation - Attachment No. 1

Scottish Power, Richardson (Supplemental Testimony)

EXHIBIT A

Performance Standards

Standard

Clarification

System Availability (SAIDI)

SAIDI will exclude extreme events (storms). This allows measurement of the underlying performance of the asset base.

System Reliability

(SAIFI)

SAIFI will exclude extreme events

Momentary Interruptions (MAIFI)

MAIFI will exclude extreme events

Worst Performing Circuits

CPI will exclude extreme events. It will also exclude instances where the company is delayed due to the company's inability to obtain the appropriate planning consents.

Supply Restoration

Restoration time will exclude extreme events. It will also exclude situations where a customer agrees to remain without power or where PacifiCorp is unable to restore supply due to problems with the customer's facility, or where PacifiCorp does not have access.

Telephone Service Levels

Telephone service levels will be defined as percent of calls answer within targeted time frame. Telephone service levels will be measured from the time the customer selects a menu option and is placed in queue until a CSE or interactive voice response (IVR) unit answers the call.

Commission Complaint Resolution

The company may request an extension of time to respond to a complaint, which may be granted by Commission Staff. Business days are defined as Monday through Friday excluding company holidays. Business hours are defined as 8:00 a.m. to 5:00 p.m.

EXHIBIT B

Customer Guarantees

Standard	Clarification
Restoring Your Supply	Guarantee does not apply if any one of the following occur: 1) Extreme events, 2) Strikes, 3) There are safety-related issues, 4) Customer has agreed to remain without power, or 5) Problems exist with the customer's facility.
Appointments	Guarantee does not apply if any one of the following occur: 1) Extreme events, 2) Strikes, 3) Major system outages, 4) Customer is out when PacifiCorp calls, 5) Customer cancels the appointment, or 6) PacifiCorp cancels the appointment and provides you with at least 24 hours notice.
Switching on the Customer's Power	Guarantee does not apply if any one of the following occur: 1) Extreme events, 2) Strikes, 3) Major system outages, 4) Customer is out when PacifiCorp calls, or 5) There are safety-related issues.
Estimates for Providing a New Supply	Guarantee does not apply if any one of the following occur: 1) Extreme events, 2) Strikes, 3) Major system outages, 4) Customer is out when PacifiCorp calls, 5) Customer cancels the appointment, 6) PacifiCorp cancels the appointment and provides you with at least 24 hours notice, or 7) Customer has not supplied all the necessary information so PacifiCorp can provide the estimate.
Response to Bill Inquiry	Working days are defined as Monday through Friday

excluding company holidays.

Problems with Your Meter

Guarantee does not apply if any one of the following occur:

1) Extreme events, 2) Strikes, 3) PacifiCorp personnel do not have access to the customer's meter, 4) Meter tests shall be limited to no more frequently than once every 12 months.

Planned Interruptions

Guarantee does not apply if any one of the following occur:

1) Extreme events, 2) Strikes, 3) Major system outages, or

4) There are safety-related issues.

Power Quality Complaints

Working days are defined as Monday through Friday excluding company holidays.

Condition 2

On June 18, 1999, ScottishPower and PacifiCorp filed a proposed cost allocation methodology for the allocation of corporate and affiliate investments, expenses, and overheads. In or about October 1999, PacifiCorp and ScottishPower shall schedule a conference/meeting with regulators in all PacifiCorp states (including CCS in Utah) to discuss the proposed and alternative corporate and affiliate cost allocation methodologies. The DPU agrees to use its reasonable best efforts to reach agreement with the other state regulators as to the corporate cost allocation methodology to be recommended to the respective state commissions. In the event the state regulators are unable to reach agreement or the DPU concludes that the methodology supported by any of the other U.S. regulatory states would cause actual or perceived financial harm or inequity (on the basis of projections at that time) to the ratepayers in Utah, the DPU may support or recommend such allocation methodology to the Commission as it determines to be appropriate. ScottishPower assumes the ScottishPower assumes the risk of whatever allocation methodologies or decisions the Commission may adopt.

Any proposed methodology to be submitted to the Commission for approval will comply with the following principles:

(a) For services rendered to PacifiCorp or each cost category subject to allocation to PacifiCorp by ScottishPower or any of its affiliates, ScottishPower must be able to demonstrate that such service or cost category is necessary to PacifiCorp for the performance of its regulated operations, is not duplicative of services already being performed within PacifiCorp, and is reasonable and prudent.

(b) Cost allocations to PacifiCorp and its subsidiaries shall be based on generally accepted accounting standards, that is, in general, direct costs shall be charged to specific subsidiaries whenever possible and shared or indirect costs shall be allocated based upon the primary cost-driving factors.

(c) ScottishPower shall have in place time reporting systems adequate to support the allocation of costs of executives and other relevant personnel to PacifiCorp.

(d) An audit trail shall be maintained such that all costs subject to allocation can be specifically identified, particularly with respect to their origin. In addition, the audit trail must be adequately supported. Failure to adequately support any allocated cost may result in denial of its recovery in rates.

(e) Costs which would have been denied recovery in rates had they been incurred by PacifiCorp regulated operations will likewise be denied recovery whether they are allocated directly or indirectly through subsidiaries in the ScottishPower group.

(f) Any corporate cost allocation methodology used for rate setting in Utah, and subsequent changes thereto, must be approved by the Utah Commission.

ScottishPower also assumes the risk of the Commission's approval or adoption of corporate cost allocation methodologies which differ from those adopted by U.K. regulatory agencies.

Compliance Status:

PacifiCorp, please provide compliance status. *DPU recalls that an a cost allocation methodology for allocation of corporate and affiliate investments, expenses and overheads was filed or at least discussed at the time of merger discovery but was subsequently withdrawn. DPU understands that no new methodology has been proposed and that no cost allocations other than direct costs are being charged by Scottish Power to PacifiCorp at present. Is there a future plan for a new cost allocation methodology? Please explain.*

Condition 3

No merger transaction related costs shall be allowed in rates. Enhancements to severance costs relating to the merger will not be allowed in rates. Normal severance costs may be considered for allowance in rates. Future costs arising as a result of the transition plan which result in net cost savings may be considered for allowance in rates. The Applicants agree that they will not in any future rate case in Utah argue for inclusion in rates of any of the items described in Attachment 2.

Compliance Status:

<u>PacifiCorp, please provide compliance status.</u> At this point in time, DPU has no direct information or evidence as to whether or not PacifiCorp has complied with this condition.

<u>Condition 4</u>

Any diversified holdings and investments (e.g., non-utility business or foreign utilities) of ScottishPower shall not be held by PacifiCorp, the entity for utility operations, or a subsidiary of PacifiCorp. This condition shall not prohibit the continued holding of any existing investments or the holding of diversified businesses and investments by affiliates of PacifiCorp.

Compliance Status:

<u>PacifiCorp, please provide compliance status.</u> At this point in time, DPU has no direct information or evidence as to whether or not PacifiCorp has complied with this condition.

<u>Condition 5</u>

ScottishPower and PacifiCorp agree to notify the Commission subsequent to ScottishPower's Board approval and as soon as practicable following any public announcement of (1) an acquisition of a regulated or non-regulated business representing 5% or more of the market capitalization of ScottishPower or entering into a new business venture or expansion of an existing one, or (2) a merger, combination, transfer of stock or assets of any material part or all of PacifiCorp or the direct owner of PacifiCorp stock. In addition, PacifiCorp shall comply with the provisions of Utah Code Ann. §§ 54-4-28 through 54-4-31.

Compliance Status:

<u>PacifiCorp, please provide compliance status.</u> At this point in time, DPU has no direct information or evidence as to whether or not PacifiCorp has complied with this condition.

<u>Condition 6</u>

ScottishPower shall comply with PacifiCorp's Transfer Pricing Policy, as currently in effect or hereafter amended with the approval of the Commission, in respect of transactions with PacifiCorp.

Compliance Status:

<u>PacifiCorp, please provide compliance status.</u> Is PacifiCorp complying with the Utah PSC's adopted transfer pricing policy?

Condition 7

PacifiCorp or ScottishPower shall notify the Commission, and provide sufficient information and documentation to the Commission, prior to the implementation of plans by either PacifiCorp or ScottishPower (1) to form an affiliate entity for the purpose of transacting business with the regulated operations of PacifiCorp, (2) to commence new business transactions between an existing affiliate and with the regulated operations of PacifiCorp, or (3) to dissolve an affiliate which has transacted any substantial business with the regulated operations of PacifiCorp.

Compliance Status:

PacifiCorp, please provide compliance status. Did PacifiCorp notify the Utah Commission when it dissolved its air transportation unit "PacifiCorp Trans" ? Any other plans requiring notification?

Condition 8

PacifiCorp shall comply with the provisions of Utah Admin. Code Section R746-401 which sets out the Commission's Rules for reporting the construction, purchase, acquisition, sale, transfer or disposition of utility assets and utility plant.

Compliance Status:

PacifiCorp, please provide compliance status. DPU knows of no non-compliance with this Section of the Utah Administrative Code since November 1999. PacifiCorp, has there been any notification non-compliance?

Condition 9

ScottishPower and PacifiCorp shall be required to provide notification of and file for Commission approval of the divestiture, spin-off, or sale of any integral utility function of PacifiCorp. This condition does not limit any jurisdiction the Commission may otherwise have over the divestiture, spin-off or sale of any utility asset.

Compliance Status:

PacifiCorp, please provide compliance status. DPU knows of no non-compliance with this Section of the Utah Administrative Code since November 1999. PacifiCorp, has there been any non-compliance of this Code Section in Utah?

Condition 10

ScottishPower, PacifiCorp and all affiliates shall make their employees, officers, directors, and agents available to testify before the Commission to provide information relevant to matters within the jurisdiction of the Commission.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>. *DPU observes that PacifiCorp has made its employees, officers, directors and agents readily available to testify and provide information relevant to matters within the Commission's jurisdiction and is therefore seen as being in compliance with this merger condition.*

<u>Condition 11</u>

ScottishPower and PacifiCorp shall provide adequate access for the Commission, DPU and CCS or their authorized agents to relevant books, records and officials of all ScottishPower entities. Failure to provide adequate supporting documentation of costs may result in those costs being denied rate recovery. Requests by such entities or their authorized agents shall be deemed presumptively valid, material and relevant, with the burden falling to ScottishPower and PacifiCorp to prove otherwise. ScottishPower and PacifiCorp shall reserve the right to challenge any such request before the Commission and shall have the burden of demonstrating that any such request is not valid, material or relevant. Applicants agree that corporate records shall be available for inspection in Utah or Portland, Oregon. ScottishPower and PacifiCorp shall pay reasonable expenses incurred by the Commission, DPU and CCS in accessing corporate records and personnel located outside of the State of Utah.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>. *Audits performed by DPU personnel have shown that PacifiCorp is generally in compliance with this merger condition. We have heard of one case where Oregon regulators may have been denied certain Scottish Power Board minutes. Utah has not been denied such minutes but has not made such a request.*

<u>Condition 12</u>

For a period of five (5) years commencing with the year 2000, PacifiCorp shall include in its year-end semi-annual report a full description, calculation (with supporting work papers) and dollar identification (both total PacifiCorp and Utah's share) of merger savings achieved for the reporting year.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>. *PacifiCorp, if this has been done on the year end semi-annual reports, please provide specific documentation or reference to specific pages in the semi-annual reports (March 2000?, March 2001?) to show compliance. Please include the details of this required information in your response.*

Condition 13

No later than six months after the closing date of the merger, ScottishPower and PacifiCorp will file the merger transition plan with the Commission. The plan will include the items described in Mr. MacRitchie's Utah rebuttal testimony.

Compliance Status:

DPU notes that PacifiCorp's Merger Transition Plan, was issued within this six month period with a cover date of May 24, 2000. PacifiCorp is in compliance with this merger condition.

Condition 14

The existing Umbrella Loan Agreement between PacifiCorp and its affiliates (approved by the Commission on November 19, 1997 in Docket No. 88-2035-03), as it may hereafter be amended with approval of the Commission, will continue to govern the terms for loans between PacifiCorp and its affiliates and ScottishPower shall be deemed to be an affiliate in accordance with the terms of the Umbrella Loan Agreement.

Compliance Status:

PacifiCorp, please provide compliance status. Generally, the DPU is under the impression that PacifiCorp is in compliance with this merger condition. PacifiCorp, please provide a statement as to the current status.

Condition 15

For two years following the merger, PacifiCorp shall file a cash flow summary (or other evidence) with its dividend report, showing that service will not be impaired by payment of the dividend, and shall comply with the provisions of Utah Code Ann. §54-4-27. In addition, an officer of PacifiCorp shall be satisfied and shall formally certify to the Commission that PacifiCorp has adequate capital to meet all of its outstanding commitments and carry out its public service obligations in the State of Utah.

Compliance Status:

PacifiCorp, please provide compliance status. DPU thinks that an initial report was submitted by PacifiCorp that was not in compliance with this merger condition and that a second attempt was to be made. DPU does not think the Company is in compliance with this merger condition.

Condition 16

Any penalty payable by ScottishPower for failure to meet any of the five network performance standards in the State of Utah, as specified at page 9 of the Direct Testimony of Bob Moir, shall be paid as designated by the Commission. Upon the assessment of any such penalties, PacifiCorp and ScottishPower shall consult with the DPU and the CCS to identify an appropriate recipient and shall file its proposal with the Commission. PacifiCorp and ScottishPower agree to be bound by the Commission's decision in this regard.

Compliance Status:

PacifiCorp, please provide compliance status. PC could be required to pay penalties ($1 for each customer in Utah) for failure to meet any one of the five network standards during 2005. Thus, PC will be required to pay these penalties if it fails to:

- ❑ *Reduce each of SAIDI, SAIFI, and MAIFI by 10%, 10%, and 5% from the 1994 through 1998 (adjusted) average baseline levels by the end of 2005.*
- ❑ *Restore supply within 3 hours 80% of the time on a Statewide basis.*
- ❑ *Reduce the CPI by 20% for all worst performing circuits. This includes the five worst performing circuits identified each year for which two-year improvement periods have elapsed.*

See the status reports on merger conditions #1, #27, #29, and #30 for more information regarding PC's progress in implementing Merger Condition 16.

Condition 17

General and Financial reports - To be filed with the Commission:

a. FERC form 1 - PacifiCorp and Utah state;
b. Annual and quarterly reports (if any) to shareholders of ScottishPower;
c. Semi Annual reports showing Utah and PacifiCorp operating results, allocation factors, coal reports, demand side management report, production costs modeling, peak loads by jurisdiction, normalizing adjustments and work papers, all in respect of the regulated operations of PacifiCorp;
d. Monthly financial and operating reports of the regulated operations of PacifiCorp;
e. Securities and Exchange Commission Reports 10-Q (quarterly) and 10K (annually) of PacifiCorp;
f. Annual class cost of service studies for the regulated operations of PacifiCorp;
g. Monthly Energy Information Administration Form EIA 826 for the regulated operations of PacifiCorp;
h. Annual affiliated interest report for PacifiCorp and relevant affiliates; and
i. Five year financial plan and forecast of financial condition (including capital expenditures) for PacifiCorp, provided that such shall not be filed with Commission but shall be available for inspection at the offices of PacifiCorp or its attorneys in Utah on an annual basis.

Compliance Status:

PacifiCorp, please provide compliance status. The DPU observes that PacifiCorp is generally in compliance with timely submittal of the listed reports in Condition 17. The DPU has not seen quarterly reports to shareholders of Scottish Power (17c). DPU needs more information concerning item 17g Form EIA 826. DPU auditors indicate they think we are missing the last annual affiliated interest report for regulated operations of PacifiCorp (item 17h). DPU has seen item (17i), 'five year financial plan and forecast of financial condition' during audit trips to Portland. PacifiCorp, please give us information on each on these 9 items to help us make an accurate compliance report to the PSC.

Condition 18

For the purpose of U.S. regulatory reporting, ScottishPower shall follow FASB 52 .

Compliance Status:

PacifiCorp, please provide compliance status. DPU desires confirmation of compliance with this item. DPU is of the opinion that PacifiCorp is in compliance with this merger condition.

Condition 19

Unless otherwise approved by the Commission, the Applicants agree to the use of a hypothetical capital structure to determine the correct costs of capital for ratemaking purposes in Utah. The capital structure shall be constructed using a group of A-rated electric utilities comparable to PacifiCorp.

Compliance Status:

PacifiCorp is in compliance with this merger condition. Hypothetical capital structure using A-rated comparable electric utilities has been used in the most recent rate cases before the Utah Commission.

Condition 20

Within 90 days after closing of the merger, PacifiCorp and ScottishPower shall provide a detailed report indicating PacifiCorp's proportionate share of the ScottishPower group's total assets, total operating revenues, operating and maintenance expense, and number of employees. Subsequent to this initial report, this information shall be included as part of PacifiCorp's semi-annual filing with the Commission.

Compliance Status:

PacifiCorp, please provide compliance status. If this report was provided in the first 90 days following the close of the merger (which the DPU seems to recall it was), please indicate the date submitted and provide a copy to the Division. Has this information been included in the semi-annual filings to the Utah Commission since this 90 day report? Please indicate where.

Condition 21

Except as provided in Condition 22, until approved by the Commission in a separate proceeding, PacifiCorp shall maintain separate long term debt.

Compliance Status:

PacifiCorp, please provide compliance status. The DPU understands that PacifiCorp is in compliance with this merger condition. A status statement from PacifiCorp will be appreciated.

Condition 22

With the exception of inter-group loans which shall be provided in accordance with Condition 14, PacifiCorp shall apply to the Commission for approval of debt issuances by PacifiCorp or on its behalf, in accordance with Utah Code Ann. §54-4-31 provided that the DPU and CCS agree that PacifiCorp may apply for a waiver of this requirement following 12 months after the closing of the merger.

Compliance Status:

PacifiCorp is in compliance with this merger condition. In Docket No. 00-035-16, filed on December 4, 2000, roughly 12 months following the closure of the merger, PacifiCorp applied for this waiver and was granted the waiver in a PSC Order on February 23, 2001. As part of the Order, PacifiCorp was to provide quarterly reports that included bond rating analysis, change to bond ratings and issuance expenses. Has the Company made these reports?

Condition 23

PacifiCorp and ScottishPower agree not to assert in any future Utah proceeding that the provisions of PUHCA or the related Ohio Power v FERC case preempt the Commission's jurisdiction over affiliated interest transactions and will explicitly waive any such defense in those proceedings. In the event that PUHCA is repealed or modified, PacifiCorp and ScottishPower agree not to seek any preemption under any subsequent modification or repeal of PUHCA.

Compliance Status:

PacifiCorp, please provide compliance status. DPU observes that PacifiCorp is in compliance with this merger condition to the date of this report. PUHCA has not been repealed or modified to our *knowledge and PacifiCorp has not made any claims as yet on this topic of affiliated interest transactions.*

Condition 24

PacifiCorp and ScottishPower shall provide the DPU and the CCS with a copy of any SEC filed lobbying reports.

Compliance Status:

PacifiCorp, please provide compliance status. Have any SEC lobbying reports been filed? If so, has PacifiCorp filed these with the DPU and CCS? Please provide any such reports again at this time.

Condition 25

If ScottishPower is able to lower the costs of capital, then those savings shall be reflected in rates in accordance with regulatory practices in the State of Utah. If, however, the cost of capital of electric operations of PacifiCorp increases as a direct result of the merger, ScottishPower's shareholders will bear that cost.

Compliance Status:

In Docket No. 99-035-10, PacifiCorp complied with this merger condition. In this case they used a lower cost of debt and no higher cost of debt was asked for. PSC Order was May 24, 2000. Any additional PacifiCorp comments will be appreciated on this status statement for this condition.

Condition 26

Rates will be set based upon original and not revalued costs. Any premium paid by ScottishPower for PacifiCorp stock will be disregarded for ratemaking purposes.

Compliance Status:

PacifiCorp, please provide compliance status.

The DPU observes that PacifiCorp, to date, is in compliance with this merger condition as no stock premiums have been granted in the last two Utah rate cases.

Condition 27

(a) PacifiCorp will comply with ScottishPower's proposed performance standards and service guarantees and will not allow its underlying outages to increase above current levels for the periods set out in ScottishPower witness Moir's direct testimony.

(b) PacifiCorp will include the proposed performance standards and service guarantees in its tariff.

(c) During 2004, PacifiCorp will review and if necessary revise its performance standards, service guarantees and related requirements. In any event, PacifiCorp will submit for Commission approval its proposals for the continuation of performance standards, service guarantees and related requirements.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>. *The DPU observes that PacifiCorp has been complying with Scottish Power's proposed performance standards and service guarantees.*

The DPU has not yet determined whether PacifiCorp will be able to reliably estimate average outage baseline levels for 1994 through 1998. On 2/15/02, PacifiCorp plans to provide data on this point. The data may indicate whether it is possible to reliably estimate PacifiCorp's average 1994 through 1998 average-outage baselines.

On 2/15/02, PacifiCorp is also expected to provide data quantifying an estimate that it reduced outage incidents by approximately 24% from 2000 to 2001. If the Company did reduce outage incidents 24%, Utah customers are possibly realizing over $40 million annually in reduced economic losses.

The $40 million annual savings is being realized if: 1. PacifiCorp actually did reduce the # of outage incidents by approximately 24% during 2000 and 2001, and 2. The reduction in outage incidents strongly correlates with comparable reductions in average outage durations and momentaries (less than five minute) outages. The $40 million would be in addition to savings attributable to more timely field responses and improved call handling.

PacifiCorp has included the proposed performance standards and service guarantees in its tariff.

The Commission has granted PacifiCorp an exemption from the January 2002 requirement to answer 80% of all incoming calls within 10 seconds. The Company will continue to meet the 20-second requirement.

<u>Condition 28</u>

PacifiCorp will fund network expenditures required to implement the service standards commitments in ScottishPower's direct testimony from efficiency savings and redirected internal funding; and will report funding sources and expenditures against the $55 million estimate.

PacifiCorp will report on expenditures and sources of funds in its year-end semi-annual report.

Compliance Status:

<u>PacifiCorp, please provide compliance status.</u> PacifiCorp has been reporting its funding sources and expenditures against a $55 million estimate. This is because PacifiCorp stipulated to funding its expenditures -- required for meeting service standard commitments -- from efficiency savings and redirected internal funding.

During 2002, the DPU plans to meet with PacifiCorp representatives to clarify the Company's sources and expenditures Report.

If PacifiCorp has reported this information in its March 2001 semi-annual report, please help the DPU to identify where it was reported.

<u>Condition 29</u>

PacifiCorp will operate its current outage reporting system in parallel with Prosper (an automated system expected to verify customer reported outages) until the earlier of Commission approval to terminate the current system or until the establishment of baselines in accordance with Condition 30.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>. PacifiCorp implemented Prosper in Southern Utah during November 2000 and in Northern Utah during February 2001. In doing so, the Company terminated the manual outage reporting system. Contrary to the merger requirement, the Company did not request that the Commission approve termination of the system.

*PC has not yet estimated and recommended outage **baselines** in accord with conditions 27 and 30. At this time, the Company plans to recommend outage baselines for SAIDI and SAIFI by 5/15/02 and for MAIFI during early 2005.*

<u>Condition 30</u>

(a) PacifiCorp will perform audits at six-month intervals to ascertain the differences between customer reported faults (from the telephone systems) and those recorded in the fault reporting systems to ascertain the differences due to reporting deficiencies. These three audits will terminate 18 months after approval of the transaction. *PacifiCorp will install Prosper no later than 18 months after the merger transaction.* Thereafter, PacifiCorp will perform audits upon request of the DPU or the Commission.

(b) Based on that data, the DPU will, within 18 months after approval of the transaction, file a report with the Commission recommending outage baselines. Disputes, if any, regarding the outage baselines will be resolved by the Commission.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>. In Condition #29, the DPU indicated that PacifiCorp

implemented Prosper in Southern Utah during November 2000 and in Northern Utah during February 2001, within the 18 month period after the close of the merger transaction in November 1999. The Company is required to conduct three audits at six-month intervals to ascertain differences between customer reported faults (from the telephone system) and those recorded in the automated fault reporting system (Prosper). The objective is to measure recording and reporting inaccuracies.

PacifiCorp conducted one audit during 2001 in the Cedar City area. As of 8/29/01, the Company had planned to conduct two additional audits over the next 10 – 12 months (PacifiCorp, status please). (Although the Division has the prerogative, it has not requested that PacifiCorp conduct an additional audit.)

In May of 2001, PacifiCorp did not recommend 1994 to 1998 outage baselines by May 2001 as planned. At this time, PacifiCorp plans to recommend outage baselines for SAIDI and SAIFI by 5/15/02 and for MAIFI by early 2005.

Condition 31

Subject to the following reporting and dispute resolution provisions, PacifiCorp may use the IEEE criteria to determine what constitutes an "extreme event" as proposed in the Direct Testimony of ScottishPower witness Moir. The claim by PacifiCorp may involve judgments regarding design limits of or extensive damage to the power system. If so, PacifiCorp will file with the DPU a report specifying the basis for the claim and any disputes regarding the merits of the claim will be resolved by the Commission.

Compliance Status:

PacifiCorp, please provide compliance status. During 2001, PacifiCorp used the IEEE criteria to claim three extreme events. Based upon the #s of customers affected in operating areas, the DPU has recommended that the UPSC approve two of the three claims. During early 2002, the DPU will make a recommendation on PacifiCorp's recent third extreme event claim.

Condition 32

PacifiCorp will audit, in response to DPU requests, to determine actual outage levels – after correcting for under or inaccurate recording. The results of that determination will be submitted to the DPU and will be subject to audit by the DPU or its designated expert.

Compliance Status:

PacifiCorp, please provide compliance status. As indicated in the status report on merger condition #30, the Division has not requested that PC conduct an additional audit to determine outage levels.

Condition 33

PacifiCorp will provide quarterly reports of outages on a district basis. The report will include a comparison of the average district outage levels (for outage durations, outage frequencies, and short duration outages) with the outage level for the highest and lowest circuits. PacifiCorp recognizes that the DPU has the statutory authority to request additional information. PacifiCorp agrees to provide explanations or corrective action plans regarding unfavorable outage variances in response to DPU requests.

After Prosper is in place, PacifiCorp will include in the quarterly reports the numbers of customers in each district for whom outages have exceeded PacifiCorp's average outage frequency rate.

Compliance Status:

PacifiCorp, please provide compliance status. PacifiCorp has been providing quarterly outage reports on a district basis. The reports indicate the average outage levels for each district with results for the strongest and weakest performing circuits. Results are shown for average outage durations, average #s of customers affected, and average #s of customers affected by momentary outages (SAIDI, SAIFI, and MAIFI, respectively). The more recent 5/31/01 and 10/31/01 service quality reports also include the Customer Average Interruption Index (CAIDI). CAIDI measures the average outage-duration intervals for affected customers.

By February 2001, PacifiCorp had implemented the Prosper outage reporting system throughout Utah. On 12/20/01, PacifiCorp was therefore able to supplement its 10/31/01 quarterly service report with a report on the #s of customers in each district for whom outages exceeded the PacifiCorp's average outage frequency rate. PacifiCorp plans to include this data in future quarterly service reports.

More recently, PacifiCorp advised the DPU that Excel's autofilter feature could be used to sort circuits having outages above or below designated levels. This feature allows the DPU to more readily identify and report circuits (and the districts where they are located) having favorable or unfavorable variances. The goal is to report performance by geographic area on an exception-principle basis.

Condition 34

PacifiCorp shall continue with internal meter set and meter test field response standards in Northern Utah. It shall establish reasonable internal targets for field responses where none currently exist and for which targets have not yet been set and report performance against all district targets on a quarterly basis.

Compliance Status:

PacifiCorp, please provide compliance status. PacifiCorp reports field response performance for both guaranteed and non-guaranteed field responses. The Company has been improving both their *field response reporting methodology and their field response performance.*

PacifiCorp's 10/31/01 service quality report depicted, on a district basis:

- ❑ *% outages restored within 3 hours*

- ❑ *#s failures for each of customer guarantees 1 through 8. Future reports are expected to include the %s of failures to total events, thus, providing a performance focus, for exception-principle reporting*

- ❑ *for non-guaranteed field responses:*
  - Ø *meter sets - - % restored within 5 days*
  - Ø *temporary meter sets - - % restored within 15 days*
  - Ø *two types of responses to tree trimming requests - - average # days*
  - Ø *responses to miscellaneous field requests - - average # days.*

On 1/31/02, PacifiCorp began reporting field response-service results on Excel spreadsheets. This allows the use of autofilter (an Excel feature) in sorting and reporting favorable and unfavorable variables on a district basis. PacifiCorp's future reports are expected to include performance ratios for guarantee failures. The DPU will thereafter be able to provide performance reports to the Commission and public (on the DPU's web site) on an exception-principle basis.

Condition 35

PacifiCorp shall report call-handling results during wide-scale outages against average answer speeds, hold times, and busy indications.

Compliance Status:

PacifiCorp, please provide compliance status. *PacifiCorp has been reporting call-handling results during "wide-scale outages" against average answer speeds, hold times, and busy indications. The Company defines a wide-scale outage during business hours as a situation wherein its call center receives more than 2,000 calls per hour. A non-business hour wide-scale outage would develop more than twelve Commission or Hotline complaints during the non-business evening or early-morning hours.*

Based upon its wide-scale outage experiences, the Company has also been reporting "lessons learned" and follow-up on those lessons.

Condition 36

PacifiCorp shall report, each quarter, district data showing credits to customers for failures to meet customer guarantees. PacifiCorp will do so for the period of the commitment to these guarantees, as set out in the direct testimony of Bob Moir.

Compliance Status:

PacifiCorp, please provide compliance status. PacifiCorp has been reporting each quarter, district data showing the # and dollar amounts of credits to customers for failures to meet customer guarantees. As noted in condition 35 status, PacifiCorp plans to include the #s of failures as %s of totals in future reports, thereby providing a performance focus.

Condition 37

PacifiCorp shall implement and include in its tariff a dispute resolution process for dealing with customer claims resulting from customer guarantee failures on a fair and consistent basis.

Customers will continue to have the right to file informal complaints with the DPU or formal complaints with the Commission.

Compliance Status:

PacifiCorp, please provide compliance status. The Division observes that PacifiCorp is in compliance with this merger condition. Through the rulemaking process in collaboration with the DPU Customer Service Section and others, and through re-written Electric Service Regulations (Regulation No. 1) in the last rate case, Docket No. 01-035-01, completed in November of 2001, PacifiCorp has strengthened its dispute resolution process. Its Regulation No. 25, "Customer Guarantees", Paragraph 5, "Dispute Resolution" directs customers with customer guarantee failure claims or disputes to PacifiCorp's Customer Guarantee Claim Center. If a customer is not satisfied with claim handling at this center, this same Paragraph 5 directs them to the provisions of dispute resolution in Regulation 1 (which is the informal and formal complaint process) mentioned above.

Condition 38

Following the introduction of Prosper, PacifiCorp will provide a quarterly report of the number of customer reported transmission outages where customers report loss of supply. For each customer reported transmission outage, PacifiCorp agrees to report as precisely as is possible the locality (that is, the PacifiCorp district, wholesale electric cooperative, municipality or other wholesale customer location) from which the customer report came.

Compliance Status:

PacifiCorp, please provide compliance status. By February 2001, PacifiCorp had implemented the Prosper outage reporting system throughout Utah. PacifiCorp thereafter improved the accuracy of the automated system. On 12/20/01, PacifiCorp supplemented its 10/31/01 quarterly service report indicating the #s of customers in each district affected by transmission caused outages. PacifiCorp plans to include #s of customers affected in each district in its future quarterly service reports.

Condition 39

PacifiCorp recognizes that it has a statutory obligation to provide adequate, efficient, just and reasonable service to each retail customer. PacifiCorp also recognizes that the Commission has the authority to supervise and regulate PacifiCorp's service and to enforce its orders, including through the provisions of Section 54-7-25.

Compliance Status:

PacifiCorp, please provide compliance status. In general, the Division observes that PacifiCorp is in compliance with this merger condition thus far since the merger. The regulatory rate case process attempts to insure adequate, efficient, just and reasonable service to each retail customer. PacifiCorp has recently run the gauntlet of several heavily litigated rate cases before the Utah Commission where each of these merger condition service issues have been addressed. The DPU is unaware of any cases where 54-7-25 "Violations by Utilities - Penalty" have been brought before the Utah PSC for resolution since the close of the merger in 1999, so as far as the DPU knows, PacifiCorp still recognizes the Commission's authority to impose penalties under this statute. The DPU's records indicate that the number of customer complaints to the Utah PSC concerning PacifiCorp decreased slightly in 2000 and 2001 from the number received in 1999.

Condition 40

PacifiCorp will continue to produce Integrated Resource Plans every two years, according to the then current schedule and the then current Commission rules.

Compliance Status:

PacifiCorp, please provide compliance status. The DPU observes that the IRP/RAMPP process has not been current and especially effective in the years just prior to completion of the November 1999 merger or in the years since that merger. Had adequate generation resources been in place as a result of an effective IRP process before or after the merger, PacifiCorp possibly would not have been as exposed to high cost market power prices in 2000 and 2001 and would have had the necessary new power plants in place instead of having to use the somewhat short term measures of load curtailment, temporary gas turbines, etc., to serve customers. PacifiCorp's generation resource capacity has not kept up with the growth in Utah. The Company is still struggling to provide sufficient power for the summer of 2002. The DPU recognizes that many other power companies were affected and surprised by the energy crisis during this period as well and that some of what PacifiCorp experienced was beyond its control, but even PacifiCorp's own older IRP plans indicated the need for new resources in the early 2000's which were not built.

PacifiCorp is in compliance with its effort to continue to produce IRP's every two years but numerous time extensions have been needed before plans have been published. To its credit, PacifiCorp has renewed its efforts to re-focus on IRP planning processes (partially in response to *a recent PSC Order) and is having a series of meetings with stakeholders to obtain input into a new and improved IRP process and product. Some employees at PacifiCorp are even saying that future IRP's might become a tool for the Company to use in charting actual direction and operations of the Company as the DPU and others have hoped the IRP tool would have been used for in the past.*

Condition 41

PacifiCorp shall make a showing in a rate proceeding that any additions of renewable resources to the rate base or the revenue requirement first appearing in that rate proceeding are prudent investments.

Compliance Status:

PacifiCorp, please provide compliance status. To date, PacifiCorp is in compliance with this merger condition. PacifiCorp has not requested any rate base or revenue requirement treatment in rate proceedings since November 1999 for any renewable resource costs that, for the first time, might have appeared in those rate cases. Renewable resources cost recovery requested in cases since November 1999 were for subsequent year amortized renewable resource expenditures that were purchased and approved in Utah prior to the November 1999 merger (Solar I, Dangling Rope Marina solar field). PacifiCorp's new renewable investments (Wyoming wind, etc.) are yet to come before the Commission for prudence review. PacifiCorp seems to understand that rulings on prudence of renewable resource expenditures need to be obtained prior to costs being allowed into rate base or in revenue requirement.

Condition 42

For the two years following the final approval of the merger, ScottishPower/PacifiCorp shall comply with the provisions of the merger agreement in respect of employee benefit plans.

Compliance Status:

PacifiCorp, please provide compliance status. The DPU has no specific information on this merger condition compliance, either way, and will need to understand from PacifiCorp how it has complied with this condition.

Condition 43

ScottishPower and PacifiCorp agree to provide guaranteed merger related cost-of-service reductions for four years through an annual merger credit. The amount of the credit shall be $12 million per year for years 2000, 2001, 2002 and 2003. The total credit in years 2000-2003 will be $48 million. The merger credit shall be allocated among PacifiCorp's retail tariff customers on the basis of a percentage of the customer bill, exclusive of taxes. At the end of each year, the aggregate amount of credit allocated in that year shall be calculated. These calculations shall be audited by the DPU, who shall report their audit results to the Commission. In the event the merger credit does not equal $12 million in any of the first three years, the excess or shortfall shall be applied to the $12 million due in the following year.

For each of the years 2002 and 2003, ScottishPower and PacifiCorp may reduce or offset the $12 million merger credit to the extent that cost reductions related to the merger are reflected in rates.

The dates set forth in this Condition assume that the merger transaction closes in 1999. If closing is delayed, ScottishPower and PacifiCorp may adjust the dates so that the merger credit begins as soon as practicable but not later than 30 days after the closing date.

In the event that restructuring of the electricity business occurs in Utah prior to the end of the four years for payment of the merger credit, the Commission shall determine at that time how the outstanding merger credit shall be paid.

Any other terms required to implement this merger credit shall be included in the merger credit tariff for approval by the Commission.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>. *The DPU audits the merger credit each year with assistance from PacifiCorp's Regulatory Department (Ron Burrup with Bill Griffith) regarding updates of Electric Service Schedule No. 99. Attached is a copy of DPU's March 27, 2001 letter to the Utah PSC, a first year report on the status of the merger credit. DPU is currently working with PacifiCorp on an second year merger credit update report. PacifiCorp plans to file an advice letter with an update to Schedule 99 for PSC approval.*

<u>Condition 44</u>

Rates in Utah shall not increase as a result of the merger.

Compliance Status:

<u>PacifiCorp, please provide compliance status</u>. *To date, the DPU observes that PacifiCorp is in compliance with this merger condition.*

<u>Condition 45</u>

ScottishPower and PacifiCorp agree that they shall assume all risks that may result from less than full system cost recovery if interjurisdictional allocation methods differ among PacifiCorp's various state jurisdictions. The DPU agrees to use its reasonable best efforts to reach agreement with the other state regulators as to the interjurisdiction cost allocation methodology to be recommended to the respective state commissions. In the event the state regulators are unable to reach agreement or the DPU concludes that the methodology supported by any of the other U.S. regulatory states would cause actual or perceived financial harm or inequity (on the basis of projections at that time) to the ratepayers in Utah, the DPU may support or recommend such allocation methodology to the Commission as it determines to be appropriate. ScottishPower and PacifiCorp assume the risk of whatever allocation methodologies or decisions the Commission may adopt. In addition, ScottishPower and PacifiCorp assume all risks that may result from any difference among PacifiCorp's various state jurisdictions in respect of the conditions imposed by the different state commissions relating to this merger transaction.

Compliance Status:

PacifiCorp, please provide compliance status. Sometime after Utah went to the "full rolled in" interstate allocation method (for cost allocation of pre-merger plant) as a result of the IJA (Interstate Joint Allocation) Docket Order, PacifiCorp indicates it is not recovering all of its costs from its state jurisdictions and that they are experience what they call an "allocation hole" or allocation shortfall. Although this merger condition seems to indicate that Scottish Power and PacifiCorp accepted the risk of revenue shortfalls caused by different allocation methods adopted by its states, PacifiCorp, in its restructuring Docket, 01-035-15, is asking for a compromise allocation method called "Fair Share" in each state to solve its pre-merger plant cost allocation shortfall. This problem of PacifiCorp and Regulators is yet to be resolved.

Condition 46

PacifiCorp shall continue to comply with the procurement policy and competitive bidding requirements approved by the Commission on January 16, 1991 in Docket No. 90-2035-05, as the same may hereafter be amended by the Commission.

Compliance Status:

PacifiCorp, please provide compliance status. To date, and since the close of the merger, the DPU has no information that might indicate that PacifiCorp is not in compliance with this merger condition in either its procurement policy and/or competitive bidding requirements. PacifiCorp presently has a Request For Proposal out for energy suppliers to provide power to meet its 2002 summer peak load requirements in Utah. The DPU may eventually be involved in auditing this RFP process and PacifiCorp's competitive award processes as power supply contracts may be awarded.

Condition 47

ScottishPower shall not change its corporate structure to form a holding company or make any other major change in corporate structure without prior notice to the Commission along with an explanation of any expected impacts of the changes on PacifiCorp or Commission regulation.

Compliance Status:

PacifiCorp, please provide compliance status. The DPU understands that PacifiCorp's corporate *restructuring application in Docket No. 01-035-15 (SRP) does propose major changes in its corporate structure including creation of a holding company. (However, as reported in PacifiCorp's December 31, 2001 Form 10 Q, PacifiCorp did an internal restructuring to transfer non-regulated businesses out of PacifiCorp that affected the capital structure. While the PSC was notified, no analysis was made about the impact of the changes on the Company.*

Condition 48

PacifiCorp shall not, without the approval of the Commission, assume any obligation or liability as guarantor, endorser, surety or otherwise for ScottishPower or its affiliates provided that this condition shall not prevent PacifiCorp from assuming any obligation or liability on behalf of a subsidiary of PacifiCorp. ScottishPower shall not pledge any of the assets of the regulated business of PacifiCorp as backing for any securities which ScottishPower or its affiliates (but excluding PacifiCorp and its subsidiaries) may issue.

Compliance Status:

PacifiCorp, please provide compliance status. DPU has no information on PacifiCorp's actions (if any) regarding this condition.

Condition 49

ScottishPower and PacifiCorp agree they shall provide management and financial resources adequate to enable PacifiCorp to meet its commitments, carry out its authorized activities and comply with its public service obligations.

Compliance Status:

PacifiCorp, please provide compliance status. DPU observes that, to date, PacifiCorp is generally in compliance with this merger condition.

Condition 50

In the event that PacifiCorp or ScottishPower does not comply with the above conditions, the Commission may make appropriate ratemaking adjustments to give full effect to these conditions. The Commission may exercise its authority to make, for retail ratemaking purposes, adjustments for misallocation of costs from non-regulated business to PacifiCorp or ScottishPower.

Compliance Status:

PacifiCorp, please provide compliance status. DPU observes that, to date, there does not appear to have been any significant failure by PacifiCorp to meet merger conditions that would require the PSC to make ratemaking adjustments to "give full effect to these conditions".

Condition 51

PacifiCorp and ScottishPower may request confidential treatment for any information or documents filed with the Commission, the DPU or the CCS or made available to them or their agents, in compliance with these conditions. Any request for confidential treatment will be handled as provided in the Government Records Access and Management Act, Utah Code Ann. § 63-2-101 et seq., or pursuant to a Protective Order issued by the Commission.

Compliance Status:

PacifiCorp, please provide compliance status. DPU observes that PacifiCorp has continued to request confidential treatment of information or documents filed with the PSC and has been granted that opportunity in pending and recently concluded rate proceedings.

Condition 52 (PSC's "Additional Condition" From Merger Order

" 6. The following is adopted as an additional condition to approval of the merger:

The parties to this Docket preserve their right to raise the issue of the treatment of upstream tax savings and costs in future rate cases. All parties preserve their positions and have not waived their rights on this issue. ScottishPower commits to retain records regarding upstream tax savings and costs relating to the merger and make these records available to the DPU, CCS and other parties in accordance with Stipulation Ex. 1 and the discovery rules of the Commission."

Compliance Status:

PacifiCorp, please provide compliance status. DPU observes that an industrial party tried to raise this issue in a recent rate proceeding and then withdrew its position. The option to raise this upstream tax savings issue in future rate cases remains. PacifiCorp appears to be in compliance with this merger condition to date.

OERP/LAWF STIPULATION

This Stipulation was executed on July 26, 1999, among Applicants, OERP [now the Utah Energy Office] and the LAW Fund. Its purpose is to address the impact of the merger on the environmental and public purpose programs. It provides that ScottishPower will produce integrated resource plans according to the current schedule and current Commission rules. ScottishPower will incorporate the recommendations of the Commission's Energy efficiency and Renewable Energy Task force in implementing its commitments to develop an additional 50 MW of renewable resources. ScottishPower will file a green resource tariff in Utah. ScottishPower will support funding for cost-effective and prudent energy efficiency in Utah.

Compliance Status:

PacifiCorp, please provide compliance status. DPU observes that PacifiCorp is involved in many actions that may help bring itself into compliance with this multi-faceted merger stipulation but requests a detailed summary from PacifiCorp as a data response compliance statement especially since this stipulation was between PacifiCorp and other parties. IRP issues are being followed as a result of the merger case and the last two rate cases with active meetings open to all stakeholders. The 50 MW of renewable resources has been acquired and is available to power customers. Rate Schedule No. 70 is the Blue Sky green resource tariff for Utah. PacifiCorp has established additional energy efficiency programs in Utah since the close of the merger in November 1999.

CROSSROADS AND CAP STIPULATION

This Stipulation was executed on June 18, 1999, between Applicants, and Crossroads and CAP. Its purpose is to resolve all issues among the signatory parties relating to the impact of the merger on low-income customers. ScottishPower and PacifiCorp agree to work with the signatory parties and others to identify cost-effective programs that will benefit low-income customers through reduction of energy usage and improvement in customer's ability to pay current and past electric bills. Under the Stipulation, PacifiCorp will support a lifeline rate in Utah and Applicants will fund low-income initiatives in Utah for three years with shareholder funds at $300,000 more per year than the amount spent on similar programs in Utah in 1998.

Compliance Status:

PacifiCorp, please provide compliance status. DPU observes that PacifiCorp is involved in actions that may help bring itself into compliance with this merger stipulation but requests a detailed summary from PacifiCorp as a data response compliance statement especially since this stipulation was between PacifiCorp and other parties. PacifiCorp has applied for and been granted approval of its Electric Rate Schedule No. 91 - Surcharge to Fund Low Income Residential Lifeline Program, sometimes called the HELP program.

DG&T STIPULATION

This Stipulation, executed August 2, 1999, between Applicants and DG&T, provides for discussions between Applicants and DG&T to attempt to resolve any service reliability problems at the Middleton delivery point, and follow-up efforts to implement any identified solutions.

Compliance Status:

PacifiCorp, please provide compliance status. DPU observes that PacifiCorp is involved in several actions that may help bring itself into compliance with this merger stipulation but requests a detailed summary from PacifiCorp as a data response compliance statement especially since this stipulation was between PacifiCorp and other parties. The following is quoted from a January 30, 2002 letter to the DPU from Mr. Mike Peterson, Executive Director, Utah Rural Electric Association *regarding his view of the compliance status of this merger stipulation: "Please be advised that the parties continue to work cooperatively to resolve the reliability issues at Middleton. Dixie Escalante REA is constructing and financing a two mile section of 138 kV transmission line, which will parallel UP&L's existing 69 kV transmission line, to the Red Cliff Switch point. Dixie will also purchase a 138 kV transformer and PacifiCorp will buy Dixie's interest in the existing 138/69 transformer at Middleton". (This letter was in response to the DPU's request to UREA as to its view of PacifiCorp's compliance with this merger stipulation).*

LETTER AGREEMENT WITH DCED AND DBED

This letter agreement, dated August 2, 1999, is among ScottishPower, DCED and DBED. It sets forth ScottishPower's commitment to locate a senior executive in Utah. According to the letter agreement, this senior executive will report directly to the CEO of PacifiCorp, and will have broad influence over PacifiCorp's operations in Utah, including authority to approve corporate involvement in economic development and corporate citizenship activities. The letter agreement further provides that the corporate offices of PacifiCorp will remain within the states of PacifiCorp's service area, and Utah Power's headquarters will be located in Utah.

Compliance Status:

PacifiCorp, please provide compliance. DPU observes that PacifiCorp is most likely in compliance with this merger letter agreement but requests a definitive statement from PacifiCorp as a compliance statement especially since this agreement was between PacifiCorp and other parties. DPU observes that a Mr. Landels now resides and works in Salt Lake City and seems to operate as the senior executive in Utah for PacifiCorp. It would be helpful to know if Mr. Landels is the person in question in this stipulation, whether he does in fact report to the CEO of PacifiCorp, whether he is considered to have "broad influence" over PacifiCorp's operation's in Utah, etc., and whether PacifiCorp's offices in Utah are considered Utah Power's headquarters.

REVIEWED BY COMMISSIONERS
STEPHEN F. MECHAM
CONSTANCE B. WHITE
RICHARD M. CAMPBELL

Feb 20 7 59 AM '02

SERVICE COMMISSION

EXHIBIT "A"

I have reviewed the Protective Order approved by the Public Service Commission of Utah on the 25th day of January, 1999, in Docket No. 98-2035-04, and agree to be bound by the terms and conditions of such Order.

Paul I. Nippes
Signature

PAUL I. NIPPES
Name (Type or Print)

1 TALL TREE RD
Residence Address
MIDDLETOWN, NJ 07748

NIPPES BELL ASSOC. INC
Employer or Firm

2135 HWY 35, HOLMDEL, NJ 07733
Business Address

Party

Date

1900 S.W. Fourth Avenue
Portland, Oregon 97201

PACIFICORP
Pacific Power Utah Power

RECEIVED
FEB 1 9 33

VIA OVERNIGHT MAIL

SERVICE COMMISSION

January 31, 2002

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City UT 84114

REVIEWED BY COMMISSIONERS
STEPHEN F. MECHAM
CONSTANCE B. WHITE CBW 2/4
RICHARD M. CAMPBELL RC

Attention: Julie P. Orchard
Commission Secretary

RE: Docket No. 98-2035-04 ScottishPower/PacifiCorp Merger Commitments

Please find enclosed PacifiCorp's third quarter report for the period October 2001 through December 2001 detailing the Company's performance in meeting the Customer Guarantees which were agreed to as a result of the merger between ScottishPower and PacifiCorp. Year-to-date information is provided as well.

The Outage Detail Report will be delayed until February 15, 2002 to allow for an update of customer counts by circuit.

If you have any questions or require further information, please call me at (503) 813-7408.

Sincerely,

Carole Rockney/sly

Carole Rockney, Director,
Customer and Regulatory Liaison

c: Mark Flandro - Utah Division of Public Utilities
Bob Maloney - Utah Division of Public Utilities
Rea Petersen - Utah Division of Public Utilities
Matthew Wright - Executive Vice President, Power Delivery

Enclosures

Table of Contents

	Description	October-December 2001 Events	Failures	Paid	Fiscal YTD 2002 Events	Failures	Paid	Fiscal YTD 2001 Events	Failures	Paid
CG1	Restoring Supply	349,593	2	$150	1,312,649	11	$875	710,907	7	$425
CG2	Appointments	1,308	3	$150	4,670	9	$450	4,642	14	$700
CG3	Switching on Power	4,027	15	$2,325	21,301	42	$6,100	19,023	44	$7,875
CG4	Estimates	1,571	30	$1,500	5,447	100	$5,000	6,346	110	$5,500
CG5	Respond to Billing Inquiries	2,237	17	$850	6,898	34	$1,700	5,703	15	$750
CG6	Respond to Meter Problems	147	1	$50	385	4	$200	849	4	$200
CG7	Notification of Planned Interruptions	4,309	8	$400	19,344	31	$1,600	8,532	27	$1,450
CG8	Power Quality Complaints	19	1	$50	429	7	$350	2,150	192	$9,600
		363,211	**77**	**$5,475**	**1,371,123**	**238**	**$16,275**	**758,152**	**413**	**$26,500**

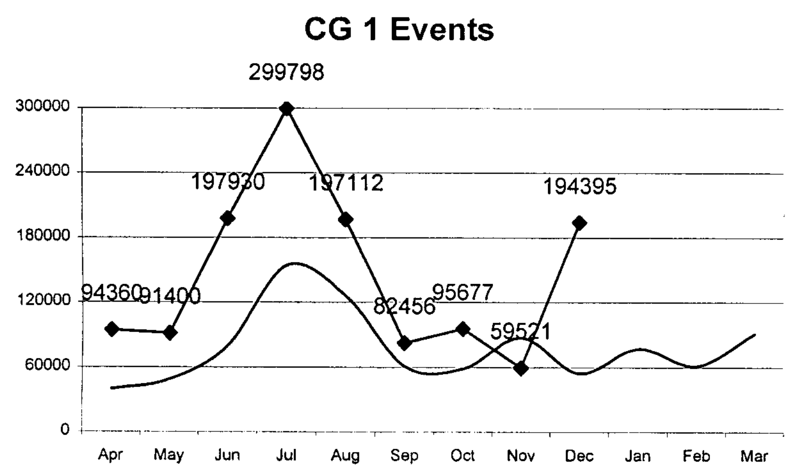
Summary analysis:

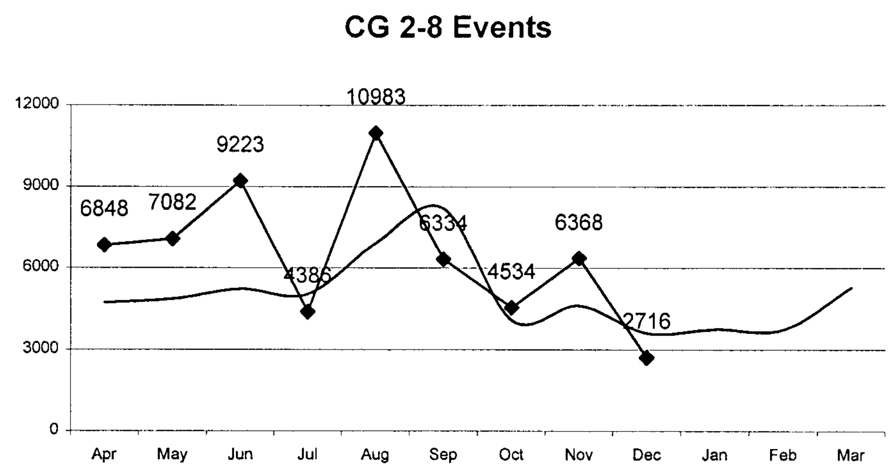
General Comments - Similar to last year, failure counts during the last quarter were lower due to an overall decreased number of CG2-8 events during the winter months.

CG1 - Restoring Supply - Events were again elevated during the quarter primarily due to extreme weather conditions. These are exclusive of the major event that was declared in Novembe[illegible] affecting most communities along the Wasatch Front.

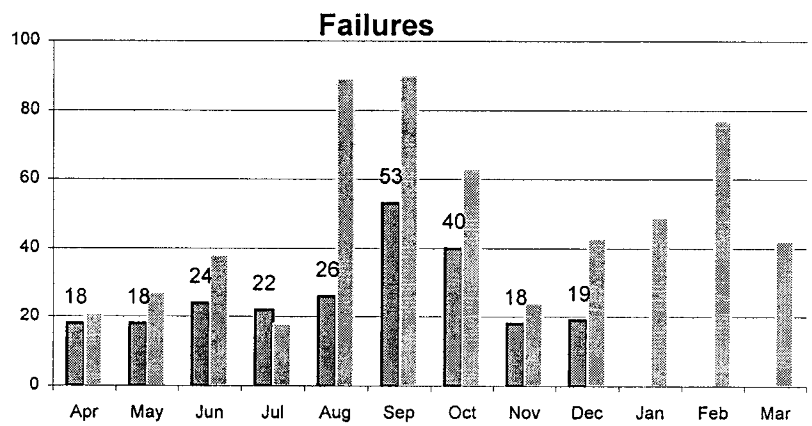
CG8 - Power Quality Complaints - Failures have been reduced significantly compared to last year due to process refinements and training efforts to help employees better understand the definition of this guarantee. Inquiries regarding outages with no power quality or voltage component had been incorrectly classified as CG8 events in FY 2001. In FY 2002 only power quality/voltage related inquiries are reported as CG8 events.

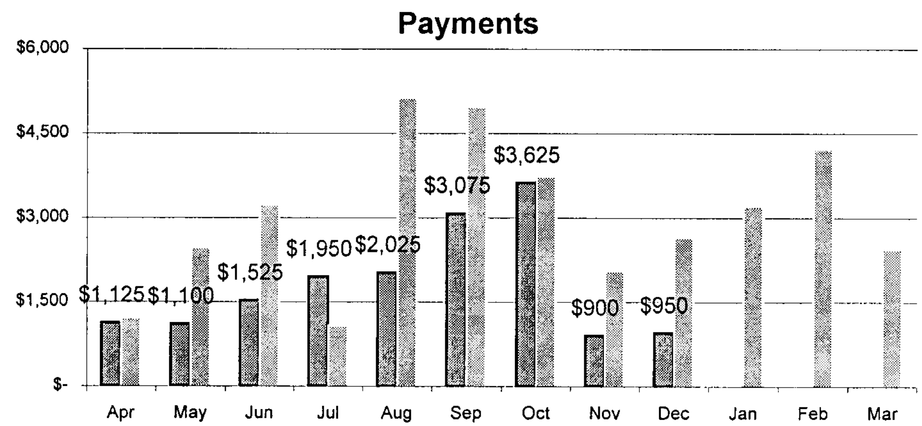
Exclu[illegible]ajor events





Current Year Previous Year





Current Year Previous Year

Exclud[illegible]ajor events

customer*guarantees*

PACIFICORP

Utah - Failures

Sort the table by District or Guarantee to see individual District performance or overall Guarantee performance
3rd Quarter - Fiscal Year 2002
October-December 2001

District	Guarantee	Description	Qtr Count	Qtr Paid	YTD Count	YTD Paid
American Fork	CG2	Appointments			1	$50.00
American Fork	CG3	Switching on Power			3	$325.00
American Fork	CG4	Estimates	4	$200.00	29	$1,450.00
American Fork	CG5	Respond to Billing Inquiries	5	$250.00	10	$500.00
American Fork	CG7	Notification of Planned Interruptions			1	$50.00
Cedar City	CG3	Switching on Power	1	$50.00	5	$375.00
Cedar City	CG4	Estimates	1	$50.00	4	$200.00
Cedar City	CG7	Notification of Planned Interruptions	2	$100.00	2	$100.00
Evanston	CG4	Estimates			1	$50.00
Jordan Valley	CG1	Restoring Supply	2	$150.00	6	$350.00
Jordan Valley	CG2	Appointments			2	$100.00
Jordan Valley	CG3	Switching on Power	2	$500.00	5	$700.00
Jordan Valley	CG4	Estimates	4	$200.00	13	$650.00
Jordan Valley	CG5	Respond to Billing Inquiries	4	$200.00	7	$350.00
Jordan Valley	CG7	Notification of Planned Interruptions	6	$300.00	15	$750.00
Jordan Valley	CG8	Power Quality Complaints	1	$50.00	2	$100.00
Layton	CG2	Appointments	2	$100.00	2	$100.00
Layton	CG3	Switching on Power	3	$1,125.00	5	$1,300.00
Layton	CG4	Estimates	4	$200.00	4	$200.00
Layton	CG5	Respond to Billing Inquiries	1	$50.00	2	$100.00
Layton	CG6	Respond to Meter Problems	1	$50.00	3	$150.00
Moab	CG2	Appointments			1	$50.00
Moab	CG4	Estimates	2	$100.00	3	$150.00
Ogden	CG3	Switching on Power	3	$175.00	4	$275.00
Ogden	CG4	Estimates	7	$350.00	7	$350.00
Ogden	CG5	Respond to Billing Inquiries			1	$50.00
Ogden	CG7	Notification of Planned Interruptions			2	$100.00
Park City	CG4	Estimates			1	$50.00
Park City	CG5	Respond to Billing Inquiries	1	$50.00	1	$50.00
Price	CG1	Restoring Supply			1	$50.00
Price	CG3	Switching on Power			1	$275.00
Price	CG4	Estimates			1	$50.00
Richfield	CG1	Restoring Supply			1	$100.00
Richfield	CG2	Appointments	1	$50.00	1	$50.00
Richfield	CG4	Estimates	2	$100.00	14	$700.00
SLC Metro	CG1	Restoring Supply			2	$175.00
SLC Metro	CG2	Appointments			1	$50.00
SLC Metro	CG3	Switching on Power	4	$300.00	16	$2,625.00
SLC Metro	CG4	Estimates	2	$100.00	4	$200.00
SLC Metro	CG5	Respond to Billing Inquiries	5	$250.00	12	$600.00
SLC Metro	CG6	Respond to Meter Problems			1	$50.00
SLC Metro	CG7	Notification of Planned Interruptions			10	$500.00
SLC Metro	CG8	Power Quality Complaints			5	$250.00
Smithfield	CG1	Restoring Supply			1	$200.00
Smithfield	CG3	Switching on Power	1	$125.00	1	$125.00
Smithfield	CG4	Estimates			3	$150.00
Tooele	CG2	Appointments			1	$50.00

Utah - Failures

Sort the table by District or Guarantee to see individual District performance or overall Guarantee performance
3rd Quarter - Fiscal Year 2002
October-December 2001

District	Guarantee	Description	Qtr Count	Qtr Paid	YTD Count	YTD Paid
Tooele	CG3	Switching on Power	1	$50.00	2	$100.00
Tooele	CG4	Estimates	1	$50.00	4	$200.00
Tremonton	CG4	Estimates	3	$150.00	12	$600.00
Tremonton	CG5	Respond to Billing Inquiries	1	$50.00	1	$50.00
Vernal	CG7	Notification of Planned Interruptions			1	$100.00
		TOTAL	77	$ 5,475.00	238	$ 16,275.00

Utah - Outage Restoration Performance

3rd Quarter - Fiscal Year 2002
October-December 2001

	# Customers Interrupted > 5 minutes		% Restored Within 3 hours	
District	Oct-Dec	Fiscal YTD	Oct-Dec	Fiscal YTD
American Fork	18,666	85,464	95%	92%
Cedar City	9,575	61,004	84%	79%
Jordan Valley	53,950	303,206	91%	86%
Layton	27,513	95,323	92%	89%
Moab	1,469	7,185	97%	87%
Ogden	121,641	264,406	95%	88%
Park City [1]	45,328	69,454	79%	77%
Price	833	15,579	98%	84%
Richfield [2]	4,718	18,103	64%	76%
SLC Metro	32,362	251,403	85%	87%
Smithfield	10,814	47,691	75%	88%
Tooele	19,611	68,619	92%	86%
Tremonton [3]	2,697	12,001	64%	79%
Vernal	416	13,211	95%	75%
All Districts	349,593	1,312,649	89%	86%

[1] Park City's 3rd quarter performance was impacted by a series of large outages (over 5500 customers) on the same day as transmission lines and distribution circuits were de-energized due to a large fire near Summit Park. Excluding the fire-related outages, Park City's performance would have been 91% for the quarter.

[2] In Richfield, a single 4-hour outage during the quarter affected 1,433 customers. The outage was caused by a bird in the Salina substation. The substation had to be de-energized to repair substation equipment. Performance without that particular outage would have been 94% for the quarter.

[3] Third quarter performance in Tremonton was affected by a pole fire on a single strategic pole which resulted in 4-hour outage for 478 customers.

PACIFICORP

Utah - Connects/Reconnects

CG3 Events by District

3rd Quarter - Fiscal Year 2002

October-December 2001

District	Qtr Count	YTD Count
American Fork	307	1937
Cedar City	150	625
Jordan Valley	631	3805
Laketown/Woodruff	11	56
Layton	202	1265
Moab	46	236
Ogden	667	3349
Park City	54	281
Price	64	290
Richfield	89	352
SLC Metro	1513	7678
Smithfield	60	348
Tooele	141	617
Tremonton	39	236
Vernal	53	226
	4027	21301

Utah - Guarantee Field Response Performance

Sort the table by District or Guarantee to see individual District performance or overall Guarantee performance
3rd Quarter - Fiscal Year 2002
October-December 2001

District	Guarantee	Description	Qtr Count	Qtr Avg*	YTD Count	YTD Avg*
American Fork	CG4a	Estimates - Contact within 2 days	78	2	257	2
American Fork	CG4b	Estimates - 5 days	7	<1	36	<1
American Fork	CG4c	Estimates - 15 days	78	8	204	10
American Fork	CG5	Responding to Bill Inquiries within 10 days	153	6	430	6
American Fork	CG6	Responding to Meter Problems within 15 days	11	6	31	8
Cedar City	CG4a	Estimates - Contact within 2 days	71	1	336	1
Cedar City	CG4b	Estimates - 5 days	39	<1	160	<1
Cedar City	CG4c	Estimates - 15 days	33	<1	174	3
Cedar City	CG5	Responding to Bill Inquiries within 10 days	76	5	240	5
Cedar City	CG6	Responding to Meter Problems within 15 days	4	5	20	5
Jordan Valley	CG4a	Estimates - Contact within 2 days	98	1	399	1
Jordan Valley	CG4b	Estimates - 5 days	38	1	151	1
Jordan Valley	CG4c	Estimates - 15 days	68	3	243	8
Jordan Valley	CG5	Responding to Bill Inquiries within 10 days	565	8	1689	6
Jordan Valley	CG6	Responding to Meter Problems within 15 days	34	8	84	7
Laketown/Woodruff	CG4a	Estimates - Contact within 2 days	11	1	33	1
Laketown/Woodruff	CG4b	Estimates - 5 days	2	<1	7	<1
Laketown/Woodruff	CG4c	Estimates - 15 days	12	4	26	3
Laketown/Woodruff	CG5	Responding to Bill Inquiries within 10 days	18	7	40	6
Laketown/Woodruff	CG6	Responding to Meter Problems within 15 days	0	<1	1	12
Layton	CG4a	Estimates - Contact within 2 days	27	2	97	2
Layton	CG4b	Estimates - 5 days	5	1	28	1
Layton	CG4c	Estimates - 15 days	23	7	65	7
Layton	CG5	Responding to Bill Inquiries within 10 days	142	5	392	5
Layton	CG6	Responding to Meter Problems within 15 days	15	7	43	9
Moab [1]	CG4a	Estimates - Contact within 2 days	26	4	98	4
Moab	CG4b	Estimates - 5 days	4	1	27	1
Moab	CG4c	Estimates - 15 days	17	8	58	8
Moab	CG5	Responding to Bill Inquiries within 10 days	37	6	102	4
Moab	CG6	Responding to Meter Problems within 15 days	0	<1	2	6
Ogden	CG4a	Estimates - Contact within 2 days	72	1	263	1
Ogden	CG4b	Estimates - 5 days	17	1	68	1
Ogden	CG4c	Estimates - 15 days	53	4	216	4
Ogden	CG5	Responding to Bill Inquiries within 10 days	231	8	690	6
Ogden	CG6	Responding to Meter Problems within 15 days	16	11	43	9
Park City	CG4a	Estimates - Contact within 2 days	47	2	197	2
Park City	CG4b	Estimates - 5 days	9	1	14	1
Park City	CG4c	Estimates - 15 days	88	5	169	4
Park City	CG5	Responding to Bill Inquiries within 10 days	89	6	254	6
Park City	CG6	Responding to Meter Problems within 15 days	2	2	12	7
Price	CG4a	Estimates - Contact within 2 days	20	1	62	1
Price	CG4c	Estimates - 15 days	15	2	65	2
Price	CG5	Responding to Bill Inquiries within 10 days	27	5	87	5
Price	CG6	Responding to Meter Problems within 15 days	7	13	9	12
Richfield	CG4a	Estimates - Contact within 2 days	47	1	174	1
Richfield	CG4b	Estimates - 5 days	19	1	57	1
Richfield	CG4c	Estimates - 15 days	52	4	127	7

Utah - Guarantee Field Response Performance

Sort the table by District or Guarantee to see individual District performance or overall Guarantee performance
3rd Quarter - Fiscal Year 2002
October-December 2001

District	Guarantee	Description	Qtr Count	Qtr Avg*	YTD Count	YTD Avg*
Richfield	CG5	Responding to Bill Inquiries within 10 days	34	8	110	6
Richfield	CG6	Responding to Meter Problems within 15 days	2	8	11	8
SLC Metro	CG4a	Estimates - Contact within 2 days	81	1	278	1
SLC Metro	CG4b	Estimates - 5 days	27	1	70	1
SLC Metro	CG4c	Estimates - 15 days	55	6	196	6
SLC Metro	CG5	Responding to Bill Inquiries within 10 days	822	5	2714	5
SLC Metro	CG6	Responding to Meter Problems within 15 days	49	8	108	7
Smithfield	CG4a	Estimates - Contact within 2 days	39	1	151	1
Smithfield	CG4b	Estimates - 5 days	7	1	23	1
Smithfield	CG4c	Estimates - 15 days	37	3	117	3
Smithfield	CG5	Responding to Bill Inquiries within 10 days	47	4	119	4
Tooele [2]	CG4a	Estimates - Contact within 2 days	15	7	77	3
Tooele	CG4b	Estimates - 5 days	2	1	26	1
Tooele	CG4c	Estimates - 15 days	18	4	65	7
Tooele	CG5	Responding to Bill Inquiries within 10 days	33	6	76	6
Tooele	CG6	Responding to Meter Problems within 15 days	2	9	9	9
Tremonton	CG4a	Estimates - Contact within 2 days	26	2	94	2
Tremonton	CG4b	Estimates - 5 days	9	<1	18	<1
Tremonton	CG4c	Estimates - 15 days	23	4	74	8
Tremonton	CG5	Responding to Bill Inquiries within 10 days	30	8	81	6
Vernal	CG4a	Estimates - Contact within 2 days	28	<1	91	<1
Vernal	CG4b	Estimates - 5 days	9	<1	17	<1
Vernal	CG4c	Estimates - 15 days	22	<1	76	<1
Vernal	CG5	Responding to Bill Inquiries within 10 days	17	5	39	5
Vernal	CG6	Responding to Meter Problems within 15 days	2	14	4	14

* Average response measured in working days.

[1] In Moab, one request with a response periods of 15 days and three requests with responses of 5 days were the result of waiting for customers to call back despite PacifiCorp's multiple attempts to make contact. Two more requests with responses between 2 and 4 days were also delayed for lack of customer response.

[2] A Tooele request with a response period of 17 days was the result of the customer not calling back despite PacifiCorp's multiple attempts to make contact. Once contact was made, work proceeded and the estimate was delivered on time. Three more requests exceeded the 2-day target and failure payments were processed, one in November 2001 and two in January 2002.

Utah - Non-Guarantee Field Response Performance

Field Orders

3rd Quarter - Fiscal Year 2002

October-December 2001

District	Qtr Count	Qtr Avg*	YTD Count	YTD Avg*
American Fork	61	5	192	3
Cedar City	62	9	303	5
Jordan Valley	299	2	912	2
Laketown	202	7	893	7
Layton	5	3	12	2
Moab	13	12	53	12
Ogden	238	15	942	18
Park City	27	7	88	5
Price [1]	21	28	55	15
Richfield	22	1	92	4
SLC Metro	333	14	1071	10
Smithfield	31	7	148	7
Tooele	38	4	156	7
Tremonton	20	8	74	13
Valley West	1	3	7	3
Vernal [2]	17	27	39	14
	1390		5037	

* Average response measured in working days.

[1] Price had requests with 185, 150 and 89 day responses that were completed in a reasonable period, but were never closed in the work tracking system. Requests of 54 and 34 days were waiting on the customer to do their part. Four requests actually took between 15 and 46 days to complete.

[2] In Vernal, one request with a response time of 152 days was due to incomplete communication between PacifiCorp and the customer that the problem was actually a concern with telephone and CATV lines. A second request with 112 days response time was actually completed within one day of the request, but the completion was not entered in the work tracking system. PacifiCorp waited 70 days for customer response on a third request which was closed when it was learned the customer no longer needed the work to be done. A 48-day response was due to a non-hazardous leaning pole that was repaired at the next scheduled opportunity. The remaining requests had reasonable response times.

Utah - Non-Guarantee Field Response Performance

Tree Trimming Orders

3rd Quarter - Fiscal Year 2002

October-December 2001

District	Description	3rd Qtr Count	3rd Qtr Avg*	July-Dec Count	July-Dec Avg*
American Fork	Site Inspection Required	25	4	74	4
Cedar City	Site Inspection Required	4	6	18	6
Jordan Valley	Resolved by Customer Contact	1	<1	4	<1
Jordan Valley	Site Inspection Required	169	6	384	5
Layton	Resolved by Customer Contact	0	0	1	1
Layton	Site Inspection Required	32	2	68	2
Moab	Resolved by Customer Contact	--	--	1	3
Moab [1]	Site Inspection Required	7	39	7	39
Ogden	Resolved by Customer Contact	1	1	3	2
Ogden	Site Inspection Required	97	4	275	3
Park City	Resolved by Customer Contact	1	1	1	1
Park City	Site Inspection Required	7	1	17	5
Price	Resolved by Customer Contact	--	--	1	8
Price [1]	Site Inspection Required	13	30	34	16
Richfield	Resolved by Customer Contact	--	--	2	1
Richfield [1]	Site Inspection Required	4	25	14	14
SLC Metro	Resolved by Customer Contact	4	<1	9	1
SLC Metro	Site Inspection Required	417	3	946	4
Smithfield	Resolved by Customer Contact	0	<1	2	8
Smithfield	Site Inspection Required	4	15	21	10
Tooele	Resolved by Customer Contact	0	<1	1	1
Tooele	Site Inspection Required	18	12	30	10
Tremonton	Site Inspection Required	7	4	17	3
Valley West	Site Inspection Required	0	<1	4	3
Vernal	Site Inspection Required	11	8	16	7
		822		1950	

* Average = Average working days from customer call to resolution by contact only, or where necessary, average working days from customer call to site inspection.

"--" Denotes an update in the the two quarters' counts due to a process change in extracting and documenting request data.

[1] Emergency work is always inspected and completed as soon as possible. For non-emergency requests, customers are contacted within ten days, and where necessary, the customer is informed the work will be inspected on the next scheduled visit to the district. For these three districts, such visits may be several weeks in the future.

UTAH RESIDENTIAL/SMALL COMMERCIAL METER SETS - REPORT BY DISTRICT

FISCAL YEAR TO DATE - 2ND QUARTER 2001-2002

NORTHERN UTAH

LOCATION	1st Quarter			2nd Quarter			OCTOBER			NOVEMBER			DECEMBER			3rd Quarter			Fiscal YTD			Notes
	Total Within 5 Days	%	Total	Total Within 5 Days	%	Total	Within 5 Days	%	Total	Within 5 Days	%	Total	Within 5 Days	%	Total	Total Within 5 Days	%	Total	Total Within 5 Days	%	Total	
Jordan Valley	1104	98%	1124	1374	0.98991	1388	533	100%	534	501	100%	501	430	95%	451	1464	99%	1486	3942	99%	3998	
Layton	376	96%	393	411	99%	415	194	98%	198	165	99%	167	146	95%	153	505	97%	518	1292	97%	1326	
Metro	769	99%	777	862	99%	872	747	100%	748	313	100%	313	243	91%	266	1303	98%	1327	2934	99%	2976	
Ogden	372	100%	373	506	99%	512	245	98%	249	252	98%	256	191	96%	200	688	98%	705	1566	98%	1590	
Park City	146	96%	152	230	88%	261	118	79%	149	146	87%	167	151	70%	215	415	78%	531	791	84%	944	
Smithfield	99	99%	100	149	99%	150	63	100%	63	47	100%	47	39	100%	39	149	100%	149	397	99%	399	
Tooele	148	98%	151	234	100%	234	64	98%	65	144	97%	149	28	100%	28	236	98%	242	618	99%	627	
Tremonton	36	100%	36	30	100%	30	26	100%	26	15	100%	15	10	71%	14	51	93%	55	117	97%	121	
																			0		0	
TOTAL	3050	98%	3106	3796	98%	3862	1990	98%	2032	1583	98%	1615	1238	91%	1366	4811	96%	5013	11657	97%	11981	

SOUTHERN UTAH

LOCATION	1st Quarter			2nd Quarter			OCTOBER			NOVEMBER			DECEMBER			3rd Quarter			Fiscal YTD			Notes
	Total Within 5 Days	%	Total	Total Within 5 Days	%	Total	Within 5 days	%	Total	Within 5 days	%	Total	Within 5 days	%	Total	Total Within 5 Days	%	Total	Total Within 5 Days	%	Total	
American Fork	492	100%	493	567	99%	574	242	99%	245	207	99%	210	203	99%	206	652	99%	661	1711	99%	1728	
Cedar City	142	99%	143	188	90%	208	81	87%	93	83	90%	92	68	91%	75	232	89%	260	562	92%	611	
Moab	53	100%	53	65	98%	66	21	100%	21	20	100%	20	9	100%	9	50	100%	50	168	99%	169	
Price	30	94%	32	66	100%	66	12	100%	12	8	100%	8	8	100%	8	28	100%	28	124	98%	126	
Richfield	103	100%	103	135	99%	136	38	100%	38	38	100%	38	45	100%	45	121	100%	121	359	100%	360	
Vernal	41	100%	41	35	100%	35	20	91%	22	14	100%	14	19	95%	20	53	95%	56	129	98%	132	
																			0		0	
TOTAL	861	100%	865	1056	97%	1085	414	96%	431	370	97%	382	352	97%	363	1136	97%	1176	3053	98%	3126	

TOTAL UTAH

LOCATION	1st Quarter			2nd Quarter			OCTOBER			NOVEMBER			DECEMBER			3rd Quarter			Fiscal YTD			Notes
	Total Within 5 Days	%	Total	Total Within 5 Days	%	Total	Within 5 days	%	Total	Within 5 days	%	Total	Within 5 days	%	Total	Total Within 5 Days	%	Total	Total Within 5 Days	%	Total	
TOTAL UTAH	3911	98%	3971	4852	98%	4947	2404	98%	2463	1953	98%	1997	1590	92%	1729	5947	96%	6189	14710	97%	15107	

UTAH TEMPORARY METER SETS - REPORT BY DISTRICT

FISCAL YEAR TO DATE - 2ND QUARTER 2001-2002

NORTHERN UTAH

LOCATION	1st Quarter			2nd Quarter			OCTOBER			NOVEMBER			DECEMBER			3rd Quarter			Fiscal YTD			Notes
	Total Within 10 Days	%	Total	Total Within 10 Days	%	Total	Within 10 Days	%	Total	Within 10 Days	%	Total	Within 10 Days	%	Total	Total Within 10 Days	%	Total	Total Within 10 Days	%	Total	
Jordan Valley	601	99%	608	504	99%	509	211	100%	211	128	100%	128	137	100%	137	476	100%	476	1581	99%	1593	
Layton	295	97%	303	367	98%	374	124	100%	124	71	100%	71	96	97%	99	291	99%	294	953	98%	971	
Metro	236	100%	236	240	100%	240	70	100%	70	75	99%	76	70	100%	70	215	100%	216	691	100%	692	
Ogden	342	90%	380	304	100%	304	88	100%	88	79	100%	79	68	100%	68	235	100%	235	881	96%	919	
Park City	96	100%	96	79	95%	83	43	100%	43	12	86%	14	14	100%	14	69	97%	71	244	98%	250	
Smithfield	82	100%	82	82	100%	82	26	100%	26	13	100%	13	20	100%	20	59	100%	59	223	100%	223	
Tooele	110	100%	110	141	100%	141	50	100%	50	18	100%	18	18	100%	18	86	100%	86	337	100%	337	
Tremonton	24	100%	24	29	100%	29	7	100%	7	6	100%	6	4	100%	4	17	100%	17	70	100%	70	
																			0		0	
TOTAL	1824	99%	1839	1746	99%	1762	619	100%	619	402	99%	405	427	99%	430	1448	100%	1454	5018	99%	5055	

SOUTHERN UTAH

LOCATION	1st Quarter			2nd Quarter			OCTOBER			NOVEMBER			DECEMBER			3rd Quarter			Fiscal YTD			Notes
	Total Within 10 Days	%	Total	Total Within 10 Days	%	Total	Within 10 days	%	Total	Within 10 days	%	Total	Within 10 days	%	Total	Total Within 10 Days	%	Total	Total Within 10 Days	%	Total	
American Fork	382	100%	383	379	99%	383	111	100%	111	123	100%	123	119	100%	119	353	100%	353	1114	100%	1119	
Cedar City	104	100%	104	86	100%	86	31	100%	31	21	100%	21	20	95%	21	72	99%	73	262	100%	263	
Moab	2	100%	2	2	100%	2	1	100%	1	5	100%	5	2	100%	2	8	100%	8	12	100%	12	
Price	5	100%	5	7	100%	7	2	100%	2	4	100%	4	3	100%	3	9	100%	9	21	100%	21	
Richfield	17	100%	17	25	100%	25	8	100%	8	9	100%	9	4	100%	4	21	100%	21	63	100%	63	
Vernal	7	100%	7	21	100%	21	3	100%	3	6	100%	6	3	100%	3	12	100%	12	40	100%	40	
																			0		0	
TOTAL	517	100%	518	520	99%	524	156	100%	156	168	100%	168	151	99%	152	475	100%	476	1512	100%	1518	

TOTAL UTAH

LOCATION	1st Quarter			2nd Quarter			OCTOBER			NOVEMBER			DECEMBER			3rd Quarter			Fiscal YTD			Notes
	Total Within 10 Days	%	Total	Total Within 10 Days	%	Total	Within 10 days	%	Total	Within 10 days	%	Total	Within 10 days	%	Total	Total Within 10 Days	%	Total	Total Within 10 Days	%	Total	
TOTAL UTAH	2341	99%	2357	2266	99%	2286	775	100%	775	570	99%	573	578	99%	582	1923	100%	1930	6530	99%	6573	

RECEIVED

DEC 20 7 22 AM '99

SERVICE COMMISSION

EXHIBIT "A"

I have reviewed the Protective Order approved by the Public Service Commission of Utah on the 25th day of January, 1999, in Docket No. 98-2035-04, and agree to be bound by the terms and conditions of such Order.

Paul I. Nippes
Signature

PAUL I, NIPPES
Name (Type or Print)

1 TALL TREE RD
Residence Address
MIDDLETOWN, NJ 07748

NIPPES BELL ASSOC. INC
Employer or Firm

2135 HWY 35, HOLMDEL, NJ 07733
Business Address

Party

Date

EXHIBIT "A"

I have reviewed the Protective Order approved by the Public Service Commission of Utah on the 25th day of January, 1999, in Docket No. 98-2035-04, and agree to be bound by the terms and conditions of such Order.

David A. Schlissel
Signature

DAVID A. SCHLISSEL
Name (Type or Print)

45 HORACE ROAD, BELMONT, MA 02478
Residence Address

Synapse Energy Economics, Inc.
Employer or Firm

22 Pearl St..
Cambridge, MA 02139
Business Address

Committee of Consumer Services
Party

12/20/2001

1900 S.W. Fourth Avenue
Portland, Oregon 97201

PACIFICORP
Pacific Power Utah Power

RECEIVED
DEC 21 11 05 AM '01
SERVICE COMMISSION

REVIEWED BY COMMISSIONERS
STEPHEN F. MECHAM SM 12/28/01
CONSTANCE B. WHITE CBW 12/31
RICHARD M. CAMPBELL RC

VIA OVERNIGHT MAIL

December 20, 2001

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City UT 84114

Attention: Julie P. Orchard
Commission Secretary

RE: Docket No. 98-2035-04 ScottishPower/PacifiCorp Merger Commitments

Please find enclosed PacifiCorp's addendum to the semi-annual report for the period April 1, 2001 to September 30, 2001 detailing the Company's performance in meeting the Customer Guarantees and Performance Standards which were agreed to as a result of the merger between ScottishPower and PacifiCorp. This information will be included in future reports.

If you have any questions or require further information, please call me at (503) 813-7408.

Sincerely,

Carole Rockney/sy

Carole Rockney, Director
Customer and Regulatory Liaison

c: Mark Flandro - Utah Division of Public Utilities
Andy MacRitchie - Executive Vice President, Power Delivery
Bob Maloney - Utah Division of Public Utilities
Rea Petersen - Utah Division of Public Utilities

Enclosures

Number of Utah Customers exceeding State SAIFI
By Operating Area by Quarter in fiscal year 2002

Operating Area	Quarter 1	Quarter 2
AMERICAN FORK	17,630	22,817
ASHLEY	4,108	3,582
CANYONLANDS	1104	2,139
CARBON	4302	5406
CEDAR CITY	766	6246
COTTONWOOD	5,422	0
DELTA	872	784
LAYTON	19,456	19,516
METRO	66,426	55,799
MILFORD	1334	627
OGDEN	39,416	44,902
PARK CITY	4429	6938
SALINA	2404	2647
SMITHFIELD	8,121	8,412
SOUTH VALLEY	61313	55,073
TOOELE	11,311	13,228
TREMONTON	1891	3289
UTAH	250,305	251,405

Number of Utah Customers affected by Transmission Outages
Fiscal Year 2002
4/1/2001 through 9/30/2001

Op Area	Sustained Customers Off	Customer Count
AMERICAN FORK	2,001	58,656
ASHLEY	0	8,146
CANYONLANDS	0	10,817
CARBON	2,340	9,140
CEDAR CITY	4,584	22,533
COTTONWOOD	0	5,422
DELTA	0	5,238
LAYTON	0	44,870
METRO	0	187,832
MILFORD	495	2,165
OGDEN	0	83,297
PARK CITY	539	22,559
SALINA	207	14,227
SMITHFIELD	0	17,995
SOUTH VALLEY	1,903	163,172
TOOELE	1,088	13,533
TREMONTON	0	7,402
Utah	13,157	677,004

27490

DOCKETED

- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Application of PacifiCorp and ScottishPower plc for an Order Approving the Issuance of PacifiCorp Common Stock	))))	DOCKET NO. 98-2035-04 ORDER MODIFYING CALL ANSWERING RATE

ISSUED: December 17, 2001

On October 16, 2001, PacifiCorp filed a petition (Petition) to modify the Commission's November 23, 1999, Order (November Order) issued in this docket. In the November Order, the Commission set various customer service standards, one of which dealt with the answer rate for calls placed to PacifiCorp's business centers. The November Order required call answer rates to ratchet up over time; beginning with 80% of calls answered in 30 seconds, moving to 80% of calls answered in 20 seconds in 2001, and then 80% of calls answered in 10 seconds beginning in 2002. In its Petition, PacifiCorp represents that customer research shows that customers do not necessarily place value or receive appreciable additional customer satisfaction in having the call answering rate move from 20 seconds to 10 seconds. Customers may question whether service quality may actually suffer in the haste to answer calls. PacifiCorp further represents that the nature of calls received from customers, changed call volumes and the Company's efforts to fully respond to customer inquiries on the first call make the move from 20 seconds to 10 seconds one which will incur additional expenses (personnel and other) with little or no benefit to customers. PacifiCorp also states that no other U.S. electric utility has a target higher than 80 % of calls answered in 20 seconds.

On November 21, 2001, the Division of Pubic Utilities (DPU) submitted a Memorandum supporting the requested modification. The DPU confirms that a target of 10 seconds is not used by other utilities; the 20 second level is the upper range, which a limited number of entities attempt. The DPU's Memorandum notes that PacifiCorp's performance, under the past and existing call answering standards, has been as good or better than the performance of other utilities operating in the State of Utah. The DPU's Memorandum indicates that call answering standards for some other Utah utilities is lower than the existing standard applicable to PacifiCorp. The DPU concurs in viewing a move to 10 seconds as offering little or no additional customer service satisfaction, outweighed by costs needed to achieve that level. On November 23, 2001, the Committee of Consumer Services (CCS) filed a Memorandum regarding the Petition. The CCS's Memorandum does not directly oppose the requested modification. The CCS Memorandum represents that the CCS has some concerns regarding PacifiCorp's proposal, but does not identify what these concerns may be. The CCS represents that it desires to discuss, with PacifiCorp, other aspects of the Company's handling of telephone calls in general, since this docket has been opened. Apparently, the CCS, seeks to broach these other matters through the opportunity presented by this docket raising a call answering standard modification.

We recognize the CCS's desire to take advantage of this docket and attempt to negotiate resolution of other issues in connection with the specific matter raised by the Petition. The Commission concludes, however, that it will approve the modification requested. We note the CCS's point that the call answering standards were originally included in a prior stipulation submitted in this Docket, supporting PacifiCorp's and Scottish Power's merger. The requested relief is to modify the November Order, a Commission determination, not the prior stipulation. The information submitted by Pacificorp and the DPU support modification of the standard which would otherwise become effective January, 1 2002. The CCS's unarticulated concerns concerning the specific modification, if any, do not detract from the PacifiCorp and DPU evidence that the 2002 standard, if implemented, will increase expenses without providing any additional customer satisfaction or benefit. We cannot justify requiring the Company to gear up and begin to comply, in less than three weeks, with a Commission mandated call answering standard when all evidence submitted shows it would be a waste of resources. We determine that a call answering standard of 80% of calls answered within 20 seconds is the appropriate standard, deriving an adequate level of customer satisfaction relative to the costs incurred in reaching such a target, and in light of other call answering targets applied by other utilities and other entities using call response standards.

ORDER

NOW, THEREFORE, IT IS HEREBY ORDERED, that:

Our November Order is hereby modified to set a call answering standard of 80% of calls answered within 20 seconds for 2002 and thereafter.

DATED at Salt Lake City, Utah, this 17th day of December, 2001.

Stephen F. Mecham, Chairman

Constance B. White, Commissioner

Richard M. Campbell, Commissioner

Attest:

Julie Orchard
Commission Secretary
G#27496

I hereby certify that on day, Monday, December 17, 2001, I served a true copy of the ORDER MODIFYING CALL ANSWERING RATE hereto attached on the persons whose names are set forth below by mailing such copy on said date in a post office in Salt Lake City, Utah, properly enclosed in a sealed envelope with postage prepaid thereon, legibly addressed to the addresses shown:

* See attached Mailing Lists and "E" Mailing Lists

Allison Beckstead
____

Thomas M. Zarr
THOMAS M. ZARR, P.C.
1134 SOUTH 1700 EAST
P.O. BOX 17635
SALT LAKE CITY UT 84117-0635

ERIC BLANK
LAND AND WATER FUND OF THE ROCKIES
2260 BASELINE RD STE 200
BOULDER CO 80302

E.A. PRAWITT
UTAH ASSOCIATION OF COUNTIES
5397 SOUTH VINE STREET
SALT LAKE CITY UT 84107

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Subject: Order Modifying Call Answering Rate, Docket No. 98-2035-04
Creation Date: Mon, Dec 17, 2001 3:04 PM
From: Public Service Commission

Created By: PSCCAL.PUPSC@state.ut.us

Recipients	**Action**	**Date & Time**

inet
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"cdsjoberg@stoel.com" BC ("cdsjoberg@stoel
"edwarddm@kutv2.com" BC ("edwarddm@kutv2.c
"gbmonson@stoel.com" BC ("gbmonson@stoel.c
"gkratz@desnews.com" BC ("gkratz@desnews.c
"mmcnulty@vancott.com" BC ("mmcnulty@vanco
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"steve@sltrib.com" BC ("steve@sltrib.com".

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ATMAIN.ATDOMAIN
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DTINGEY BC (Doug Tingey)
KWALGREN BC (Kent Walgren)
MGINSBER BC (Michael Ginsberg)
RWARNICK BC (Reed Warnick)

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rpbullock (Phil Bullock)

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Bna.com
Talkire (Tom Alkire)

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BRMAIN.BRCMRC
BGARDNER (Barbara Gardner)
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DMILLER (Dennis Miller)
IHENNING (Ingo Henningsen)

JJOHNSON BC (Judith Johnson)
KFRANCON BC (Kelly Francone)
LALT BC (Lowell Alt)
LNELSON BC (Laura Nelson)
MCLEVELA BC (Mary Cleveland)
MFLANDRO BC (Mark Flandro)
RBURRUP BC (Ron Burrup)
RPETERSE (Rea Petersen)
RWILSON BC (Rebecca Wilson)
TPEEL BC (Tom Peel)
WHUNTSMA (Wes Huntsman)
WPOWELL BC (William Powell)

brea.net
deyre (F. Eyre)

btlp.state.ut.us
cmichaelis BC (C. Michaelis)

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bob-rhoads (Robert Rhoads)

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steven.allred (Steven Allred)

ci.west-valley.ut.us
pmorris (Paul-pmorris Morris-@ci.west-val

costalcorp.com
tom.dobson (Tom Dobson)

dced.state.ut.us
CEMAIN.CEDOMAIN
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dstipes (Douglas Stipes)

ect.enron.com
pkaufma (Lisa-pkaufma Enron-@ect.enron.co

empireelectric.org
nstephen BC (Neal Stephens)

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	Pending	byu.edu
	Pending	ci.slc.ut.us
	Pending	ci.west-valley.ut.us
	Pending	costalcorp.com
CEMAIN.CEDOMAIN	Pending	dced.state.ut.us
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	Pending	desnews.com
	Pending	dowjones.com
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	Pending	energystrat.com
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	Pending	hollandhart.com
	Pending	home.com
	Pending	ieee.org
	Pending	inconnect.com
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	Pending	pblutah.com
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	Pending	Pur.com
	Pending	questar.com
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	Pending	rgn.com
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Options

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Notify Recipients:	Yes
Priority:	Standard
Reply Requested:	No
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Security:	Standard
To Be Delivered:	Immediate
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27294

State of Utah

DEPARTMENT OF COMMERCE
Committee of Consumer Services

RECEIVED
Nov 23 4 03 PM '01
SERVICE COMMISSION
REVIEWED BY COMMISSIONERS
STEPHEN F. MECHAM
CONSTANCE B. WHITE CBW 11/27
RICHARD M. CAMPBELL RC

To: Public Service Commission

From: Roger Ball, Administrative Secretary RB
Cheryl Murray, Utility Analyst cm

Copies To: Lowell Alt, Division of Public Utilities
Douglas Larson, PacifiCorp
Ted Boyer, Executive Director, Department of Commerce

Date: 23 November 2001

Subject: Petition of PacifiCorp for Modification of Order - Docket No 98-2035-04

On 16 October, 2001, the Company filed its Petition for Modification of the Commission's Order regarding the merger of ScottishPower and PacifiCorp. The Division responded in its 20 November 2001, Memorandum, recommending that the Commission approve PacifiCorp's request to eliminate the 80/10 answering standard.

The Committee would call the Commission's attention to the fact that the telephone service level obligations of the Company originated as a proposal by Alan Richardson of Scottish Power in his 16 April 1999 supplemental testimony. Mr Richardson's proposal was incorporated into the 28 July 1999 Stipulation of ScottishPower, PacifiCorp, the Division, and the Committee. That Stipulation was then adopted by the Commission and incorporated into its Order as an integrated agreement among the parties.

Through an oversight, while preparing to respond to the technical aspects of PacifiCorp's Petition, the Committee failed to timely respond to its legal aspects by filing a responsive pleading within thirty days. The Committee became aware of its oversight during the final stages of preparation to file a technical memorandum in response to the Commission's 25 October 2001 Action Request, which called for a response within 30 days.

Since PacifiCorp is asking the Commission to modify a term of agreement among the parties to the 28 July 1999 Stipulation, consent by the parties is certainly a proper prelude to any such modification by order. While the Division, in its 20 November 2001 Memorandum, recommends approval, the Committee is of the opinion that the requested modification - on its own - may not be in the public interest.

The Committee does not necessarily intend to withhold its consent to the Company's modification request, but there are some concerns the Committee has with the Company's proposal, and its handling of telephone calls in general, which we would like to resolve with the Company before the Commission proceeds. As the original Stipulation was the product of negotiation, we believe PacifiCorp's and the Committee's respective interests could be

27259

State of Utah
DEPARTMENT OF COMMERCE
Internet Address; http://www.commerce.state.ut.us

Michael O. Leavitt
Governor
Ted Boyer
Executive Director
Lowell E. Alt Jr.
Division Director

DIVISION OF PUBLIC UTILITIES
Heber M. Wells Building 4th Floor
160 East 300 South/ Box 146751
Salt Lake City, Utah 84114-6751
Phone (801) 530-7622
Fax (801) 530-6512 or (801) 530-6650

RECEIVED

Nov 21 8 09 AM '01

APPROVED BY COMMISSIONERS
STEPHEN F. MECHAM SM 12/12/01
CONSTANCE B. WHITE CBW 11/27
RICHARD M. CAMPBELL RC 12/12/01

To: Utah Public Service Commission

From: Utah Division of Public Utilities
Lowell Alt, Director
Judith Johnson, Energy Manager
Tom Peel, Technical Consultant
Ron Burrup, Technical Consultant

Date: November 20, 2001

RE: Docket 98-2035-04 PacifiCorp Petition for Modification of Order

Issue:

PacifiCorp filed a petition to modify the Commission's order in Docket 98-2035-04, issued November 23, 1999 which approved ScottishPower's purchase of PacifiCorp. The order adopted customer service standards. One of the standards required PacifiCorp's Business Centers to answer calls within 30 seconds, 80% of the time within the first 120 days. It also required the Company to improve each year and respond to calls within 20 seconds 80% of the time by January 1, 2001. PacifiCorp has achieved these standards. The final standard was to respond within 10 seconds by January 1, 2002.

PacifiCorp has asked that this last requirement to respond to 80% of calls within 10 seconds by January 1, 2002 be eliminated from call center Customer Performance Standards.

Recommendation:

The Division recommends that the Commission approve the petition to modify the order because the 80/10 standard is not used by any other utilities, does not appear to increase customer satisfaction, and causes additional call center labor costs. The DPU has not received any complaints from customers that PacifiCorp does not promptly respond to phone calls. The 10 second target may actually work against good customer service if PacifiCorp representatives rush through each call in order to meet the 10 second target.

Explanation:

Qwest's customer standard is established by Commission rules (R746-340-8E). The

Mission Statement
"To promote the public interest in utility regulation and work to assure that all utility customers have access to safe, reliable service at reasonable prices."

standard from January 1, 2001 to July 7, 2001 was "no more than a 45-second time in queue on average". Beginning July 8, 2001, the average wait time was changed to 35 seconds. In some months Qwest is not able to reach these averages.

Questar has reached the 80% in 20 seconds standard in the past, but is currently not at that standard. Questar has no plans to move to an 80% with in 10 second standard. The Division also asked about the call standards at a major local bank's customer service center and determined that call abandon rates (where the caller hangs up before being answered) was their main measurement. They try to maintain abandon call rate below 6%. PacifiCorp's abandoned call rate for the last four years has declined significantly, 1998 - 9.3%, 1999 - 4.6%, 2000 - 1.7% and 2001 - 2.1%. PacifiCorp's average speed of answer (ASA) has also declined, 1998 ASA 75 seconds, 1999 ASA 38 seconds, 2000 ASA 15 seconds, and 2001 ASA 19 seconds.

Results of an EEI Bench-marking survey show that of 50 major electric utilities, none had a call answering target of 10 seconds, only 14 utilities have answering targets of 20 seconds, 24 utilities have call answering targets of 30 seconds, and one has a target of 85 seconds. Of the utilities that have targets, only 3 reached their target a greater percentage of the time than PacifiCorp (86%). The Division's analysis shows that the 80% within 10 seconds is not a target used by other utilities

PacifiCorp conducted focus group research in December 2000. The prevailing opinion was that the 80% within 20 seconds was above and beyond customer expectations and that going to 80% within 10 seconds was not deemed necessary or important, nor would it increase the level of satisfaction. PacifiCorp's customer satisfaction survey validates this research. In 1998, before the merger, 62.7% of customers were very satisfied with wait times. After the merger, in 2000, when the standard was 80% within 30 seconds, 70.4% of customers were very satisfied with wait times. When the call standard went to 80% within 20 seconds in 2001, the percentage of customers who were very satisfied, through August 2001, was 70.2% identical to the previous year. This indicates that answering calls within 10 seconds would not increase satisfaction. Based on the focus group and customer survey results, the Division believes that the 10 second standard would not result in any greater customer satisfaction.

Although complaints about hold time is not a specific category of complaints, the DPU staff who respond to and monitor customer complaints could not remember customers complaining about PacifiCorp call centers not answering the phones promptly.

In order to meet the 80% within 10 seconds standard by January 1, 2002, PacifiCorp would have to pay overtime to call center employees. The Division believes this is an unnecessary expense.

cc: Wes Huntsman
PacifiCorp
CCS

1900 S.W. Fourth Avenue
Portland, Oregon 97201

PACIFICORP
Pacific Power Utah Power

RECEIVED

REVIEWED BY COMMISSIONERS
STEPHEN F. MECHAM
CONSTANCE B. WHITE CBW 11/15
RICHARD M. CAMPBELL RC

VIA OVERNIGHT MAIL

October 31, 2001

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City UT 84114

Attention: Julie P. Orchard
Commission Secretary

RE: Docket No. 98-2035-04 ScottishPower/PacifiCorp Merger Commitments

Please find enclosed PacifiCorp's semi-annual report for the period April 2001 through September 2001 detailing the Company's performance in meeting the Customer Guarantees and Performance Standards which were agreed to as a result of the merger between ScottishPower and PacifiCorp. Quarterly information for the second quarter of the fiscal year is provided as well. A table of contents is included that describes the detailed reporting which is required by the Merger.

If you have any questions or require further information, please call Carole Rockney at (503) 813-7408.

Sincerely,

D. Larson/cr

D. Douglas Larson,
Vice President, Regulation

c: Mark Flandro - Utah Division of Public Utilities
Andy MacRitchie - Executive Vice President, Power Delivery
Bob Maloney - Utah Division of Public Utilities
Rea Petersen - Utah Division of Public Utilities

Enclosures

Table of Contents

PACIFICORP

Utah

Customer Service Commitments - Guarantees

July-September 2001

	Description	July-September 2001			Fiscal YTD 2002			Fiscal YTD 2001		
		Events	Failures	Paid	Events	Failures	Paid	Events	Failures	Paid
CG1	Restoring Supply	579,366	9	$725	963,056	9	$725	510,563	4	$225
CG2	Appointments	1,673	3	$150	3,362	6	$300	3,265	9	$450
CG3	Switching on Power	8,525	15	$2,475	17,274	27	$3,775	15,336	30	$5,350
CG4	Estimates	1,729	40	$2,000	3,876	70	$3,500	4,296	45	$2,250
CG5	Respond to Billing Inquiries	2,900	13	$650	4,661	17	$850	3,591	7	$350
CG6	Respond to Meter Problems	145	3	$150	238	3	$150	549	1	$50
CG7	Notification of Planned Interruptions	6,630	12	$600	15,035	23	$1,200	6,152	19	$1,000
CG8	Power Quality Complaints	101	6	$300	410	6	$300	1,771	168	$8,400
		601,069	**101**	**$7,050**	**1,007,912**	**161**	**$10,800**	**545,523**	**283**	**$18,075**

Summary analysis:

General Comments - Utah experienced a jump in the number of failures during the quarter. Under ISO 9001 standards, this is an expected pattern in the early years of a quality program. As internal audits and on-going training continue, the procedures become more embedded in local processes and employee's work habits. This further embedding of the program has the effect of not only ensuring more consistently applied standards of quality service across the state, but of also more consistently bringing to light instances where our service falls short of the guarantees. This pattern highlights opportunities for improving program quality and is expected to continue through the next 2 years when the first internal audit cycle will have been completed.

CG1 - Restoring Supply - Events increased significantly during the quarter primarily due to extreme weather conditions, including lightning and high winds.

CG4 - Estimates - Internal audits and estimator training have improved the understanding of guarantee procedures in field offices, leading to recognition of more failures.

CG6 - Respond to Meter Problems - Fewer CG6 requests were the result of successful efforts to resolve customer questions over the telephone.

CG7 - Planned Interruptions - Planned Interruption Notification processes are being analyzed to improve efficiency, control failures and improve reporting accuracy.

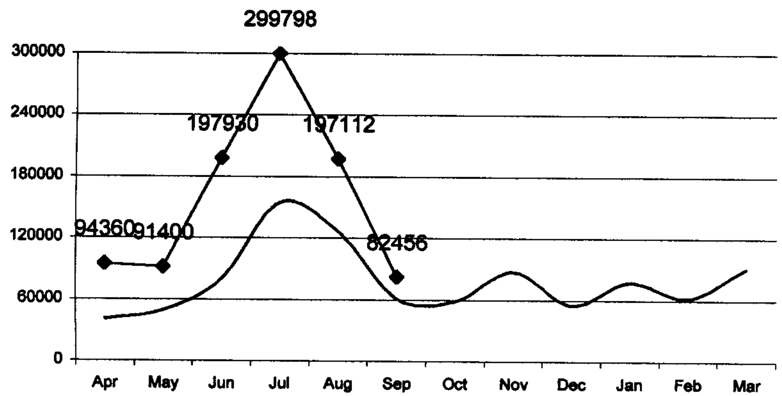
CG8 - Power Quality Complaints - Failures have been reduced significantly due to process refinement efforts and training efforts to help employees better understand the definition of this guarantee. Inquiries regarding outages with no power quality or voltage component had been incorrectly classified as CG8 events in FY 2001. In FY 2002 only power quality/voltage related inquiries are reported as CG8 events.

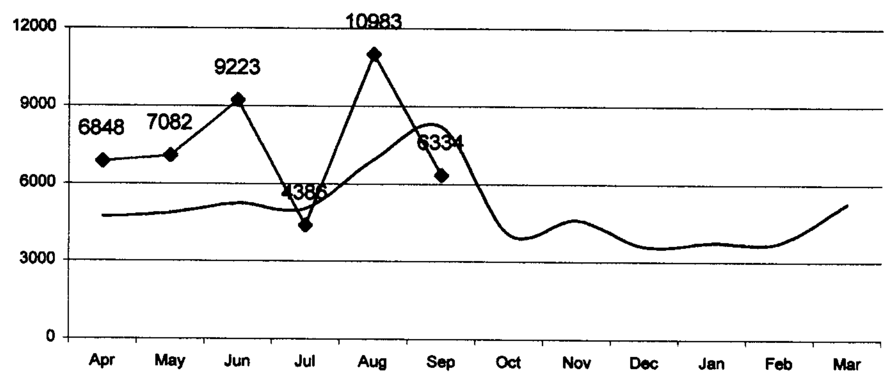
PACIFICORP

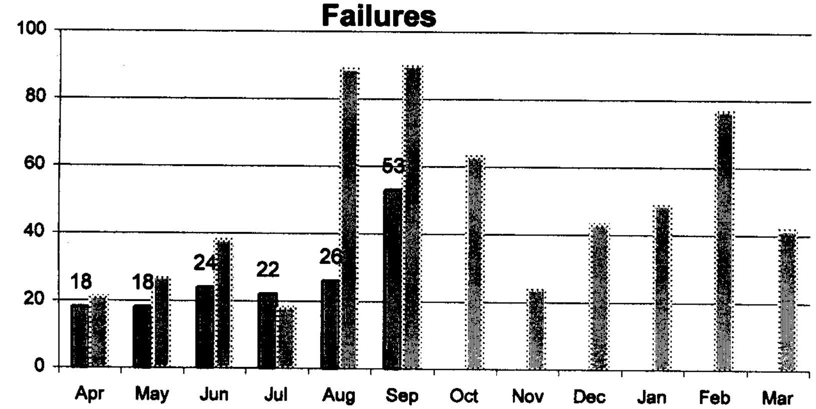
Utah

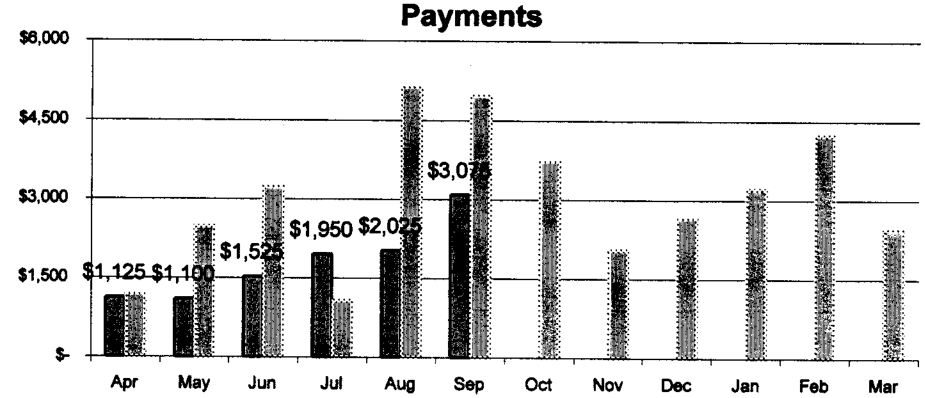
Customer Service Commitments - Guarantees

July-September 2001









Description	Baseline	Performance at Sept 2000	Performance at Sept 2001	Goal
• SAIDI (System availability in minutes per customer)	Revised baselines under development[1]	87.1	137.9	Reduce SAIDI by 10% from revised baseline
• SAIFI (System reliability in interruptions per customer)		0.8	1.4	Reduce SAIFI by 10% from revised baseline
• MAIFI (Momentary interruptions per customer)		4.8	0.2	Reduce MAIFI by 5% from revised baseline
• Worst Performing Circuits - Circuit Performance Indicator (CPI)[2]		CPI performance wil be reviewed at end of the 2-year improvement period.		Reduce CPI's by 20% from revised baseline
Fiscal Year 2001:				
Coalville 12	288			
Lewiston 11	377			
Pioneer 11	425			
Pioneer 13	529			
Pioneer 14	393			
Fiscal Year 2002:				
Woods Cross 11	311			
Eden 11	339			
Rattlesnake 22	308			
Lark 11	419			
Bothwell 11	323			
• Power supply restored within 3 hours	Not applicable	83%	85%	80%
• Calls answered				
• Within 30 seconds (standard effective through Dec 2000)	Not applicable	86%		80%
• Within 20 seconds (new standard effective Jan 2001)[3]	Not applicable		80%	80%
• Respond to commission complaints within 3 days	Not applicable	99%	99%	100%
• Respond to commission complaints regarding service disconnects within 4 hours	Not applicable	100%	100%	100%
• Commission complaints resolved within 30 days[4]	Not applicable	99%	97%	95%

1 The Computer Aided Distribution Operations System (CADOPS) has been operating in Southern Utah since November 2000 and Northern Utah since February of this year. Preliminary analysis for SAIDI and SAIFI indicates the increases are due to improved connectivity associated with the implementation of CADOPS. PacifiCorp plans to recommend modified 1994 to 1998 baselines by February 2002. We plan to increase the baselines based upon three uplift factors; number of occurrences (incidents); duration of outages; and number of customers affected by outages.

2 Baseline CPI figures are based on 3-years ended data as of December 31, 1998 for FY 2001 circuits; 3-years ended data as of December 31, 2000 for FY 2002 circuits.

3 Including the impacts of the major events in May and June, performance was 79%.

4 Commitment target increased from 90% to 95% effective January 1, 2001.

Note: Performance figures exlude impacts of major events.

Customer Service Commitments

UTAH FAILURES July - September 2001

American Fork	*CG #*	*Description*	*July-Sept*	*FYTD*	*Paid*
	CG2	Appointments	1	1	$50
	CG3	Switching on Power	3	3	$325
	CG4	Estimates [1]	9	25	$1,250
	CG5	Respond to Billing Inquiries	5	5	$250
	CG7	Notification of Planned	1	1	$50
		Total	**19**	**35**	**$1,925**

Cedar City	*CG #*	*Description*	*July-Sept*	*FYTD*	*Paid*
	CG3	Switching on Power	3	4	$325
	CG4	Estimates	2	3	$150
		Total	**5**	**7**	**$475**

Jordan Valley	*CG #*	*Description*	*July-Sept*	*FYTD*	*Paid*
	CG1	Restoring Supply	4	4	$200
	CG2	Appointments	1	2	$100
	CG3	Switching on Power	2	4	$250
	CG4	Estimates	5	9	$450
	CG5	Respond to Billing Inquiries	1	3	$150
	CG7	Notification of Planned	6	9	$450
	CG8	Power Quality Complaints	1	1	$50
		Total	**20**	**32**	**$1,650**

[1] Strong development growth in the American Fork district has led to an increased number of CG4 failures.

	CG #	Description	July-Sept	FYTD	Paid
Laketown/Woodruff					
	CG4	Estimates	0	1	$50
		Total	**0**	**1**	**$50**

	CG #	Description	July-Sept	FYTD	Paid
Layton					
	CG3	Switching on Power	0	2	$175
	CG5	Respond to Billing Inquiries	0	1	$50
	CG6	Respond to Meter Problems	2	2	$100
		Total	**2**	**5**	**$325**

	CG #	Description	July-Sept	FYTD	Paid
Moab					
	CG2	Appointments	1	1	$50
	CG4	Estimates	1	1	$50
		Total	**2**	**2**	**$100**

	CG #	Description	July-Sept	FYTD	Paid
Ogden					
	CG3	Switching on Power	1	1	$100
	CG5	Respond to Billing Inquiries	1	1	$50
	CG7	Notification of Planned	2	2	$100
		Total	**4**	**4**	**$250**

	CG #	Description	July-Sept	FYTD	Paid
Park City					
	CG4	Estimates	0	1	$50
		Total	**0**	**1**	**$50**

Price	*CG #*	*Description*	*July-Sept*	*FYTD*	*Paid*
	CG1	Restoring Supply	1	1	$50
	CG3	Switching on Power	1	1	$275
	CG4	Estimates	0	1	$50
		Total	**2**	**3**	**$375**

Richfield	*CG #*	*Description*	*July-Sept*	*FYTD*	*Paid*
	CG1	Restoring Supply	1	1	$100
	CG4	Estimates[2]	11	12	$600
		Total	**12**	**13**	**$700**

SLC Metro	*CG #*	*Description*	*July-Sept*	*FYTD*	*Paid*
	CG1	Restoring Supply	2	2	$175
	CG2	Appointments	0	1	$50
	CG3	Switching on Power	4	11	$2,275
	CG4	Estimates	1	2	$100
	CG5	Respond to Billing Inquiries	6	7	$350
	CG6	Respond to Meter Problems	1	1	$50
	CG7	Notification of Planned	3	10	$500
	CG8	Power Quality Complaints	5	5	$250
		Total	**22**	**39**	**$3,750**

Smithfield	*CG #*	*Description*	*July-Sept*	*FYTD*	*Paid*
	CG1	Restoring Supply	1	1	$200
	CG4	Estimates	3	3	$150
		Total	**4**	**4**	**$350**

[2] Richfield's broad geographic area has contributed to an increased number of CG4 failures.

	CG #	Description	July-Sept	FYTD	Paid
Tooele					
	CG2	Appointments	0	1	$50
	CG3	Switching on Power	1	1	$50
	CG4	Estimates	2	3	$150
		Total	**3**	**5**	**$250**

	CG #	Description	July-Sept	FYTD	Paid
Tremonton					
	CG4	Estimates	6	9	$450
		Total	**6**	**9**	**$450**

	CG #	Description	July-Sept	FYTD	Paid
Vernal					
	CG7	Notification of Planned	0	1	$100
		Total	**0**	**1**	**$100**

State Total	**101**	**161**	**$10,800**

Customer Service Commitments

UTAH OUTAGE RESTORATION PERFORMANCE

July - September 2001

District	# Customers Interrupted > 5 Minutes		% Restored Within 3 Hours	
	July-Sept	*FYTD*	*July-Sept*	*FYTD*
American Fork	37,646	66,798	91%	92%
Cedar City	43,273	51,429	76%	80%
Jordan Valley	132,183	249,256	80%	88%
Layton	30,491	67,810	77%	91%
Moab	4,416	5,716	88%	83%
Ogden	92,662	142,765	81%	82%
Park City [1]	13,547	24,126	73%	74%
Price	6,950	14,746	77%	86%
Richfield	7,323	13,385	80%	79%
SLC Metro	152,855	219,041	87%	88%
Smithfield	13,712	36,877	89%	92%
Tooele	31,310	49,008	90%	80%
Tremonton [2]	6,621	9,304	89%	76%
Vernal [3]	6,377	12,795	75%	73%
All Districts	**579,366**	**1,154,526**	**83%**	**86%**

Notes:

[1] Park City's performance was impacted by a single outage when a vehicle accident sheared off both the old and the new poles along a construction zone and pulled down multiple lengths of conductor.

[2] Year-to-date performance in Tremonton is still being affected by the single outage involving the failure of special equipment as reported in the first quarter.

[3] Performance was affected in Vernal due to a single outage in which extensive tree trimming was required to remove downed limbs before power could be restored.

Customer Service Commitments

UTAH CONNECTS/RECONNECTS July-September 2001

CG3 Events by District

DISTRICT	July-Sept	FYTD
American Fork	868	1630
Cedar City	227	475
Jordan Valley	1602	3174
Laketown/Woodruff	11	45
Layton	585	1063
Moab	84	190
Ogden	1317	2682
Park City	107	227
Price	133	226
Richfield	131	263
SLC Metro	2922	6165
Smithfield	128	288
Tooele	220	476
Tremonton	81	197
Vernal	107	173
All Districts	**8523**	**17274**

Customer Service Commitments

UTAH GUARANTEE FIELD RESPONSE PERFORMANCE July-September 2001

American Fork	*Description*	# Customer Requests July-Sept	# Customer Requests Fiscal YTD	Average # Days to Respond July-Sept	Average # Days to Respond Fiscal YTD
CG4a	Estimates - Contact within 2 days	78	179	3[1]	2
CG4b	Estimates - 5 days	16	29	< 1	< 1
CG4c	Estimates - 15 days	45	126	7	11
CG5	Responding to Bill Inquiries within 10 days	177	277	7	6
CG6	Responding to Meter Problems within 15 days	9	20	8	9

Cedar City	*Description*	# Customer Requests July-Sept	# Customer Requests Fiscal YTD	Average # Days to Respond July-Sept	Average # Days to Respond Fiscal YTD
CG4a	Estimates - Contact within 2 days	133	265	1	1
CG4b	Estimates - 5 days	55	121	< 1	< 1
CG4c	Estimates - 15 days	72	141	4	4
CG5	Responding to Bill Inquiries within 10 days	87	164	5	5
CG6	Responding to Meter Problems within 15 days	9	16	6	5

Laketown/Woodruff	*Description*	# Customer Requests July-Sept	# Customer Requests Fiscal YTD	Average # Days to Respond July-Sept	Average # Days to Respond Fiscal YTD
CG4a	Estimates - Contact within 2 days	8	22	1	1
CG4b	Estimates - 5 days	4	5	< 1	< 1
CG4c	Estimates - 15 days	6	14	3	2
CG5	Responding to Bill Inquiries within 10 days	7	22	7	5
CG6	Responding to Meter Problems within 15 days	0	1	0	12

[1] American Fork 'requests for estimates' with response periods of 34, 13 and another with 13 days, were the result of mishandled requests, which resulted in failure payments. Another 16 requests exceeded the 2-day target, most exempt from failure due to the customer not calling back despite PacifiCorp's multiple attempts to make contact. American Fork is currently experiencing strong development growth.

Layton	*Description*	# Customer Requests July-Sept	# Customer Requests Fiscal YTD	Average # Days to Respond July-Sept	Average # Days to Respond Fiscal YTD
CG4a	Estimates - Contact within 2 days	29	70	3[2]	2
CG4b	Estimates - 5 days	7	23	3	1
CG4c	Estimates - 15 days	17	42	6	7
CG5	Responding to Bill Inquiries within 10 days	153	250	5	5
CG6	Responding to Meter Problems within 15 days	19	28	11	10

Jordan Valley	*Description*	# Customer Requests July-Sept	# Customer Requests Fiscal YTD	Average # Days to Respond July-Sept	Average # Days to Respond Fiscal YTD
CG4a	Estimates - Contact within 2 days	130	301	1	1
CG4b	Estimates - 5 days	38	113	1	1
CG4c	Estimates - 15 days	82	175	11	10
CG5	Responding to Bill Inquiries within 10 days	716	1124	5	5
CG6	Responding to Meter Problems within 15 days	33	50	6	6

Moab	*Description*	# Customer Requests July-Sept	# Customer Requests Fiscal YTD	Average # Days to Respond July-Sept	Average # Days to Respond Fiscal YTD
CG4a	Estimates - Contact within 2 days	39	72	3[3]	4
CG4b	Estimates - 5 days	11	23	1	1
CG4c	Estimates - 15 days	23	41	9	8
CG5	Responding to Bill Inquiries within 10 days	35	65	3	3
CG6	Responding to Meter Problems within 15 days	0	2	0	6

[2] Layton's performance is impacted by 1 request with a 70-day response. A failure payment is in process.

[3] In Moab, requests with response periods of 57 and 38 days were the result of 2 customers not calling back despite PacifiCorp's multiple attempts to make contact. The requests were closed. 6 requests with responses between 2 and 8 days were also delayed for lack of customer response. One customer waited six days for a response and a failure was paid.

Ogden	Description	# Customer Requests July-Sept	# Customer Requests Fiscal YTD	Average # Days to Respond July-Sept	Average # Days to Respond Fiscal YTD
CG4a	Estimates - Contact within 2 days	82	191	1	1
CG4b	Estimates - 5 days	24	51	< 1	1
CG4c	Estimates - 15 days	69	163	3	4
CG5	Responding to Bill Inquiries within 10 days	281	459	5	5
CG6	Responding to Meter Problems within 15 days	17	27	8	8

Park City	Description	# Customer Requests July-Sept	# Customer Requests Fiscal YTD	Average # Days to Respond July-Sept	Average # Days to Respond Fiscal YTD
CG4a	Estimates - Contact within 2 days	81	150	3[4]	2
CG4b	Estimates - 5 days	4	5	1	1
CG4c	Estimates - 15 days	51	81	3	3
CG5	Responding to Bill Inquiries within 10 days	76	165	6	6
CG6	Responding to Meter Problems within 15 days	6	10	9	8

Price	Description	# Customer Requests July-Sept	# Customer Requests Fiscal YTD	Average # Days to Respond July-Sept	Average # Days to Respond Fiscal YTD
CG4a	Estimates - Contact within 2 days	26	42	1	1
CG4c	Estimates - 15 days	21	50	1	2
CG5	Responding to Bill Inquiries within 10 days	35	60	4	5
CG6	Responding to Meter Problems within 15 days	1	2	6	8

[4] A Park City request with a 31-day response period was the result of a data entry error which cannot be corrected in our system since the request is closed. Another request took 12 days before contact was made despite PacifiCorp's multiple attempts to make contact within the initial 2 days.

Richfield	Description	# Customer Requests July-Sept	# Customer Requests Fiscal YTD	Average # Days to Respond July-Sept	Average # Days to Respond Fiscal YTD
CG4a	Estimates - Contact within 2 days	49	127	< 1	1
CG4b	Estimates - 5 days	17	38	1	1
CG4c	Estimates - 15 days	26	75	15	9
CG5	Responding to Bill Inquiries within 10 days	43	76	5	5
CG6	Responding to Meter Problems within 15 days	4	9	6	8

SLC Metro	Description	# Customer Requests July-Sept	# Customer Requests Fiscal YTD	Average # Days to Respond July-Sept	Average # Days to Respond Fiscal YTD
CG4a	Estimates - Contact within 2 days	65	197	1	1
CG4b	Estimates - 5 days	10	43	1	1
CG4c	Estimates - 15 days	66	141	5	6
CG5	Responding to Bill Inquiries within 10 days	1238	1892	5	5
CG6	Responding to Meter Problems within 15 days	38	59	6	6

Smithfield	Description	# Customer Requests July-Sept	# Customer Requests Fiscal YTD	Average # Days to Respond July-Sept	Average # Days to Respond Fiscal YTD
CG4a	Estimates - Contact within 2 days	49	112	1	1
CG4b	Estimates - 5 days	9	16	2	1
CG4c	Estimates - 15 days	37	80	3	3
CG5	Responding to Bill Inquiries within 10 days	40	72	4	4

Tooele	*Description*	# Customer Requests July-Sept	# Customer Requests Fiscal YTD	Average # Days to Respond July-Sept	Average # Days to Respond Fiscal YTD
	CG4a Estimates - Contact within 2 days	30	62	< 1	2
	CG4b Estimates - 5 days	12	24	< 1	< 1
	CG4c Estimates - 15 days	19	47	8	8
	CG5 Responding to Bill Inquiries within 10 days	22	43	8	6
	CG6 Responding to Meter Problems within 15 days	3	7	4	9

Tremonton	*Description*	# Customer Requests July-Sept	# Customer Requests Fiscal YTD	Average # Days to Respond July-Sept	Average # Days to Respond Fiscal YTD
	CG4a Estimates - Contact within 2 days	21	68	4	2
	CG4b Estimates - 5 days	3	9	< 1	< 1
	CG4c Estimates - 15 days	19	51	12	10
	CG5 Responding to Bill Inquiries within 10 days	34	51	5	5

Vernal	*Description*	# Customer Requests July-Sept	# Customer Requests Fiscal YTD	Average # Days to Respond July-Sept	Average # Days to Respond Fiscal YTD
	CG4a Estimates - Contact within 2 days	35	63	< 1	< 1
	CG4b Estimates - 5 days	7	8	< 1	< 1
	CG4c Estimates - 15 days	28	54	< 1	< 1
	CG5 Responding to Bill Inquiries within 10 days	12	22	5	5
	CG6 Responding to Meter Problems within 15 days	1	2	14	14

Customer Service Commitments

UTAH - Non Guarantee

July-September 2001

Field Response Performance

	# Customer Requests		Average # Days to Respond	
	July-Sept	Fiscal YTD	July-Sept	Fiscal YTD
American Fork	50	131	2	2
Cedar City	112	241	3	4
Jordan Valley	338	691	7	7
Layton	305	613	2	2
Laketown/Woodruff	4	7	1	1
Moab	20	40	3	12
Ogden[1]	364	704	28	19
Park City	27	61	3	4
Price	16	34	9	7
Richfield	43	70	5	5
SLC Metro	369	738	5	8
Smithfield	62	117	5	7
Tooele	52	118	0	8
Tremonton[2]	31	54	22	15
Valley West	2	6	3	3
Vernal	13	22	3	4
TOTALS	1808	3647		

[1] In Ogden, 575 of the YTD requests were completed within 20 days; 76 within 20-100 days and 53 were resolved between 100-225 days. For those over 100 days, only 5 took that long to complete. The rest were requests held open waiting for customers to express continued interest and receiving none, they were finally closed.

[2] Tremonton's performance was impacted by 1 request involving crossed meters that took 170 days to complete. 3 other requests were help open for similar periods waiting for customers to express continued interest. After over 100 days had passed, the requests were marked as closed.

Customer Service Commitments

UTAH - Non Guarantee

July-September 2001

Tree Response Performance

		# Customer Requests	Average # Days to Respond
American Fork	SITE INSPECTION REQUIRED	49	4
Cedar City	SITE INSPECTION REQUIRED	14	6
Jordan Valley	RESOLVED BY CUSTOMER CONTACT	3	0
	SITE INSPECTION REQUIRED	215	4
Layton	RESOLVED BY CUSTOMER CONTACT	1	1
	SITE INSPECTION REQUIRED	36	2
Moab	RESOLVED BY CUSTOMER CONTACT	4	4
Ogden	RESOLVED BY CUSTOMER CONTACT	2	2
	SITE INSPECTION REQUIRED	178	2
Park City	SITE INSPECTION REQUIRED	10	7
Price	RESOLVED BY CUSTOMER CONTACT	6	4
	SITE INSPECTION REQUIRED	21	7
Richfield	RESOLVED BY CUSTOMER CONTACT	3	5
	SITE INSPECTION REQUIRED	10	9
SLC Metro	RESOLVED BY CUSTOMER CONTACT	5	3
	SITE INSPECTION REQUIRED	529	4
Smithfield	RESOLVED BY CUSTOMER CONTACT	2	4
	SITE INSPECTION REQUIRED	17	9
Tooele	RESOLVED BY CUSTOMER CONTACT	1	0
	SITE INSPECTION REQUIRED	12	8
Tremonton	SITE INSPECTION REQUIRED	10	2
Valley West	SITE INSPECTION REQUIRED	4	3
Vernal	SITE INSPECTION REQUIRED	5	5
State Totals	**RESOLVED BY CUSTOMER CONTACT**	**27**	
	SITE INSPECTION REQUIRED	**1110**	

UTAH RESIDENTIAL/SMALL COMMERCIAL METER SETS - REPORT BY DISTRICT

FISCAL YEAR TO DATE - 2ND QUARTER 2001-2002

NORTHERN UTAH

LOCATION	1st Quarter			JULY			AUGUST			SEPTEMBER			2nd Quarter			Fiscal YTD			Notes
	Total Within 5 Days	%	Total	Within 5 Days	%	Total	Within 5 Days	%	Total	Within 5 Days	%	Total	Total Within 5 Days	%	Total	Total Within 5 Days	%	Total	
Jordan Valley	1104	98%	1124	516	99%	520	451	98%	461	407	100%	407	1374	99%	1388	2478	99%	2512	
Layton	376	96%	393	112	100%	112	172	99%	174	127	98%	129	411	99%	415	787	97%	808	
Metro	769	99%	777	214	96%	223	321	100%	321	327	100%	328	862	99%	872	1631	99%	1649	
Ogden	372	100%	373	148	100%	148	176	97%	182	182	100%	182	506	99%	512	878	99%	885	
Park City	146	96%	152	73	96%	76	64	83%	77	93	86%	108	230	88%	261	376	91%	413	
Smithfield	99	99%	100	58	100%	58	50	98%	51	41	100%	41	149	99%	150	248	99%	250	
Tooele	148	98%	151	82	100%	82	63	100%	63	89	100%	89	234	100%	234	382	99%	385	
Tremonton	36	100%	36	15	100%	15	7	100%	7	8	100%	8	30	100%	30	66	100%	66	
TOTAL	3050	98%	3106	1218	99%	1234	1304	98%	1336	1274	99%	1292	3796	98%	3862	6846	98%	6968	

SOUTHERN UTAH

LOCATION	1st Quarter			JULY			AUGUST			SEPTEMBER			2nd Quarter			Fiscal YTD			Notes
	Total Within 5 Days	%	Total	Within 5 days	%	Total	Within 5 days	%	Total	Within 5 days	%	Total	Total Within 5 Days	%	Total	Total Within 5 Days	%	Total	
American Fork	492	100%	493	190	98%	193	190	98%	194	187	100%	187	567	99%	574	1059	99%	1067	
Cedar City	142	99%	143	73	99%	74	55	95%	58	60	79%	76	188	90%	208	330	94%	351	
Moab	53	100%	53	13	100%	13	17	100%	17	35	97%	36	65	98%	66	118	99%	119	
Price	30	94%	32	14	100%	14	33	100%	33	19	100%	19	66	100%	66	96	98%	98	
Richfield	103	100%	103	43	100%	43	40	100%	40	52	98%	53	135	99%	136	238	100%	239	
Vernal	41	100%	41	9	100%	9	16	100%	16	10	100%	10	35	100%	35	76	100%	76	
TOTAL	861	100%	865	342	99%	346	351	98%	358	363	95%	381	1056	97%	1085	1917	98%	1950	

TOTAL UTAH

LOCATION	1st Quarter			JULY			AUGUST			SEPTEMBER			2nd Quarter			Fiscal YTD			Notes
	Total Within 5 Days	%	Total	Within 5 days	%	Total	Within 5 days	%	Total	Within 5 days	%	Total	Total Within 5 Days	%	Total	Total Within 5 Days	%	Total	
TOTAL UTAH	3911	98%	3971	1560	99%	1580	1655	98%	1694	1637	98%	1673	4852	98%	4947	8763	98%	8918	

UTAH TEMPORARY METER SETS - REPORT BY DISTRICT

FISCAL YEAR TO DATE - 2ND QUARTER 2001-2002

NORTHERN UTAH

LOCATION	1st Quarter			JULY			AUGUST			SEPTEMBER			2nd Quarter			Fiscal YTD			Notes
	Total Within 10 Days	%	Total	Within 10 Days	%	Total	Within 10 Days	%	Total	Within 10 Days	%	Total	Total Within 10 Days	%	Total	Total Within 10 Days	%	Total	
Jordan Valley	601	99%	608	171	99%	173	190	98%	193	143	100%	143	504	99%	509	1105	99%	1117	
Layton	295	97%	303	129	96%	135	137	99%	138	101	100%	101	367	98%	374	662	98%	677	
Metro	236	100%	236	66	100%	66	112	100%	112	62	100%	62	240	100%	240	476	100%	476	
Ogden	342	90%	380	108	100%	108	103	100%	103	93	100%	93	304	100%	304	646	94%	684	
Park City	96	100%	96	29	97%	30	26	100%	26	24	89%	27	79	95%	83	175	98%	179	
Smithfield	82	100%	82	25	100%	25	37	100%	37	20	100%	20	82	100%	82	164	100%	164	
Tooele	110	100%	110	65	100%	65	46	100%	46	30	100%	30	141	100%	141	251	100%	251	
Tremonton	24	100%	24	9	100%	9	11	100%	11	9	100%	9	29	100%	29	53	100%	53	
TOTAL	1824	99%	1839	602	99%	611	662	99%	666	482	99%	485	1746	99%	1762	3570	99%	3601	

SOUTHERN UTAH

LOCATION	1st Quarter			JULY			AUGUST			SEPTEMBER			2nd Quarter			Fiscal YTD			Notes
	Total Within 10 Days	%	Total	Within 10 days	%	Total	Within 10 days	%	Total	Within 10 days	%	Total	Total Within 10 Days	%	Total	Total Within 10 Days	%	Total	
American Fork	382	100%	383	122	98%	124	129	98%	131	128	100%	128	379	99%	383	761	99%	766	
Cedar City	104	100%	104	38	100%	38	21	100%	21	27	100%	27	86	100%	86	190	100%	190	
Moab	2	100%	2	2	100%	2	0	-	0	0	100%	0	2	100%	2	4	100%	4	
Price	5	100%	5	3	100%	3	4	100%	4	0	100%	0	7	100%	7	12	100%	12	
Richfield	17	100%	17	5	100%	5	6	100%	6	14	100%	14	25	100%	25	42	100%	42	
Vernal	7	100%	7	9	100%	9	10	100%	10	2	100%	2	21	100%	21	28	100%	28	
TOTAL	517	100%	518	179	99%	181	170	99%	172	171	100%	171	520	99%	524	1037	100%	1042	

TOTAL UTAH

LOCATION	1st Quarter			JULY			AUGUST			SEPTEMBER			2nd Quarter			Fiscal YTD			Notes
	Total Within 10 Days	%	Total	Within 10 days	%	Total	Within 10 days	%	Total	Within 10 days	%	Total	Total Within 10 Days	%	Total	Total Within 10 Days	%	Total	
TOTAL UTAH	2341	99%	2357	781	99%	792	832	99%	838	653	100%	656	2266	99%	2286	4607	99%	4643	

2ND Quarter   Fiscal Year 2002   UTAH OUTAGE DETAIL BY DISTRICT 07/01/2001 to 09/30/2001

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off	Number of Occurrences
Customer Requested	Utah			0.026	0.000	0.000	0.000	241.184	694,828	76	5
Planned	Utah			0.624	0.010	0.000	0.000	65.363	694,828	6,630	63
Unplanned	Utah			89.164	0.833	0.068	0.068	106.995	694,828	579,032	3,839
Planned	AMERICAN FORK			0.004	0.000	0.000	0.000	129.500	66,008	2	1
Unplanned	AMERICAN FORK			52.778	0.570	0.117	0.117	92.541	66,008	37,646	290
Customer Requested	AMERICAN FORK			0.000	0.000	0.000	0.000	0.000	66,008	0	0
High SAIDI	AMERICAN FORK	EUR12	EUREKA #12	278.767	1.977	0.000	0.000	141.024	43	85	2
Low SAIDI	AMERICAN FORK	19	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	AMERICAN FORK	SAN12	SANTAQUIN #12	107.607	2.430	0.000	0.000	44.287	1,808	4,393	21
Low SAIFI	AMERICAN FORK	19	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	AMERICAN FORK	HIG15	HIGHLAND #15	51.729	1.381	2.002	2.002	37.464	1,497	2,067	12
Low MAIFI	AMERICAN FORK	60	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	AMERICAN FORK	HIG15	HIGHLAND #15	51.729	1.381	2.002	2.002	37.464	1,497	2,067	12
Low MAIFI(e)	AMERICAN FORK	60	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	AMERICAN FORK	AMF11	AMERICAN FORK #11	208.866	1.231	0.000	0.000	169.669	2,147	2,643	8
Low Customer Minutes Lost	AMERICAN FORK	18	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	ASHLEY (Vernal)			0.000	0.000	0.000	0.000	0.000	8,169	0	0
Unplanned	ASHLEY (Vernal)			101.048	0.781	0.000	0.000	129.443	8,169	6,377	63
Customer Requested	ASHLEY (Vernal)			0.000	0.000	0.000	0.000	0.000	8,169	0	0
High SAIDI	ASHLEY (Vernal)	VER12	VERNAL #12	376.764	1.217	0.000	0.000	309.704	1,210	1,472	14
Low SAIDI	ASHLEY (Vernal)	5	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	ASHLEY (Vernal)	VER14	VERNAL #14	192.756	2.182	0.000	0.000	88.352	1,310	2,858	12
Low SAIFI	ASHLEY (Vernal)	5	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	ASHLEY (Vernal)	12	***** Circuits with a High MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
Low MAIFI	ASHLEY (Vernal)	12	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	ASHLEY (Vernal)	12	***** Circuits with a High MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
Low MAIFI(e)	ASHLEY (Vernal)	12	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	ASHLEY (Vernal)	VER12	VERNAL #12	376.764	1.217	0.000	0.000	309.704	1,210	1,472	14
Low Customer Minutes Lost	ASHLEY (Vernal)	5	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	CANYONLANDS (Moab)	SO42-1	MOAB-HATCH-69KV	0.000	0.000	1.000	1.000	0.000	3,130	0	0
High MAIFI	CANYONLANDS (Moab)	SVN11	SEVEN MILE #11	308.114	2.000	1.000	1.000	154.057	35	70	2
Planned	CANYONLANDS (Moab)			0.411	0.002	0.000	0.000	202.000	10,822	22	3
Unplanned	CANYONLANDS (Moab)			42.272	0.408	0.292	0.292	103.594	10,822	4,416	93
Customer Requested	CANYONLANDS (Moab)			0.000	0.000	0.000	0.000	0.000	10,822	0	0
High SAIDI	CANYONLANDS (Moab)	RAT22	RATTLESNAKE #22	654.064	4.178	0.000	0.000	156.545	393	1,642	31
Low SAIDI	CANYONLANDS (Moab)	25	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	CANYONLANDS (Moab)	RAT22	RATTLESNAKE #22	654.064	4.178	0.000	0.000	156.545	393	1,642	31
Low SAIFI	CANYONLANDS (Moab)	25	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
Low MAIFI	CANYONLANDS (Moab)	38	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	CANYONLANDS (Moab)	SO42-1	MOAB-HATCH-69KV	0.000	0.000	1.000	1.000	0.000	3,130	0	0
High MAIFI(e)	CANYONLANDS (Moab)	SVN11	SEVEN MILE #11	308.114	2.000	1.000	1.000	154.057	35	70	2
Low MAIFI(e)	CANYONLANDS (Moab)	38	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	CANYONLANDS (Moab)	RAT22	RATTLESNAKE #22	654.064	4.178	0.000	0.000	156.545	393	1,642	31
Low Customer Minutes Lost	CANYONLANDS (Moab)	22	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	CARBON (Price)			0.016	0.000	0.000	0.000	50.667	9,215	3	1
Unplanned	CARBON (Price)			106.683	0.754	0.000	0.000	141.450	9,215	6,950	97
Customer Requested	CARBON (Price)			0.000	0.000	0.000	0.000	0.000	9,215	0	0
High SAIDI	CARBON (Price)	EMR11	EMERY CITY #11	1,511.553	2.250	0.000	0.000	671.801	188	423	5
Low SAIDI	CARBON (Price)	24	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	CARBON (Price)	SCO11	SCOFIELD CITY #11	670.870	2.775	0.000	0.000	241.764	231	641	4
Low SAIFI	CARBON (Price)	24	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	CARBON (Price)	CBN12	CARBONVILLE #12	106.798	1.083	0.004	0.004	98.642	907	982	5
Low MAIFI	CARBON (Price)	46	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	CARBON (Price)	CBN12	CARBONVILLE #12	106.798	1.083	0.004	0.004	98.642	907	982	5
Low MAIFI(e)	CARBON (Price)	46	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	CARBON (Price)	EMR11	EMERY CITY #11	1,511.553	2.250	0.000	0.000	671.801	188	423	5
Low Customer Minutes Lost	CARBON (Price)	24	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0

2ND Quarter Fiscal Year 2002 UTAH OUTAGE DETAIL BY DISTRICT 07/01/2001 to 09/30/2001

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off	Number of Occurrences
Planned	CEDAR CITY			3.953	0.024	0.000	0.000	167.627	27,393	646	7
Unplanned	CEDAR CITY			210.190	1.525	0.029	0.029	137.837	27,393	41,772	220
Customer Requested	CEDAR CITY			0.000	0.000	0.000	0.000	0.000	27,393	0	0
High SAIDI	CEDAR CITY	TOQ32	TOQUERVILLE #32	2,101.111	9.250	0.000	0.000	227.155	785	7,261	13
Low SAIDI	CEDAR CITY	48	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	CEDAR CITY	TOQ31	TOQUERVILLE #31	1,325.232	9.648	0.000	0.000	137.359	622	6,001	14
Low SAIFI	CEDAR CITY	48	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	CEDAR CITY	CLM15	COLEMAN #15	281.352	4.464	1.023	1.023	63.031	785	3,504	18
Low MAIFI	CEDAR CITY	84	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	CEDAR CITY	CLM15	COLEMAN #15	281.352	4.464	1.023	1.023	63.031	785	3,504	18
Low MAIFI(e)	CEDAR CITY	84	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	CEDAR CITY	TOQ32	TOQUERVILLE #32	2,101.111	9.250	0.000	0.000	227.155	785	7,261	13
Low Customer Minutes Lost	CEDAR CITY	48	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	COTTONWOOD (Jordan Valley)			0.000	0.000	0.000	0.000	0.000	5,445	0	0
Unplanned	COTTONWOOD (Jordan Valley)			25.806	0.155	0.017	0.017	166.288	5,445	845	27
Customer Requested	COTTONWOOD (Jordan Valley)			0.000	0.000	0.000	0.000	0.000	5,445	0	0
High SAIDI	COTTONWOOD (Jordan Valley)	DMP12	DIMPLE DELL #12	46.495	0.185	0.000	0.000	251.576	1,607	297	9
Low SAIDI	COTTONWOOD (Jordan Valley)	DMP13	DIMPLE DELL #13	11.006	0.141	0.000	0.000	78.080	2,937	414	6
High SAIFI	COTTONWOOD (Jordan Valley)	DMP12	DIMPLE DELL #12	46.495	0.185	0.000	0.000	251.576	1,607	297	9
Low SAIFI	COTTONWOOD (Jordan Valley)	DMP13	DIMPLE DELL #13	11.006	0.141	0.000	0.000	78.080	2,937	414	6
High MAIFI	COTTONWOOD (Jordan Valley)	DMP11	DIMPLE DELL #11	37.148	0.149	0.102	0.102	249.776	901	134	12
Low MAIFI	COTTONWOOD (Jordan Valley)	2	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	COTTONWOOD (Jordan Valley)	DMP11	DIMPLE DELL #11	37.148	0.149	0.102	0.102	249.776	901	134	12
Low MAIFI(e)	COTTONWOOD (Jordan Valley)	2	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	COTTONWOOD (Jordan Valley)	DMP12	DIMPLE DELL #12	46.495	0.185	0.000	0.000	251.576	1,607	297	9
Low Customer Minutes Lost	COTTONWOOD (Jordan Valley)	DMP13	DIMPLE DELL #13	11.006	0.141	0.000	0.000	78.080	2,937	414	6
Planned	DELTA (Richfield)			0.000	0.000	0.000	0.000	0.000	5,761	0	0
Unplanned	DELTA (Richfield)			67.470	0.454	0.000	0.000	148.698	5,761	2,614	50
Customer Requested	DELTA (Richfield)			0.000	0.000	0.000	0.000	0.000	5,761	0	0
High SAIDI	DELTA (Richfield)	STH21	SUTHERLAND #21	601.364	4.180	0.000	0.000	143.879	462	1,931	16
Low SAIDI	DELTA (Richfield)	20	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	DELTA (Richfield)	STH21	SUTHERLAND #21	601.364	4.180	0.000	0.000	143.879	462	1,931	16
Low SAIFI	DELTA (Richfield)	20	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	DELTA (Richfield)	30	***** Circuits with a High MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
Low MAIFI	DELTA (Richfield)	30	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	DELTA (Richfield)	30	***** Circuits with a High MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
Low MAIFI(e)	DELTA (Richfield)	30	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	DELTA (Richfield)	STH21	SUTHERLAND #21	601.364	4.180	0.000	0.000	143.879	462	1,931	16
Low Customer Minutes Lost	DELTA (Richfield)	20	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	LAYTON			1.851	0.089	0.000	0.000	20.863	49,466	4,388	7
Unplanned	LAYTON			54.615	0.616	0.117	0.117	88.602	49,466	30,491	202
Customer Requested	LAYTON			0.000	0.000	0.000	0.000	0.000	49,466	0	0
High SAIDI	LAYTON	SYR15	SYRACUSE #15	263.101	2.710	0.000	0.000	97.093	1,175	3,184	8
Low SAIDI	LAYTON	14	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	LAYTON	SYR15	SYRACUSE #15	263.101	2.710	0.000	0.000	97.093	1,175	3,184	8
Low SAIFI	LAYTON	14	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	LAYTON	CLN11	CLINTON #11	67.757	2.060	1.000	1.000	32.895	4,498	9,265	9
Low MAIFI	LAYTON	30	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	LAYTON	CLN11	CLINTON #11	67.757	2.060	1.000	1.000	32.895	4,498	9,265	9
Low MAIFI(e)	LAYTON	30	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	LAYTON	CLD13	CLEARFIELD #13	203.488	1.102	0.000	0.000	184.731	3,654	4,025	14
Low Customer Minutes Lost	LAYTON	11	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	METRO			0.307	0.001	0.000	0.000	298.416	202,977	209	6
Unplanned	METRO			69.784	0.752	0.102	0.102	92.839	202,977	152,571	819
Customer Requested	METRO			0.068	0.000	0.000	0.000	405.706	202,977	34	2
High SAIDI	METRO	RTR11	RITER #11	5,333.850	31.150	0.000	0.000	171.231	20	623	8
Low SAIDI	METRO	127	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	METRO	RTR11	RITER #11	5,333.850	31.150	0.000	0.000	171.231	20	623	8

2ND Quarter **Fiscal Year 2002** **UTAH OUTAGE DETAIL BY DISTRICT 07/01/2001 to 09/30/2001**

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off	Number of Occurrences
Low SAIFI	METRO	128	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	METRO	OAK13	OAKLAND #13	9.962	0.069	1.947	1.947	143.983	1,691	117	6
Low MAIFI	METRO	235	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	METRO	OAK13	OAKLAND #13	9.962	0.069	1.947	1.947	143.983	1,691	117	6
Low MAIFI(e)	METRO	235	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	METRO	MCL12	MCCLELLAND #12	324.468	5.331	1.011	1.011	60.867	4,713	25,124	17
Low Customer Minutes Lost	METRO	122	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	MILFORD (Richfield)	ELK11	ELK MEADOWS #11	0.000	0.000	1.000	1.000	0.000	161	0	0
High MAIFI	MILFORD (Richfield)	ELK12	ELK MEADOWS #12	0.000	0.000	1.000	1.000	0.000	25	0	0
Planned	MILFORD (Richfield)			0.000	0.000	0.000	0.000	0.000	2,343	0	0
Unplanned	MILFORD (Richfield)			70.298	0.641	0.080	0.080	109.732	2,343	1,501	56
Customer Requested	MILFORD (Richfield)			0.000	0.000	0.000	0.000	0.000	2,343	0	0
High SAIDI	MILFORD (Richfield)	BKL12	BROOKLAWN #12	246.267	1.377	0.000	0.000	178.881	146	201	9
Low SAIDI	MILFORD (Richfield)	9	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	MILFORD (Richfield)	SML11	SOUTH MILFORD #11	225.496	2.440	0.000	0.000	92.427	141	344	12
Low SAIFI	MILFORD (Richfield)	9	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
Low MAIFI	MILFORD (Richfield)	15	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	MILFORD (Richfield)	ELK11	ELK MEADOWS #11	0.000	0.000	1.000	1.000	0.000	161	0	0
High MAIFI(e)	MILFORD (Richfield)	ELK12	ELK MEADOWS #12	0.000	0.000	1.000	1.000	0.000	25	0	0
Low MAIFI(e)	MILFORD (Richfield)	15	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	MILFORD (Richfield)	MLF11	MILFORD #11	70.596	0.673	0.000	0.000	104.960	675	454	2
Low Customer Minutes Lost	MILFORD (Richfield)	9	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	OGDEN			0.128	0.001	0.000	0.000	127.356	89,223	90	7
Unplanned	OGDEN			124.797	1.039	0.039	0.039	120.165	89,223	92,662	489
Customer Requested	OGDEN			0.000	0.000	0.000	0.000	0.000	89,223	0	0
High SAIDI	OGDEN	EDN12	EDEN #12	569.493	2.803	0.000	0.000	203.138	1,206	3,381	21
Low SAIDI	OGDEN	48	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	OGDEN	MAR12	MARRIOTT #12	130.194	3.020	0.000	0.000	43.104	587	1,773	5
Low SAIFI	OGDEN	48	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	OGDEN	TWE04	TWENTY-THIRD ST #4	561.571	1.662	1.000	1.000	337.903	704	1,170	3
Low MAIFI	OGDEN	99	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	OGDEN	TWE04	TWENTY-THIRD ST #4	561.571	1.662	1.000	1.000	337.903	704	1,170	3
Low MAIFI(e)	OGDEN	99	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	OGDEN	PIO11	PIONEER #11	267.600	2.071	0.018	0.018	129.185	3,569	7,393	15
Low Customer Minutes Lost	OGDEN	45	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	PARK CITY			0.000	0.000	0.000	0.000	0.000	23,069	0	0
Unplanned	PARK CITY			100.131	0.587	0.007	0.007	170.512	23,069	13,547	157
Customer Requested	PARK CITY			0.000	0.000	0.000	0.000	0.000	23,069	0	0
High SAIDI	PARK CITY	TBL11	TIMBER LAKES #11	490.041	3.604	0.000	0.000	135.955	541	1,950	8
Low SAIDI	PARK CITY	12	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	PARK CITY	TBL11	TIMBER LAKES #11	490.041	3.604	0.000	0.000	135.955	541	1,950	8
Low SAIFI	PARK CITY	12	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	PARK CITY	SL017	COALVILLE-SILVER CREEK-46KV	51.000	1.000	2.000	2.000	51.000	1	1	1
Low MAIFI	PARK CITY	32	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	PARK CITY	SL017	COALVILLE-SILVER CREEK-46KV	51.000	1.000	2.000	2.000	51.000	1	1	1
Low MAIFI(e)	PARK CITY	32	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	PARK CITY	KAM12	KAMAS #12	460.310	1.022	0.000	0.000	450.443	1,324	1,353	13
Low Customer Minutes Lost	PARK CITY	12	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	SALINA (Richfield)			0.000	0.000	0.000	0.000	0.000	14,266	0	0
Unplanned	SALINA (Richfield)			33.033	0.330	0.001	0.001	100.179	14,266	4,704	110
Customer Requested	SALINA (Richfield)			0.000	0.000	0.000	0.000	0.000	14,266	0	0
High SAIDI	SALINA (Richfield)	FTG12	FOUNTAIN GREEN #12	810.800	4.321	0.012	0.012	187.633	165	713	8
Low SAIDI	SALINA (Richfield)	46	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	SALINA (Richfield)	FTG12	FOUNTAIN GREEN #12	810.800	4.321	0.012	0.012	187.633	165	713	8
Low SAIFI	SALINA (Richfield)	46	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	SALINA (Richfield)	T43	GUNNISON-SIGURD-46KV	0.000	0.000	1.000	1.000	0.000	1	0	0
Low MAIFI	SALINA (Richfield)	65	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	SALINA (Richfield)	T43	GUNNISON-SIGURD-46KV	0.000	0.000	1.000	1.000	0.000	1	0	0

2ND Quarter **Fiscal Year 2002** **UTAH OUTAGE DETAIL BY DISTRICT 07/01/2001 to 09/30/2001**

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off	Number of Occurrences
Low MAIFI(e)	SALINA (Richfield)	65	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	SALINA (Richfield)	FTG12	FOUNTAIN GREEN #12	810.800	4.321	0.012	0.012	187.633	165	713	8
Low Customer Minutes Lost	SALINA (Richfield)	46	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	SMITHFIELD			0.124	0.002	0.000	0.000	71.833	20,857	36	2
Unplanned	SMITHFIELD			60.454	0.655	0.001	0.001	92.250	20,857	13,668	169
Customer Requested	SMITHFIELD			0.008	0.000	0.000	0.000	159.000	20,857	1	1
High SAIDI	SMITHFIELD	EAH11	EAST HYRUM #11	269.092	1.025	0.000	0.000	262.539	601	616	6
Low SAIDI	SMITHFIELD	5	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	SMITHFIELD	MIL12	MILLVILLE #12	204.501	2.512	0.000	0.000	81.404	781	1,962	14
Low SAIFI	SMITHFIELD	5	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	SMITHFIELD	NIB21	NIBLEY #21	57.555	0.915	0.011	0.011	62.907	1,916	1,753	30
Low MAIFI	SMITHFIELD	25	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	SMITHFIELD	NIB21	NIBLEY #21	57.555	0.915	0.011	0.011	62.907	1,916	1,753	30
Low MAIFI(e)	SMITHFIELD	25	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	SMITHFIELD	MIL13	MILLVILLE #13	161.270	1.241	0.000	0.000	129.928	2,367	2,938	13
Low Customer Minutes Lost	SMITHFIELD	4	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	SOUTH VALLEY (Jordan Valley)			0.814	0.006	0.000	0.000	133.397	176,761	1,078	27
Unplanned	SOUTH VALLEY (Jordan Valley)			79.605	0.743	0.015	0.013	107.137	176,761	131,337	758
Customer Requested	SOUTH VALLEY (Jordan Valley)			0.025	0.000	0.000	0.000	106.756	176,761	41	2
High SAIDI	SOUTH VALLEY (Jordan Valley)	BLF13	BLUFFDALE #13	503.463	2.507	0.000	0.000	200.858	1,903	4,770	16
Low SAIDI	SOUTH VALLEY (Jordan Valley)	39	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	SOUTH VALLEY (Jordan Valley)	SL063	90TH SOUTH-LARK-46KV	270.000	4.000	0.000	0.000	67.500	1	4	4
Low SAIFI	SOUTH VALLEY (Jordan Valley)	40	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	SOUTH VALLEY (Jordan Valley)	UNN14	UNION #14	144.972	1.322	0.723	0.644	109.677	2,806	3,709	14
Low MAIFI	SOUTH VALLEY (Jordan Valley)	97	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	SOUTH VALLEY (Jordan Valley)	UNN14	UNION #14	144.972	1.322	0.723	0.644	109.677	2,806	3,709	14
Low MAIFI(e)	SOUTH VALLEY (Jordan Valley)	97	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	SOUTH VALLEY (Jordan Valley)	KRN12	KEARNS #12	482.896	4.019	0.000	0.000	120.152	3,044	12,234	24
Low Customer Minutes Lost	SOUTH VALLEY (Jordan Valley)	27	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	TOOELE			0.624	0.012	0.000	0.000	54.167	13,534	156	2
Unplanned	TOOELE			210.158	2.313	0.146	0.146	90.843	13,534	31,310	128
Customer Requested	TOOELE			0.000	0.000	0.000	0.000	0.000	13,534	0	0
High SAIDI	TOOELE	SKU11	SKULL VALLEY #11	1,409.700	6.780	0.000	0.000	207.920	50	339	10
Low SAIDI	TOOELE	12	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	TOOELE	SKU11	SKULL VALLEY #11	1,409.700	6.780	0.000	0.000	207.920	50	339	10
Low SAIFI	TOOELE	12	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	TOOELE	SL061	LAKEPOINT-TOOELE-46KV	0.000	0.000	1.000	1.000	0.000	1	0	0
Low MAIFI	TOOELE	24	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	TOOELE	SL061	LAKEPOINT-TOOELE-46KV	0.000	0.000	1.000	1.000	0.000	1	0	0
Low MAIFI(e)	TOOELE	24	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	TOOELE	TOO13	TOOELE #13	245.609	2.446	0.000	0.000	100.401	4,318	10,563	16
Low Customer Minutes Lost	TOOELE	12	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	TREMONTON			0.000	0.000	0.000	0.000	0.000	7,692	0	0
Unplanned	TREMONTON			103.245	0.861	0.089	0.089	119.946	7,692	6,621	111
Customer Requested	TREMONTON			0.000	0.000	0.000	0.000	0.000	7,692	0	0
High SAIDI	TREMONTON	BLU11	BLUE CREEK #11	420.868	1.491	0.000	0.000	282.269	167	249	7
Low SAIDI	TREMONTON	8	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	TREMONTON	FDG11	FIELDING #11	412.750	3.219	0.000	0.000	128.207	629	2,025	24
Low SAIFI	TREMONTON	8	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	TREMONTON	SNO12	SNOWVILLE #12	49.991	0.580	2.000	2.000	86.154	324	188	4
Low MAIFI	TREMONTON	18	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	TREMONTON	SNO12	SNOWVILLE #12	49.991	0.580	2.000	2.000	86.154	324	188	4
Low MAIFI(e)	TREMONTON	18	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	TREMONTON	FDG11	FIELDING #11	412.750	3.219	0.000	0.000	128.207	629	2,025	24
Low Customer Minutes Lost	TREMONTON	8	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	UINTA			0.000	0.000	0.000	0.000	0.000	2	0	0
Unplanned	UINTA			0.000	0.000	0.000	0.000	0.000	2	0	0
Customer Requested	UINTA			0.000	0.000	0.000	0.000	0.000	2	0	0

2ND Quarter **Fiscal Year 2002** **UTAH OUTAGE DETAIL BY DISTRICT 07/01/2001 to 09/30/2001**

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off	Number of Occurrences
High SAIDI	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0
Low SAIDI	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0
High SAIFI	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0
Low SAIFI	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0
High MAIFI	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0
Low MAIFI	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0
High MAIFI(e)	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0
Low MAIFI(e)	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0
High Customer Minutes Lost	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0
Low Customer Minutes Lost	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0

Note 1: Work is in progress to update Average Customer Counts at the district level. Revised reports for affected quarters willbe submittedwhenthe work is completed.

Note 2: The count of customers impacted by transmission outages in the 2nd quarter are includedin the "Customers Off" column. The "Customers Off" as reported for the quarter ended June 2001 also includedthe customers affected by transmission outages. In both cases, the countwas includedin the district assignedresponsibilityto maintainthe transmission line. An additionalreport willbe prepared for the 3rd quarter whichwillincludemore information regardingtransmission-levelcustomers affected by outages.

Fiscal YTD **Fiscal Year 2002** **UTAH OUTAGE DETAIL BY DISTRICT 04/01/2001 to 09/30/2001**

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off	Number of Occurrences
Customer Requested	Utah			0.027	0.000	0.000	0.000	219.241	694,828	87	9
Planned	Utah			2.327	0.022	0.000	0.000	107.547	694,828	15,035	170
Unplanned	Utah			137.876	1.385	0.164	0.164	99.545	694,828	962,373	6,637
Planned	AMERICAN FORK			1.259	0.024	0.000	0.000	51.708	66,008	1,607	10
Unplanned	AMERICAN FORK			82.430	1.012	0.189	0.189	81.455	66,008	66,798	501
Customer Requested	AMERICAN FORK			0.004	0.000	0.000	0.000	245.000	66,008	1	1
High SAIDI	AMERICAN FORK	SAR11	SARATOGA #11	773.315	6.160	0.000	0.000	125.532	368	2,267	24
Low SAIDI	AMERICAN FORK	20	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	AMERICAN FORK	SAR11	SARATOGA #11	773.315	6.160	0.000	0.000	125.532	368	2,267	24
Low SAIFI	AMERICAN FORK	20	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	AMERICAN FORK	ORE11	OREM #11	91.809	0.841	2.841	2.841	109.216	320	269	1
Low MAIFI	AMERICAN FORK	55	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	AMERICAN FORK	ORE11	OREM #11	91.809	0.841	2.841	2.841	109.216	320	269	1
Low MAIFI(e)	AMERICAN FORK	55	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	AMERICAN FORK	SAR13	SARATOGA #13	583.265	3.456	0.059	0.059	168.747	953	3,294	16
Low Customer Minutes Lost	AMERICAN FORK	13	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	ASHLEY (Vernal)			0.000	0.000	0.000	0.000	0.000	8,169	0	0
Unplanned	ASHLEY (Vernal)			228.234	1.566	0.120	0.120	145.717	8,169	12,795	113
Customer Requested	ASHLEY (Vernal)			0.000	0.000	0.000	0.000	0.000	8,169	0	0
High SAIDI	ASHLEY (Vernal)	VER12	VERNAL #12	756.219	2.247	0.000	0.000	336.530	1,210	2,719	20
Low SAIDI	ASHLEY (Vernal)	5	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	ASHLEY (Vernal)	VER14	VERNAL #14	399.602	4.374	0.750	0.750	91.357	1,310	5,730	20
Low SAIFI	ASHLEY (Vernal)	5	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	ASHLEY (Vernal)	VER14	VERNAL #14	399.602	4.374	0.750	0.750	91.357	1,310	5,730	20
Low MAIFI	ASHLEY (Vernal)	10	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	ASHLEY (Vernal)	VER14	VERNAL #14	399.602	4.374	0.750	0.750	91.357	1,310	5,730	20
Low MAIFI(e)	ASHLEY (Vernal)	10	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	ASHLEY (Vernal)	VER12	VERNAL #12	756.219	2.247	0.000	0.000	336.530	1,210	2,719	20
Low Customer Minutes Lost	ASHLEY (Vernal)	5	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	CANYONLANDS (Moab)			0.411	0.002	0.000	0.000	202.000	10,822	22	3
Unplanned	CANYONLANDS (Moab)			60.193	0.528	0.293	0.293	113.962	10,822	5,716	132
Customer Requested	CANYONLANDS (Moab)			0.000	0.000	0.000	0.000	0.000	10,822	0	0
High SAIDI	CANYONLANDS (Moab)	RAT22	RATTLESNAKE #22	972.394	5.234	0.000	0.000	185.781	393	2,057	40
Low SAIDI	CANYONLANDS (Moab)	22	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	CANYONLANDS (Moab)	RAT22	RATTLESNAKE #22	972.394	5.234	0.000	0.000	185.781	393	2,057	40
Low SAIFI	CANYONLANDS (Moab)	22	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	CANYONLANDS (Moab)	SO42-1	MOAB-HATCH-69KV	0.000	0.000	1.000	1.000	0.000	3,130	0.000	0.000
High MAIFI	CANYONLANDS (Moab)	SVN11	SEVEN MILE #11	308.114	2.000	1.000	1.000	154.057	35	70.000	2.000
Low MAIFI	CANYONLANDS (Moab)	38	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	CANYONLANDS (Moab)	SO42-1	MOAB-HATCH-69KV	0.000	0.000	1.000	1.000	0.000	3,130	0	0
High MAIFI(e)	CANYONLANDS (Moab)	SVN11	SEVEN MILE #11	308.114	2.000	1.000	1.000	154.057	35	70	2
Low MAIFI(e)	CANYONLANDS (Moab)	38	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	CANYONLANDS (Moab)	RAT22	RATTLESNAKE #22	972.394	5.234	0.000	0.000	185.781	393	2,057	40
Low Customer Minutes Lost	CANYONLANDS (Moab)	20	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	CARBON (Price)			2.007	0.014	0.000	0.000	140.144	9,215	132	3
Unplanned	CARBON (Price)			184.996	1.600	0.010	0.010	115.607	9,215	14,746	162
Customer Requested	CARBON (Price)			0.000	0.000	0.000	0.000	0.000	9,215	0	0
High SAIDI	CARBON (Price)	EMR11	EMERY CITY #11	1,707.755	4.271	0.000	0.000	399.823	188	803	7

Fiscal YTD — Fiscal Year 2002 — UTAH OUTAGE DETAIL BY DISTRICT 04/01/2001 to 09/30/2001

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off	Number of Occurrences
Low SAIDI	CARBON (Price)	26	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	CARBON (Price)	SOL11	SOLDIER SUMMIT #11	501.050	4.400	0.000	0.000	113.875	20	88	5
Low SAIFI	CARBON (Price)	26	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	CARBON (Price)	CCK11	CLEAR CREEK #11	351.298	2.000	1.018	1.018	175.649	57	114	2
Low MAIFI	CARBON (Price)	43	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	CARBON (Price)	CCK11	CLEAR CREEK #11	351.298	2.000	1.018	1.018	175.649	57	114	2
Low MAIFI(e)	CARBON (Price)	43	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	CARBON (Price)	FER11	FERRON #11	414.389	3.117	0.000	0.000	132.939	794	2,475	16
Low Customer Minutes Lost	CARBON (Price)	24	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	CEDAR CITY			4.052	0.026	0.000	0.000	153.531	27,393	723	10
Unplanned	CEDAR CITY			225.535	1.725	0.034	0.034	130.737	27,393	47,256	317
Customer Requested	CEDAR CITY			0.004	0.000	0.000	0.000	106.000	27,393	1	1
High SAIDI	CEDAR CITY	TOQ32	TOQUERVILLE #32	2,103.994	9.273	0.000	0.000	226.904	785	7,279	15
Low SAIDI	CEDAR CITY	51	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	CEDAR CITY	TOQ32	TOQUERVILLE #32	2,103.994	9.273	0.000	0.000	226.904	785	7,279	15
Low SAIFI	CEDAR CITY	51	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	CEDAR CITY	CLM15	COLEMAN #15	287.817	4.577	1.122	1.122	62.882	785	3,593	24
Low MAIFI	CEDAR CITY	83	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	CEDAR CITY	CLM15	COLEMAN #15	287.817	4.577	1.122	1.122	62.882	785	3,593	24
Low MAIFI(e)	CEDAR CITY	83	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	CEDAR CITY	TOQ32	TOQUERVILLE #32	2,103.994	9.273	0.000	0.000	226.904	785	7,279	15
Low Customer Minutes Lost	CEDAR CITY	47	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	COTTONWOOD (Jordan Valley)			1.269	0.045	0.000	0.000	28.212	5,445	245	3
Unplanned	COTTONWOOD (Jordan Valley)			237.096	1.814	0.119	0.068	130.706	5,445	9,877	64
Customer Requested	COTTONWOOD (Jordan Valley)			0.000	0.000	0.000	0.000	0.000	5,445	0	0
High SAIDI	COTTONWOOD (Jordan Va	DMP12	DIMPLE DELL #12	345.208	2.278	0.346	0.174	151.571	1,607	3,660	29
Low SAIDI	COTTONWOOD (Jordan Va	DMP13	DIMPLE DELL #13	191.644	1.691	0.000	0.000	113.320	2,937	4,967	14
High SAIFI	COTTONWOOD (Jordan Va	DMP12	DIMPLE DELL #12	345.208	2.278	0.346	0.174	151.571	1,607	3,660	29
Low SAIFI	COTTONWOOD (Jordan Va	DMP11	DIMPLE DELL #11	192.428	1.387	0.102	0.102	138.702	901	1,250	21
High MAIFI	COTTONWOOD (Jordan Va	DMP12	DIMPLE DELL #12	345.208	2.278	0.346	0.174	151.571	1,607	3,660	29
Low MAIFI	COTTONWOOD (Jordan Va	DMP13	DIMPLE DELL #13	191.644	1.691	0.000	0.000	113.320	2,937	4,967	14
High MAIFI(e)	COTTONWOOD (Jordan Va	DMP12	DIMPLE DELL #12	345.208	2.278	0.346	0.174	151.571	1,607	3,660	29
Low MAIFI(e)	COTTONWOOD (Jordan Va	DMP13	DIMPLE DELL #13	191.644	1.691	0.000	0.000	113.320	2,937	4,967	14
High Customer Minutes Lost	COTTONWOOD (Jordan Va	DMP13	DIMPLE DELL #13	191.644	1.691	0.000	0.000	113.320	2,937	4,967	14
Low Customer Minutes Lost	COTTONWOOD (Jordan Va	DMP11	DIMPLE DELL #11	192.428	1.387	0.102	0.102	138.702	901	1,250	21
Planned	DELTA (Richfield)			0.000	0.000	0.000	0.000	0.000	5,761	0	0
Unplanned	DELTA (Richfield)			101.769	0.761	0.991	0.991	133.673	5,761	4,386	93
Customer Requested	DELTA (Richfield)			0.000	0.000	0.000	0.000	0.000	5,761	0	0
High SAIDI	DELTA (Richfield)	STH21	SUTHERLAND #21	826.814	6.485	1.039	1.039	127.499	462	2,996	38
Low SAIDI	DELTA (Richfield)	18	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	DELTA (Richfield)	STH21	SUTHERLAND #21	826.814	6.485	1.039	1.039	127.499	462	2,996	38
Low SAIFI	DELTA (Richfield)	18	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	DELTA (Richfield)	STH21	SUTHERLAND #21	826.814	6.485	1.039	1.039	127.499	462	2,996	38
Low MAIFI	DELTA (Richfield)	4	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	DELTA (Richfield)	STH21	SUTHERLAND #21	826.814	6.485	1.039	1.039	127.499	462	2,996	38
Low MAIFI(e)	DELTA (Richfield)	4	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	DELTA (Richfield)	STH21	SUTHERLAND #21	826.814	6.485	1.039	1.039	127.499	462	2,996	38
Low Customer Minutes Lost	DELTA (Richfield)	18	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	LAYTON			1.981	0.090	0.000	0.000	21.982	49,466	4,458	13

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Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off	Number of Occurrences
Unplanned	LAYTON			103.425	1.371	0.127	0.127	75.447	49,466	67,810	350
Customer Requested	LAYTON			0.000	0.000	0.000	0.000	0.000	49,466	0	0
High SAIDI	LAYTON	SYR11	SYRACUSE #11	386.367	5.172	0.004	0.004	74.708	2,953	15,272	21
Low SAIDI	LAYTON	10	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	LAYTON	SYR11	SYRACUSE #11	386.367	5.172	0.004	0.004	74.708	2,953	15,272	21
Low SAIFI	LAYTON	10	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	LAYTON	CLN11	CLINTON #11	108.054	4.146	1.000	1.000	26.063	4,498	18,648	22
Low MAIFI	LAYTON	28	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	LAYTON	CLN11	CLINTON #11	108.054	4.146	1.000	1.000	26.063	4,498	18,648	22
Low MAIFI(e)	LAYTON	28	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	LAYTON	SYR11	SYRACUSE #11	386.367	5.172	0.004	0.004	74.708	2,953	15,272	21
Low Customer Minutes Lost	LAYTON	10	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	METRO			2.556	0.015	0.000	0.000	171.652	202,977	3,023	37
Unplanned	METRO			99.299	1.079	0.233	0.233	92.017	202,977	219,041	1,514
Customer Requested	METRO			0.068	0.000	0.000	0.000	405.706	202,977	34	2
High SAIDI	METRO	RTR11	RITER #11	5,838.600	34.300	0.000	0.000	170.222	20	686	15
Low SAIDI	METRO	117	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	METRO	RTR11	RITER #11	5,838.600	34.300	0.000	0.000	170.222	20	686	15
Low SAIFI	METRO	117	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	METRO	RTR12	RITER #12	4.098	0.029	2.000	2.000	143.018	3,979	114	16
Low MAIFI	METRO	216	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	METRO	RTR12	RITER #12	4.098	0.029	2.000	2.000	143.018	3,979	114	16
Low MAIFI(e)	METRO	216	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	METRO	MCL12	MCCLELLAND #12	327.796	5.345	1.018	1.018	61.332	4,713	25,189	24
Low Customer Minutes Lost	METRO	107	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	MILFORD (Richfield)			0.000	0.000	0.000	0.000	0.000	2,343	0	0
Unplanned	MILFORD (Richfield)			205.769	1.781	0.085	0.085	115.532	2,343	4,173	88
Customer Requested	MILFORD (Richfield)			0.000	0.000	0.000	0.000	0.000	2,343	0	0
High SAIDI	MILFORD (Richfield)	BKL12	BROOKLAWN #12	921.774	4.390	0.000	0.000	209.952	146	641	13
Low SAIDI	MILFORD (Richfield)	6	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	MILFORD (Richfield)	BKL11	BROOKLAWN #11	579.547	4.510	0.000	0.000	128.502	349	1,574	28
Low SAIFI	MILFORD (Richfield)	6	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	MILFORD (Richfield)	ELK11	ELK MEADOWS #11	0.000	0.000	1.000	1.000	0.000	161	0	0
High MAIFI	MILFORD (Richfield)	ELK12	ELK MEADOWS #12	0.000	0.000	1.000	1.000	0.000	25	0	0
Low MAIFI	MILFORD (Richfield)	15	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	MILFORD (Richfield)	ELK11	ELK MEADOWS #11	0.000	0.000	1.000	1.000	0.000	161	0	0
High MAIFI(e)	MILFORD (Richfield)	ELK12	ELK MEADOWS #12	0.000	0.000	1.000	1.000	0.000	25	0	0
Low MAIFI(e)	MILFORD (Richfield)	15	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	MILFORD (Richfield)	BKL11	BROOKLAWN #11	579.547	4.510	0.000	0.000	128.502	349	1,574	28
Low Customer Minutes Lost	MILFORD (Richfield)	6	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	OGDEN			5.257	0.024	0.002	0.002	223.688	89,223	2,097	29
Unplanned	OGDEN			183.459	1.600	0.079	0.079	114.655	89,223	142,765	801
Customer Requested	OGDEN			0.004	0.000	0.000	0.000	43.667	89,223	9	2
High SAIDI	OGDEN	TWE04	TWENTY-THIRD ST #4	561.571	1.662	1.000	1.000	337.903	704	1,170	3
Low SAIDI	OGDEN	48	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	OGDEN	LIN15	LINCOLN #15	198.360	3.797	0.000	0.000	52.239	2,450	9,303	11
Low SAIFI	OGDEN	48	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	OGDEN	TWE04	TWENTY-THIRD ST #4	561.571	1.662	1.000	1.000	337.903	704	1,170	3
Low MAIFI	OGDEN	96	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0

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Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off	Number of Occurrences
High MAIFI(e)	OGDEN	TWE04	TWENTY-THIRD ST #4	561.571	1.662	1.000	1.000	337.903	704	1,170	3
Low MAIFI(e)	OGDEN	96	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	OGDEN	RIV14	RIVERDALE #14	414.355	2.110	0.000	0.000	196.341	3,035	6,405	24
Low Customer Minutes Lost	OGDEN	41	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	PARK CITY			1.446	0.008	0.000	0.000	188.446	23,069	177	2
Unplanned	PARK CITY			157.010	1.046	0.009	0.009	150.132	23,069	24,126	280
Customer Requested	PARK CITY			0.000	0.000	0.000	0.000	0.000	23,069	0	0
High SAIDI	PARK CITY	DSR11	DESERET #11	901.000	3.000	0.000	0.000	300.333	1	3	3
Low SAIDI	PARK CITY	11	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	PARK CITY	TBL11	TIMBER LAKES #11	490.041	3.604	0.000	0.000	135.955	541	1,950	8
Low SAIFI	PARK CITY	11	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	PARK CITY	SL017	COALVILLE-SILVER CREEK-46KV	51.000	1.000	3.000	3.000	51.000	1	1	1
Low MAIFI	PARK CITY	30	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	PARK CITY	SL017	COALVILLE-SILVER CREEK-46KV	51.000	1.000	3.000	3.000	51.000	1	1	1
Low MAIFI(e)	PARK CITY	30	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	PARK CITY	OKY11	OAKLEY #11	467.320	2.188	0.000	0.000	213.563	1,865	4,081	51
Low Customer Minutes Lost	PARK CITY	9	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	SALINA (Richfield)			0.249	0.002	0.000	0.000	148.000	14,266	24	1
Unplanned	SALINA (Richfield)			74.675	0.631	0.014	0.014	118.381	14,266	8,999	188
Customer Requested	SALINA (Richfield)			0.000	0.000	0.000	0.000	0.000	14,266	0	0
High SAIDI	SALINA (Richfield)	FTG12	FOUNTAIN GREEN #12	815.885	4.370	0.012	0.012	186.714	165	721	12
Low SAIDI	SALINA (Richfield)	41	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	SALINA (Richfield)	FTG12	FOUNTAIN GREEN #12	815.885	4.370	0.012	0.012	186.714	165	721	12
Low SAIFI	SALINA (Richfield)	41	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	SALINA (Richfield)	T43	GUNNISON-SIGURD-46KV	0.000	0.000	1.000	1.000	0.000	1	0	0
High MAIFI	SALINA (Richfield)	T23	SIGURD-GUNNISON #2-46KV	0.000	0.000	1.000	1.000	0.000	1	0	0
Low MAIFI	SALINA (Richfield)	62	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	SALINA (Richfield)	T43	GUNNISON-SIGURD-46KV	0.000	0.000	1.000	1.000	0.000	1	0	0
High MAIFI(e)	SALINA (Richfield)	T23	SIGURD-GUNNISON #2-46KV	0.000	0.000	1.000	1.000	0.000	1	0	0
Low MAIFI(e)	SALINA (Richfield)	62	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	SALINA (Richfield)	PAN12	PANGUITCH #12	300.662	1.035	0.000	0.000	290.455	683	707	8
Low Customer Minutes Lost	SALINA (Richfield)	41	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	SMITHFIELD			0.132	0.002	0.000	0.000	68.850	20,857	40	3
Unplanned	SMITHFIELD			143.186	1.735	0.044	0.044	82.512	20,857	36,194	309
Customer Requested	SMITHFIELD			0.008	0.000	0.000	0.000	159.000	20,857	1	1
High SAIDI	SMITHFIELD	NIB21	NIBLEY #21	425.583	4.000	0.011	0.011	106.396	1,916	7,664	45
Low SAIDI	SMITHFIELD	5	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	SMITHFIELD	NIB21	NIBLEY #21	425.583	4.000	0.011	0.011	106.396	1,916	7,664	45
Low SAIFI	SMITHFIELD	5	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	SMITHFIELD	AMA14	AMALGA #14	90.790	2.027	1.000	1.000	44.797	262	531	15
Low MAIFI	SMITHFIELD	21	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	SMITHFIELD	AMA14	AMALGA #14	90.790	2.027	1.000	1.000	44.797	262	531	15
Low MAIFI(e)	SMITHFIELD	21	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	SMITHFIELD	NIB21	NIBLEY #21	425.583	4.000	0.011	0.011	106.396	1,916	7,664	45
Low Customer Minutes Lost	SMITHFIELD	4	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	SOUTH VALLEY (Jordan Valley)			1.420	0.013	0.000	0.000	110.558	176,761	2,271	51
Unplanned	SOUTH VALLEY (Jordan Valley)			123.763	1.354	0.095	0.093	91.389	176,761	239,379	1,348
Customer Requested	SOUTH VALLEY (Jordan Valley)			0.025	0.000	0.000	0.000	106.756	176,761	41	2
High SAIDI	SOUTH VALLEY (Jordan Va	BLF13	BLUFFDALE #13	794.321	6.549	0.002	0.002	121.296	1,903	12,462	27

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Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off	Number of Occurrences
Low SAIDI	SOUTH VALLEY (Jordan Va	38	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	SOUTH VALLEY (Jordan Va	KRN12	KEARNS #12	612.107	8.052	0.000	0.000	76.017	3,044	24,511	46
Low SAIFI	SOUTH VALLEY (Jordan Va	38	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	SOUTH VALLEY (Jordan Va	CAS11	CASTO #11	485.745	4.244	1.000	1.000	114.444	1,784	7,572	42
High MAIFI	SOUTH VALLEY (Jordan Va	HAM13	HAMMER #13	0.000	0.000	1.000	1.000	0.000	6,077	0	0
High MAIFI	SOUTH VALLEY (Jordan Va	MDV12	MIDVALE #12	25.677	0.063	1.000	1.000	406.328	2,168	137	3
Low MAIFI	SOUTH VALLEY (Jordan Va	87	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	SOUTH VALLEY (Jordan Va	CAS11	CASTO #11	485.745	4.244	1.000	1.000	114.444	1,784	7,572	42
High MAIFI(e)	SOUTH VALLEY (Jordan Va	HAM13	HAMMER #13	0.000	0.000	1.000	1.000	0.000	6,077	0	0
High MAIFI(e)	SOUTH VALLEY (Jordan Va	MDV12	MIDVALE #12	25.677	0.063	1.000	1.000	406.328	2,168	137	3
Low MAIFI(e)	SOUTH VALLEY (Jordan Va	87	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	SOUTH VALLEY (Jordan Va	KRN12	KEARNS #12	612.107	8.052	0.000	0.000	76.017	3,044	24,511	46
Low Customer Minutes Lost	SOUTH VALLEY (Jordan Va	25	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	TOOELE			1.107	0.015	0.000	0.000	74.915	13,534	200	3
Unplanned	TOOELE			392.167	3.621	0.785	0.785	108.300	13,534	49,008	212
Customer Requested	TOOELE			0.000	0.000	0.000	0.000	0.000	13,534	0	0
High SAIDI	TOOELE	SKU11	SKULL VALLEY #11	1,909.100	7.800	0.000	0.000	244.756	50	390	12
Low SAIDI	TOOELE	12	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	TOOELE	SKU11	SKULL VALLEY #11	1,909.100	7.800	0.000	0.000	244.756	50	390	12
Low SAIFI	TOOELE	12	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	TOOELE	TOO13	TOOELE #13	348.809	4.273	2.001	2.001	81.626	4,318	18,452	26
Low MAIFI	TOOELE	24	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	TOOELE	TOO13	TOOELE #13	348.809	4.273	2.001	2.001	81.626	4,318	18,452	26
Low MAIFI(e)	TOOELE	24	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	TOOELE	TOO13	TOOELE #13	348.809	4.273	2.001	2.001	81.626	4,318	18,452	26
Low Customer Minutes Lost	TOOELE	10	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	TREMONTON			0.171	0.002	0.000	0.000	82.437	7,692	16	2
Unplanned	TREMONTON			143.338	1.210	0.089	0.089	118.504	7,692	9,304	164
Customer Requested	TREMONTON			0.000	0.000	0.000	0.000	0.000	7,692	0	0
High SAIDI	TREMONTON	FDG11	FIELDING #11	580.413	4.639	0.000	0.000	125.113	629	2,918	33
Low SAIDI	TREMONTON	9	***** Circuits with a Low SAIDI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High SAIFI	TREMONTON	FDG11	FIELDING #11	580.413	4.639	0.000	0.000	125.113	629	2,918	33
Low SAIFI	TREMONTON	9	***** Circuits with a Low SAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI	TREMONTON	SNO12	SNOWVILLE #12	50.389	0.583	2.000	2.000	86.381	324	189	5
Low MAIFI	TREMONTON	18	***** Circuits with a Low MAIFI of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High MAIFI(e)	TREMONTON	SNO12	SNOWVILLE #12	50.389	0.583	2.000	2.000	86.381	324	189	5
Low MAIFI(e)	TREMONTON	18	***** Circuits with a Low MAIFI(e) of 0.0000 *****	0.000	0.000	0.000	0.000	0.000	0	0	0
High Customer Minutes Lost	TREMONTON	FDG11	FIELDING #11	580.413	4.639	0.000	0.000	125.113	629	2,918	33
Low Customer Minutes Lost	TREMONTON	8	***** Circuits with a Low Customer Minutes Lost of 0.0000 *	0.000	0.000	0.000	0.000	0.000	0	0	0
Planned	UINTA			0.000	0.000	0.000	0.000	0.000	2	0	0
Unplanned	UINTA			0.000	0.000	0.000	0.000	0.000	2	0	1
Customer Requested	UINTA			0.000	0.000	0.000	0.000	0.000	2	0	0
High SAIDI	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0
Low SAIDI	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0
High SAIFI	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0
Low SAIFI	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0
High MAIFI	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0
Low MAIFI	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0
High MAIFI(e)	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0

Fiscal YTD **Fiscal Year 2002** **UTAH OUTAGE DETAIL BY DISTRICT 04/01/2001 to 09/30/2001**

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off	Number of Occurrences
Low MAIFI(e)	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0
High Customer Minutes Lost	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0
Low Customer Minutes Lost	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0

Note 1: Work is in progress to update Average Customer Counts at the district level. Revised reports for affected quarters will be submitted when the work is completed.

Note: The count of customers impacted by transmission outages in the 2nd quarter are included in the "Customers Off" column. The "Customers Off" as reported for the quarter ended June 2001 also included the customers affected by transmission outages. In both cases, the count was included in the district assigned responsibility to maintain the transmission line. An additional report will be prepared for the 3rd quarter which will include more information regarding transmission-level customers affected by outages.

ACTION REQUEST

Date: October 25, 2001

TO: Division of Public Utilities
FROM: Public Service Commission

RESPONSE DUE BY: ASAP
URGENT ________

SUBJECT: 98-2035-04 PacifiCorp
(Company Name, Case Number, etc.)

This is a request for the Division to conduct:

________ Review Tariff Compliance

________ Analysis of Complaint

___X___ Investigation

________ Other

EXPLANATION AND STATEMENT OF ISSUES TO BE ADDRESSED

In the Matter of the Application of PacifiCorp and Scottish Power plc for an Order Approving the Issuance of PacifiCorp Common Stock – PacifiCorp's Petition for Modification of Order

26860

STOEL RIVES LLP

ATTORNEYS

STANDARD INSURANCE CENTER
900 SW FIFTH AVENUE, SUITE 2600
PORTLAND, OREGON 97204-1268
Phone (503) 224-3380 *Fax* (503) 220-24
TDD (503) 221-1045
Internet: www.stoel.com

Sally, what do you suggest?

~~SPM~~
~~SM~~
CBW
~~RMC~~

APPROVED BY COMMISSIONERS
STEPHEN F. MECHAM Issue 20-day tentative order
CONSTANCE B. WHITE CBW 10/22
RICHARD M. CAMPBELL RC

although we should consider any comments from DPU, CCS, before issuing an order

October 15, 2001

JAMES C. PAINE
Direct Dial
(503) 294-9246
email jcpaine@stoel.com

OVERNIGHT MAIL

Commission Secretary
Public Service Commission of Utah
160 East 300 South, 4th Floor
Salt Lake City, UT 84111

Re: Docket No. 98-2035-04
Petition of PacifiCorp for Modification of Order

Enclosed for filing with the Commission are an original and eight copies of the Petition of PacifiCorp for Modification of Order.

Very truly yours,

James C

8 NOV 01
PSC could issue a tentative order granting relief if no protest is filed 20 days after Tentative Order (Rule 110 fashion). Or send notice of PSC intent to grant unless protest is filed w/in 20 days and then issue order after 20 days

Enclosures

Portlnd3-1358972.1 0017509-00044

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Attorneys for Applicant

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of PacifiCorp and ScottishPower plc for an Order Approving the Issuance of PacifiCorp Common Stock	))))	DOCKET NO. 98-2035-04

PETITION OF PACIFICORP FOR MODIFICATION OF ORDER

PacifiCorp files this Petition for Modification of Order No. 98-2035-04 pursuant to the provisions of § 54-7-13 U.C.A. Order No. 98-2035-04, issued November 23, 1999 (the "Order"), approved Scottish Power plc's ("ScottishPower") purchase of PacifiCorp (collectively the "Joint Applicants") pursuant to the Agreement and Plan of Merger dated December 6, 1998 (as amended on February 23, 1999). In the Order, the Commission adopted a number of conditions to granting the application, including implementation of a number of Performance Standards and Customer Guarantees proposed by the Joint Applicants.

In the Order, the Commission adopted a number of conditions to granting the application, including implementation of a number of Performance Standards and Customer Guarantees proposed by the Joint Applicants. PacifiCorp seeks modification of the Order regarding one standard; *viz.*, Customer Service Performance Standard 6, addressing response times for PacifiCorp Business Center incoming telephone calls.

1. Background

In the Order, the Commission adopted a number of proposed conditions to the granting of the application including network performance standards, customer service performance standards, and customer guarantees. See, Appendix 1 to Order reflecting the July 28, 1999 Stipulation among the Joint Applicants, the Division of Public Utilities and the Committee of Consumer Services. The Customer Service Performance Standards adopted by the Commission are reflected in Attachment No. 1 to Appendix 1 of the Order. Among the standards was a Customer Service Performance addressing telephone response times at PacifiCorp's business centers which specifically provides:

> 1. Telephone Service Levels. Within 120 days after completion of the transaction 80% of calls to PacifiCorp's Business Centers will be answered within 30 seconds. This target will be increased to 80% in 20 seconds by January 1, 2001 and 80% in 10 seconds by January 1, 2002." Section I. B. Customer Benefits of Attachment 1 to Order Appendix 1.

PacifiCorp reports to the Commission on compliance with meeting the performance standards on an annual basis. There are no monetary penalties associated with failure to meet the telephone service level customer service performance standards. Due to the Joint Applicants' focus on the commitment to meet the performance standards and the systems and process improvements that were implemented during and after the merger proceedings, the

Joint Applicants surpassed the 80%-in-30-seconds ("80/30") target during the first year following the merger. The 80%-in-20-seconds ("80/20") target took effect January 1, 2001, and we expect this target will be met on an annual basis although current service levels are just below 80%.

2. Relief Requested and Reasons for Seeking Modification

In this request for modification, PacifiCorp seeks to eliminate the 80%-in-10 seconds ("80/10") target that was intended to go into effect January 1, 2002. At the time this commitment was made, today's energy environment with tight energy supplies, volatility in energy markets and the increase in the number of programs (e.g., Customer Energy Challenge, increased interest in demand side management programs, etc.) was not envisioned. While we have made technology improvements over the past few years which have allowed us to improve work queue management while ensuring that customer calls are handled as quickly as possible; these improvements do not offset the unanticipated increase in the volume of calls as well as the receipt of more complex calls by PacifiCorp's Business Centers. In addition, the Company is working to resolve the customers' concerns with the first call, thus potentially lengthening the duration of calls.

In further support of the Company's request to eliminate the 80/10 target, a Residential Focus Group Research Report was conducted December 18-20, 2000 and indicated that the goal of answering 80% of calls within 10 seconds is unnecessary and not particularly important to the customer. In this research, customers questioned whether the quality of service would suffer in the haste to answer calls. In addition, customers in the focus groups reported that 80/10 would not increase their level of satisfaction. The Company's "pulse" research also shows that customer satisfaction with call center wait times was 70.4% "very satisfied" in 2000 with the 80/30 standard. The "pulse" research is a monthly telephone survey of 200 randomly selected customers throughout the Company's service territory. Through August 2001, customer satisfaction with wait times in 2001 is 70.2% "very satisfied" although the standard was raised to 80/20 effective January 1, 2001. This demonstrates that while performance has improved in 2001, customer satisfaction has remained stable.

Lastly, the Company has verified that the current 80/20 standard is on the high end relative to the level of service provided by other United States electric utilities based on a preliminary benchmarking data. This benchmarking data shows that no other electric utility in the U.S. has a higher target than 80 percent of calls answered in 20 seconds. Of the utilities included in the Edison Electric Institute's 2001 Call Center Benchmarking Study, PacifiCorp's call center service level is among the best in the U.S.

3. Summary

To summarize, PacifiCorp believes that the service received by customers as a result of implementing Performance Standard 6 has significantly and measurably increased customer satisfaction. In fact, research shows that satisfaction with wait time to speak to a customer service representative has increased significantly from 62.7% "very satisfied" in 1998 to70.2% "very satisfied" year-to-date in 2001 (January-August). As noted above, achieving 80/10 would not increase customer satisfaction and is not considered important to customers, although this fact was not known at the time this commitment was developed. Also not known at the time this commitment was made was the complexity in the energy marketplace that has occurred over the past few years, as described above. Even given this complexity, our customers have received, and will continue to receive quality call center telephone response service through the 80/20 standard currently in place. Eliminating the 80/10 response time in no way lessens the Company's commitment to service excellence in all areas of performance. PacifiCorp will continue to monitor customer satisfaction levels to ensure that these satisfaction levels remain high and we will consider and implement suggested changes to improve satisfaction levels in the future.

For the reasons set forth above, PacifiCorp respectfully Petitions the Commission to Modify Order No. 98-2035-04 to eliminate the 80/10 call center Customer Performance Standard.

DATED: October 15, 2001.

Respectfully submitted,

James C. Paine
Stoel Rives, LLP
Suite 2600
900 SW Fifth Avenue
Portland, OR 97204-1268
Of Attorneys for PacifiCorp

CERTIFICATE OF SERVICE

I hereby certify that I caused the foregoing document to be served upon the following persons by mailing a true and correct copy of the same, postage prepaid, to the following:

Michael Ginsberg
Assistant Attorney General
Division of Public Utilities
160 East 300 South, 5th Floor
Salt Lake City, UT 84111

Doug Tingey
Assistant Attorney General
Committee of Consumer Service
160 East 300 South, 5th Floor
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Salt Lake City, UT 84111

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The Three Parties
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Stephen R. Randle
Randle, Deamer, Zarr, Romrell & Lee P.C.
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Salt Lake City, UT 84111-1004

Fred Finlinson
Callister, Nebeker & McCullough
Gateway Tower East
10 East South Temple, Suite 900
Salt Lake City, UT 84133

DATED: October 15, 2001.

James C. Paine

JAMES C. PAINE

26481

State of Utah
DEPARTMENT OF COMMERCE
Internet Address; http://www.commerce.state.ut.us

Michael O. Leavitt
Governor
Ted Boyer
Executive Director
Lowell E. Alt Jr.
Division Director

DIVISION OF PUBLIC UTILITIES
Heber M. Wells Building 4th Floor
160 East 300 South/ Box 146751
Salt Lake City, Utah 84114-6751
Phone (801) 530-7622
Fax (801) 530-6512 or (801) 530-6650

RECEIVED
Sep 18 3 53 PM '01

APPROVED BY COMMISSIONERS
STEPHEN F. MECHAM
CONSTANCE B. WHITE CBW 9/21
RICHARD M. CAMPBELL RC

98-2035-04

To: Utah State Public Service Commission and Committee of Consumer Services

From: Lowell Alt, Director, Division of Public Utilities LEA
Judith Johnson, Manager, Energy Section JJ
Bob Maloney, Management Analyst BM

Subject: Recommendation to Approve PacifiCorp's Claimed Major Event Exclusions for May 2 through May 5, 2001 and June 12 through June 14, 2001

Date: Tuesday, September 18, 2001

We recommend that the Commission approve PacifiCorp's claimed major event exclusions for two wide-scale outages occurring during May 2nd through May 5th, 2001 and June 12th through June 14,th 2001

PacifiCorp has submitted data showing that significantly more than 10% of the customers in affected Utah operating areas experienced a sustained outage of more than five minutes duration during the two major events. ScottishPower/PacifiCorp merger condition #31 indicates that the Company may use the IEEE criteria to determine major events. IEEE criteria include:

1. Exceeds the design limits of the power system
2. Causes extensive damage to the power system
3. Results in more than 10% of the customers in an operating area experiencing a sustained outage.

We recommend approval based upon criterion #3. This is because significantly more than 10% of PacifiCorp's Utah customers in affected operating areas experienced sustained outages during the two major event periods.

1900 S.W. 4th Ave.
Portland, Oregon 97201

PACIFICORP
PACIFIC POWER UTAH POWER

RECEIVED

VIA OVERNIGHT MAIL

July 31, 2001

REVIEWED BY COMMISSIONERS
STEPHEN F. MECHAM
CONSTANCE B. WHITE GBW 8/9
RICHARD M. CAMPBELL

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City UT 84114

Attention: Julie P. Orchard
Commission Secretary

RE: Docket No. 98-2035-04 ScottishPower/PacifiCorp Merger Commitments

Please find enclosed PacifiCorp's quarterly report for the period April 2001 through June 2001 detailing the Company's performance in meeting the Customer Guarantees which were agreed upon as a result of the merger between ScottishPower and PacifiCorp. A comparison of performance for this quarter compared to performance for last year is included as well.

As required by merger Stipulation Conditions 33 and 36, detailed outage performance and customer guarantee performance by district are also being reported. These reports are enclosed. Meter set response and temporary services response by district as required by merger Stipulation Condition 34 are also enclosed. Additional reports are provided outlining the number of requests and average days to respond for Customer Guarantees 4, 5 and 6, power restoration performance, field response performance and the number of tree trimming requests.

If you have any questions or require further information, please call Carole Rockney at (503) 813-7408.

Sincerely,

D. Douglas Larson /kms

D. Douglas Larson,
Vice President, Regulation

c: Mark Flandro - Utah Division of Public Utilities
Rea Petersen - Utah Division of Public Utilities
Andy MacRitchie - Executive Vice President, Power Delivery

Enclosures

PACIFICORP

Utah

Customer Service Commitments - Guarantees

April-June 2001

		April-June 2001			April-June 2000		
	Description	Events	Failures	Paid	Events	Failures	Paid
CG1	Restoring Supply	383,690	0	$0	168,969	0	$0
CG2	Appointments	1,689	3	$150	1,502	7	$350
CG3	Switching on Power	8,749	12	$1,300	7,755	23	$3,700
CG4	Estimates	2,147	30	$1,500	1,778	19	$950
CG5	Respond to Billing Inquiries	1,761	4	$200	1,233	5	$250
CG6	Respond to Meter Problems	93	0	$0	175	1	$50
CG7	Notification of Planned Interruptions	8,405	11	$600	1,751	18	$950
CG8	Power Quality Complaints	309	0	$0	606	13	$650
		406,843	**60**	**$3,750**	**183,769**	**86**	**$6,900**

Summary analysis:

General Comments - A continuing low rate of failures begins the second year of the guarantees. PacifiCorp employees in Utah are working hard to keep failures to a minimum.

- Employees are encouraged to submit suggestions to improve business processes related to the guarantees. Small groups are assigned periodically to study such suggestions, and implement those that have merit. This will continue over the future.

CG1 - Restoring Supply - Events increased significantly during June primarily due to hot weather and wind.

CG3 - Switching on Power - Process improvement efforts since June 2000 have reduced the failure rate compared to last year.

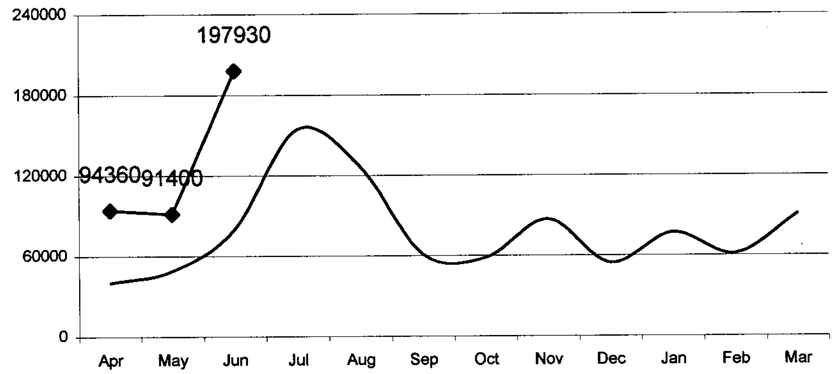
CG4 - Estimates - More failures are reported in recent months after internal audits have helped improve the understanding of guarantee procedures in field offices.

CG8 - Power Quality Complaints - Process improvements have led to a reduced number of failures compared to last year.

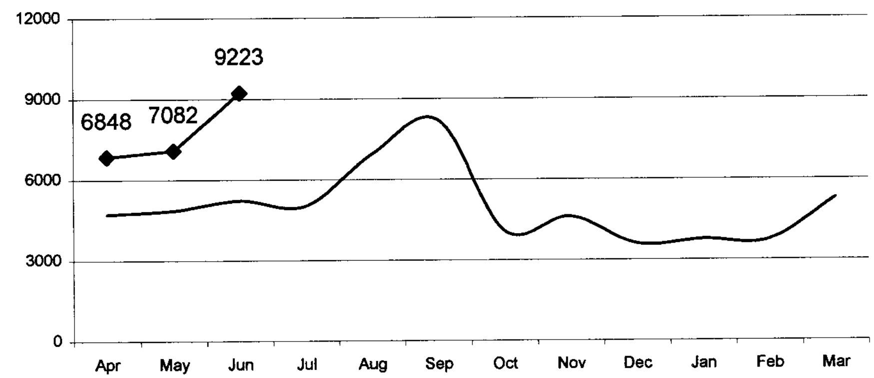
PACIFICORP
Utah

Customer Service Commitments - Guarantees
April-June 2001

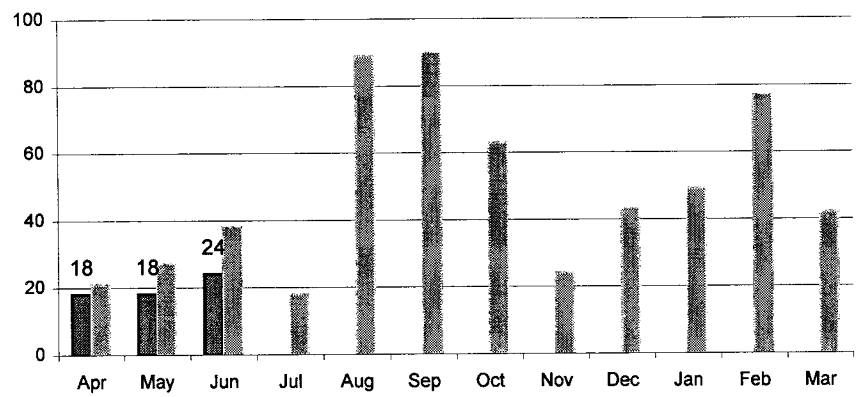
CG 1 Events



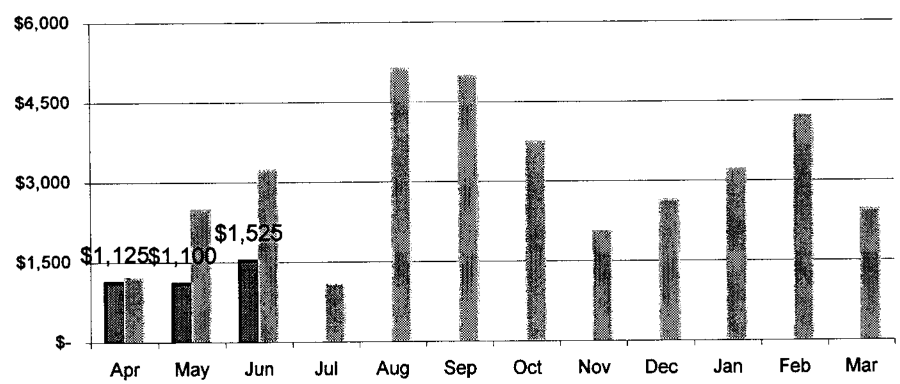
CG 2-8 Events



Failures



Payments



1st Quarter **Fiscal Year 2002** **04/01/2001 to 06/30/2001**

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off	Number of Occurrences
Customer Requested	Utah			0.001	0.000	0.000	0.000	0.000	628,250	5,495	4
Planned	Utah			1.884	0.013	0.000	0.000	144.923	628,250	8,405	106
Unplanned	Utah			53.840	0.610	0.104	0.103	88.262	628,250	383,051	5,398
								0.000			
Planned	AMERICAN FORK			1.304	0.025	0.000	0.000	52.160	63,521	1,605	9
Unplanned	AMERICAN FORK			30.812	0.459	0.075	0.075	67.129	63,521	29,152	206
Customer Requested	AMERICAN FORK			0.004	0.000	0.000	0.000	0.000	63,521	1	1
High SAIDI	AMERICAN FORK	EUR12	EUREKA #12	6,095.000	43.000	0.000	0.000	141.744	43	43	1
Low SAIDI	AMERICAN FORK	17	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	AMERICAN FORK	EUR12	EUREKA #12	6,095.000	43.000	0.000	0.000	141.744	43	43	1
Low SAIFI	AMERICAN FORK	17	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	AMERICAN FORK	CHW15	CHERRYWOOD #15	0.419	0.008	1.698	1.698	52.375	2,125	17	4
Low MAIFI	AMERICAN FORK	69	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	AMERICAN FORK	CHW15	CHERRYWOOD #15	0.419	0.008	1.698	1.698	52.375	2,125	17	4
Low MAIFI(e)	AMERICAN FORK	63	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	AMERICAN FORK	SAR13	SARATOGA #13	882.313	5.166	0.124	0.124	170.792	453	2,340	6
Low Customer Minutes Lost	AMERICAN FORK	15	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	ASHLEY (VERNAL)			0.000	0.000	0.000	0.000	0.000	9,382	0	0
Unplanned	ASHLEY (VERNAL)			110.742	0.684	0.105	0.105	161.904	9,382	6,418	50
Customer Requested	ASHLEY (VERNAL)			0.000	0.000	0.000	0.000	0.000	9,382	0	0
High SAIDI	ASHLEY (VERNAL)	VER12	VERNAL #12	428.703	1.164	0.000	0.000	368.302	1,071	1,247	6
Low SAIDI	ASHLEY (VERNAL)	5	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	ASHLEY (VERNAL)	VER14	VERNAL #14	154.839	1.641	0.561	0.561	94.356	1,750	2,872	8
Low SAIFI	ASHLEY (VERNAL)	5	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	ASHLEY (VERNAL)	VER14	VERNAL #14	154.839	1.641	0.561	0.561	94.356	1,750	2,872	8
Low MAIFI	ASHLEY (VERNAL)	10	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	ASHLEY (VERNAL)	VER14	VERNAL #14	154.839	1.641	0.561	0.561	94.356	1,750	2,872	8
Low MAIFI(e)	ASHLEY (VERNAL)	10	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	ASHLEY (VERNAL)	VER12	VERNAL #12	428.703	1.164	0.000	0.000	368.302	1,071	1,247	6
Low Customer Minutes Lost	ASHLEY (VERNAL)	5	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	CANYONLANDS (MOAB)			0.000	0.000	0.000	0.000	0.000	14,226	0	0
Unplanned	CANYONLANDS (MOAB)			13.633	0.091	0.001	0.001	149.813	14,226	1,300	37
Customer Requested	CANYONLANDS (MOAB)			0.000	0.000	0.000	0.000	0.000	14,226	0	0
High SAIDI	CANYONLANDS (MOAB)	RAT22	RATTLESNAKE #22	156.380	0.519	0.000	0.000	301.310	800	415	9
Low SAIDI	CANYONLANDS (MOAB)	28	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	CANYONLANDS (MOAB)	WSW11	WESTWATER #11	78.080	1.110	0.000	0.000	70.342	100	111	2
Low SAIFI	CANYONLANDS (MOAB)	28	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	CANYONLANDS (MOAB)	WSW11	WESTWATER #11	78.080	1.110	0.000	0.000	70.342	100	111	2
Low MAIFI	CANYONLANDS (MOAB)	39	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	CANYONLANDS (MOAB)	WSW11	WESTWATER #11	78.080	1.110	0.000	0.000	70.342	100	111	2
Low MAIFI(e)	CANYONLANDS (MOAB)	39	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	CANYONLANDS (MOAB)	RAT22	RATTLESNAKE #22	156.380	0.519	0.000	0.000	301.310	800	415	9
Low Customer Minutes Lost	CANYONLANDS (MOAB)	28	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	CARBON (PRICE)			1.790	0.013	0.000	0.000	137.692	10,248	129	2
Unplanned	CARBON (PRICE)			70.419	0.761	0.009	0.009	92.535	10,248	7,796	62
Customer Requested	CARBON (PRICE)			0.000	0.000	0.000	0.000	0.000	10,248	0	0
High SAIDI	CARBON (PRICE)	FER11	FERRON #11	328.430	1.790	0.000	0.000	183.480	920	1,647	9
Low SAIDI	CARBON (PRICE)	29	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	CARBON (PRICE)	MAT12	MATHIS #12	296.604	3.878	0.000	0.000	76.484	498	1,931	6
Low SAIFI	CARBON (PRICE)	29	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	CARBON (PRICE)	CCK11	CLEAR CREEK #11	0.000	0.000	1.568	1.568	0.000	37	0	0
Low MAIFI	CARBON (PRICE)	44	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	CARBON (PRICE)	CCK11	CLEAR CREEK #11	0.000	0.000	1.568	1.568	0.000	37	0	0
Low MAIFI(e)	CARBON (PRICE)	44	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	CARBON (PRICE)	FER11	FERRON #11	328.430	1.790	0.000	0.000	183.480	920	1,647	9

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Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off	Number of Occurrences
Low Customer Minutes Lost	CARBON (PRICE)	27	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	CEDAR CITY			0.163	0.005	0.000	0.000	32.600	16,630	77	3
Unplanned	CEDAR CITY			25.277	0.330	0.007	0.007	76.597	16,630	5,484	96
Customer Requested	CEDAR CITY			0.006	0.000	0.000	0.000	0.000	16,630	1	1
High SAIDI	CEDAR CITY	MDD24	MIDDLETON #24	802.981	10.406	0.000	0.000	77.165	318	3,309	15
Low SAIDI	CEDAR CITY	57	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	CEDAR CITY	MDD24	MIDDLETON #24	802.981	10.406	0.000	0.000	77.165	318	3,309	15
Low SAIFI	CEDAR CITY	57	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	CEDAR CITY	CLM15	COLEMAN #15	101.500	1.780	1.560	1.560	57.022	50	89	6
Low MAIFI	CEDAR CITY	81	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	CEDAR CITY	CLM15	COLEMAN #15	101.500	1.780	1.560	1.560	57.022	50	89	6
Low MAIFI(e)	CEDAR CITY	81	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	CEDAR CITY	MDD24	MIDDLETON #24	802.981	10.406	0.000	0.000	77.165	318	3,309	15
Low Customer Minutes Lost	CEDAR CITY	55	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	COTTONWOOD (JORDAN VALLEY)			1.766	0.063	0.000	0.000	28.032	3,913	245	3
Unplanned	COTTONWOOD (JORDAN VALLEY)			294.013	2.308	0.142	0.071	127.389	3,913	9,032	37
Customer Requested	COTTONWOOD (JORDAN VALLEY)			0.000	0.000	0.000	0.000	0.000	3,913	0	0
High SAIDI	COTTONWOOD (JORDAN VALLEY)	DMP13	DIMPLE DELL #13	430.628	3.696	0.000	0.000	116.512	1,232	4,553	8
Low SAIDI	COTTONWOOD (JORDAN VALLEY)	DMP11	DIMPLE DELL #11	151.252	1.206	0.000	0.000	125.416	925	1,116	9
High SAIFI	COTTONWOOD (JORDAN VALLEY)	DMP13	DIMPLE DELL #13	430.628	3.696	0.000	0.000	116.512	1,232	4,553	8
Low SAIFI	COTTONWOOD (JORDAN VALLEY)	DMP11	DIMPLE DELL #11	151.252	1.206	0.000	0.000	125.416	925	1,116	9
High MAIFI	COTTONWOOD (JORDAN VALLEY)	DMP12	DIMPLE DELL #12	273.366	1.915	0.317	0.159	142.750	1,756	3,363	20
Low MAIFI	COTTONWOOD (JORDAN VALLEY)	2	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	COTTONWOOD (JORDAN VALLEY)	DMP12	DIMPLE DELL #12	273.366	1.915	0.317	0.159	142.750	1,756	3,363	20
Low MAIFI(e)	COTTONWOOD (JORDAN VALLEY)	2	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	COTTONWOOD (JORDAN VALLEY)	DMP13	DIMPLE DELL #13	430.628	3.696	0.000	0.000	116.512	1,232	4,553	8
Low Customer Minutes Lost	COTTONWOOD (JORDAN VALLEY)	DMP11	DIMPLE DELL #11	151.252	1.206	0.000	0.000	125.416	925	1,116	9
Planned	DELTA (RICHFIELD)			0.000	0.000	0.000	0.000	0.000	5,766	0	0
Unplanned	DELTA (RICHFIELD)			34.214	0.306	0.990	0.990	111.810	5,766	1,767	42
Customer Requested	DELTA (RICHFIELD)			0.000	0.000	0.000	0.000	0.000	5,766	0	0
High SAIDI	DELTA (RICHFIELD)	STH21	SUTHERLAND #21	225.450	2.305	1.039	1.039	97.809	462	1,065	22
Low SAIDI	DELTA (RICHFIELD)	19	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	DELTA (RICHFIELD)	STH21	SUTHERLAND #21	225.450	2.305	1.039	1.039	97.809	462	1,065	22
Low SAIFI	DELTA (RICHFIELD)	19	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	DELTA (RICHFIELD)	STH21	SUTHERLAND #21	225.450	2.305	1.039	1.039	97.809	462	1,065	22
Low MAIFI	DELTA (RICHFIELD)	4	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	DELTA (RICHFIELD)	STH21	SUTHERLAND #21	225.450	2.305	1.039	1.039	97.809	462	1,065	22
Low MAIFI(e)	DELTA (RICHFIELD)	4	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	DELTA (RICHFIELD)	STH21	SUTHERLAND #21	225.450	2.305	1.039	1.039	97.809	462	1,065	22
Low Customer Minutes Lost	DELTA (RICHFIELD)	2	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	LAYTON			0.174	0.002	0.000	0.000	87.000	37,001	70	6
Unplanned	LAYTON			65.254	1.009	0.012	0.012	64.672	37,001	37,319	148
Customer Requested	LAYTON			0.000	0.000	0.000	0.000	0.000	37,001	0	0
High SAIDI	LAYTON	SYR15	SYRACUSE #15	49,394.000	1,371.000	0.000	0.000	36.028	1	1,371	4
Low SAIDI	LAYTON	12	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	LAYTON	SYR15	SYRACUSE #15	49,394.000	1,371.000	0.000	0.000	36.028	1	1,371	4
Low SAIFI	LAYTON	12	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	LAYTON	ANG14	ANGEL #14	62.155	1.575	0.167	0.167	39.463	2,050	3,228	4
Low MAIFI	LAYTON	34	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	LAYTON	ANG14	ANGEL #14	62.155	1.575	0.167	0.167	39.463	2,050	3,228	4
Low MAIFI(e)	LAYTON	34	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	LAYTON	SYR11	SYRACUSE #11	7,654.121	111.168	0.000	0.000	68.852	107	11,895	8
Low Customer Minutes Lost	LAYTON	12	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	SLC METRO			2.478	0.015	0.000	0.000	165.200	184,202	2,814	30
Unplanned	SLC METRO			32.412	0.359	0.136	0.136	90.284	184,202	66,186	633

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Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off	Number of Occurrences
Customer Requested	**SLC METRO**			0.000	0.000	0.000	0.000	0.000	184,202	0	0
High SAIDI	**SLC METRO**	UNI01	UNIVERSITY #1	8,327.000	111.000	0.000	0.000	75.018	1	111	1
Low SAIDI	**SLC METRO**	115	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	**SLC METRO**	UNI01	UNIVERSITY #1	8,327.000	111.000	0.000	0.000	75.018	1	111	1
Low SAIFI	**SLC METRO**	115	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	**SLC METRO**	VLY13	VALLEY CENTER #13	5.834	0.031	3.461	3.461	188.194	453	14	1
Low MAIFI	**SLC METRO**	220	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	**SLC METRO**	VLY13	VALLEY CENTER #13	5.834	0.031	3.461	3.461	188.194	453	14	1
Low MAIFI(e)	**SLC METRO**	220	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	**SLC METRO**	LPK12	LAKEPARK #12	263.723	0.971	0.000	0.000	271.599	3,065	2,975	3
Low Customer Minutes Lost	**SLC METRO**	114	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	**MILFORD (CEDAR CITY)**			0.000	0.000	0.000	0.000	0.000	1,679	0	0
Unplanned	**MILFORD (CEDAR CITY)**			189.046	1.591	0.007	0.007	118.822	1,679	2,672	31
Customer Requested	**MILFORD (CEDAR CITY)**			0.000	0.000	0.000	0.000	0.000	1,679	0	0
High SAIDI	**MILFORD (CEDAR CITY)**	BKL11	BROOKLAWN #11	1,372.256	9.529	0.000	0.000	144.008	121	1,153	9
Low SAIDI	**MILFORD (CEDAR CITY)**	8	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	**MILFORD (CEDAR CITY)**	BKL11	BROOKLAWN #11	1,372.256	9.529	0.000	0.000	144.008	121	1,153	9
Low SAIFI	**MILFORD (CEDAR CITY)**	8	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	**MILFORD (CEDAR CITY)**	SML12	SOUTH MILFORD #12	5.573	0.031	0.115	0.115	179.774	96	3	3
Low MAIFI	**MILFORD (CEDAR CITY)**	18	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	**MILFORD (CEDAR CITY)**	SML12	SOUTH MILFORD #12	5.573	0.031	0.115	0.115	179.774	96	3	3
Low MAIFI(e)	**MILFORD (CEDAR CITY)**	18	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	**MILFORD (CEDAR CITY)**	BKL11	BROOKLAWN #11	1,372.256	9.529	0.000	0.000	144.008	121	1,153	9
Low Customer Minutes Lost	**MILFORD (CEDAR CITY)**	8	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	**OGDEN**			6.499	0.029	0.002	0.002	224.103	70,416	2,007	22
Unplanned	**OGDEN**			74.330	0.712	0.050	0.050	104.396	70,416	50,103	309
Customer Requested	**OGDEN**			0.006	0.000	0.000	0.000	0.000	70,416	9	2
High SAIDI	**OGDEN**	WOG12	WEST OGDEN #12	1,250.750	19.394	0.000	0.000	64.492	188	3,646	10
Low SAIDI	**OGDEN**	49	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	**OGDEN**	WOG12	WEST OGDEN #12	1,250.750	19.394	0.000	0.000	64.492	188	3,646	10
Low SAIFI	**OGDEN**	49	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	**OGDEN**	NOG12	NORTH OGDEN #12	15.648	0.132	1.070	1.070	118.545	2,000	264	8
Low MAIFI	**OGDEN**	99	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	**OGDEN**	NOG12	NORTH OGDEN #12	15.648	0.132	1.070	1.070	118.545	2,000	264	8
Low MAIFI(e)	**OGDEN**	99	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	**OGDEN**	BRK11	BRICKYARD #11	514.345	1.943	0.000	0.000	264.717	1,306	2,537	6
Low Customer Minutes Lost	**OGDEN**	49	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	**PARK CITY**			2.077	0.011	0.000	0.000	188.818	16,060	177	2
Unplanned	**PARK CITY**			81.703	0.659	0.003	0.003	123.980	16,060	10,579	119
Customer Requested	**PARK CITY**			0.000	0.000	0.000	0.000	0.000	16,060	0	0
High SAIDI	**PARK CITY**	DSR11	DESERET #11	411.000	1.000	0.000	0.000	411.000	1	1	1
Low SAIDI	**PARK CITY**	12	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	**PARK CITY**	JUD12	JUDGE #12	251.583	4.750	3.167	3.167	52.965	12	57	3
Low SAIFI	**PARK CITY**	12	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	**PARK CITY**	JUD12	JUDGE #12	251.583	4.750	3.167	3.167	52.965	12	57	3
Low MAIFI	**PARK CITY**	33	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	**PARK CITY**	JUD12	JUDGE #12	251.583	4.750	3.167	3.167	52.965	12	57	3
Low MAIFI(e)	**PARK CITY**	33	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	**PARK CITY**	OKY11	OAKLEY #11	405.549	1.923	0.000	0.000	210.894	1,936	3,722	28
Low Customer Minutes Lost	**PARK CITY**	12	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	**SALINA (RICHFIELD)**			0.268	0.002	0.000	0.000	134.000	13,236	24	1
Unplanned	**SALINA (RICHFIELD)**			44.883	0.324	0.014	0.014	138.528	13,236	4,295	76
Customer Requested	**SALINA (RICHFIELD)**			0.000	0.000	0.000	0.000	0.000	13,236	0	0
High SAIDI	**SALINA (RICHFIELD)**	CTL11	CENTRAL #11	572.556	5.172	0.000	0.000	110.703	99	512	5
Low SAIDI	**SALINA (RICHFIELD)**	43	***** circuits with Low SAIDI of 0.000 *****	0.000							

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Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off	Number of Occurrences
High SAIFI	SALINA (RICHFIELD)	CTL11	CENTRAL #11	572.556	5.172	0.000	0.000	110.703	99	512	5
Low SAIFI	SALINA (RICHFIELD)	43	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	SALINA (RICHFIELD)	SCI11	SCIPIO #11	269.797	2.087	1.000	1.000	129.275	172	359	3
Low MAIFI	SALINA (RICHFIELD)	66	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	SALINA (RICHFIELD)	SCI11	SCIPIO #11	269.797	2.087	1.000	1.000	129.275	172	359	3
Low MAIFI(e)	SALINA (RICHFIELD)	66	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	SALINA (RICHFIELD)	GUN12	GUNNISON #12	524.454	1.233	0.000	0.000	425.348	339	418	5
Low Customer Minutes Lost	SALINA (RICHFIELD)	43	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	SMITHFIELD			0.013	0.000	0.000	0.000	0.000	13,148	4	1
Unplanned	SMITHFIELD			131.240	1.713	0.068	0.068	76.614	13,148	22,526	139
Customer Requested	SMITHFIELD			0.000	0.000	0.000	0.000	0.000	13,148	0	0
High SAIDI	SMITHFIELD	LEW11	LEWISTON #11	695.575	6.176	0.000	0.000	112.625	306	1,890	12
Low SAIDI	SMITHFIELD	5	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	SMITHFIELD	AMA11	AMALGA #11	271.423	12.960	0.000	0.000	20.943	227	2,942	7
Low SAIFI	SMITHFIELD	5	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	SMITHFIELD	AMA14	AMALGA #14	67.519	1.706	0.894	0.894	39.577	293	500	8
Low MAIFI	SMITHFIELD	21	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	SMITHFIELD	AMA14	AMALGA #14	67.519	1.706	0.894	0.894	39.577	293	500	8
Low MAIFI(e)	SMITHFIELD	21	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	SMITHFIELD	NIB21	NIBLEY #21	300.572	2.520	0.000	0.000	119.275	2,346	5,911	15
Low Customer Minutes Lost	SMITHFIELD	5	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	SOUTH VALLEY (JORDAN VALLEY)			0.701	0.008	0.000	0.000	87.625	153,028	1,193	24
Unplanned	SOUTH VALLEY (JORDAN VALLEY)			51.007	0.706	0.092	0.092	72.248	153,028	108,041	581
Customer Requested	SOUTH VALLEY (JORDAN VALLEY)			0.000	0.000	0.000	0.000	0.000	153,028	0	0
High SAIDI	SOUTH VALLEY (JORDAN VALLEY)	90S12	90TH SOUTH #12	36,470.000	1,044.000	0.000	0.000	34.933	1	1,044	1
Low SAIDI	SOUTH VALLEY (JORDAN VALLEY)	32	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	SOUTH VALLEY (JORDAN VALLEY)	90S12	90TH SOUTH #12	36,470.000	1,044.000	0.000	0.000	34.933	1	1,044	1
Low SAIFI	SOUTH VALLEY (JORDAN VALLEY)	33	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	SOUTH VALLEY (JORDAN VALLEY)	MDV12	MIDVALE #12	121.432	0.297	4.734	4.734	408.862	458	136	2
Low MAIFI	SOUTH VALLEY (JORDAN VALLEY)	99	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	SOUTH VALLEY (JORDAN VALLEY)	MDV12	MIDVALE #12	121.432	0.297	4.734	4.734	408.862	458	136	2
Low MAIFI(e)	SOUTH VALLEY (JORDAN VALLEY)	99	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	SOUTH VALLEY (JORDAN VALLEY)	BLF13	BLUFFDALE #13	418.368	5.814	0.002	0.002	71.959	1,323	7,692	11
Low Customer Minutes Lost	SOUTH VALLEY (JORDAN VALLEY)	31	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	TOOELE			0.697	0.005	0.000	0.000	139.400	9,368	44	1
Unplanned	TOOELE			262.949	1.889	0.923	0.923	139.200	9,368	17,698	80
Customer Requested	TOOELE			0.000	0.000	0.000	0.000	0.000	9,368	0	0
High SAIDI	TOOELE	STN13	STANSBURY #13	1,836.009	4.034	0.000	0.000	455.134	325	1,311	5
Low SAIDI	TOOELE	14	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	TOOELE	TOO11	TOOELE #11	747.515	4.415	0.000	0.000	169.313	511	2,256	6
Low SAIFI	TOOELE	14	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	TOOELE	TOO13	TOOELE #13	136.692	2.420	2.651	2.651	56.484	3,260	7,889	10
Low MAIFI	TOOELE	25	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	TOOELE	TOO13	TOOELE #13	136.692	2.420	2.651	2.651	56.484	3,260	7,889	10
Low MAIFI(e)	TOOELE	25	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	TOOELE	STN13	STANSBURY #13	1,836.009	4.034	0.000	0.000	455.134	325	1,311	5
Low Customer Minutes Lost	TOOELE	14	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	TREMONTON			0.205	0.002	0.000	0.000	102.500	6,424	16	2
Unplanned	TREMONTON			48.007	0.418	0.000	0.000	114.849	6,424	2,683	53
Customer Requested	TREMONTON			0.000	0.000	0.000	0.000	0.000	6,424	0	0
High SAIDI	TREMONTON	BRR14	BEAR RIVER #14	235.501	1.415	0.000	0.000	166.432	349	494	4
Low SAIDI	TREMONTON	9	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	TREMONTON	BRR12	BEAR RIVER #12	205.146	2.886	0.000	0.000	71.083	219	632	6
Low SAIFI	TREMONTON	9	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	TREMONTON	WSH01	WASHAKIE #1	0.000	0.000	0.000	0.000	0.000	1	0	0

1st Quarter **Fiscal Year 2002** **04/01/2001 to 06/30/2001**

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off	Number of Occurrences
Low MAIFI	TREMONTON	22	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	TREMONTON	WSH01	WASHAKIE #1	0.000	0.000	0.000	0.000	0.000	1	0	0
Low MAIFI(e)	TREMONTON	22	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	TREMONTON	FDG11	FIELDING #11	188.996	1.600	0.000	0.000	118.123	558	893	9
Low Customer Minutes Lost	TREMONTON	9	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	UINTA			0.000	0.000	0.000	0.000	0.000	2	0	0
Unplanned	UINTA			0.000	0.000	0.000	0.000	0.000	2	0	0
Customer Requested	UINTA			0.000	0.000	0.000	0.000	0.000	2	0	0
High SAIDI	UINTA	D029	PAINTER-CLEAR CREEK-138KV (UTAH SECTION)	0.000	0.000	0.000	0.000	0.000	2	0	0
Low SAIDI	UINTA	D029	PAINTER-CLEAR CREEK-138KV (UTAH SECTION)	0.000	0.000	0.000	0.000	0.000	2	0	0
High SAIFI	UINTA	D029	PAINTER-CLEAR CREEK-138KV (UTAH SECTION)	0.000	0.000	0.000	0.000	0.000	2	0	0
Low SAIFI	UINTA	D029	PAINTER-CLEAR CREEK-138KV (UTAH SECTION)	0.000	0.000	0.000	0.000	0.000	2	0	0
High MAIFI	UINTA	D029	PAINTER-CLEAR CREEK-138KV (UTAH SECTION)	0.000	0.000	0.000	0.000	0.000	2	0	0
Low MAIFI	UINTA	D029	PAINTER-CLEAR CREEK-138KV (UTAH SECTION)	0.000	0.000	0.000	0.000	0.000	2	0	0
High MAIFI(e)	UINTA	D029	PAINTER-CLEAR CREEK-138KV (UTAH SECTION)	0.000	0.000	0.000	0.000	0.000	2	0	0
Low MAIFI(e)	UINTA	D029	PAINTER-CLEAR CREEK-138KV (UTAH SECTION)	0.000	0.000	0.000	0.000	0.000	2	0	0
High Customer Minutes Lost	UINTA	D029	PAINTER-CLEAR CREEK-138KV (UTAH SECTION)	0.000	0.000	0.000	0.000	0.000	2	0	0
Low Customer Minutes Lost	UINTA	D029	PAINTER-CLEAR CREEK-138KV (UTAH SECTION)	0.000	0.000	0.000	0.000	0.000	2	0	0

Fiscal YTD Fiscal Year 2002 04/01/2001 to 06/30/2001

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off	Number of Occurrences
Customer Requested	Utah			0.001	0.000	0.000	0.000	0.000	628,250	5,495	4
Planned	Utah			1.884	0.013	0.000	0.000	144.923	628,250	8,405	106
Unplanned	Utah			53.840	0.610	0.104	0.103	88.262	628,250	383,051	5,398
								0.000			
Planned	AMERICAN FORK			1.304	0.025	0.000	0.000	52.160	63,521	1,605	9
Unplanned	AMERICAN FORK			30.812	0.459	0.075	0.075	67.129	63,521	29,152	206
Customer Requested	AMERICAN FORK			0.004	0.000	0.000	0.000	0.000	63,521	1	1
High SAIDI	AMERICAN FORK	EUR12	EUREKA #12	6,095.000	43.000	0.000	0.000	141.744	1	43	1
Low SAIDI	AMERICAN FORK	17	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	AMERICAN FORK	EUR12	EUREKA #12	6,095.000	43.000	0.000	0.000	141.744	1	43	1
Low SAIFI	AMERICAN FORK	17	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	AMERICAN FORK	CHW15	CHERRYWOOD #15	0.419	0.008	1.698	1.698	52.375	2,125	17	4
Low MAIFI	AMERICAN FORK	69	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	AMERICAN FORK	CHW15	CHERRYWOOD #15	0.419	0.008	1.698	1.698	52.375	2,125	17	4
Low MAIFI(e)	AMERICAN FORK	63	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	AMERICAN FORK	SAR13	SARATOGA #13	882.313	5.166	0.124	0.124	170.792	453	2,340	6
Low Customer Minutes Lost	AMERICAN FORK	15	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	ASHLEY			0.000	0.000	0.000	0.000	0.000	9,382	0	0
Unplanned	ASHLEY			110.742	0.684	0.105	0.105	161.904	9,382	6,418	50
Customer Requested	ASHLEY			0.000	0.000	0.000	0.000	0.000	9,382	0	0
High SAIDI	ASHLEY	VER12	VERNAL #12	428.703	1.164	0.000	0.000	368.302	1,071	1,247	6
Low SAIDI	ASHLEY	5	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	ASHLEY	VER14	VERNAL #14	154.839	1.641	0.561	0.561	94.356	1,750	2,872	8
Low SAIFI	ASHLEY	5	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	ASHLEY	VER14	VERNAL #14	154.839	1.641	0.561	0.561	94.356	1,750	2,872	8
Low MAIFI	ASHLEY	10	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	ASHLEY	VER14	VERNAL #14	154.839	1.641	0.561	0.561	94.356	1,750	2,872	8
Low MAIFI(e)	ASHLEY	10	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	ASHLEY	VER12	VERNAL #12	428.703	1.164	0.000	0.000	368.302	1,071	1,247	6
Low Customer Minutes Lost	ASHLEY	5	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	CANYONLANDS			0.000	0.000	0.000	0.000	0.000	14,226	0	0
Unplanned	CANYONLANDS			13.633	0.091	0.001	0.001	149.813	14,226	1,300	37
Customer Requested	CANYONLANDS			0.000	0.000	0.000	0.000	0.000	14,226	0	0
High SAIDI	CANYONLANDS	RAT22	RATTLESNAKE #22	156.380	0.519	0.000	0.000	301.310	800	415	9
Low SAIDI	CANYONLANDS	28	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	CANYONLANDS	WSW11	WESTWATER #11	78.080	1.110	0.000	0.000	70.342	100	111	2
Low SAIFI	CANYONLANDS	28	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	CANYONLANDS	WSW11	WESTWATER #11	78.080	1.110	0.000	0.000	70.342	100	111	2
Low MAIFI	CANYONLANDS	39	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	CANYONLANDS	WSW11	WESTWATER #11	78.080	1.110	0.000	0.000	70.342	100	111	2
Low MAIFI(e)	CANYONLANDS	39	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	CANYONLANDS	RAT22	RATTLESNAKE #22	156.380	0.519	0.000	0.000	301.310	800	415	9
Low Customer Minutes Lost	CANYONLANDS	28	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	CARBON			1.790	0.013	0.000	0.000	137.692	10,248	129	2
Unplanned	CARBON			70.419	0.761	0.009	0.009	92.535	10,248	7,796	62
Customer Requested	CARBON			0.000	0.000	0.000	0.000	0.000	10,248	0	0

Fiscal YTD **Fiscal Year 2002** **04/01/2001 to 06/30/2001**

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off	Number of Occurrences
High SAIDI	CARBON	FER11	FERRON #11	328.430	1.790	0.000	0.000	183.480	920	1,647	9
Low SAIDI	CARBON	29	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	CARBON	MAT12	MATHIS #12	296.604	3.878	0.000	0.000	76.484	498	1,931	6
Low SAIFI	CARBON	29	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	CARBON	CCK11	CLEAR CREEK #11	0.000	0.000	1.568	1.568	0.000	37	0	0
Low MAIFI	CARBON	44	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	CARBON	CCK11	CLEAR CREEK #11	0.000	0.000	1.568	1.568	0.000	37	0	0
Low MAIFI(e)	CARBON	44	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	CARBON	FER11	FERRON #11	328.430	1.790	0.000	0.000	183.480	920	1,647	9
Low Customer Minutes Lost	CARBON	27	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	**CEDAR CITY**			0.163	0.005	0.000	0.000	32.600	16,630	77	3
Unplanned	**CEDAR CITY**			25.277	0.330	0.007	0.007	76.597	16,630	5,484	96
Customer Requested	**CEDAR CITY**			0.006	0.000	0.000	0.000	0.000	16,630	1	1
High SAIDI	CEDAR CITY	MDD24	MIDDLETON #24	802.981	10.406	0.000	0.000	77.165	318	3,309	15
Low SAIDI	CEDAR CITY	57	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	CEDAR CITY	MDD24	MIDDLETON #24	802.981	10.406	0.000	0.000	77.165	318	3,309	15
Low SAIFI	CEDAR CITY	57	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	CEDAR CITY	CLM15	COLEMAN #15	101.500	1.780	1.560	1.560	57.022	50	89	6
Low MAIFI	CEDAR CITY	81	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	CEDAR CITY	CLM15	COLEMAN #15	101.500	1.780	1.560	1.560	57.022	50	89	6
Low MAIFI(e)	CEDAR CITY	81	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	CEDAR CITY	MDD24	MIDDLETON #24	802.981	10.406	0.000	0.000	77.165	318	3,309	15
Low Customer Minutes Lost	CEDAR CITY	55	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	**COTTONWOOD**			1.766	0.063	0.000	0.000	28.032	3,913	245	3
Unplanned	**COTTONWOOD**			294.013	2.308	0.142	0.071	127.389	3,913	9,032	37
Customer Requested	**COTTONWOOD**			0.000	0.000	0.000	0.000	0.000	3,913	0	0
High SAIDI	COTTONWOOD	DMP13	DIMPLE DELL #13	430.628	3.696	0.000	0.000	116.512	1,232	4,553	8
Low SAIDI	COTTONWOOD	DMP11	DIMPLE DELL #11	151.252	1.206	0.000	0.000	125.416	925	1,116	9
High SAIFI	COTTONWOOD	DMP13	DIMPLE DELL #13	430.628	3.696	0.000	0.000	116.512	1,232	4,553	8
Low SAIFI	COTTONWOOD	DMP11	DIMPLE DELL #11	151.252	1.206	0.000	0.000	125.416	925	1,116	9
High MAIFI	COTTONWOOD	DMP12	DIMPLE DELL #12	273.366	1.915	0.317	0.159	142.750	1,756	3,363	20
Low MAIFI	COTTONWOOD	2	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	COTTONWOOD	DMP12	DIMPLE DELL #12	273.366	1.915	0.317	0.159	142.750	1,756	3,363	20
Low MAIFI(e)	COTTONWOOD	2	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	COTTONWOOD	DMP13	DIMPLE DELL #13	430.628	3.696	0.000	0.000	116.512	1,232	4,553	8
Low Customer Minutes Lost	COTTONWOOD	DMP11	DIMPLE DELL #11	151.252	1.206	0.000	0.000	125.416	925	1,116	9
Planned	**DELTA**			0.000	0.000	0.000	0.000	0.000	5,766	0	0
Unplanned	**DELTA**			34.214	0.306	0.990	0.990	111.810	5,766	1,767	42
Customer Requested	**DELTA**			0.000	0.000	0.000	0.000	0.000	5,766	0	0
High SAIDI	DELTA	STH21	SUTHERLAND #21	225.450	2.305	1.039	1.039	97.809	462	1,065	22
Low SAIDI	DELTA	19	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	DELTA	STH21	SUTHERLAND #21	225.450	2.305	1.039	1.039	97.809	462	1,065	22
Low SAIFI	DELTA	19	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	DELTA	STH21	SUTHERLAND #21	225.450	2.305	1.039	1.039	97.809	462	1,065	22
Low MAIFI	DELTA	4	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	DELTA	STH21	SUTHERLAND #21	225.450	2.305	1.039	1.039	97.809	462	1,065	22

Fiscal YTD **Fiscal Year 2002** **04/01/2001 to 06/30/2001**

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off	Number of Occurrences
Low MAIFI(e)	DELTA	4	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	DELTA	STH21	SUTHERLAND #21	225.450	2.305	1.039	1.039	97.809	462	1,065	22
Low Customer Minutes Lost	DELTA	2	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	LAYTON			0.174	0.002	0.000	0.000	87.000	37,001	70	6
Unplanned	LAYTON			65.254	1.009	0.012	0.012	64.672	37,001	37,319	148
Customer Requested	LAYTON			0.000	0.000	0.000	0.000	0.000	37,001	0	0
High SAIDI	LAYTON	SYR15	SYRACUSE #15	49,394.000	#######	0.000	0.000	36.028	1	1,371	4
Low SAIDI	LAYTON	12	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	LAYTON	SYR15	SYRACUSE #15	49,394.000	#######	0.000	0.000	36.028	1	1,371	4
Low SAIFI	LAYTON	12	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	LAYTON	ANG14	ANGEL #14	62.155	1.575	0.167	0.167	39.463	2,050	3,228	4
Low MAIFI	LAYTON	34	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	LAYTON	ANG14	ANGEL #14	62.155	1.575	0.167	0.167	39.463	2,050	3,228	4
Low MAIFI(e)	LAYTON	34	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	LAYTON	SYR11	SYRACUSE #11	7,654.121	111.168	0.000	0.000	68.852	107	11,895	8
Low Customer Minutes Lost	LAYTON	12	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	METRO			2.478	0.015	0.000	0.000	165.200	184,202	2,814	30
Unplanned	METRO			32.412	0.359	0.136	0.136	90.284	184,202	66,186	633
Customer Requested	METRO			0.000	0.000	0.000	0.000	0.000	184,202	0	0
High SAIDI	METRO	UNI01	UNIVERSITY #1	8,327.000	111.000	0.000	0.000	75.018	1	111	1
Low SAIDI	METRO	115	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	METRO	UNI01	UNIVERSITY #1	8,327.000	111.000	0.000	0.000	75.018	1	111	1
Low SAIFI	METRO	115	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	METRO	VLY13	VALLEY CENTER #13	5.834	0.031	3.461	3.461	188.194	453	14	1
Low MAIFI	METRO	220	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	METRO	VLY13	VALLEY CENTER #13	5.834	0.031	3.461	3.461	188.194	453	14	1
Low MAIFI(e)	METRO	220	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	METRO	LPK12	LAKEPARK #12	263.723	0.971	0.000	0.000	271.599	3,065	2,975	3
Low Customer Minutes Lost	METRO	114	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	MILFORD			0.000	0.000	0.000	0.000	0.000	1,679	0	0
Unplanned	MILFORD			189.046	1.591	0.007	0.007	118.822	1,679	2,672	31
Customer Requested	MILFORD			0.000	0.000	0.000	0.000	0.000	1,679	0	0
High SAIDI	MILFORD	BKL11	BROOKLAWN #11	1,372.256	9.529	0.000	0.000	144.008	121	1,153	9
Low SAIDI	MILFORD	8	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	MILFORD	BKL11	BROOKLAWN #11	1,372.256	9.529	0.000	0.000	144.008	121	1,153	9
Low SAIFI	MILFORD	8	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	MILFORD	SML12	SOUTH MILFORD #12	5.573	0.031	0.115	0.115	179.774	96	3	3
Low MAIFI	MILFORD	18	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	MILFORD	SML12	SOUTH MILFORD #12	5.573	0.031	0.115	0.115	179.774	96	3	3
Low MAIFI(e)	MILFORD	18	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	MILFORD	BKL11	BROOKLAWN #11	1,372.256	9.529	0.000	0.000	144.008	121	1,153	9
Low Customer Minutes Lost	MILFORD	8	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	OGDEN			6.499	0.029	0.002	0.002	224.103	70,416	2,007	22
Unplanned	OGDEN			74.330	0.712	0.050	0.050	104.396	70,416	50,103	309
Customer Requested	OGDEN			0.006	0.000	0.000	0.000	0.000	70,416	9	2
High SAIDI	OGDEN	WOG12	WEST OGDEN #12	1,250.750	19.394	0.000	0.000	64.492	188	3,646	10

Fiscal YTD   Fiscal Year 2002   04/01/2001 to 06/30/2001

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off	Number of Occurrences
Low SAIDI	OGDEN	49	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	OGDEN	WOG12	WEST OGDEN #12	1,250.750	19.394	0.000	0.000	64.492	188	3,646	10
Low SAIFI	OGDEN	49	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	OGDEN	NOG12	NORTH OGDEN #12	15.648	0.132	1.070	1.070	118.545	2,000	264	8
Low MAIFI	OGDEN	99	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	OGDEN	NOG12	NORTH OGDEN #12	15.648	0.132	1.070	1.070	118.545	2,000	264	8
Low MAIFI(e)	OGDEN	99	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	OGDEN	BRK11	BRICKYARD #11	514.345	1.943	0.000	0.000	264.717	1,306	2,537	6
Low Customer Minutes Lost	OGDEN	49	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	**PARK CITY**			2.077	0.011	0.000	0.000	188.818	16,060	177	2
Unplanned	**PARK CITY**			81.703	0.659	0.003	0.003	123.980	16,060	10,579	119
Customer Requested	**PARK CITY**			0.000	0.000	0.000	0.000	0.000	16,060	0	0
High SAIDI	PARK CITY	DSR11	DESERET #11	411.000	1.000	0.000	0.000	411.000	1	1	1
Low SAIDI	PARK CITY	12	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	PARK CITY	JUD12	JUDGE #12	251.583	4.750	3.167	3.167	52.965	12	57	3
Low SAIFI	PARK CITY	12	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	PARK CITY	JUD12	JUDGE #12	251.583	4.750	3.167	3.167	52.965	12	57	3
Low MAIFI	PARK CITY	33	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	PARK CITY	JUD12	JUDGE #12	251.583	4.750	3.167	3.167	52.965	12	57	3
Low MAIFI(e)	PARK CITY	33	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	PARK CITY	OKY11	OAKLEY #11	405.549	1.923	0.000	0.000	210.894	1,936	3,722	28
Low Customer Minutes Lost	PARK CITY	12	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	**SALINA**			0.268	0.002	0.000	0.000	134.000	13,236	24	1
Unplanned	**SALINA**			44.883	0.324	0.014	0.014	138.528	13,236	4,295	76
Customer Requested	**SALINA**			0.000	0.000	0.000	0.000	0.000	13,236	0	0
High SAIDI	SALINA	CTL11	CENTRAL #11	572.556	5.172	0.000	0.000	110.703	99	512	5
Low SAIDI	SALINA	43	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	SALINA	CTL11	CENTRAL #11	572.556	5.172	0.000	0.000	110.703	99	512	5
Low SAIFI	SALINA	43	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	SALINA	SCI11	SCIPIO #11	269.797	2.087	1.000	1.000	129.275	172	359	3
Low MAIFI	SALINA	66	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	SALINA	SCI11	SCIPIO #11	269.797	2.087	1.000	1.000	129.275	172	359	3
Low MAIFI(e)	SALINA	66	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	SALINA	GUN12	GUNNISON #12	524.454	1.233	0.000	0.000	425.348	339	418	5
Low Customer Minutes Lost	SALINA	43	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	**SMITHFIELD**			0.013	0.000	0.000	0.000	0.000	13,148	4	1
Unplanned	**SMITHFIELD**			131.240	1.713	0.068	0.068	76.614	13,148	22,526	139
Customer Requested	**SMITHFIELD**			0.000	0.000	0.000	0.000	0.000	13,148	0	0
High SAIDI	SMITHFIELD	LEW11	LEWISTON #11	695.575	6.176	0.000	0.000	112.625	306	1,890	12
Low SAIDI	SMITHFIELD	5	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	SMITHFIELD	AMA11	AMALGA #11	271.423	12.960	0.000	0.000	20.943	227	2,942	7
Low SAIFI	SMITHFIELD	5	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	SMITHFIELD	AMA14	AMALGA #14	67.519	1.706	0.894	0.894	39.577	293	500	8
Low MAIFI	SMITHFIELD	21	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	SMITHFIELD	AMA14	AMALGA #14	67.519	1.706	0.894	0.894	39.577	293	500	8
Low MAIFI(e)	SMITHFIELD	21	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				

Fiscal YTD   Fiscal Year 2002   04/01/2001 to 06/30/2001

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off	Number of Occurrences
High Customer Minutes Lost	**SMITHFIELD**	NIB21	NIBLEY #21	300.572	2.520	0.000	0.000	119.275	2,346	5,911	15
Low Customer Minutes Lost	**SMITHFIELD**	5	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	**SOUTH VALLEY**			0.701	0.008	0.000	0.000	87.625	153,028	1,193	24
Unplanned	**SOUTH VALLEY**			51.007	0.706	0.092	0.092	72.248	153,028	108,041	581
Customer Requested	**SOUTH VALLEY**			0.000	0.000	0.000	0.000	0.000	153,028	0	0
High SAIDI	**SOUTH VALLEY**	90S12	90TH SOUTH #12	36,470.000	#######	0.000	0.000	34.933	1	1,044	1
Low SAIDI	**SOUTH VALLEY**	32	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	**SOUTH VALLEY**	90S12	90TH SOUTH #12	36,470.000	#######	0.000	0.000	34.933	1	1,044	1
Low SAIFI	**SOUTH VALLEY**	33	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	**SOUTH VALLEY**	MDV12	MIDVALE #12	121.432	0.297	4.734	4.734	408.862	458	136	2
Low MAIFI	**SOUTH VALLEY**	99	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	**SOUTH VALLEY**	MDV12	MIDVALE #12	121.432	0.297	4.734	4.734	408.862	458	136	2
Low MAIFI(e)	**SOUTH VALLEY**	99	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	**SOUTH VALLEY**	BLF13	BLUFFDALE #13	418.368	5.814	0.002	0.002	71.959	1,323	7,692	11
Low Customer Minutes Lost	**SOUTH VALLEY**	31	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	**TOOELE**			0.697	0.005	0.000	0.000	139.400	9,368	44	1
Unplanned	**TOOELE**			262.949	1.889	0.923	0.923	139.200	9,368	17,698	80
Customer Requested	**TOOELE**			0.000	0.000	0.000	0.000	0.000	9,368	0	0
High SAIDI	**TOOELE**	STN13	STANSBURY #13	1,836.009	4.034	0.000	0.000	455.134	325	1,311	5
Low SAIDI	**TOOELE**	14	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	**TOOELE**	TOO11	TOOELE #11	747.515	4.415	0.000	0.000	169.313	511	2,256	6
Low SAIFI	**TOOELE**	14	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	**TOOELE**	TOO13	TOOELE #13	136.692	2.420	2.651	2.651	56.484	3,260	7,889	10
Low MAIFI	**TOOELE**	25	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	**TOOELE**	TOO13	TOOELE #13	136.692	2.420	2.651	2.651	56.484	3,260	7,889	10
Low MAIFI(e)	**TOOELE**	25	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	**TOOELE**	STN13	STANSBURY #13	1,836.009	4.034	0.000	0.000	455.134	325	1,311	5
Low Customer Minutes Lost	**TOOELE**	14	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	**TREMONTON**			0.205	0.002	0.000	0.000	102.500	6,424	16	2
Unplanned	**TREMONTON**			48.007	0.418	0.000	0.000	114.849	6,424	2,683	53
Customer Requested	**TREMONTON**			0.000	0.000	0.000	0.000	0.000	6,424	0	0
High SAIDI	**TREMONTON**	BRR14	BEAR RIVER #14	235.501	1.415	0.000	0.000	166.432	349	494	4
Low SAIDI	**TREMONTON**	9	***** circuits with Low SAIDI of 0.000 *****	0.000							
High SAIFI	**TREMONTON**	BRR12	BEAR RIVER #12	205.146	2.886	0.000	0.000	71.083	219	632	6
Low SAIFI	**TREMONTON**	9	***** circuits with Low SAIFI of 0.000 *****		0.000						
High MAIFI	**TREMONTON**	WSH01	WASHAKIE #1	0.000	0.000	0.000	0.000	0.000	1	0	0
Low MAIFI	**TREMONTON**	22	***** circuits with Low MAIFI of 0.000 *****			0.000					
High MAIFI(e)	**TREMONTON**	WSH01	WASHAKIE #1	0.000	0.000	0.000	0.000	0.000	1	0	0
Low MAIFI(e)	**TREMONTON**	22	***** circuits with Low MAIFI(e) of 0.000 *****				0.000				
High Customer Minutes Lost	**TREMONTON**	FDG11	FIELDING #11	188.996	1.600	0.000	0.000	118.123	558	893	9
Low Customer Minutes Lost	**TREMONTON**	9	***** circuits with Low Customer Minutes Lost of 0.000 *****								
Planned	**UINTA**			0.000	0.000	0.000	0.000	0.000	2	0	0
Unplanned	**UINTA**			0.000	0.000	0.000	0.000	0.000	2	0	0
Customer Requested	**UINTA**			0.000	0.000	0.000	0.000	0.000	2	0	0
High SAIDI	**UINTA**	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0
Low SAIDI	**UINTA**	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0

Fiscal YTD **Fiscal Year 2002** **04/01/2001 to 06/30/2001**

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	CAIDI	Average Customer Count	Customers Off	Number of Occurrences
High SAIFI	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0
Low SAIFI	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0
High MAIFI	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0
Low MAIFI	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0
High MAIFI(e)	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0
Low MAIFI(e)	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0
High Customer Minutes Lost	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0
Low Customer Minutes Lost	UINTA	D029	PAINTER-CLEAR CREEK-138KV	0.000	0.000	0.000	0.000	0.000	2	0	0

Attachment B
Service Quality Standards
1st Quarter Fiscal 2002
Worst Performing Feeders

Five worst feeders - North

Circuit	Circuit Name	12 Mo. Rolling Average Circuit SAIDI	Annual Goal SAIDI	12 Mo. Rolling Average Circuit SAIFI	Annual Goal SAIFI	12 Mo. Rolling Average Circuit MAIFI	Annual Goal MAIFI	Location of Circuit	Corrective Action
WDS11	WOODS CROSS #11	290.289	1.126	1.720	1.250	4.390	6.221	Metro	Under Investigation
EDN11	EDEN #11	446.031	1.126	2.572	1.250	0.000	6.221	Ogden	Under Investigation
BTH11	BOTHWELL #11	0.353	1.126	0.007	1.250	2.000	6.221	Tremonton	Under Investigation
JOR04	JORDAN #4	500.261	1.126	2.870	1.250	5.000	6.221	Metro	Under Investigation
SNO11	SNOWVILLE #11	434.000	1.126	5.263	1.250	7.000	6.221	Tremonton	Under Investigation

Six worst feeders - South

Circuit	Circuit Name	12 Mo. Rolling Average Circuit SAIDI	Annual Goal SAIDI	12 Mo. Rolling Average Circuit SAIFI	Annual Goal SAIFI	12 Mo. Rolling Average Circuit MAIFI	Annual Goal MAIFI	Location of Circuit	Corrective Action
RAT22	RATTLESNAKE #22	508.731	1.126	3.724	1.250	3.000	6.221	Canyonlands	Under Investigation
LRK11	LARK #11	750.594	1.126	1.419	1.250	7.000	6.221	South Valley	Under Investigation
MDD24	MIDDLETON #24	1060.236	1.126	13.503	1.250	22.000	6.221	Cedar City	Under Investigation
WIT11	WHITE MESA #11	561.381	1.126	3.357	1.250	13.054	6.221	Canyonlands	Under Investigation
CLM15	COLEMAN #15	465.260	1.126	4.880	1.250	3.560	6.221	Cedar City	Under Investigation
SML11	SOUTH MILFORD #11	1291.767	1.126	14.467	1.250	4.000	6.221	Milford	Under Investigation

Attachment B
Service Quality Standards
1st Quarter Fiscal 2002
Worst Performing Feeders

Five worst feeders - North

Circuit	Circuit Name	YTD Average Circuit SAIDI	Annual Goal SAIDI	YTD Circuit SAIFI	Annual Goal SAIFI	YTD Circuit MAIFI	Annual Goal MAIFI	Location of Circuit	Corrective Action
WDS11	WOODS CROSS #11	53.411	1.126	0.214	1.250	0.390	6.221	Metro	Under Investigation
EDN11	EDEN #11	84.054	1.126	0.719	1.250	0.000	6.221	Ogden	Under Investigation
BTH11	BOTHWELL #11	0.000	1.126	0.000	1.250	0.000	6.221	Tremonton	Under Investigation
JOR04	JORDAN #4	7.913	1.126	0.043	1.250	0.000	6.221	Metro	Under Investigation
SNO11	SNOWVILLE #11	46.895	1.126	0.579	1.250	0.000	6.221	Tremonton	Under Investigation

Six worst feeders - South

Circuit	Circuit Name	YTD Average Circuit SAIDI	Annual Goal SAIDI	YTD Circuit SAIFI	Annual Goal SAIFI	YTD Circuit MAIFI	Annual Goal MAIFI	Location of Circuit	Corrective Action
RAT22	RATTLESNAKE #22	156.380	1.126	0.519	1.250	0.000	6.221	Canyonlands	Under Investigation
LRK11	LARK #11	693.796	1.126	0.998	1.250	0.000	6.221	South Valley	Under Investigation
MDD24	MIDDLETON #24	802.981	1.126	10.406	1.250	0.000	6.221	Cedar City	Under Investigation
WIT11	WHITE MESA #11	0.000	1.126	0.000	1.250	0.000	6.221	Canyonlands	Under Investigation
CLM15	COLEMAN #15	101.500	1.126	1.780	1.250	1.560	6.221	Cedar City	Under Investigation
SML11	SOUTH MILFORD #11	434.900	1.126	5.100	1.250	0.000	6.221	Milford	Under Investigation

Customer Service Commitments

UTAH FAILURES April-June 2001

American Fork	CG #	Description	1st Qtr	Paid
	CG4	Estimates	15	$750
		Total	**15**	**$750**

Cedar City	CG #	Description	1st Qtr	Paid
	CG3	Switching on Power	1	$175
	CG4	Estimates	1	$50
		Total	**2**	**$225**

Jordan Valley	CG #	Description	1st Qtr	Paid
	CG2	Appointments	1	$50
	CG3	Switching on Power	2	$125
	CG4	Estimates	4	$200
	CG5	Respond to Billing Inquiries	2	$100
	CG7	Notification of Planned	3	$150
		Total	**12**	**$625**

Laketown	CG #	Description	1st Qtr	Paid
	CG4	Estimates	1	$50
		Total	**1**	**$50**

Layton	CG #	Description	1st Qtr	Paid
	CG3	Switching on Power	2	$175
	CG5	Respond to Billing Inquiries	1	$50
		Total	**3**	**$225**

Park City	CG #	Description	1st Qtr	Paid
	CG4	Estimates	1	$50
		Total	**1**	**$50**

Price	CG #	Description	1st Qtr	Paid
	CG4	Estimates	1	$50
		Total	**1**	**$50**

UTAH FAILURES April-June 2001

Richfield	CG #	Description	1st Qtr	Paid
	CG4	Estimates	1	$50
		Total	**1**	**$50**

Santaquin	CG #	Description	1st Qtr	Paid
	CG4	Estimates	1	$50
		Total	**1**	**$50**

SLC Metro	CG #	Description	1st Qtr	Paid
	CG2	Appointments	1	$50
	CG3	Switching on Power	7	$825
	CG4	Estimates	1	$50
	CG5	Respond to Billing Inquiries	1	$50
	CG7	Notification of Planned	7	$350
		Total	**17**	**$1,325**

Tooele	CG #	Description	1st Qtr	Paid
	CG2	Appointments	1	$50
	CG4	Estimates	1	$50
		Total	**2**	**$100**

Tremonton	CG #	Description	1st Qtr	Paid
	CG4	Estimates	3	$150
		Total	**3**	**$150**

Vernal	CG #	Description	1st Qtr	Paid
	CG7	Notification of Planned	1	$100
		Total	**1**	**$100**

State Total	**60**	**$3,750**

UTAH RESIDENTIAL/SMALL COMMERCIAL METER SETS - REPORT BY DISTRICT

FISCAL YEAR TO DATE - 1ST QUARTER 2002

NORTHERN UTAH

LOCATION	April 2001			May 2001			June 2001			FYD - 1st Quarter			Notes
	Within 5 Days	%	Total	Within 5 Days	%	Total	Within 5 Days	%	Total	Total Within 5 Days	1st Quarter %	Total	
Jordan Valley	338	97%	347	446	99%	450	320	98%	327	1104	98%	1124	
Layton/Davis	159	98%	163	86	100%	86	131	91%	144	376	96%	393	
Metro	279	99%	283	253	100%	254	237	99%	240	769	99%	777	
Ogden	117	100%	117	118	99%	119	137	100%	137	372	100%	373	
Park City	30	97%	31	48	98%	49	68	94%	72	146	96%	152	
Smithfield	32	97%	33	39	100%	39	28	100%	28	99	99%	100	
Tooele	41	100%	41	61	98%	62	46	96%	48	148	98%	151	
Tremonton	6	100%	6	13	100%	13	17	100%	17	36	100%	36	
TOTAL	1002	98%	1021	1064	99%	1072	984	97%	1013	3050	98%	3106	

SOUTHERN UTAH

LOCATION	April 2001			May 2001			June 2001			FYD - 1st Quarter			Notes
	Within 5 days	%	Total	Within 5 days	%	Total	Within 5 days	%	Total	Total Within 5 Days	1st Quarter %	Total	
American Fork	114	99%	115	163	100%	163	153	100%	153	430	100%	431	
Cedar City	44	98%	45	60	100%	60	38	100%	38	142	99%	143	
Moab	17	100%	17	14	100%	14	22	100%	22	53	100%	53	
Price	7	78%	9	9	100%	9	14	100%	14	30	94%	32	Customers partly responsible for April delay
Richfield	45	100%	45	26	100%	26	32	100%	32	103	100%	103	
Santaquin	17	100%	17	27	100%	27	18	100%	18	62	100%	62	
Vernal	14	100%	14	16	100%	16	11	100%	11	41	100%	41	
TOTAL	258	98%	262	315	100%	315	288	100%	288	861	100%	865	

TOTAL UTAH

LOCATION	APRIL			MAY			JUNE			FYD - 1st Quarter			Notes
	Within 5 days	%	Total	Within 5 days	%	Total	Within 5 days	%	Total	Total Within 5 Days	1st Quarter %	Total	
TOTAL UTAH	1260	98%	1283	1379	99%	1387	1272	98%	1301	3911	98%	3971	

UTAH TEMPORARY METER SETS - REPORT BY DISTRICT

FISCAL YEAR TO DATE - 1st QUARTER 2002

NORTHERN UTAH

LOCATION	April 2001			May 2001			June 2001			FYD - 1st Quarter			Notes
	Within 10 Days	%	Total	Within 10 Days	%	Total	Within 10 Days	%	Total	Total Within 10 Days	1st Quarter %	Total	
Jordan Valley	167	97%	172	224	100%	225	210	100%	211	601	99%	608	
Layton/Davis	81	94%	86	85	97%	88	129	100%	129	295	97%	303	
Metro	82	100%	82	62	100%	62	92	100%	92	236	100%	236	
Ogden	119	100%	119	149	100%	149	112	100%	112	342	90%	380	
Park City	22	100%	22	39	100%	39	35	100%	35	96	100%	96	
Smithfield	36	100%	36	28	100%	28	18	100%	18	82	100%	82	
Tooele	35	100%	35	36	100%	36	39	100%	39	110	100%	110	
Tremonton	11	100%	11	9	100%	9	4	100%	4	24	100%	24	
TOTAL	553	98%	563	632	99%	636	639	100%	640	1824	99%	1839	

SOUTHERN UTAH

LOCATION	April 2001			May 2001			June 2001			FYD - 1st Quarter			Notes
	Within 10 days	%	Total	Within 10 days	%	Total	Within 10 days	%	Total	Total Within 10 Days	1st Quarter %	Total	
American Fork	105	99%	106	124	100%	124	113	100%	113	342	100%	343	
Cedar City	36	100%	36	43	100%	43	25	100%	25	104	100%	104	
Moab	0		0	1	100%	1	1	100%	1	2	100%	2	
Price	1	100%	1	3	100%	3	1	100%	1	5	100%	5	
Richfield	6	100%	6	5	100%	5	6	100%	6	17	100%	17	
Santaquin	14	100%	14	11	100%	11	15	100%	15	40	100%	40	
Vernal	2	100%	2	4	100%	4	1	100%	1	7	100%	7	
TOTAL	164	99%	165	191	100%	191	162	100%	162	517	100%	518	

TOTAL UTAH

LOCATION	APRIL			MAY			JUNE			FYD - 1st Quarter			Notes
	Within 10 days	%	Total	Within 10 days	%	Total	Within 10 days	%	Total	Total Within 10 Days	1st Quarter %	Total	
TOTAL UTAH	717	98%	728	823	100%	827	801	100%	802	2341	99%	2357	

Customer Service Commitments

UTAH CONNECTS/RECONNECTS April-June 2001

CG3 Events by District

DISTRICT	1st Quarter
American Fork	761
Cedar City	248
Jordan Valley	1572
Laketown	34
Layton	478
Moab	106
Ogden	1365
Park City	120
Price	93
Richfield	132
SLC Metro	3242
Smithfield	160
Tooele	256
Tremonton	116
Vernal	66
All Districts	**8749**

Customer Service Commitments

UTAH GUARANTEE FIELD RESPONSE PERFORMANCE April - June 2001

American Fork	*Description*	# Guaranteed Customer Requests	Average # Days to Respond
CG4a	Estimates - Contact within 2 days	101	1
CG4b	Estimates - 5 days	13	0
CG4c	Estimates - 15 days	81	13
CG5	Responding to Bill Inquiries within 10 days	100	5
CG6	Responding to Meter Problems within 15 days	11	10

Cedar City	*Description*	# Guaranteed Customer Requests	Average # Days to Respond
CG4a	Estimates - Contact within 2 days	132	1
CG4b	Estimates - 5 days	66	0
CG4c	Estimates - 15 days	69	4
CG5	Responding to Bill Inquiries within 10 days	77	5
CG6	Responding to Meter Problems within 15 days	7	4

Jordan Valley	*Description*	# Guaranteed Customer Requests	Average # Days to Respond
CG4a	Estimates - Contact within 2 days	171	1
CG4b	Estimates - 5 days	75	1
CG4c	Estimates - 15 days	93	9
CG5	Responding to Bill Inquiries within 10 days	408	5
CG6	Responding to Meter Problems within 15 days	17	6

UTAH GUARANTEE FIELD RESPONSE PERFORMANCE April - June 2001

Laketown	*Description*	# Guaranteed Customer Requests	Average # Days to Respond
	CG4a Estimates - Contact within 2 days	14	1
	CG4b Estimates - 5 days	1	0
	CG4c Estimates - 15 days	8	1
	CG5 Responding to Bill Inquiries within 10 days	15	4
	CG6 Responding to Meter Problems within 15 days	1	12

Layton	*Description*	# Guaranteed Customer Requests	Average # Days to Respond
	CG4a Estimates - Contact within 2 days	41	1
	CG4b Estimates - 5 days	16	0
	CG4c Estimates - 15 days	25	8
	CG5 Responding to Bill Inquiries within 10 days	97	5
	CG6 Responding to Meter Problems within 15 days	9	7

Moab	*Description*	# Guaranteed Customer Requests	Average # Days to Respond
	CG4a Estimates - Contact within 2 days	33	5*
	CG4b Estimates - 5 days	12	1
	CG4c Estimates - 15 days	18	7
	CG5 Responding to Bill Inquiries within 10 days	30	3
	CG6 Responding to Meter Problems within 15 days	2	6

*One request in Moab with a response of 61 days resulted when, after repeated attempts by Utah Power to make contact, the customer finally called back more than 2 months later. Another request took 58 days until response due to a mishandled request, resulting in a failure payment.

UTAH GUARANTEE FIELD RESPONSE PERFORMANCE April - June 2001

Ogden	*Description*	# Guaranteed Customer Requests	Average # Days to Respond
	CG4a Estimates - Contact within 2 days	109	1
	CG4b Estimates - 5 days	27	2
	CG4c Estimates - 15 days	94	5
	CG5 Responding to Bill Inquiries within 10 days	178	5
	CG6 Responding to Meter Problems within 15 days	10	8

Park City	*Description*	# Guaranteed Customer Requests	Average # Days to Respond
	CG4a Estimates - Contact within 2 days	69	1
	CG4b Estimates - 5 days	1	0
	CG4c Estimates - 15 days	30	3
	CG5 Responding to Bill Inquiries within 10 days	89	6
	CG6 Responding to Meter Problems within 15 days	4	7

Price	*Description*	# Guaranteed Customer Requests	Average # Days to Respond
	CG4a Estimates - Contact within 2 days	16	1
	CG4c Estimates - 15 days	29	3
	CG5 Responding to Bill Inquiries within 10 days	25	6
	CG6 Responding to Meter Problems within 15 days	1	10

Richfield	*Description*	# Guaranteed Customer Requests	Average # Days to Respond
	CG4a Estimates - Contact within 2 days	78	2
	CG4b Estimates - 5 days	21	1
	CG4c Estimates - 15 days	49	6
	CG5 Responding to Bill Inquiries within 10 days	33	5
	CG6 Responding to Meter Problems within 15 days	5	10

SLC Metro	*Description*	# Guaranteed Customer Requests	Average # Days to Respond
	CG4a Estimates - Contact within 2 days	133	1
	CG4b Estimates - 5 days	33	1
	CG4c Estimates - 15 days	75	7
	CG5 Responding to Bill Inquiries within 10 days	654	5
	CG6 Responding to Meter Problems within 15 days	21	6

Smithfield	*Description*	# Guaranteed Customer Requests	Average # Days to Respond
	CG4a Estimates - Contact within 2 days	63	1
	CG4b Estimates - 5 days	7	0
	CG4c Estimates - 15 days	43	3
	CG5 Responding to Bill Inquiries within 10 days	32	4

Tooele	*Description*	# Guaranteed Customer Requests	Average # Days to Respond
	CG4a Estimates - Contact within 2 days	31	2
	CG4b Estimates - 5 days	12	0
	CG4c Estimates - 15 days	28	8
	CG5 Responding to Bill Inquiries within 10 days	21	4
	CG6 Responding to Meter Problems within 15 days	4	13

Tremonton	*Description*	# Guaranteed Customer Requests	Average # Days to Respond
	CG4a Estimates - Contact within 2 days	47	1
	CG4b Estimates - 5 days	6	1
	CG4c Estimates - 15 days	32	9
	CG5 Responding to Bill Inquiries within 10 days	17	5

Vernal	*Description*	# Guaranteed Customer Requests	Average # Days to Respond
	CG4a Estimates - Contact within 2 days	28	0
	CG4b Estimates - 5 days	1	0
	CG4c Estimates - 15 days	26	0
	CG5 Responding to Bill Inquiries within 10 days	10	5
	CG6 Responding to Meter Problems within 15 days	1	14

Customer Service Commitments

UTAH OUTAGE RESTORATION PERFORMANCE — April-June 2001

District	# Customers Interrupted > 5 minutes	% Restored Within 3 Hours
American Fork	29,152	91%
Cedar City	8,156	91%
Jordan Valley	117,073	91%
Layton	37,319	95%
Moab	1,300	71%[1]
Ogden	50,103	82%
Park City	10,579	73%[2]
Price	7,796	89%
Richfield	6,062	80%
SLC Metro	66,186	89%
Smithfield	23,165	93%
Tooele	17,698	70%[3]
Tremonton	2,683	66%[4]
Vernal	6,418	74%[1]
All Districts	**383,690**	**88%**

Notes:

1. Performance was affected in Moab, Park City and Vernal due to large coverage areas, difficult terrain and the nature of the outages requiring pole replacements.

2. Further investigation of Park City outages identified data entry errors in a closed system which, had the errors not been made, would have resulted in a performance level better than 80%.

3. Performance in Tooele was impacted by 3 extended outages caused by animals in the substation, multi-pole damage due to fire, and malfunctioning substation equipment.

4. Performance in Tremonton was affected by a single outage involving the failure of special equipment.

Customer Service Commitments

UTAH-Non-Guarantee April - June 2001

FIELD RESPONSE PERFORMANCE

DISTRICT	Count of Field Requests	Average # Days to Respond
American Fork	81	2
Cedar City	129	5
Jordan Valley	353	7
Laketown	3	1
Layton	308	2
Moab	20	21
Ogden	340	9
Park City	34	5
Price	18	5
Richfield	27	5
SLC Metro	369	11
Smithfield	55	9
Tooele	66	14
Tremonton	23	6
Valley West	4	3
Vernal	9	6

Utah - Total Requests **1839**

Customer Service Commitments

UTAH Non-Guarantee

April - June 2001

Tree Trimming

DISTRICT	Count of Tree Trim Requests
American Fork	91
Cedar City	11
Davis (Layton)	57
Jordan Valley	370
Moab	9
Ogden	195
Park City	11
Price	40
Richfield	26
SLC Metro	689
Smithfield	20
Tooele	27
Tremonton	9
Vernal	17
All Districts	1,572

1900 S.W. 4th Ave.
Portland, Oregon 97201

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UTAH PUBLIC SERVICE COMMISSION

July 12, 2001

REVIEWED BY COMMISSIONERS
STEPHEN F. MECHAM SFM 7/26/01
CONSTANCE B. WHITE CBW 7/23
RICHARD M. CAMPBELL RC

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

Attn: Julie Orchard

RE: PacifiCorp Major Event Report – No. 2

Pursuant to Merger Condition 31, the Company is claiming a "major event" exclusion for the windstorm, which occurred beginning June 12 and ending June 14, 2001 throughout Northern Utah. The basis for this exemption is primarily the extensive damage that occurred to PacifiCorp's facilities as a result of the thunderstorm that moved through the area and the number of customers impacted by this event. PacifiCorp will exclude outage information during this event from the "normal" SAIDI, SAIFI and MAIFI reporting and from customer guarantee failure payments.

The "major event" affected 133,000 customers overall, or more than 21% of the customers in the five Utah operating districts impacted for a total of 37,505,324 sustained customer minutes lost. Attached you will find details regarding the major event including details on the number of customers off supply and the SAIDI, SAIFI, MAIFI figures.

If you require further information regarding this report, please contact me at (503) 813-7408.

Sincerely,

Carole Rockney

Carole Rockney, Director
Customer and Regulatory Liaison

C: Mark Flandro, DPU
Bob Maloney, DPU
Rea Peterson, DPU

Enclosure

Report to the Utah Public Service Commission
Major Event Report

Date of Exclusion:	June 12 through 14, 2001
Location:	Wasatch Front, Utah
Exclude from Reporting Statistics:	Yes
Report Prepared by:	Rick L. Bielby, SE Wires Director

Major Event Filing:
Outages took place in PacifiCorp's American Fork, Metro, Ogden, South Valley and Tooele operating districts starting on Tuesday, June 12 and continuing through Thursday, June 14 as a result of a fierce and fast moving thunderstorm that whipped through Northern Utah. Considering the number of customers involved and damage to PacifiCorp's facilities, PacifiCorp is designating this storm and its consequences as a "Major Event."

Event Description:
The severe storm began in Ogden, Utah, and moved south along the Wasatch Front and through Tooele. It began late in the afternoon at approximately 4:30 p.m. and most locations along the Wasatch Front were pounded by fierce winds, microbursts, rain, and in some places snow. Winds whipped through the area at 80 miles per hour, snapping arms off poles like they were twigs, uprooting trees and felling power poles and lines. Twenty-five power poles were sheared off just a few feet from the ground in Skull Valley, Utah and over more than two miles of conductor had to be replaced. Records indicate 104 circuit breakers locked out, affecting customers throughout the region. More than 133,000 customers were affected by the outage. Our employees were kept on shift 24 hours a day until all customers were restored. Contract crews were also brought in to aid the restoration process. A Salt Lake City transmission crew was dispatched to Richfield to help restore the Sigurd-Sevier 138kV line. Three structures were down there and needed to be replaced.

The Salt Lake Regional Emergency Action Center and four Utah Emergency Acton Centers were activated to help direct activities to restore power during the outage.

Duration and Customers Out:

	Customer Analysis					Customers Restored by Intervals				
	Sustained Customers Off	Average Customer Count	% Sustained Customers Off	CML	Number of Sustained Interruptions	5 Minutes or Less (Momentary)	> 5 Minutes and <3 Hours	>= 3 Hours and <= 24 Hours	> 24 Hours	% Sustained Customers Restored in Less Than 3 Hours
UTAH	133,562	621,991	21%	37,505,324	324	15,517	64,981	50,799	293	56%
AMERICAN FORK	11,901	37,001	32%	4,402,938	50	4,080	7,684	6,157	0	56%
METRO	66,187	184,202	36%	14,432,803	145	10,137	31,345	18,548	186	63%
OGDEN	12,594	70,416	18%	3,766,835	15	0	833	2,797	0	23%
SOUTH VALLEY	37,553	146,769	26%	12,230,599	108	1,271	25,119	18,330	107	58%
TOOELE	5,327	9,368	57%	2,672,149	6	29	0	4,967	0	0%

Number of Crews, Servicemen, etc. Assigned at Various Intervals:

17 company crews
12 contract crews
8 tree crews
32 Servicemen / Troubleshooters
17 dedicated Damage Assessors
All Construction and Field Ops Management with the Region

Utah Storm 6/12/2001 - 06/14/2001

	Cause Analysis			
	Direct Cause Category Code	Direct Cause Category	Customer Minutes Lost for Incident	Customers in Incident Sustained
AMERICAN FORK	00	Environment	4,380,851	11,770
AMERICAN FORK	01	Weather	22,087	131
AMERICAN FORK	03	Equipment Failure	0	0
AMERICAN FORK	09	Trees	0	0
			4,402,938	**11,901**
METRO	00	Environment	12,167,232	49,125
METRO	01	Weather	2,193,821	16,876
METRO	03	Equipment Failure	29,821	91
METRO	09	Trees	41,929	95
			14,432,803	**66,187**
OGDEN	00	Environment	2,012,009	9,335
OGDEN	01	Weather	1,754,826	3,259
OGDEN	03	Equipment Failure	0	0
OGDEN	09	Trees	0	0
			3,766,835	**12,594**
SOUTH VALLEY	00	Environment	11,944,035	36,934
SOUTH VALLEY	01	Weather	277,904	511
SOUTH VALLEY	03	Equipment Failure	0	0
SOUTH VALLEY	09	Trees	8,660	108
			12,230,599	**37,553**
TOOELE	00	Environment	2,665,297	5,291
TOOELE	01	Weather	6,852	36
TOOELE	03	Equipment Failure	0	0
TOOELE	09	Trees	0	0
			2,672,149	**5,327**

June 1, 2001 through June 14, 2001

	Major Events Included			Major Events Excluded		
	SAIDI	SAIFI	MAIFI	SAIDI	SAIFI	MAIFI
UTAH	88.583	0.473	0.052	28.158	0.258	0.027
AMERICAN FORK	78.929	0.299	0.108	9.637	0.112	0.044
METRO	122.781	0.676	0.132	24.488	0.225	0.063
OGDEN	83.686	0.361	0.044	30.192	0.182	0.044
SOUTH VALLEY	666.996	3.666	0.049	227.773	2.317	0.003
TOOELE	298.951	0.658	0.003	13.709	0.090	0.000

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Portland, Oregon 97232
(503) 464-5000

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UTAH PUBLIC SERVICE COMMISSION

REVIEWED BY COMMISSIONERS
STEPHEN F. MECHAM ____
CONSTANCE B. WHITE CBW 6/13
RICHARD M. CAMPBELL ____

PACIFICORP
PACIFIC POWER UTAH POWER

May 30, 2001

Utah Public Service Commission
Heber M. Wells Building
160 East 300 South
Salt Lake City, UT 84110

ATTN: Ms. Julie Orchard

Re: Docket No. 98-2035-04

Dear Commissioners:

As required by Section 54-4-27 of the Utah Public Utilities Code, under separate cover PacifiCorp has given notice to the Commission of the declaration of a dividend on its common stock aggregating $80,277,643.08.

In connection with that dividend and pursuant to Condition 15 in the July 28, 1999 Stipulation included in the above matter, PacifiCorp hereby files a summary of its cash flows for the year ended March 31, 2001.

PacifiCorp believes that the attached summary shows that the dividend will not adversely affect PacifiCorp's ability to meet its service obligations in the State of Utah. In addition, the undersigned officer of PacifiCorp hereby certifies that PacifiCorp has adequate capital to meet all of its commitments and public service obligations in the State of Utah. It should be understood that these statements concerning PacifiCorp's ability to meet its obligations are subject to various risks and uncertainties, including actions taken by the utility commissions that regulate its rates, and are qualified in that respect.

If there are questions concerning this matter, please contact me at (503) 813-7205.

Very truly yours,

PACIFICORP

By: Karen Clark
Title: Senior Vice President and Chief Financial Officer

Attachment: Cash Flow Summary

Utah Dividend Cert feb 01

PacifiCorp

CONSOLIDATED STATEMENT OF CASH FLOWS

FOR THE TWELVE MONTHS ENDED MARCH 31, 2001

(in thousands of dollars)

OPERATING ACTIVITIES		
Net loss	$	(88.2)
Adjustment to reconcile net loss to net cash provided by operating activities		
Depreciation and amortization		429.0
Deferred income tax & investment tax credits		(26.4)
Interest capitalized - equity funds		(4.4)
ScottishPower merger accrued liabilities		(5.9)
Regulatory asset establishment - net		(35.1)
Loss on sale or impairment of assets		189.2
Deferred power costs		(137.5)
Other		(44.8)
Accounts receivable and prepayments		(161.8)
Materials, supplies and inventory		(9.3)
Accounts payable and accrued liabilities		543.8
Net cash provided by continuing operations		648.6
Net cash provided by discontinued operations		-
CASH FLOWS PROVIDED BY OPERATING ACTIVITIES		648.6
INVESTING ACTIVITIES		
Construction		(485.7)
Proceeds from sale of finance assets and principal payments		48.5
ScottishPower note receivable		(356.0)
Proceeds from sale of assets		1,010.0
Other		11.1
CASH FLOWS PROVIDED BY INVESTING ACTIVITIES		227.9
FINANCING ACTIVITIES		
Changes in short-term debt		131.5
Proceeds from long term debt		1,114.0
Dividends paid		(347.7)
Repayments of long-term debt		(1,787.0)
Redemptions of preferred stock		-
Other		(2.1)
CASH FLOWS USED IN FINANCING ACTIVITIES		(891.3)
DECREASE IN CASH AND CASH EQUIVALENTS	$	(14.8)

25185

State of Utah
DEPARTMENT OF COMMERCE
Internet Address; http://www.commerce.state.ut.us

Michael O. Leavitt
Governor
Ted Boyer
Executive Director
Lowell E. Alt Jr.
Division Director

DIVISION OF PUBLIC UTILITIES
Heber M. Wells Building 4th Floor
160 East 300 South/ Box 146751
Salt Lake City, Utah 84114-6751
Phone (801) 530-7622
Fax (801) 530-6512 or (801) 530-6650

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SERVICE COMMISSION

REVIEWED BY COMMISSIONERS
STEPHEN F. MECHAM 2 6/8/01
CONSTANCE B. WHITE CBW 6/8
RICHARD M. CAMPBELL

To: Utah State Public Service Commission and Committee of Consumer Services

From: Lowell Alt, Director, Division of Public Utilities
Judith Johnson, Manager, Energy Section
Bob Maloney, Management Analyst

98-2035-04

Subject: PacifiCorp Merger Conditions – Recommended Outage Baselines, Due May 23, 2001
Date: Thursday, June 07, 2001

Recommendation and Summary:

The Division's recommendation regarding PC's (PacifiCorp's) proposed outage baselines is expected to be available for your review during October 2001.

PC, after encountering unexpected mapping work has been delayed in proposing outage baselines for the 1994 through 1998 period. The Company expects to provide its proposals by September 2001. The Division will subsequently make its recommendation to the Commission to accept, reject, or modify the Company's proposals.

Merger Conditions and Status

Merger Condition 29 -- PacifiCorp will operate its current outage reporting system in parallel with Prosper (an automated system expected to verify customer reported outages) until the earlier of Commission approval to terminate the current system or until the establishment of baselines in accordance with condition 30.

Status -- The Company implemented Prosper and Computer Aided Distribution Operations Systems in Southern Utah during November 2000 and in Northern Utah during January 2001.

Condition 30a --PacifiCorp will perform audits at six-month intervals to ascertain the differences between customer reported faults (from telephone systems) and those recorded in the fault reporting systems to ascertain the differences due to reporting deficiencies. These three audits will terminate 18 months after approval of the transaction. Thereafter, PacifiCorp will perform audits upon request of the Division or the Commission.

Status -- PacifiCorp plans to provide copies of three audit reports by July 30, 2001. The Company will develop three "uplift factors" (mentioned below) using primarily the most recent automated Prosper outage reports, but also findings from the audit reports. The factors will adjust previously understated outage levels during 1994 through 1998. The Division may request a fourth audit.

Condition 30b -- Based upon that data, the Division will, within 18 months after approval of the transaction, file a report with the Commission recommending outage baselines. Disputes if any regarding the outage baselines will be resolved by the Commission.

Status -- PacifiCorp plans to recommend modified 1994 to 1998 average baselines by September 2001. The Company encountered unexpected (labor-intensive) mapping work and engaged contractors to help with this work. Nevertheless, the unexpected work has delayed the Company's proposals beyond the May 23, 2001 (18 months after 11/23/99-transaction approval) target date. PC plans to increase the 1994 to 1998 outage averages using three "uplift factors." The factors will adjust understated outage levels during 1994 through 1998 and will include numbers of occurrences (incidents), durations of outages, and numbers of customers affected by outages.

The Company will measure its outage performance during 2005 against the "uplifted" (upwardly adjusted) 1994 to 1998 average baselines. PC plans to achieve 10%, 10%, and 5% outage-level reduction targets for outage durations, outage frequencies, and momentaries. The Company expects to have achieved these reductions as measured during the April 1, 2005 through March 31, 2006 period.

Please contact Bob Maloney at 530 6660 if you have any questions. In addition, an eight-page document listing questions and PC's replies to the questions is available upon request. PC's replies to the questions were used to develop this memo.

1900 S.W. 4th Ave.
Portland, Oregon 97201

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VIA OVERNIGHT MAIL

May 31, 2001

REVIEWED BY COMMISSIONERS
STEPHEN F. MECHAM Sm 6/7/01
CONSTANCE B. WHITE CBW 6/1
RICHARD M. CAMPBELL RC

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City UT 84114

Attention: Julie P. Orchard
Commission Secretary

RE: Docket No. 98-2035-04 ScottishPower/PacifiCorp Merger Commitments

Please find enclosed PacifiCorp's annual report for the period April 2000 through March 2001 detailing the Company's performance in meeting the Customer Guarantees and Performance Standards which were agreed to as a result of the recent merger between ScottishPower and PacifiCorp. Quarterly information for the last quarter of the fiscal year is provided as well.

As required by merger Stipulation Conditions 33 and 36, detailed outage performance and customer guarantee performance by district are also being reported. These reports are enclosed. Meter set response and temporary services response by district as required by merger Stipulation Condition 34 are also enclosed. Additional reports are provided outlining the number of requests and average days to respond for Customer Guarantees 4, 5 and 6, power restoration performance, field response performance and the number of tree trimming requests (performance to be reported in later reports).

If you have any questions or require further information, please call Carole Rockney at (503) 813-7408.

Sincerely,

Doug Larson /cr

D. Douglas Larson,
Vice President, Regulation

c: Mark Flandro - Utah Division of Public Utilities
Rea Petersen - Utah Division of Public Utilities
Andy MacRitchie - Executive Vice President, Power Delivery

Enclosures

Customer Service Commitments

Utah – Annual Report – Fiscal Year 2001

Customer Guarantees

The first year of the Guarantees program has impacted management and employee roles throughout the Company, and re-shaped how we look at customer expectations. The program was awarded with ISO 9001:2000 quality certification during the last quarter of the fiscal year. This standard certifies the consistency of processes throughout the Company, focusing on how well the program is implemented and managed. Internal and external audits of the program will continue to maintain this status.

CG3 – Switching on Power

61 failures were paid for CG3, primarily because of misrouted work requests on weekends and over holidays.

CG4 – Estimates

Estimate failures have been high compared to the other guarantees primarily due to new process requirements.

CG7 – Notification of Planned Interruptions

50 customers were paid during the year where planned interruptions took place without a complete notification being completed.

CG8 – Power Quality

Power Quality (CG8) failures were heavy primarily due to Summer 2000 outages in the Salt Lake valley.

The figures for other guarantees were not significant.

Attached below is a guide to understanding the methods used to count the events against which failures are compared.

Performance Standards

The Computer Aided Distribution Operations System (CADOPS) has been operating in Southern Utah since November 2000 and Northern Utah since February of this year. A meeting with the Commission Staff was held on May 23, 2001 to discuss the revised baselines for SAIDI, SAIFI and MAIFI based upon the improved reporting since the implementation of CADOPS.

The five worst circuits selected for Fiscal Years 2001 and 2002 are reported along with their baseline circuit performance indicator (CPI). The final CPI to determine whether the performance standard was met for FY 2001 circuits will be reported after one more year has passed.

Customer calls were answered at a rate exceeding the standard, even after the new 20-second standard became effective January 1, 2001. This required significant effort, focus and teamwork on the part of Customer Services employees. The figures shown for the 6-month period of October 2000 through March 2001 are reported under the 30 or 20 second standard in effect for the two quarters.

Performance Standard 7 was implemented to ensure that customers receive a timely response and resolution of complaints received from State Commissions. For a non-disconnect-related complaint the Company will respond directly to the customer or the Commission within three business days and for a disconnect-related complaint the Company will respond within 4 business hours. The Company strives to meet this target 100% of the time although this is not always possible with complex issues. During the first year of performance we responded to more than 99% of Commission complaints within the targeted response time.

The Company also committed to resolving Commission complaints within 30 calendar days 90% of the time. We exceeded this target with 99% of complaints being resolved within the 30 calendar days. This is a system wide commitment. In Utah the Company strives to resolve complaints within five business days.

Counting Guarantee Events

Outage Related

Upon restoration of any outage, pre-arranged or not, pertinent information regarding the outage (i.e. outage duration, # of customers out of power) is gathered and entered into the Computer Aided Distribution Operation System (CADOPS) or the Outage Reporting System (ORS). Only sustained outages exceeding 5 minutes in duration for the applicable state and reporting period are included.

CG1 – Restoring Supply: Events are counted utilizing CADOPS and ORS data. Outages that are pre-arranged by PacifiCorp, customer requested outages and outages related to major events are excluded. The number of customers out of power is reported as events.

CG7 – Notification of Planned Interruptions: Events are counted utilizing CADOPS and ORS data. The number of customers out of power due to planned interruptions is reported as events.

All Other Customer Guarantees:

PacifiCorp tracks appointments with customers, connect/reconnect requests, requests for estimates for new power supply, billing inquiries, inquiries regarding meter problems, and power quality inquiries in an electronic system called Work Tracking. Each customer call that cannot be resolved over the phone results in a work order consisting of several individual work activities required to fulfill the customer's request. A monthly extract from the Work Tracking system counts the number of completed activities related to the guarantees for each state. The Customer Service Commitment group analyzes the data, performs several validation steps, and records the data for final reporting as events. Unique characteristics for each guarantee are as follows:

CG2 – Appointments: Mutually agreed appointments are recorded as individual activities in relation to any request for service from a customer.

CG3 - Switching on Power: An event is counted for each customer request for connect or reconnect request where facilities exist. Also counted are reconnect requests following a customer-requested temporary disconnect.

CG4 – Estimates: An activity is recorded for both the customer contact within 2 days and the actual delivery of the estimate, essentially counting 2 guaranteed events for each estimate request.

CG5 – Billing Inquiries: A customer contact regarding their bill which cannot be resolved at the time of the call results in a work order for further follow-up. Upon completion of the response to the customer, the work order is counted as an event.

CG6 – Meter Inquiries: A customer contact regarding meter concerns (such as a request for a meter test) that cannot be resolved at the time of the call results in a work order for further follow-up. Upon completion of the response to the customer, the work order is counted as an event.

CG8 – Power Quality Complaints: A customer contact regarding power quality that cannot be resolved at the time of the call results in a work order for further follow-up. Upon completion of the response to the customer or escalation to the local service center, the work order is counted as an event.

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Customer Service Commitments - Guarantees

Utah

January-March 2001

		January-March 2001			Year to Date		
	Description	Events	Failures	Paid	Events	Failures	Paid
CG1	Restoring Supply	229,674	2	$150	940,581	9	$575
CG2	Appointments	1,695	8	$400	6,337	22	$1,100
CG3	Switching on Power	3,906	17	$2,275	22,929	61	$10,150
CG4	Estimates	2,713	98	$4,900	9,059	208	$10,400
CG5	Respond to Billing Inquiries	1,981	11	$550	7,684	26	$1,300
CG6	Respond to Meter Problems	325	2	$100	1,174	6	$300
CG7	Notification of Planned Interruptions	1,983	23	$1,150	10,515	50	$2,600
CG8	Power Quality Complaints	167	7	$350	2,317	199	$9,950
		242,444	**168**	**$9,875**	**1,000,596**	**581**	**$36,375**

Summary analysis:

General Comments - An external quality audit completed by EAQA USA during February 2001 led to Pacificorp receiving a certificate of compliance to the ISO 9001:2000 standard for the administration and reporting of the Customer Guarantees Program. The award was issued on March 1, 2001.

- Throughout the year, employee understanding of the guarantees has steadily improved through refinement of processes, recurring training and on-going audits. This will continue over the future.

- Root cause analyses are conducted where warranted to identify process, people or system issues that do not complement the guarantees. Several actions have already been implemented to help increase the number of successful interactions with customers.

CG4 - Estimates - Failures increased significantly in February. Most of these failures were identified as a result of the internal audits and the improving understanding of the guarantees in field offices.

CG7 - Planned Interruptions - Twenty-one claims were paid during February due to some customers not being notified during two planned interruptions. .

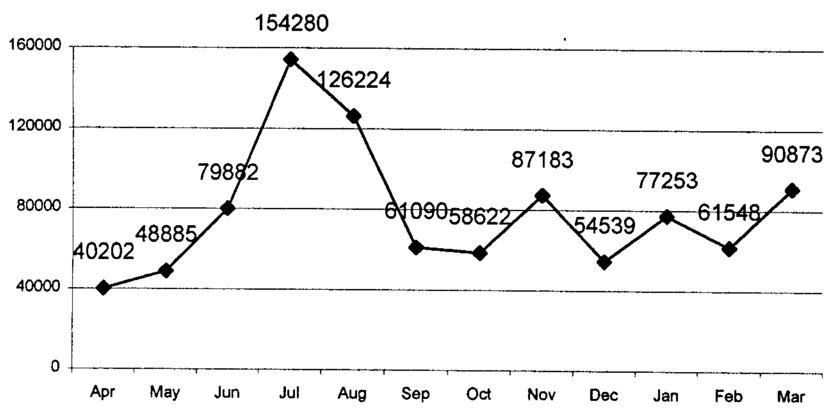
PACIFICORP

Utah

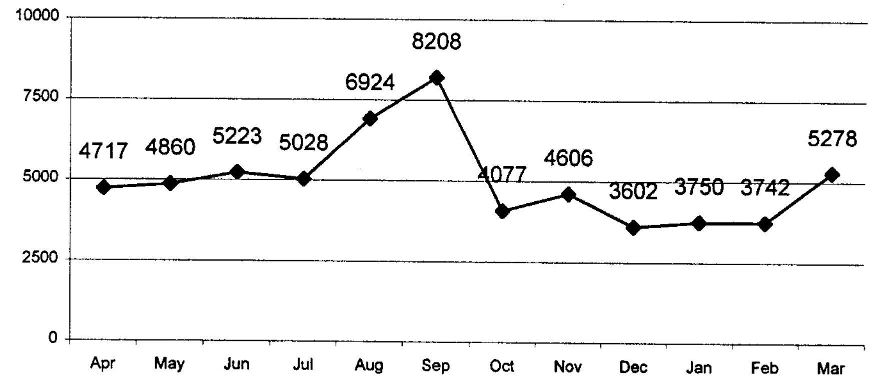
Customer Service Commitments - Guarantees

January-March 2001

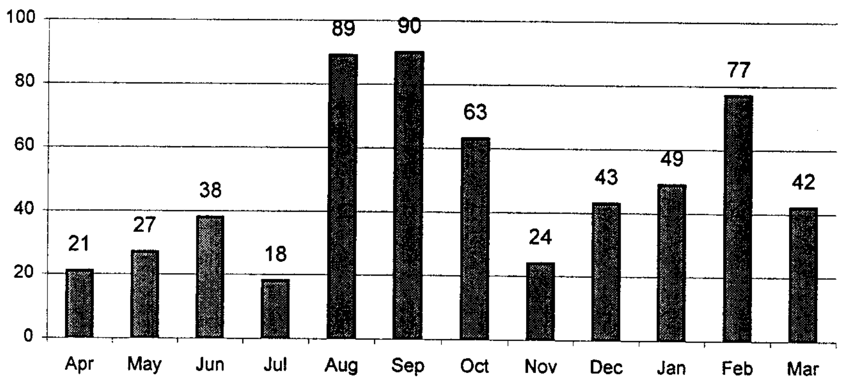
CG 1 Events



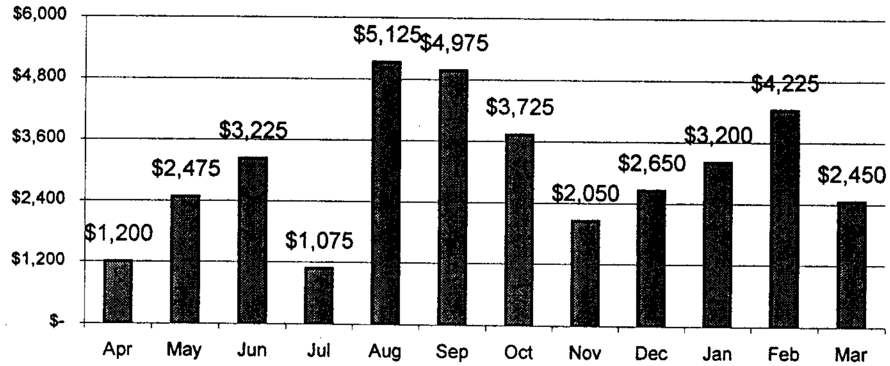
CG 2-8 Events



Failures



Payments



Description	Baseline	Performance at Sept 2000	Performance at March 2001	Goal
• SAIDI (System availability in minutes per customer)	Revised baselines under development[1]	87.1	141.9	Reduce SAIDI by 10% from revised baseline
• SAIFI (System reliability in interruptions per customer)		0.8	1.5	Reduce SAIFI by 10% from revised baseline
• MAIFI (Momentary interruptions per customer)		4.8	5.6	Reduce MAIFI by 5% from revised baseline
• Worst Performing Circuits - Circuit Performance Indicator (CPI)[2]		CPI performance wll be reviewed at end of the 2-year improvement period.		Reduce CPI's by 20% from revised baseline
Fiscal Year 2001:				
Coalville 12	288			
Lewiston 11	377			
Pioneer 11	425			
Pioneer 13	529			
Pioneer 14	393			
Fiscal Year 2002:				
Woods Cross 11	311			
Eden 11	339			
Rattlesnake 22	308			
Lark 11	419			
Bothwell 11	323			
• Power supply restored within 3 hours	Not applicable	83%	86%	80%
• Calls answered				
• Within 30 seconds (standard effective through Dec 2000)	Not applicable	86%	85%	80%
• Within 20 seconds (new standard effective Jan 2001)	Not applicable		81%	80%
• Respond to commission complaints within 3 days	Not applicable	99%	99%	100%
• Respond to commission complaints regarding service disconnects within 4 hours	Not applicable	100%	100%	100%
• Commission complaints resolved within 30 days	Not applicable	99%	99%	90%

1 CADOPS has been operating in Southern Utah since November 2000 and Northern Utah since February of this year. PacifiCorp plans to recommend modified 1994 to 1998 baselines by September 2001. We plan to increase the baselines based upon three uplift factors; number of occurrences (incidents); duration of outages; and number of customers affected by outages.

2 Baseline CPI figures are based on 3-years ended data as of December 31, 1998 for FY 2001 circuits; 3-years ended data as of December 31, 2000 for FY 2002 circuits.

Customer Service Commitments

UTAH GUARANTEE FIELD RESPONSE PERFORMANCE — January-March 2001

American Fork	*Description*	# Customer Requests 4th Q	# Customer Requests 3rd + 4th	Average # Days to Respond 4th Q	Average # Days to Respond 3rd + 4th
CG4a	Estimates - Contact within 2 days	143	285	1	2
CG4b	Estimates - 5 days	22	43	3	2
CG4c	Estimates - 15 days	97	213	21	21
CG5	Responding to Bill Inquiries within 10 days	90	211	4	4
CG6	Responding to Meter Problems within 15 days	21	39	8	7

Cedar City	*Description*	# Customer Requests 4th Q	# Customer Requests 3rd + 4th	Average # Days to Respond 4th Q	Average # Days to Respond 3rd + 4th
CG4a	Estimates - Contact within 2 days	133	237	1	1
CG4b	Estimates - 5 days	59	105	0	0
CG4c	Estimates - 15 days	76	136	3	3
CG5	Responding to Bill Inquiries within 10 days	113	188	5	5
CG6	Responding to Meter Problems within 15 days	18	26	5	4

Davis	*Description*	# Customer Requests 4th Q	# Customer Requests 3rd + 4th	Average # Days to Respond 4th Q	Average # Days to Respond 3rd + 4th
CG4a	Estimates - Contact within 2 days	60	144	1	1
CG4b	Estimates - 5 days	19	30	1	1
CG4c	Estimates - 15 days	45	88	8	7
CG5	Responding to Bill Inquiries within 10 days	126	237	4	4
CG6	Responding to Meter Problems within 15 days	30	58	8	8

Jordan Valley	*Description*	# Customer Requests 4th Q	3rd + 4th	Average # Days to Respond 4th Q	3rd + 4th
CG4a	Estimates - Contact within 2 days	220	352	1	1
CG4b	Estimates - 5 days	65	92	1	1
CG4c	Estimates - 15 days	126	225	7	7
CG5	Responding to Bill Inquiries within 10 days	415	862	4	4
CG6	Responding to Meter Problems within 15 days	70	129	7	7

Laketown	*Description*	# Customer Requests 4th Q	3rd + 4th	Average # Days to Respond 4th Q	3rd + 4th
CG4a	Estimates - Contact within 2 days	4	14	1	1
CG4b	Estimates - 5 days		3		3
CG4c	Estimates - 15 days	10	16	1	1
CG5	Responding to Bill Inquiries within 10 days	14	26	4	4
CG6	Responding to Meter Problems within 15 days	3	3	10	10

Moab	*Description*	# Customer Requests 4th Q	3rd + 4th	Average # Days to Respond 4th Q	3rd + 4th
CG4a	Estimates - Contact within 2 days	39	59	1	1
CG4b	Estimates - 5 days	10	15	0	0
CG4c	Estimates - 15 days	15	38	3	5
CG5	Responding to Bill Inquiries within 10 days	56	101	3	3
CG6	Responding to Meter Problems within 15 days	5	8	4	6

UTAH GUARANTEE FIELD RESPONSE PERFORMANCE January-March 2001

Ogden	Description	# Customer Requests 4th Q	# Customer Requests 3rd + 4th	Average # Days to Respond 4th Q	Average # Days to Respond 3rd + 4th
	CG4a Estimates - Contact within 2 days	164	269	2	2
	CG4b Estimates - 5 days	29	51	0	0
	CG4c Estimates - 15 days	83	149	8	7
	CG5 Responding to Bill Inquiries within 10 days	194	388	4	4
	CG6 Responding to Meter Problems within 15 days	33	63	6	6

Park City	Description	# Customer Requests 4th Q	# Customer Requests 3rd + 4th	Average # Days to Respond 4th Q	Average # Days to Respond 3rd + 4th
	CG4a Estimates - Contact within 2 days	71	142	1	4
	CG4b Estimates - 5 days	3	8	3	2
	CG4c Estimates - 15 days	31	113	4	3
	CG5 Responding to Bill Inquiries within 10 days	56	121	5	5
	CG6 Responding to Meter Problems within 15 days	8	13	8	9

Price	Description	# Customer Requests 4th Q	# Customer Requests 3rd + 4th	Average # Days to Respond 4th Q	Average # Days to Respond 3rd + 4th
	CG4a Estimates - Contact within 2 days	29	46	1	1
	CG4c Estimates - 15 days	19	34	4	3
	CG5 Responding to Bill Inquiries within 10 days	34	58	4	4
	CG6 Responding to Meter Problems within 15 days	6	10	6	5

Richfield	Description	# Customer Requests 4th Q	# Customer Requests 3rd + 4th	Average # Days to Respond 4th Q	Average # Days to Respond 3rd + 4th
CG4a	Estimates - Contact within 2 days	82	138	1	1
CG4b	Estimates - 5 days	26	55	1	1
CG4c	Estimates - 15 days	45	70	8	7
CG5	Responding to Bill Inquiries within 10 days	60	101	4	4
CG6	Responding to Meter Problems within 15 days	9	14	5	6

Santaquin	Description	# Customer Requests 4th Q	# Customer Requests 3rd + 4th	Average # Days to Respond 4th Q	Average # Days to Respond 3rd + 4th
CG4a	Estimates - Contact within 2 days	2	4	6	11
CG4c	Estimates - 15 days	1	1	5	5

SLC Metro	Description	# Customer Requests 4th Q	# Customer Requests 3rd + 4th	Average # Days to Respond 4th Q	Average # Days to Respond 3rd + 4th
CG4a	Estimates - Contact within 2 days	188	322	1	1
CG4b	Estimates - 5 days	54	82	1	1
CG4c	Estimates - 15 days	142	268	6	5
CG5	Responding to Bill Inquiries within 10 days	702	1531	4	4
CG6	Responding to Meter Problems within 15 days	97	216	6	7

Smithfield	*Description*	# Customer Requests 4th Q	# Customer Requests 3rd + 4th	Average # Days to Respond 4th Q	Average # Days to Respond 3rd + 4th
CG4a	Estimates - Contact within 2 days	54	99	1	1
CG4b	Estimates - 5 days	14	17	0	0
CG4c	Estimates - 15 days	35	71	4	3
CG5	Responding to Bill Inquiries within 10 days	32	59	4	4
CG6	Responding to Meter Problems within 15 days	3	10	5	7

Tooele	*Description*	# Customer Requests 4th Q	# Customer Requests 3rd + 4th	Average # Days to Respond 4th Q	Average # Days to Respond 3rd + 4th
CG4a	Estimates - Contact within 2 days	42	68	2	2
CG4b	Estimates - 5 days	9	12	0	0
CG4c	Estimates - 15 days	22	46	9	8
CG5	Responding to Bill Inquiries within 10 days	31	108	5	5
CG6	Responding to Meter Problems within 15 days	5	15	6	9

Tremonton	*Description*	# Customer Requests 4th Q	# Customer Requests 3rd + 4th	Average # Days to Respond 4th Q	Average # Days to Respond 3rd + 4th
CG4a	Estimates - Contact within 2 days	38	64	1	1
CG4b	Estimates - 5 days		1		0
CG4c	Estimates - 15 days	31	56	6	8
CG5	Responding to Bill Inquiries within 10 days	28	52	4	4
CG6	Responding to Meter Problems within 15 days	10	12	6	5

Valley West	*Description*	# Customer Requests 4th Q	# Customer Requests 3rd + 4th	Average # Days to Respond 4th Q	Average # Days to Respond 3rd + 4th
	CG4a Estimates - Contact within 2 days	3	7	1	1
	CG4b Estimates - 5 days	3	3	0	0
	CG4c Estimates - 15 days	1	2	15	12
	CG5 Responding to Bill Inquiries within 10 days	3	6	4	5
	CG6 Responding to Meter Problems within 15 days		1		7

Vernal	*Description*	# Customer Requests 4th Q	# Customer Requests 3rd + 4th	Average # Days to Respond 4th Q	Average # Days to Respond 3rd + 4th
	CG4a Estimates - Contact within 2 days	29	63	0	0
	CG4b Estimates - 5 days	5	10	0	0
	CG4c Estimates - 15 days	21	48	0	0
	CG5 Responding to Bill Inquiries within 10 days	35	53	4	4
	CG6 Responding to Meter Problems within 15 days	8	10	10	10

Customer Service Commitments

UTAH – Non-Guarantee

FIELD RESPONSE PERFORMANCE

January-March 2001

OFFICE	Count of Field (FLD) Requests	Average # Days to Respond
American Fork	54	7
Cedar City	50	5
Davis	200	2
Jordan Valley	151	15
Laketown	2	2
Moab	17	12
Ogden	200	13
Park City	20	1
Price	10	8
Richfield	19	5
SLC Metro	255	34
Smithfield	29	10
Tooele	36	3
Tremonton	16	2
Valley West	2	54
Vernal	5	1
All Offices	**1066**	**15**

Customer Service Commitments

UTAH – Non-Guarantee

TREE TRIMMING REQUESTS January-March 2001

OFFICE	Count of Tree Trimming (TRE) Requests
American Fork	18
Cedar City	2
Davis	7
Jordan Valley	165
Moab	6
Ogden	43
Park City	13
Price	2
Richfield	4
SLC Metro	332
Smithfield	12
Tooele	8
Tremonton	4
Valley West	5
Vernal	1
All Offices	**622**

UTAH RESIDENTIAL/SMALL COMMERCIAL METER SETS - REPORT BY DISTRICT

2000-2001

FISCAL YEAR 2-4 QUARTERS 2000-2001

NORTHERN UTAH

LOCATION	FY 2nd Quarter			FY 3rd Quarter			JANUARY			FEBRUARY			MARCH			FY 4th Quarter			FY 2-4 Quarters			Notes
	Total Within 5 Days	2nd Qtr %	Total	Total Within 5 Days	3rd Qtr %	Total	Within 5 Days	%	Total	Within 5 Days	%	Total	Within 5 Days	%	Total	Total Within 5 Days	4th Qtr %	Total	Total Within 5 Days	%	Total	
Jordan Valley	845	89%	948	719	70%	1021	314	77%	409	227	97%	235	272	94%	288	813	87%	932	2377	82%	2901	Vacation scheduling affected performance in December and January. Corrective action implemented mid-January.
Layton/Davis	327	92%	354	346	100%	346	116	95%	122	89	100%	89	111	97%	114	316	97%	325	989	96%	1025	
Metro	576	97%	593	810	94%	858	303	98%	310	246	100%	247	311	99%	313	860	99%	870	2246	97%	2321	
Ogden	776	99%	783	583	98%	594	174	99%	176	140	99%	141	171	99%	172	485	99%	489	1844	99%	1866	
Park City	178	92%	194	229	92%	249	57	98%	58	38	100%	38	38	90%	42	133	96%	138	540	93%	581	
Smithfield	51	100%	51	86	99%	87	29	100%	29	26	100%	26	15	100%	15	70	100%	70	207	100%	208	Reporting began in August.
Tooele	280	86%	325	283	98%	289	46	98%	47	40	100%	40	60	100%	60	146	99%	147	709	93%	761	
Tremonton	50	88%	57	54	86%	63	11	100%	11	5	100%	5	14	88%	16	30	94%	32	134	88%	152	Corrective action implemented for 4th quarter.
TOTAL	3083	93%	3305	3110	89%	3507	1050	90%	1162	811	99%	821	992	97%	1020	2853	95%	3003	9046	92%	9815	

SOUTHERN UTAH

LOCATION	FY 2nd Quarter			FY 3rd Quarter			JANUARY			FEBRUARY			MARCH			FY 4th Quarter			FY 2-4 Quarters			Notes
	Total Within 5 Days	2nd Qtr %	Total	Total Within 5 Days	3rd Qtr %	Total	Within 5 days	%	Total	Within 5 days	%	Total	Within 5 days	%	Total	Total Within 5 Days	4th Qtr %	Total	Total Within 5 Days	%	Total	
American Fork	421	99%	425	514	99%	517	123	97%	127	109	99%	110	135	99%	136	367	98%	373	1302	99%	1315	
Cedar City	220	97%	226	238	97%	246	60	98%	61	37	97%	38	76	96%	79	173	97%	178	631	97%	650	
Moab	31	89%	35	47	100%	47	24	92%	26	23	96%	24	21	95%	22	68	94%	72	146	95%	154	Reporting began in August.
Price	56	100%	56	42	100%	42	3	100%	3	1	100%	1	6	100%	6	10	100%	10	108	100%	108	
Richfield	134	100%	134	97	100%	97	34	100%	34	18	100%	18	33	100%	33	85	100%	85	316	100%	316	Reporting began in August.
Santaquin	125	100%	125	69	100%	69	30	100%	30	15	100%	15	24	100%	24	69	100%	69	263	100%	263	
Vernal	20	91%	22	43	93%	46	17	100%	17	10	91%	11	8	89%	9	35	95%	37	98	93%	105	Reporting began in August.
TOTAL	1007	98%	1023	1050	99%	1064	291	98%	298	213	98%	217	303	98%	309	807	98%	824	2864	98%	2911	

TOTAL UTAH

LOCATION	FY 2nd Quarter			FY 3rd Quarter			JANUARY			FEBRUARY			MARCH			FY 4th Quarter			FY 2-4 Quarters			Notes
	Total Within 5 Days	2nd Qtr %	Total	Total Within 5 Days	3rd Qtr %	Total	Within 5 days	%	Total	Within 5 days	%	Total	Within 5 days	%	Total	Total Within 5 Days	3rd Qtr %	Total	Total Within 5 Days	%	Total	
TOTAL UTAH	4090	95%	4328	4160	91%	4571	1341	92%	1460	1024	99%	1038	1295	97%	1329	3660	96%	3827	11910	94%	12726	

UTAH TEMPORARY METER SETS - REPORT BY DISTRICT

2000-2001

FISCAL YEAR 3-4 QUARTERS 2000-2001

NORTHERN UTAH

LOCATION	FY 3rd Quarter			JANUARY			FEBRUARY			MARCH			FYD - 4th Quarter			Notes
	Total Within 10 Days	3rd Qtr %	Total	Within 10 Days	%	Total	Within 10 Days	%	Total	Within 10 Days	%	Total	Total Within 10 Days	4th Qtr %	Total	
Jordan Valley	327	91%	360	174	86%	203	126	100%	126	169	98%	172	469	94%	501	
Layton/Davis	220	100%	220	86	100%	86	93	100%	93	159	100%	159	338	100%	338	
Metro	202	100%	203	73	100%	73	73	100%	73	102	100%	102	248	100%	248	
Ogden	242	100%	243	65	100%	65	75	100%	75	104	100%	104	265	100%	265	
Park City	67	99%	68	28	93%	30	13	100%	13	26	100%	26	67	97%	69	
Smithfield	108	100%	108	11	100%	11	7	100%	7	26	100%	26	44	100%	44	
Tooele	95	100%	95	34	100%	34	31	100%	31	42	100%	42	107	100%	107	
Tremonton	12	92%	13	4	100%	4	2	100%	2	11	100%	11	17	100%	17	
TOTAL	1273	97%	1310	475	94%	506	420	100%	420	639	100%	642	1534	98%	1568	

SOUTHERN UTAH

LOCATION	FY 3rd Quarter			JANUARY			FEBRUARY			MARCH			FYD - 4th Quarter			Notes
	Total Within 10 Days	3rd Qtr %	Total	Within 10 days	%	Total	Within 10 days	%	Total	Within 10 days	%	Total	Total Within 10 Days	4th Qtr %	Total	
American Fork	241	100%	242	75	100%	75	77	99%	78	99	100%	99	251	100%	252	
Cedar City	116	100%	116	18	100%	18	21	100%	21	42	100%	42	81	100%	81	
Moab	9	100%	9	4	100%	4	17	100%	17	2	100%	2	23	100%	23	
Price	17	100%	17	2	100%	2	2	100%	2	2	100%	2	6	100%	6	
Richfield	16	100%	16	7	100%	7	11	100%	11	9	100%	9	27	100%	27	
Santaquin	19	100%	19	16	100%	16	11	100%	11	23	100%	23	50	100%	50	
Vernal	10	100%	10	1	100%	1	3	100%	3	5	100%	5	9	100%	9	
TOTAL	428	100%	429	123	100%	123	142	99%	143	182	100%	182	447	100%	448	

TOTAL UTAH

LOCATION	FY 3rd Quarter			JANUARY			FEBRUARY			MARCH			FYD - 4th Quarter			Notes
	Total Within 10 Days	3rd Qtr %	Total	Within 10 days	%	Total	Within 10 days	%	Total	Within 10 days	%	Total	Total Within 10 Days	4th Qtr %	Total	
TOTAL UTAH	1701	98%	1739	598	95%	629	562	100%	563	821	100%	824	1981	98%	2016	

4-17-0

4th Quarter **Fiscal Year 2001** **01/01/2001 to 03/31/2001**

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Nu Ccc
Unplanned	Utah			27.380	0.370	0.143	0.140	620,897	229,659	
Planned	Utah			0.560	0.003	0.000	0.000	620,897	2,085	
Customer Requested	Utah			0.001	0.000	0.000	0.000	620,897	4	
Unplanned	AMERICAN FORK			5.232	0.088	0.001	0.001	63,521	5,603	
Planned	AMERICAN FORK			0.338	0.002	0.000	0.000	63,521	111	
Customer Requested	AMERICAN FORK			0.000	0.000	0.000	0.000	63,521	0	
High SAIDI	AMERICAN FORK	EUR12	EUREKA #12	4,373.000	86.000	0.000	0.000	1	86	
Low SAIDI	AMERICAN FORK	29	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	AMERICAN FORK	EUR12	EUREKA #12	4,373.000	86.000	0.000	0.000	1	86	
Low SAIFI	AMERICAN FORK	30	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	AMERICAN FORK	AMF12	AMERICAN FORK #12	0.022	0.001	0.018	0.018	1,402	1	
Low MAIFI	AMERICAN FORK	69	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	AMERICAN FORK	AMF12	AMERICAN FORK #12	0.022	0.001	0.018	0.018	1,402	1	
Low MAIFI(e)	AMERICAN FORK	66	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	AMERICAN FORK	ORE13	OREM #13	23.810	0.100	0.000	0.000	2,539	253	
Low Customer Minutes Lost	AMERICAN FORK	29	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	ASHLEY (VERNAL)			5.969	0.044	0.000	0.000	9,382	410	
Planned	ASHLEY (VERNAL)			0.044	0.000	0.000	0.000	9,382	4	
Customer Requested	ASHLEY (VERNAL)			0.000	0.000	0.000	0.000	9,382	0	
High SAIDI	ASHLEY (VERNAL)	VER12	VERNAL #12	32.171	0.138	0.000	0.000	1,071	148	
Low SAIDI	ASHLEY (VERNAL)	6	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	ASHLEY (VERNAL)	VER12	VERNAL #12	32.171	0.138	0.000	0.000	1,071	148	
Low SAIFI	ASHLEY (VERNAL)	6	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	ASHLEY (VERNAL)	VER15	VERNAL #15	2.894	0.022	0.001	0.001	1,543	34	
Low MAIFI	ASHLEY (VERNAL)	11	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	ASHLEY (VERNAL)	VER15	VERNAL #15	2.894	0.022	0.001	0.001	1,543	34	
Low MAIFI(e)	ASHLEY (VERNAL)	11	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	ASHLEY (VERNAL)	VER12	VERNAL #12	32.171	0.138	0.000	0.000	1,071	148	
Low Customer Minutes Lost	ASHLEY (VERNAL)	6	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	CANYONLANDS (MOAB)			12.406	0.106	0.001	0.001	14,226	1,513	
Planned	CANYONLANDS (MOAB)			0.003	0.000	0.000	0.000	14,226	1	
Customer Requested	CANYONLANDS (MOAB)			0.000	0.000	0.000	0.000	14,226	0	
High SAIDI	CANYONLANDS (MOAB)	SUP12	SUPERIOR #12	149.473	1.063	0.000	0.000	332	353	
Low SAIDI	CANYONLANDS (MOAB)	26	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	CANYONLANDS (MOAB)	SUP12	SUPERIOR #12	149.473	1.063	0.000	0.000	332	353	
Low SAIFI	CANYONLANDS (MOAB)	26	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	CANYONLANDS (MOAB)	BFD01	BLUFF #11	17.164	0.980	0.066	0.066	152	149	
Low MAIFI	CANYONLANDS (MOAB)	37	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	CANYONLANDS (MOAB)	BFD01	BLUFF #11	17.164	0.980	0.066	0.066	152	149	
Low MAIFI(e)	CANYONLANDS (MOAB)	37	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	CANYONLANDS (MOAB)	RAT22	RATTLESNAKE #22	82.629	0.473	0.000	0.000	800	378	
Low Customer Minutes Lost	CANYONLANDS (MOAB)	26	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	CARBON (PRICE)			11.522	0.083	0.000	0.000	10,248	848	
Planned	CARBON (PRICE)			0.000	0.000	0.000	0.000	10,248	0	
Customer Requested	CARBON (PRICE)			0.000	0.000	0.000	0.000	10,248	0	

4th Quarter Fiscal Year 2001 01/01/2001 to 03/31/2001

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off
High SAIDI	CARBON (PRICE)	SCO11	SCOFIELD CITY #11	126.576	0.597	0.000	0.000	238	142
Low SAIDI	CARBON (PRICE)	33	***** circuits with Low SAIDI of 0.000 *****	0.000					
High SAIFI	CARBON (PRICE)	CBN12	CARBONVILLE #12	70.850	0.632	0.000	0.000	828	523
Low SAIFI	CARBON (PRICE)	33	***** circuits with Low SAIFI of 0.000 *****		0.000				
High MAIFI	CARBON (PRICE)	46	***** circuits with High MAIFI of 0.000 *****	0.000	0.000	0.000	0.000	572	0
Low MAIFI	CARBON (PRICE)	46	***** circuits with Low MAIFI of 0.000 *****			0.000			
High MAIFI(e)	CARBON (PRICE)	46	***** circuits with High MAIFI(e)of 0.000 *****	0.000	0.000	0.000	0.000	1	0
Low MAIFI(e)	CARBON (PRICE)	46	***** circuits with Low MAIFI(e) of 0.000 *****				0.000		
High Customer Minutes Lost	CARBON (PRICE)	CBN12	CARBONVILLE #12	70.850	0.632	0.000	0.000	828	523
Low Customer Minutes Lost	CARBON (PRICE)	33	***** circuits with Low Customer Minutes Lost of 0.000 *****						
Unplanned	CEDAR CITY			144.314	1.065	1.211	1.211	16,630	17,705
Planned	CEDAR CITY			0.234	0.001	0.000	0.000	16,630	17
Customer Requested	CEDAR CITY			0.000	0.000	0.000	0.000	16,630	0
High SAIDI	CEDAR CITY	WCD29	WEST CEDAR #29	833,659.000	4,162.000	2,775.000	2,775.000	1	4,162
Low SAIDI	CEDAR CITY	59	***** circuits with Low SAIDI of 0.000 *****	0.000					
High SAIFI	CEDAR CITY	WCD29	WEST CEDAR #29	833,659.000	4,162.000	2,775.000	2,775.000	1	4,162
Low SAIFI	CEDAR CITY	59	***** circuits with Low SAIFI of 0.000 *****		0.000				
High MAIFI	CEDAR CITY	WCD29	WEST CEDAR #29	833,659.000	4,162.000	2,775.000	2,775.000	1	4,162
Low MAIFI	CEDAR CITY	8	***** circuits with Low MAIFI of 0.000 *****			0.000			
High MAIFI(e)	CEDAR CITY	WCD29	WEST CEDAR #29	833,659.000	4,162.000	2,775.000	2,775.000	1	4,162
Low MAIFI(e)	CEDAR CITY	8	***** circuits with Low MAIFI(e) of 0.000 *****				0.000		
High Customer Minutes Lost	CEDAR CITY	WCD29	WEST CEDAR #29	833,659.000	4,162.000	2,775.000	2,775.000	1	4,162
Low Customer Minutes Lost	CEDAR CITY	5	***** circuits with Low Customer Minutes Lost of 0.000 *****						
Unplanned	COTTONWOOD (JORDAN VALLEY)			2.221	0.009	0.662	0.662	3,913	34
Planned	COTTONWOOD (JORDAN VALLEY)			0.000	0.000	0.000	0.000	3,913	0
Customer Requested	COTTONWOOD (JORDAN VALLEY)			0.000	0.000	0.000	0.000	3,913	0
High SAIDI	COTTONWOOD (JORDAN VALLEY)	DMP13	DIMPLE DELL #13	5.788	0.013	0.096	0.096	1,232	16
Low SAIDI	COTTONWOOD (JORDAN VALLEY)	DMP11	DIMPLE DELL #11	0.262	0.002	0.000	0.000	925	2
High SAIFI	COTTONWOOD (JORDAN VALLEY)	DMP13	DIMPLE DELL #13	5.788	0.013	0.096	0.096	1,232	16
Low SAIFI	COTTONWOOD (JORDAN VALLEY)	DMP11	DIMPLE DELL #11	0.262	0.002	0.000	0.000	925	2
High MAIFI	COTTONWOOD (JORDAN VALLEY)	DMP12	DIMPLE DELL #12	0.751	0.009	1.408	1.408	1,756	16
Low MAIFI	COTTONWOOD (JORDAN VALLEY)	DMP11	DIMPLE DELL #11	0.262	0.002	0.000	0.000	925	2
High MAIFI(e)	COTTONWOOD (JORDAN VALLEY)	DMP12	DIMPLE DELL #12	0.751	0.009	1.408	1.408	1,756	16
Low MAIFI(e)	COTTONWOOD (JORDAN VALLEY)	DMP11	DIMPLE DELL #11	0.262	0.002	0.000	0.000	925	2
High Customer Minutes Lost	COTTONWOOD (JORDAN VALLEY)	DMP13	DIMPLE DELL #13	5.788	0.013	0.096	0.096	1,232	16
Low Customer Minutes Lost	COTTONWOOD (JORDAN VALLEY)	DMP11	DIMPLE DELL #11	0.262	0.002	0.000	0.000	925	2
Unplanned	DELTA (RICHFIELD)			1.052	0.010	0.000	0.000	5,766	56
Planned	DELTA (RICHFIELD)			0.000	0.000	0.000	0.000	5,766	0
Customer Requested	DELTA (RICHFIELD)			0.000	0.000	0.000	0.000	5,766	0
High SAIDI	DELTA (RICHFIELD)	FLC11	FOOL CREEK #11	13.800	0.160	0.000	0.000	25	4
Low SAIDI	DELTA (RICHFIELD)	24	***** circuits with Low SAIDI of 0.000 *****	0.000					
High SAIFI	DELTA (RICHFIELD)	FLC11	FOOL CREEK #11	13.800	0.160	0.000	0.000	25	4
Low SAIFI	DELTA (RICHFIELD)	24	***** circuits with Low SAIFI of 0.000 *****		0.000				
High MAIFI	DELTA (RICHFIELD)	30	***** circuits with High MAIFI of 0.000 *****	0.000	0.000	0.000	0.000	1	0
Low MAIFI	DELTA (RICHFIELD)	30	***** circuits with Low MAIFI of 0.000 *****			0.000			
High MAIFI(e)	DELTA (RICHFIELD)	30	***** circuits with High MAIFI(e) of 0.000 *****	0.000	0.000	0.000	0.000	100	0

4th Quarter Fiscal Year 2001 01/01/2001 to 03/31/2001

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Nu Occ
Low MAIFI(e)	DELTA (RICHFIELD)	30	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	DELTA (RICHFIELD)	STH21	SUTHERLAND #21	11.426	0.102	0.000	0.000	462	47	
Low Customer Minutes Lost	DELTA (RICHFIELD)	24	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	LAYTON (DAVIS)			17.749	0.288	0.298	0.256	37,001	10,665	
Planned	LAYTON (DAVIS)			0.074	0.001	0.000	0.000	37,001	41	
Customer Requested	LAYTON (DAVIS)			0.005	0.000	0.000	0.000	37,001	1	
High SAIDI	LAYTON (DAVIS)	SYR15	SYRACUSE #15	531.000	3.000	0.000	0.000	1	3	
Low SAIDI	LAYTON (DAVIS)	15	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	LAYTON (DAVIS)	SYR15	SYRACUSE #15	531.000	3.000	0.000	0.000	1	3	
Low SAIFI	LAYTON (DAVIS)	15	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	LAYTON (DAVIS)	LAY13	LAYTON #13	42.255	0.851	1.676	0.838	1,860	1,583	
Low MAIFI	LAYTON (DAVIS)	29	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	LAYTON (DAVIS)	CLN11	CLINTON #11	181.742	1.113	1.000	1.000	806	897	
High MAIFI(e)	LAYTON (DAVIS)	ELA11	EAST LAYTON #11	0.070	0.001	1.000	1.000	790	1	
High MAIFI(e)	LAYTON (DAVIS)	LAY17	LAYTON #17	4.267	0.025	1.000	1.000	2,743	68	
High MAIFI(e)	LAYTON (DAVIS)	SYR11	SYRACUSE #11	20.860	0.140	1.000	1.000	107	15	
Low MAIFI(e)	LAYTON (DAVIS)	29	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	LAYTON (DAVIS)	ANG14	ANGEL #14	76.934	1.692	0.000	0.000	2,050	3,469	
Low Customer Minutes Lost	LAYTON (DAVIS)	15	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	SLC METRO			25.884	0.500	0.112	0.112	184,202	92,053	
Planned	SLC METRO			0.986	0.005	0.000	0.000	184,202	861	
Customer Requested	SLC METRO			0.000	0.000	0.000	0.000	184,202	0	
High SAIDI	SLC METRO	BRU801	BRUNSWICK #801	581.714	11.429	0.000	0.000	70	800	
Low SAIDI	SLC METRO	143	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	SLC METRO	BRU801	BRUNSWICK #801	581.714	11.429	0.000	0.000	70	800	
Low SAIFI	SLC METRO	144	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	SLC METRO	CNT12	CENTENNIAL #12	0.000	0.000	4.700	4.700	50	0	
Low MAIFI	SLC METRO	224	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	SLC METRO	CNT12	CENTENNIAL #12	0.000	0.000	4.700	4.700	50	0	
Low MAIFI(e)	SLC METRO	224	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	SLC METRO	ROS12	ROSE PARK #12	288.631	1.893	0.000	0.000	2,399	4,541	
Low Customer Minutes Lost	SLC METRO	137	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	MILFORD (CEDAR CITY)			51.142	0.674	0.993	0.993	1,689	1,139	
Planned	MILFORD (CEDAR CITY)			3.193	0.085	0.000	0.000	1,689	143	
Customer Requested	MILFORD (CEDAR CITY)			0.000	0.000	0.000	0.000	1,689	0	
High SAIDI	MILFORD (CEDAR CITY)	ELK12	ELK MEADOWS #12	372.500	2.083	1.000	1.000	12	25	
Low SAIDI	MILFORD (CEDAR CITY)	11	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	MILFORD (CEDAR CITY)	MNV11	MINERSVILLE #11	142.787	2.853	1.000	1.000	300	856	
Low SAIFI	MILFORD (CEDAR CITY)	11	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	MILFORD (CEDAR CITY)	T07	CAMERON-UPPER BEAVER-46KV	0.000	0.000	1.000	1.000	1	0	
High MAIFI	MILFORD (CEDAR CITY)	SML12	SOUTH MILFORD #12	12.844	0.125	1.000	1.000	96	12	
High MAIFI	MILFORD (CEDAR CITY)	SML11	SOUTH MILFORD #11	9.800	0.067	1.000	1.000	30	2	
High MAIFI	MILFORD (CEDAR CITY)	PND11	PONDEROSA #11	0.000	0.000	1.000	1.000	50	0	
High MAIFI	MILFORD (CEDAR CITY)	MTV11	MILFORD TV #11	0.000	0.000	1.000	1.000	4	0	
High MAIFI	MILFORD (CEDAR CITY)	MNV11	MINERSVILLE #11	142.787	2.853	1.000	1.000	300	856	
High MAIFI	MILFORD (CEDAR CITY)	MLF34	CAMERON	0.000	0.000	1.000	1.000	2	0	

4th Quarter **Fiscal Year 2001** **01/01/2001 to 03/31/2001**

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Nu Occ
High MAIFI	MILFORD (CEDAR CITY)	MLF13	MILFORD #13	0.358	0.006	1.000	1.000	344	2	
High MAIFI	MILFORD (CEDAR CITY)	MLF12	MILFORD #12	0.531	0.006	1.000	1.000	175	1	
High MAIFI	MILFORD (CEDAR CITY)	MLF11	MILFORD #11	0.237	0.004	1.000	1.000	270	1	
High MAIFI	MILFORD (CEDAR CITY)	LWB11	OLD LOWER BEAVER PLANT SITE - STOCK WAT.	0.000	0.000	1.000	1.000	4	0	
High MAIFI	MILFORD (CEDAR CITY)	ELK12	ELK MEADOWS #12	372.500	2.083	1.000	1.000	12	25	
High MAIFI	MILFORD (CEDAR CITY)	ELK11	ELK MEADOWS #11	355.420	1.988	1.000	1.000	81	161	
High MAIFI	MILFORD (CEDAR CITY)	CVF11	COVE FORT #11	0.000	0.000	1.000	1.000	16	0	
High MAIFI	MILFORD (CEDAR CITY)	CMR44	LINE TO MILFORD, BLUNDELL PLANT	0.000	0.000	1.000	1.000	2	0	
High MAIFI	MILFORD (CEDAR CITY)	BKL18A	BEAVER CNYN SECTIONALIZER	0.000	0.000	1.000	1.000	50	0	
High MAIFI	MILFORD (CEDAR CITY)	BKL12	BROOKLAWN #12	0.000	0.000	1.000	1.000	120	0	
High MAIFI	MILFORD (CEDAR CITY)	BKL11	BROOKLAWN #11	70.050	0.653	1.000	1.000	121	79	
Low MAIFI	MILFORD (CEDAR CITY)	2	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	MILFORD (CEDAR CITY)	T07	CAMERON-UPPER BEAVER-46KV	0.000	0.000	1.000	1.000	1	0	
High MAIFI(e)	MILFORD (CEDAR CITY)	SML12	SOUTH MILFORD #12	12.844	0.125	1.000	1.000	96	12	
High MAIFI(e)	MILFORD (CEDAR CITY)	SML11	SOUTH MILFORD #11	9.800	0.067	1.000	1.000	30	2	
High MAIFI(e)	MILFORD (CEDAR CITY)	PND11	PONDEROSA #11	0.000	0.000	1.000	1.000	50	0	
High MAIFI(e)	MILFORD (CEDAR CITY)	MTV11	MILFORD TV #11	0.000	0.000	1.000	1.000	4	0	
High MAIFI(e)	MILFORD (CEDAR CITY)	MNV11	MINERSVILLE #11	142.787	2.853	1.000	1.000	300	856	
High MAIFI(e)	MILFORD (CEDAR CITY)	MLF34	CAMERON	0.000	0.000	1.000	1.000	2	0	
High MAIFI(e)	MILFORD (CEDAR CITY)	MLF13	MILFORD #13	0.358	0.006	1.000	1.000	344	2	
High MAIFI(e)	MILFORD (CEDAR CITY)	MLF12	MILFORD #12	0.531	0.006	1.000	1.000	175	1	
High MAIFI(e)	MILFORD (CEDAR CITY)	MLF11	MILFORD #11	0.237	0.004	1.000	1.000	270	1	
High MAIFI(e)	MILFORD (CEDAR CITY)	LWB11	OLD LOWER BEAVER PLANT SITE - STOCK WAT.	0.000	0.000	1.000	1.000	4	0	
High MAIFI(e)	MILFORD (CEDAR CITY)	ELK12	ELK MEADOWS #12	372.500	2.083	1.000	1.000	12	25	
High MAIFI(e)	MILFORD (CEDAR CITY)	ELK11	ELK MEADOWS #11	355.420	1.988	1.000	1.000	81	161	
High MAIFI(e)	MILFORD (CEDAR CITY)	CVF11	COVE FORT #11	0.000	0.000	1.000	1.000	16	0	
High MAIFI(e)	MILFORD (CEDAR CITY)	CMR44	LINE TO MILFORD, BLUNDELL PLANT	0.000	0.000	1.000	1.000	2	0	
High MAIFI(e)	MILFORD (CEDAR CITY)	BKL18A	BEAVER CNYN SECTIONALIZER	0.000	0.000	1.000	1.000	50	0	
High MAIFI(e)	MILFORD (CEDAR CITY)	BKL12	BROOKLAWN #12	0.000	0.000	1.000	1.000	120	0	
High MAIFI(e)	MILFORD (CEDAR CITY)	BKL11	BROOKLAWN #11	70.050	0.653	1.000	1.000	121	79	
Low MAIFI(e)	MILFORD (CEDAR CITY)	2	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	MILFORD (CEDAR CITY)	MNV11	MINERSVILLE #11	142.787	2.853	1.000	1.000	300	856	
Low Customer Minutes Lost	MILFORD (CEDAR CITY)	2	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	OGDEN			27.724	0.296	0.037	0.037	70,416	20,842	
Planned	OGDEN			0.658	0.004	0.000	0.000	70,416	251	
Customer Requested	OGDEN			0.001	0.000	0.000	0.000	70,416	2	
High SAIDI	OGDEN	WOG14	WEST OGDEN #14	7,658.000	19.000	0.000	0.000	1	19	
Low SAIDI	OGDEN	50	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	OGDEN	WOG14	WEST OGDEN #14	7,658.000	19.000	0.000	0.000	1	19	
Low SAIFI	OGDEN	50	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	OGDEN	PIO12	PIONEER #12	1.077	0.018	1.000	1.000	1,448	26	
Low MAIFI	OGDEN	98	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	OGDEN	PIO12	PIONEER #12	1.077	0.018	1.000	1.000	1,448	26	
Low MAIFI(e)	OGDEN	98	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	OGDEN	RIV12	RIVERDALE #12	359.319	1.599	0.406	0.406	2,389	3,821	
Low Customer Minutes Lost	OGDEN	48	***** circuits with Low Customer Minutes Lost of 0.000 *****							

4th Quarter **Fiscal Year 2001** **01/01/2001 to 03/31/2001**

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Nu Occ
Low MAIFI	SALINA (RICHFIELD)	41	***** circuits with Low MAIFI of 0.000 *****							
High MAIFI(e)	SALINA (RICHFIELD)	WNK11	WINKLEMAN #11			0.000				
High MAIFI(e)	SALINA (RICHFIELD)	T33A	JERUSALEM-MORONI FEED-46KV	0.000	0.000	1.000	1.000	15	0	
High MAIFI(e)	SALINA (RICHFIELD)	T28	MINERAL PRODUCTS-PANGUITCH-46KV	213.000	1.000	1.000	1.000	2	2	
High MAIFI(e)	SALINA (RICHFIELD)	SVR47	SEVIER-MILFORD 46 KV LINE	0.000	0.000	1.000	1.000	1	0	
High MAIFI(e)	SALINA (RICHFIELD)	SVR45	SEVIER-MIN. PROD. 46 KV LINE	0.000	0.000	1.000	1.000	2	0	
High MAIFI(e)	SALINA (RICHFIELD)	SVR43	SIG-SEV #1 N.O.AT CENTRAL 40A	0.000	0.000	1.000	1.000	1	0	
High MAIFI(e)	SALINA (RICHFIELD)	SVR11	SEVIER #11	0.000	0.000	1.000	1.000	2	0	
High MAIFI(e)	SALINA (RICHFIELD)	PAN12F	PANG LK EST RECLOSER	184.631	4.164	1.000	1.000	122	508	
High MAIFI(e)	SALINA (RICHFIELD)	PAN12E	S PANG LAKE RECLOSER	0.000	0.000	1.000	1.000	92	0	
High MAIFI(e)	SALINA (RICHFIELD)	PAN12D	PANG LAKE RECLOSER	0.000	0.000	1.000	1.000	143	0	
High MAIFI(e)	SALINA (RICHFIELD)	PAN12C	W PANGUITCH SECTIONALIZER	0.000	0.000	1.000	1.000	13	0	
High MAIFI(e)	SALINA (RICHFIELD)	PAN12B	S W PANGUITCH SECTIONALIZER	0.000	0.000	1.000	1.000	153	0	
High MAIFI(e)	SALINA (RICHFIELD)	PAN12	PANGUITCH #12	0.000	0.000	1.000	1.000	191	0	
High MAIFI(e)	SALINA (RICHFIELD)	PAN11B	EAST PANG SECTIONALIZER	0.485	0.008	1.000	1.000	367	3	
High MAIFI(e)	SALINA (RICHFIELD)	PAN11	PANGUITCH #11	0.000	0.000	1.000	1.000	100	0	
High MAIFI(e)	SALINA (RICHFIELD)	MRY11B	THMPSNVL RECLOSER	1.465	0.007	1.000	1.000	722	5	
High MAIFI(e)	SALINA (RICHFIELD)	MRY01	MARYSVALE #1	0.000	0.000	1.000	1.000	45	0	
High MAIFI(e)	SALINA (RICHFIELD)	KAI11	KAIBAB #11	0.000	0.000	1.000	1.000	256	0	
High MAIFI(e)	SALINA (RICHFIELD)	JUN11B	CIRCLEVILLE LINE SECTIONALIZER	0.000	0.000	1.000	1.000	3	0	
High MAIFI(e)	SALINA (RICHFIELD)	JUN11	JUNCTION #11	0.000	0.000	1.000	1.000	15	0	
High MAIFI(e)	SALINA (RICHFIELD)	FRE11	FREEDOM #11	0.000	0.000	1.000	1.000	190	0	
High MAIFI(e)	SALINA (RICHFIELD)	ELS11B	S OF ELSINORE SECTIONALIZER	0.000	0.000	1.000	1.000	5	0	
High MAIFI(e)	SALINA (RICHFIELD)	ELS11	ELSINORE #11	0.000	0.000	1.000	1.000	140	0	
High MAIFI(e)	SALINA (RICHFIELD)	CTL11B	ANNABELLA RECLOSER	0.360	0.004	1.000	1.000	283	1	
High MAIFI(e)	SALINA (RICHFIELD)	CTL11	CENTRAL #11	0.000	0.000	1.000	1.000	211	0	
High MAIFI(e)	SALINA (RICHFIELD)	CIR11	CIRCLEVILLE #11	145.747	4.899	1.000	1.000	99	485	
Low MAIFI(e)	SALINA (RICHFIELD)	41	***** circuits with Low MAIFI(e) of 0.000 *****	12.255	0.032	1.000	1.000	251	8	
High Customer Minutes Lost	SALINA (RICHFIELD)	MOR12	MORONI #12				0.000			
Low Customer Minutes Lost	SALINA (RICHFIELD)	28	***** circuits with Low Customer Minutes Lost of 0.000 *****	425.511	3.229	0.000	0.000	454	1,466	
Unplanned	SMITHFIELD									
Planned	SMITHFIELD			72.189	0.824	0.052	0.052	13,148	10,835	
Customer Requested	SMITHFIELD			0.011	0.000	0.000	0.000	13,148	1	
High SAIDI	SMITHFIELD	GRC12	GARDEN CITY #12	0.000	0.000	0.000	0.000	13,148	0	
Low SAIDI	SMITHFIELD	6	***** circuits with Low SAIDI of 0.000 *****	679.104	3.050	0.000	0.000	338	1,031	
High SAIFI	SMITHFIELD	LOG1	LOGAN CANYON CKT#1	0.000						
Low SAIFI	SMITHFIELD	6	***** circuits with Low SAIFI of 0.000 *****	252.476	4.762	0.000	0.000	21	100	
High MAIFI	SMITHFIELD	NTN12	NEWTON #12		0.000					
High MAIFI	SMITHFIELD	NTN11	NEWTON #11	0.295	0.005	1.000	1.000	403	2	
Low MAIFI	SMITHFIELD	22	***** circuits with Low MAIFI of 0.000 *****	75.737	0.947	1.000	1.000	243	230	
High MAIFI(e)	SMITHFIELD	NTN12	NEWTON #12			0.000				
High MAIFI(e)	SMITHFIELD	NTN11	NEWTON #11	0.295	0.005	1.000	1.000	403	2	
Low MAIFI(e)	SMITHFIELD	22	***** circuits with Low MAIFI(e) of 0.000 *****	75.737	0.947	1.000	1.000	243	230	
High Customer Minutes Lost	SMITHFIELD	GRC12	GARDEN CITY #12				0.000			
Low Customer Minutes Lost	SMITHFIELD	6	***** circuits with Low Customer Minutes Lost of 0.000 *****	679.104	3.050	0.000	0.000	338	1,031	
Unplanned	SOUTH VALLEY (JORDAN VALLEY)			19.720	0.293	0.161	0.161	145,665	42,652	

Fiscal Y-T-D **Fiscal Year 2001** **04/01/00 to 03/31/01**

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Nu Occ
Unplanned	Utah			141.818	1.514	5.636	5.292	620,897	939,986	
Planned	Utah			2.499	0.017	0.000	0.000	620,897	10,515	
Customer Requested	Utah			0.050	0.000	0.001	0.001	620,897	258	
Unplanned	AMERICAN FORK			97.392	1.162	1.895	1.894	63,521	73,801	
Planned	AMERICAN FORK			1.055	0.008	0.001	0.001	63,521	514	
Customer Requested	AMERICAN FORK			0.048	0.001	0.000	0.000	63,521	80	
High SAIDI	AMERICAN FORK	EUR12	EUREKA #12	4,373.000	86.000	0.000	0.000	1	86	
Low SAIDI	AMERICAN FORK	52	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	AMERICAN FORK	EUR12	EUREKA #12	4,373.000	86.000	0.000	0.000	1	86	
Low SAIFI	AMERICAN FORK	8	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	AMERICAN FORK	ORE14	OREM #14	28.699	0.299	15.000	15.000	1,916	572	
Low MAIFI	AMERICAN FORK	69	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	AMERICAN FORK	ORE14	OREM #14	28.699	0.299	15.000	15.000	1,916	572	
Low MAIFI(e)	AMERICAN FORK	33	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	AMERICAN FORK	TRI11	TRI CITY #11	675.176	1.004	0.000	0.000	1,500	1,506	
Low Customer Minutes Lost	AMERICAN FORK	7	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	ASHLEY (VERNAL)			40.931	0.336	0.009	0.009	9,382	3,150	
Planned	ASHLEY (VERNAL)			0.044	0.000	0.000	0.000	9,382	4	
Customer Requested	ASHLEY (VERNAL)			0.000	0.000	0.000	0.000	9,382	0	
High SAIDI	ASHLEY (VERNAL)	MAE11	MAESER #11	152.149	1.309	0.048	0.048	1,714	2,243	
Low SAIDI	ASHLEY (VERNAL)	10	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	ASHLEY (VERNAL)	MAE11	MAESER #11	152.149	1.309	0.048	0.048	1,714	2,243	
Low SAIFI	ASHLEY (VERNAL)	4	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	ASHLEY (VERNAL)	MAE11	MAESER #11	152.149	1.309	0.048	0.048	1,714	2,243	
Low MAIFI	ASHLEY (VERNAL)	10	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	ASHLEY (VERNAL)	MAE11	MAESER #11	152.149	1.309	0.048	0.048	1,714	2,243	
Low MAIFI(e)	ASHLEY (VERNAL)	10	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	ASHLEY (VERNAL)	MAE11	MAESER #11	152.149	1.309	0.048	0.048	1,714	2,243	
Low Customer Minutes Lost	ASHLEY (VERNAL)	4	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	CANYONLANDS (MOAB)			112.426	0.906	2.616	2.609	14,226	12,894	
Planned	CANYONLANDS (MOAB)			1.747	0.011	0.000	0.000	14,226	156	
Customer Requested	CANYONLANDS (MOAB)			0.060	0.000	0.000	0.000	14,226	3	
High SAIDI	CANYONLANDS (MOAB)	WIT11	WHITE MESA #11	577.750	3.452	14.750	14.185	168	580	
Low SAIDI	CANYONLANDS (MOAB)	36	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	CANYONLANDS (MOAB)	HAV21	HAVASU #21	379.014	3.943	3.000	3.000	70	276	
Low SAIFI	CANYONLANDS (MOAB)	8	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	CANYONLANDS (MOAB)	WIT11	WHITE MESA #11	577.750	3.452	14.750	14.185	168	580	
Low MAIFI	CANYONLANDS (MOAB)	SO73	HATCH-UNOCAL-46KV	0.000	0.000	0.000	0.000	1	0	
High MAIFI(e)	CANYONLANDS (MOAB)	WIT11	WHITE MESA #11	577.750	3.452	14.750	14.185	168	580	
Low MAIFI(e)	CANYONLANDS (MOAB)	SO73	HATCH-UNOCAL-46KV	0.000	0.000	0.000	0.000	1	0	
High Customer Minutes Lost	CANYONLANDS (MOAB)	MOA13	MOAB #13	419.348	2.038	2.000	2.000	1,146	2,336	
Low Customer Minutes Lost	CANYONLANDS (MOAB)	SO73	HATCH-UNOCAL-46KV	0.000	0.000	0.000	0.000	1	0	
Unplanned	CARBON (PRICE)			150.483	1.620	3.120	2.978	10,248	16,599	
Planned	CARBON (PRICE)			6.138	0.062	0.000	0.000	10,248	634	
Customer Requested	CARBON (PRICE)			0.015	0.000	0.000	0.000	10,248	1	

Fiscal Y-T-D   Fiscal Year 2001   04/01/00 to 03/31/01

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Nu Occ
Low SAIDI	DELTA (RICHFIELD)	29	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	DELTA (RICHFIELD)	HDN11	HOLDEN #11	1,502.379	4.212	1.000	1.000	66	278	
Low SAIFI	DELTA (RICHFIELD)	13	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	DELTA (RICHFIELD)	FLC11	FOOL CREEK #11	136.120	1.240	6.000	6.000	25	31	
High MAIFI	DELTA (RICHFIELD)	NFD11	NORTH FIELDS #11	237.620	2.440	6.000	6.000	50	122	
High MAIFI	DELTA (RICHFIELD)	SMA11	SOMA TRACK HEATERS	0.000	0.000	6.000	6.000	1	0	
Low MAIFI	DELTA (RICHFIELD)	13	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	DELTA (RICHFIELD)	FLC11	FOOL CREEK #11	136.120	1.240	6.000	6.000	25	31	
High MAIFI(e)	DELTA (RICHFIELD)	NFD11	NORTH FIELDS #11	237.620	2.440	6.000	6.000	50	122	
High MAIFI(e)	DELTA (RICHFIELD)	SMA11	SOMA TRACK HEATERS	0.000	0.000	6.000	6.000	1	0	
Low MAIFI(e)	DELTA (RICHFIELD)	13	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	DELTA (RICHFIELD)	HDN11	HOLDEN #11	1,502.379	4.212	1.000	1.000	66	278	
Low Customer Minutes Lost	DELTA (RICHFIELD)	4	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	LAYTON (DAVIS)			80.678	1.400	8.838	8.213	37,001	51,807	
Planned	LAYTON (DAVIS)			3.972	0.024	0.001	0.001	37,001	873	
Customer Requested	LAYTON (DAVIS)			0.050	0.000	0.000	0.000	37,001	5	
High SAIDI	LAYTON (DAVIS)	SYR15	SYRACUSE #15	651.000	4.000	0.000	0.000	1	4	
Low SAIDI	LAYTON (DAVIS)	18	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	LAYTON (DAVIS)	SYR11	SYRACUSE #11	439.589	4.374	11.000	11.000	107	468	
Low SAIFI	LAYTON (DAVIS)	9	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	LAYTON (DAVIS)	LAY17	LAYTON #17	49.744	1.380	20.000	19.000	2,743	3,784	
Low MAIFI	LAYTON (DAVIS)	8	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	LAYTON (DAVIS)	LAY17	LAYTON #17	49.744	1.380	20.000	19.000	2,743	3,784	
Low MAIFI(e)	LAYTON (DAVIS)	8	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	LAYTON (DAVIS)	ANG14	ANGEL #14	292.178	3.717	1.000	1.000	2,050	7,620	
Low Customer Minutes Lost	LAYTON (DAVIS)	6	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	SLC METRO			136.627	1.533	6.076	5.720	184,202	282,470	
Planned	SLC METRO			1.128	0.006	0.000	0.000	184,202	1,025	
Customer Requested	SLC METRO			0.036	0.000	0.000	0.000	184,202	31	
High SAIDI	SLC METRO	JOR04	JORDAN #4	844.522	3.261	6.000	6.000	23	75	
Low SAIDI	SLC METRO	222	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	SLC METRO	BRU801	BRUNSWICK #801	641.429	12.429	0.000	0.000	70	870	
Low SAIFI	SLC METRO	59	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	SLC METRO	WDS13	WOODS CROSS #13	176.303	2.367	26.000	24.000	1,290	3,054	
Low MAIFI	SLC METRO	104	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	SLC METRO	WDS13	WOODS CROSS #13	176.303	2.367	26.000	24.000	1,290	3,054	
Low MAIFI(e)	SLC METRO	104	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	SLC METRO	ROS12	ROSE PARK #12	594.336	3.358	8.000	6.000	2,399	8,055	
Low Customer Minutes Lost	SLC METRO	51	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	MILFORD (CEDAR CITY)			259.683	4.258	4.131	4.131	1,689	7,192	
Planned	MILFORD (CEDAR CITY)			4.359	0.094	0.000	0.000	1,689	158	
Customer Requested	MILFORD (CEDAR CITY)			0.000	0.000	0.000	0.000	1,689	0	
High SAIDI	MILFORD (CEDAR CITY)	SML11	SOUTH MILFORD #11	1,081.533	13.100	4.000	4.000	30	393	
Low SAIDI	MILFORD (CEDAR CITY)	15	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	MILFORD (CEDAR CITY)	SML11	SOUTH MILFORD #11	1,081.533	13.100	4.000	4.000	30	393	
Low SAIFI	MILFORD (CEDAR CITY)	2	***** circuits with Low SAIFI of 0.000 *****		0.000					

Fiscal Y-T-D **Fiscal Year 2001** **04/01/00 to 03/31/01**

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Nu Occ
High MAIFI	MILFORD (CEDAR CITY)	CVF11	COVE FORT #11	423.813	5.188	10.000	10.000	16	83	
High MAIFI	MILFORD (CEDAR CITY)	MTV11	MILFORD TV #11	427.000	4.750	10.000	10.000	4	19	
Low MAIFI	MILFORD (CEDAR CITY)	2	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	MILFORD (CEDAR CITY)	CVF11	COVE FORT #11	423.813	5.188	10.000	10.000	16	83	
High MAIFI(e)	MILFORD (CEDAR CITY)	MTV11	MILFORD TV #11	427.000	4.750	10.000	10.000	4	19	
Low MAIFI(e)	MILFORD (CEDAR CITY)	2	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	MILFORD (CEDAR CITY)	MNV11	MINERSVILLE #11	248.420	5.467	4.000	4.000	300	1,640	
Low Customer Minutes Lost	MILFORD (CEDAR CITY)	2	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	OGDEN			150.076	1.679	5.127	4.722	70,416	118,261	
Planned	OGDEN			6.916	0.035	0.000	0.000	70,416	2,449	
Customer Requested	OGDEN			0.149	0.001	0.000	0.000	70,416	78	
High SAIDI	OGDEN	WOG14	WEST OGDEN #14	7,658.000	19.000	0.000	0.000	1	19	
Low SAIDI	OGDEN	54	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	OGDEN	WOG14	WEST OGDEN #14	7,658.000	19.000	0.000	0.000	1	19	
Low SAIFI	OGDEN	32	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	OGDEN	UIN13	UINTAH #13	198.842	1.180	27.000	27.000	1,001	1,181	
Low MAIFI	OGDEN	330	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	OGDEN	UIN13	UINTAH #13	198.842	1.180	27.000	27.000	1,001	1,181	
Low MAIFI(e)	OGDEN	49	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	OGDEN	RIV12	RIVERDALE #12	646.443	3.672	2.406	2.406	2,389	8,772	
Low Customer Minutes Lost	OGDEN	21	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	PARK CITY			141.136	1.257	6.418	6.326	16,060	20,183	
Planned	PARK CITY			0.000	0.000	0.000	0.000	16,060	0	
Customer Requested	PARK CITY			0.004	0.000	0.000	0.000	16,060	2	
High SAIDI	PARK CITY	TBL11	TIMBER LAKES #11	1,011.240	46.160	0.000	0.000	50	2,308	
Low SAIDI	PARK CITY	35	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	PARK CITY	TBL11	TIMBER LAKES #11	1,011.240	46.160	0.000	0.000	50	2,308	
Low SAIFI	PARK CITY	9	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	PARK CITY	COA12	COALVILLE #12	65.301	0.286	22.000	22.000	479	137	
Low MAIFI	PARK CITY	330	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	PARK CITY	COA12	COALVILLE #12	65.301	0.286	22.000	22.000	479	137	
Low MAIFI(e)	PARK CITY	14	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	PARK CITY	SNY12	SNYDERVILLE #12	520.998	4.695	14.001	14.001	871	4,089	
Low Customer Minutes Lost	PARK CITY	5	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	SALINA (RICHFIELD)			149.436	1.305	2.095	2.095	13,236	17,270	
Planned	SALINA (RICHFIELD)			2.805	0.012	0.000	0.000	13,236	156	
Customer Requested	SALINA (RICHFIELD)			0.023	0.000	0.000	0.000	13,236	1	
High SAIDI	SALINA (RICHFIELD)	PAN11B	EAST PANG SECTIONALIZER	732.000	3.000	8.000	8.000	100	300	
Low SAIDI	SALINA (RICHFIELD)	61	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	SALINA (RICHFIELD)	CTL11	CENTRAL #11	304.313	6.354	3.000	3.000	99	629	
Low SAIFI	SALINA (RICHFIELD)	13	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	SALINA (RICHFIELD)	SVR47	SEVIER-MILFORD 46 KV LINE	304.000	3.000	12.000	12.000	2	6	
Low MAIFI	SALINA (RICHFIELD)	330	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	SALINA (RICHFIELD)	SVR47	SEVIER-MILFORD 46 KV LINE	304.000	3.000	12.000	12.000	2	6	
Low MAIFI(e)	SALINA (RICHFIELD)	14	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	SALINA (RICHFIELD)	PAN11	PANGUITCH #11	496.118	3.115	8.000	8.000	722	2,249	

Fiscal Y-T-D **Fiscal Year 2001** **04/01/00 to 03/31/01**

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Nu Occ
Low Customer Minutes Lost	SALINA (RICHFIELD)	6	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	SMITHFIELD			174.814	2.233	3.679	1.689	13,148	29,354	
Planned	SMITHFIELD			0.012	0.000	0.000	0.000	13,148	2	
Customer Requested	SMITHFIELD			0.015	0.000	0.026	0.026	13,148	4	
High SAIDI	SMITHFIELD	GRC12	GARDEN CITY #12	857.018	6.086	1.000	1.000	338	2,057	
Low SAIDI	SMITHFIELD	25	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	SMITHFIELD	GRC12	GARDEN CITY #12	857.018	6.086	1.000	1.000	338	2,057	
Low SAIFI	SMITHFIELD	4	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	SMITHFIELD	AMA12	AMALGA #12	308.681	3.435	21.000	7.000	1,000	3,435	
Low MAIFI	SMITHFIELD	330	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	SMITHFIELD	AMA12	AMALGA #12	308.681	3.435	21.000	7.000	1,000	3,435	
Low MAIFI(e)	SMITHFIELD	12	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	SMITHFIELD	AMA12	AMALGA #12	308.681	3.435	21.000	7.000	1,000	3,435	
Low Customer Minutes Lost	SMITHFIELD	4	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	SOUTH VALLEY (JORDAN VALLEY)			120.344	1.304	6.647	6.338	145,665	189,925	
Planned	SOUTH VALLEY (JORDAN VALLEY)			0.624	0.006	0.000	0.000	145,665	875	
Customer Requested	SOUTH VALLEY (JORDAN VALLEY)			0.030	0.000	0.000	0.000	145,665	31	
High SAIDI	SOUTH VALLEY (JORDAN VALLEY)	UNN12	UNION #12	659.689	0.700	16.000	15.000	2,175	1,523	
Low SAIDI	SOUTH VALLEY (JORDAN VALLEY)	70	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	SOUTH VALLEY (JORDAN VALLEY)	KRN12	KEARNS #12	404.056	6.628	12.187	12.187	932	6,177	
Low SAIFI	SOUTH VALLEY (JORDAN VALLEY)	8	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	SOUTH VALLEY (JORDAN VALLEY)	DUM16	DUMAS #16	56.247	2.311	43.175	39.175	2,000	4,621	
Low MAIFI	SOUTH VALLEY (JORDAN VALLEY)	330	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	SOUTH VALLEY (JORDAN VALLEY)	DUM16	DUMAS #16	56.247	2.311	43.175	39.175	2,000	4,621	
Low MAIFI(e)	SOUTH VALLEY (JORDAN VALLEY)	19	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	SOUTH VALLEY (JORDAN VALLEY)	HOG11	HOGGARD #11	355.855	6.063	5.000	5.000	5,161	31,293	
Low Customer Minutes Lost	SOUTH VALLEY (JORDAN VALLEY)	3	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	TOOELE			913.565	4.283	13.851	13.026	9,368	40,121	
Planned	TOOELE			10.689	0.082	0.007	0.007	9,368	765	
Customer Requested	TOOELE			0.243	0.002	0.000	0.000	9,368	19	
High SAIDI	TOOELE	TOO11	TOOELE #11	2,142.219	11.209	2.000	2.000	511	5,728	
Low SAIDI	TOOELE	19	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	TOOELE	TOO11	TOOELE #11	2,142.219	11.209	2.000	2.000	511	5,728	
Low SAIFI	TOOELE	2	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	TOOELE	TOO13	TOOELE #13	892.044	3.178	28.000	26.000	3,260	10,361	
Low MAIFI	TOOELE	330	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	TOOELE	TOO13	TOOELE #13	892.044	3.178	28.000	26.000	3,260	10,361	
Low MAIFI(e)	TOOELE	7	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	TOOELE	TOO13	TOOELE #13	892.044	3.178	28.000	26.000	3,260	10,361	
Low Customer Minutes Lost	TOOELE	2	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	TREMONTON			208.520	2.743	6.058	5.288	6,424	17,624	
Planned	TREMONTON			0.000	0.000	0.000	0.000	6,424	0	
Customer Requested	TREMONTON			0.084	0.000	0.000	0.000	6,424	1	
High SAIDI	TREMONTON	BLU11	BLUE CREEK #11	1,259.758	5.883	3.000	3.000	128	753	
Low SAIDI	TREMONTON	22	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	TREMONTON	SNO11	SNOWVILLE #11	712.947	7.895	8.000	8.000	19	150	

Fiscal Y-T-D **Fiscal Year 2001** **04/01/00 to 03/31/01**

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Nur Occu
Low SAIFI	TREMONTON	6	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	TREMONTON	BRR13	BR RIVER #13	54.530	2.431	12.000	10.000	868	2,110	
Low MAIFI	TREMONTON	330	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	TREMONTON	BRR12	BEAR RIVER #12	357.265	7.237	11.000	11.000	219	1,585	
Low MAIFI(e)	TREMONTON	VULC1	VULCRAFT CORP.	0.000	0.000	0.000	0.000	1	0	
High Customer Minutes Lost	TREMONTON	BSH12	BUSH #12	899.990	5.641	1.000	1.000	398	2,245	
Low Customer Minutes Lost	TREMONTON	VULC1	VULCRAFT CORP.	0.000	0.000	0.000	0.000	1	0	

4th Quarter **Fiscal Year 2001** **01/01/2001 to 03/31/2001**

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Nur Occu
Unplanned	PARK CITY			29.793	0.541	0.000	0.000	16,060	8,693	
Planned	PARK CITY			0.000	0.000	0.000	0.000	16,060	0	
Customer Requested	PARK CITY			0.000	0.000	0.000	0.000	16,060	0	
High SAIDI	PARK CITY	TBL11	TIMBER LAKES #11	746.880	42.920	0.000	0.000	50	2,146	
Low SAIDI	PARK CITY	18	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	PARK CITY	TBL11	TIMBER LAKES #11	746.880	42.920	0.000	0.000	50	2,146	
Low SAIFI	PARK CITY	18	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	PARK CITY	SUM11	SUMMITT PARK #11	229.680	3.232	0.003	0.003	353	1,141	
Low MAIFI	PARK CITY	34	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	PARK CITY	SUM11	SUMMITT PARK #11	229.680	3.232	0.003	0.003	353	1,141	
Low MAIFI(e)	PARK CITY	34	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	PARK CITY	SNY12	SNYDERVILLE #12	234.660	3.145	0.000	0.000	871	2,739	
Low Customer Minutes Lost	PARK CITY	18	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	SALINA (RICHFIELD)			36.502	0.345	0.259	0.259	13,236	4,562	
Planned	SALINA (RICHFIELD)			2.617	0.010	0.000	0.000	13,236	131	
Customer Requested	SALINA (RICHFIELD)			0.000	0.000	0.000	0.000	13,236	0	
High SAIDI	SALINA (RICHFIELD)	FTG12	FOUNTAIN GREEN #12	579.677	2.515	0.000	0.000	99	249	
Low SAIDI	SALINA (RICHFIELD)	47	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	SALINA (RICHFIELD)	CTL11	CENTRAL #11	145.747	4.899	1.000	1.000	99	485	
Low SAIFI	SALINA (RICHFIELD)	47	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	SALINA (RICHFIELD)	WNK11	WINKLEMAN #11	0.000	0.000	1.000	1.000	15	0	
High MAIFI	SALINA (RICHFIELD)	T33A	JERUSALEM-MORONI FEED-46KV	213.000	1.000	1.000	1.000	2	2	
High MAIFI	SALINA (RICHFIELD)	T28	MINERAL PRODUCTS-PANGUITCH-46KV	0.000	0.000	1.000	1.000	1	0	
High MAIFI	SALINA (RICHFIELD)	SVR47	SEVIER-MILFORD 46 KV LINE	0.000	0.000	1.000	1.000	2	0	
High MAIFI	SALINA (RICHFIELD)	SVR45	SEVIER-MIN. PROD. 46 KV LINE	0.000	0.000	1.000	1.000	1	0	
High MAIFI	SALINA (RICHFIELD)	SVR43	SIG-SEV #1 N.O.AT CENTRAL 40A	0.000	0.000	1.000	1.000	2	0	
High MAIFI	SALINA (RICHFIELD)	SVR11	SEVIER #11	184.631	4.164	1.000	1.000	122	508	
High MAIFI	SALINA (RICHFIELD)	PAN12F	PANG LK EST RECLOSER	0.000	0.000	1.000	1.000	92	0	
High MAIFI	SALINA (RICHFIELD)	PAN12E	S PANG LAKE RECLOSER	0.000	0.000	1.000	1.000	143	0	
High MAIFI	SALINA (RICHFIELD)	PAN12D	PANG LAKE RECLOSER	0.000	0.000	1.000	1.000	13	0	
High MAIFI	SALINA (RICHFIELD)	PAN12C	W PANGUITCH SECTIONALIZER	0.000	0.000	1.000	1.000	153	0	
High MAIFI	SALINA (RICHFIELD)	PAN12B	S W PANGUITCH SECTIONALIZER	0.000	0.000	1.000	1.000	191	0	
High MAIFI	SALINA (RICHFIELD)	PAN12	PANGUITCH #12	0.485	0.008	1.000	1.000	367	3	
High MAIFI	SALINA (RICHFIELD)	PAN11B	EAST PANG SECTIONALIZER	0.000	0.000	1.000	1.000	100	0	
High MAIFI	SALINA (RICHFIELD)	PAN11	PANGUITCH #11	1.465	0.007	1.000	1.000	722	5	
High MAIFI	SALINA (RICHFIELD)	MRY11B	THMPSNVL RECLOSER	0.000	0.000	1.000	1.000	45	0	
High MAIFI	SALINA (RICHFIELD)	MRY01	MARYSVALE #1	0.000	0.000	1.000	1.000	256	0	
High MAIFI	SALINA (RICHFIELD)	KAI11	KAIBAB #11	0.000	0.000	1.000	1.000	3	0	
High MAIFI	SALINA (RICHFIELD)	JUN11B	CIRCLEVILLE LINE SECTIONALIZER	0.000	0.000	1.000	1.000	15	0	
High MAIFI	SALINA (RICHFIELD)	JUN11	JUNCTION #11	0.000	0.000	1.000	1.000	190	0	
High MAIFI	SALINA (RICHFIELD)	FRE11	FREEDOM #11	0.000	0.000	1.000	1.000	5	0	
High MAIFI	SALINA (RICHFIELD)	ELS11B	S OF ELSINORE SECTIONALIZER	0.000	0.000	1.000	1.000	140	0	
High MAIFI	SALINA (RICHFIELD)	ELS11	ELSINORE #11	0.360	0.004	1.000	1.000	283	1	
High MAIFI	SALINA (RICHFIELD)	CTL11B	ANNABELLA RECLOSER	0.000	0.000	1.000	1.000	211	0	
High MAIFI	SALINA (RICHFIELD)	CTL11	CENTRAL #11	145.747	4.899	1.000	1.000	99	485	
High MAIFI	SALINA (RICHFIELD)	CIR11	CIRCLEVILLE #11	12.255	0.032	1.000	1.000	251	8	

1900 S.W. 4th Ave.
Portland, Oregon 97201

REVIEWED BY COMMISSIONERS
STEPHEN F. MECHAM
CONSTANCE B. WHITE CBW 2/5
[illegible] D. JONES

PACIFICORP
PACIFIC POWER UTAH POWER

VIA OVERNIGHT MAIL

January 30, 2001

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City UT 84114

Attention: Julie P. Orchard
Commission Secretary

RE: Docket No. 98-2035-04 ScottishPower/PacifiCorp Merger Commitments

Please find enclosed PacifiCorp's third quarter report for the period October 2000 through December 2000 detailing the Company's performance in meeting the Customer Guarantees which were agreed to as a result of the recent merger between ScottishPower and PacifiCorp. Year-to-date information is provided as well.

As required by merger Stipulation Conditions 33 and 36, detailed outage performance and customer guarantee performance by district are also being reported. These reports are enclosed. Meter set response and temporary services response by district as required by merger Stipulation Condition 34 are also enclosed. In addition, new reports outlining the number of requests and average days to respond are included for Customer Guarantees 4,5 and 6, along with new information provided on power restoration.

If you have any questions or require further information, please call Carole Rockney at (503) 813-7408.

Sincerely,

Matthew Wright / cr

Matthew Wright
Vice President, Regulation

c: Mark Flandro - Utah Division of Public Utilities
Rea Petersen - Utah Division of Public Utilities
Andy MacRitchie - Senior Vice President, Power Delivery

Enclosure

PACIFICORP

Customer Service Commitments - Guarantees

Utah

October-December 2000

		October-December 2000			Year to Date		
	Description	Events	Failures	Paid	Events	Failures	Paid
CG1	Restoring Supply	200,344	3	$200	710,907	7	$425
CG2	Appointments	1,377	5	$250	4,642	14	$700
CG3	Switching on Power	3,687	14	$2,525	19,023	44	$7,875
CG4	Estimates	2,050	65	$3,250	6,346	110	$5,500
CG5	Respond to Billing Inquiries	2,112	8	$400	5,703	15	$750
CG6	Respond to Meter Problems	300	3	$150	849	4	$200
CG7	Notification of Planned Interruptions	2,380	8	$450	8,532	27	$1,450
CG8	Power Quality Complaints	379	24	$1,200	2,150	192	$9,600
		212,629	**130**	**$8,425**	**758,152**	**413**	**$26,500**

Summary analysis:

General Comments - PacifiCorp continues to work through its first year of the guarantees. Recent internal audits have indicated that some failure and event totals may be incomplete and therefore future reports may reflect higher levels of failures and events. The company is following up by delivering additional training and support and continuing with regular internal audits. PacifiCorp is also seeking ISO 9001 registration for the administration and reporting of the Customer Guarantees, with the first audit scheduled for February 2001.

CG3 - Switching on Power - Failures were lower in the quarter due to continuing efforts to improve processes and seasonal reduction in collection activity.

CG4 - Estimate - Most of the CG4 payments were due to firm estimates not being delivered within 15 days.

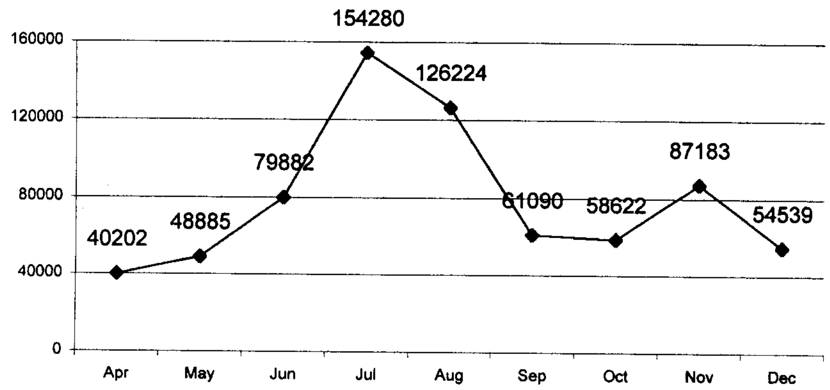
CG8 - Power Quality - Cooler temperatures and reduced demand brought relief to the number of power quality calls. Also, additional training and improved processes have significantly improved the handling of power quality inquiries in the quarter. CG8 events were over reported in September by 281 events and this is reflected in the YTD total shown on this report.

PACIFICORP
Utah

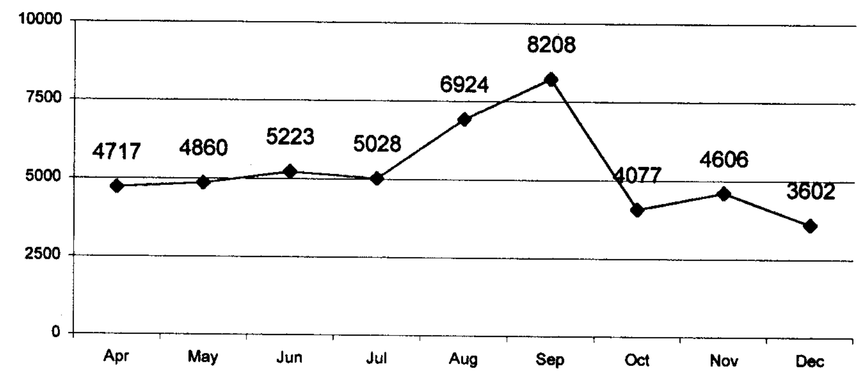
Customer Service Commitments - Guarantees

October-December 2000

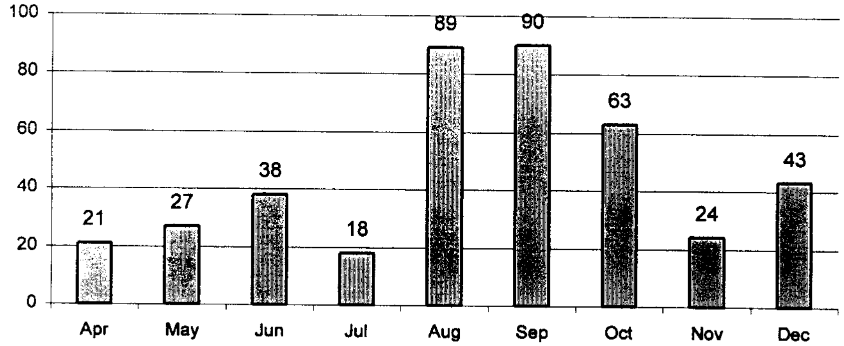
CG 1 Events



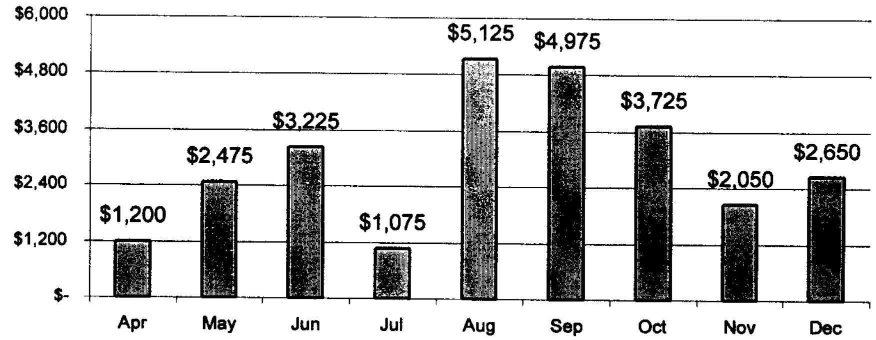
CG 2-8 Events



Failures



Payments



Customer Service Commitments

UTAH FAILURES	October-December 2000		3rd Quarter		Year to Date	
American Fork	***CG #***	***Description***	***Failure***	***Paid***	***Failure***	***Paid***
	CG2	Appointments	1	$50	3	$150
	CG3	Switching on Power	0		2	$525
	CG4	Estimates	30	$1,500	44	$2,200
	CG8	Power Quality Complaints	0		5	$250
		Total	**31**	**$1,550**	**54**	**$3,125**
Cedar City	***CG #***	***Description***	***Failure***	***Paid***	***Failure***	***Paid***
	CG3	Switching on Power*	3	$725	7	$1,725
	CG4	Estimates	2	$100	5	$250
	CG7	Notification of Planned	0		1	$50
	CG8	Power Quality Complaints	0		2	$100

* Two $250 payments were issued to the same customer when we failed to reconnect 2 of 3 meters that had been cut for non-payment. Customer did not call for 5 days regarding the "no power" status. One $225 payment was issued for a connect that was mishandled over the Thanksgiving holiday.

		Total	**5**	**$825**	**15**	**$2,125**
Jordan Valley	***CG #***	***Description***	***Failure***	***Paid***	***Failure***	***Paid***
	CG1	Restoring Supply	0		3	$150
	CG3	Switching on Power	1	$50	8	$525
	CG4	Estimates	4	$200	11	$550
	CG5	Respond to Billing Inquiries	1	$50	3	$150
	CG6	Respond to Meter Problems	1	$50	1	$50
	CG7	Notification of Planned	0		4	$250
	CG8	Power Quality Complaints	9	$450	84	$4,200
		Total	**16**	**$800**	**114**	**$5,875**
Laketown	***CG #***	***Description***	***Failure***	***Paid***	***Failure***	***Paid***
	CG2	Appointments	1	$50	1	$50
		Total	**1**	**$50**	**1**	**$50**
Layton (Davis)	***CG #***	***Description***	***Failure***	***Paid***	***Failure***	***Paid***
	CG2	Appointments	1	$50	3	$150
	CG3	Switching on Power	3	$425	6	$675
	CG4	Estimates	6	$300	6	$300
	CG5	Respond to Billing Inquiries	1	$50	1	$50
	CG6	Respond to Meter Problems	1	$50	1	$50
	CG7	Notification of Planned	0		4	$200

			3rd Quarter		Year to Date	
Layton (Davis)	***CG #***	***Description***	***Failure***	***Paid***	***Failure***	***Paid***
	CG8	Power Quality Complaints	1	$50	20	$1,000
		Total	**13**	**$925**	**41**	**$2,425**
Moab (Canyonlands)	***CG #***	***Description***	***Failure***	***Paid***	***Failure***	***Paid***
	CG1	Restoring Supply	0		1	$75
	CG2	Appointments	0		1	$50
	CG3	Switching on Power	2	$300	2	$300
	CG4	Estimates	0		2	$100
		Total	**2**	**$300**	**6**	**$525**
Ogden	***CG #***	***Description***	***Failure***	***Paid***	***Failure***	***Paid***
	CG2	Appointments	1	$50	1	$50
	CG3	Switching on Power*	5	$1,025	5	$1,025
	CG4	Estimates	5	$250	8	$400
	CG5	Respond to Billing Inquiries	1	$50	1	$50
	CG7	Notification of Planned	4	$250	6	$350
	CG8	Power Quality Complaints	5	$250	18	$900

* One payment of $700 was issued when a landlord requested service connection, the service status in CSS showed as "on" so no connect order was issued. Customer did not call for two weeks regarding the "no power" status.

		Total	**21**	**$1,875**	**39**	**$2,775**
Park City	***CG #***	***Description***	***Failure***	***Paid***	***Failure***	***Paid***
	CG3	Switching on Power	0		2	$300
	CG4	Estimates	1	$50	2	$100
	CG5	Respond to Billing Inquiries	1	$50	1	$50
	CG6	Respond to Meter Problems	1	$50	1	$50
	CG8	Power Quality Complaints	0		3	$150
		Total	**3**	**$150**	**9**	**$650**
Price (Carbon)	***CG #***	***Description***	***Failure***	***Paid***	***Failure***	***Paid***
	CG4	Estimates	0		1	$50
	CG5	Respond to Billing Inquiries	0		1	$50
	CG7	Notification of Planned	1	$50	2	$100
	CG8	Power Quality Complaints	0		1	$50
		Total	**1**	**$50**	**5**	**$250**
Richfield	***CG #***	***Description***	***Failure***	***Paid***	***Failure***	***Paid***
	CG3	Switching on Power	0		1	$500

UTAH FAILURES	October-December 2000		3rd Quarter		Year to Date	
Richfield	*CG #*	*Description*	*Failure*	*Paid*	*Failure*	*Paid*
	CG4	Estimates	3	$150	8	$400
	CG8	Power Quality Complaints	0		1	$50
		Total	**3**	**$150**	**10**	**$950**
Santaquin	*CG #*	*Description*	*Failure*	*Paid*	*Failure*	*Paid*
	CG2	Appointments	1	$50	2	$100
	CG4	Estimates	1	$50	2	$100
	CG8	Power Quality Complaints	0		2	$100
		Total	**2**	**$100**	**6**	**$300**
SLC Metro	*CG #*	*Description*	*Failure*	*Paid*	*Failure*	*Paid*
	CG1	Restoring Supply	3	$200	3	$200
	CG2	Appointments	0		2	$100
	CG3	Switching on Power	0		9	$2,100
	CG4	Estimates	4	$200	6	$300
	CG5	Respond to Billing Inquiries	4	$200	8	$400
	CG7	Notification of Planned	3	$150	10	$500
	CG8	Power Quality Complaints	5	$250	30	$1,500
		Total	**19**	**$1,000**	**68**	**$5,100**
Smithfield	*CG #*	*Description*	*Failure*	*Paid*	*Failure*	*Paid*
	CG4	Estimates	0		1	$50
	CG8	Power Quality Complaints	1	$50	5	$250
		Total	**1**	**$50**	**6**	**$300**
Tooele	*CG #*	*Description*	*Failure*	*Paid*	*Failure*	*Paid*
	CG2	Appointments	0		1	$50
	CG3	Switching on Power	0		1	$125
	CG4	Estimates	1	$50	1	$50
	CG8	Power Quality Complaints	3	$150	20	$1,000
		Total	**4**	**$200**	**23**	**$1,225**
Tremonton	*CG #*	*Description*	*Failure*	*Paid*	*Failure*	*Paid*
	CG4	Estimates	8	$400	13	$650
	CG6	Respond to Meter Problems	0		1	$50
	CG8	Power Quality Complaints	0		1	$50

UTAH FAILURES	October-December 2000		3rd Quarter		Year to Date	
Tremonton	*CG #*	*Description*	*Failure*	*Paid*	*Failure*	*Paid*
		Total	8	$400	15	$750
Vernal (Ashley)	*CG #*	*Description*	*Failure*	*Paid*	*Failure*	*Paid*
	CG3	Switching on Power	0		1	$75
		Total	0		1	$75

State Total	**130**	**$8,425**	**413**	**$26,500**

3rd Quarter **Fiscal Year 2001** **10/01/00 to 12/31/00**

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Nu Occ
Unplanned	Utah			27.888	0.323	0.713	0.679	620,887	200,372	
Planned	Utah			0.509	0.004	0.000	0.000	620,887	2,278	
Customer Requested	Utah			0.015	0.000	0.000	0.000	620,887	44	
Unplanned	AMERICAN FORK			21.379	0.250	0.188	0.188	63,542	15,895	
Planned	AMERICAN FORK			0.103	0.001	0.000	0.000	63,542	87	
Customer Requested	AMERICAN FORK			0.002	0.000	0.000	0.000	63,542	2	
High SAIDI	AMERICAN FORK	SAR13	SARATOGA #13	567.503	1.075	0.000	0.000	453	487	
Low SAIDI	AMERICAN FORK	25	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	AMERICAN FORK	PEL11	PELICAN POINT #11	327.556	4.333	0.000	0.000	9	39	
Low SAIFI	AMERICAN FORK	26	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	AMERICAN FORK	VIN11	VINEYARD #11	23.430	0.091	3.000	3.000	875	80	
Low MAIFI	AMERICAN FORK	70	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	AMERICAN FORK	VIN11	VINEYARD #11	23.430	0.091	3.000	3.000	875	80	
Low MAIFI(e)	AMERICAN FORK	61	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	AMERICAN FORK	AMF11	AMERICAN FORK #11	372.618	3.375	0.000	0.000	1,103	3,723	
Low Customer Minutes Lost	AMERICAN FORK	25	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	ASHLEY (VERNAL)			3.230	0.015	0.009	0.009	9,382	138	
Planned	ASHLEY (VERNAL)			0.000	0.000	0.000	0.000	9,382	0	
Customer Requested	ASHLEY (VERNAL)			0.000	0.000	0.000	0.000	9,382	0	
High SAIDI	ASHLEY (VERNAL)	MAE12	MAESER #12	11.495	0.025	0.000	0.000	1,371	34	
Low SAIDI	ASHLEY (VERNAL)	6	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	ASHLEY (VERNAL)	MAE11	MAESER #11	2.805	0.040	0.048	0.048	1,714	68	
Low SAIFI	ASHLEY (VERNAL)	6	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	ASHLEY (VERNAL)	MAE11	MAESER #11	2.805	0.040	0.048	0.048	1,714	68	
Low MAIFI	ASHLEY (VERNAL)	11	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	ASHLEY (VERNAL)	MAE11	MAESER #11	2.805	0.040	0.048	0.048	1,714	68	
Low MAIFI(e)	ASHLEY (VERNAL)	11	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	ASHLEY (VERNAL)	MAE12	MAESER #12	11.495	0.025	0.000	0.000	1,371	34	
Low Customer Minutes Lost	ASHLEY (VERNAL)	6	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	CANYONLANDS (MOAB)			9.235	0.052	0.883	0.883	14,226	744	
Planned	CANYONLANDS (MOAB)			0.000	0.000	0.000	0.000	14,226	0	
Customer Requested	CANYONLANDS (MOAB)			0.000	0.000	0.000	0.000	14,226	0	
High SAIDI	CANYONLANDS (MOAB)	WIT11	WHITE MESA #11	338.286	2.024	1.696	1.696	168	340	
Low SAIDI	CANYONLANDS (MOAB)	22	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	CANYONLANDS (MOAB)	WIT11	WHITE MESA #11	338.286	2.024	1.696	1.696	168	340	
Low SAIFI	CANYONLANDS (MOAB)	22	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	CANYONLANDS (MOAB)	WIT11	WHITE MESA #11	338.286	2.024	1.696	1.696	168	340	
Low MAIFI	CANYONLANDS (MOAB)	11	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	CANYONLANDS (MOAB)	WIT11	WHITE MESA #11	338.286	2.024	1.696	1.696	168	340	
Low MAIFI(e)	CANYONLANDS (MOAB)	11	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	CANYONLANDS (MOAB)	RAT22	RATTLESNAKE #22	77.629	0.290	1.000	1.000	800	232	
Low Customer Minutes Lost	CANYONLANDS (MOAB)	22	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	CARBON (PRICE)			16.057	0.172	0.590	0.590	10,248	1,767	
Planned	CARBON (PRICE)			1.744	0.047	0.000	0.000	10,248	483	
Customer Requested	CARBON (PRICE)			0.015	0.000	0.000	0.000	10,248	1	

3rd Quarter **Fiscal Year 2001** **10/01/00 to 12/31/00**

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Nu Occu
High SAIDI	CARBON (PRICE)	SCR11	SCOFIELD RES #11	180.000	1.000	0.000	0.000	197	197	
Low SAIDI	CARBON (PRICE)	27	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	CARBON (PRICE)	RAI11	RAINS #11	166.000	2.000	0.000	0.000	12	24	
Low SAIFI	CARBON (PRICE)	27	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	CARBON (PRICE)	CCK11	CLEAR CREEK #11	0.000	0.000	3.000	3.000	37	0	
High MAIFI	CARBON (PRICE)	CCK2	CIRCUIT #12	0.000	0.000	3.000	3.000	3	0	
Low MAIFI	CARBON (PRICE)	24	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	CARBON (PRICE)	CCK11	CLEAR CREEK #11	0.000	0.000	3.000	3.000	37	0	
High MAIFI(e)	CARBON (PRICE)	CCK2	CIRCUIT #12	0.000	0.000	3.000	3.000	3	0	
Low MAIFI(e)	CARBON (PRICE)	24	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	CARBON (PRICE)	ORN11	ORANGEVILLE #11	59.853	0.896	0.000	0.000	750	672	
Low Customer Minutes Lost	CARBON (PRICE)	27	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	CEDAR CITY			26.521	0.250	1.148	1.148	16,630	4,154	
Planned	CEDAR CITY			5.759	0.029	0.000	0.000	16,630	486	
Customer Requested	CEDAR CITY			0.005	0.000	0.000	0.000	16,630	2	
High SAIDI	CEDAR CITY	IRM11	IRON MOUNTAIN #11	910.500	9.500	23.500	23.500	2	19	
Low SAIDI	CEDAR CITY	39	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	CEDAR CITY	IRM11	IRON MOUNTAIN #11	910.500	9.500	23.500	23.500	2	19	
Low SAIFI	CEDAR CITY	39	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	CEDAR CITY	IRM11	IRON MOUNTAIN #11	910.500	9.500	23.500	23.500	2	19	
Low MAIFI	CEDAR CITY	9	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	CEDAR CITY	IRM11	IRON MOUNTAIN #11	910.500	9.500	23.500	23.500	2	19	
Low MAIFI(e)	CEDAR CITY	9	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	CEDAR CITY	LNT11	LONE TREE #11	98.250	1.005	1.000	1.000	843	847	
Low Customer Minutes Lost	CEDAR CITY	39	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	COTTONWOOD (JORDAN VALLEY)			21.490	0.244	0.478	0.478	95,223	23,266	
Planned	COTTONWOOD (JORDAN VALLEY)			0.105	0.001	0.000	0.000	95,223	78	
Customer Requested	COTTONWOOD (JORDAN VALLEY)			0.009	0.000	0.000	0.000	95,223	5	
High SAIDI	COTTONWOOD (JORDAN VALLEY)	STR12	STAIRS PLANT #12	210.000	1.000	0.000	0.000	90	90	
Low SAIDI	COTTONWOOD (JORDAN VALLEY)	SDY11	SANDY #11	0.000	0.000	0.000	0.000	2,355	0	
High SAIFI	COTTONWOOD (JORDAN VALLEY)	DMP13	DIMPLE DELL #13	43.406	1.801	1.000	1.000	1,232	2,219	
Low SAIFI	COTTONWOOD (JORDAN VALLEY)	SDY11	SANDY #11	0.000	0.000	0.000	0.000	2,355	0	
High MAIFI	COTTONWOOD (JORDAN VALLEY)	DMP11	DIMPLE DELL #11	1.945	0.024	4.000	4.000	925	22	
Low MAIFI	COTTONWOOD (JORDAN VALLEY)	34	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	COTTONWOOD (JORDAN VALLEY)	DMP11	DIMPLE DELL #11	1.945	0.024	4.000	4.000	925	22	
Low MAIFI(e)	COTTONWOOD (JORDAN VALLEY)	34	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	COTTONWOOD (JORDAN VALLEY)	DUM11	DUMAS #11	138.287	1.222	1.000	1.000	2,015	2,462	
Low Customer Minutes Lost	COTTONWOOD (JORDAN VALLEY)	SDY11	SANDY #11	0.000	0.000	0.000	0.000	2,355	0	
Unplanned	DELTA (RICHFIELD)			15.402	0.206	0.810	0.810	5,766	1,190	
Planned	DELTA (RICHFIELD)			0.000	0.000	0.000	0.000	5,766	0	
Customer Requested	DELTA (RICHFIELD)			0.000	0.000	0.000	0.000	5,766	0	
High SAIDI	DELTA (RICHFIELD)	HDN11	HOLDEN #11	105.136	1.015	1.000	1.000	66	67	
Low SAIDI	DELTA (RICHFIELD)	19	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	DELTA (RICHFIELD)	DLT14	DELTA #14	80.393	1.028	0.000	0.000	527	542	
Low SAIFI	DELTA (RICHFIELD)	19	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	DELTA (RICHFIELD)	DLT13	DELTA #13	1.103	0.036	3.000	3.000	388	14	

3rd Quarter **Fiscal Year 2001** **10/01/00 to 12/31/00**

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off
Low MAIFI	DELTA (RICHFIELD)	16	***** circuits with Low MAIFI of 0.000 *****			0.000			
High MAIFI(e)	DELTA (RICHFIELD)	DLT13	DELTA #13	1.103	0.036	3.000	3.000	388	14
Low MAIFI(e)	DELTA (RICHFIELD)	16	***** circuits with Low MAIFI(e) of 0.000 *****				0.000		
High Customer Minutes Lost	DELTA (RICHFIELD)	DLT14	DELTA #14	80.393	1.028	0.000	0.000	527	542
Low Customer Minutes Lost	DELTA (RICHFIELD)	19	***** circuits with Low Customer Minutes Lost of 0.000 *****						
Unplanned	LAKE (SLC METRO)			59.651	0.609	1.319	1.102	22,021	13,420
Planned	LAKE (SLC METRO)			0.003	0.000	0.000	0.000	22,021	2
Customer Requested	LAKE (SLC METRO)			0.003	0.000	0.000	0.000	22,021	1
High SAIDI	LAKE (SLC METRO)	JOR04	JORDAN #4	417.391	0.870	1.000	1.000	23	20
Low SAIDI	LAKE (SLC METRO)	18	***** circuits with Low SAIDI of 0.000 *****	0.000					
High SAIFI	LAKE (SLC METRO)	ORA11	ORANGE #11	294.075	2.125	1.325	1.325	40	85
Low SAIFI	LAKE (SLC METRO)	18	***** circuits with Low SAIFI of 0.000 *****		0.000				
High MAIFI	LAKE (SLC METRO)	WDS12	WOODS CROSS #12	116.964	1.012	4.172	4.172	732	741
Low MAIFI	LAKE (SLC METRO)	26	***** circuits with Low MAIFI of 0.000 *****			0.000			
High MAIFI(e)	LAKE (SLC METRO)	WDS12	WOODS CROSS #12	116.964	1.012	4.172	4.172	732	741
Low MAIFI(e)	LAKE (SLC METRO)	26	***** circuits with Low MAIFI(e) of 0.000 *****				0.000		
High Customer Minutes Lost	LAKE (SLC METRO)	NSL12	NORTH SALT LAKE #12	155.800	2.009	4.000	4.000	2,223	4,467
Low Customer Minutes Lost	LAKE (SLC METRO)	18	***** circuits with Low Customer Minutes Lost of 0.000 *****						
Unplanned	LAYTON (DAVIS)			15.310	0.233	1.075	1.075	37,001	8,618
Planned	LAYTON (DAVIS)			0.150	0.002	0.000	0.000	37,001	76
Customer Requested	LAYTON (DAVIS)			0.019	0.000	0.000	0.000	37,001	1
High SAIDI	LAYTON (DAVIS)	ANG14	ANGEL #14	180.351	1.002	1.000	1.000	2,050	2,054
Low SAIDI	LAYTON (DAVIS)	16	***** circuits with Low SAIDI of 0.000 *****	0.000					
High SAIFI	LAYTON (DAVIS)	ANG11	ANGEL #14	13.500	1.011	0.000	0.000	2,540	2,569
Low SAIFI	LAYTON (DAVIS)	16	***** circuits with Low SAIFI of 0.000 *****		0.000				
High MAIFI	LAYTON (DAVIS)	CLN13	CLINTON #13	2.619	0.029	6.000	6.000	859	25
Low MAIFI	LAYTON (DAVIS)	21	***** circuits with Low MAIFI of 0.000 *****			0.000			
High MAIFI(e)	LAYTON (DAVIS)	CLN13	CLINTON #13	2.619	0.029	6.000	6.000	859	25
Low MAIFI(e)	LAYTON (DAVIS)	21	***** circuits with Low MAIFI(e) of 0.000 *****				0.000		
High Customer Minutes Lost	LAYTON (DAVIS)	ANG14	ANGEL #14	180.351	1.002	1.000	1.000	2,050	2,054
Low Customer Minutes Lost	LAYTON (DAVIS)	16	***** circuits with Low Customer Minutes Lost of 0.000 *****						
Unplanned	SLC METRO			31.718	0.398	0.601	0.582	146,834	58,450
Planned	SLC METRO			0.057	0.001	0.000	0.000	146,834	87
Customer Requested	SLC METRO			0.012	0.000	0.000	0.000	146,834	10
High SAIDI	SLC METRO	RSR12	RESEARCH #12	678.000	1.933	0.000	0.000	15	29
Low SAIDI	SLC METRO	87	***** circuits with Low SAIDI of 0.000 *****	0.000					
High SAIFI	SLC METRO	GRN14	GRANGER #14	190.578	2.974	0.000	0.000	1,000	2,974
Low SAIFI	SLC METRO	89	***** circuits with Low SAIFI of 0.000 *****		0.000				
High MAIFI	SLC METRO	CTN10	COTTONWOOD #10	284.323	2.633	5.000	5.000	300	790
High MAIFI	SLC METRO	EML14	EAST MILLCREEK #14	23.216	0.280	5.000	5.000	1,047	293
High MAIFI	SLC METRO	OAK13	OAKLAND #13	54.728	1.026	5.000	5.000	2,025	2,077
Low MAIFI	SLC METRO	153	***** circuits with Low MAIFI of 0.000 *****			0.000			
High MAIFI(e)	SLC METRO	CTN10	COTTONWOOD #10	284.323	2.633	5.000	5.000	300	790
High MAIFI(e)	SLC METRO	EML14	EAST MILLCREEK #14	23.216	0.280	5.000	5.000	1,047	293
High MAIFI(e)	SLC METRO	OAK13	OAKLAND #13	54.728	1.026	5.000	5.000	2,025	2,077
Low MAIFI(e)	SLC METRO	154	***** circuits with Low MAIFI(e) of 0.000 *****				0.000		

3rd Quarter Fiscal Year 2001 10/01/00 to 12/31/00

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Nu Occ
High Customer Minutes Lost	SLC METRO	EMI11	EMIGRATION #11	183.352	1.049	2.250	2.250	2,412	2,530	
Low Customer Minutes Lost	SLC METRO	87	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	MILFORD (CEDAR CITY)			27.393	0.314	1.088	1.088	1,679	528	
Planned	MILFORD (CEDAR CITY)			0.000	0.000	0.000	0.000	1,679	0	
Customer Requested	MILFORD (CEDAR CITY)			0.000	0.000	0.000	0.000	1,679	0	
High SAIDI	MILFORD (CEDAR CITY)	ELK12	ELK MEADOWS #12	300.000	2.083	2.000	2.000	12	25	
Low SAIDI	MILFORD (CEDAR CITY)	8	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	MILFORD (CEDAR CITY)	ELK12	ELK MEADOWS #12	300.000	2.083	2.000	2.000	12	25	
Low SAIFI	MILFORD (CEDAR CITY)	8	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	MILFORD (CEDAR CITY)	ELK11	ELK MEADOWS #11	291.037	2.025	2.000	2.000	81	164	
High MAIFI	MILFORD (CEDAR CITY)	ELK12	ELK MEADOWS #12	300.000	2.083	2.000	2.000	12	25	
High MAIFI	MILFORD (CEDAR CITY)	LWB11	OLD LOWER BEAVER PLANT SITE - STOCK WAT.	0.000	0.000	2.000	2.000	4	0	
High MAIFI	MILFORD (CEDAR CITY)	PND11	PONDEROSA #11	0.000	0.000	2.000	2.000	50	0	
High MAIFI	MILFORD (CEDAR CITY)	T07	CAMERON-UPPER BEAVER-46KV	0.000	0.000	2.000	2.000	1	0	
Low MAIFI	MILFORD (CEDAR CITY)	T11	MINERAL PRODUCTS-DEER TRAIL-46KV	0.000	0.000	0.000	0.000	1	0	
High MAIFI(e)	MILFORD (CEDAR CITY)	ELK11	ELK MEADOWS #11	291.037	2.025	2.000	2.000	81	164	
High MAIFI(e)	MILFORD (CEDAR CITY)	ELK12	ELK MEADOWS #12	300.000	2.083	2.000	2.000	12	25	
High MAIFI(e)	MILFORD (CEDAR CITY)	LWB11	OLD LOWER BEAVER PLANT SITE - STOCK WAT.	0.000	0.000	2.000	2.000	4	0	
High MAIFI(e)	MILFORD (CEDAR CITY)	PND11	PONDEROSA #11	0.000	0.000	2.000	2.000	50	0	
High MAIFI(e)	MILFORD (CEDAR CITY)	T07	CAMERON-UPPER BEAVER-46KV	0.000	0.000	2.000	2.000	1	0	
Low MAIFI(e)	MILFORD (CEDAR CITY)	T11	MINERAL PRODUCTS-DEER TRAIL-46KV	0.000	0.000	0.000	0.000	1	0	
High Customer Minutes Lost	MILFORD (CEDAR CITY)	ELK11	ELK MEADOWS #11	291.037	2.025	2.000	2.000	81	164	
Low Customer Minutes Lost	MILFORD (CEDAR CITY)	8	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	OGDEN			49.764	0.584	1.327	1.289	70,416	41,149	
Planned	OGDEN			2.114	0.010	0.000	0.000	70,416	730	
Customer Requested	OGDEN			0.062	0.000	0.000	0.000	70,416	15	
High SAIDI	OGDEN	BRK11	BRICKYARD #11	295.639	2.931	1.000	1.000	1,306	3,828	
Low SAIDI	OGDEN	40	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	OGDEN	BRK11	BRICKYARD #11	295.639	2.931	1.000	1.000	1,306	3,828	
Low SAIFI	OGDEN	40	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	OGDEN	LIN11	LINCOLN #11	0.348	0.005	7.000	7.000	2,327	12	
High MAIFI	OGDEN	NOG12	NORTH OGDEN #12	74.375	1.006	7.000	7.000	2,000	2,011	
Low MAIFI	OGDEN	58	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	OGDEN	LIN11	LINCOLN #11	0.348	0.005	7.000	7.000	2,327	12	
High MAIFI(e)	OGDEN	NOG12	NORTH OGDEN #12	74.375	1.006	7.000	7.000	2,000	2,011	
Low MAIFI(e)	OGDEN	58	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	OGDEN	RIV12	RIVERDALE #12	222.465	1.003	0.000	0.000	2,389	2,395	
Low Customer Minutes Lost	OGDEN	40	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	PARK CITY			45.567	0.277	0.666	0.666	16,060	4,455	
Planned	PARK CITY			0.000	0.000	0.000	0.000	16,060	0	
Customer Requested	PARK CITY			0.004	0.000	0.000	0.000	16,060	2	
High SAIDI	PARK CITY	SNY12	SNYDERVILLE #12	270.471	1.358	6.000	6.000	871	1,183	
Low SAIDI	PARK CITY	12	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	PARK CITY	SNY12	SNYDERVILLE #12	270.471	1.358	6.000	6.000	871	1,183	
Low SAIFI	PARK CITY	12	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	PARK CITY	SNY12	SNYDERVILLE #12	270.471	1.358	6.000	6.000	871	1,183	

3rd Quarter **Fiscal Year 2001** **10/01/00 to 12/31/00**

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Nu Occ
Low MAIFI	PARK CITY	27	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	PARK CITY	SNY12	SNYDERVILLE #12	270.471	1.358	6.000	6.000	871	1,183	
Low MAIFI(e)	PARK CITY	27	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	PARK CITY	SNY12	SNYDERVILLE #12	270.471	1.358	6.000	6.000	871	1,183	
Low Customer Minutes Lost	PARK CITY	12	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	SALINA (RICHFIELD)			20.524	0.220	0.430	0.430	13,236	2,913	
Planned	SALINA (RICHFIELD)			0.018	0.000	0.000	0.000	13,236	2	
Customer Requested	SALINA (RICHFIELD)			0.000	0.000	0.000	0.000	13,236	0	
High SAIDI	SALINA (RICHFIELD)	PAN11B	EAST PANG SECTIONALIZER	330.000	1.000	2.000	2.000	100	100	
Low SAIDI	SALINA (RICHFIELD)	44	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	SALINA (RICHFIELD)	GUN13	GUNNISON #13	172.465	1.953	0.000	0.000	318	621	
Low SAIFI	SALINA (RICHFIELD)	44	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	SALINA (RICHFIELD)	SVR45	SEVIER-MIN. PROD. 46 KV LINE	0.000	0.000	5.000	5.000	1	0	
Low MAIFI	SALINA (RICHFIELD)	41	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	SALINA (RICHFIELD)	SVR45	SEVIER-MIN. PROD. 46 KV LINE	0.000	0.000	5.000	5.000	1	0	
Low MAIFI(e)	SALINA (RICHFIELD)	41	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	SALINA (RICHFIELD)	RCH12	RICHFIELD #12	89.304	0.388	0.000	0.000	815	316	
Low Customer Minutes Lost	SALINA (RICHFIELD)	44	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	SMITHFIELD			17.222	0.199	0.061	0.061	13,127	2,610	
Planned	SMITHFIELD			0.001	0.000	0.000	0.000	13,127	1	
Customer Requested	SMITHFIELD			0.005	0.000	0.000	0.000	13,127	1	
High SAIDI	SMITHFIELD	NOL12	NORTH LOGAN #12	146.800	2.018	0.000	0.000	1,000	2,018	
Low SAIDI	SMITHFIELD	8	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	SMITHFIELD	NOL12	NORTH LOGAN #12	146.800	2.018	0.000	0.000	1,000	2,018	
Low SAIFI	SMITHFIELD	8	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	SMITHFIELD	AMA14	AMALGA #14	2.765	0.024	1.000	1.000	293	7	
High MAIFI	SMITHFIELD	LEW13	LEWISTON #13	0.675	0.014	1.000	1.000	505	7	
Low MAIFI	SMITHFIELD	23	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	SMITHFIELD	AMA14	AMALGA #14	2.765	0.024	1.000	1.000	293	7	
High MAIFI(e)	SMITHFIELD	LEW13	LEWISTON #13	0.675	0.014	1.000	1.000	505	7	
Low MAIFI(e)	SMITHFIELD	23	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	SMITHFIELD	NOL12	NORTH LOGAN #12	146.800	2.018	0.000	0.000	1,000	2,018	
Low Customer Minutes Lost	SMITHFIELD	8	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	SOUTH VALLEY (JORDAN VALLEY)			25.064	0.211	0.216	0.216	27,846	5,884	
Planned	SOUTH VALLEY (JORDAN VALLEY)			0.000	0.000	0.000	0.000	27,846	0	
Customer Requested	SOUTH VALLEY (JORDAN VALLEY)			0.000	0.000	0.000	0.000	27,846	0	
High SAIDI	SOUTH VALLEY (JORDAN VALLEY)	HOG12	HOGGARD #12	187.165	0.551	0.000	0.000	2,036	1,121	
Low SAIDI	SOUTH VALLEY (JORDAN VALLEY)	8	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	SOUTH VALLEY (JORDAN VALLEY)	SDY14	SANDY #14	80.125	2.324	0.000	0.000	546	1,269	
Low SAIFI	SOUTH VALLEY (JORDAN VALLEY)	8	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	SOUTH VALLEY (JORDAN VALLEY)	BGT12	BANGERTER #12	25.182	0.120	2.000	2.000	965	116	
Low MAIFI	SOUTH VALLEY (JORDAN VALLEY)	23	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	SOUTH VALLEY (JORDAN VALLEY)	BGT12	BANGERTER #12	25.182	0.120	2.000	2.000	965	116	
Low MAIFI(e)	SOUTH VALLEY (JORDAN VALLEY)	23	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	SOUTH VALLEY (JORDAN VALLEY)	HOG12	HOGGARD #12	187.165	0.551	0.000	0.000	2,036	1,121	
Low Customer Minutes Lost	SOUTH VALLEY (JORDAN VALLEY)	8	***** circuits with Low Customer Minutes Lost of 0.000 *****							

3rd Quarter   Fiscal Year 2001   10/01/00 to 12/31/00

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Nu Occ
Unplanned	**TOOELE**			18.772	0.270	0.943	0.943	9,368	2,525	
Planned	**TOOELE**			1.787	0.015	0.000	0.000	9,368	143	
Customer Requested	**TOOELE**			0.128	0.000	0.000	0.000	9,368	4	
High SAIDI	**TOOELE**	SKU11	SKULL VALLEY #11	228.000	2.000	0.000	0.000	119	238	
Low SAIDI	**TOOELE**	13	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	**TOOELE**	LAK11	LAKE POINT #11	91.335	2.849	2.358	2.358	218	621	
Low SAIFI	**TOOELE**	13	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	**TOOELE**	LAK11	LAKE POINT #11	91.335	2.849	2.358	2.358	218	621	
Low MAIFI	**TOOELE**	19	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	**TOOELE**	LAK11	LAKE POINT #11	91.335	2.849	2.358	2.358	218	621	
Low MAIFI(e)	**TOOELE**	19	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	**TOOELE**	GRA11	GRANTSVILLE #11	36.706	0.328	1.000	1.000	1,621	532	
Low Customer Minutes Lost	**TOOELE**	13	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	**TREMONTON**			34.157	0.633	3.265	2.691	6,424	4,064	
Planned	**TREMONTON**			0.000	0.000	0.000	0.000	6,424	0	
Customer Requested	**TREMONTON**			0.000	0.000	0.000	0.000	6,424	0	
High SAIDI	**TREMONTON**	BRR14	BEAR RIVER #14	128.556	2.579	6.000	4.000	349	900	
Low SAIDI	**TREMONTON**	8	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	**TREMONTON**	BRR14	BEAR RIVER #14	128.556	2.579	6.000	4.000	349	900	
Low SAIFI	**TREMONTON**	8	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	**TREMONTON**	BRR13	BR RIVER #13	4.942	0.013	11.000	9.000	868	11	
Low MAIFI	**TREMONTON**	11	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	**TREMONTON**	BRR13	BR RIVER #13	4.942	0.013	11.000	9.000	868	11	
Low MAIFI(e)	**TREMONTON**	11	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	**TREMONTON**	BRR11	BEAR RIVER #11	94.561	2.000	5.000	4.000	1,254	2,508	
Low Customer Minutes Lost	**TREMONTON**	8	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	**VALLEY WEST**			15.394	0.206	0.886	0.720	41,856	8,602	
Planned	**VALLEY WEST**			0.137	0.002	0.000	0.000	41,856	103	
Customer Requested	**VALLEY WEST**			0.000	0.000	0.000	0.000	41,856	0	
High SAIDI	**VALLEY WEST**	SPK12	SOUTH PARK #12	300.000	1.000	0.000	0.000	1	1	
Low SAIDI	**VALLEY WEST**	8	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	**VALLEY WEST**	TAY11	TAYLORSVILLE #11	85.300	1.408	0.000	0.000	901	1,269	
Low SAIFI	**VALLEY WEST**	8	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	**VALLEY WEST**	SPK11	SOUTH PARK #11	26.811	0.187	5.000	5.000	1,086	203	
Low MAIFI	**VALLEY WEST**	18	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	**VALLEY WEST**	SPK11	SOUTH PARK #11	26.811	0.187	5.000	5.000	1,086	203	
Low MAIFI(e)	**VALLEY WEST**	18	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	**VALLEY WEST**	RDG12	RIDGELAND #12	115.587	1.089	4.000	1.000	2,314	2,521	
Low Customer Minutes Lost	**VALLEY WEST**	8	***** circuits with Low Customer Minutes Lost of 0.000 *****							

Fiscal Y-T-D   Fiscal Year 2001   04/01/00 to 12/31/00

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Nu Occ
Unplanned	Utah			**114.439**	**1.144**	**5.493**	**5.152**	**620,887**	**710,327**	
Planned	Utah			**1.939**	**0.014**	**0.000**	**0.000**	**620,887**	**8,430**	
Customer Requested	Utah			**0.049**	**0.000**	**0.001**	**0.001**	**620,887**	**254**	
Unplanned	**AMERICAN FORK**			92.161	1.074	1.893	1.892	63,542	68,213	
Planned	**AMERICAN FORK**			0.717	0.006	0.001	0.001	63,542	403	
Customer Requested	**AMERICAN FORK**			0.048	0.001	0.000	0.000	63,542	80	
High SAIDI	**AMERICAN FORK**	SAR13	SARATOGA #13	1,786.940	6.263	2.000	2.000	453	2,837	
Low SAIDI	**AMERICAN FORK**	11	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	**AMERICAN FORK**	PEL11	PELICAN POINT #11	597.556	6.333	0.000	0.000	9	57	
Low SAIFI	**AMERICAN FORK**	11	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	**AMERICAN FORK**	ORE14	OREM #14	28.676	0.298	15.000	15.000	1,916	571	
Low MAIFI	**AMERICAN FORK**	70	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	**AMERICAN FORK**	ORE14	OREM #14	28.676	0.298	15.000	15.000	1,916	571	
Low MAIFI(e)	**AMERICAN FORK**	34	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	**AMERICAN FORK**	TRI11	TRI CITY #11	675.176	1.004	0.000	0.000	1,500	1,506	
Low Customer Minutes Lost	**AMERICAN FORK**	11	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	**ASHLEY (VERNAL)**			34.962	0.292	0.009	0.009	9,382	2,740	
Planned	**ASHLEY (VERNAL)**			0.000	0.000	0.000	0.000	9,382	0	
Customer Requested	**ASHLEY (VERNAL)**			0.000	0.000	0.000	0.000	9,382	0	
High SAIDI	**ASHLEY (VERNAL)**	MAE11	MAESER #11	151.984	1.306	0.048	0.048	1,714	2,239	
Low SAIDI	**ASHLEY (VERNAL)**	4	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	**ASHLEY (VERNAL)**	MAE11	MAESER #11	151.984	1.306	0.048	0.048	1,714	2,239	
Low SAIFI	**ASHLEY (VERNAL)**	4	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	**ASHLEY (VERNAL)**	MAE11	MAESER #11	151.984	1.306	0.048	0.048	1,714	2,239	
Low MAIFI	**ASHLEY (VERNAL)**	11	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	**ASHLEY (VERNAL)**	MAE11	MAESER #11	151.984	1.306	0.048	0.048	1,714	2,239	
Low MAIFI(e)	**ASHLEY (VERNAL)**	11	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	**ASHLEY (VERNAL)**	MAE11	MAESER #11	151.984	1.306	0.048	0.048	1,714	2,239	
Low Customer Minutes Lost	**ASHLEY (VERNAL)**	4	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	**CANYONLANDS (MOAB)**			100.020	0.800	2.615	2.608	14,226	11,381	
Planned	**CANYONLANDS (MOAB)**			1.745	0.011	0.000	0.000	14,226	155	
Customer Requested	**CANYONLANDS (MOAB)**			0.060	0.000	0.000	0.000	14,226	3	
High SAIDI	**CANYONLANDS (MOAB)**	RDR02	RED ROCK #2	577.500	2.800	1.050	1.050	20	56	
Low SAIDI	**CANYONLANDS (MOAB)**	8	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	**CANYONLANDS (MOAB)**	HAV21	HAVASU #21	379.014	3.943	3.000	3.000	70	276	
Low SAIFI	**CANYONLANDS (MOAB)**	8	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	**CANYONLANDS (MOAB)**	WIT11	WHITE MESA #11	576.833	3.446	14.702	14.137	168	579	
Low MAIFI	**CANYONLANDS (MOAB)**	SO73	HATCH-UNOCAL-46KV	0.000	0.000	0.000	0.000	1	0	
High MAIFI(e)	**CANYONLANDS (MOAB)**	WIT11	WHITE MESA #11	576.833	3.446	14.702	14.137	168	579	
Low MAIFI(e)	**CANYONLANDS (MOAB)**	SO73	HATCH-UNOCAL-46KV	0.000	0.000	0.000	0.000	1	0	
High Customer Minutes Lost	**CANYONLANDS (MOAB)**	MOA13	MOAB #13	419.348	2.038	2.000	2.000	1,146	2,336	
Low Customer Minutes Lost	**CANYONLANDS (MOAB)**	8	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	**CARBON (PRICE)**			138.961	1.537	3.120	2.978	10,248	15,751	
Planned	**CARBON (PRICE)**			6.138	0.062	0.000	0.000	10,248	634	
Customer Requested	**CARBON (PRICE)**			0.015	0.000	0.000	0.000	10,248	1	

Fiscal Y-T-D **Fiscal Year 2001** **04/01/00 to 12/31/00**

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Nur Occu
High SAIDI	CARBON (PRICE)	HUN11	HUNTINGTON CITY #11	296.609	3.185	2.000	2.000	460	1,465	
Low SAIDI	CARBON (PRICE)	15	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	CARBON (PRICE)	HUN11	HUNTINGTON CITY #11	296.609	3.185	2.000	2.000	460	1,465	
Low SAIFI	CARBON (PRICE)	15	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	CARBON (PRICE)	KYU01	KYUNE #1	0.000	0.000	9.000	6.000	1	0	
High MAIFI	CARBON (PRICE)	CLT01	COLTON #1	0.000	0.000	9.000	6.000	12	0	
High MAIFI	CARBON (PRICE)	RYL01	ROYAL #1	0.000	0.000	9.000	6.000	5	0	
High MAIFI	CARBON (PRICE)	SCO11	SCOFIELD CITY #11	9.202	0.076	9.000	6.000	238	18	
High MAIFI	CARBON (PRICE)	SOL11	SOLDIER SUMMIT #11	26.000	0.400	9.000	6.000	30	12	
High MAIFI	CARBON (PRICE)	SCR11	SCOFIELD RES #11	207.183	1.173	9.000	6.000	197	231	
Low MAIFI	CARBON (PRICE)	14	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	CARBON (PRICE)	CCK11	CLEAR CREEK #11	0.000	0.000	8.000	8.000	37	0	
High MAIFI(e)	CARBON (PRICE)	CCK2	CIRCUIT #12	0.000	0.000	8.000	8.000	3	0	
Low MAIFI(e)	CARBON (PRICE)	14	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	CARBON (PRICE)	WLG11	WELLINGTON #11	275.184	2.040	2.000	2.000	830	1,693	
Low Customer Minutes Lost	CARBON (PRICE)	15	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	CEDAR CITY			136.808	2.148	6.125	5.729	16,630	35,720	
Planned	CEDAR CITY			18.945	0.173	0.008	0.008	16,630	2,884	
Customer Requested	CEDAR CITY			0.005	0.000	0.000	0.000	16,630	2	
High SAIDI	CEDAR CITY	IRM11	IRON MOUNTAIN #11	5,270.000	69.000	100.500	100.500	2	138	
Low SAIDI	CEDAR CITY	WOL11	WOOLSEY CIRCUIT	0.000	0.000	0.000	0.000	6	0	
High SAIFI	CEDAR CITY	IRM11	IRON MOUNTAIN #11	5,270.000	69.000	100.500	100.500	2	138	
Low SAIFI	CEDAR CITY	WOL11	WOOLSEY CIRCUIT	0.000	0.000	0.000	0.000	6	0	
High MAIFI	CEDAR CITY	IRM11	IRON MOUNTAIN #11	5,270.000	69.000	100.500	100.500	2	138	
Low MAIFI	CEDAR CITY	3	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	CEDAR CITY	IRM11	IRON MOUNTAIN #11	5,270.000	69.000	100.500	100.500	2	138	
Low MAIFI(e)	CEDAR CITY	3	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	CEDAR CITY	BHD11	BRIAN HEAD #11	302.147	3.522	7.000	6.000	726	2,557	
Low Customer Minutes Lost	CEDAR CITY	WOL11	WOOLSEY CIRCUIT	0.000	0.000	0.000	0.000	6	0	
Unplanned	COTTONWOOD (JORDAN VALLEY)			84.400	0.846	7.252	6.939	95,223	80,604	
Planned	COTTONWOOD (JORDAN VALLEY)			0.160	0.001	0.000	0.000	95,223	116	
Customer Requested	COTTONWOOD (JORDAN VALLEY)			0.018	0.000	0.000	0.000	95,223	8	
High SAIDI	COTTONWOOD (JORDAN VALLEY)	UNN12	UNION #12	658.663	0.669	16.000	15.000	2,175	1,455	
Low SAIDI	COTTONWOOD (JORDAN VALLEY)	SDY11	SANDY #11	0.191	0.001	1.000	1.000	2,355	2	
High SAIFI	COTTONWOOD (JORDAN VALLEY)	STR12	STAIRS PLANT #12	493.000	3.333	6.000	6.000	90	300	
Low SAIFI	COTTONWOOD (JORDAN VALLEY)	SDY11	SANDY #11	0.191	0.001	1.000	1.000	2,355	2	
High MAIFI	COTTONWOOD (JORDAN VALLEY)	DUM16	DUMAS #16	54.743	2.306	43.175	39.175	2,000	4,611	
Low MAIFI	COTTONWOOD (JORDAN VALLEY)	11	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	COTTONWOOD (JORDAN VALLEY)	DUM16	DUMAS #16	54.743	2.306	43.175	39.175	2,000	4,611	
Low MAIFI(e)	COTTONWOOD (JORDAN VALLEY)	11	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	COTTONWOOD (JORDAN VALLEY)	UNN12	UNION #12	658.663	0.669	16.000	15.000	2,175	1,455	
Low Customer Minutes Lost	COTTONWOOD (JORDAN VALLEY)	SDY11	SANDY #11	0.191	0.001	1.000	1.000	2,355	2	
Unplanned	DELTA (RICHFIELD)			66.890	0.533	2.821	2.371	5,766	3,074	
Planned	DELTA (RICHFIELD)			0.021	0.000	0.000	0.000	5,766	1	
Customer Requested	DELTA (RICHFIELD)			0.000	0.000	0.000	0.000	5,766	0	
High SAIDI	DELTA (RICHFIELD)	HDN11	HOLDEN #11	1,502.379	4.212	1.000	1.000	66	278	

Fiscal Y-T-D Fiscal Year 2001 04/01/00 to 12/31/00

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Nu Occ
Low SAIDI	DELTA (RICHFIELD)	13	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	DELTA (RICHFIELD)	HDN11	HOLDEN #11	1,502.379	4.212	1.000	1.000	66	278	
Low SAIFI	DELTA (RICHFIELD)	13	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	DELTA (RICHFIELD)	SMA11	SOMA TRACK HEATERS	0.000	0.000	6.000	6.000	1	0	
High MAIFI	DELTA (RICHFIELD)	FLC11	FOOL CREEK #11	122.320	1.080	6.000	6.000	25	27	
High MAIFI	DELTA (RICHFIELD)	NFD11	NORTH FIELDS #11	235.000	2.420	6.000	6.000	50	121	
Low MAIFI	DELTA (RICHFIELD)	13	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	DELTA (RICHFIELD)	SMA11	SOMA TRACK HEATERS	0.000	0.000	6.000	6.000	1	0	
High MAIFI(e)	DELTA (RICHFIELD)	FLC11	FOOL CREEK #11	122.320	1.080	6.000	6.000	25	27	
High MAIFI(e)	DELTA (RICHFIELD)	NFD11	NORTH FIELDS #11	235.000	2.420	6.000	6.000	50	121	
Low MAIFI(e)	DELTA (RICHFIELD)	13	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	DELTA (RICHFIELD)	HDN11	HOLDEN #11	1,502.379	4.212	1.000	1.000	66	278	
Low Customer Minutes Lost	DELTA (RICHFIELD)	13	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	LAKE (SLC METRO)			172.014	1.355	7.267	6.454	22,021	29,833	
Planned	LAKE (SLC METRO)			0.010	0.000	0.000	0.000	22,021	3	
Customer Requested	LAKE (SLC METRO)			0.191	0.001	0.000	0.000	22,021	19	
High SAIDI	LAKE (SLC METRO)	JOR04	JORDAN #4	831.957	3.217	6.000	6.000	23	74	
Low SAIDI	LAKE (SLC METRO)	4	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	LAKE (SLC METRO)	RED16	REDWOOD #16	558.743	4.645	11.000	9.000	307	1,426	
Low SAIFI	LAKE (SLC METRO)	4	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	LAKE (SLC METRO)	WDS13	WOODS CROSS #13	156.240	2.080	26.000	24.000	1,290	2,683	
Low MAIFI	LAKE (SLC METRO)	17	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	LAKE (SLC METRO)	WDS13	WOODS CROSS #13	156.240	2.080	26.000	24.000	1,290	2,683	
Low MAIFI(e)	LAKE (SLC METRO)	17	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	LAKE (SLC METRO)	NSL12	NORTH SALT LAKE #12	490.608	3.510	18.000	16.000	2,223	7,802	
Low Customer Minutes Lost	LAKE (SLC METRO)	4	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	LAYTON (DAVIS)			62.929	1.112	8.540	7.957	37,001	41,142	
Planned	LAYTON (DAVIS)			3.899	0.022	0.001	0.001	37,001	832	
Customer Requested	LAYTON (DAVIS)			0.045	0.000	0.000	0.000	37,001	4	
High SAIDI	LAYTON (DAVIS)	SYR11	SYRACUSE #11	418.729	4.234	10.000	10.000	107	453	
Low SAIDI	LAYTON (DAVIS)	10	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	LAYTON (DAVIS)	SYR11	SYRACUSE #11	418.729	4.234	10.000	10.000	107	453	
Low SAIFI	LAYTON (DAVIS)	10	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	LAYTON (DAVIS)	LAY17	LAYTON #17	45.476	1.355	19.000	18.000	2,743	3,716	
Low MAIFI	LAYTON (DAVIS)	8	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	LAYTON (DAVIS)	LAY17	LAYTON #17	45.476	1.355	19.000	18.000	2,743	3,716	
Low MAIFI(e)	LAYTON (DAVIS)	8	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	LAYTON (DAVIS)	ANG14	ANGEL #14	215.243	2.025	1.000	1.000	2,050	4,151	
Low Customer Minutes Lost	LAYTON (DAVIS)	10	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	SLC METRO			107.945	1.045	5.565	5.293	146,834	153,415	
Planned	SLC METRO			0.177	0.001	0.000	0.000	146,834	161	
Customer Requested	SLC METRO			0.017	0.000	0.000	0.000	146,834	12	
High SAIDI	SLC METRO	RSR12	RESEARCH #12	678.000	1.933	0.000	0.000	15	29	
Low SAIDI	SLC METRO	58	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	SLC METRO	CTN11	COTTONWOOD #11	599.882	4.824	2.000	2.000	34	164	
Low SAIFI	SLC METRO	58	***** circuits with Low SAIFI of 0.000 *****		0.000					

Fiscal Y-T-D　　Fiscal Year 2001　　04/01/00 to 12/31/00

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Nur Occu
High MAIFI	SLC METRO	MCL12	MCCLELLAND #12	116.106	1.057	22.002	20.002	2,693	2,847	
Low MAIFI	SLC METRO	90	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	SLC METRO	MCL12	MCCLELLAND #12	116.106	1.057	22.002	20.002	2,693	2,847	
Low MAIFI(e)	SLC METRO	90	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	SLC METRO	EMI11	EMIGRATION #11	343.106	1.786	16.250	16.250	2,412	4,308	
Low Customer Minutes Lost	SLC METRO	58	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	**MILFORD (CEDAR CITY)**			209.784	3.605	3.157	3.157	1,679	6,053	
Planned	**MILFORD (CEDAR CITY)**			1.173	0.009	0.000	0.000	1,679	15	
Customer Requested	**MILFORD (CEDAR CITY)**			0.000	0.000	0.000	0.000	1,679	0	
High SAIDI	MILFORD (CEDAR CITY)	SML11	SOUTH MILFORD #11	1,071.733	13.033	3.000	3.000	30	391	
Low SAIDI	MILFORD (CEDAR CITY)	T11	MINERAL PRODUCTS-DEER TRAIL-46KV	0.000	0.000	0.000	0.000	1	0	
High SAIFI	MILFORD (CEDAR CITY)	SML11	SOUTH MILFORD #11	1,071.733	13.033	3.000	3.000	30	391	
Low SAIFI	MILFORD (CEDAR CITY)	T11	MINERAL PRODUCTS-DEER TRAIL-46KV	0.000	0.000	0.000	0.000	1	0	
High MAIFI	MILFORD (CEDAR CITY)	CVF11	COVE FORT #11	423.813	5.188	9.000	9.000	16	83	
High MAIFI	MILFORD (CEDAR CITY)	MTV11	MILFORD TV #11	427.000	4.750	9.000	9.000	4	19	
Low MAIFI	MILFORD (CEDAR CITY)	T11	MINERAL PRODUCTS-DEER TRAIL-46KV	0.000	0.000	0.000	0.000	1	0	
High MAIFI(e)	MILFORD (CEDAR CITY)	CVF11	COVE FORT #11	423.813	5.188	9.000	9.000	16	83	
High MAIFI(e)	MILFORD (CEDAR CITY)	MTV11	MILFORD TV #11	427.000	4.750	9.000	9.000	4	19	
Low MAIFI(e)	MILFORD (CEDAR CITY)	T11	MINERAL PRODUCTS-DEER TRAIL-46KV	0.000	0.000	0.000	0.000	1	0	
High Customer Minutes Lost	MILFORD (CEDAR CITY)	MLF13	MILFORD #13	203.110	4.407	3.000	3.000	344	1,516	
Low Customer Minutes Lost	MILFORD (CEDAR CITY)	T11	MINERAL PRODUCTS-DEER TRAIL-46KV	0.000	0.000	0.000	0.000	1	0	
Unplanned	**OGDEN**			122.352	1.383	5.090	4.685	70,416	97,419	
Planned	**OGDEN**			6.257	0.031	0.000	0.000	70,416	2,198	
Customer Requested	**OGDEN**			0.147	0.001	0.000	0.000	70,416	76	
High SAIDI	OGDEN	LMT18	LITTLE MOUNTAIN #18	1,495.000	2.833	0.000	0.000	6	17	
Low SAIDI	OGDEN	31	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	OGDEN	NOG13	NORTH OGDEN #13	331.672	5.471	11.000	10.000	1,200	6,565	
Low SAIFI	OGDEN	31	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	OGDEN	UIN13	UINTAH #13	194.825	1.139	27.000	27.000	1,001	1,140	
Low MAIFI	OGDEN	48	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	OGDEN	UIN13	UINTAH #13	194.825	1.139	27.000	27.000	1,001	1,140	
Low MAIFI(e)	OGDEN	48	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	OGDEN	RIV12	RIVERDALE #12	287.124	2.072	2.000	2.000	2,389	4,951	
Low Customer Minutes Lost	OGDEN	31	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	**PARK CITY**			111.344	0.715	6.418	6.326	16,060	11,490	
Planned	**PARK CITY**			0.000	0.000	0.000	0.000	16,060	0	
Customer Requested	**PARK CITY**			0.004	0.000	0.000	0.000	16,060	2	
High SAIDI	PARK CITY	THF21	THIEF CREEK #21	890.200	3.800	0.000	0.000	10	38	
Low SAIDI	PARK CITY	9	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	PARK CITY	DSR11	DESERET #11	693.000	5.000	5.000	5.000	1	5	
Low SAIFI	PARK CITY	9	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	PARK CITY	COA12	COALVILLE #12	64.902	0.284	22.000	22.000	479	136	
Low MAIFI	PARK CITY	14	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	PARK CITY	COA12	COALVILLE #12	64.902	0.284	22.000	22.000	479	136	
Low MAIFI(e)	PARK CITY	14	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	PARK CITY	PKC15	PARK CITY #15	339.311	1.392	0.000	0.000	1,016	1,414	

Fiscal Y-T-D | Fiscal Year 2001 | 04/01/00 to 12/31/00

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Nur Occu
Low Customer Minutes Lost	PARK CITY	9	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	SALINA (RICHFIELD)			112.933	0.960	1.836	1.836	13,236	12,708	
Planned	SALINA (RICHFIELD)			0.188	0.002	0.000	0.000	13,236	25	
Customer Requested	SALINA (RICHFIELD)			0.023	0.000	0.000	0.000	13,236	1	
High SAIDI	SALINA (RICHFIELD)	PAN11B	EAST PANG SECTIONALIZER	732.000	3.000	7.000	7.000	100	300	
Low SAIDI	SALINA (RICHFIELD)	15	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	SALINA (RICHFIELD)	PAN12	PANGUITCH #12	548.956	4.120	7.000	7.000	367	1,512	
Low SAIFI	SALINA (RICHFIELD)	15	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	SALINA (RICHFIELD)	SVR47	SEVIER-MILFORD 46 KV LINE	304.000	3.000	11.000	11.000	2	6	
Low MAIFI	SALINA (RICHFIELD)	14	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	SALINA (RICHFIELD)	SVR47	SEVIER-MILFORD 46 KV LINE	304.000	3.000	11.000	11.000	2	6	
Low MAIFI(e)	SALINA (RICHFIELD)	14	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	SALINA (RICHFIELD)	PAN11	PANGUITCH #11	494.652	3.108	7.000	7.000	722	2,244	
Low Customer Minutes Lost	SALINA (RICHFIELD)	15	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	SMITHFIELD			102.636	1.410	3.633	1.640	13,127	18,504	
Planned	SMITHFIELD			0.001	0.000	0.000	0.000	13,127	1	
Customer Requested	SMITHFIELD			0.015	0.000	0.026	0.026	13,127	4	
High SAIDI	SMITHFIELD	RAN11	RANDOLPH #11	373.991	3.821	0.000	0.000	324	1,238	
Low SAIDI	SMITHFIELD	4	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	SMITHFIELD	RAN11	RANDOLPH #11	373.991	3.821	0.000	0.000	324	1,238	
Low SAIFI	SMITHFIELD	4	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	SMITHFIELD	AMA12	AMALGA #12	304.193	3.307	21.000	7.000	1,000	3,307	
Low MAIFI	SMITHFIELD	11	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	SMITHFIELD	AMA12	AMALGA #12	304.193	3.307	21.000	7.000	1,000	3,307	
Low MAIFI(e)	SMITHFIELD	11	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	SMITHFIELD	AMA12	AMALGA #12	304.193	3.307	21.000	7.000	1,000	3,307	
Low Customer Minutes Lost	SMITHFIELD	4	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	SOUTH VALLEY (JORDAN VALLEY)			136.505	1.694	6.663	6.230	27,846	47,181	
Planned	SOUTH VALLEY (JORDAN VALLEY)			0.551	0.004	0.000	0.000	27,846	123	
Customer Requested	SOUTH VALLEY (JORDAN VALLEY)			0.009	0.000	0.000	0.000	27,846	2	
High SAIDI	SOUTH VALLEY (JORDAN VALLEY)	BNG12	BINGHAM #12	458.910	2.874	1.002	1.002	531	1,526	
Low SAIDI	SOUTH VALLEY (JORDAN VALLEY)	8	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	SOUTH VALLEY (JORDAN VALLEY)	HOG11	HOGGARD #11	132.503	4.199	5.000	5.000	5,161	21,670	
Low SAIFI	SOUTH VALLEY (JORDAN VALLEY)	8	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	SOUTH VALLEY (JORDAN VALLEY)	HOG13	HOGGARD #13	114.409	0.419	19.000	19.000	1,226	514	
Low MAIFI	SOUTH VALLEY (JORDAN VALLEY)	7	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	SOUTH VALLEY (JORDAN VALLEY)	HOG13	HOGGARD #13	114.409	0.419	19.000	19.000	1,226	514	
Low MAIFI(e)	SOUTH VALLEY (JORDAN VALLEY)	7	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	SOUTH VALLEY (JORDAN VALLEY)	BNG11	BINGHAM #11	344.869	1.287	5.000	5.000	2,710	3,487	
Low Customer Minutes Lost	SOUTH VALLEY (JORDAN VALLEY)	8	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	TOOELE			756.216	3.670	13.742	12.918	9,368	34,379	
Planned	TOOELE			10.533	0.080	0.000	0.000	9,368	746	
Customer Requested	TOOELE			0.243	0.002	0.000	0.000	9,368	19	
High SAIDI	TOOELE	GRA12	GRANTSVILLE #12	1,196.333	6.419	4.000	4.000	105	674	
Low SAIDI	TOOELE	2	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	TOOELE	SKU11	SKULL VALLEY #11	1,020.202	8.437	3.000	3.000	119	1,004	

Fiscal Y-T-D **Fiscal Year 2001** **04/01/00 to 12/31/00**

Measure	Operating Area	UCID	Circuit Name	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Num Occu
Low SAIFI	TOOELE	2	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	TOOELE	TOO13	TOOELE #13	881.667	3.129	28.000	26.000	3,260	10,202	
Low MAIFI	TOOELE	7	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	TOOELE	TOO13	TOOELE #13	881.667	3.129	28.000	26.000	3,260	10,202	
Low MAIFI(e)	TOOELE	7	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	TOOELE	TOO13	TOOELE #13	881.667	3.129	28.000	26.000	3,260	10,202	
Low Customer Minutes Lost	TOOELE	2	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	TREMONTON			180.147	1.762	5.856	5.087	6,424	11,317	
Planned	TREMONTON			0.000	0.000	0.000	0.000	6,424	0	
Customer Requested	TREMONTON			0.084	0.000	0.000	0.000	6,424	1	
High SAIDI	TREMONTON	BLU11	BLUE CREEK #11	1,165.555	3.266	3.000	3.000	128	418	
Low SAIDI	TREMONTON	6	***** circuits with Low SAIDI of 0.000 *****	0.000						
High SAIFI	TREMONTON	SNO11	SNOWVILLE #11	712.947	7.895	5.000	5.000	19	150	
Low SAIFI	TREMONTON	6	***** circuits with Low SAIFI of 0.000 *****		0.000					
High MAIFI	TREMONTON	BRR13	BR RIVER #13	11.521	0.077	12.000	10.000	868	67	
Low MAIFI	TREMONTON	VULC1	VULCRAFT CORP.	0.000	0.000	0.000	0.000	1	0	
High MAIFI(e)	TREMONTON	BRR12	BEAR RIVER #12	177.374	1.402	11.000	11.000	219	307	
Low MAIFI(e)	TREMONTON	VULC1	VULCRAFT CORP.	0.000	0.000	0.000	0.000	1	0	
High Customer Minutes Lost	TREMONTON	BSH12	BUSH #12	800.374	3.935	1.000	1.000	398	1,566	
Low Customer Minutes Lost	TREMONTON	6	***** circuits with Low Customer Minutes Lost of 0.000 *****							
Unplanned	VALLEY WEST			88.831	0.702	5.464	5.201	41,856	29,403	
Planned	VALLEY WEST			0.257	0.003	0.000	0.000	41,856	133	
Customer Requested	VALLEY WEST			0.057	0.000	0.000	0.000	41,856	20	
High SAIDI	VALLEY WEST	TAY11	TAYLORSVILLE #11	528.582	4.746	7.000	7.000	901	4,276	
Low SAIDI	VALLEY WEST	RDG13	RIDGELAND #13	0.000	0.000	1.000	1.000	455	0	
High SAIFI	VALLEY WEST	TAY11	TAYLORSVILLE #11	528.582	4.746	7.000	7.000	901	4,276	
Low SAIFI	VALLEY WEST	RDG13	RIDGELAND #13	0.000	0.000	1.000	1.000	455	0	
High MAIFI	VALLEY WEST	LPK12	LAKEPARK #12	8.620	0.037	21.000	21.000	3,065	114	
Low MAIFI	VALLEY WEST	3	***** circuits with Low MAIFI of 0.000 *****			0.000				
High MAIFI(e)	VALLEY WEST	LPK12	LAKEPARK #12	8.620	0.037	21.000	21.000	3,065	114	
Low MAIFI(e)	VALLEY WEST	3	***** circuits with Low MAIFI(e) of 0.000 *****				0.000			
High Customer Minutes Lost	VALLEY WEST	TAY11	TAYLORSVILLE #11	528.582	4.746	7.000	7.000	901	4,276	
Low Customer Minutes Lost	VALLEY WEST	RDG13	RIDGELAND #13	0.000	0.000	1.000	1.000	455	0	

Customer Service Commitments

UTAH OUTAGE RESTORATION PERFORMANCE

October-December 2000

District	Total Number of Customers Affected	% Restored Within 3 Hours
American Fork	15,895	89%
Cedar City	4,681	93%
Davis (Layton)	9,644	77%
Jordan Valley	29,644	86%
Moab (Canyonlands) *	744	60%
Ogden	40,128	91%
Park City	4,455	70%
Price (Carbon)	1,767	88%
Richfield	4,102	87%
SLC Metro	71,820	86%
Smithfield	2,638	92%
Tooele	2,022	100%
Tremonton	4,064	94%
Valley West	8,602	93%
Vernal (Ashley) **	138	62%
Total	**200,344**	**87.3%**

* A *large coverage area and difficult terrain affected Moab's performance.*

** *Further investigation identified a data entry error in a closed system which, had the error not been made, would have resulted in a revised performance figure of 84% for Vernal.*

UTAH RESIDENTIAL/SMALL COMMERCIAL METER SETS - REPORT BY DISTRICT

2000-2001

FISCAL YEAR 2nd & 3rd QUARTERS 2000-2001

NORTHERN UTAH

LOCATION	FY 2nd Quarter			OCTOBER			NOVEMBER			DECEMBER			FY 3rd Quarter			FY 2nd & 3rd Quarters			Notes
	Total Within 5 Days	2nd Quarter %	Total	Within 5 Days	%	Total	Within 5 Days	%	Total	Within 5 Days	%	Total	Total Within 5 Days	3rd Quarter %	Total	Total Within 5 Days	%	Total	
Jordan Valley	845	89%	948	355	95%	375	188	76%	246	176	44%	400	719	70%	1021	1564	79%	1969	Vacation scheduling affected performance -- corrective action under review.
Layton/Davis	327	92%	354	124	100%	124	119	100%	119	103	100%	103	346	100%	346	673	96%	700	
Metro	576	97%	593	277	96%	288	250	91%	274	283	96%	296	810	94%	858	1386	96%	1451	
Ogden	776	99%	783	231	100%	231	192	96%	201	160	99%	162	583	98%	594	1359	99%	1377	
Park City	178	92%	194	111	93%	119	54	89%	61	64	93%	69	229	92%	249	407	92%	443	
Smithfield	51	100%	51	17	94%	18	43	100%	43	26	100%	26	86	99%	87	137	99%	138	Reporting began in August.
Tooele	280	86%	325	144	98%	147	67	99%	68	72	97%	74	283	98%	289	563	92%	614	
Tremonton	50	88%	57	27	87%	31	19	86%	22	8	80%	10	54	86%	63	104	87%	120	
TOTAL	3083	93%	3305	1286	96%	1333	932	90%	1034	892	78%	1140	3110	89%	3507	6193	91%	6812	

SOUTHERN UTAH

LOCATION	FY 2nd Quarter			OCTOBER			NOVEMBER			DECEMBER			FY 3rd Quarter			FY 2nd & 3rd Quarters			Notes
	Total Within 5 Days	2nd Quarter %	Total	Within 5 days	%	Total	Within 5 days	%	Total	Within 5 days	%	Total	Total Within 5 Days	3rd Quarter %	Total	Total Within 5 Days	%	Total	
American Fork	421	99%	425	170	99%	171	194	99%	196	150	100%	150	514	99%	517	935	99%	942	
Cedar City	220	97%	226	97	97%	100	82	98%	84	59	95%	62	238	97%	246	458	97%	472	
Moab	31	89%	35	15	100%	15	21	100%	21	11	100%	11	47	100%	47	78	95%	82	Reporting began in August.
Price	56	100%	56	11	100%	11	15	100%	15	16	100%	16	42	100%	42	98	100%	98	
Richfield	134	100%	134	33	100%	33	32	100%	32	32	100%	32	97	100%	97	231	100%	231	Reporting began in August.
Santaquin	125	100%	125	27	100%	27	22	100%	22	20	100%	20	69	100%	69	194	100%	194	
Vernal	20	91%	22	17	94%	18	13	93%	14	13	93%	14	43	93%	46	63	93%	68	Reporting began in August.
TOTAL	1007	98%	1023	370	99%	375	379	99%	384	301	99%	305	1050	99%	1064	2057	99%	2087	

TOTAL UTAH

LOCATION	FY 2nd Quarter			OCTOBER			NOVEMBER			DECEMBER			FY 3rd Quarter			FY 2nd & 3rd Quarters			Notes
	Total Within 5 Days	2nd Quarter %	Total	Within 5 days	%	Total	Within 5 days	%	Total	Within 5 days	%	Total	Total Within 5 Days	3rd Quarter %	Total	Total Within 5 Days	%	Total	
TOTAL UTAH	4090	95%	4328	1656	97%	1708	1311	92%	1418	1193	83%	1445	4160	91%	4571	8250	93%	8899	

UTAH TEMPORARY METER SETS - REPORT BY DISTRICT

2000-2001

FISCAL YEAR 3rd QUARTER 2000-2001

NORTHERN UTAH

LOCATION	OCTOBER			NOVEMBER			DECEMBER			FY 3rd Quarter			Notes
	Within 10 Days	%	Total	Within 10 Days	%	Total	Within 10 Days	%	Total	Total Within 10 Days	3rd Quarter %	Total	
Jordan Valley	141	94%	150	95	94%	101	91	83%	109	327	91%	360	
Layton/Davis	86	100%	86	83	100%	83	51	100%	51	220	100%	220	
Metro	79	100%	79	49	98%	50	74	100%	74	202	100%	203	
Ogden	93	100%	93	82	100%	82	67	99%	68	242	100%	243	
Park City	26	96%	27	23	100%	23	18	100%	18	67	99%	68	
Smithfield	66	100%	66	28	100%	28	14	100%	14	108	100%	108	
Tooele	28	100%	28	36	100%	36	31	100%	31	95	100%	95	
Tremonton	1	100%	1	10	100%	10	1	50%	2	12	92%	13	
TOTAL	520	98%	530	406	98%	413	347	95%	367	1273	97%	1310	

SOUTHERN UTAH

LOCATION	OCTOBER			NOVEMBER			DECEMBER			FY 3rd Quarter			Notes
	Within 10 days	%	Total	Within 10 days	%	Total	Within 10 days	%	Total	Total Within 10 Days	3rd Quarter %	Total	
American Fork	82	99%	83	84	100%	84	75	100%	75	241	100%	242	
Cedar City	43	100%	43	39	100%	39	34	100%	34	116	100%	116	
Moab	3	100%	3	2	100%	2	4	100%	4	9	100%	9	
Price	2	100%	2	15	100%	15	0	#DIV/0!	0	17	100%	17	
Richfield	7	100%	7	5	100%	5	4	100%	4	16	100%	16	
Santaquin	7	100%	7	6	100%	6	6	100%	6	19	100%	19	
Vernal	4	100%	4	2	100%	2	4	100%	4	10	100%	10	
TOTAL	148	99%	149	153	100%	153	127	100%	127	428	100%	429	

TOTAL UTAH

LOCATION	OCTOBER			NOVEMBER			DECEMBER			FYD - 3rd Quarter			Notes
	Within 10 days	%	Total	Within 10 days	%	Total	Within 10 days	%	Total	Total Within 10 Days	3rd Quarter %	Total	
TOTAL UTAH	668	98%	679	559	99%	566	474	96%	494	1701	98%	1739	

Customer Service Commitments

UTAH GUARANTEE FIELD RESPONSE PERFORMANCE October-December 2000

American Fork	*CG #*	*Description*	# Customer Requests	Average # Days to Respond
	CG4a	Estimates - Contact within 2 days	138	2
	CG4b	Estimates - 5 days	21	1
	CG4c	Estimates - 15 days *	112	21
	CG5	Responding to Bill Inquiries within 10 days	121	4
	CG6	Responding to Meter Problems within 15 days	18	6

Cedar City	*CG #*	*Description*	# Customer Requests	Average # Days to Respond
	CG4a	Estimates - Contact within 2 days	102	1
	CG4b	Estimates - 5 days	47	1
	CG4c	Estimates - 15 days	56	3
	CG5	Responding to Bill Inquiries within 10 days	75	4
	CG6	Responding to Meter Problems within 15 days	8	4

Davis (Layton)	*CG #*	*Description*	# Customer Requests	Average # Days to Respond
	CG4a	Estimates - Contact within 2 days	78	1
	CG4b	Estimates - 5 days	9	< 1
	CG4c	Estimates - 15 days	29	5
	CG5	Responding to Bill Inquiries within 10 days	111	4
	CG6	Responding to Meter Problems within 15 days	28	8

* *Response time is greater than target due to a backlog of requests in the quarter, and also due to estimators needing additional training regarding the guarantee processes. The estimators have now received the necessary re-training.*

	CG #	Description	# Customer Requests	Average # Days to Respond
Jordan Valley	***CG #***	***Description***	**# Customer Requests**	**Average # Days to Respond**
	CG4a	Estimates - Contact within 2 days	107	1
	CG4b	Estimates - 5 days	18	1
	CG4c	Estimates - 15 days	94	6
	CG5	Responding to Bill Inquiries within 10 days	447	5
	CG6	Responding to Meter Problems within 15 days	59	7
Laketown	***CG #***	***Description***	**# Customer Requests**	**Average # Days to Respond**
	CG4a	Estimates - Contact within 2 days	10	1
	CG4b	Estimates - 5 days	3	3
	CG4c	Estimates - 15 days	6	< 1
	CG5	Responding to Bill Inquiries within 10 days	12	4
Moab (Canyonlands)	***CG #***	***Description***	**# Customer Requests**	**Average # Days to Respond**
	CG4a	Estimates - Contact within 2 days	18	1
	CG4b	Estimates - 5 days	5	< 1
	CG4c	Estimates - 15 days	15	6
	CG5	Responding to Bill Inquiries within 10 days	45	3
	CG6	Responding to Meter Problems within 15 days	3	9
Ogden	***CG #***	***Description***	**# Customer Requests**	**Average # Days to Respond**
	CG4a	Estimates - Contact within 2 days	102	2
	CG4b	Estimates - 5 days	18	< 1
	CG4c	Estimates - 15 days	61	5
	CG5	Responding to Bill Inquiries within 10 days	194	4
	CG6	Responding to Meter Problems within 15 days	30	6

	CG #	Description	# Customer Requests	Average # Days to Respond
Park City				
	CG4a	Estimates - Contact within 2 days *	63	5
	CG4b	Estimates - 5 days	5	1
	CG4c	Estimates - 15 days	74	2
	CG5	Responding to Bill Inquiries within 10 days	65	5
	CG6	Responding to Meter Problems within 15 days	5	10

Price (Carbon)	CG #	Description	# Customer Requests	Average # Days to Respond
	CG4a	Estimates - Contact within 2 days	17	1
	CG4c	Estimates - 15 days	16	2
	CG5	Responding to Bill Inquiries within 10 days	24	4
	CG6	Responding to Meter Problems within 15 days	4	4

Richfield	CG #	Description	# Customer Requests	Average # Days to Respond
	CG4a	Estimates - Contact within 2 days	60	2
	CG4b	Estimates - 5 days	29	1
	CG4c	Estimates - 15 days	25	5
	CG5	Responding to Bill Inquiries within 10 days	41	3
	CG6	Responding to Meter Problems within 15 days	5	8

Santaquin	CG #	Description	# Customer Requests	Average # Days to Respond
	CG4a	Estimates - Contact within 2 days	1	< 1

* *Response time is greater than target due to a backlog of requests in the quarter, and also due to estimators needing additional training regarding the guarantee processes. The estimators have now received the necessary re-training.*

SLC Metro	*CG #*	*Description*	# Customer Requests	Average # Days to Respond
	CG4a	Estimates - Contact within 2 days	125	1
	CG4b	Estimates - 5 days	18	1
	CG4c	Estimates - 15 days	120	4
	CG5	Responding to Bill Inquiries within 10 days	829	4
	CG6	Responding to Meter Problems within 15 days	119	7

Smithfield	*CG #*	*Description*	# Customer Requests	Average # Days to Respond
	CG4a	Estimates - Contact within 2 days	43	2
	CG4b	Estimates - 5 days	3	< 1
	CG4c	Estimates - 15 days	35	2
	CG5	Responding to Bill Inquiries within 10 days	27	4
	CG6	Responding to Meter Problems within 15 days	7	8

Tooele	*CG #*	*Description*	# Customer Requests	Average # Days to Respond
	CG4a	Estimates - Contact within 2 days	22	2
	CG4b	Estimates - 5 days	3	< 1
	CG4c	Estimates - 15 days	25	7
	CG5	Responding to Bill Inquiries within 10 days	77	5
	CG6	Responding to Meter Problems within 15 days	10	10

Tremonton	*CG #*	*Description*	**# Customer Requests**	**Average # Days to Respond**
	CG4a	Estimates - Contact within 2 days	26	1
	CG4b	Estimates - 5 days	1	< 1
	CG4c	Estimates - 15 days	25	9
	CG5	Responding to Bill Inquiries within 10 days	24	3
	CG6	Responding to Meter Problems within 15 days	2	3

Valley West	*CG #*	*Description*	**# Customer Requests**	**Average # Days to Respond**
	CG4a	Estimates - Contact within 2 days	4	1
	CG4c	Estimates - 15 days	1	10
	CG5	Responding to Bill Inquiries within 10 days	3	6
	CG6	Responding to Meter Problems within 15 days	1	7

Vernal (Ashley)	*CG #*	*Description*	**# Customer Requests**	**Average # Days to Respond**
	CG4a	Estimates - Contact within 2 days	35	< 1
	CG4b	Estimates - 5 days	6	< 1
	CG4c	Estimates - 15 days	28	1
	CG5	Responding to Bill Inquiries within 10 days	18	3
	CG6	Responding to Meter Problems within 15 days	2	10

EXHIBIT "A"

I have reviewed the Protective Order approved by the Public Service Commission of Utah on the 25th day of January, 1999, in Docket No. 98-2035-04, and agree to be bound by the terms and conditions of such Order.

[signature]

Signature

Helmuth W. Schultz III

Name (Type or Print)

Residence Address

Larkin & Associates, PLLC

Employer or Firm

15728 Farmington Rd.
Livonia, MI 48154

Business Address

Committee of Consumer Services

Party

1-26-01

Date

RECEIVED

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SERVICE COMMISSION

EXHIBIT "A"

I have reviewed the Protective Order approved by the Public Service Commission of Utah on the 25th day of January, 1999, in Docket No. 98-2035-04, and agree to be bound by the terms and conditions of such Order.

Hugh Larkin Jr
Signature

HUGH LARKIN JR
Name (Type or Print)

Residence Address

Larkin & Associates, PLLC
Employer or Firm

15728 Farmington Rd.
Livonia, MI 48154
Business Address

Committee of Consumer Services
Party

Date 1/25/01

EXHIBIT "A"

I have reviewed the Protective Order approved by the Public Service Commission of Utah on the 25th day of January, 1999, in Docket No. 98-2035-04, and agree to be bound by the terms and conditions of such Order.

Donna DeRonne
Signature

Donna DeRonne
Name (Type or Print)

Residence Address

Larkin+Associates, PLLC
Employer or Firm

15728 Farmington Rd., Livonia, MI 48154
Business Address

Committee of Consumer Services
Party

1/25/01
Date

825 N.E. Multnomah
Portland, Oregon 97232
(503) 813-5000

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NOV 1 11 22 AM '00
SERVICE COMMISSION

REVIEWED BY COMMISSIONERS
STEPHEN F. MECHAM 11/2/..
CONSTANCE B. WHITE CBW 11/2
CLARK D. JONES 11/2

PACIFICORP
PACIFIC POWER UTAH POWER

October 31, 2000

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

Attention: Julie Orchard
Commission Secretary

RE: Schedule 70 – New Wind, Geothermal and Solar Power Rider Annual Report

PacifiCorp committed to annual reports in its application for the approval of Schedule 70 – New Wind, Geothermal and Solar Power Rider. The reports are to contain revenues received, blocks purchased, blocks generated or contracted for and other program costs. Attached please find the first annual report for the period ending September 30, 2000.

Also attached is a detail of the marketing plan to date. This information is provided to inform the reader of the efforts undertaken by the Company with regards to enrollments for Schedule 70 and their effectiveness.

At this time PacifiCorp has not built or contracted for resources to serve the Schedule 70 purchases. Consequently, the Company has incurred no power-related costs. The Company anticipates signing a contract for new wind resources before the end of the year. At the time that a power purchase agreement is signed the Company will update the financial analysis that was used to determine the initial Schedule 70 rate. Included in the analysis will be updated market forecasts, power purchase prices, updated penetration rates and updated marketing and administration costs. This analysis will be presented to the Commission and other interested parties to demonstrate and establish the ongoing rate for Schedule 70.

Please address all comments or questions to me at the address below or at 503-813-6081.

PacifiCorp
825 NE Multnomah Street, Suite 800
Portland, Oregon 97232

Sincerely,

Brian Hedman
Manager Regulation

Enclosures

PacifiCorp
Blue Sky Program
Period Ending 9/30/00

12 months ending 9/30/00

State	Enrollments Residential	Business	Total	Shares Residential	Business	Total	Total kWh purchased	kWh generated	Revenue	Expenses Marketing	Advertising	Tech services	Admin	Power costs	Total Expenses
Oregon	611	14	625	880	1,100	1,980	765,939	0	$36,382.10	$36,342	$157,916	$27,862	$15,247	$0	$237,367
Utah	518	4	522	748	8	756	160,140	0	$7,606.66	$58,929	$96,493	$4,656	$7,037	$0	$167,115
Washington	76	0	76	104	0	104	20,848	0	$990.28	$4,547	$398	$1,322	$586	$0	$6,853
Wyoming	119	4	123	160	9	169	33,819	0	$1,606.38	$4,592	$398	$1,323	$586	$0	$6,899
Total			1,346			3,009	980,746		$46,585.42	$104,410	$255,205	$35,163	$23,456	$0	$418,234

Program to date as of 9/30/00

State	Enrollments Residential	Business	Total	Shares Residential	Business	Total	Total kWh purchased	kWh generated	Revenue	Expenses Marketing	Advertising	Tech services	Admin	Power costs	Total Expenses
Oregon	611	14	625	880	1,100	1,980	765,939	0	$36,382.10	$36,342	$157,916	$27,862	$15,247	$0	$237,367
Utah	518	4	522	748	8	756	160,140	0	$7,606.66	$58,929	$96,493	$4,656	$7,037	$0	$167,115
Washington	76	0	76	104	0	104	20,848	0	$990.28	$4,547	$398	$1,322	$586	$0	$6,853
Wyoming	119	4	123	160	9	169	33,819	0	$1,606.38	$4,592	$398	$1,323	$586	$0	$6,899
Total			1,346			3,009	980,746		$46,585.42	$104,410	$255,205	$35,163	$23,456	$0	$418,234

PacifiCorp

Blue Sky Program

Period Ending 9/30/00

Activity	Budget	2000 Targets	Timing	Impressions	Actual Y-T-D	Enroll-ments (1)
Business & Government Customers						
Proactive Accounts	------	2,300	June to present	152 presentation	------	38
Renewable NW Project Partnership	$25,000	2,810	April to present	30 presentation	$18,750	1,088
	$25,000				**$18,750**	
Awareness Building						
Mass Media	$308,000	3,475	April - June	Radio and newspaper in five communities	$255,205	282
Local events (bubbles, shirts, Frisbees)	$12,000	Awareness	April to present	35 events	$9,386	
Media contacts & milestone PR and	$30,000	Awareness	April to present	~40 published	$11,238	
Support materials		Awareness	April to present		$19,001	
NWEA Contract	$25,000	New contrac	October to presen	------	$3,000	------
	$375,000				**$297,830**	
Residential Sales						
Bill inserts	$64,000	6,912	May, September	Two inserts at 1.2M One insert to 500,000	$64,785	2,540
VOICES newsletters (four)	Not incremental	1,503	May, July, September, November	Four inserts to 1.2m	------	
	$64,000				**$64,785**	
	$464,000	**17,000**	$27		$381,365	**3,948**

(1) Enrollments through October 26, 2000

1900 S.W. 4th Ave.
Portland, Oregon 97201

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Nov 1 11 21 AM '00

SERVICE COMMISSION

VIA OVERNIGHT MAIL

October 31, 2000

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City UT 84114

Attention: Julie P. Orchard
Commission Secretary

RE: Docket No. 98-2035-04 ScottishPower/PacifiCorp Merger Commitments

Please find enclosed PacifiCorp's second quarter report for the period July 2000 through September 2000 detailing the Company's performance in meeting the Customer Guarantees which were agreed to as a result of the recent merger between ScottishPower and PacifiCorp. Year-to-date information is provided as well.

PacifiCorp will submit it's third quarterly report in January 2001 for the period October 2000 through December 2000.

As required by merger Stipulation Conditions 33 and 36, detailed outage performance and customer guarantee performance by district are also being reported. These reports are enclosed. Meter set response standards by district as required by merger Stipulation Condition 34 are also enclosed.

If you have any questions or require further information, please call Carole Rockney at (503) 813-7408.

Sincerely,

Matthew Wright/cr

Matthew Wright
Vice President, Regulation

c: Mark Flandro - Utah Division of Public Utilities
Rea Petersen - Utah Division of Public Utilities
Andy MacRitchie - Senior Vice President, Power Delivery

Enclosure

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Utah

Customer Service Commitments - Guarantees

July-September 2000

		July-September 2000			Year to Date		
	Description	Events	Failures	Paid	Events	Failures	Paid
CG1	Restoring Supply	341,594	4	$225	510,563	4	$225
CG2	Appointments	1,763	2	$100	3,265	9	$450
CG3	Switching on Power	7,581	7	$1,650	15,336	30	$5,350
CG4	Estimates	2,518	26	$1,300	4,296	45	$2,250
CG5	Respond to Billing Inquiries	2,358	2	$100	3,591	7	$350
CG6	Respond to Meter Problems	374	0	$0	549	1	$50
CG7	Notification of Planned Interruptions	4,401	1	$50	6,152	19	$1,000
CG8	Power Quality Complaints	1,446	155	$7,750	2,052	168	$8,400
		362,035	**197**	**$11,175**	**545,804**	**283**	**$18,075**

Summary analysis:

General - Implementation has gone well in first 6 months of fiscal year. Customer feedback has been very positive. Supported by renewed training and internal communications efforts, employees have a growing awareness of our guarantee processes, and the role each employee plays in delivering quality service to our customers.

CG2 - Employees continue to adjust to processes required to meet increased focus on appointments with customers.

CG3 - Failures have trended downward since initial implementation as employees work to improve processes relating to 'Switching on Power'. After-hours and weekend handoffs have caused most of the failures.

CG4 - Most of the CG4 payments were due to our failure to contact the customer within 2 days.

CG5 - The few failures that have occurred have been a result of employees still becoming familiar with new procedures.

CG7 - Nearly half of the payments related to 2 interruptions. Also, the significant increase in events in the quarter is primarily due to a single large planned interruption in Cedar City that affected 2,190 customers. Customers are expressing appreciation for the advance notification.

CG8 - The high number of failures is primarily due to the high volume of customer calls requesting investigations into the multiple outages that occurred in the Salt Lake valley related to summer heat and high demand.

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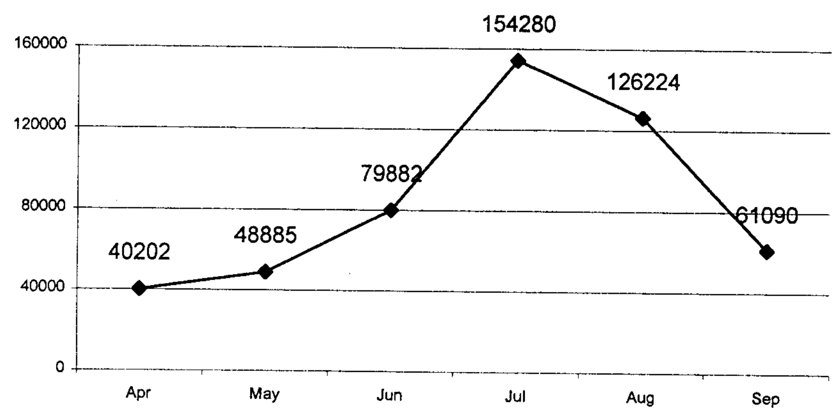
Utah

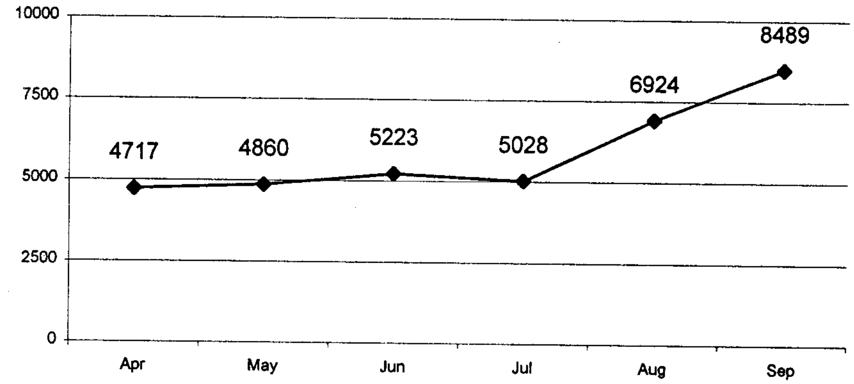
Customer Service Commitments - Guarantees

July-September 2000

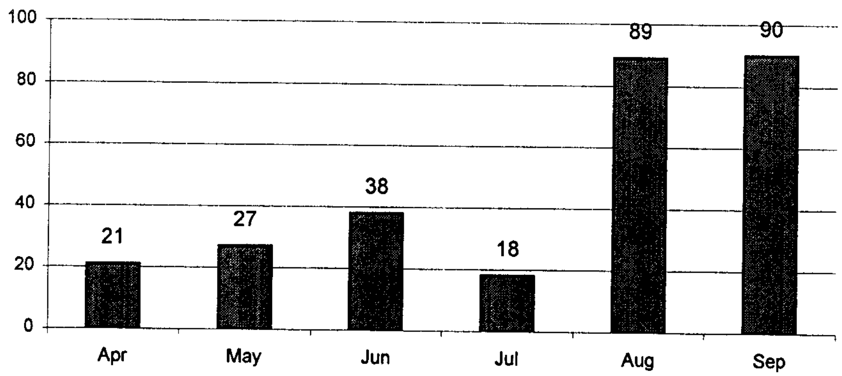
CG 1 Events



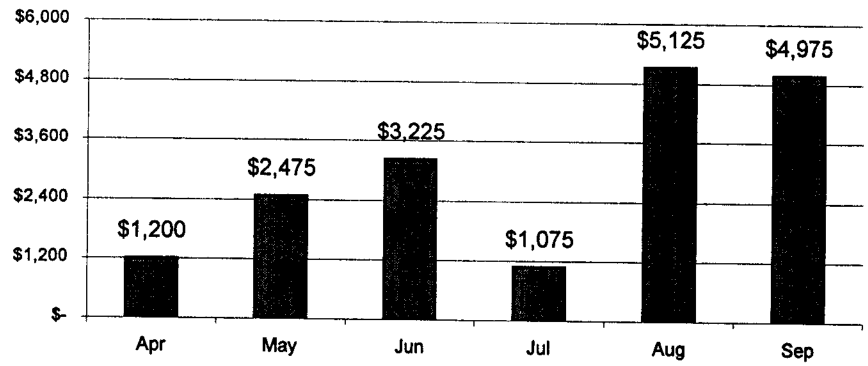
CG 2-8 Events



Failures



Payments



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Utah

Customer Service Commitments - Performance Standards

April-September 2000

Description	Baseline	Performance	Goal
• SAIDI (System availability in minutes per customer)	Revised baselines under development[1]	87.147	Reduce SAIDI by 10% from revised baseline
• SAIFI (System reliability in interruptions per customer)		0.826	Reduce SAIFI by 10% from revised baseline
• MAIFI (Momentary interruptions per customer)		4.838	Reduce MAIFI by 5% from revised baseline
• Worst Performing Circuits - Circuit Performance Indicator (CPI)[2]		CPI performance wll be reviewed at end of 2-year improvement period.	Reduce CPI's by 20% from revised baseline
Coalville 12	288		
Lewiston 11	377		
Pioneer 11	425		
Pioneer 13	529		
Pioneer 14	393		
• Power supply restored within 3 hours	Not applicable	83%	80%
• Calls answered within 30 seconds	Not applicable	86%	80%
• Respond to commission complaints within 3 days	Not applicable	99%	100%
• Respond to commission complaints regarding service disconnects within 4 hours	Not applicable	100%	100%
• Commission complaints resolved within 30 days	Not applicable	99%	90%

1 Work on revised baselines, required because of under-reporting of outages in prior periods, is still underway. The new "ProsperUS" reporting system will begin a phased implementation late this year. A progress update on the revised baseline development and the implementation of the new ProsperUS system will be provided in the next semi-annual report.

2 Baseline CPI figures are based on 3-years ended data as of December 31, 1998. This is the data originally used to select the 5 worst circuits per state.

UTAH RESIDENTIAL/SMALL COMMERCIAL METER SETS - REPORT BY DISTRICT

2000-2001

FISCAL YEAR TO DATE - 2nd QUARTER 2000-2001

NORTHERN UTAH

LOCATION	JULY			AUGUST			SEPTEMBER			FYD - 2nd Quarter			Notes
	Within 5 Days	%	Total	Within 5 Days	%	Total	Within 5 Days	%	Total	Total Within 5 Days	2nd Quarter %	Total	
Jordan Valley	249	86%	289	263	91%	289	333	90%	370	845	89%	948	
Layton/Davis	79	84%	94	121	95%	128	127	96%	132	327	92%	354	
Metro	124	98%	127	221	94%	235	231	100%	231	576	97%	593	
Ogden	281	100%	281	216	98%	221	279	99%	281	776	99%	783	
Park City	65	97%	67	58	98%	59	55	81%	68	178	92%	194	
Smithfield				23	100%	23	28	100%	28	51	100%	51	Reporting began in August
Tooele	82	67%	123	119	98%	122	79	99%	80	280	86%	325	
Tremonton	10	83%	12	20	95%	21	20	83%	24	50	88%	57	
TOTAL	890	90%	993	1041	95%	1098	1152	95%	1214	3083	93%	3305	

SOUTHERN UTAH

LOCATION	JULY			AUGUST			SEPTEMBER			FYD - 2nd Quarter			Notes
	Within 5 days	%	Total	Within 5 days	%	Total	Within 5 days	%	Total	Total Within 5 Days	2nd Quarter %	Total	
American Fork	115	100%	115	191	99%	192	115	97%	118	421	99%	425	
Cedar City	58	97%	60	104	97%	107	58	98%	59	220	97%	226	
Moab				19	83%	23	12	100%	12	31	89%	35	Reporting began in August
Price	20	100%	20	18	100%	18	18	100%	18	56	100%	56	
Richfield				83	100%	83	51	100%	51	134	100%	134	Reporting began in August
Santaquin	41	100%	41	34	100%	34	50	100%	50	125	100%	125	
Vernal				9	90%	10	11	92%	12	20	91%	22	Reporting began in August
TOTAL	234	99%	236	458	98%	467	315	98%	320	1007	98%	1023	

TOTAL UTAH

LOCATION	JULY			AUGUST			SEPTEMBER			FYD - 2nd Quarter			Notes
	Within 5 days	%	Total	Within 5 days	%	Total	Within 5 days	%	Total	Total Within 5 Days	2nd Quarter %	Total	
TOTAL UTAH	1124	91%	1229	1499	96%	1565	1467	96%	1534	4090	95%	4328	

Customer Service Commitments

UTAH FAILURES July-September 2000 — 2nd Quarter / Year to Date

	CG #	Description	2nd Quarter Failure	2nd Quarter Paid	Year to Date Failure	Year to Date Paid
American Fork	***CG #***	***Description***	***Failure***	***Paid***	***Failure***	***Paid***
	CG2	Appointments	0		2	$100
	CG3	Switching on Power	1	$400	2	$525
	CG4	Estimates	9	$450	14	$700
	CG8	Power Quality Complaints	4	$200	5	$250
		Total	**14**	**$1,050**	**23**	**$1,575**
Cedar City	***CG #***	***Description***	***Failure***	***Paid***	***Failure***	***Paid***
	CG3	Switching on Power	2	$750	4	$1,000
	CG4	Estimates	1	$50	3	$150
	CG7	Notification of Planned	0		1	$50
	CG8	Power Quality Complaints	2	$100	2	$100
		Total	**5**	**$900**	**10**	**$1,300**
Jordan Valley	***CG #***	***Description***	***Failure***	***Paid***	***Failure***	***Paid***
	CG1	Restoring Supply	3	$150	3	$150
	CG3	Switching on Power	2	$225	7	$475
	CG4	Estimates	3	$150	7	$350
	CG5	Respond to Billing Inquiries	0		2	$100
	CG7	Notification of Planned	0		4	$250
	CG8	Power Quality Complaints	73	$3,650	75	$3,750
		Total	**81**	**$4,175**	**98**	**$5,075**
Layton	***CG #***	***Description***	***Failure***	***Paid***	***Failure***	***Paid***
	CG2	Appointments	0		2	$100
	CG3	Switching on Power	1	$50	3	$250
	CG7	Notification of Planned	0		4	$200
	CG8	Power Quality Complaints	18	$900	19	$950
		Total	**19**	**$950**	**28**	**$1,500**
Moab	***CG #***	***Description***	***Failure***	***Paid***	***Failure***	***Paid***
	CG1	Restoring Supply	1	$75	1	$75
	CG2	Appointments	0		1	$50
	CG4	Estimates	0		2	$100
		Total	**1**	**$75**	**4**	**$225**

NOTE: District definitions remain in review status as part of the merger transition process.

UTAH FAILURES	July-September 2000		2nd Quarter		Year to Date	
Ogden	***CG #***	***Description***	***Failure***	***Paid***	***Failure***	***Paid***
	CG4	Estimates	2	$100	3	$150
	CG7	Notification of Planned	1	$50	2	$100
	CG8	Power Quality Complaints	12	$600	13	$650
		Total	**15**	**$750**	**18**	**$900**
Park City	***CG #***	***Description***	***Failure***	***Paid***	***Failure***	***Paid***
	CG3	Switching on Power	0		2	$300
	CG4	Estimates	1	$50	1	$50
	CG8	Power Quality Complaints	3	$150	3	$150
		Total	**4**	**$200**	**6**	**$500**
Price	***CG #***	***Description***	***Failure***	***Paid***	***Failure***	***Paid***
	CG4	Estimates	1	$50	1	$50
	CG5	Respond to Billing Inquiries	1	$50	1	$50
	CG7	Notification of Planned	0		1	$50
	CG8	Power Quality Complaints	1	$50	1	$50
		Total	**3**	**$150**	**4**	**$200**
Richfield	***CG #***	***Description***	***Failure***	***Paid***	***Failure***	***Paid***
	CG3	Switching on Power	0		1	$500
	CG4	Estimates	3	$150	5	$250
	CG8	Power Quality Complaints	1	$50	1	$50
		Total	**4**	**$200**	**7**	**$800**
Santaquin	***CG #***	***Description***	***Failure***	***Paid***	***Failure***	***Paid***
	CG2	Appointments	1	$50	1	$50
	CG4	Estimates	1	$50	1	$50
	CG8	Power Quality Complaints	1	$50	2	$100
		Total	**3**	**$150**	**4**	**$200**
SLC Metro	***CG #***	***Description***	***Failure***	***Paid***	***Failure***	***Paid***
	CG2	Appointments	0		2	$100
	CG3	Switching on Power	1	$225	9	$2,100
	CG4	Estimates	1	$50	2	$100
	CG5	Respond to Billing Inquiries	1	$50	4	$200
	CG7	Notification of Planned	0		7	$350

NOTE: District definitions remain in review status as part of the merger transition process.

			2nd Quarter		Year to Date	
SLC Metro	***CG #***	***Description***	***Failure***	***Paid***	***Failure***	***Paid***
	CG8	Power Quality Complaints	21	$1,050	25	$1,250
		Total	24	$1,375	49	$4,100
Smithfield	***CG #***	***Description***	***Failure***	***Paid***	***Failure***	***Paid***
	CG4	Estimates	0		1	$50
	CG8	Power Quality Complaints	4	$200	4	$200
		Total	4	$200	5	$250
Tooele	***CG #***	***Description***	***Failure***	***Paid***	***Failure***	***Paid***
	CG2	Appointments	1	$50	1	$50
	CG3	Switching on Power	0		1	$125
	CG8	Power Quality Complaints	14	$700	17	$850
		Total	15	$750	19	$1,025
Tremonton	***CG #***	***Description***	***Failure***	***Paid***	***Failure***	***Paid***
	CG4	Estimates	4	$200	5	$250
	CG6	Respond to Meter Problems	0		1	$50
	CG8	Power Quality Complaints	1	$50	1	$50
		Total	5	$250	7	$350
Vernal	***CG #***	***Description***	***Failure***	***Paid***	***Failure***	***Paid***
	CG3	Switching on Power	0		1	$75
		Total	0		1	$75
		State Total	**197**	**$11,175**	**283**	**$18,075**

NOTE: District definitions remain in review status as part of the merger transition process.

2nd Quarter **Fiscal Year 2001** **07/01/00 to 09/30/00**

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT		SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occur-rences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	UTA	STATE OF UTAH	60.381	0.521	2.899	2.775	617,289	321,393	5,315	37,272,331	782,731
Planned	UTA	STATE OF UTAH	0.868	0.007	0.000	0.010	617,289	4,401	142	536,059	19,664
Customer Requested	UTA	STATE OF UTAH	0.014	0.000	0.000	0.000	617,289	119	20	8,570	2,965

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occur-rences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	021 AMERICAN FORK	50.512	0.505	1.001	1.027	63,513	32,080	513	3,208,166	55,104
Planned	021 AMERICAN FORK	0.561	0.005	0.001	0.100	63,513	290	8	35,613	818
Customer Requested	021 AMERICAN FORK	0.027	0.001	0.000	0.000	63,513	56	6	1,710	945
High SAIDI	SAR13 SARATOGA 13 TO CEDAR VALLEY	780.022	3.157	1.000	1.000	453	1,430	18	353,350	
Low SAIDI	*7 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	SAR13 SARATOGA 13 TO CEDAR VALLEY	780.022	3.157	1.000	1.000	453	1,430	18	353,350	
Low SAIFI	*7 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	TSL11 CIRCUIT #11	38.571	0.429	9.000	6.000	7	3	1	270	
Low MAIFI	*36 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	WAL13 WALLSBURG 13 TO WALLSBURG CITY	264.823	1.815	8.000	8.000	130	236	15	34,427	
High $MAIFI_{(e)}$	HAL12 HALE CKT 12 TO WORD PERFECT & S. CYN RD	7.494	0.047	8.000	8.000	1,281	60	3	9,600	
Low $MAIFI_{(e)}$	*36 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	TRI11 TRY-CITY #11 (TEMP CIRCUIT)	675.176	1.004	0.000	0.000	1,500	1,506	2	1,012,764	
Low Customer Minutes Lost	*7 circuits with zero Customer Minutes Lost*								0	

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occur-rences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	029 ASHLEY (Vernal)	29.186	0.246	0.000	0.000	9,382	2,308	58	273,819	7,026
Planned	029 ASHLEY (Vernal)	0.000	0.000	0.000	0.000	9,382	0	0	0	0
Customer Requested	029 ASHLEY (Vernal)	0.000	0.000	0.000	0.000	9,382	0	0	0	0
High SAIDI	MAE11 MAESER #11 NORTH AND EAST	142.701	1.177	0.000	0.000	1,714	2,017	20	244,589	
Low SAIDI	*4 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	MAE11 MAESER #11 NORTH AND EAST	142.701	1.177	0.000	0.000	1,714	2,017	20	244,589	
Low SAIFI	*4 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI										
Low MAIFI	*All 12 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$										
Low $MAIFI_{(e)}$	*All 12 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	MAE11 MAESER #11 NORTH AND EAST	142.701	1.177	0.000	0.000	1,714	2,017	20	244,589	
Low Customer Minutes Lost	*4 circuits with zero Customer Minutes Lost*	0.000							0	

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occur-rences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	025 CANYONLANDS (Moab)	74.325	0.471	1.732	1.957	14,152	6,670	183	1,051,847	24,738
Planned	025 CANYONLANDS (Moab)	1.716	0.011	0.000	0.000	14,152	149	2	24,280	490
Customer Requested	025 CANYONLANDS (Moab)	0.060	0.000	0.000	0.000	14,152	3	1	855	285
High SAIDI	RDR02 RED ROCK #2	565.500	2.750	2.000	2.000	20	55	4	11,310	
Low SAIDI	*11 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	HAV21 HAVASU #21 N. BAY	350.571	3.471	1.000	1.000	70	243	7	24,540	
Low SAIFI	*11 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	WIT11 WHITE MESA CCT#11	392.905	2.347	20.000	19.000	95	223	15	37,326	
Low MAIFI	*2 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	SAN12 CIRCUIT #11	231.431	2.342	231.431	2.342	1,530	3,583	30	354,089	
Low $MAIFI_{(e)}$	*2 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	MOA13 MOAB #13 (SOUTH)	418.969	2.029	1.000	1.000	1,146	2,325	6	480,138	
Low Customer Minutes Lost	*11 circuits with zero Customer Minutes Lost*									

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occur-rences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	026 CARBON (Price)	83.335	0.946	1.824	1.682	10,247	9,693	131	853,936	15,113
Planned	026 CARBON (Price)	0.003	0.000	0.000	0.000	10,247	1	1	30	30
Customer Requested	026 CARBON (Price)	0.000	0.000	0.000	0.000	10,247	0	0	0	0
High SAIDI	HUN11 CIRCUIT #11	293.304	3.146	2.000	2.000	460	1,447	11	134,920	
Low SAIDI	*26 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	HUN11 CIRCUIT #11	293.304	3.146	2.000	2.000	460	1,447	11	134,920	
Low SAIFI	*26 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	SOL1 CIRCUIT #11	22.000	0.367	8.000	5.000	30	11	1	660	
High MAIFI	SCR1 CIRCUIT #11	23.680	0.137	8.000	5.000	197	27	6	4,665	
High MAIFI	SCO1 CIRCUIT #11	1.134	0.013	8.000	5.000	238	3	2	270	
High MAIFI	KYU1 CIRCUIT #1 WEST	0.000	0.000	8.000	5.000	1	0	0	0	
High MAIFI	RYL1 CIRCUIT #1	0.000	0.000	8.000	5.000	5	0	0	0	
High MAIFI	CTL1 CIRCUIT #1	0.000	0.000	8.000	5.000	12	0	0	0	
Low MAIFI	*15 circuits with a MAIFI of 0.0000*			0.000						
High MAIFI$_{(e)}$	SOL1 CIRCUIT #11	22.000	0.367	8.000	5.000	30	11	1	660	
High MAIFI$_{(e)}$	SCR1 CIRCUIT #11	23.680	0.137	8.000	5.000	197	27	6	4,665	
High MAIFI$_{(e)}$	SCO1 CIRCUIT #11	1.134	0.013	8.000	5.000	238	3	2	270	
High MAIFI$_{(e)}$	KYU1 CIRCUIT #1 WEST	0.000	0.000	8.000	5.000	1	0	0	0	
High MAIFI$_{(e)}$	RYL1 CIRCUIT #1	0.000	0.000	8.000	5.000	5	0	0	0	
High MAIFI$_{(e)}$	CTL1 CIRCUIT #1	0.000	0.000	8.000	5.000	12	0	0	0	
Low MAIFI$_{(e)}$	*15 circuits with a MAIFI$_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	WLG11 CIRCUIT #11	274.163	2.028	1.000	1.000	830	1,683	13	227,555	
Low Customer Minutes Lost	*26 circuits with zero Customer Minutes Lost*								0	

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occur-rences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	075 CEDAR CITY	39.826	0.727	4.162	3.982	16,027	11,654	220	638,288	19,012
Planned	075 CEDAR CITY	13.330	0.146	0.000	0.000	16,027	2,346	14	213,635	2,455
Customer Requested	075 CEDAR CITY	0.000	0.000	0.000	0.000	16,027	0	0	0	0
High SAIDI	WCD28 W CEDAR -DIXIE DEER 35 KV	503.200	4.040	2.000	2.000	25	101	5	12,580	
Low SAIDI	*24 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	SDR11 SANDERS RANCH AREA	419.000	4.333	2.000	2.000	15	65	5	6,285	
Low SAIFI	*24 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	DMR12 DIAMOND VALLEY	205.105	2.526	18.000	17.000	95	240	3	19,485	
High MAIFI	WNC11 WINCHESTER HILLS SUBDIVISION	56.290	1.403	18.000	17.000	124	174	2	6,980	
High MAIFI	MDD24 MIDDLETON-DIXIE DEER 35 KV	22.736	1.025	18.000	17.000	318	326	7	7,230	
High MAIFI	GNL1 GUNLOCK PLANT	20.000	1.000	18.000	17.000	1	1	1	20	
High MAIFI	VEY1 VEYO HYDRO PLANT	20.000	1.000	18.000	17.000	1	1	1	20	
High MAIFI	SNC1 HYDRO PLANT CB	20.000	1.000	18.000	17.000	1	1	1	20	
High MAIFI	DMR11 DAMMERON VALLEY	20.000	1.000	18.000	17.000	121	121	1	2,420	
Low MAIFI	*3 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	DMR12 DIAMOND VALLEY	205.105	2.526	18.000	17.000	95	240	3	19,485	
High $MAIFI_{(e)}$	WNC11 WINCHESTER HILLS SUBDIVISION	56.290	1.403	18.000	17.000	124	174	2	6,980	
High $MAIFI_{(e)}$	MDD24 MIDDLETON-DIXIE DEER 35 KV LINE	22.736	1.025	18.000	17.000	318	326	7	7,230	
High $MAIFI_{(e)}$	GNL1 GUNLOCK PLANT	20.000	1.000	18.000	17.000	1	1	1	20	
High $MAIFI_{(e)}$	VEY1 VEYO HYDRO PLANT	20.000	1.000	18.000	17.000	1	1	1	20	
High $MAIFI_{(e)}$	SNC1 HYDRO PLANT CB	20.000	1.000	18.000	17.000	1	1	1	20	
High $MAIFI_{(e)}$	DMR11 DAMMERON VALLEY	20.000	1.000	18.000	17.000	121	121	1	2,420	
Low $MAIFI_{(e)}$	*3 circuits with a $MAIFI_{(E)}$ of 0.0000*	0.000			0.000					
High Customer Minutes Lost	CLM12 NE CEDAR, BLOWHARD - (COL12 IN SAP)	133.178	0.458	2.021	3.000	1,215	557	18	161,811	
Low Customer Minutes Lost	*24 circuits with zero Customer Minutes Lost*	0.000							0	

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occur-rences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	003 COTTONWOOD (Jordan Valley)	46.454	0.451	4.405	4.089	91,310	41,169	501	4,241,742	96,226
Planned	003 COTTONWOOD (Jordan Valley)	0.016	0.000	0.000	0.000	91,310	14	4	1,498	472
Customer Requested	003 COTTONWOOD (Jordan Valley)	0.003	0.000	0.000	0.000	91,310	1	1	230	230
High SAIDI	UNN12 UNION #12	653.118	0.641	11.000	12.000	2,175	1,395	12	1,420,532	
Low SAIDI	*BRI11, QRY17*	0.000								
High SAIFI	BTL16 BUTLERVILLE #16	69.290	2.148	4.000	4.000	2,007	4,312	9	139,065	
Low SAIFI	*SDY11, BRI11, QRY17*		0.000							
High MAIFI	WJDN13 WEST JORDAN #13	30.524	1.006	28.000	28.000	2,451	2,466	5	74,815	
Low MAIFI	*18 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	WJDN13 WEST JORDAN #13	30.524	1.006	28.000	28.000	2,451	2,466	5	74,815	
Low $MAIFI_{(e)}$	*18 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	UNN12 UNION #12	653.118	0.641	11.000	12.000	2,175	1,395	12	1,420,532	
Low Customer Minutes Lost	*2 Circuits with zero Customer Minutes Lost*	0.000							0	

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occur-rences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	072 DELTA (Richfield)	30.964	0.120	1.006	1.006	5,766	691	75	178,537	13,196
Planned	072 DELTA (Richfield)	0.021	0.000	0.000	0.000	5,766	1	1	120	120
Customer Requested	072 DELTA (Richfield)	0.000	0.000	0.000	0.000	5,766	0	0	0	0
High SAIDI	HDN11 HOLDEN AREA	1,369.970	2.591	0.000	0.000	66	171	10	90,418	
Low SAIDI	*15 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	HDN11 HOLDEN AREA	1,369.970	2.591	0.000	0.000	66	171	10	90,418	
Low SAIFI	*15 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	NFD11 NORTH FIELDS LINE	202.200	1.900	3.000	3.000	50	95	5	10,110	
High MAIFI	FLC11 FOOL CREEK AREA IRRIGATION PUMPS	38.400	0.120	3.000	3.000	25	3	2	960	
High MAIFI	SMA11 SOMA TRACK HEATERS	0.000	0.000	3.000	3.000	1	0	0	0	
Low MAIFI	*20 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	NFD11 NORTH FIELDS LINE	202.200	1.900	3.000	3.000	50	95	5	10,110	
High $MAIFI_{(e)}$	FLC11 FOOL CREEK AREA IRRIGATION PUMPS	38.400	0.120	3.000	3.000	25	3	2	960	
High $MAIFI_{(e)}$	SMA11 SOMA TRACK HEATERS	0.000	0.000	3.000	3.000	1	0	0	0	
Low $MAIFI_{(e)}$	*20 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	HDN11 HOLDEN AREA	1,369.970	2.591	0.000	0.000	66	171	10	90,418	
Low Customer Minutes Lost	*15 circuits with zero Customer Minutes Lost*								0	

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occur-rences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	008 LAKE	73.338	0.563	2.665	2.507	28,240	15,887	249	2,071,073	42,284
Planned	008 LAKE	0.000	0.000	0.000	0.000	28,240	0	0	0	0
Customer Requested	008 LAKE	0.004	0.000	0.000	0.000	28,240	1	1	120	120
High SAIDI	CAN12 CANNON #12	414.469	1.222	0.000	0.000	1,255	1,533	11	520,159	
Low SAIDI	*8 circuits with a SAID I of 0.0000*	0.000								
High SAIFI	TRM11 TERMINAL #11	131.634	3.146	0.000	0.000	41	129	7	5,397	
Low SAIFI	*8 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	NSL12 NORTH SALT LAKE #12	327.426	1.435	14.000	12.000	2,223	3,189	17	727,867	
Low MAIFI	*28 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	NSL12 NORTH SALT LAKE #12	327.426	1.435	14.000	12.000	2,223	3,189	17	727,867	
High $MAIFI_{(e)}$	WDS13 WOODS CROSS #13	17.093	0.062	12.000	12.000	1,290	80	6	22,050	
Low $MAIFI_{(e)}$	*28 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	NSL12 NORTH SALT LAKE #12	327.426	1.435	14.000	12.000	2,223	3,189	17	727,867	
Low Customer Minutes Lost	*8 circuits with zero Customer Minutes Lost*	0.000								

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occur-rences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	012 LAYTON	23.244	0.638	3.795	3.451	34,429	21,962	171	800,267	20,935
Planned	012 LAYTON	3.528	0.016	0.000	0.000	34,429	563	34	121,456	2,479
Customer Requested	012 LAYTON	0.006	0.000	0.000	0.000	34,429	1	1	210	210
High SAIDI	SYR15 SYRACUSE CKT#15 CT-PLASTICS	120.000	1.000	0.000	0.000	1	1	1	120	
Low SAIDI	*10 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	ANG11 ANGEL CKT#11 NORTH-WEST	48.783	2.135	0.000	0.000	2,540	5,422	14	123,910	
Low SAIFI	*10 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	FAR11 FARMINGTON SOUTH	14.610	1.014	9.000	6.000	1,820	1,846	7	26,590	
Low MAIFI	*13 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	CLIN11 CLINTON EAST	24.846	0.272	7.000	7.000	806	219	18	20,026	
Low $MAIFI_{(e)}$	*13 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	ANG11 ANGEL CKT#11 NORTH-WEST	48.783	2.135	0.000	0.000	2,540	5,422	14	123,910	
Low Customer Minutes Lost	*10 circuits with zero Customer Minutes Lost*								0	

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occur-rences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	001 METRO	43.533	0.294	2.946	2.945	137,753	40,499	851	5,996,849	141,426
Planned	001 METRO	0.034	0.000	0.000	0.000	137,753	37	2	4,676	308
Customer Requested	001 METRO	0.000	0.000	0.000	0.000	137,753	0	0	0	0
High SAIDI	VLY12 VALLEY CENTER #12	395.668	0.683	5.000	5.000	1,588	1,084	5	628,320	
Low SAIDI	*69 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	OLY11 OLYMPUS #11	284.455	3.864	1.000	1.000	1,159	4,478	54	329,683	
Low SAIFI	*69 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	MC12 MORTON COURT #12	52.135	0.410	15.000	15.000	1,000	410	14	52,135	
Low MAIFI	*97 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	MC12 MORTON COURT #12	52.135	0.410	15.000	15.000	1,000	410	14	52,135	
Low $MAIFI_{(e)}$	*97 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	VLY12 VALLEY CENTER #12	395.668	0.683	5.000	5.000	1,588	1,084	5	628,320	
Low Customer Minutes Lost	*69 circuits with zero Customer Minutes Lost*								0	

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occur-rences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	074 MILFORD (Richfield)	77.105	0.900	1.923	1.923	1,678	1,510	79	129,383	8,206
Planned	074 MILFORD (Richfield)	1.031	0.008	0.000	0.000	1,678	14	4	1,730	415
Customer Requested	074 MILFORD (Richfield)	0.000	0.000	0.000	0.000	1,678	0	0	0	0
High SAIDI	SML11 CENTRAL MILFORD FLATS	831.000	9.133	2.000	2.000	30	274	14	24,930	
Low SAIDI	*3 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	SML11 CENTRAL MILFORD FLATS	831.000	9.133	2.000	2.000	30	274	14	24,930	
Low SAIFI	*3 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	CVF11 COVE FORT, SULPHURDALE AREAS	197.813	1.188	3.000	3.000	16	19	4	3,165	
High MAIFI	MTV11 MILFORD TV LINE	90.000	0.750	3.000	3.000	4	3	1	360	
Low MAIFI	*ELK11 MT. HOLLY SKI AREAS*	77.901	0.358	1.000	1.000	81	29	4	6,310	
Low MAIFI	*LWB11 OLD LOWER BEAVER PLANT SITE*	30.000	0.250	1.000	1.000	4	1	1	120	
Low MAIFI	*PND11 BEAVER CANYON CABINS*	4.800	0.040	1.000	1.000	50	2	2	240	
Low MAIFI	*PAC534 CAMERON-UPPER BEAVER*	0.000	0.000	1.000	1.000	1	0	0	0	
Low MAIFI	*CMR44 LINE TO MILFORD, BLUNDELL PLA*	0.000	0.000	1.000	1.000	2	0	0	0	
Low MAIFI	*ELK12 S W CONDOS & CABINS*	0.000	0.000	1.000	1.000	12	0	0	0	
High $MAIFI_{(e)}$	CVF11 COVE FORT, SULPHURDALE AREAS	197.813	1.188	3.000	3.000	16	19	4	3,165	
High $MAIFI_{(e)}$	MTV11 MILFORD TV LINE	90.000	0.750	3.000	3.000	4	3	1	360	
Low $MAIFI_{(e)}$	*ELK11 MT. HOLLY SKI AREAS*	77.901	0.358	1.000	1.000	81	29	4	6,310	
Low $MAIFI_{(e)}$	*LWB11 OLD LOWER BEAVER PLANT SITE*	30.000	0.250	1.000	1.000	4	1	1	120	
Low $MAIFI_{(e)}$	*PND11 BEAVER CANYON CABINS*	4.800	0.040	1.000	1.000	50	2	2	240	
Low $MAIFI_{(e)}$	*PAC534 CAMERON-UPPER BEAVER*	0.000	0.000	1.000	1.000	1	0	0	0	
Low $MAIFI_{(e)}$	*CMR44 LINE TO MILFORD, BLUNDELL PLA*	0.000	0.000	1.000	1.000	2	0	0	0	
Low $MAIFI_{(e)}$	*ELK12 S W CONDOS & CABINS*	0.000	0.000	1.000	1.000	12	0	0	0	
High Customer Minutes Lost	MLF13 W & N W MILFORD	117.006	1.945	2.000	2.000	344	669	13	40,250	
Low Customer Minutes Lost	*3 circuits with zero Customer Minutes Lost*								0	

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occur-rences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	011 OGDEN	52.108	0.591	2.384	2.181	72,980	43,139	783	3,802,829	86,651
Planned	011 OGDEN	1.298	0.010	0.000	0.000	72,980	695	47	94,716	8,152
Customer Requested	011 OGDEN	0.070	0.001	0.000	0.000	72,980	53	7	5,125	985
High SAIDI	MGN11 MORGAN	537.690	0.771	2.000	2.000	306	236	21	164,533	
Low SAIDI	*36 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	NOG13 CIRCUIT #13	200.137	3.151	5.000	4.000	1,200	3,781	23	240,164	
Low SAIFI	*36 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	UIN13 UINTAH CKT#13 COMBE RD EAST	151.067	0.822	14.000	14.000	1,001	823	30	151,218	
High MAIFI	WRY14 WEST ROY/WEST	46.594	0.554	14.000	12.000	834	462	18	38,859	
Low MAIFI	*58 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	UIN13 UINTAH CKT#13 COMBE RD EAST	151.067	0.822	14.000	14.000	1,001	823	30	151,218	
Low $MAIFI_{(e)}$	*58 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	UIN11 UINTAH CKT#11 (OLD #12 CHANGED 1/9/91)	359.695	0.709	5.000	4.000	1,277	905	7	459,330	
Low Customer Minutes Lost	*36 circuits with zero Customer Minutes Lost*								0	

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occur-rences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	005 PARK CITY	27.203	0.149	2.523	2.486	16,053	2,397	283	436,684	38,836
Planned	005 PARK CITY	0.000	0.000	0.000	0.000	16,053	0	0	0	0
Customer Requested	005 PARK CITY	0.000	0.000	0.000	0.000	16,053	0	0	0	0
High SAIDI	THF21 THIEF CREEK #21	606.100	1.200	0.000	0.000	10	12	3	6,061	
Low SAIDI	*7 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	COA13 COALVILLE #13	507.750	2.000	2.000	2.000	20	40	5	10,155	
Low SAIFI	*7 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	COA12 COALVILLE #12	10.785	0.090	13.000	13.000	479	43	20	5,166	
Low MAIFI	*16 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	COA12 COALVILLE #12	10.785	0.090	13.000	13.000	479	43	20	5,166	
Low $MAIFI_{(e)}$	*16 circuits with a $MAIFI_{(E)}$ of 0.0000*								0	
High Customer Minutes Lost	PC12 PARK CITY #12	66.716	0.186	0.000	0.000	1,081	201	2	72,120	
Low Customer Minutes Lost	*7 circuits with zero Customer Minutes Lost*								0	

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occur-rences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	071 SALINA (Richfield)	68.309	0.356	1.203	1.203	13,235	4,710	185	904,067	19,124
Planned	071 SALINA (Richfield)	0.161	0.002	0.000	0.000	13,235	20	5	2,130	390
Customer Requested	071 SALINA (Richfield)	0.000	0.000	0.000	0.000	13,235	0	0	0	0
High SAIDI	PAN11 E. PANGUITCH	359.183	1.075	5.000	5.000	722	776	6	259,330	
Low SAIDI	*23 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	SAL13 N SALINA, REDMOND	60.692	2.108	1.000	1.000	390	822	5	23,670	
Low SAIFI	*23 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	PAN11 E. PANGUITCH	359.183	1.075	5.000	5.000	722	776	6	259,330	
High MAIFI	PAN12 W PANGUITCH, LAKE	354.741	1.033	5.000	5.000	367	379	4	130,190	
High MAIFI	CIR11 CIRCLEVILLE	352.749	1.024	5.000	5.000	251	257	4	88,540	
High MAIFI	JUN11 JUNCTION, KINGSTON	351.605	1.016	5.000	5.000	190	193	4	66,805	
High MAIFI	PAC559 MINERAL PPRODUCTS-PANQUITCH	350.000	1.000	5.000	5.000	1	1	1	350	
High MAIFI	KAI11 W PANGUITCH LUMBER MILLS	350.000	1.000	5.000	5.000	3	3	1	1,050	
High MAIFI	PAN12D PANG LAKE RECLOSER	350.000	1.000	5.000	5.000	13	13	1	4,550	
High MAIFI	JUN11B CIRCLEVILLE LINE SECTIONALIZER	350.000	1.000	5.000	5.000	15	15	1	5,250	
High MAIFI	PAN12F PANG LK EST RECLOSER	350.000	1.000	5.000	5.000	92	92	1	32,200	
High MAIFI	PAN11B EAST PANG SECTIONALIZER	350.000	1.000	5.000	5.000	100	100	1	35,000	
High MAIFI	PAN12E S PANG LAKE RECLOSER	350.000	1.000	5.000	5.000	143	143	1	50,050	
High MAIFI	PAN12C W PANGUITCH SECTIONALIZER	350.000	1.000	5.000	5.000	153	153	1	53,550	
High MAIFI	PAN12B S W PANGUITCH SECTIONALIZER	350.000	1.000	5.000	5.000	191	191	1	66,850	
Low MAIFI	*30 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	PAN11 E. PANGUITCH	359.183	1.075	5.000	5.000	722	776	6	259,330	
High $MAIFI_{(e)}$	PAN12 W PANGUITCH, LAKE	354.741	1.033	5.000	5.000	367	379	4	130,190	
High $MAIFI_{(e)}$	CIR11 CIRCLEVILLE	352.749	1.024	5.000	5.000	251	257	4	88,540	
High $MAIFI_{(e)}$	JUN11 JUNCTION, KINGSTON	351.605	1.016	5.000	5.000	190	193	4	66,805	
High $MAIFI_{(e)}$	PAC559 MINERAL PPRODUCTS-PANQUITCH	350.000	1.000	5.000	5.000	1	1	1	350	
High $MAIFI_{(e)}$	KAI11 W PANGUITCH LUMBER MILLS	350.000	1.000	5.000	5.000	3	3	1	1,050	
High $MAIFI_{(e)}$	PAN12D PANG LAKE RECLOSER	350.000	1.000	5.000	5.000	13	13	1	4,550	

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occur-rences	Customer Minutes Lost	Duration Total (Minutes)
High $MAIFI_{(e)}$	JUN11B CIRCLEVILLE LINE SECTIONALIZER	350.000	1.000	5.000	5.000	15	15	1	5,250	
High $MAIFI_{(e)}$	PAN12F PANG LK EST RECLOSER	350.000	1.000	5.000	5.000	92	92	1	32,200	
High $MAIFI_{(e)}$	PAN11B EAST PANG SECTIONALIZER	350.000	1.000	5.000	5.000	100	100	1	35,000	
High $MAIFI_{(e)}$	PAN12E S PANG LAKE RECLOSER	350.000	1.000	5.000	5.000	143	143	1	50,050	
High $MAIFI_{(e)}$	PAN12C W PANGUITCH SECTIONALIZER	350.000	1.000	5.000	5.000	153	153	1	53,550	
High $MAIFI_{(e)}$	PAN12B S W PANGUITCH SECTIONALIZER	350.000	1.000	5.000	5.000	191	191	1	66,850	
Low $MAIFI_{(e)}$	*30 circuits with a $MAIFI_{(E)}$ of 0.0000*									
High Customer Minutes Lost	PAN11 E. PANGUITCH	359.183	1.075	5.000	5.000	722	776	6	259,330	
Low Customer Minutes Lost	*23 circuits with zero Customer Minutes Lost*								0	

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occur-rences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	014 SMITHFIELD	63.744	0.742	0.979	0.456	13,126	9,743	232	836,701	26,366
Planned	014 SMITHFIELD	0.000	0.000	0.000	0.000	13,126	0	0	0	0
Customer Requested	014 SMITHFIELD	0.000	0.000	0.000	0.000	13,126	0	0	0	0
High SAIDI	AMA12 AMALGA/SMITHFIELD	295.928	3.206	7.000	2.000	1,000	3,206	26	295,928	
Low SAIDI	*3 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	AMA12 AMALGA/SMITHFIELD	295.928	3.206	7.000	2.000	1,000	3,206	26	295,928	
Low SAIFI	*3 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	AMA12 AMALGA/SMITHFIELD	295.928	3.206	7.000	2.000	1,000	3,206	26	295,928	
High MAIFI	AMA11 AMALGA/BENSON CT11	2.819	0.048	7.000	1.000	227	11	5	640	
Low MAIFI	*16 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	AMA12 AMALGA/SMITHFIELD	295.928	3.206	7.000	2.000	1,000	3,206	26	295,928	
High $MAIFI_{(e)}$	LEW11 LEWISTON/SOUTH #11	65.101	2.114	2.000	2.000	306	647	13	19,921	
Low $MAIFI_{(e)}$	*16 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	AMA12 AMALGA/SMITHFIELD	295.928	3.206	7.000	2.000	1,000	3,206	26	295,928	
Low Customer Minutes Lost	*3 circuits with zero Customer Minutes Lost*	0.000							0	

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occur-rences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	007 SOUTH VALLEY (Jordan Valley)	89.421	1.212	5.654	5.483	27,842	33,745	292	2,489,661	70,474
Planned	007 SOUTH VALLEY (Jordan Valley)	0.306	0.003	0.000	0.000	27,842	91	7	8,530	980
Customer Requested	007 SOUTH VALLEY (Jordan Valley)	0.009	0.000	0.000	0.000	27,842	2	1	260	130
High SAIDI	BNG12 BINGHAM #12	397.245	2.469	1.002	2.000	531	1,311	35	210,937	
Low SAIDI	*5 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	HOG11 HOGGARD #11	68.169	3.164	4.000	4.000	5,161	16,327	23	351,820	
Low SAIFI	*5 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	HOG13 HOGGARD #13	110.946	0.411	19.000	19.000	1,226	504	4	136,020	
Low MAIFI	*5 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	HOG13 HOGGARD #13	110.946	0.411	19.000	19.000	1,226	504	4	136,020	
Low $MAIFI_{(e)}$	*5 circuits with a $MAIFI_{(E)}$ of 0.0000*									
High Customer Minutes Lost	BNG11 BINGHAM #11	330.361	1.211	4.000	4.000	2,710	3,283	29	895,278	
Low Customer Minutes Lost	*5 circuits with zero Customer Minutes Lost*								0	

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occur-rences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	004 TOOELE	501.599	2.136	6.548	6.205	13,276	28,358	221	6,659,225	36,772
Planned	004 TOOELE	1.739	0.012	0.000	0.000	13,276	158	9	23,085	1,715
Customer Requested	004 TOOELE	0.005	0.000	0.000	0.000	13,276	2	2	60	60
High SAIDI	GRA12 GRANTSVILLE #12	952.571	4.448	1.000	1.000	105	467	8	100,020	
Low SAIDI	*CII11, PAC475, TIM*	0.000								
High SAIFI	TOO11 TOOELE #11	835.133	5.366	1.000	1.000	511	2,742	24	426,753	
Low SAIFI	*CII11, PAC475, TIM*		0.000							
High MAIFI	TOO13 TOOELE #13	877.029	3.078	14.000	13.000	3,260	10,034	25	2,859,116	
Low MAIFI	*7 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	TOO13 TOOELE #13	877.029	3.078	14.000	13.000	3,260	10,034	25	2,859,116	
Low $MAIFI_{(e)}$	*7 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	TOO13 TOOELE #13	877.029	3.078	14.000	13.000	3,260	10,034	25	2,859,116	
Low Customer Minutes Lost	*3 circuits with zero Customer Minutes Lost*								0	

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occur-rences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	013 TREMONTON	101.312	0.564	0.462	0.462	6,424	3,625	101	650,827	16,304
Planned	013 TREMONTON	0.000	0.000	0.000	0.000	6,424	0	0	0	0
Customer Requested	013 TREMONTON	0.000	0.000	0.000	0.000	6,424	0	0	0	0
High SAIDI	BLU BLUE CREEK	1,048.438	2.008	0.000	0.000	128	257	3	134,200	
Low SAIDI	*7 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	SNO11 SNOWVILLE CKT#11	368.632	3.579	3.000	3.000	19	68	7	7,004	
Low SAIFI	*7 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	BCY1 BRIGHAM CITY	0.000	0.000	4.000	3.000	1	0	0	0	
Low MAIFI	*13 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	BCY1 BRIGHAM CITY	0.000	0.000	4.000	3.000	1	0	0	0	
High $MAIFI_{(e)}$	SNO11 SNOWVILLE CKT#11	368.632	3.579	3.000	3.000	19	68	7	7,004	
High $MAIFI_{(e)}$	SNO12 SNOWVILLE CKT#12	67.802	1.173	3.000	3.000	324	380	7	21,968	
Low $MAIFI_{(e)}$	*13 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	BSH12 BUSH CKT #12	452.286	1.638	0.000	0.000	398	652	7	180,010	
Low Customer Minutes Lost	*7 circuits with zero Customer Minutes Lost*								0	

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occur-rences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	002 VALLEY WEST (Jordan Valley)	48.940	0.276	2.447	2.447	41,856	11,553	186	2,048,430	44,928
Planned	002 VALLEY WEST (Jordan Valley)	0.109	0.001	0.000	0.000	41,856	22	4	4,560	840
Customer Requested	002 VALLEY WEST (Jordan Valley)	0.000	0.000	0.000	0.000	41,856	0	0	0	0
High SAIDI	TAY11 TAYLORSVILLE #11	392.827	3.012	1.000	1.000	901	2,714	5	353,937	
Low SAIDI	*4 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	TAY11 TAYLORSVILLE #11	392.827	3.012	1.000	1.000	901	2,714	5	353,937	
Low SAIFI	*4 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	LPK12 LAKEPARK #12	8.620	0.037	14.000	14.000	3,065	114	10	26,419	
Low MAIFI	*16 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	LPK12 LAKEPARK #12	8.620	0.037	14.000	14.000	3,065	114	10	26,419	
Low $MAIFI_{(e)}$	*16 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	TAY11 TAYLORSVILLE #11	392.827	3.012	1.000	1.000	901	2,714	5	353,937	
Low Customer Minutes Lost	*4 circuits with zero Customer Minutes Lost*	0.000							0	

Year to Date **Fiscal Year 2001** **04/01/00 to 09/30/00**

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT		SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occurrences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	UTA	STATE OF UTAH	87.055	0.826	4.838	4.546	617,289	509,956	8,643	53,738,312	1,114,742
Planned	UTA	STATE OF UTAH	1.439	0.010	0.000	0.013	617,289	6,152	226	888,178	31,247
Customer Requested	UTA	STATE OF UTAH	0.034	0.000	0.001	0.001	617,289	210	50	21,144	8,544

Year to Date **Fiscal Year 2001** **04/01/00 to 09/30/00**

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occurrences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	021 AMERICAN FORK	70.814	0.824	1.707	1.771	63,513	52,318	827	4,497,624	82,380
Planned	021 AMERICAN FORK	0.614	0.005	0.001	0.100	63,513	316	13	39,023	1,348
Customer Requested	021 AMERICAN FORK	0.047	0.001	0.000	0.000	63,513	78	15	2,963	1,808
High SAIDI	SAR13 SARATOGA 13 TO CEDAR VALLEY	1,219.437	5.188	2.000	2.000	453	2,350	30	552,405	
Low SAIDI	*7 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	SAR13 SARATOGA 13 TO CEDAR VALLEY	1,219.437	5.188	2.000	2.000	453	2,350	30	552,405	
Low SAIFI	*7 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	ORE14 OREM #14 TO SOUTH MAIN	28.126	0.284	15.000	15.000	1,916	544	20	53,889	
Low MAIFI	*31 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	ORE14 OREM #14 TO SOUTH MAIN	28.126	0.284	15.000	15.000	1,916	544	20	53,889	
Low $MAIFI_{(e)}$	*31 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	TRI11 TRY-CITY #11 (TEMP CIRCUIT)	675.176	1.004	0.000	0.000	1,500	1,506	2	1,012,764	
Low Customer Minutes Lost	*7 circuits with zero Customer Minutes Lost*								0	

Year to Date **Fiscal Year 2001** **04/01/00 to 09/30/00**

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occurrences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	029 ASHLEY (Vernal)	31.732	0.277	0.000	0.000	9,382	2,602	104	297,714	7,506
Planned	029 ASHLEY (Vernal)	0.000	0.000	0.000	0.000	9,382	0	0	0	0
Customer Requested	029 ASHLEY (Vernal)	0.000	0.000	0.000	0.000	9,382	0	0	0	0
High SAIDI	MAE11 MAESER #11 NORTH AND EAST	149.180	1.267	0.000	0.000	1,714	2,171	31	255,694	
Low SAIDI	*4 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	MAE11 MAESER #11 NORTH AND EAST	149.180	1.267	0.000	0.000	1,714	2,171	31	255,694	
Low SAIFI	*4 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI										
Low MAIFI	*All 12 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$										
Low $MAIFI_{(e)}$	*All 12 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	MAE11 MAESER #11 NORTH AND EAST	149.180	1.267	0.000	0.000	1,714	2,171	31	255,694	
Low Customer Minutes Lost	*4 circuits with zero Customer Minutes Lost*								0	

Year to Date **Fiscal Year 2001** **04/01/00 to 09/30/00**

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occurrences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	025 CANYONLANDS (Moab)	91.259	0.752	1.769	2.158	14,152	10,637	266	1,291,497	34,354
Planned	025 CANYONLANDS (Moab)	1.754	0.011	0.000	0.000	14,152	155	3	24,820	580
Customer Requested	025 CANYONLANDS (Moab)	0.060	0.000	0.000	0.000	14,152	3	1	855	285
High SAIDI	RDR02 RED ROCK #2	577.500	2.800	2.000	2.000	20	56	5	11,550	
Low SAIDI	*8 circuits with a SAIDI of 0.0000*									
High SAIFI	HAV21 HAVASU #21 N. BAY	376.286	3.900	2.000	2.000	70	273	8	26,340	
Low SAIFI	*8 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	WIT11 WHITE MESA CCT#11	421.853	2.516	23.000	22.000	95	239	18	40,076	
Low MAIFI	*2 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	WIT11 WHITE MESA CCT#11	421.853	2.516	23.000	22.000	95	239	18	40,076	
Low $MAIFI_{(e)}$	*2 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	MOA13 MOAB #13 (SOUTH)	419.257	2.034	1.000	1.000	1,146	2,331	9	480,468	
Low Customer Minutes Lost	*11 circuits with zero Customer Minutes Lost*									

Year to Date **Fiscal Year 2001** **04/01/00 to 09/30/00**

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occurrences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	026 CARBON (Price)	122.916	1.365	2.529	2.388	10,247	13,984	233	1,259,524	18,592
Planned	026 CARBON (Price)	4.394	0.015	0.000	0.000	10,247	151	2	45,030	330
Customer Requested	026 CARBON (Price)	0.000	0.000	0.000	0.000	10,247	0	0	0	0
High SAIDI	HUN11 CIRCUIT #11	295.913	3.174	2.000	2.000	460	1,460	17	136,120	
Low SAIDI	*15 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	HUN11 CIRCUIT #11	295.913	3.174	2.000	2.000	460	1,460	17	136,120	
Low SAIFI	*15 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	SOL1 CIRCUIT #11	26.000	0.400	9.000	6.000	30	12	2	780	
High MAIFI	SCR1 CIRCUIT #11	27.183	0.173	9.000	6.000	197	34	9	5,355	
High MAIFI	SCO1 CIRCUIT #11	4.160	0.034	9.000	6.000	238	8	4	990	
High MAIFI	CTL1 CIRCUIT #1	0.000	0.000	9.000	6.000	12	0	0	0	
High MAIFI	KYU1 CIRCUIT #1 WEST	0.000	0.000	9.000	6.000	1	0	0	0	
High MAIFI	RYL1 CIRCUIT #1	0.000	0.000	9.000	6.000	5	0	0	0	
Low MAIFI	*15 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	SOL1 CIRCUIT #11	26.000	0.400	9.000	6.000	30	12	2	780	
High $MAIFI_{(e)}$	SCR1 CIRCUIT #11	27.183	0.173	9.000	6.000	197	34	9	5,355	
High $MAIFI_{(e)}$	SCO1 CIRCUIT #11	4.160	0.034	9.000	6.000	238	8	4	990	
High $MAIFI_{(e)}$	CTL1 CIRCUIT #1	0.000	0.000	9.000	6.000	12	0	0	0	
High $MAIFI_{(e)}$	KYU1 CIRCUIT #1 WEST	0.000	0.000	9.000	6.000	1	0	0	0	
High $MAIFI_{(e)}$	RYL1 CIRCUIT #1	0.000	0.000	9.000	6.000	5	0	0	0	
Low $MAIFI_{(e)}$	*15 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	WLG11 CIRCUIT #11	274.705	2.034	2.000	2.000	830	1,688	16	228,005	
Low Customer Minutes Lost	*15 circuits with zero Customer Minutes Lost*								0	

Year to Date Fiscal Year 2001 04/01/00 to 09/30/00

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occurrences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	075 CEDAR CITY	114.437	1.970	5.164	4.827	16,027	31,567	482	1,834,081	46,210
Planned	075 CEDAR CITY	13.683	0.150	0.008	0.008	16,027	2,398	16	219,290	2,792
Customer Requested	075 CEDAR CITY	0.000	0.000	0.000	0.000	16,027	0	0	0	0
High SAIDI	WCD28 W CEDAR -DIXIE DEER 35 KV	647.200	7.240	2.000	2.000	25	181	10	16,180	
Low SAIDI	*2 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	SDR11 SANDERS RANCH AREA	557.000	7.333	2.000	2.000	15	110	8	8,355	
Low SAIFI	*2 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	DMR12 DIAMOND VALLEY	258.474	3.537	19.000	18.000	95	336	5	24,555	
High MAIFI	WNC11 WINCHESTER HILLS SUBDIVISION	56.290	1.403	18.000	17.000	124	174	2	6,980	
High MAIFI	MDD24 MIDDLETON-DIXIE DEER 35 KV	22.736	1.025	18.000	17.000	318	326	7	7,230	
High MAIFI	GNL1 GUNLOCK PLANT	20.000	1.000	18.000	17.000	1	1	1	20	
High MAIFI	VEY1 VEYO HYDRO PLANT	20.000	1.000	18.000	17.000	1	1	1	20	
High MAIFI	SNC1 HYDRO PLANT CB	20.000	1.000	18.000	17.000	1	1	1	20	
High MAIFI	DMR11 DAMMERON VALLEY	20.000	1.000	18.000	17.000	121	121	1	2,420	
Low MAIFI	*3 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	DMR12 DIAMOND VALLEY	258.474	3.537	19.000	18.000	95	336	5	24,555	
High $MAIFI_{(e)}$	DMR11 DAMMERON VALLEY	120.066	3.000	19.000	18.000	121	363	3	14,528	
High $MAIFI_{(e)}$	WNC11 WINCHESTER HILLS SUBDIVISION	108.290	2.403	19.000	18.000	124	298	3	13,428	
High $MAIFI_{(e)}$	MDD24 MIDDLETON-DIXIE DEER 35 KV LINE	79.692	2.088	19.000	18.000	318	664	12	25,342	
High $MAIFI_{(e)}$	GNL1 GUNLOCK PLANT	72.000	2.000	19.000	18.000	1	2	2	72	
High $MAIFI_{(e)}$	SNC1 HYDRO PLANT CB	72.000	2.000	19.000	18.000	1	2	2	72	
High $MAIFI_{(e)}$	VEY1 VEYO HYDRO PLANT	72.000	2.000	19.000	18.000	1	2	2	72	
Low $MAIFI_{(e)}$	*3 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					

Year to Date **Fiscal Year 2001** **04/01/00 to 09/30/00**

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occurrences	Customer Minutes Lost	Duration Total (Minutes)
High Customer Minutes Lost	BHD11 BRIAN HEAD TOWN	297.733	3.501	7.000	6.000	726	2,542	9	216,154	
Low Customer Minutes Lost	*2 circuits with zero Customer Minutes Lost*	0.000							0	

Year to Date **Fiscal Year 2001** **04/01/00 to 09/30/00**

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occurrences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	003 COTTONWOOD (Jordan Valley)	64.711	0.622	6.871	6.417	91,310	56,835	818	5,908,790	138,051
Planned	003 COTTONWOOD (Jordan Valley)	0.056	0.000	0.000	0.000	91,310	36	10	5,098	1,732
Customer Requested	003 COTTONWOOD (Jordan Valley)	0.009	0.000	0.000	0.000	91,310	3	2	860	860
High SAIDI	UNN12 UNION #12	658.222	0.668	16.000	16.000	2,175	1,453	16	1,431,632	
Low SAIDI	*SDY11 SANDY #11*	0.191	0.001	1.000	1.000	2,355	2	2	450	
High SAIFI	MDV11 MIDVALE #11	294.906	2.387	1.000	1.000	424	1,012	13	125,040	
Low SAIFI	*SDY11 SANDY #11*	0.191	0.001	1.000	1.000	2,355	2	2	450	
High MAIFI	DUM16 DUMAS #16	50.845	2.246	42.000	38.000	2,000	4,491	13	101,690	
Low MAIFI	*15 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	DUM16 DUMAS #16	50.845	2.246	42.000	38.000	2,000	4,491	13	101,690	
Low $MAIFI_{(e)}$	*15 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	UNN12 UNION #12	658.222	0.668	16.000	16.000	2,175	1,453	16	1,431,632	
Low Customer Minutes Lost	*SDY11 SANDY #11*	0.191	0.001	1.000	1.000	2,355	2	2	450	

Year to Date **Fiscal Year 2001** **04/01/00 to 09/30/00**

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occurrences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	072 DELTA (Richfield)	51.488	0.327	2.011	1.562	5,766	1,884	131	296,880	28,204
Planned	072 DELTA (Richfield)	0.021	0.000	0.000	0.000	5,766	1	1	120	120
Customer Requested	072 DELTA (Richfield)	0.000	0.000	0.000	0.000	5,766	0	0	0	0
High SAIDI	HDN11 HOLDEN AREA	1,397.242	3.197	0.000	0.000	66	211	11	92,218	
Low SAIDI	*14 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	HDN11 HOLDEN AREA	1,397.242	3.197	0.000	0.000	66	211	11	92,218	
Low SAIFI	*14 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	NFD11 NORTH FIELDS LINE	203.500	1.920	6.000	6.000	50	96	6	10,175	
High MAIFI	FLC11 FOOL CREEK AREA IRRIGATION PUMPS	50.400	0.160	6.000	6.000	25	4	3	1,260	
High MAIFI	SMA11 SOMA TRACK HEATERS	0.000	0.000	6.000	6.000	1	0	0	0	
Low MAIFI	*20 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	NFD11 NORTH FIELDS LINE	203.500	1.920	6.000	6.000	50	96	6	10,175	
Low $MAIFI_{(e)}$	*20 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	HDN11 HOLDEN AREA	1,397.242	3.197	0.000	0.000	66	211	11	92,218	
Low Customer Minutes Lost	*14 circuits with zero Customer Minutes Lost*								0	

Year to Date **Fiscal Year 2001** **04/01/00 to 09/30/00**

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occurrences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	008 LAKE	129.038	0.943	5.299	4.835	28,240	26,639	431	3,644,043	47,678
Planned	008 LAKE	0.005	0.000	0.000	0.000	28,240	1	1	150	150
Customer Requested	008 LAKE	0.147	0.001	0.000	0.000	28,240	18	3	4,155	595
High SAIDI	CAN12 CANNON #12	446.997	1.688	4.000	4.000	1,255	2,119	19	560,981	
Low SAIDI	*2 circuits with a SAID I of 0.0000*	0.000								
High SAIFI	RED16 REDWOOD #16	444.883	3.919	10.000	8.000	307	1,203	22	136,579	
Low SAIFI	*2 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	WDS13 WOODS CROSS #13	19.814	0.074	23.000	21.000	1,290	95	9	25,560	
Low MAIFI	*17 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	WDS13 WOODS CROSS #13	19.814	0.074	23.000	21.000	1,290	95	9	25,560	
Low $MAIFI_{(e)}$	*17 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	NSL12 NORTH SALT LAKE #12	334.807	1.500	14.000	12.000	2,223	3,335	24	744,277	
Low Customer Minutes Lost	*2 circuits with zero Customer Minutes Lost*	0.000								

Year to Date **Fiscal Year 2001** **04/01/00 to 09/30/00**

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occurrences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	012 LAYTON	48.495	0.915	7.608	6.982	34,429	31,498	286	1,669,629	35,863
Planned	012 LAYTON	4.025	0.022	0.001	0.044	34,429	754	61	138,560	4,175
Customer Requested	012 LAYTON	0.027	0.000	0.000	0.000	34,429	3	3	930	930
High SAIDI	SYR11 SYRACUSE/1000 WEST	418.729	4.234	7.000	7.000	107	453	11	44,804	
Low SAIDI	*7 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	SYR11 SYRACUSE/1000 WEST	418.729	4.234	7.000	7.000	107	453	11	44,804	
Low SAIFI	*7 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	LAY17 LAYTON #17	45.422	1.353	18.000	17.000	2,743	3,711	21	124,592	
Low MAIFI	*8 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	LAY17 LAYTON #17	45.422	1.353	18.000	17.000	2,743	3,711	21	124,592	
Low $MAIFI_{(e)}$	*8 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	CLD11 CLEARFIELD CKT#11	64.952	2.339	7.000	7.000	2,787	6,519	15	181,020	
Low Customer Minutes Lost	*7 circuits with zero Customer Minutes Lost*								0	

Year to Date   Fiscal Year 2001   04/01/00 to 09/30/00

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occurrences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	001 METRO	72.761	0.615	5.155	4.929	137,753	84,739	1,402	10,023,037	183,066
Planned	001 METRO	0.128	0.001	0.000	0.000	137,753	74	6	17,566	1,558
Customer Requested	001 METRO	0.005	0.000	0.000	0.000	137,753	2	2	631	631
High SAIDI	CTN11 COTTONWOOD #11 (ST MARK'S HOSPITAL)	599.882	4.824	2.000	2.000	34	164	16	20,396	
Low SAIDI	*60 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	CTN11 COTTONWOOD #11 (ST MARK'S HOSPITAL)	599.882	4.824	2.000	2.000	34	164	16	20,396	
Low SAIFI	*60 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	MCL12 MCCLELLAND #12	115.370	1.049	22.002	21.000	2,693	2,824	13	310,692	
Low MAIFI	*89 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	MCL12 MCCLELLAND #12	115.370	1.049	22.002	21.000	2,693	2,824	13	310,692	
Low $MAIFI_{(e)}$	*89 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	VLY12 VALLEY CENTER #12	411.870	0.793	16.000	15.000	1,588	1,259	10	654,050	
Low Customer Minutes Lost	*60 circuits with zero Customer Minutes Lost*								0	

Year to Date   Fiscal Year 2001   04/01/00 to 09/30/00

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occur-rences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	074 MILFORD (Richfield)	182.499	3.293	2.070	2.070	1,678	5,525	193	306,234	16,437
Planned	074 MILFORD (Richfield)	1.174	0.009	0.000	0.000	1,678	15	5	1,970	655
Customer Requested	074 MILFORD (Richfield)	0.000	0.000	0.000	0.000	1,678	0	0	0	0
High SAIDI	SML11 CENTRAL MILFORD FLATS	1,055.667	12.867	2.000	2.000	30	386	31	31,670	
Low SAIDI	*CMR44 LINE TO MILFORD, BLUNDELL PL*	52.000	1.000	1.000	1.000	2	2	1	104	
High SAIFI	SML11 CENTRAL MILFORD FLATS	1,055.667	12.867	2.000	2.000	30	386	31	31,670	
Low SAIFI	*CMR44 LINE TO MILFORD, BLUNDELL PL*	52.000	1.000	1.000	1.000	2	2	1	104	
High MAIFI	CVF11 COVE FORT, SULPHURDALE AREAS	303.813	4.188	8.000	8.000	16	67	7	4,861	
High MAIFI	MTV11 MILFORD TV LINE	196.000	3.750	8.000	8.000	4	15	4	784	
Low MAIFI	*CMR44 LINE TO MILFORD, BLUNDELL PL*	52.000	1.000	1.000	1.000	2	2	1	104	
High $MAIFI_{(e)}$	CVF11 COVE FORT, SULPHURDALE AREAS	303.813	4.188	8.000	8.000	16	67	7	4,861	
Low $MAIFI_{(e)}$	*CMR44 LINE TO MILFORD, BLUNDELL PL*	52.000	1.000	1.000	1.000	2	2	1	104	
High Customer Minutes Lost	MLF13 W & N W MILFORD	192.625	4.061	2.000	2.000	344	1,397	30	66,263	
Low Customer Minutes Lost	*CMR44 LINE TO MILFORD, BLUNDELL PL*	52.000	1.000	1.000	1.000	2	2	1	104	

Year to Date   Fiscal Year 2001   04/01/00 to 09/30/00

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occurrences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	011 OGDEN	71.303	0.785	3.827	3.492	72,980	57,296	1,122	5,203,715	113,092
Planned	011 OGDEN	4.000	0.020	0.000	0.000	72,980	1,470	67	291,891	12,157
Customer Requested	011 OGDEN	0.083	0.001	0.000	0.000	72,980	61	12	6,035	1,700
High SAIDI	LMT18 SOUTH POND	1,495.000	2.833	0.000	0.000	6	17	5	8,970	
Low SAIDI	*33 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	RIV11 RIVERDALE/SO.WBR	296.027	4.142	8.000	8.000	148	613	6	43,812	
Low SAIFI	*33 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	UIN13 UINTAH CKT#13 COMBE RD EAST	189.740	1.037	26.000	26.000	1,001	1,038	39	189,930	
Low MAIFI	*55 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	UIN13 UINTAH CKT#13 COMBE RD EAST	189.740	1.037	26.000	26.000	1,001	1,038	39	189,930	
Low $MAIFI_{(e)}$	*55 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	UIN11 UINTAH CKT#11 (OLD #12 CHANGED 1/9/91)	457.822	1.709	5.000	4.000	1,277	2,183	9	584,639	
Low Customer Minutes Lost	*33 circuits with zero Customer Minutes Lost*								0	

Year to Date **Fiscal Year 2001** **04/01/00 to 09/30/00**

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occurrences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	005 PARK CITY	65.805	0.438	5.755	5.783	16,053	7,035	442	1,056,374	65,818
Planned	005 PARK CITY	0.000	0.000	0.000	0.000	16,053	0	0	0	0
Customer Requested	005 PARK CITY	0.000	0.000	0.000	0.000	16,053	0	0	0	0
High SAIDI	THF21 THIEF CREEK #21	879.700	3.500	0.000	0.000	10	35	6	8,797	
Low SAIDI	*6 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	DSR DESERET	595.000	4.000	5.000	5.000	1	4	4	595	
Low SAIFI	*6 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	COA12 COALVILLE #12	63.681	0.263	22.000	22.000	479	126	27	30,503	
Low MAIFI	*13 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	COA12 COALVILLE #12	63.681	0.263	22.000	22.000	479	126	27	30,503	
Low $MAIFI_{(e)}$	*13 circuits with a $MAIFI_{(E)}$ of 0.0000*								0	
High Customer Minutes Lost	PC15 PARK CITY #15	336.982	1.360	0.000	0.000	1,016	1,382	19	342,374	
Low Customer Minutes Lost	*6 circuits with zero Customer Minutes Lost*								0	

Year to Date **Fiscal Year 2001** **04/01/00 to 09/30/00**

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occurrences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	071 SALINA (Richfield)	92.416	0.740	1.405	1.405	13,235	9,795	298	1,223,125	32,428
Planned	071 SALINA (Richfield)	0.170	0.002	0.000	0.000	13,235	23	7	2,245	460
Customer Requested	071 SALINA (Richfield)	0.023	0.000	0.000	0.000	13,235	1	1	305	305
High SAIDI	PAN12 W PANGUITCH, LAKE	484.782	3.114	5.000	5.000	367	1,143	8	177,915	
Low SAIDI	*14 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	PAN12 W PANGUITCH, LAKE	484.782	3.114	5.000	5.000	367	1,143	8	177,915	
Low SAIFI	*14 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	SVR47 SEVIER-MILFORD 46 KV LINE	140.000	2.000	8.000	8.000	2	4	2	280	
Low MAIFI	*14 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	SVR47 SEVIER-MILFORD 46 KV LINE	140.000	2.000	8.000	8.000	2	4	2	280	
Low $MAIFI_{(e)}$	*14 circuits with a $MAIFI_{(E)}$ of 0.0000*									
High Customer Minutes Lost	PAN11 E. PANGUITCH	414.091	2.105	5.000	5.000	722	1,520	11	298,974	
Low Customer Minutes Lost	*14 circuits with zero Customer Minutes Lost*								0	

Year to Date **Fiscal Year 2001** **04/01/00 to 09/30/00**

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occurrences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	014 SMITHFIELD	85.421	1.211	3.777	1.655	13,126	15,894	349	1,121,233	28,222
Planned	014 SMITHFIELD	0.000	0.000	0.000	0.000	13,126	0	0	0	0
Customer Requested	014 SMITHFIELD	0.010	0.000	0.026	0.026	13,126	3	2	135	105
High SAIDI	RAN11 RANDOLPH CKT#11	371.491	3.809	0.000	0.000	324	1,234	24	120,363	
Low SAIDI	*3 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	RAN11 RANDOLPH CKT#11	371.491	3.809	0.000	0.000	324	1,234	24	120,363	
Low SAIFI	*3 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	AMA12 AMALGA/SMITHFIELD	303.773	3.299	23.000	8.000	1,000	3,299	32	303,773	
Low MAIFI	*10 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	AMA12 AMALGA/SMITHFIELD	303.773	3.299	23.000	8.000	1,000	3,299	32	303,773	
Low $MAIFI_{(e)}$	*10 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	AMA12 AMALGA/SMITHFIELD	303.773	3.299	23.000	8.000	1,000	3,299	32	303,773	
Low Customer Minutes Lost	*3 circuits with zero Customer Minutes Lost*								0	

Year to Date **Fiscal Year 2001** **04/01/00 to 09/30/00**

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occur-rences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	007 SOUTH VALLEY (Jordan Valley)	111.457	1.483	6.448	6.177	27,842	41,297	436	3,103,196	92,965
Planned	007 SOUTH VALLEY (Jordan Valley)	0.551	0.004	0.000	0.000	27,842	123	11	15,350	1,675
Customer Requested	007 SOUTH VALLEY (Jordan Valley)	0.009	0.000	0.000	0.000	27,842	2	1	260	130

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occur-rences	Customer Minutes Lost
High SAIDI	BNG12 BINGHAM #12	440.134	2.746	1.002	2.000	531	1,458	51	233,711
Low SAIDI	*5 circuits with a SAIDI of 0.0000*	0.000							
High SAIFI	HOG11 HOGGARD #11	132.265	4.197	5.000	5.000	5,161	21,663	35	682,622
Low SAIFI	*5 circuits with a SAIFI of 0.0000*		0.000						
High MAIFI	HOG13 HOGGARD #13	113.772	0.416	19.000	19.000	1,226	510	7	139,485
Low MAIFI	*4 circuits with a MAIFI of 0.0000*			0.000					
High $MAIFI_{(e)}$	HOG13 HOGGARD #13	113.772	0.416	19.000	19.000	1,226	510	7	139,485
Low $MAIFI_{(e)}$	*4 circuits with a $MAIFI_{(E)}$ of 0.0000*								
High Customer Minutes Lost	BNG11 BINGHAM #11	343.811	1.283	4.000	4.000	2,710	3,478	40	931,727
Low Customer Minutes Lost	*5 circuits with zero Customer Minutes Lost*								0

Year to Date — Fiscal Year 2001 — 04/01/00 to 09/30/00

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occurrences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	004 TOOELE	526.516	2.437	11.469	10.857	13,276	32,357	314	6,990,026	62,132
Planned	004 TOOELE	6.181	0.046	0.000	0.000	13,276	605	15	82,055	2,390
Customer Requested	004 TOOELE	0.081	0.001	0.000	0.000	13,276	15	6	1,075	535
High SAIDI	GRA12 GRANTSVILLE #12	1,196.333	6.419	3.000	3.000	105	674	12	125,615	
Low SAIDI	*2 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	SKU SKULL VALLEY #11	792.202	6.437	3.000	3.000	119	766	10	94,272	
Low SAIFI	*2 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	TOO13 TOOELE #13	878.863	3.093	26.000	24.000	3,260	10,084	37	2,865,095	
Low MAIFI	*6 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	TOO13 TOOELE #13	878.863	3.093	26.000	24.000	3,260	10,084	37	2,865,095	
Low $MAIFI_{(e)}$	*6 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	TOO13 TOOELE #13	878.863	3.093	26.000	24.000	3,260	10,084	37	2,865,095	
Low Customer Minutes Lost	*2 circuits with zero Customer Minutes Lost*								0	

Year to Date **Fiscal Year 2001** **04/01/00 to 09/30/00**

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occurrences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	013 TREMONTON	145.990	1.129	2.591	2.395	6,424	7,253	181	937,841	20,492
Planned	013 TREMONTON	0.000	0.000	0.000	0.000	6,424	0	0	0	0
Customer Requested	013 TREMONTON	0.084	0.000	0.000	0.000	6,424	1	1	540	540
High SAIDI	BLU BLUE CREEK	1,147.977	3.070	1.000	1.000	128	393	9	146,941	
Low SAIDI	*7 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	SNO11 SNOWVILLE CKT#11	694.474	6.789	4.000	4.000	19	129	13	13,195	
Low SAIFI	*7 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	BRR12 BEAR RIVER/GARLAND	177.374	1.402	8.000	8.000	219	307	11	38,845	
Low MAIFI	*1 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	BRR12 BEAR RIVER/GARLAND	177.374	1.402	8.000	8.000	219	307	11	38,845	
Low $MAIFI_{(e)}$	*1 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	BSH12 BUSH CKT #12	799.131	3.925	1.000	1.000	398	1,562	15	318,054	
Low Customer Minutes Lost	*7 circuits with zero Customer Minutes Lost*								0	

Year to Date **Fiscal Year 2001** **04/01/00 to 09/30/00**

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	MAIFI	MAIFI(e)	Average Customer Count	Customers Off	Number of Occurrences	Customer Minutes Lost	Duration Total (Minutes)
Unplanned	002 VALLEY WEST (Jordan Valley)	73.436	0.497	4.578	4.481	41,856	20,801	327	3,073,749	61,232
Planned	002 VALLEY WEST (Jordan Valley)	0.120	0.001	0.000	0.000	41,856	30	8	5,010	1,125
Customer Requested	002 VALLEY WEST (Jordan Valley)	0.057	0.000	0.000	0.000	41,856	20	1	2,400	120
High SAIDI	TAY11 TAYLORSVILLE #11	443.282	3.337	7.000	7.000	901	3,007	11	399,397	
Low SAIDI	*2 circuits with a SAIDI of 0.0000*	0.000								
High SAIFI	TAY11 TAYLORSVILLE #11	443.282	3.337	7.000	7.000	901	3,007	11	399,397	
Low SAIFI	*2 circuits with a SAIFI of 0.0000*		0.000							
High MAIFI	LPK12 LAKEPARK #12	8.620	0.037	21.000	21.000	3,065	114	10	26,419	
Low MAIFI	*4 circuits with a MAIFI of 0.0000*			0.000						
High $MAIFI_{(e)}$	LPK12 LAKEPARK #12	8.620	0.037	21.000	21.000	3,065	114	10	26,419	
Low $MAIFI_{(e)}$	*4 circuits with a $MAIFI_{(E)}$ of 0.0000*				0.000					
High Customer Minutes Lost	TAY11 TAYLORSVILLE #11	443.282	3.337	7.000	7.000	901	3,007	11	399,397	
Low Customer Minutes Lost	*2 circuits with zero Customer Minutes Lost*								0	

825 N.E. Multnomah
Portland, Oregon 97232
(503) 813-5000

REVIEWED BY COMMISSIONERS
STEPHEN F. MECHAM ________
CONSTANCE B. WHITE ________
CLARK D. JONES ________

RECEIVED
OCT 3 9 06 AM '00
UTAH PUBLIC SERVICE COMMISSION

PACIFICORP
PACIFIC POWER UTAH POWER

Corrected September 29, 2000

September 26, 2000

Utah Public Service Commission
Heber M. Wells Building
160 East 300 South
Salt Lake City, UT 84110

ATTN: Ms. Julie Orchard

Re: Docket No. 98-2035-04

Dear Commissioners:

As required by Section 54-4-27 of the Utah Public Utilities Code, under separate cover PacifiCorp has given notice to the Commission of the declaration of a dividend on its common stock aggregating $80,277,643.08.

In connection with that dividend and pursuant to Condition 15 in the July 28, 1999 Stipulation included in the above matter, PacifiCorp hereby files a summary of its cash flows for the year ended June 30, 2000. The attached summary shows that PacifiCorp's cash from operations for the year ended June 30, 2000 was approximately ~~$805~~$881 million.

PacifiCorp believes that the attached summary shows that the dividend will not adversely affect PacifiCorp's ability to meet its service obligations in the State of Utah. In addition, the undersigned officer of PacifiCorp hereby certifies that PacifiCorp has adequate capital to meet all of its commitments and public service obligations in the State of Utah.

If there are questions concerning this matter, please contact me at (503) 813-7221.

Very truly yours,

PACIFICORP

By: Robert R Dalley
Title: Controller and Chief Accounting Officer

Attachment: Cash Flow Summary

Utah Dividend Cert nov 00

CC: Karen Clark, Bob Dalley, John Schweitzer, Gloria Quirk, Bruce Williams, Matthew Wright

PacifiCorp

CONSOLIDATED STATEMENT OF CASH FLOWS

FOR THE TWELVE MONTHS ENDED JUNE 30, 2000

(in thousands of dollars)

OPERATING ACTIVITIES		
Net loss	$	(107.1)
Adjustment to reconcile net loss to net cash provided by operating activities		
Depreciation and amortization		482.4
Deferred income tax & investment tax credits		57.4
Interest capitalized - equity funds		(11.2)
ScottishPower merger accrued liabilities		71.0
Loss on sale or impairment of assets		201.6
Other		4.1
Accounts receivable and prepayments		(161.7)
Materials, supplies and inventory		10.7
Accounts payable and accrued liabilities		321.7
Net cash provided by continuing operations		868.9
Net cash provided by discontinued operations		11.9
CASH FLOWS PROVIDED BY OPERATING ACTIVITIES		880.8
INVESTING ACTIVITIES		
Construction		(530.6)
Proceeds from sale of finance assets and principal payments		36.2
Proceeds from sale of assets		281.5
Other		24.8
CASH FLOWS USED IN INVESTING ACTIVITIES		(188.1)
FINANCING ACTIVITIES		
Changes in short-term debt		(45.8)
Proceeds from long term debt		1,843.1
Dividends paid		(338.5)
Repayments of long-term debt		(2,106.1)
Redemptions of preferred stock		(26.1)
Other		7.0
CASH FLOWS USED IN FINANCING ACTIVITIES		(666.4)
DECREASE IN CASH AND CASH EQUIVALENTS		26.3

825 N.E. Multnomah
Portland, Oregon 97232
(503) 813-5000

RECEIVED

SEP 29 8 20 AM '00

UTAH PUBLIC
SERVICE COMMISSION

REVIEWED BY COMMISSIONERS
STEPHEN F. MECHAM SM
CONSTANCE B. WHITE CBW 10/2
CLARK D. JONES CDJ 10/4

PACIFICORP
PACIFIC POWER UTAH POWER

September 26, 2000

Utah Public Service Commission
Heber M. Wells Building
160 East 300 South
Salt Lake City, UT 84110

ATTN: Ms. Julie Orchard

Re: Docket No. 98-2035-04

Dear Commissioners:

As required by Section 54-4-27 of the Utah Public Utilities Code, under separate cover PacifiCorp has given notice to the Commission of the declaration of a dividend on its common stock aggregating $80,277,643.08.

In connection with that dividend and pursuant to Condition 15 in the July 28, 1999 Stipulation included in the above matter, PacifiCorp hereby files a summary of its cash flows for the year ended June 30, 2000. The attached summary shows that PacifiCorp's cash from operations for the year ended June 30, 2000 was approximately $805 million.

PacifiCorp believes that the attached summary shows that the dividend will not adversely affect PacifiCorp's ability to meet its service obligations in the State of Utah. In addition, the undersigned officer of PacifiCorp hereby certifies that PacifiCorp has adequate capital to meet all of its commitments and public service obligations in the State of Utah.

If there are questions concerning this matter, please contact me at (503) 813-7221.

Very truly yours,

PACIFICORP

By: Robert R. Dalley
Title: Controller and Chief Accounting Officer

Attachment: Cash Flow Summary

Utah Dividend Cert nov 00

PacifiCorp

CONSOLIDATED STATEMENT OF CASH FLOWS

FOR THE TWELVE MONTHS ENDED JUNE 30, 2000

(in thousands of dollars)

OPERATING ACTIVITIES		
Net loss	$	(107.1)
Adjustment to reconcile net loss to net cash provided by operating activities		
Depreciation and amortization		482.4
Deferred income tax & investment tax credits		57.4
Interest capitalized - equity funds		(11.2)
ScottishPower merger accrued liabilities		71.0
Loss on sale or impairment of assets		201.6
Other		4.1
Accounts receivable and prepayments		(161.7)
Materials, supplies and inventory		10.7
Accounts payable and accrued liabilities		321.7
Net cash provided by continuing operations		868.9
Net cash provided by discontinued operations		11.9
CASH FLOWS PROVIDED BY OPERATING ACTIVITIES		880.8
INVESTING ACTIVITIES		
Construction		(530.6)
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Changes in short-term debt		(45.8)
Proceeds from long term debt		1,843.1
Dividends paid		(338.5)
Repayments of long-term debt		(2,106.1)
Redemptions of preferred stock		(26.1)
Other		7.0
CASH FLOWS USED IN FINANCING ACTIVITIES		(666.4)
DECREASE IN CASH AND CASH EQUIVALENTS		26.3

1900 S.W. 4th Ave.
Portland, Oregon 97201

PACIFICORP
PACIFIC POWER UTAH POWER

RECEIVED
AUG 2 9 39 AM '00
UTAH PUBLIC SERVICE COMMISSION

VIA OVERNIGHT MAIL

July 31, 2000

REVIEWED BY COMMISSIONERS
STEPHEN F. MECHAM
CONSTANCE B. WHITE CBW 8/2
RIC D. JONES

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City UT 84114

Attention: Julie P. Orchard
Commission Secretary

RE: Docket No. 98-2035-04 ScottishPower/PacifiCorp Merger Commitments

Please find enclosed PacifiCorp's first quarterly report for the period April through June 2000 detailing the Company's performance in meeting the Customer Guarantees which were agreed to as a result of the recent merger between ScottishPower and PacifiCorp.

PacifiCorp will submit it's second quarterly report in October 2000 after the close of the second fiscal year quarter covering the period July 2000 through September 2000.

Merger Stipulation Conditions 33 and 36 required additional quarterly reports detailing outage performance and customer guarantee performance reported by district. These reports are enclosed. In addition, Merger Stipulation Condition 34 requires PacifiCorp to report on performance with regard to meter set response standards by district and this report is enclosed as well showing performance in Northern Utah and one district in Southern Utah. We expect to roll out this standard in the rest of Southern Utah during the second quarter. We will also be exploring whether any additional internal targets for field responses are needed given the comprehensive nature of the customer guarantees.

Also enclosed are quarterly reports detailing the Company's meter set and outage performance by district, as well as a report showing customer guarantee payments by district.

If you have any questions or require further information, please call Carole Rockney at (503) 813-7408.

Sincerely,

Matthew Wright/cr

Matthew Wright
Vice President, Regulation

c: Mark Flandro - Utah Division of Public Utilities
Rea Petersen - Utah Division of Public Utilities
Andy MacRitchie - Senior Vice President, Power Delivery

Enclosure

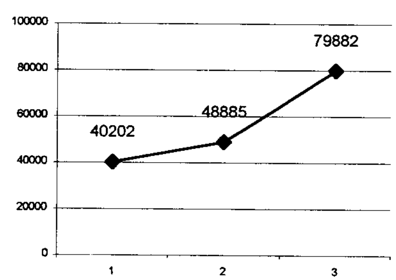
PACIFICORP

Customer Service Commitments

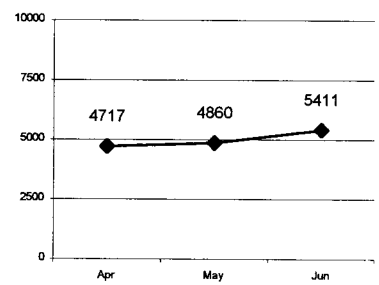
Utah - April-June 2000

	Description	Total Events (Year to Date)	Total Failures (Year to Date)	Amount Paid (Year to Date)
CG1	Restoring Supply*	168,969	0	$0
CG2	Appointments	1,502	7	$350
CG3	Switching on Power	7,755	23	$3,700
CG4	Estimates	1,778	19	$950
CG5	Respond to Billing Inquiries	1,233	5	$250
CG6	Respond to Meter Problems	175	1	$50
CG7	Notification of Planned Interruptions	1,751	18	$950
CG8	Power Quality Complaints	794	13	$650
		183,957	**86**	**$6,900**

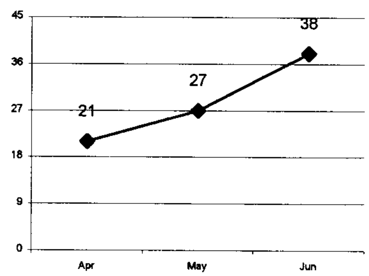
CG 1 Events (>5 minutes)



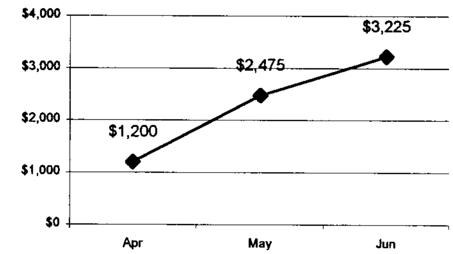
CG 2-8 Events



Failures



Payments



* CG1 events are defined as "total customers out more than 5 minutes".

Customer Service Commitments

Utah – For the Quarter April-June 2000 - Failures

American Fork	*CG #*	*Description*	*Total*	*Total Paid*
	CG2a	All Other RCMS Appointmts	1	$50.00
	CG2b	Non-RCMS Appointments	1	$50.00
	CG3	Switching on Power	1	$125.00
	CG4a	Contact Customer - 2 days	2	$100.00
	CG4c	15-days, Network Changes	3	$150.00
	CG8a	Respond in 5 days	2	$100.00
		Total	10	$575.00

Cedar City	*CG #*	*Description*	*Total*	*Total Paid*
	CG3	Switching on Power	2	$250.00
	CG4a	Contact Customer - 2 days	2	$100.00
	CG7	Planned Interruptions	1	$50.00
		Total	5	$400.00

Layton	*CG #*	*Description*	*Total*	*Total Paid*
	CG2.3	CG3 Appointments	1	$50.00
	CG2.4	CG4 Appointments	1	$50.00
	CG3	Switching on Power	1	$125.00
	CG7	Planned Interruptions	4	$200.00
	CG8a	Respond in 5 days	1	$50.00
		Total	8	$475.00

Jordan Valley	*CG #*	*Description*	*Total*	*Total Paid*
	CG3	Switching on Power	8	$825.00
	CG4a	Contact Customer - 2 days	4	$200.00
	CG5	Respond to Bill Inquiries	2	$100.00
	CG7	Planned Interruptions	2	$150.00
	CG8a	Respond in 5 days	2	$100.00
		Total	18	$1,375.00

Moab	*CG #*	*Description*	*Total*	*Total Paid*
	CG2.4	CG4 Appointments	1	$50.00
	CG4a	Contact Customer - 2 days	2	$100.00
		Total	3	$150.00

Note: This report is prepared using proposed "reporting districts." District definitions remain in review status as part of the merger transition process.

Ogden	CG #	Description	Total	Total Paid
	CG4a	Contact Customer - 2 days	1	$50.00
	CG7	Planned Interruptions	1	$50.00
	CG8a	Respond in 5 days	1	$50.00
		Total	3	$150.00

Park City	CG #	Description	Total	Total Paid
	CG3	Switching on Power	2	$300.00
	CG4a	Contact Customer - 2 days	1	$50.00
		Total	3	$350.00

Price	CG #	Description	Total	Total Paid
	CG7	Planned Interruptions	1	$50.00
		Total	1	$50.00

Richfield	CG #	Description	Total	Total Paid
	CG3	Switching on Power	1	$500.00
	CG4a	Contact Customer - 2 days	2	$100.00
		Total	3	$600.00

SLC Metro	CG #	Description	Total	Total Paid
	CG2.5	CG5 Appointments	1	$50.00
	CG2a	All Other RCMS Appointmts	1	$50.00
	CG3	Switching on Power	6	$1,375.00
	CG5	Respond to Bill Inquiries	3	$150.00
	CG7	Planned Interruptions	9	$450.00
	CG8a	Respond in 5 days	4	$200.00
		Total	24	$2,275.00

Smithfield	CG #	Description	Total	Total Paid
	CG4a	Contact Customer - 2 days	1	$50.00
		Total	1	$50.00

Tooele	CG #	Description	Total	Total Paid
	CG3	Switching on Power	1	$125.00
	CG8a	Respond in 5 days	3	$150.00
		Total	4	$275.00

Tremonton	*CG #*	*Description*	*Total*	*Total Paid*
	CG4a	Contact Customer - 2 days	1	$50.00
	CG6	Respond to Meter Problems	1	$50.00
		Total	2	$100.00

Vernal	*CG #*	*Description*	*Total*	*Total Paid*
	CG3	Switching on Power	1	$75.00
		Total	1	$75.00

State Total	**86**	**$6,900.00**

UTAH RESIDENTIAL/SMALL COMMERCIAL METER SETS - REPORT BY DISTRICT

2000-2001

FISCAL YEAR TO DATE - 1ST QUARTER 2000-2001

NORTHERN UTAH

LOCATION	APRIL			MAY			JUNE			FYD - 1st Quarter			Notes
	Within 5 Days	%	Total	Within 5 Days	%	Total	Within 5 Days	%	Total	Total Within 5 Days	1st Quarter %	Total	Smithfield, Utah will begin reporting during second quarter.
Jordan Valley	201	91%	222	241	90%	268	289	85%	341	731	88%	831	
Layton/Davis	159	98%	163	124	94%	132	149	89%	168	432	93%	463	
Metro	193	99%	195	183	99%	184	221	99%	224	597	99%	603	
Ogden	166	100%	166	214	100%	215	253	100%	253	633	100%	634	
Park City	32	100%	32	57	100%	57	58	100%	58	147	100%	147	
Tooele	66	86%	77	60	81%	74	55	64%	86	181	76%	237	
Tremonton	16	94%	17	13	87%	15	33	97%	34	62	94%	66	
TOTAL	833	96%	872	892	94%	945	1058	91%	1164	2783	93%	2981	

SOUTHERN UTAH

LOCATION	APRIL			MAY			JUNE			FYD - 1st Quarter			Notes
	Within 5 days	%	Total	Within 5 days	%	Total	Within 5 days	%	Total	Total Within 5 Days	1st Quarter %	Total	In process of rolling out in Southern Utah. Second quarter will reflect further implementation.
Cedar City	80	100%	80	64	94%	68	69	96%	72	213	97%	220	

TOTAL UTAH

LOCATION	APRIL			MAY			JUNE			FYD - 1st Quarter			Notes
	Within 5 days	%	Total	Within 5 days	%	Total	Within 5 days	%	Total	Total Within 5 Days	1st Quarter %	Total	
TOTAL UTAH	913	96%	952	956	94%	1013	1127	91%	1236	2996	94%	3201	

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	Average Customer Count	Customers Off	Number of Occurr	Customer Minutes Lost	Duration Total (Minutes)
	AMERICAN FORK	21.892	0.344	58,900	20,238	314	1,289,458	
High SAIDI	SAR13 SARATOGA 13 TO CEDAR VALLEY	439.415	2.031	453	920	12	199,055	
Low SAIDI	*9 circuits with a SAIDI of 0.0000*							
High SAIFI	SAN12 CIRCUIT #11	231.431	2.342	1,530	3,583	30	354,089	
Low SAIFI	*10 circuits with a SAIFI of 0.0000*							
High Customer Minutes Lost	SAN12 CIRCUIT #11	231.431	2.342	1,530	3,583	30	354,089	
Low Customer Minutes Lost	*9 circuits with zero Customer Minutes Lost*							
Planned		0.058	0.000		26	5	3,410	530
Unplanned		21.892	0.344		20,238	314	1,289,458	32,573
Customer Requested		0.021	0.000		22	9	1,253	863
	ASHLEY (Vernal)	2.547	0.031	9,382	294	46	23,895	
High SAIDI	PRT22 PARIETTE #22	15.789	0.053	19	1	1	300	
Low SAIDI	MYT1, WOL, WON1 and JEN2	0.000	0.000	Varies	0	0	0	
High SAIFI	MAE11 MAESER #11 NORTH AND EAST	6.479	0.090	1,714	154	11	11,105	
Low SAIFI	MYT1, WOL, WON1 and JEN2	0.000	0.000	Varies	0	0	0	
High Customer Minutes Lost	MAE11 MAESER #11 NORTH AND EAST	6.479	0.090	1,714	154	11	11,105	
Low Customer Minutes Lost	MYT1, WOL, WON1 and JEN2	0.000	0.000	Varies	0	0	0	
Planned		0.000	0.000		0	0	0	0
Unplanned		2.547	0.031		294	46	23,895	5,010
Customer Requested		0.000	0.000		0	0	0	0

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	Average Customer Count	Customers Off	Number of Occurr	Customer Minutes Lost	Duration Total (Minutes)
	CANYONLANDS (Moab)	21.163	0.350	11,324	3,967	83	239,650	
High SAIDI	GRR11 GREEN RIVER #11 (EAST)	107.113	1.086	408	443	6	43,702	
Low SAIDI	*13 circuits with a SAIDI of 0.0000*							
High SAIFI	GRR12 GREEN RIVER #12 (WEST)	105.257	1.109	350	388	4	36,840	
Low SAIFI	*13 circuits with a SAIFI of 0.0000*							
High Customer Minutes Lost	GRR11 GREEN RIVER #11 (EAST)	107.113	1.086	408	443	6	43,702	
Low Customer Minutes Lost	*13 circuits with zero Customer Minutes Lost*							
Planned		0.048	0.001		6	1	540	90
Unplanned		21.163	0.350		3,967	83	239,650	10,141
Customer Requested		0.000	0.000		0	0	0	0
	CARBON (Price)	39.581	0.419	10,247	4,291	102	405,588	
High SAIDI	HEL1 HELPER CITY	256.000	2.000	1	2	2	256	
Low SAIDI	*16 circuits with a SAIDI of 0.0000*							
High SAIFI	MAT11 WEST TO PRICE	228.441	2.060	447	921	15	102,113	
Low SAIFI	*16 circuits with a SAIFI of 0.0000*							
High Customer Minutes Lost	DTN1 CIRCUIT #11	109.436	1.093	1,031	1,127	8	112,829	
Low Customer Minutes Lost	*16 circuits with zero Customer Minutes Lost*							
Planned		4.392	0.015		150	1	45,000	300
Unplanned		39.581	0.419		4,291	102	405,588	11,088
Customer Requested		0.000	0.000		0	0	0	0
	CEDAR CITY	74.611	1.242	16,027	19,193	262	1,195,793	
High SAIDI	ENT11 ENTERPRISE 11 CIRCUIT	320.333	4.133	15	62	6	4,805	

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	Average Customer Count	Customers Off	Number of Occurr	Customer Minutes Lost	Duration Total (Minutes)
Low SAIDI	DXD11, WOL11 and VEY50			Varies		0		
High SAIFI	PRV46 BUCKHORN CB 46	458.769	3.513	39	137	8	17,892	
Low SAIFI	DXD11, WOL11 and VEY50			Varies		0		
High Customer Minutes Lost	BHD11 BRIAN HEAD TOWN	205.347	2.497	726	1,813	5	149,082	
Low Customer Minutes Lost	DXD11, WOL11 and VEY50			Varies		0		
Planned		0.353	0.003		52	2	5,655	290
Unplanned		74.611	1.242		19,913	262	1,195,793	21,826
Customer Requested		0.000	0.000		0	0	0	0
	COTTONWOOD (Jordan Valley)	18.257	0.172	91,310	15,666	317	1,667,048	
High SAIDI	CAS11 CASTO #11	444.444	1.318	1,246	1,642	15	553,777	
Low SAIDI	BRI21, MDV14, UNN16, HOL11 and QRY15	0.000	0.000	Varies	0	0	0	
High SAIFI	CAS11 CASTO #11	444.444	1.318	1,246	1,642	15	553,777	
Low SAIFI	BRI21, MDV14, UNN16, HOL11 and QRY15	0.000	0.000	Varies	0	0	0	
High Customer Minutes Lost	CAS11 CASTO #11	444.444	1.318	1,246	1,642	15	553,777	
Low Customer Minutes Lost	BRI21, MDV14, UNN16, HOL11 and QRY15	0.000	0.000	Varies	0	0	0	
Planned		0.039	0.000		22	6	3,600	1,260
Unplanned		18.257	0.172		15,666	317	1,667,048	62,115
Customer Requested		0.007	0.000		2	1	630	450
	DELTA (Richfield)	20.524	0.207	5,766	1,193	56	118,343	
High SAIDI	LYN11B LEAMINGTON RECLOSER	210.000	1.000	240	240	1	50,400	
Low SAIDI	*19 circuits with a SAIDI of 0.0000*							

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	Average Customer Count	Customers Off	Number of Occurr	Customer Minutes Lost	Duration Total (Minutes)
High SAIFI	STH21 SUTHERLAND, ABRAHAM	100.942	1.524	462	704	17	46,635	
Low SAIFI	*19 circuits with a SAIFI of 0.0000*							
High Customer Minutes Lost	LYN11B LEAMINGTON RECLOSER	210.000	1.000	240	240	1	50,400	
Low Customer Minutes Lost	*19 circuits with zero Customer Minutes Lost*							
Planned		0.000	0.000		0	0	0	0
Unplanned		20.524	0.207		1,193	56	118,343	7,003
Customer Requested		0.000	0.000		0	0	0	0
	LAKE	55.700	0.381	28,240	10,752	182	1,572,970	
High SAIDI	JOR4 JORDAN #4	352.174	0.435	23	10	1	8,100	
Low SAIDI	PEP, RED14, TRM12, JOR2	0.000	0.000	Varies	0	0	0	
High SAIFI	GRO11 GROW #11 (AIRPORT NORTH SUPPO	144.692	1.308	13	17	4	1,881	
Low SAIFI	PEP, RED14, TRM12, JOR2	0.000	0.000	Varies	0	0	0	
High Customer Minutes Lost	ROS12 ROSE PARK #12	259.468	1.140	2,399	2,734	10	622,463	
Low Customer Minutes Lost	PEP, RED14, TRM12, JOR2	0.000	0.000	Varies	0	0	0	
Planned		0.005	0.000		1	1	150	150
Unplanned		55.700	0.381		10,752	182	1,572,970	29,447
Customer Requested		0.143	0.001		17	2	4,035	475
	LAYTON	25.251	0.277	34,429	9,536	115	869,362	
High SAIDI	SYR11 SYRACUSE/1000 WEST	344.710	2.542	107	272	8	36,884	
Low SAIDI	*10 circuits with a SAIDI of 0.0000*							
High SAIFI	SYR11 SYRACUSE/1000 WEST	344.710	2.542	107	272	8	36,884	
Low SAIFI	*10 circuits with a SAIFI of 0.0000*							

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	Average Customer Count	Customers Off	Number of Occurr	Customer Minutes Lost	Duration Total (Minutes)
High Customer Minutes Lost	FRS11 FRUIT HEIGHTS #11	152.663	0.713	905	645	7	138,160	
Low Customer Minutes Lost	*10 circuits with zero Customer Minutes Lost*							
Planned		0.497	0.006		191	27	17,104	1,691
Unplanned		25.251	0.277		9,536	115	869,362	13,527
Customer Requested		0.021	0.000		2	2	720	720
	METRO	29.228	0.321	137,753	44,240	551	4,026,188	
High SAIDI	CTN11 COTTONWOOD #11 (ST MARK'S HOS	370.794	3.235	34	110	10	12,607	
Low SAIDI	*83 circuits with a SAIDI of 0.0000*							
High SAIFI	CTN11 COTTONWOOD #11 (ST MARK'S HOS	370.794	3.235	34	110	10	12,607	
Low SAIFI	*83 circuits with a SAIFI of 0.0000*							
High Customer Minutes Lost	GRN12 GRANGER #12	138.175	0.607	2,150	1,304	4	297,077	
Low Customer Minutes Lost	*83 circuits with zero Customer Minutes Lost*							
Planned		0.094	0.000		37	4	12,890	1,250
Unplanned		29.228	0.321		44,240	551	4,026,188	90,545
Customer Requested		0.005	0.000		2	2	631	631
	MILFORD (Richfield)	105.394	2.393	1,678	4,015	114	176,851	
High SAIDI	PND11 BEAVER CANYON CABINS	349.000	4.000	50	200	4	17,450	
Low SAIDI	CMR44 LINE TO MILFORD, BLUNDELL PLAN	52.000	1.000	2	2	1	104	
High SAIFI	PND11 BEAVER CANYON CABINS	349.000	4.000	50	200	4	17,450	
Low SAIFI	CMR44 LINE TO MILFORD, BLUNDELL PLAN	52.000	1.000	2	2	1	104	
High Customer Minutes Lost	MLF11 CENTRAL AND NORTHEAST MILFOR	123.574	2.678	270	723	9	33,365	

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	Average Customer Count	Customers Off	Number of Occurr	Customer Minutes Lost	Duration Total (Minutes)
Low Customer Minutes Lost	CMR44 LINE TO MILFORD, BLUNDELL PLAN	52.000	1.000	2	2	1	104	
Planned		0.143	0.001		1	1	240	240
Unplanned		105.394	2.393		4,015	114	176,851	6,634
Customer Requested		0.000	0.000		0	0	0	0
	OGDEN	19.195	0.194	72,980	14,157	339	1,400,886	
High SAIDI	LMT18 SOUTH POND	1,125.000	1.833	6	11	2	6,750	
Low SAIDI	*40 circuits with a SAIDI of 0.0000*							
High SAIFI	RIV11 RIVERDALE/SO.WBR	279.000	4.000	148	592	4	41,292	
Low SAIFI	*40 circuits with a SAIFI of 0.0000*							
High Customer Minutes Lost	UIN11 UINTAH CKT#11 (OLD #12 CHANGED	98.128	1.001	1,277	1,278	2	125,309	
Low Customer Minutes Lost	*40 circuits with zero Customer Minutes Lost*							
Planned		2.702	0.011		775	20	197,175	4,005
Unplanned		19.195	0.194		14,157	339	1,400,886	45,426
Customer Requested		0.012	0.000		8	5	910	715
	PARK CITY	38.603	0.289	16,053	4,638	159	619,690	
High SAIDI	PC15 PARK CITY #15	320.844	1.299	1,016	1,320	12	325,978	
Low SAIDI	*10 circuits with a SAIDI of 0.0000*							
High SAIFI	DSR DESERET	190.000	3.000	1	3	3	190	
Low SAIFI	*10 circuits with a SAIFI of 0.0000*							
High Customer Minutes Lost	PC15 PARK CITY #15	320.844	1.299	1,016	1,320	12	325,978	
Low Customer Minutes Lost	*10 circuits with zero Customer Minutes Lost*							

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	Average Customer Count	Customers Off	Number of Occurr	Customer Minutes Lost	Duration Total (Minutes)
Planned		0.000	0.000		0	0	0	0
Unplanned		38.603	0.289		4,638	159	619,690	20,971
Customer Requested		0.000	0.000		0	0	0	0
	SALINA (Richfield)	24.107	0.384	13,235	5,085	113	319,058	
High SAIDI	SVR47 SEVIER-MILFORD 46 KV LINE	140.000	2.000	2	44	2	280	
Low SAIDI	*21 circuits with a SAIDI of 0.0000*							
High SAIFI	PAN12 W PANGUITCH, LAKE	130.041	2.082	367	764	4	47,725	
Low SAIFI	*10 circuits with a SAIFI of 0.0000*							
High Customer Minutes Lost	PAN12 W PANGUITCH, LAKE	130.041	2.082	367	764	4	47,725	
Low Customer Minutes Lost	*21 circuits with zero Customer Minutes Lost*							
Planned		0.009	0.000		3	2	115	70
Unplanned		24.107	0.384		5,085	113	319,058	11,576
Customer Requested		0.023	0.000		1	1	305	305
	SMITHFIELD	21.677	0.469	13,126	6,151	117	284,532	
High SAIDI	AMA14 AMALGA/TRENTON	90.802	1.993	293	584	7	26,605	
Low SAIDI	CVDA1, HYRM1, LOGN1 and AMA13	0.000	0.000	Varies	0.0000	0	0.0000	
High SAIFI	GRC12 GARDEN CTY/LAKETWN	88.101	2.254	338	762	21	29,778	
Low SAIFI	CVDA1, HYRM1, LOGN1 and AMA13	0.000	0.000	Varies	0.0000	0	0.0000	
High Customer Minutes Lost	RMD11 RICHMOND/SOUTH #11	60.708	1.076	643	692	8	39,035	
Low Customer Minutes Lost	CVDA1, HYRM1, LOGN1 and AMA13	0.000	0.000	Varies	0.0000	0	0.0000	
Planned		0.000	0.000		0	0	0	0
Unplanned		21.677	0.469		6,151	117	284,532	11,978

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	Average Customer Count	Customers Off	Number of Occurr	Customer Minutes Lost	Duration Total (Minutes)
Customer Requested		0.010	0.000		3	2	135	105
	SOUTH VALLEY (Jordan Valley)	23.469	0.289	26,142	7,552	144	613,535	
High SAIDI	HOG11 HOGGARD #11	64.096	1.034	5,161	5,336	12	330,802	
Low SAIDI	*7 circuits with a SAIDI of 0.0000*							
High SAIFI	HOG11 HOGGARD #11	64.096	1.034	5,161	5,336	12	330,802	
Low SAIFI	*7 circuits with a SAIFI of 0.0000*							
High Customer Minutes Lost	HOG11 HOGGARD #11	64.096	1.034	5,161	5,336	12	330,802	
Low Customer Minutes Lost	*7 circuits with zero Customer Minutes Lost*							
Planned		0.261	0.001		32	4	6,820	695
Unplanned		23.469	0.289		7,552	144	613,535	28,692
Customer Requested		0.000	0.000		0	0	0	0
	TOOELE	24.917	0.301	13,276	3,999	93	330,801	
High SAIDI	GRA12 GRANTSVILLE #12	243.762	1.971	105	207	4	25,595	
Low SAIDI	*14 circuits with a SAIDI of 0.0000*							
High SAIFI	STJ ST JOHN #11	18.458	2.026	347	703	8	6,405	
Low SAIFI	*14 circuits with a SAIFI of 0.0000*							
High Customer Minutes Lost	GRA11 GRANTSVILLE #11	75.469	1.007	1,621	1,632	9	122,336	
Low Customer Minutes Lost	*14 circuits with zero Customer Minutes Lost*							
Planned		4.442	0.034		447	6	58,970	675
Unplanned		24.917	0.301		3,999	93	330,801	11,773
Customer Requested		0.076	0.001		13	4	1,015	475

Outage Level	UTAH OUTAGES BY DISTRICT/CIRCUIT	SAIDI (minutes)	SAIFI	Average Customer Count	Customers Off	Number of Occurr	Customer Minutes Lost	Duration Total (Minutes)
	TREMONTON	44.678	0.565	6,424	3,628	80	287,014	
High SAIDI	BSH12 BUSH CKT #12	346.844	2.286	398	910	8	138,044	
Low SAIDI	*8 circuits with a SAIDI of 0.0000*							
High SAIFI	SNO11 SNOWVILLE CKT#11	325.842	3.211	19	61	6	6,191	
Low SAIFI	*8 circuits with a SAIFI of 0.0000*							
High Customer Minutes Lost	BSH12 BUSH CKT #12	346.844	2.286	398	910	8	138,044	
Low Customer Minutes Lost	*8 circuits with zero Customer Minutes Lost*							
Planned		0.000	0.000		0	0	0	0
Unplanned		44.678	0.565		3,628	80	287,014	7,346
Customer Requested		0.084	0.000		1	1	540	540
	VALLEY WEST (Jordan Valley)	24.496	0.221	41,856	9,248	141	1,025,319	
High SAIDI	TAY18 TAYLORSVILLE #18	239.168	0.347	577	200	1	138,000	
Low SAIDI	RDG13, RDG14, WEL15, LPK12 and SPK12	0.000	0.000	Varies	0	0	0	
High SAIFI	WEL12 WELBY #12	161.744	1.791	761	1,363	5	123,087	
Low SAIFI	RDG13, RDG14, WEL15, LPK12 and SPK12	0.000	0.000	455	0	0	0	
Low SAIFI	SPK12 SOUTHPARK #12	0.000	0.000	Varies	0	0	0	
High Customer Minutes Lost	TAY14 TAYLORSVILLE #14	60.782	0.435	3,147	1,368	15	191,280	
Low Customer Minutes Lost	RDG13, RDG14, WEL15, LPK12 and SPK12	0.000	0.000	Varies	0	0	0	
Planned		0.011	0.000		8	4	450	285
Unplanned		24.496	0.221		9,248	141	1,025,319	29,157
Customer Requested		0.057	0.000		20	1	2,400	120

825 N.E. Multnomah
Portland, Oregon 97232
(503) 813-5000

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UTAH PUBLIC
SERVICE COMMISSION

PACIFICORP
PACIFIC POWER UTAH POWER

June 27, 2000

REVIEWED BY COMMISSIONERS
STEPHEN F. MECHAM
CONSTANCE B. WHITE CBW 6/28
CLARK D. JONES

Utah Public Service Commission
Heber M. Wells Building
160 East 300 South
Salt Lake City, UT 84110

ATTN: Ms. Julie Orchard

Re: Docket No. 98-2035-04

Dear Commissioners:

As required by Section 54-4-27 of the Utah Public Utilities Code, under separate cover PacifiCorp has given notice to the Commission of the declaration of a dividend on its common stock aggregating $80,277,643.08.

In connection with that dividend and pursuant to Condition 15 in the July 28, 1999 Stipulation included in the above matter, PacifiCorp hereby files a summary of its cash flows for the year ended March 31, 2000. The attached summary shows that PacifiCorp's cash from operations for the year ended March 31, 2000 was approximately $759 million.

PacifiCorp believes that the attached summary shows that the dividend will not adversely affect PacifiCorp's ability to meet its service obligations in the State of Utah. In addition, the undersigned officer of PacifiCorp hereby certifies that PacifiCorp has adequate capital to meet all of its commitments and public service obligations in the State of Utah.

If there are questions concerning this matter, please contact me at (503) 813-7221.

Very truly yours,

PACIFICORP

By: Robert R Dalley
Title: Controller and Chief Accounting Officer

Attachment: Cash Flow Summary

Utah Dividend Cert aug 00.doc

PacifiCorp

CONSOLIDATED STATEMENT OF CASH FLOWS

FOR THE YEAR ENDED MARCH 31, 2000

(in millions of dollars)

CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$	83.7
Adjustment to reconcile net income to net cash provided by operating activities		
Gain on disposal of discontinued operations		(1.1)
Depreciation and amortization		482.5
Deferred income tax and investment tax credits - net		136.7
Interest capitalized - equity funds		(11.2)
Gain on sale of assets		(1.0)
Change in cash due to subsidiary's differing year end		(7.3)
Other		24.4
Utah rate order		(40.3)
ScottishPower merger accrued liabilities		71.0
Accounts receivable and prepayments		(40.9)
Materials, supplies, fuel stock and inventory		3.9
Accounts payable and accrued liabilities		66.3
Net cash provided by continuing operations		766.7
Net cash used in discontinued operations		(8.1)
CASH FLOWS PROVIDED BY OPERATING ACTIVITIES		758.6
CASH FLOWS FROM INVESTING ACTIVITIES		
Construction		(574.0)
Operating companies and assets acquired		(1.1)
Investments in and advances to affiliates - net		(2.6)
Proceeds from sale of finance assets and principal payments		47.8
Proceeds from sale of assets		169.3
Other		3.7
CASH FLOWS USED IN INVESTING ACTIVITIES		(356.9)
CASH FLOWS FROM FINANCING ACTIVITIES		
Changes in short-term debt		(88.1)
Proceeds from long term debt		1,812.0
Dividends paid		(269.5)
Repayments of long-term debt		(2,099.0)
Redemptions of capital stock		(26.1)
Other		7.0
CASH FLOWS USED IN FINANCING ACTIVITIES		(663.7)
DECREASE IN CASH AND CASH EQUIVALENTS		(262.0)
CASH AND CASH EQUIVALENTS AT APRIL 1, 1999		416.2
CASH AND CASH EQUIVALENTS AT MARCH 31, 2000	$	154.2

825 N.E. Multnomah
Portland, Oregon 97232
(503) 813-5000

4/25 FYI
Connie gave this to me to file after their UP+L mtg in Rm 427.
ASM

RECEIVED
MAY 25 10 37 AM '00
UTAH PUBLIC SERVICE COMMISSION

REVIEWED BY COMMISSIONERS
STEPHEN F. MECHAM
CONSTANCE B. WHITE CBW 5/26
CLARK D. JONES

See Exhibit file for Filing.

May 24, 2000

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

RE: Docket Number 98-2035-04
Informational Filing
Merger Commitment Condition 13

In accordance with ScottishPower's commitment made as part of its merger with PacifiCorp (Condition 13), please find enclosed a copy of ScottishPower's "Transition Plan", designed to transform PacifiCorp into a Top 10 U.S. utility by 2004.

This document is the same as that provided to the ScottishPower Board for the purpose of obtaining approval to proceed with the Plan. It contains details of:

- The transition planning process
- Key findings
- Vision and strategy
- Transition Plan enablers – investments to achieve the Transition Plan outcomes
- Transition Plan workstreams – separate reports for each major part of the business
- Organizational changes

The Transition Plan sets challenging targets for PacifiCorp but the changes will be implemented in a thoughtful and measured way over a five year period. The Company will become more efficient, but customer service and network performance will also improve in line with the commitments made during the merger. You can also be assured that there will also be absolutely no compromise on safety. The Transition Plan is also aspirational, designed to establish PacifiCorp as an industry leader in the West. I look forward to receiving your full support over the coming years as we strive to improve PacifiCorp's performance for the benefit of all its stakeholders.

The Transition Plan document represents a summary of the findings and recommendations developed by a 60-strong team of ScottishPower and PacifiCorp Utah managers over a five month period. It is designed to convey the key elements of the transformation process in a concise and readable format. Recognizing the widespread interest in the Transition Plan, it is also written as a non-confidential document that can be shared with interested parties without the need for a protective order.

Separately, I also attach a list of the 200 or so initiatives that will be undertaken over the next five years to deliver the Transition Plan targets and objectives. These initiatives range from straightforward and immediate actions to very complex change programs that will be further refined and developed over the coming years. It is, therefore, not possible to be definitive about every aspect of the Plan's implementation in advance. Rather, it will be evolutionary, and dependent upon business and operating conditions as the Company moves forward. A scenario-based approach, more fully described on Page 4 of the Executive Summary, has been used to estimate Transition Plan impacts given certain operating assumptions.

Nevertheless, it is important for regulatory and other purposes that the costs and benefits of the Transition Plan are precisely monitored. This will be the responsibility of a bespoke department, reporting directly to the CEO, which will track progress against each of the listed initiatives. This will enable accurate and timely reporting of Transition Plan impacts on an actual basis.

Inevitably, the enclosed documents will not answer all of the questions you may have regarding the effects of the Transition Plan on PacifiCorp. However, it should provide you with a comprehensive overview of the scope and nature of the transformation process. I would, of course, be pleased to receive any further questions you may have.

Sincerely,

M. R. Wright

Matthew Wright
Vice President, Regulation

Enclosures

State of Utah
DEPARTMENT OF COMMERCE
Internet Address; http://www.commerce.state.ut.us

Michael O. Leavitt
Governor
Douglas C. Borba
Executive Director
Ric Campbell
Division Director

DIVISION OF PUBLIC UTILITIES
Heber M. Wells Building 4th Floor
160 East 300 South/ Box 146751
Salt Lake City, Utah 84114-6751
Phone (801) 530-7622
Fax (801) 530-6512 or (801) 530-6650

May 24,2000

98-2035-04

Mr. D. Douglas Larson
Director, Regulatory Policy
One Utah Center, Suite 2300
201 South Main Street
Salt Lake City, Utah 84140

Dear Mr. Larson:

The ScottishPower merger order required PacifiCorp to continue to comply with the procurement policy and competitive bidding requirements approved by the Commission on January 16, 1991, in Docket No. 90-2035-05. The Division has not reviewed this issue for a number of years.

In order to validate the Company's compliance the Division of Public Utilities would like to review PacifiCorp's procurement policy and competitive bidding practices. We would like to meet with representatives of PacifiCorp to outline our audit objectives, review your internal audits regarding procurement, and set a time frame to review purchasing documents.

In preparation for the meeting please provide a copy of the Company's procurement policy and competitive bidding manuals.

Sincerely,

Lowell E Alt

Lowell Alt, Manager
Energy Section
Division of Public Utilities

cc: Utah Public Service Commission

825 N.E. Multnomah
Portland, Oregon 97232
(503) 813-5000

NEC

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MAY 22 8 44 AM '00

UTAH PUBLIC
SERVICE COMMISSION

PACIFICORP
PACIFIC POWER UTAH POWER

May 18, 2000

REVIEWED BY COMMISSIONERS
STEPHEN F. MECHAM SFM 5/30/00
CONSTANCE B. WHITE CBW 5/25
CLARK D. JONES CDJ 5/30

Utah Public Service Commission
Heber M. Wells Building
160 East 300 South
Salt Lake City, UT 84110

ATTN: Ms. Julie Orchard

Re: Docket No. 98-2035-04

Dear Commissioners:

As required by Section 54-4-27 of the Utah Public Utilities Code, under separate cover PacifiCorp has given notice to the Commission of the declaration of a dividend on its common stock aggregating $149,212,352.52.

In connection with that dividend and pursuant to Condition 15 in the July 28, 1999 Stipulation included in the above matter, PacifiCorp hereby files a summary of its cash flows for the 11 months ended February 29, 2000. The attached summary shows that PacifiCorp's cash from operations for the 11 months ended February 29, 2000 was approximately $729 million.

PacifiCorp believes that the attached summary shows that the dividend will not adversely affect PacifiCorp's ability to meet its service obligations in the State of Utah. In addition, the undersigned officer of PacifiCorp hereby certifies that PacifiCorp has adequate capital to meet all of its commitments and public service obligations in the State of Utah.

If there are questions concerning this matter, please contact me at (503) 813-7205.

Very truly yours,

PACIFICORP

By: Karen Clark
Title: Chief Financial Officer

Attachment:
Cash Flow Summary

Utah Dividend Cert feb & may 00.doc

PacifiCorp

CONSOLIDATED STATEMENT OF CASH FLOWS

FOR THE ELEVEN MONTHS ENDED FEBRUARY 29, 2000

(unaudited; in millions of dollars)

OPERATING ACTIVITIES		
Net income	$	40.8
Adjustment to reconcile net income to net cash provided by operating activities		
Income from discontinued operations		(1.1)
Depreciation and amortization		430.3
Deferred income tax & investment tax credits		107.7
Interest capitalized - equity funds		(11.2)
Gain on sale of assets		(1.0)
Other		17.8
Utah rate order refund		(41.5)
Scottish Power merger costs		108.0
Accounts receivable and prepayments		(29.2)
Materials, supplies and inventory		2.8
Accounts payable and accrued liabilities		113.6
Net cash provided by continuing operations		737.0
Net cash used in discontinued operations		(8.1)
CASH FLOWS PROVIDED BY OPERATING ACTIVITIES		728.9
INVESTING ACTIVITIES		
Construction		(519.2)
Investments in and advances to affiliates		(1.4)
Operating companies and assets acquired		(1.1)
Proceeds from sale of finance assets and principal payments		42.3
Proceeds from sale of assets		169.1
Other		8.1
CASH FLOWS USED IN INVESTING ACTIVITIES		(302.2)
FINANCING ACTIVITIES		
Changes in short-term debt		(104.3)
Proceeds from long term debt		1,412.3
Dividends paid		(269.5)
Repayments of long-term debt		(1,693.4)
Redemptions of preferred stock		(26.1)
Other		6.5
CASH FLOWS USED IN FINANCING ACTIVITIES		(674.5)
DECREASE IN CASH AND CASH EQUIVALENTS		(247.8)
CASH AND CASH EQUIVALENTS AT APRIL 1, 1999		416.2
CASH AND CASH EQUIVALENTS AT FEBRUARY 29, 2000	$	168.4

825 N.E. Multnomah
Portland, Oregon 97232
(503) 813-5000

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MAY 2 10 27 AM '00

UTAH PUBLIC
SERVICE COMMISSION

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PACIFICORP
PACIFIC POWER UTAH POWER

May 1, 2000

REVIEWED BY COMMISSIONERS
STEPHEN F. MECHAM 5/2
CONSTANCE B. WHITE CBW 5/5
CLARK D. JONES 5/5

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City UT 84114

Attention: Julie P. Orchard
Commission Secretary

RE: Docket No. 98-2035-04 ScottishPower/PacifiCorp Merger Commitments

Please find enclosed a Revised March 2000 report detailing the Company's performance in meeting the Customer Guarantees that were agreed to as a result of the merger. The report has been revised slightly to reflect the proper assignment of failures to each state.

If you have any questions or require further information, please call Carole Rockney at (503) 813-6091.

Sincerely,

Matthew Wright/cr

Matthew Wright
Vice President, Regulation

c: Mark Flandro - Utah Division of Public Utilities
Rea Petersen - Utah Division of Public Utilities
Rich Walje - Vice President, Distribution

Enclosure

PACIFICORP CUSTOMER GUARANTEE REPORT
REVISED MARCH 2000
UTAH

GUARANTEE	DESCRIPTION	TOTAL EVENTS	TOTAL FAILURES	AMOUNT PAID
CG1	Restoring Supply	53,406	2	$125.00
CG2	Appointments	528	1	$50.00
CG3	Switching on Power	1,086	3	$250.00
CG4	Estimates	697	1	$50.00
CG5	Respond to Billing Inquiries	459	0	$0.00
CG6	Respond to Meter Problems	82	0	$0.00
CG7	Notification of Planned Interruptions	472	2	$100.00
CG8	Power Quality Complaints	295	0	$0.00
	TOTAL	**57,025**	**9**	**$575.00**

825 N.E. Multnomah
Portland, Oregon 97232
(503) 813-5000 NEC

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SERVICE COMMISSION

PACIFICORP
PACIFIC POWER UTAH POWER

REVIEWED BY COMMISSIONERS
STEPHEN F. MECHAM
CONSTANCE B. WHITE CBW 4/21
CLARK D. JONES 4/24

April 20, 2000

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City UT 84114

Attention: Julie P. Orchard
Commission Secretary

RE: Docket No. 98-2035-04 ScottishPower/PacifiCorp Merger Commitments

Please find enclosed PacifiCorp's March 2000 Report detailing the Company's performance in meeting the Customer Guarantees which were agreed to as a result of the recent merger between ScottishPower and PacifiCorp.

PacifiCorp will submit it's first quarterly report in July 2000 after the close of the first fiscal year quarter covering the period April 2000 through June 2000.

If you have any questions or require further information, please call Carole Rockney at (503) 813-6091.

Sincerely,

Matthew Wright /cr

Matthew Wright
Vice President, Regulation

c: Mark Flandro - Utah Division of Public Utilities
Rea Petersen - Utah Division of Public Utilities
Rich Walje - Vice President, Distribution

Enclosure

PACIFICORP CUSTOMER GUARANTEE REPORT
MARCH 2000
UTAH

GUARANTEE	DESCRIPTION	TOTAL EVENTS	TOTAL FAILURES	AMOUNT PAID
CG1	Restoring Supply	53,406	2	$125.00
CG2	Appointments	528	1	$50.00
CG3	Switching on Power	1,086	3	$250.00
CG4	Estimates	249	1	$50.00
CG5	Respond to Billing Inquiries	459	1	$50.00
CG6	Respond to Meter Problems	82	0	$0.00
CG7	Notification of Planned Interruptions	472	2	$100.00
CG8	Power Quality Complaints	295	0	$0.00
	TOTAL	**56,577**	**10**	**$625.00**

NEC

825 N.E. Multnomah
Portland, Oregon 97232
(503) 813-5000

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UTAH PUBLIC
SERVICE COMMISSION

PACIFICORP
PACIFIC POWER UTAH POWER

February 29, 2000

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

Attention: Julie Orchard
Commission Secretary

RE: Docket No. 98-2035-04 ScottishPower / PacifiCorp Merger Commitment Condition 20

On July 28, 1999 the Public Service Commission of Utah approved the merger between ScottishPower and PacifiCorp in Docket No.98-2035-04. The merger was approved with certain conditions. Condition number 20 of the Stipulation calls for the Company to provide within 90 days of the merger a report indicting PacifiCorp's proportionate share of ScottishPower's total assets, total operating revenues, operating and maintenance expense and number of employees. Attached is information that satisfies the Company's obligation pursuant to condition 20.

If you have any questions or require further information, please call Henry Lay at (503) 813-6179.

Matthew R. Wright/cr
Matthew Wright
Vice President, Regulation

Attachment

PacifiCorp/ScottishPower
Merger Commitment 5.1

	%
Total assets	53.3% [a,c,d,f]
Total operating revenues	44.6% [b,c,d,g]
Operating and maintenance expense	N/A [e]
Number of employees	36.8% [a]

[a] The data presented is as of September 30, 1999. The data for PacifiCorp is from the September 30, 1999 Form 10-Q. ScottishPower data is from the September 30, 1999 Interim Report

[b] The data presented is for the six months ended September 30, 1999. The data for PacifiCorp is derived from the September 30, 1999 and March 31, 1999 Form 10-Qs. ScottishPower data is from the September 30, 1999 Interim Report.

[c] Amounts have not been adjusted for Fair Market Value calculations resulting from the acquisition.

[d] PacifiCorp numbers have been calculated in accordance with US GAAP whereas ScottishPower numbers have been calculated in accordance with UK GAAP. No adjustments have been made to reflect these accounting differences.

[e] ScottishPower does not present operating and maintenance expense under UK GAAP therefore this is not available.

[f] ScottishPower assets were converted at 1.6473, the closing exchange rate on September 30, 1999, per Bloomberg.

[g] ScottishPower revenues were converted at 1.6041, the average rate for the six months ended September 30, 1999, per Bloomberg.

Fax

To: Julie Orchard

From: PacifiCorp Attn: Carole Rockney
(503) 813-6091

Fax: (801) 530-6796

Pages: 3 (Including Cover Page)

Phone: (801) 530-6716

Date: February 29, 2000

Company: UPSC

Re: Docket No. 98-2035-04 ScottishPower / PacifiCorp Merger Commitment Condition 20

X URGENT ☐ FOR REVIEW ☐ PLEASE COMMENT ☐ PLEASE REPLY ☐ PLEASE RECYCLE

● COMMENTS

THE ORIGINAL AND 10 COPIES WILL BE SENT TODAY VIA FEDEX OVERNIGHT MAIL

825 N.E. Multnomah
Portland, Oregon 97232
(503) 813-5000

PACIFICORP
PACIFIC POWER UTAH POWER

February 29, 2000

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

Attention: Julie Orchard
Commission Secretary

RE: Docket No. 98-2035-04 ScottishPower / PacifiCorp Merger Commitment Condition 20

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If you have any questions or require further information, please call Henry Lay at (503) 813-6179.

Matthew R. Wright /cr
Matthew Wright
Vice President, Regulation

Attachment

PacifiCorp/ScottishPower
Merger Commitment 5.1

	%
Total assets	53.3% [a,c,d,f]
Total operating revenues	44.6% [b,c,d,g]
Operating and maintenance expense	N/A [e]
Number of employees	36.8% [a]

[a] The data presented is as of September 30, 1999. The data for PacifiCorp is from the September 30, 1999 Form 10-Q. ScottishPower data is from the September 30, 1999 Interim Report

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18922

State of Utah

DEPARTMENT OF COMMERCE
Internet Address: http://www.commerce.state.ut.us

Michael O. Leavitt
Governor
Douglas C. Borba
Executive Director
Ric Campbell
Division Director

DIVISION OF PUBLIC UTILITIES
Heber M. Wells Building 4th Floor
160 East 300 South/ Box 146751
Salt Lake City, Utah 84114-6751
Telephone: (801) 530-6651
Fax (801) 530-6512 or (801) 530-6650

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UTAH PUBLIC
SERVICE COMMISSION

APPROVED BY COMMISSIONERS
STEPHEN F. MECHAM SFM 12/15/99
CONSTANCE B. WHITE CBW 12/15
CLARK D. JONES CDJ 12/15

To: Utah Public Service Commission

From: Ric Campbell, Director RC
Lowell Alt, Manager LA
Ron Burrup, Technical Consultant RB

Date: December 13, 1999

RE: PacifiCorp Application for Tariff PSCU No. 42. Tariff Revisions as specified in Docket 98-2035-04 - Docket 99-035-T03

Issue:
Pursuant to the merger stipulation, PacifiCorp is filing two new tariff pages. The first is a revised list of electric service schedules, and the second is a new Schedule 99, Credit from ScottishPower.

Recommendation:
The Division recommends that the Commission approve the tariff pages as filed, with the effective date to be January 10, 2000 as requested. We further recommend that each future change in the merger credit also take place on the 10th day of the month. The DPU has discussed this with PacifiCorp and they support our recommendation.

The "First Revised Sheet No. B" does not include the new Decorative Street Lighting Tariff No. 13, however, PacifiCorp will apply the merger credit to this new tariff.

Explanation:
The new tariff pages are intended to implement merger credit condition number 43.

> 43. ScottishPower and PacifiCorp agree to provide guaranteed merger related cost-of-service reductions for four years through an annual merger credit. The amount of the credit shall be \$12 million per year for years 2000, 2001, 2002, and 2003. The total credit in years 2000-2003 will be \$48 million. The merger credit shall be allocated among PacifiCorp's retail tariff customers on the basis of a percentage of the customer bill, exclusive of taxes. At the end of each year, the aggregate amount of the credit allocated in that year shall be calculated. These calculations shall be audited by the DPU,

who shall report their audit results to the Commission. In the event the merger credit does not equal $12 million in any of the first three years, the excess or shortfall shall be applied to the $12 million due in the following year.

The dates set forth in this Condition assume that the merger transaction closes in 1999. If closing is delayed, ScottishPower and PacifiCorp may adjust the dates so that the merger credit begins as soon as practicable but not later than 30 days after the closing date.

The new Schedule 99 Credit from ScottishPower reduces each customers total electric bill by 1.8%, (exclusive of taxes), based on 1998 Utah normalized revenues. This reduces rates by $12 million. The reduction is effective January 10, 2000.

The Commission's order states that the merger credit is to take place "not later than 30 days after the closing date". This would make the credit effective on December 30, 1999. Because of Y2K concerns, PacifiCorp has instituted a computer lock down in which no changes to the customer billing system will be made for several days before and after the new year. PacifiCorp has spent millions of dollars to avoid Y2K problems. We think the lock down is prudent, and support the merger credit becoming effective January 10, 2000.

As a result of the January 10 date, we recommend each future change in the merger credit calculation also take place on the 10th day of the month. The will allow each customer to get an equal share of the credit because subsequent changes would happen on the same day of the month, and no customers would be disadvantaged because of different billing cycles. The Division has discussed this concept with PacifiCorp and the company agrees with this provision.

cc: CCS
PacifiCorp, Attn: Doug Larson

18771

DOCKETED

- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Application of PacifiCorp and ScottishPower plc for an Order Approving the Issuance of PacifiCorp Common Stock	))))	DOCKET NO. 98-2035-04 REPORT AND ORDER

ISSUED: November 23, 1999

SHORT TITLE

ScottishPower/PacificCorp Merger

SYNOPSIS

The Public Service Commission of Utah ("Commission") approves ScottishPower plc's ("ScottishPower") purchase of PacifiCorp pursuant to the Agreement and Plan of Merger dated December 6, 1998, amended and restated in the Amended and Restated Agreement and Plan of Merger as of February 23, 1999 ("Merger Agreement"). The Commission grants authority for PacifiCorp to issue common stock as requested in the Application in connection with the merger. The Commission orders PacifiCorp and ScottishPower to implement the $48 million merger credit over four years reducing rates to tariff customers and to comply with the numerous conditions which are mandated relating to PacifiCorp and ScottishPower in connection with this approval.

TABLE OF CONTENTS

APPEARANCES

Edward A. Hunter James F. Fell	for	PacificCorp
Brian W. Burnett James M. Van Nostrand	"	ScottishPower
Michael L. Ginsberg Assistant Attorney General	"	Division of Public Utilities
Douglas C. Tingey Assistant Attorney General	"	Committee of Consumer Services
Brian L. Farr Assistant Attorney General	"	Utah Department of Community and Economic Development and the Board of Business and Economic Development
F. Robert Reeder William J. Evans	"	UIEC
Gary A. Dodge	"	Large Customer Group
Matthew F. McNulty, III	"	Utah Associated Municipal Power Systems
Peter J. Mattheis Matthew J. Jones Glen E. Davies	"	Nucor Steel, a Division of Nucor Corporation
Joro Walker Eric Blank	"	Land and Water Fund
Arthur F. Sandack	"	International Brotherhood of Electrical Workers, Local 57
Steve R. Randle	"	Utah Farm Bureau Federation
Jeff Fox Betsy Wolf	"	Crossroads Urban Center and Salt Lake Community Action Program
David F. Crabtree	"	Deseret Generation & Transmission Co-Operative
Steven W. Allred Paul T. Morris Roger O. Tew	"	Utah League of Cities and Towns

Lee R. Brown	"	Magnesium Corporation of America
Bill Thomas Peters David W. Scofield	"	Emery County
Daniel G. Moquin Assistant Attorney General	"	Office of Energy and Resource Planning State of Utah

By The Commission:

I. PROCEDURAL HISTORY

On December 31, 1998, PacifiCorp and ScottishPower (collectively "Applicants") filed a Joint Application requesting an Order from the Commission approving the issuance of PacifiCorp common stock incidental to the transaction described in the Agreement and Plan of Merger, dated December 6, 1998, which was later amended and restated in the Amended and Restated Agreement and Plan of Merger as of February 23, 1999 ("Merger Agreement"). Under terms of the Merger Agreement between ScottishPower and PacifiCorp, the outstanding common shares of PacifiCorp will be converted into the right to receive, at the option of the holder of such shares, either newly issued ordinary shares of ScottishPower or such shares represented by American Depository Shares of ScottishPower and evidenced by American Depository Receipts. PacifiCorp shareholders will receive cash payments for fractional shares of ScottishPower ordinary shares or American Depository Receipts. As a result of the transaction, ScottishPower will acquire indirect ownership and control of all of the voting capital stock of PacifiCorp, and PacifiCorp will remain in place.

Applications similar to the one filed in Utah were also filed with the public utility regulatory commissions in the states of California, Idaho, Oregon, Washington and Wyoming and with the Federal Energy Regulatory Commission ("FERC"), each of which regulates PacifiCorp.

On January 25, 1999, the Commission issued a Protective Order which provides a framework for protection of information claimed to be confidential.

A Prehearing Conference was held pursuant to notice on January 26, 1999, to discuss the schedule, discovery, prefiled testimony, and other issues related to this proceeding. The Commission issued a Scheduling Order dated February 8, 1999, establishing a procedural schedule with a February 17, 1999 deadline for petitions to intervene. The Applicants, the Division of Public Utilities, the Committee of Consumer Services, and each party petitioning to intervene were ordered to file statements on February 17, 1999, identifying the issues to be considered in the case.

The following parties petitioned to intervene: the Utah Associated Municipal Power Systems ("UAMPS"); Deseret Generation & Transmission Co-Operative and its members, Bridger Valley Electric Association, Inc., Dixie-Escalante Rural Electric Association, Inc., Flowell Electric Association, Inc., Garkane Power Association, Inc., Moon Lake Electric Association, Inc., and Mount Wheeler Power, Inc. (collectively "DG&T"); the Utah League of Cities and Towns ("ULCT"); the Land and Water Fund of the Rockies ("LAW Fund"); the Salt Lake Community Action Program ("CAP") and the Crossroads Urban Center ("Crossroads"); the Office of Energy and Resource Planning, State of Utah ("OERP"); the Utah Farm Bureau Federation ("Farm Bureau"); Emery County; Abbot Critical Care, Amoco Oil Company, Fairchild Semiconductor Corporation, Holnam, Inc., Kennecott Utah Copper Corporation, Kimberly-Clark Corporation, Micron Technology, Inc., Praxair, Inc., and Westinghouse/Western Zirconium Division (collectively "Utah Industrial Energy Consumers" or "UIEC"); Alliant Techsystems, Inc., Hexcel Corporation, Thiokol Corporation, Chevron, S F Phosphates, E. A. Miller, Inc., IHC Hospitals, Inc., Geneva Steel, Western Electrochemical Company and Utah Electric Deregulation Group (collectively "Large Customer Group" or "LCG"); Nucor Steel, a Division of Nucor Corporation ("Nucor"); Magnesium Corporation of America ("Magcorp"); the Department of Community and Economic Development ("DCED") and the Division of Business and Economic Development ("DBED"); and the International Brotherhood of Electrical Workers, Local 57 ("IBEW"). The Commission granted all Petitions to Intervene.

Issue Statements were filed by the Applicants, Utah Division of Public Utilities ("Division"), Committee of Consumer Services ("Committee"), UAMPS, DG&T, ULCT, LAW Fund, CAP and Crossroads, OERP, Emery County, UIEC, LCG, Magcorp, and DCED and DBED.

Applicants filed their direct testimony on February 26, 1999. A Prehearing Conference was held on March 5, 1999, to discuss the Issue Statements. Additional Issue Statements were filed by LCG/UIEC and the CCS on March 31, 1999. Issues were discussed at a Prehearing Conference on April 2, 1999. The Commission issued a Supplemental Scheduling Order on April 2, 1999, requesting that the parties file memoranda on April 12, 1999, with responsive memoranda filed on April 29, 1999, identifying those issues which are irrelevant and those issues which are relevant, but for which parties other than the Applicants have a burden of proof. The Commission also issued a Memorandum to Parties on April 2, 1999, in which we concluded that the Applicants would have to meet the net positive benefits standard for the merger to be approved. All parties agreed that that was the appropriate standard for this Docket. The Applicants had filed testimony complying with the net positive benefits standard.

On April 16, 1999, the Applicants filed Supplemental Testimony addressing additional issues in the proceeding as well as outlining the commitments and benefits of the transaction.

On May 4, 1999, the Commission held a hearing to discuss issues in the proceeding. Based upon the information presented at the hearing, the Commission issued an Order on May 10, 1999, requiring each party in their Direct Testimony to identify all issues it deemed important. In addition, the parties were to state why each issue should be considered in the Docket, indicate specifically how each issue could be affected by the proposed merger, and set forth the remedy the party was seeking.

On June 18, 1999, the Division, the Committee, UAMPS, DG&T, ULCT, the LAW Fund, CAP/Crossroads, OERP, Emery County, UIEC, LCG, Nucor and DCED/DBED filed Direct Testimony.

On July 16, 1999, the Applicants, the Division, the Committee, the LAW Fund, UIEC, Nucor and IBEW filed Rebuttal Testimony. The Applicants filed Motions to Strike portions of the testimony of Maurice Brubaker for UIEC, Carl N. Stover, Jr. for DG&T, Dennis W. Goins for Nucor, and Tom Dolan for ULCT.

On July 28, 1999, ScottishPower, PacifiCorp, the Division and the Committee entered into and filed a Stipulation in which Applicants agreed to meet 51 conditions addressing specific concerns of the Division and the Committee ("Stipulation").

Pursuant to public notice, the Commission held a public hearing in this matter from August 2 through August 6, and on August 9, 1999. At the hearing, a panel of witnesses testified in support of the Stipulation. The panel consisted of Matthew Wright for ScottishPower, Douglas Larson for PacifiCorp, Lowell E. Alt, Jr. for the Division and Dan Gimble for the Committee. PacifiCorp presented the testimony of Richard T. O'Brien. ScottishPower presented the testimony of Alan V. Richardson, Bob Moir, Robin MacLaren, Andrew MacRitchie, Graham Morris and Jack Kelly. The Division presented the testimony of Lowell E. Alt, Jr., Ronald L. Burrup, Mary H. Cleveland, Robert J. Maloney, William A. Powell and Kenneth B. Powell. The Committee presented the testimony of Daniel E. Gimble, Bruce E. Biewald, Paul Chernick and Neil H. Talbot. UAMPS presented the testimony of Stephen Page Daniel. DG&T presented the testimony of Carl N. Stover, Jr., Carl Albright and R. Leon Bowler. ULCT presented the testimony of Tom Dolan. The LAW Fund presented the testimony of John Nielsen. CAP/Crossroads presented the testimony of Jeff Fox. OERP presented the testimony of Jeffrey S. Burks. Emery County presented the testimony of J. Robert Malko. UIEC presented the testimony of Maurice Brubaker. The LCG presented the testimony of Richard M. Anderson. Nucor presented the testimony of Dennis Goins. DCED/DBED presented the testimony of David B. Winder and Frank Davis.

At the hearing, counsel for UIEC moved to strike certain portions of Andrew MacRitchie's testimony. The Commission denied this Motion to Strike as well as the Applicants' Motions to Strike.

At the hearing, the following Stipulations were presented: the July 28, 1999 Stipulation among ScottishPower, PacifiCorp, the Division and the Committee (Joint Exhibit No.1); the Stipulation and Settlement of Issues Related to Public Purpose Programs among PacifiCorp, ScottishPower, OERP, and the LAW Fund (SP Exhibit No. 7); and the Stipulation and Settlement of Issues Related to Low-Income Customers among PacifiCorp, ScottishPower, Crossroads and CAP (SP Exhibit No. 8). A Stipulation among PacifiCorp, ScottishPower and DG&T was filed with the Commission. In addition, a letter agreement among ScottishPower, DCED and DBED was presented in SP Exhibit No. 1R.1.

On August 6, 1999, the Commission held a public witness day where the following witnesses appeared and provided sworn testimony: Thomas O. Breitling, Julius Hoggard, Barbara Toomer, Roger Monia, Betsy Wolf, Terra Jordan, Henry Eyring, Lee R. Brown, Lew Pilkington, and Richard Laramee. In addition, the Commission received letters from various legislators and others regarding the merger which are on file in this Docket.

On September 3, 1999, the Commission received Post Hearing Briefs from the Applicants, the Division and the Committee jointly, UIEC, LCG, Nucor, Magcorp, DCED/DBED, the Farm Bureau, DG&T and Emery County.

On September 17, 1999, the Commission received Reply Briefs from the Applicants, the Division and the Committee, UIEC, LCG, Nucor and Magcorp.

II. STIPULATIONS

The main provisions of the four stipulations and the letter agreement are summarized below. The full provisions are set forth in the documents themselves and the summaries are not intended to substitute for the text of the stipulations or the letter agreement. The documents are appended to this Order.

A. Stipulation Among ScottishPower, PacifiCorp, the Committee, and the Division Supporting Approval of Merger (Appendix 1)

This Stipulation was executed on July 28, 1999, among Applicants, the Division, and the Committee. The Stipulation resolves all outstanding issues among the signatory parties in

51 proposed conditions plus five implementation provisions. Included as an Attachment to the Stipulation is a list of ScottishPower's Utah commitments, as originally set forth in SP Exhibit 1S.1 to Alan Richardson's Supplemental Testimony (Attachment 1). Also included with the Stipulation is an itemization of merger-related costs for which Applicants commit not to seek rate recovery (Attachment 2).

The Stipulation states that ScottishPower will accept an Order by the Commission which includes the terms set out in the Stipulation. With these terms and conditions, the Division and the Committee testify that ScottishPower and PacifiCorp have satisfied the merger approval standard, positive net benefits to customers. These parties therefore recommend approval of the Application.

The merger conditions contained in the Stipulation include provisions as follows:

Merger Credit. Applicants agree to a merger credit for a four-year period beginning in 2000. The credit will be $12 million per year for years 2000, 2001, 2002, and 2003. The merger credit for years 2000 and 2001 is guaranteed and will be reflected in rates whether or not a general rate case is held. The merger credit for 2002 and 2003 may be offset or reduced to the extent that cost reductions resulting from the merger are reflected in rates (Condition 43).

Performance Standards and Customer Guarantees. Applicants agree to implement the service quality improvements described in Section I, Customer Service, of Attachment 1 to the Stipulation. These include five network performance standards, two customer service performance standards, and eight customer service guarantees. Conditions 16, and 27-38 of the Stipulation contain additional service quality provisions, and provide that the proposed performance standards and customer service guarantees will be included in PacifiCorp's tariff (Condition 27). In addition, Condition 28 provides that the network expenditures necessary to implement the service standards will be funded from efficiency savings and redirected internal funding.

Transition Plan. Within six months of the closing of the merger, ScottishPower will file a merger transition plan setting forth its plan to transform PacifiCorp's operations. The plan will include time lines, actions necessary to implement the merger and realize benefits and cost savings, capital and operating expenditures, and workforce changes (Condition 13).

Rate Effects of the Merger. Applicants testify that no merger-related transaction costs will be allowed in the rates (Condition 3); any premium paid by ScottishPower for PacifiCorp stock will be disregarded for ratemaking purposes (Condition 26); and rates in Utah will not increase as a result of the merger (Condition 44). Rates will also be affected by the merger credit as described above.

Financial Issues. Applicants agree that any reduction in the cost of capital will be reflected in rates in Utah, but any increase in the cost of capital of electric operations of PacifiCorp that is a direct result of the merger will be borne by shareholders (Condition 25). Applicants also agree that a hypothetical capital structure based on A-rated electric utilities comparable to PacifiCorp should be used to determine the correct cost of capital for ratemaking purposes (Condition 19). In addition, Applicants agree to maintain separate long-term debt (Condition 21) and to apply to the Commission for approval of debt issuances (Condition 22).

Affiliated Interest and Cost Allocation Issues. Applicants agree to waive any defense that the Commission's jurisdiction over affiliated interest transactions is preempted by the Public Utility Holding Company Act of 1935 (PUHCA) or *Ohio Power v. FERC* (Condition 23). They agree to maintain an audit trail for cost allocations (Condition 2). In addition, Applicants agree in Condition 45 to assume all risks that may result from less than full system cost recovery if interjurisdictional allocation methods differ among PacifiCorp's various state jurisdictions.

Access to Books and Records. Applicants agree to conditions which assure that the Commission will have access to the information and records necessary to perform its regulatory role (Condition 11). Applicants agree to bear reasonable expenses incurred by the Commission, the Division and the Committee in accessing corporate records and personnel located outside the State of Utah.

Enforcement. Condition 50 sets forth a procedure for the enforcement of the merger conditions. If the Commission finds that either ScottishPower or PacifiCorp has violated one or more conditions, it may make appropriate ratemaking adjustments to give full effect to these conditions.

B. Stipulation and Settlement of Issues Related to Public Purpose Programs among PacifiCorp, ScottishPower, OERP, and the LAW Fund (Appendix 2)

This Stipulation was executed on July 26, 1999, among Applicants, OERP and the LAW Fund. Its purpose is to address the impact of the merger on the environment and public purpose programs. It provides that ScottishPower will produce integrated resource plans according to the current schedule and current Commission rules. ScottishPower will incorporate the recommendations of the Commission's Energy Efficiency and Renewable Energy Task Force in implementing its commitments to develop an additional 50 MW of renewable resources. ScottishPower will file a green resource tariff in Utah. ScottishPower will support funding for cost-effective and prudent energy efficiency in Utah.

C. Stipulation and Settlement of Issues Related to Low-Income Customers among PacifiCorp, ScottishPower, Crossroads and CAP (Appendix 3)

This Stipulation was executed on June 18, 1999, between Applicants, and Crossroads and CAP. Its purpose is to resolve all issues among the signatory parties relating to the impact of the merger on low-income customers.

ScottishPower and PacifiCorp agree to work with the signatory parties and others to identify cost-effective programs that will benefit low-income customers through reduction of energy usage and improvement in customers' ability to pay current and past electric bills. Under the Stipulation, PacifiCorp will support a lifeline rate in Utah and Applicants will fund low-income initiatives in Utah for three years with shareholder funds at $300,000 more per year than the amount spent on similar programs in Utah in 1998.

D. Stipulation Among PacifiCorp, ScottishPower, and DG&T (Appendix 4)

This Stipulation, executed August 2, 1999, between Applicants and DG&T, provides for discussions between Applicants and DG&T to attempt to resolve any service reliability problems at the Middleton delivery point, and follow-up efforts to implement any identified solutions.

E. Letter Agreement with DCED and DBED (Appendix 5)

This letter agreement, dated August 3, 1999, is among ScottishPower, DCED and DBED. It sets forth ScottishPower's commitment to locate a senior executive in Utah. According to the letter agreement, this senior executive will report directly to the CEO of PacifiCorp, and will have broad influence over PacifiCorp's operations in Utah, including authority to approve corporate involvement in economic development and corporate citizenship activities. The letter agreement further provides that the corporate offices of PacifiCorp will remain within the states of PacifiCorp's service area, and Utah Power's headquarters will be located in Utah.

F. Discussion and Findings With Respect to the Stipulations

1. Benefits of the Transaction

Stipulations and supporting testimony promise customers certain benefits from the merger. On the basis of these benefits, and the Conditions in the July 28, 1999 Stipulation which signatory parties assert mitigate the risks of the merger and prevent rate recovery of transaction costs, these parties argue the merger meets the net positive benefits approval standard we have adopted. We first consider the merger benefit claims. These arise in two categories, the merger credit and the network performance and customer service improvements. We turn, thereafter, to the other Stipulations.

a. Merger Credit

By the terms of the July 28, 1999 Stipulation (Condition No. 43), a $12 million credit is provided to customers in each of four years. In the first two years, the credit is guaranteed. In the final two years, the credit can be offset if merger-related cost reductions identified in the new management's "transition plan" are reflected in rates. In the view of these parties, this means a $48 million merger benefit will be delivered to customers either through a direct credit on their bills or indirectly by reduced rates. The merger credit is offered as a merger benefit.

UIEC, LCG and Nucor (collectively, the "Industrial Customers") challenge the stipulating parties' assertion that the credit is a merger benefit. A merger benefit, they argue, can only be identified through comparison of two operating scenarios, the one with and the other without the merger, which are not on the record. In addition, Nucor asserts that the difficulty of identifying whether costs or savings are merger related invites further argument and undermines the credit's usefulness as an effective remedy to the risks associated with the merger.

Industrial Customers term the amount of the credit insignificant and not much greater than the net present value of the annual corporate cost savings proposed in the Applicants' initial filings. They challenge ScottishPower's claim that it will achieve cost savings once the merged entity is operating under new management, and offer evidence that a properly managed PacifiCorp would do better on its own. They claim (confidential Cross-Examination Exhibit No. 23) that PacifiCorp projects lower operation and maintenance expense levels without the merger than ScottishPower projects with the merger.

Industrial Customers recommend delaying merger approval until the transition plan, containing ScottishPower's proposals to increase efficiency, reduce costs, and realize benefits, has been filed and evaluated.

Applicants dispute the projections prepared by Industrial Customers in Cross-Examination Exhibit No. 23 and their claim that the merger credit is insignificant. The transition plan, the Applicants assert, will identify cost savings in a manner enabling the Commission to discern those that are due to the merger (Stipulation Condition 13). Applicants testify that the transition plan cannot be filed prior to the merger-approval decision, and argue that such a requirement would be both impractical and unnecessary. It would be impractical, they state, because prior to the closing of the transaction ScottishPower faces legal and practical impediments to the development of a meaningful plan; it would be unnecessary because the merger credit is guaranteed whether or not the efficiencies identified in the plan are realized.

We first examine whether the merger credit is, as the Industrial Customers claim, insignificant and turn next to whether it is a merger benefit. We also examine the stipulating parties' intention to employ merger savings (benefits) after the merger in a ratemaking context.

The evidence shows that the analysis in Cross-Examination Exhibit No. 23 is of limited value. Projections made by PacifiCorp of its unmerged operations and by ScottishPower of merged operations reflect differences in starting points and differences in assumptions. Given this, the case comparison is inconclusive as to whether PacifiCorp is capable of a more efficient operation standing alone than merged. The analysis does raise the point, however, that absent the merger, a capable PacifiCorp management should be expected to perform much better than the former management actually has done. We return to this subject below.

When pressed in cross examination, a ScottishPower witness acknowledged that the true benefit of the merger is replacement of PacifiCorp's existing management with a new management that will be focused, committed, and armed with both different management practices and new technologies. With its experience, it will be able to deliver higher quality service to customers at lower cost. These improvements, Applicants assert, will be accomplished faster and with greater certainty than the former management could have done.

The record shows that the non-production operation and maintenance expenses PacifiCorp incurs to provide service have grown in recent years beyond that expected of an efficient utility operation. According to PacifiCorp witnesses, management was "distracted" by a failed global growth strategy and did not control utility costs carefully. Having recognized the problem, PacifiCorp revised its strategic plan and announced its intention to refocus on its core electric business in the western United States, divest all business other than its western business and Powercor Australia, Ltd., and implement a share repurchase program. Changes in management personnel were made at the highest levels, and costs, following a new, short-term "Refocus" plan, are, apparently, now better managed. For the future, however, current management has no specific plan, only the general intention to reduce costs and to increase rates where the Company is earning less than its allowed rate of return. PacifiCorp testifies, and we conclude, that no detailed and well-formulated business plan exists for PacifiCorp's utility operations in the unmerged case.

By contrast, we find the record contains convincing assurance, in the form of positive, focused attitudes and clear though preliminary statements of initiatives and intentions, that the new management following merger should more capably manage the utility. The promised transition plan -- 'Applicants' "business plan going forward" -- is intended to implement ScottishPower's pledge to reduce costs enough to bring the utility operation to a position of top-ten efficiency within the ranks of domestic electric utilities. We believe the plan, as a statement of management's objectives and initiatives, will be useful to regulatory auditors. It will be, in short, ScottishPower's roadmap to higher quality, more efficiently produced and delivered utility service. On this basis, we conclude that the transition to a new management team poses less risk for customers than would retention of the existing management. Thus, we will not make merger approval contingent upon the transition plan.

We also reject the Industrial Customers' assertion that the merger credit is insignificant. While true that the Applicants have identified in a preliminary way a potential for reducing certain nonproduction costs of providing service by an amount much larger than the merger credit, it is our intention to monitor the utility's post-merger performance carefully. If cost of service declines, a general rate case to set new rates accordingly is the proper response. In this context, it cannot reasonably be said that a $12 million per year credit to ratepayers is insignificant.

The merger credit, however, is the product of stipulation. As a proposed merger benefit, it circumvents the evaluative procedure upon which the identification of merger benefits normally depends. Differentiating benefits arising from a merger requires two equally well specified scenarios showing how the utility would be efficiently operated and with what results, both with and without the merger. Neither of these scenarios exists at this time. The merged scenario will be the subject of ScottishPower's transition plan, its "business plan going forward," but this will not be completed until six months after merger. The initiatives contained in the plan are not developed in a public process and are not subject to Commission approval. The unmerged scenario, a business plan for PacifiCorp standing alone, has not been prepared and does not exist. Any future effort to depict a stand-alone PacifiCorp business plan will obviously be an after-the-fact undertaking, one which we believe will inevitably be biased or influenced by the Applicants' merger. Nevertheless, it is clear to us that the credit is a benefit of the merger, and we accept it as such. The Stipulation presents the merger credit as a specific, identifiable annual credit that will be received by Utah customers. The credits to customers' bills during the four-year period are in addition to any savings that Utah customers will receive through the changes in the operations and efficiencies in the utility's service that may be reflected in future rates.

Where the absence of the two scenarios does present a problem is the Stipulation's intention to offset the merger credit with "merger savings" in the last two of the four-year credit period. The concept of a merger benefit is germane to the merger approval decision. When applied to ratemaking considerations, it creates substantial demands upon regulatory rate setting mechanisms and the resources and efforts of the Commission and parties participating in the ratemaking process. We have learned from experience that the injection of the concept of "merger savings" into ratemaking considerations adds considerable complexity and uncertainty to what is already an involved process and risks unintended consequences.

Applicants claim merger savings, a form of merger benefit, are identifiable in the transition plan. Neither the Division nor the Committee is able to testify how, in the absence of the required scenarios, this may be done. Both note that the burden to demonstrate merger savings will be borne by ScottishPower. For its part, ScottishPower simply assures us merger savings will be clearly identified in the transition plan as the result of initiatives that are incremental to any PacifiCorp currently has in place or would have been able to achieve through 1999.

The logical difficulty here is plain. The unmerged scenario does not exist, and there is no indication that it can be developed. The merged scenario, in the form of the transition plan, will be formulated later. In the Division's opinion, to develop and compare two scenarios under this circumstance would be "folly." The appropriate comparison would be between the merged company's operations and an effectively managed and efficiently run stand-alone PacifiCorp. What PacifiCorp currently has in place or would have been able to achieve through 1999 is not necessarily indicative of the appropriate reference with which to compare the merged utility's operations when offsets to the merger credit are to be considered. When we deal with merger credit offsets, we will require more than a comparison of the merged utility's operations with PacifiCorp's past performance. Due to the lack of any Pacificorp business plan for the future, we are skeptical of future PacifiCorp stand-alone scenarios. Our general conclusion, therefore, is that the transition plan can demonstrate merger savings only if such savings are uniquely the product of merger. If it does not, there will be no offset to the merger credit in the third and fourth years.

b. Network Performance and Customer Service

Applicants voluntarily commit to provide a comprehensive set of performance standards and customer guarantees for improvements in network performance and customer service. They commit (Condition 28) to funding a five-year, $55 million investment in customer service and system performance improvements from a redirection of existing budgets and savings in other areas. On this basis, it is their intent to add no new incremental costs for ratepayers to support. ScottishPower testifies that its experience guarantees improvements will occur more quickly, more efficiently, and with greater certainty than PacifiCorp on its own could deliver.

Applicants intend a decline in the duration and frequency of service interruptions which they believe will have an estimated dollar value, based on studies in the literature, in a range of $30 to $60 million annually, and up to $600 million on a net present value basis. Utah customers will benefit, they state, by approximately $20 million per year from network performance improvement.

The Division believes the voluntary nature of ScottishPower's proposal will save considerable effort and is likely to be more effective than if improvements were instead an imposed requirement. Industrial Customers, by contrast, argue that the benefits of improved network performance are speculative, unnecessary, and, because the costs are unknown and benefits unsubstantiated, perhaps not cost effective.

Industrial Customers, however, are concerned about service quality and reliability. They testify that ScottishPower's proposed network performance improvements focus on the distribution system rather than the transmission system from which they take service. Any decrease in reliability, they state, would cause them financial harm.

Applicants' focus on the quality and reliability of utility service is most welcome to us. We have experience with regulatory attempts to influence quality and reliability, and are acquainted with the difficulty of gaining improvement when the will is absent and little but an apprehension of the public interest drives the effort. Though we agree with Division testimony on the importance of the voluntary nature of ScottishPower's proposals, the lack of firm evidence upon which to evaluate current performance, coupled with the absence on this record of either baseline performance measures or improvement objectives must influence how we consider the proposal as a merger benefit.

Industrial Customers have raised these concerns, noting that the performance improvement proposals are directed to the distribution system. They question whether the transmission system, at which level they take service, will benefit. The response that can be developed from the record is twofold. First, ScottishPower commits to work closely with the Western Systems Coordinating Council to meet transmission system performance and reliability standards. Second, the high degree of interdependency of transmission and distribution systems implies that successful work on the one depends upon the performance of the other. In a sense, the benefit is indirect. The large size of each industrial customer ensures a direct service relationship with utility representatives, a benefit not enjoyed by the many thousands of smaller customers. We conclude that the Industrial Customers have not established that they will be harmed.

Applicants pledge to reduce the amount of time required to answer telephone calls from customers, and to resolve customer complaints faster. Applicants guarantee payment of a penalty (usually $50) to individual customers if certain customer service standards are not met. These include restoration of power supply, keeping appointments, service installation, estimates for installation of new service, responses to bill inquiries, meter testing, planned interruptions, and handling power quality complaints. These customer service proposals also have the merit and value of being voluntary commitments. The relationship customers have with the business office on service concerns is the subject of pending investigation outside this Docket. We have the Division's testimony to assure us that the ScottishPower proposals go beyond what has previously been considered. We accept them as significant in this light.

Nevertheless, our immediate obligation is to assess the network performance and customer service proposal as a merger benefit. According to testimony, Applicants will not complete a baseline assessment of the network until 18 months after the merger is complete. Only then will it be known whether PacifiCorp's current practices are deficient. And only after a finding of deficiency can the scope of Applicants' proposal to redirect $55 million over five years be understood to further the public interest in an adequate, efficiently operating network. We find that the lack of an evidentiary basis for evaluating either the current performance of the network or placing the proposal in the necessary context of public interest objectives makes quantitative evaluation of this merger benefit difficult. We reach this conclusion advisedly, because we are most interested in a post-merger cooperative approach to network and service evaluation and, as necessary, improvement.

We are also reluctant to place a monetary value on improvements in network performance. Quality and reliability of service are in part qualitative matters, even though dollar figures, of larger or smaller magnitude depending on individual customer's electricity requirements, can be worked up to show the impact of changes in reliability. The range of dollar values introduced by Applicants for service improvements may be suggestive, but it has not been evaluated on this record. Consequently, we will not rely on any dollar valuation of proposed network performance and customer service improvements in reaching our decision about the benefits of merger.

c. Other Stipulations

Stipulation and Settlement of Issues Related to Public Purpose Programs among PacifiCorp, ScottishPower, OERP, and the LAW Fund (SP Exhibit No. 7) was executed on July 26, 1999, to address the impact of the merger on the environment and public purpose programs. Under its terms, ScottishPower will produce integrated resource plans according to the current PacifiCorp schedule and current Commission rules. ScottishPower will incorporate, where appropriate, the recommendations of the Commission's Energy Efficiency and Renewable Energy Task Force including development of an additional 50 MWs of renewable resources within five years, systemwide, and submission of a green pricing tariff within 60 days following approval of the merger. ScottishPower also agrees to support funding for cost-effective and prudent energy efficiency measures in Utah, and will use the integrated resource planning process and other mechanisms to establish Utah energy efficiency targets. ScottishPower will establish an Environmental Forum to provide expertise on such environmental issues as distributive generation, state-sponsored energy programs for national parks and public land management agencies, public buildings, and regional haze.

We find that the Stipulation and settlement of public purpose program issues continues and strengthens PacifiCorp's commitment to environmental protection programs. The Applicants will consider all cost-effective, environmentally benign, supply-side and demand-side resources, to meet customer energy service requirements. We accept the Stipulation, and expect the merged company to work cooperatively with interested groups to further environmental and public-purpose programs.

Stipulation and Settlement of Issues Related to Low-Income Customers among PacifiCorp, ScottishPower, Crossroads and CAP (SP Exhibit No. 8) was executed on June 18, 1999, to resolve all issues among the signatory parties relating to the impact of the merger on low-income customers. ScottishPower and PacifiCorp agree to work with signatory parties and others to identify cost-effective programs that will benefit low-income customers through reduction of energy use and improved ability to pay current and past electric bills.

Under the terms of the Stipulation, Applicants will support a Utah lifeline rate. The rate proposed by Crossroads and CAP in Docket No. 97-035-01 will be a candidate. Applicants will use $300,000 of shareholder funds for low-income initiatives in Utah each year for three years, an amount over and above that spent by PacifiCorp for similar Utah programs in 1998. Applicants will work with appropriate parties to identify cost-effective programs for low-income customers.

We accept this Stipulation and find that it is in the public interest. We direct the Company to file information with the Division indicating 1998 expenditures on low-income programs so we may track this provision.

Stipulation Among PacifiCorp, ScottishPower, and DG&T was executed August 2, 1999. By its terms, Applicants and DG&T will attempt to resolve any service reliability problems at the Middleton delivery point. We accept this Stipulation and find that it is in the public interest.

2. Affiliation Issues and the Ability to Properly Regulate the Utility

Applicants testify that they agree to comply with all existing statutes and Commission requirements regarding transactions with affiliates, and that the Commission will retain jurisdiction over transactions with affiliates (Condition 23). PacifiCorp will maintain an accounting system separate from ScottishPower's and corporate records will be available for inspection in Utah or Portland, Oregon (Condition 11). They assure us (Conditions 10 and 11) of all necessary access to officers and employees, and to the books and records of ScottishPower, including those pertaining to transactions between PacifiCorp and affiliates. They acknowledge Commission authority to audit any ScottishPower and unregulated subsidiary accounting records that are the basis for charges to PacifiCorp. The Stipulation also requires filing general and financial reports with the Commission (Condition 17).

In other conditions, ScottishPower agrees to maintain current practice whereby an A-rated hypothetical capital structure is used for regulatory determination of PacifiCorp's cost of capital (Condition 19), to adhere to PacifiCorp's previously established Umbrella Loan

Agreement (Condition 14) and Transfer Pricing Policy (Condition 6), and to apply to the Commission for approval of security issuances by or on behalf of PacifiCorp (Condition 22). PacifiCorp is to maintain separate long-term debt (Condition 21). Nonutility businesses or foreign utilities owned by ScottishPower are not to be held by PacifiCorp or its subsidiaries (Condition 4), although this condition does not affect the current holdings of PacifiCorp and its subsidiaries. PacifiCorp, without Commission approval, will not assume any obligation or liability for ScottishPower or its affiliates, nor will PacifiCorp's regulated utility assets be used as backing for securities issued by ScottishPower or its affiliates (Condition 48).

By Condition 5, ScottishPower will notify the Commission of any decision to enter another business or to merge, combine, or sell PacifiCorp stock or assets. In Condition 8, ScottishPower agrees to abide by Commission Rule R746-401, and will notify us of decisions on purchase, sale or other disposition of PacifiCorp assets. We interpret Condition 9 to strengthen this agreement. By it, ScottishPower agrees to seek approval of any decision to divest, spin-off, or sell an "integral utility function."

Stipulation conditions intended to ensure the independent operation of the utility and to protect our ability to regulate it in the public interest are important because the merger brings a number of changes. There will be a new holding company corporate structure, corporate headquarters will be in another country with regulatory practices unlike those here, there will be accounting system differences, and there may be new affiliates with which the utility may develop relationships. Thus, we must be satisfied that Stipulation conditions address key points in language conveying a clear and unambiguous intent to maintain unimpaired our ability to regulate the utility.

Our experience with PacifiCorp following the merger of Utah Power and Pacific Power teaches us to be wary of pre-merger claims that the merger will not complicate our ability to regulate the utility. A merger creates new circumstances, even unanticipated ones. It is necessary to state this, though we recognize that Stipulation conditions are intended, in apparent good faith, to protect our ability to regulate the utility in the public interest.

Stipulation conditions address concerns about regulating the utility in a new holding company structure not only through guaranteed access to employees, books and records, but through ScottishPower's commitment to work with regulators on the allocation of corporate and other costs from ScottishPower to PacifiCorp. We note approvingly the commitment to provide access to books and records of both sides of transactions between affiliates and PacifiCorp, the agreement to comply with statutes and regulations regarding affiliate transactions, and the commitment not to subsidize affiliates through PacifiCorp. We accept Applicants' statement that Stipulation conditions are designed to prevent subsidization of nonutility operations through affiliated interest transactions or cost allocations, and that any cost allocation method adopted will comply with principles set forth in the Stipulation requiring both adequate documentation and complete and effective audit (Condition 2).

We accept and will rely on the ScottishPower and PacifiCorp agreement to waive any defense they may have that our jurisdiction over affiliated interest transactions is preempted by the PUHCA or *Ohio Power v. FERC* (Condition 23). We likewise accept and will rely on their agreement to notify us of any proposed change in corporate structure (Condition 49), including the relationship between PacifiCorp and affiliates, whether through creation of a new affiliate, new business transactions with an existing affiliate, or dissolving an affiliate with which PacifiCorp has done business (Condition 7).

Nevertheless, our review of the record reveals aspects of these conditions that require comment and interpretation before we can accept them. Neither Condition 7 nor 47 requires obtaining Commission approval, only notification. Notification enables the Division to perform its auditing task. Condition 2 may bind the Division to interjurisdictional agreements reached by staffs of the several state commissions on allocation issues. Condition 9 may unacceptably delimit the necessity of Commission approval for divestiture, spin-off or sale to transactions involving an "integral utility function," an undefined term.

By law, the Division is our investigative staff. We depend upon its independent evaluation of all aspects of issues before us. If, by entering into agreement with the Company and the staffs of other commissions, it is prevented from thoroughly airing issues on the record in our proceedings, it cannot adequately perform its duties. The Division must not be bound by any interjurisdictional allocation agreement which threatens its independent investigative role. We therefore rely on the Division's on-the-record statement that Condition 2 will not bind it in this way. We expect the Division to inform us immediately should this reliance prove inappropriate.

Condition 9 uses the undefined term "integral utility function." A ScottishPower witness testifies that the term is intended to limit the necessity of regulatory approval to situations involving more than just any utility asset. Division and Committee witnesses say the Condition is intended to apply to any asset that is "important enough." Noting these expressions of regulatory intent, we will rely on the Division and Committee statement that the Condition is to apply to assets that reach some threshold of importance. The Commission will decide in future cases when the threshold is met.

Industrial Customers contend and the record establishes that the Condition does not cover cases of "spin-down," that is, when utility assets are transferred to a subsidiary. We agree with Industrial Customers that spin-down must be covered by the Condition and will order modification to include it.

3. Merger-Related Transaction Costs.

Applicants stipulate that neither merger-related transaction costs nor the acquisition premium will be recovered in rates (Conditions 3, 26). Transactions costs are listed in Attachment 2 to the Stipulation, as is the premium. ScottishPower and PacifiCorp testify that this is a complete list of merger transactions costs, and give the total as $259.8 million. The Division and the Committee accept this statement.

The Division quantified the value of the acquisition premium to be approximately $1.6 billion on the day the merger was announced, December 7, 1998. In the merger, a share of PacifiCorp common stock can be converted into .58 American Depository Receipts of ScottishPower, traded in dollars on the New York Stock Exchange, or 2.32 ordinary shares of ScottishPower, traded on the London Stock Exchange. Ultimately the value of the acquisition premium will be determined by the values of PacifiCorp and ScottishPower share prices when the merger closes. The merger is to be closed five days after all necessary approvals have been obtained. As the necessary approvals and the expectation of the merger become more certain, we would expect the acquisition premium to decline, reflecting the fixed conversion rate of PacifiCorp shares for ScottishPower shares since the share prices decreasingly reflect the values of independent companies.

The acquisition premium, ScottishPower states, will appear on its books as goodwill, to be amortized over a number of years. PacifiCorp's separate books are said to insulate it from the premium. Industrial Customers caution that the transaction costs and acquisition premium place additional pressure on the Applicants to obtain significant cost reductions from utility operations.

Industrial Customers question whether ScottishPower might seek to recover the premium as a stranded cost. They argue that payment of a large acquisition premium is evidence PacifiCorp faces no stranded costs and urge the Commission, as a condition of merger approval, to require Applicants to renounce any future claim to recover PacifiCorp stranded costs.

The record leaves some doubt about possible effects of the premium even though cited Stipulation conditions are intended to insulate the utility and its customers from any recovery of it. The Division interprets Condition 26 to prevent recovery of the premium in stranded costs. Applicants state that accounting for goodwill reduces earnings during the amortization period. Asked whether this will increase PacifiCorp's cost of capital, they respond that it will not for two reasons. First, PacifiCorp's books will be separate and a hypothetical capital structure will be used to determine its cost of capital. Second, investors will be influenced more by cash flow than by the premium's effect on earnings.

Should the acquisition premium be large, and we understand that its magnitude varies with the share prices of both ScottishPower and PacifiCorp, we are concerned that management may be pressured to make up its effects on earnings from utility operations. The $260 million in transaction costs may exert similar pressure. We will rely on the Division to inform us if and when evidence of such effects arises. Our overall conclusion, however, relying on the clear testimony of the Division, the Committee and the Applicants, is that neither the premium nor the transaction costs will affect rates.

Industrial Customers assert that the acquisition premium should end the stranded cost debate. The Division, too, states, "the willingness of ScottishPower to pay an acquisition premium may be an indication that PacifiCorp would not face any stranded costs if the electric industry were restructured." These statements are cogent but they do not lead us to decide the issue on this record. We are aware, for example, of conflicting definitions of stranded costs. The subject is both complex and controversial. We defer judgment about such costs, and the effect of the premium, to an appropriate docket.

In our review of the record on transaction costs and of the Stipulation conditions which pertain to them, we find no mention of the possibility that some costs may not yet have been identified. Applicants believe the list in Stipulation Attachment 2 is complete. The Division and the Committee have no independent opinion. Common sense suggests that costs other than those in Attachment 2 may exist. For instance, we note that the time spent pursuing the merger by senior officials of PacifiCorp is not listed as a transaction cost. Competent audit may reveal other examples as well.

To assure us that no transaction cost is recovered in rates, the Division testifies that it will perform an audit and act upon its results in a general rate case. We will rely on this. Such an audit is necessary to ensure that all transaction costs, including any not identified by the Applicants, are accounted for below-the-line.

4. Duties Of A Regulated Utility

Several Stipulation conditions express an acknowledgment of the statutes and Commission requirements pertaining to a regulated electric utility doing business in the state of Utah (among others, conditions 5, 8, 15, 39, 41, 46, and 49). The purpose of these conditions is to reduce ambiguity, to clarify and ensure the Applicants recognize and understand their statutory obligation to abide by the Utah Code, rules and Commission orders. As such, these conditions are not a merger benefit, and only in a minimal way may they be said to mitigate its associated risks. For this reason, they do not weigh heavily in our consideration whether the merger meets the net positive benefits standard.

5. Risks of The Merger

Industrial Customers identify a number of risks of the merger transaction. In their view, the magnitude of the acquisition premium and transaction costs may pressure management to reduce utility costs significantly, yielding the risk that necessary maintenance, investment, and system improvement may not be forthcoming. In order to meet a dividend objective, they state, customers may be at risk of decreased service reliability and higher long-term costs. In addition, they point to the intention of Applicants to recover the costs of transition plan initiatives from ratepayers; if cost savings are not realized, they argue, customers may face rate increases. Industrial Customers are also concerned that changes in the regulatory climate in the United Kingdom, ScottishPower's goal to become an international multi-utility, and its holding company corporate structure may cause a loss of focus on the utility in the west, create pressure for cost reductions there, and weaken this Commission's ability to regulate the utility in the public interest.

Applicants claim the conditions reached in the July 28, 1999 Stipulation with the Division and the Committee neutralize merger risks. They cite DPU Exhibit 1.0 SR, which lists the issues of concern to the Division and shows how the conditions address them. The merger, Applicants state, is a simple stock transaction, involving only a change in the shareholders of PacifiCorp. They testify that PacifiCorp will operate its regulated utility within the corporate structure on an independent basis, the Commission will continue to exercise the regulatory oversight it does today, and certain Stipulation conditions including numbers 11 (access to books and records), 12 (annual merger savings reports for five years), and 17 (reports to be filed by PacifiCorp) ensure that the information necessary to effective regulation will continue to be provided. Applicants maintain in addition that risks of the merger are outweighed by its benefits, and argue that nothing on the record supports the assertion that the merger may undermine effective regulation. The Division and the Committee testify that Stipulation conditions adequately mitigate the risks faced by Utah customers.

We find record support for the position of the Applicants, the Division and the Committee. In addition to Conditions 11, 12, and 17, we have acknowledged the conditions cited in our discussion of Affiliation Issues which guarantee the independence of the utility within the holding company structure, insulate it from the financial affairs of the overall corporation, and provide an independent basis for estimating the utility's cost of capital. We rely on these conditions for assurance that the utility will not be adversely affected by either regulatory events in the United Kingdom or the business strategies of the overall corporation. We find that cost recovery for initiatives in the transition plan is not unusual. We expect a competent management to develop plans for the efficient and effective operation of the utility, and unless the resulting costs of providing utility service were either unreasonable or illegitimate, they would be recoverable in rates through our normal ratemaking process. We have considered the risks of the merger and find that they are adequately mitigated by the Stipulation's conditions.

III. OTHER ISSUES RAISED BY THE PARTIES

A. The Legal Standard

The Commission must determine whether merger of ScottishPower and PacifiCorp is in the public interest and has interpreted applicable statutory language (UCA 54-4-31) to mean that a merger, to be approved, must meet a net positive benefit standard. See CP National Corp., Docket No. 80-023-01; Utah Power & Light and Pacific Power & Light Companies, Docket No. 87-035-27. In Docket No. 87-035-27, the Commission stated that its "task is to consider them all [positive benefits and negative impacts], giving each its proper weight, and determine whether on balance the merger is beneficial or detrimental to the public." By Memorandum issued April 2, 1999, we notified parties that the net positive benefit standard would be employed in the present Docket, all parties having agreed to it and the Applicants having, by that time, filed testimony in full cognizance of it. Applicants, however, reserve the argument that Utah law requires a no-harm standard only.

B. Potential Tax Savings

The Industrial Customers request that we address potential income tax savings resulting from the acquisition of PacifiCorp in this Docket. Applicants oppose this, and based in part on confidential Cross-Examination Exhibit No. 3, argue that the tax impact on the ScottishPower holding company from acquisition of PacifiCorp may or may not be a savings. The Division testifies that Utah regulation generally does not consider the tax consequences of consolidated operations, but acknowledges that, if considered, it should be a rate case issue. The Committee agrees with the Division.

Applicants argue potential tax savings will not arise from the transaction itself, but from the calculation of the tax liability on an ongoing basis following the transaction. Any such tax saving is speculative, they assert, because it would depend on tax law and policy in existence at the time the tax liability is calculated. For these reasons, Applicants argue the issue cannot properly be addressed in this proceeding, but should be reserved for a subsequent general rate proceeding when the facts regarding the tax liability after the transaction are known. Applicants offer the following to resolve the consolidated tax issue:

> The parties to this Docket preserve their right to raise the issue of the treatment of upstream tax savings and costs in future rate cases. All parties preserve their positions and have not waived their rights on this issue. ScottishPower commits to retain records regarding upstream tax savings and costs relating to the merger and make these records available to the DPU, CCS and other parties in accordance with Stipulation Ex. 1 and the discovery rules of the Commission.

UIEC accepts this language if the information necessary to assess the magnitude of savings is forthcoming from ScottishPower and if it allows the Commission to decide what the savings are and how they should be shared.

The Commission will adopt Applicants' proposed language. Only after consideration in a general rate case will it be known whether tax savings, if any materialize, should be passed through to PacifiCorp ratepayers. We will not impose a merger approval condition requiring tax benefits to flow to ratepayers, but will make the language advanced by Applicants a condition of approval. This new condition properly preserves the issue for subsequent general rate treatment.

C. Rate Cap Proposal

Industrial Customers and the Farm Bureau recommend a rate cap to ensure that the merger will meet the public interest standard. They believe the costs and risks of the merger outweigh its benefits, even with the Stipulations in place, and argue the Stipulations do little to mitigate risks either to the general body of ratepayers or to their particular interest as large industrial consumers of electricity. Since the costs of implementing the transition plan initiatives may be recovered from ratepayers, and the anticipated cost reductions are uncertain and are neither identified nor quantified, these parties argue that a rate cap plan would equalize the risks and benefits of the merger and protect ratepayers from any failure to achieve the plan's objectives. A rate cap, they argue, would provide a proper incentive to make beneficial changes that reduce cost and would limit debate about what costs would have been absent the merger.

Applicants maintain the evidence shows that a rate cap is not required to establish that the merger yields net positive benefits for Utah customers, and that the Stipulations have satisfied the concerns of other parties, with the principal exception of the Industrial Customers. Applicants further argue that a rate cap is not a good option because it cannot take into account business circumstances unrelated to the merger.

Although the Division began this proceeding by supporting a rate cap, it now concludes that a rate cap is unnecessary as a result of the conditions reached in the Stipulation. The Division and the Committee testify that the potential risks of the merger are adequately mitigated by Stipulation conditions, so that a rate cap is not required to enable the merger to meet the net public benefit standard.

We find record support for the position of the Applicants, the Division and the Committee, and on that basis conclude that a rate cap is not required for the merger to satisfy the approval standard. The conditions set forth in the Stipulation provide appropriate protections for customers.

D. Cash Balances of PacifiCorp

Industrial Customers raise a concern regarding cash held in PacifiCorp. They argue that conditions must be in place to prevent the movement of this cash upstream in the merged entity at least until Utah service quality has been found adequate. Applicants in response name several Stipulation conditions said to address the issue, including their agreement in Condition 14 to the provisions of PacifiCorp's existing Umbrella Loan Agreement placing limits on short-term loans between PacifiCorp and affiliates, naming ScottishPower an affiliate for purposes of the Condition. Applicants point to Condition 22, by which the Commission must approve the issuance of PacifiCorp debt, Condition 15, governing dividend policy, Condition 49, requiring adequate financial resources to enable PacifiCorp to meet its public service obligations, and Conditions 16 and 27-39, which deal with service quality.

The Commission is aware that PacifiCorp entered merger negotiations with large cash balances on hand. These arose from sale of subsidiary activities in areas beyond our regulatory jurisdiction. Our obligation is to ensure that the utility is able to provide public service of adequate quality and reliability. Therefore, given the record in this Docket, we look to the Stipulation for assurance that the merger will not damage, and may in fact enhance, this ability. We find a number of conditions, including those mentioned by Applicants, that not only directly address the financial wherewithal of the utility but create a situation of independence for it within the corporate structure of the merged entity. The record shows that two of these conditions, numbers 14 (umbrella loan agreement) and 15 (dividend policy and adequate capital), were adopted at the suggestion of the Industrial Customers. For these reasons, we conclude that we need not inquire further into the issue of cash balances in this Docket.

E. Access to Employees and Records

Industrial Customers request access to employees and records for Intervenors in the same manner as is assured for representatives of the Division and the Committee.

Condition 11 provides for access to relevant books, records and officials of ScottishPower entities. Applicants pledge that corporate records will be available for inspection in Utah or Portland, Oregon, and that Intervenors will have, as is the current practice, access to records there. ScottishPower, PacifiCorp and all affiliates are required by Condition 10 of the Stipulation to make their employees, officers, directors and agents available to testify and to provide information.

In light of the various measures in the Stipulation which address this issue, the Commission concludes that further provisions are unnecessary. Industrial Customers, as intervenors in Commission proceedings, will retain the same access to books, records, and officials of the utility that they have under current practices.

F. Utah Presence

Industrial Customers recommend a merger approval condition which would require ScottishPower and PacifiCorp to provide agents in Utah capable of binding PacifiCorp and making decisions regarding Utah operations. Applicants' response is the letter agreement with the DCED and DBED (SP Exhibit 1R.1), wherein ScottishPower pledges to place a senior executive in residence in Utah. That executive, the letter states, will report directly to the CEO of PacifiCorp, will have "broad influence" over PacifiCorp's operations in Utah, and will handle economic development and community concerns. In addition, Applicants state that Utah Power headquarters will be located in Utah.

The Utah Power/Pacific Power merger creating PacifiCorp electric operations doing business in Utah as Utah Power has taught this Commission that when made at a distance corporate decisions may reflect a ranking of investment options different from that a local perspective may have achieved. This is an oblique way of saying that our resulting concern for the proper maintenance and operation of the public utility in Utah is not wholly assuaged by the letter agreement to place an executive in Utah whose responsibilities might be interpreted to center instead on area economic development and the merged entity's community presence. While we acknowledge the importance of these, our obligation rests with the adequacy and reliability of utility service in this State. Service quality and reliability turn not only on the utility's maintenance but its investment practices. Corporate investment decisions, the letter suggests, will not be the concern of the individual posted to Utah, but solely that of senior management in Glasgow, Scotland, or perhaps Portland, Oregon.

We do not expect to alter this situation, which is, we believe, a matter of management prerogative. Nevertheless, distant corporate decisions must neither rank nor allocate resources in a manner harmful, in either the short- or the long run, to the public service requirements of this utility in Utah. As this record shows, PacifiCorp in recent years pursued a global business strategy which resulted in neglect of its utility responsibilities.

The first priority of the executive located in Utah must be maintenance of a high-quality Utah utility operation. We accept the letter agreement as indication of such a commitment. We rely on the record testimony of senior ScottishPower officials revealing the attitudes, experience, and expertise necessary to a high-quality result. We further rely on Stipulation conditions which both direct that result and provide for effective regulation. For these reasons, we will not impose the merger approval condition advanced by Industrial Customers.

G. Participation in a Regional Transmission Organization

Industrial Customers recommend as a requirement of merger approval that Applicants join a regional transmission organization within 24 months after merger. In the alternative, Industrial Customers request a condition requiring Applicants to file, within 18 months after the merger is approved, a definitive plan to place transmission assets with an independent third-party administrator. In this way, they argue, the Commission could have a meaningful impact on the characteristics of such an organization. They regard such a role for the Commission as important.

Applicants respond that the merger will not affect either the availability of transmission services or competitive issues. Applicants point out that UIEC intervened at FERC and argued that the ScottishPower/PacifiCorp transaction would have an adverse impact on competition. FERC was asked by UIEC to condition approval of the merger on the Applicants participating in the formation of and joining a regional transmission organization. Because ScottishPower and PacifiCorp do not compete in the same geographic markets, FERC found that market concentration would be unchanged by the merger. FERC declined to impose the condition.

UIEC acknowledges that mergers in which approval depended on a requirement to join a regional transmission organization were situations where enhancement of market power was a concern. The record shows no such concern exists here. Moreover, no regional transmission organization now exists for PacifiCorp to join. In the recent past, PacifiCorp attempted to form such an organization, but without success.

We do note, however, that FERC has established a Notice of Proposed Rulemaking, Docket RM99-2 regarding "Regional Transmission Organizations" and proposes to establish characteristics and functions for appropriate regional transmission organizations. Under terms of the rulemaking, participation in an organization would be voluntary rather than ordered by a state commission.

Due to differences between the laws, regulations and level of regulation in the United Kingdom and that in Utah, we find no support for Industrial Customers' insistence that the "special share" held by the United Kingdom government, supports the proposed requirement. We rely on the Supplemental Testimony of Applicant's witness Alan Richardson, which states:

> The practical effect of the "special share" is to require government approval before control of ScottishPower may be transferred, much like the regulatory statutes in many of the states which require utility commission approval before control of a regulated utility passes to another. It comes into play only if a transfer of ownership of ScottishPower is involved, and does not in any way impose any restrictions on the actions which ScottishPower may take with respect to its own business or PacifiCorp.

Membership in a regional transmission organization does not require the sale of transmission assets.

We find that the issue of participation in a regional transmission organization is unrelated to the merger. Enhancement of market power, the basis for an approval condition in other mergers, is not an issue here. The record shows that FERC reached the same conclusion. We therefore decline to impose the condition suggested by Industrial Customers, but intend to influence the development of any future organization involving the merged company.

H. Special Contracts

Industrial Customers recommend that special contracts that expire during the merger-credit period (through December 31, 2003) be extended for that period if desired by the customer. Industrial Customers support this request with the claim that special contract negotiations were unilaterally terminated once the application in this docket was filed. They believe that nothing today suggests that current costs of the special contracts will fail to be compensatory through the transition period. They argue that, as a result of the operational efficiencies Applicants claim for the merger, there is little risk that either the company or its tariffed customers will be harmed if special contracts are extended as requested. Finally, the Industrial Customers claim that special contract customers need protection against merger-related risks; thus, it would be discriminatory to deny extension of the contracts while tariffed customers receive the benefit of the merger credit.

Applicants respond that following the merger all contractual obligations will be honored. For this reason, they testify, the Industrial Customers' proposal is unnecessary. Applicants cite the Commission's March 4, 1999 Report and Order in Docket No. 97-035-01 which established a task force to study standards the Commission should employ to approve special contracts. In the Order, the Commission stated that guidelines and definitions for regulatory treatment of special contracts should be examined, as should risk-sharing between the Company and its customers. The Commission ordered an evaluation of the confidential treatment customarily given the rates and terms of service in Utah special contracts, given an increasingly competitive environment. Applicants assert that evaluation of special contracts should come after completion of the merger and that it should be done in parallel with the work of this task force. For these reasons, they argue, discussion of special contracts is premature.

Applicants believe the record contains no evidence to support the assertion that the merger has influenced either the timing of negotiations or Applicants' willingness to negotiate. The contention that costs in current contracts will remain compensatory throughout the period ending December 31, 2003, they also view as unsupported. Applicants disagree that merger-related cost reductions could eliminate risks of serving special contract customers at current prices through that period. To the claim that special contract customers need special protection, Applicants cite the Commission's response to similar argument in Docket No. 87-035-27, the Utah Power/Pacific Power merger proceeding: "[I]n this era of increased competition and low energy prices the industrial customers have other options for power supply. . . . It is therefore unlikely that these customers will be left "holding the bag" after the merger is consummated."

The Division testifies that regulatory approval of current Utah special contracts was based on analyses showing PacifiCorp had no need of additional capacity during the term of those contracts. The Division indicates it is aware of changes in PacifiCorp's load and resource balance that could now require capacity additions. Applicants contend that the need for new capacity will not be affected by merger cost reductions. They state that PacifiCorp is facing potential changes in its load and resource balances.

The Division argues that contracts and any extensions should be evaluated based on circumstances at the time they are negotiated. Current procedures allow for such review.

The Commission's reasoning in the prior merger case is applicable to special contract customer arguments in the present Docket as well. These customers are eligible for special contracts because they have other options for power supply. We intend to hold Applicants to their commitment to address special contract customer concerns in good faith and to complete any negotiations with them promptly. We do not find adequate evidence on the record to support the claim that the merger will alter the risks these customers face, or the alternatives they have. Nor do we believe this proceeding is the forum to resolve special contract issues. As noted by

Applicants, a regulatory task force is now reviewing special contract issues. The conditions in the July 28, 1999 Stipulation, along with the assurances made on the record at the hearings, provide protection against the perceived risks that the Industrial Customers claim exist for special contract customers. On this basis, we reject the request to require extension of special contracts.

I. Franchise Issues

The Utah League of Cities and Towns requests a condition of merger approval that would require Applicants to "reopen current franchise agreements." Applicants argue that abrogation of contracts, including franchise agreements, is not appropriate. We find that the record shows that the issue of franchise agreements is an inappropriate merger-approval consideration. Whether or not franchise agreements permit ScottishPower to step into PacifiCorp's position, or whether separate approvals are required under those agreements, are matters of law that are beyond our jurisdiction. This is not the appropriate forum in which to address such matters.

J. Magnesium Corporation of America ("Magcorp") Issues

Magcorp argues that it is excluded from the benefits of the Stipulation and "denied the opportunity to negotiate a future supply arrangement." As a result, it contends decertification is the appropriate remedy. Applicants respond that this in effect is a request for revocation of PacifiCorp's certificate so that a retail access zone could be created for Magcorp. Applicants claim there is no evidence to justify revocation of PacifiCorp's certificate. Applicants further state that Magcorp cites no case or statute which would justify creation of a separate regulatory structure for Magcorp.

We again note Applicants' commitment to commence and promptly complete negotiations regarding supply arrangements. Neither Magcorp's assertions nor its proposed condition are supported on this record. Retail access is currently under review by the Utah legislature. We find that Magcorp's issues are not merger related and are therefore not relevant to this Docket, but we may need to address them in a future docket.

IV. CONCLUSIONS

Based upon the foregoing Discussion and Findings, the Commission makes the following conclusions of law.

1. All hearings held in this case were properly noticed and were conducted in accordance with the Commission's hearing procedures. All persons with a valid interest in the case, who desired to intervene, were allowed to do so. All parties were given adequate opportunity to conduct discovery, present evidence, cross examine evidence introduced by others, and to make argument on relevant issues properly before the Commission.

2. PacifiCorp, doing business in Utah as Utah Power and Light Company, is an electrical corporation as defined in Utah Code Ann. § 54-2-1(6) and a public utility as defined in Utah Code Ann. § 54-2-1(14). The Commission has authority to regulate PacifiCorp in the State of Utah and to supervise all of the public utility business of PacifiCorp in the State of Utah pursuant to Utah Code Ann. § 54-4-1.

3. ScottishPower is a public limited company registered in Scotland, with multi-utility businesses located in the United Kingdom. After consummation of the merger between PacifiCorp and ScottishPower, PacifiCorp will become an indirectly wholly-owned subsidiary of ScottishPower.

4. Based upon its findings of fact, the Commission concludes that the stipulations and the letter agreement executed by PacifiCorp, ScottishPower, and the various signatory parties, should be approved. The Commission concludes that the proposed merger, as modified by the stipulations, the letter agreement, the merger conditions contained therein and the further conditions set forth in this Order, meets the net positive benefit standard and will serve PacifiCorp's customers in the public interest, as required by Utah Code Ann. § 54-4-31. The Commission further concludes that because the proposed merger as modified meets the requirements of Utah Code Ann. 54-4-31, PacifiCorp should be authorized to issue common stock incidental to the proposed transaction.

V. ORDER

NOW, THEREFORE, based upon the foregoing Findings of Fact and Conclusions of Law, IT IS HEREBY ORDERED, that:

1. The Stipulation executed on July 28, 1999, by ScottishPower, PacifiCorp, the Division and the Committee (Joint Exhibit No. 1), as modified herein with respect to Condition 9, is adopted by the Commission and incorporated by reference in this Order.

2. The Stipulation and Settlement of Issues Related to Public Purposes Programs executed on July 26, 1999, by ScottishPower, PacifiCorp, OERP and the LAW Fund (SP Exhibit No. 7) is adopted by the Commission and incorporated by reference in this Order.

3. The Stipulation and Settlement of Issues Relating to Low Income Customers, executed on June 18, 1999, by ScottishPower, PacifiCorp, Crossroads and CAP (SP Exhibit No. 8) is adopted by the Commission and incorporated by reference in this Order.

4. The Stipulation among PacifiCorp, ScottishPower, and DG&T, executed August 2, 1999, is adopted by the Commission and incorporated by reference in the Order.

5. The Letter Agreement among ScottishPower, DCED, and DBED dated August 3, 1999 (SP Exhibit No. 1R.1), as interpreted herein, is adopted by the Commission and incorporated by reference in this Order.

6. The following is adopted as an additional condition to approval of the merger:

> The parties to this Docket preserve their right to raise the issue of the treatment of upstream tax savings and costs in future rate cases. All parties preserve their positions and have not waived their rights on this issue. ScottishPower commits to retain records regarding upstream tax savings and costs relating to the merger and make these records available to the DPU, CCS and other parties in accordance with Stipulation Ex. 1 and the discovery rules of the Commission.

7. The joint application of PacifiCorp and ScottishPower plc for a Commission order authorizing the issuance of PacifiCorp common stock incidental to the proposed transaction, pursuant to Utah Code Ann. § 54-4-31, is granted.

8. The grant of the joint application in Ordering Paragraph 6 above is subject to the merger conditions contained in Attachment 1, and the commitments contained in Attachment 2, appended to the Stipulation executed on July 26, 1999, by ScottishPower, PacifiCorp, the Division, and the Committee (Joint Exhibit No. 1).

9. The merger of an indirect subsidiary of ScottishPower plc with and into PacifiCorp pursuant to the Agreement and Plan of Merger dated December 6, 1998, amended and restated in the Amended and Restated Agreement and Plan of Merger as of February 23, 1999, is hereby approved.

DATED at Salt Lake City, Utah, this 23rd day of November, 1999.

Stephen F. Mecham, Chairman

Constance B. White, Commissioner

Clark D. Jones, Commissioner

Attest:

Julie Orchard
Commission Secretary
ss#18771

APPENDICES

1. July 28, 1999 Stipulation Among ScottishPower, PacifiCorp, the Committee and the Division Supporting Approval of Merger.

2. July 26, 1999 Stipulation and Settlement of Issues Related to Public Purpose Programs among PacifiCorp, ScottishPower, OERP, and the LAW Fund.

3. June 18, 1999 Stipulation and Settlement of Issues Related to Low-Income Customers among PacifiCorp, ScottishPower, Crossroads and CAP.

4. August 2,1999 Stipulation Among PacifiCorp, ScottishPower, and DG&T.

5. August 3, 1999 Letter Agreement with DCED and DBED.

APPENDIX 1

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In The Matter of The Application of PacifiCorp And ScottishPower plc for an Order Approving the Issuance of PacifiCorp Common Stock	DOCKET NO. 98-2035-04 STIPULATION

This Stipulation ("Stipulation") is entered into among PacifiCorp ("PacifiCorp"), ScottishPower plc ("ScottishPower"), the Division of Public Utilities ("DPU") and the Committee of Consumer Services ("CCS"). PacifiCorp and ScottishPower are referred to jointly as the "Applicants". References to ScottishPower shall include New ScottishPower plc, as defined in the Amended and Restated Agreement and Plan of Merger, dated as of December 6, 1998 and amended as of January 29, 1999 and February 9, 1999. PacifiCorp, ScottishPower, DPU, and CCS are referred to individually as a "Party" and collectively as "Parties".

BACKGROUND

A. PacifiCorp is an Oregon corporation and an electric public utility in the state of Utah. PacifiCorp provides retail electric service in the states of California, Idaho, Oregon, Utah, Washington, and Wyoming.

B. ScottishPower is a public limited company in Scotland. ScottishPower provides retail electric service in the United Kingdom and, through its subsidiaries, also provides telecommunications, water, and waste water services.

C. On December 31, 1998, PacifiCorp and ScottishPower filed an Application with the Public Service Commission of Utah ("Commission") requesting an Order approving the issuance of PacifiCorp common stock, pursuant to Utah Code Ann. §54-4-31, in connection with a merger transaction whereby PacifiCorp shall become a wholly owned, indirect subsidiary of ScottishPower.

D. The DPU and the CCS have reviewed the Application, the prefiled testimony of the Applicants, and the responses to extensive discovery requests submitted by parties to this and other proceedings. On June 18, 1999, the DPU filed testimony in this proceeding, recommending that the merger be approved by the Commission, subject to adoption of conditions proposed by the DPU. The CCS filed testimony recommending that the merger be rejected by the Commission unless adequate conditions, including a credible rate plan for Utah retail customers, were imposed.

E. PacifiCorp, ScottishPower, the DPU, and the CCS have met to discuss the proposed transaction and resolve as many of the DPU's proposed conditions and the CCS's issues as possible. This Stipulation constitutes the negotiated resolution of all of the issues between the Applicants, the DPU, and the CCS. ScottishPower agrees that it is willing to accept an Order issued by the Commission with the terms set out in this Stipulation. Based upon the terms and conditions of this Stipulation, DPU and CCS acknowledge that ScottishPower and PacifiCorp have satisfied the standard in Utah for Commission approval of the proposed merger transaction and recommend that the Commission approve the Application, incorporating the conditions of this Stipulation.

TERMS OF STIPULATION

The terms and conditions of this Stipulation are set forth below.

1. ScottishPower and PacifiCorp shall agree to all commitments and conditions as included in Witness Alan Richardson's Supplemental Testimony Exhibit AVR-1 (a copy of which is attached as Attachment 1). In the event of any conflict between Attachment 1 and this Stipulation, the terms of this Stipulation shall govern.

2. On June 18, 1999, ScottishPower and PacifiCorp filed a proposed cost allocation methodology for the allocation of corporate and affiliate investments, expenses, and overheads. In or about October 1999, PacifiCorp and ScottishPower shall schedule a conference/meeting with regulators in all PacifiCorp states (including CCS in Utah) to discuss the proposed and alternative corporate and affiliate cost allocation methodologies. The DPU agrees to use its reasonable best efforts to reach agreement with the other state regulators as to the corporate cost allocation methodology to be recommended to the respective state commissions. In the event the state regulators are unable to reach agreement or the DPU concludes that the methodology supported by any of the other U.S. regulatory states would cause actual or perceived financial harm or inequity (on the basis of projections at that time) to the ratepayers in Utah, the DPU may support or recommend such allocation methodology to the Commission as it determines to be appropriate. ScottishPower assumes the risk of whatever allocation methodologies or decisions the Commission may adopt.

Any proposed methodology to be submitted to the Commission for approval will comply with the following principles:

(a) For services rendered to PacifiCorp or each cost category subject to allocation to PacifiCorp by ScottishPower or any of its affiliates, ScottishPower must be able to demonstrate that such service or cost category is necessary to PacifiCorp for the performance of its regulated operations, is not duplicative of services already being performed within PacifiCorp, and is reasonable and prudent.

(b) Cost allocations to PacifiCorp and its subsidiaries shall be based on generally accepted accounting standards, that is, in general, direct costs shall be charged to specific subsidiaries whenever possible and shared or indirect costs shall be allocated based upon the primary cost-driving factors.

(c) ScottishPower shall have in place time reporting systems adequate to support the allocation of costs of executives and other relevant personnel to PacifiCorp.

(d) An audit trail shall be maintained such that all costs subject to allocation can be specifically identified, particularly with respect to their origin. In addition, the audit trail must be adequately supported. Failure to adequately support any allocated cost may result in denial of its recovery in rates.

(e) Costs which would have been denied recovery in rates had they been incurred by PacifiCorp regulated operations will likewise be denied recovery whether they are allocated directly or indirectly through subsidiaries in the ScottishPower group.

(f) Any corporate cost allocation methodology used for rate setting in Utah, and subsequent changes thereto, must be approved by the Utah Commission.

ScottishPower also assumes the risk of the Commission's approval or adoption of corporate cost allocation methodologies which differ from those adopted by U.K. regulatory agencies.

3. No merger transaction related costs shall be allowed in rates. Enhancements to severance costs relating to the merger will not be allowed in rates. Normal severance costs may be considered for allowance in rates. Future costs arising as a result of the transition plan which result in net cost savings may be considered for allowance in rates. The Applicants agree that they will not in any future rate case in Utah argue for inclusion in rates of any of the items described in Attachment 2.

4. Any diversified holdings and investments (e.g., non-utility business or foreign utilities) of ScottishPower shall not be held by PacifiCorp, the entity for utility operations, or a subsidiary of PacifiCorp. This condition shall not prohibit the continued holding of any existing investments or the holding of diversified businesses and investments by affiliates of PacifiCorp.

5. ScottishPower and PacifiCorp agree to notify the Commission subsequent to ScottishPower's Board approval and as soon as practicable following any public announcement of (1) an acquisition of a regulated or non-regulated business representing 5% or more of the market capitalization of ScottishPower or entering into a new business venture or expansion of an existing one, or (2) a merger, combination, transfer of stock or assets of any material part or all of PacifiCorp or the direct owner of PacifiCorp stock. In addition, PacifiCorp shall comply with the provisions of Utah Code Ann. §§54-4-28 through 54-4-31.

6. ScottishPower shall comply with PacifiCorp's Transfer Pricing Policy, as currently in effect or hereafter amended with the approval of the Commission, in respect of transactions with PacifiCorp.

7. PacifiCorp or ScottishPower shall notify the Commission, and provide sufficient information and documentation to the Commission, prior to the implementation of plans by either PacifiCorp or ScottishPower (1) to form an affiliate entity for the purpose of transacting business with the regulated operations of PacifiCorp, (2) to commence new business transactions between an existing affiliate and with the regulated operations of PacifiCorp, or (3) to dissolve an affiliate which has transacted any substantial business with the regulated operations of PacifiCorp.

8. PacifiCorp shall comply with the provisions of Utah Admin. Code Section R746-401 which sets out the Commission's Rules for reporting the construction, purchase, acquisition, sale, transfer or disposition of utility assets and utility plant.

9. ScottishPower and PacifiCorp shall be required to provide notification of and file for Commission approval of the divestiture, spin-off, or sale of any integral utility function of PacifiCorp. This condition does not limit any jurisdiction the Commission may otherwise have over the divestiture, spin-off or sale of any utility asset.

10. ScottishPower, PacifiCorp and all affiliates shall make their employees, officers, directors, and agents available to testify before the Commission to provide information relevant to matters within the jurisdiction of the Commission.

11. ScottishPower and PacifiCorp shall provide adequate access for the Commission, DPU and CCS or their authorized agents to relevant books, records and officials of all ScottishPower entities. Failure to provide adequate supporting documentation of costs may result in those costs being denied rate recovery. Requests by such entities or their authorized agents shall be deemed presumptively valid, material and relevant, with the burden falling to ScottishPower and PacifiCorp to prove otherwise. ScottishPower and PacifiCorp shall reserve the right to challenge any such request before the Commission and shall have the burden of demonstrating that any such request is not valid, material or relevant. Applicants agree that corporate records shall be available for inspection in Utah or Portland, Oregon. ScottishPower and PacifiCorp shall pay reasonable expenses incurred by the Commission, DPU and CCS in accessing corporate records and personnel located outside of the State of Utah.

12. For a period of five (5) years commencing with the year 2000, PacifiCorp shall include in its year-end semi-annual report a full description, calculation (with supporting work papers) and dollar identification (both total PacifiCorp and Utah's share) of merger savings achieved for the reporting year.

13. No later than six months after the closing date of the merger, ScottishPower and PacifiCorp will file the merger transition plan with the Commission. The plan will include the items described in Mr. MacRitchie's Utah rebuttal testimony.

14. The existing Umbrella Loan Agreement between PacifiCorp and its affiliates (approved by the Commission on November 19, 1997 in Docket No. 88-2035-03), as it may hereafter be amended with approval of the Commission, will continue to govern the terms for

loans between PacifiCorp and its affiliates and ScottishPower shall be deemed to be an affiliate in accordance with the terms of the Umbrella Loan Agreement.

15. For two years following the merger, PacifiCorp shall file a cash flow summary (or other evidence) with its dividend report, showing that service will not be impaired by payment of the dividend, and shall comply with the provisions of Utah Code Ann. §54-4-27. In addition, an officer of PacifiCorp shall be satisfied and shall formally certify to the Commission that PacifiCorp has adequate capital to meet all of its outstanding commitments and carry out its public service obligations in the State of Utah.

16. Any penalty payable by ScottishPower for failure to meet any of the five network performance standards in the State of Utah, as specified at page 9 of the Direct Testimony of Bob Moir, shall be paid as designated by the Commission. Upon the assessment of any such penalties, PacifiCorp and ScottishPower shall consult with the DPU and the CCS to identify an appropriate recipient and shall file its proposal with the Commission. PacifiCorp and ScottishPower agree to be bound by the Commission's decision in this regard.

17. General and Financial reports - To be filed with the Commission:

(a) FERC form 1 - PacifiCorp and Utah state;

(b) Annual and quarterly reports (if any) to shareholders of ScottishPower;

(c) Semi Annual reports showing Utah and PacifiCorp operating results, allocation factors, coal reports, demand side management report, production costs modeling, peak loads by jurisdiction, normalizing adjustments and work papers, all in respect of the regulated operations of PacifiCorp;

(d) Monthly financial and operating reports of the regulated operations of PacifiCorp;

(e) Securities and Exchange Commission Reports 10-Q (quarterly) and 10K (annually) of PacifiCorp;

(f) Annual class cost of service studies for the regulated operations of PacifiCorp;

(g) Monthly Energy Information Administration Form EIA 826 for the regulated operations of PacifiCorp;

(h) Annual affiliated interest report for PacifiCorp and relevant affiliates; and

(i) Five year financial plan and forecast of financial condition (including capital expenditures) for PacifiCorp, provided that such shall not be filed with Commission but shall be available for inspection at the offices of PacifiCorp or its attorneys in Utah on an annual basis.

18. For the purpose of U.S. regulatory reporting, ScottishPower shall follow FASB 52.

19. Unless otherwise approved by the Commission, the Applicants agree to the use of a hypothetical capital structure to determine the correct costs of capital for ratemaking purposes in Utah. The capital structure shall be constructed using a group of A-rated electric utilities comparable to PacifiCorp.

20. Within 90 days after closing of the merger, PacifiCorp and ScottishPower shall provide a detailed report indicating PacifiCorp's proportionate share of the ScottishPower group's total assets, total operating revenues, operating and maintenance expense, and number of employees. Subsequent to this initial report, this information shall be included as part of PacifiCorp's semi-annual filing with the Commission.

21. Except as provided in Condition 22, until approved by the Commission in a separate proceeding, PacifiCorp shall maintain separate long term debt.

22. With the exception of inter-group loans which shall be provided in accordance with Condition 14, PacifiCorp shall apply to the Commission for approval of debt issuances by PacifiCorp or on its behalf, in accordance with Utah Code Ann. §54-4-31 provided that the DPU and CCS agree that PacifiCorp may apply for a waiver of this requirement following 12 months after the closing of the merger.

23. PacifiCorp and ScottishPower agree not to assert in any future Utah proceeding that the provisions of PUHCA or the related Ohio Power v FERC case preempt the Commission's jurisdiction over affiliated interest transactions and will explicitly waive any such defense in those proceedings. In the event that PUHCA is repealed or modified, PacifiCorp and ScottishPower agree not to seek any preemption under any subsequent modification or repeal of PUHCA.

24. PacifiCorp and ScottishPower shall provide the DPU and the CCS with a copy of any SEC filed lobbying reports.

25. If ScottishPower is able to lower the costs of capital, then those savings shall be reflected in rates in accordance with regulatory practices in the State of Utah. If, however, the cost of capital of electric operations of PacifiCorp increases as a direct result of the merger, ScottishPower's shareholders will bear that cost.

26. Rates will be set based upon original and not revalued costs. Any premium paid by ScottishPower for PacifiCorp stock will be disregarded for ratemaking purposes.

27. (a) PacifiCorp will comply with ScottishPower's proposed performance standards and service guarantees and will not allow its underlying outages to increase above current levels for the periods set out in ScottishPower witness Moir's direct testimony.

(b) PacifiCorp will include the proposed performance standards and service guarantees in its tariff.

(c) During 2004, PacifiCorp will review and if necessary revise its performance standards, service guarantees and related requirements. In any event, PacifiCorp will submit for Commission approval its proposals for the continuation of performance standards, service guarantees and related requirements.

28. PacifiCorp will fund network expenditures required to implement the service standards commitments in ScottishPower's direct testimony from efficiency savings and redirected internal funding; and will report funding sources and expenditures against the $55 million estimate.

PacifiCorp will report on expenditures and sources of funds in its year-end semi-annual report.

29. PacifiCorp will operate its current outage reporting system in parallel with Prosper (an automated system expected to verify customer reported outages) until the earlier of Commission approval to terminate the current system or until the establishment of baselines in accordance with Condition 30.

30. (a) PacifiCorp will perform audits at six-month intervals to ascertain the differences between customer reported faults (from the telephone systems) and those recorded in the fault reporting systems to ascertain the differences due to reporting deficiencies. These three audits will terminate 18 months after approval of the transaction. Thereafter, PacifiCorp will perform audits upon request of the DPU or the Commission.

(b) Based on that data, the DPU will, within 18 months after approval of the transaction, file a report with the Commission recommending outage baselines. Disputes, if any, regarding the outage baselines will be resolved by the Commission.

31. Subject to the following reporting and dispute resolution provisions, PacifiCorp may use the IEEE criteria to determine what constitutes an "extreme event" as proposed in the Direct Testimony of ScottishPower witness Moir. The claim by PacifiCorp may involve judgments regarding design limits of or extensive damage to the power system. If so, PacifiCorp will file with the DPU a report specifying the basis for the claim and any disputes regarding the merits of the claim will be resolved by the Commission.

32. PacifiCorp will audit, in response to DPU requests, to determine actual outage levels B after correcting for under or inaccurate recording. The results of that determination will be submitted to the DPU and will be subject to audit by the DPU or its designated expert.

33. PacifiCorp will provide quarterly reports of outages on a district basis. The report will include a comparison of the average district outage levels (for outage durations, outage

frequencies, and short duration outages) with the outage level for the highest and lowest circuits. PacifiCorp recognizes that the DPU has the statutory authority to request additional information. PacifiCorp agrees to provide explanations or corrective action plans regarding unfavorable outage variances in response to DPU requests.

After Prosper is in place, PacifiCorp will include in the quarterly reports the numbers of customers in each district for whom outages have exceeded PacifiCorp's average outage frequency rate.

34. PacifiCorp shall continue with internal meter set and meter test field response standards in Northern Utah. It shall establish reasonable internal targets for field responses where none currently exist and for which targets have not yet been set and report performance against all district targets on a quarterly basis.

35. PacifiCorp shall report call-handling results during wide-scale outages against average answer speeds, hold times, and busy indications.

36. PacifiCorp shall report, each quarter, district data showing credits to customers for failures to meet customer guarantees. PacifiCorp will do so for the period of the commitment to these guarantees, as set out in the direct testimony of Bob Moir.

37. PacifiCorp shall implement and include in its tariff a dispute resolution process for dealing with customer claims resulting from customer guarantee failures on a fair and consistent basis.

Customers will continue to have the right to file informal complaints with the DPU or formal complaints with the Commission.

38. Following the introduction of Prosper, PacifiCorp will provide a quarterly report of the number of customer reported transmission outages where customers report loss of supply. For each customer reported transmission outage, PacifiCorp agrees to report as precisely as is possible the locality (that is, the PacifiCorp district, wholesale electric cooperative, municipality or other wholesale customer location) from which the customer report came.

39. PacifiCorp recognizes that it has a statutory obligation to provide adequate, efficient, just and reasonable service to each retail customer. PacifiCorp also recognizes that the Commission has the authority to supervise and regulate PacifiCorp's service and to enforce its orders, including through the provisions of Section 54-7-25.

40. PacifiCorp will continue to produce Integrated Resource Plans every two years, according to the then current schedule and the then current Commission rules.

41. PacifiCorp shall make a showing in a rate proceeding that any additions of renewable resources to the rate base or the revenue requirement first appearing in that rate proceeding are prudent investments.

42. For the two years following the final approval of the merger, ScottishPower/PacifiCorp shall comply with the provisions of the merger agreement in respect of employee benefit plans.

43. ScottishPower and PacifiCorp agree to provide guaranteed merger related cost-of-service reductions for four years through an annual merger credit. The amount of the credit shall be $12 million per year for years 2000, 2001, 2002 and 2003. The total credit in years 2000-2003 will be $48 million. The merger credit shall be allocated among PacifiCorp's retail tariff customers on the basis of a percentage of the customer bill, exclusive of taxes. At the end of each year, the aggregate amount of credit allocated in that year shall be calculated. These calculations shall be audited by the DPU, who shall report their audit results to the Commission. In the event the merger credit does not equal $12 million in any of the first three years, the excess or shortfall shall be applied to the $12 million due in the following year.

For each of the years 2002 and 2003, ScottishPower and PacifiCorp may reduce or offset the $12 million merger credit to the extent that cost reductions related to the merger are reflected in rates.

The dates set forth in this Condition assume that the merger transaction closes in 1999. If closing is delayed, ScottishPower and PacifiCorp may adjust the dates so that the merger credit begins as soon as practicable but not later than 30 days after the closing date.

In the event that restructuring of the electricity business occurs in Utah prior to the end of the four years for payment of the merger credit, the Commission shall determine at that time how the outstanding merger credit shall be paid.

Any other terms required to implement this merger credit shall be included in the merger credit tariff for approval by the Commission.

44. Rates in Utah shall not increase as a result of the merger.

45. ScottishPower and PacifiCorp agree that they shall assume all risks that may result from less than full system cost recovery if interjurisdictional allocation methods differ among PacifiCorp's various state jurisdictions. The DPU agrees to use its reasonable best efforts to reach agreement with the other state regulators as to the interjurisdiction cost allocation methodology to be recommended to the respective state commissions. In the event the state regulators are unable to reach agreement or the DPU concludes that the methodology supported by any of the other U.S. regulatory states would cause actual or perceived financial harm or inequity (on the basis of projections at that time) to the ratepayers in Utah, the DPU may support or recommend such allocation methodology to the Commission as it determines to be appropriate.

ScottishPower and PacifiCorp assume the risk of whatever allocation methodologies or decisions the Commission may adopt. In addition, ScottishPower and PacifiCorp assume all risks that may result from any difference among PacifiCorp's various state jurisdictions in respect of the conditions imposed by the different state commissions relating to this merger transaction.

46. PacifiCorp shall continue to comply with the procurement policy and competitive bidding requirements approved by the Commission on January 16, 1991 in Docket No. 90-2035-05, as the same may hereafter be amended by the Commission.

47. ScottishPower shall not change its corporate structure to form a holding company or make any other major change in corporate structure without prior notice to the Commission along with an explanation of any expected impacts of the changes on PacifiCorp or Commission regulation.

48. PacifiCorp shall not, without the approval of the Commission, assume any obligation or liability as guarantor, endorser, surety or otherwise for ScottishPower or its affiliates provided that this condition shall not prevent PacifiCorp from assuming any obligation or liability on behalf of a subsidiary of PacifiCorp. ScottishPower shall not pledge any of the assets of the regulated business of PacifiCorp as backing for any securities which ScottishPower or its affiliates (but excluding PacifiCorp and its subsidiaries) may issue.

49. ScottishPower and PacifiCorp agree they shall provide management and financial resources adequate to enable PacifiCorp to meet its commitments, carry out its authorized activities and comply with its public service obligations.

50. In the event that PacifiCorp or ScottishPower does not comply with the above conditions, the Commission may make appropriate ratemaking adjustments to give full effect to these conditions. The Commission may exercise its authority to make, for retail ratemaking purposes, adjustments for misallocation of costs from non-regulated business to PacifiCorp or ScottishPower.

51. PacifiCorp and ScottishPower may request confidential treatment for any information or documents filed with the Commission, the DPU or the CCS or made available to them or their agents, in compliance with these conditions. Any request for confidential treatment will be handled as provided in the Government Records Access and Management Act, Utah Code Ann. §63-2-101 et seq., or pursuant to a Protective Order issued by the Commission.

GENERAL TERMS AND CONDITIONS

52. PacifiCorp, ScottishPower, the DPU and the CCS agree that this Stipulation has been reached through settlement negotiations. As such, evidence or conduct or statements made in the negotiation and discussion phases of this Stipulation shall not be admissible as evidence in any proceeding before the Commission or a court.

53. The Parties have negotiated this Stipulation as an integrated document. If the Commission rejects all or any material part of this Stipulation or imposes additional material conditions in approving the Application, any Party disadvantaged by such action shall have the right, upon written notice to the Commission and all parties to this proceeding within 15 business days of the Commission's Order, to withdraw from this Stipulation. If any Party withdraws from this Stipulation on this basis, no Party shall be bound by the terms of this Stipulation and each Party shall be entitled to seek reconsideration of the Commission Order, file any testimony it chooses, cross-examine witnesses and in general put on such case as it deems appropriate.

54. PacifiCorp, ScottishPower, the DPU and CCS agree that this Stipulation is in the public interest and that all of its terms and conditions are fair, just and reasonable. The DPU and the CCS recommend to the Commission that the Application of ScottishPower and PacifiCorp be approved with respect to the matters set out in this Stipulation.

55. Except as provided in this Stipulation, execution of this Stipulation shall not be deemed to constitute an acknowledgment by any Party of the validity or invalidity of any particular method, theory or principle of regulation, and no Party shall be deemed to have agreed that any principle, method or theory of regulation employed in arriving at this Stipulation is appropriate for resolving any issue in any other proceeding. No findings of fact or conclusions of law other than those stated herein shall be deemed to be implicit in this Stipulation.

56. The obligations of ScottishPower and PacifiCorp under this Stipulation are subject to the Commission's approval of the Application in this docket on terms and conditions acceptable to ScottishPower and PacifiCorp, in their sole discretion, and the closing of the merger transaction between ScottishPower and PacifiCorp.

Dated: July 28, 1999

UTAH DIVISION OF PUBLIC UTILITIES

By: /s/ Michael Ginsberg
Its: Attorney

PACIFICORP

By: /s/ Edward A. Hunter
Its: Attorney

COMMITTEE OF CONSUMER SERVICES

By: /s/ Douglas C. Tingey
Its: Attorney

SCOTTISH POWER PLC

By: /s/ Brian W. Burnett
Its: Attorney

July 28, 1999 Stipulation - Attachment No. 1
Scottish Power, Richardson (Supplemental Testimony)

BENEFITS TO CUSTOMERS FROM THE TRANSACTION

I. CUSTOMER SERVICE

A. Network Performance

1. System Availability. On the five-year anniversary of the completion of the transaction,[1] the underlying System Average Interruption Duration Index (SAIDI) for PacifiCorp customers in the State of Utah will have been reduced by 10%.

2. System Reliability. On the five-year anniversary of the completion of the transaction, the underlying System Average Interruption Frequency Index (SAIFI) for PacifiCorp customers in the State of Utah will have been reduced by 10%.

3. Momentary Interruptions. On the five-year anniversary of the completion of the transaction, the Momentary Average Interruption Frequency Index (MAIFI) for PacifiCorp customers in the State of Utah will have been reduced by 5%.

4. Worst Performing Circuits. The 5 worst performing circuits in the State of Utah will be selected annually on the basis of the Circuit Performance Indicator (CPI),[2] as calculated over a three-year average excluding extreme events. Corrective measures will be taken within 2 years of implementation of the performance targets to reduce the CPI by 20%.

5. Supply Restoration. For power outages because of a fault or damage on PacifiCorp's system, PacifiCorp will restore supplies on average to 80% of customers within 3 hours.

6. Penalties. For each of the standards not achieved in the State of Utah at the end of the five-year period, ScottishPower will pay a financial penalty equal to $1.00 for every customer served by PacifiCorp in Utah.

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[1] Reference to "completion of the transaction" throughout this document means the closing of the transaction pursuant to the Amended Merger Agreement.

[2] The CPI is a weighted, composite index based on the following four factors: (1) MAIFI, (2) SAIDI, (3) SAIFI, and (4) number of lockouts.

7. Implementation. Specific terms and conditions relating to the implementation of the Network Performance Standards are set forth in Appendix A.[3]

B. Customer Service Performance

1. Telephone Service Levels. Within 120 days after completion of the transaction, 80% of calls to PacifiCorp's Business Centers will be answered within 30 seconds. This target will be increased to 80% in 20 seconds by January 1, 2001 and 80% in 10 seconds by January 1, 2002.

2. Complaint Resolution.

a. Non-Disconnect Complaints. Within 90 days after completion of the transaction, PacifiCorp will investigate and provide a response to all complaints referred by the Commission within 3 business days.[4]

b. Disconnect Complaints. Within 90 days after completion of the transaction, complaints related to service disconnection will be responded to within 4 business hours.[5]

c. Commission Complaints. Within 90 days after completion of the transaction, ninety percent of complaints referred to PacifiCorp by the Commission will be resolved within 30 days. This percentage will be increased to 95 percent by 2001.

3. Implementation. Specific terms and conditions relating to the implementation of the Customer Service Performance Standards are set forth in Appendix A.

C. Customer Service Guarantees

1. Restoring the Customer's Supply.

a. Guarantee. If the customer loses electricity supply because of a fault in PacifiCorp's system, PacifiCorp will restore the customer's supply as soon as possible.

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[3] Initial benchmarks for SAIDI, SAIFI and MAIFI will be established based upon PacifiCorp's historical performance, adjusted as necessary where the change in measurement and monitoring accuracy results in a change in the reported (but not actual) reliability indices, as discussed in Mr. Moir's testimony at page 7.

[4] Business days are defined as Monday through Friday excluding company holidays.

[5] Business hours are defined as 8:00 a.m. to 5:00 p.m.

b. Penalty. If power is not restored in 24 hours, customers can claim $50 for residential customers and $100 for commercial and industrial customers For each extra period of 12 hours the customer's supply has not been activated, the customer can claim $25.

2. Appointments.

a. Guarantee. PacifiCorp will keep all mutually agreed appointments with the customer, whether over the phone or in writing. Beginning in the year 2001, PacifiCorp will offer the customer a morning appointment, between 8 AM and 1 PM, or an afternoon appointment, between 12 Noon and 5 PM.

b. Penalty. If PacifiCorp fails to meet its guarantee, PacifiCorp will automatically pay the customer $50.

3. Switching On the Customer's Power.

a. Guarantee. Upon customer request, PacifiCorp will activate the power supply within 24 hours provided no construction is required and all government requirements are met.

b. Penalty. If PacifiCorp fails to meet its guarantee, it will automatically pay the customer $50. In addition, for each extra period of 12 hours the customers power supply has not been activated, PacifiCorp will automatically pay-out $25 to the customer.

4. Estimates for Providing a New Supply.

a. Guarantee. Upon request by a customer for new power supply, PacifiCorp will call the customer back within 2 business days of the customer's initial call and schedule a mutually agreed appointment with an estimator. If PacifiCorp needs to change its network, it will provide a written estimate to the customer within 15 business days of the customer's initial meeting with the estimator. If PacifiCorp does not need to change its network, it will provide an estimate to the customer within 5 business days of the customer's initial meeting with the estimator.

b. Penalty. If PacifiCorp fails to meet its guarantee, PacifiCorp will automatically pay the customer $50 for each failure.

5. Response to Bill Inquiry.

a. Guarantee. PacifiCorp will investigate and respond within 15 business days of a customer's inquiry about its electric bill.

b. Penalty. If PacifiCorp fails to meet its guarantee, PacifiCorp will automatically pay the customer $50 for each failure.

6. Problems with the Customer's Meter.

a. Guarantee. PacifiCorp will investigate and report back to the customer within 15 business days if the customer suspects a problem with its meter.

b. Penalty. If PacifiCorp fails to meet its guarantee, PacifiCorp will automatically pay the customer $50 for each failure.

7. Planned Interruptions.

a. Guarantee. PacifiCorp will give the customer at least 2 days notice if it is necessary to turn the customer's power supply off for planned maintenance work or testing.

b. Penalty. If PacifiCorp fails to meet its guarantee, customers can claim $50 for residential customers and $100 for commercial and industrial customers.

8. Power Quality Complaints.

a. Guarantee. Upon notification from a customer about a problem with the quality of electric supply, PacifiCorp will either initiate an investigation within 7 days or explain the problem in writing within 5 business days.

b. Penalty. If PacifiCorp fails to meet its guarantee, it will automatically pay the customer $50.

9. Implementation. Specific terms and conditions relating to the implementation of the Customer Service Guarantees are set forth in Appendix B. Data calculations to measure performance will be audited by the company and an outside auditor.

10. Reporting.

a. To Customers. PacifiCorp will issue a report to the customer by June 30 of each year regarding its record in improving Performance Standards and how well it has performed against its Customer Guarantees. Each report will contain an overview of standards, targets and guarantees and describe the performance results for that year. The report will also discuss any new targets PacifiCorp will be applying in the coming year.

b. To Commission. PacifiCorp will provide an annual report to the Commission by May 31 of each year that will discuss implementation of ScottishPower's programs and procedures for providing improved performance. The report will provide a general summary of how PacifiCorp performed according to the standards, targets and guarantees. The report will: (i) provide performance results for each standard, target or guarantee; (ii) identify excluded exceptions; (iii) explain any historical and anticipated trends and events that affected or will affect the measure in the future; (iv) describe any technological advancements in data collection that will significantly change any performance indicator; (v) discuss any "phase in" of new standards, targets or guarantees; and (vi) include the name and telephone numbers of contacts at PacifiCorp to whom inquiries should be addressed. If the company is not meeting a standard, target or guarantee, the report will: (i) provide an analysis of relevant patterns and trends; (ii) describe the cause or causes of the unacceptable performance; (iii) describe the corrective measures undertaken by the company; (iv) set a target date for completion of the corrective measures; and (v) provide details of any penalty payments due.

II. REGULATORY OVERSIGHT

A. Access to Books and Records

1. PacifiCorp will maintain its own accounting system, separate from ScottishPower's accounting system. All PacifiCorp financial books and records will be kept in Portland, Oregon, and will continue to be available to the Commission upon request at PacifiCorp's offices in Portland, Salt Lake City, Utah, and elsewhere in accordance with current practice.

B. Cost Allocation, Affiliated Interest Transactions

1. By the end of the third year following the completion of the transaction, ScottishPower will have achieved a net reduction of $10 million annually in PacifiCorp's corporate costs ($15 million of annual cost savings in corporate costs which, when offset by $5 million of cost increases, will produce a net reduction of $10 million annually in corporate costs). ScottishPower will commit to reflecting this reduction in PacifiCorp's results of operations filed with the Commission.

2. ScottishPower will provide an analysis of its proposed allocation of corporate costs within ninety days after completion of the transaction.

3. To determine the reasonableness of allocation factors used by ScottishPower to assign costs to PacifiCorp and amounts subject to allocation or direct charges, the Commission or its agents may audit the records of ScottishPower which are the bases for charges to PacifiCorp. ScottishPower will cooperate fully with such Commission audits.

4. ScottishPower and PacifiCorp will provide the Commission access to all books of account, as well as all documents, data and records of their affiliated interest, which pertain to any transactions between PacifiCorp and its affiliated interests.

5. ScottishPower and PacifiCorp agree to comply with all existing Commission statutes and regulations regarding affiliated interest transactions, including timely filing of applications and reports.

6. ScottishPower will not subsidize its activities by allocating to or directly charging PacifiCorp expenses not authorized by the Commission to be so allocated or directly charged.

7. Neither ScottishPower nor PacifiCorp will assert in any future Commission proceeding that the provisions of the Public Utility Holding Company Act of 1935 preempt the Commission's jurisdiction over affiliated interest transactions.

C. Transaction Costs

1. ScottishPower and PacifiCorp will exclude all costs of the transaction from PacifiCorp's utility accounts.

D. Financial Issues

1. ScottishPower intends to achieve an actual capital structure equivalent to that of comparable, A-rated electric utilities in the U.S., with a common equity ratio for PacifiCorp of not less than 47%.

2. PacifiCorp will maintain separate debt and, if outstanding, preferred stock ratings.

3. ScottishPower and PacifiCorp will provide the Commission with unrestricted access to all written information provided to common stock, bond, or bond rating analysts, which directly or indirectly pertains to PacifiCorp.

III. COMMITMENT TO THE ENVIRONMENT

A. Renewable Resources

1. PacifiCorp will develop an additional 50 MW of renewable resources (wind, solar and/or geothermal) at an anticipated cost of approximately $60 million within five years after completion of the transaction.

2. Within 60 days after completion of the transaction, PacifiCorp will file applications in each state for a "green resource" tariff.

3. PacifiCorp will contribute $100,000 to the Bonneville Environmental Foundation for use in the development of new renewable resources and fish mitigation projects.

B. Environmental Management

1. PacifiCorp will have environmental management systems in place that are self-certified to ISO 14001 standards at all PacifiCorp operated thermal generation by the end of 2000.

2. ScottishPower will include PacifiCorp operations in ScottishPower's comprehensive annual environmental report with appropriate specific goals.

3. ScottishPower will include a PacifiCorp officer on the Environmental Policy Advisory Committee.

4. ScottishPower will develop a process to gather outside input on environmental matters, such as the establishment of an Environmental Forum.

IV. COMMITMENT TO COMMUNITIES

A. Financial Contribution

1. ScottishPower will contribute $5 million to the PacifiCorp Foundation upon completion of the transaction.

2. ScottishPower will maintain the existing level of PacifiCorp's other community-related contributions, both in terms of monetary and in-kind contributions.

B. Programs

1. ScottishPower will develop, in consultation with the appropriate Utah state educational authorities and the local business community, a "School to Work" initiative. Skill development opportunities will be made available through the Open Learning Centers, work experience mentoring, and work shadowing.

2. ScottishPower will maintain the existing Regional Advisory Boards.

C. Low-Income Customers

1. ScottishPower will commit $1.5 million per year (in addition to PacifiCorp's existing commitment of $1.5 million annually) to programs that encourage the economic well-being of communities, including the following:

a. ScottishPower will double the number of customers assisted by the heat assistance funding program for those customers who qualify under the Federal Low Income Energy Assistance Program and will reintroduce the matching concept with PacifiCorp matching customer donations to heat assistance programs annually.

b. ScottishPower will establish a debt counseling service for those customers who have difficulty in paying their monthly electric bills.

c. ScottishPower will expand the commitment to educate customers regarding energy efficiency in order to help customers with payment difficulties, and to promote electricity safety for all customers.

V. COMMITMENT TO EMPLOYEES

A. Existing Labor Agreements

1. ScottishPower will honor existing labor contracts with all levels of staff.

B. New Programs

1. ScottishPower will introduce the following programs in the PacifiCorp service territory, upon completion of the transaction, at a start-up cost of approximately $3 million and estimated annual expenditures of approximately $1 million:

a. ScottishPower will develop one "best-in-class" training center in each of Oregon and Utah. These centers will provide employees with opportunities to improve their work-related skills.

b. ScottishPower will phase in the introduction of the ScottishPower Open Learning centers. At these Open Learning centers, employees will be able to supplement their work-related skills with other skills designed to enhance their overall knowledge.

c. ScottishPower will establish partnerships with local colleges and universities to develop management training programs.

C. Occupational Health

1. ScottishPower will examine the appropriateness of introducing for PacifiCorp employees its successful programs already adopted in the U.K. to encourage a healthy lifestyle for employees.

July 28, 1999 Stipulation - Attachment No. 1
Scottish Power, Richardson (Supplemental Testimony)
EXHIBIT A

Performance Standards

Standard	Clarification
System Availability (SAIDI)	SAIDI will exclude extreme events (storms). This allows measurement of the underlying performance of the asset base.
System Reliability (SAIFI)	SAIFI will exclude extreme events
Momentary Interruptions (MAIFI)	MAIFI will exclude extreme events
Worst Performing Circuits	CPI will exclude extreme events. It will also exclude instances where the company is delayed due to the company's inability to obtain the appropriate planning consents.
Supply Restoration	Restoration time will exclude extreme events. It will also exclude situations where a customer agrees to remain without power or where PacifiCorp is unable to restore supply due to problems with the customer's facility, or where PacifiCorp does not have access.
Telephone Service Levels	Telephone service levels will be defined as percent of calls answer within targeted time frame. Telephone service levels will be measured from the time the customer selects a menu option and is placed in queue until a CSE or interactive voice response (IVR) unit answers the call.
Commission Complaint Resolution	The company may request an extension of time to respond to a complaint, which may be granted by Commission Staff. Business days are defined as Monday through Friday excluding company holidays. Business hours are defined as 8:00 a.m. to 5:00 p.m.

July 28, 1999 Stipulation - Attachment No. 1
Scottish Power, Richardson (Supplemental Testimony)
EXHIBIT B

Customer Guarantees

Standard	Clarification
Restoring Your Supply	Guarantee does not apply if any one of the following occur: 1) Extreme events, 2) Strikes, 3) There are safety-related issues, 4) Customer has agreed to remain without power, or 5) Problems exist with the customer's facility.
Appointments	Guarantee does not apply if any one of the following occur: 1) Extreme events, 2) Strikes, 3) Major system outages, 4) Customer is out when PacifiCorp calls, 5) Customer cancels the appointment, or 6) PacifiCorp cancels the appointment and provides you with at least 24 hours notice.
Switching on the Customer's Power	Guarantee does not apply if any one of the following occur: 1) Extreme events, 2) Strikes, 3) Major system outages, 4) Customer is out when PacifiCorp calls, or 5) There are safety-related issues.
Estimates for Providing a New Supply	Guarantee does not apply if any one of the following occur: 1) Extreme events, 2) Strikes, 3) Major system outages, 4) Customer is out when PacifiCorp calls, 5) Customer cancels the appointment, 6) PacifiCorp cancels the appointment and provides you with at least 24 hours notice, or 7) Customer has not supplied all the necessary information so PacifiCorp can provide the estimate.
Response to Bill Inquiry	Working days are defined as Monday through Friday excluding company holidays.
Problems with Your Meter	Guarantee does not apply if any one of the following occur: 1) Extreme events, 2) Strikes, 3) PacifiCorp personnel do not have access to the customer's meter, 4) Meter tests shall be limited to no more frequently than once every 12 months.
Planned Interruptions	Guarantee does not apply if any one of the following occur: 1) Extreme events, 2) Strikes, 3) Major system outages, or 4) There are safety-related issues.
Power Quality Complaints	Working days are defined as Monday through Friday excluding company holidays.

July 28, 1999 Stipulation - Attachment No. 2
Scottish Power/PacifiCorp (Proposed Treatment of Merger Related Costs)

SCOTTISH POWER/PACIFICORP - PROPOSED TREATMENT OF MERGER RELATED COSTS

Cost Item	$	Above the Line	Below the Line	Ref.	Comment
Goodwill	1,800m (£1124.7m)		X	SP Listing Particulars page 107	Goodwill represents the difference between the purchase price and fair value of the net assets of PacifiCorp. Goodwill is sometimes referred to as the aquisition adjustment for accounting purposes. The calculation of goodwill varies with fluctuations in ScottishPower share price.
Acquisition Costs 1)Share Issues Costs 2)Preferred Stock Redemption 3)Investment, legal, accounting, etc. **Total Acquisition Cost**	 104m (£65m) 26m (£15m) 109m **239m**		 X X X **X**	SP Listing Particulars pages 107 & 145	This is an estimate only. However, all such costs incurred directly in completing the acquisition will be charged below the line.
Preferred Stockholder Merger Approval Payments	2.5m (maximum)		X	PC Proxy Statement page 138	Special payments made to preferred Stockholders of 1% to obtain merger approval.
Payments to Directors	0.4m		X	SP Listing Particulars page 166	$50,000 payment made to non-executive directors.
Change in Control 1)Enhanced Executive Severance 2)PacifiCorp Stock Plans 3)Supplemental Executive Retirement Plan (SERP)	 8.3m (maximum) minimal cost 2.6m		 X X X	SP Listing Particulars page 163-165	Only enhanced payments resulting from the application of change in control conditions are included. To the extent that a net benefit in costs going forward can be demonstrated then such costs will be treated above the line. Final change in control costs can only be determined 24 months after closure. Numbers quoted are upper limit amounts if all eligible employees receive maximum amounts due. They include payments due to two executives who have already retired. There is no material cost associated with PacifiCorp employee stock option provisions.
Retention Incentive Payments	7m (maximum)		X	SP Listing Particulars page 166, WIEC 3.5	Payments to retain key employees during period prior to merger completion.
Bonus Pool - Merger related portion	Not known		X	SP Listing Particulars page 166	To the extent that any such payments are made in connection with "extraordinary efforts" to accomplish the successful completion of the merger only. No quantification of this portion can be determined at this time.

APPENDIX 2

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of PacifiCorp and ScottishPower plc for an Order Approving the Issuance of PacifiCorp Common Stock	))))	Docket No. 98-2035-04 Stipulation and Settlement of Issues Related to Public Purpose Programs

This Stipulation ("Stipulation") is entered into among PacifiCorp, ScottishPower plc, the Office of Energy and Resource Planning and the Land and Water Fund of the Rockies. The Office of Energy and Resource Planning, and the Land and Water Fund of the Rockies are together referred to as the "Intervenors." PacifiCorp, ScottishPower and the Intervenors are together referred to as the "Parties."

The purpose of this Stipulation is to resolve all issues in this Docket relating to the impact of the merger of ScottishPower and PacifiCorp on the environment and public purpose programs. ScottishPower/PacifiCorp have publicly committed to funding certain kinds of programs on a system-wide basis, as set in direct testimonies of Mr. Alan Richardson and Mr. Jack Kelly filed on February 26, 1999. In this Stipulation, ScottishPower/PacifiCorp agree to actions specifically applicable to the Utah jurisdiction in respect of those testimony commitments, as a negotiated resolution of the environmental and public purpose issues between the Parties.

1. **<u>Terms of Stipulation</u>**

The terms and conditions of this Stipulation are set forth below. The Parties agree that with respect to the environment and public purpose programs the commitments in this Stipulation and the proposed merger are in the public interest. The Parties recommend that the Commission approve the Application in this Docket in regard to the environment and other public purpose programs, subject to the terms of this Stipulation. The Parties will also support this Stipulation throughout the proceedings relative to this Docket.

2. **Background**

In this Docket, the Intervenors filed direct testimony commenting on the positive and credible commitments which ScottishPower/PacifiCorp made in their direct testimony with regard to the environment, renewable energy and other public purpose issues. However, Intervenors also commented on the lack of specific testimony relating to energy efficiency programs to which ScottishPower/PacifiCorp would commit upon approval of the merger or how ScottishPower/PacifiCorp's system wide investments in public purpose programs would provide net benefits to Utahns. Since that time, representatives of ScottishPower/PacifiCorp have met with the Intervenors to discuss those concerns. ScottishPower/PacifiCorp has provided clarification on the intent behind its environment and public purpose commitments and a more detailed explanation of ScottishPower/PacifiCorp's desire to work in partnership with appropriate parties to ensure that environmental, renewable energy, energy efficiency and other public purpose issues and opportunities specific to Utah can be addressed.

While ScottishPower/PacifiCorp's objectives are to improve environmental performance and deliver the merger commitments of ScottishPower/PacifiCorp, they intend to do so in such a way that enables them to seek to maximize the impact of their investment and ensure that all investments are prudent, and therefore recoverable through the rate setting mechanism.

3. **ScottishPower Commitments**

With regard to environmental and public purpose issues, ScottishPower agrees to meet the concerns expressed by the Intervenors in the following ways:

a. **Integrated Resource Planning**

The Parties agree that the Utah Public Service Commission ("Commission") approved Integrated Resource Planning process provides a valuable means for ensuring that PacifiCorp's resource plan provides the maximum benefit to PacifiCorp and its customers when evaluating a range of important criteria, such as cost, risk diversification and environmental impacts. As such, ScottishPower/PacifiCorp commits to produce Integrated Resource Plans according to the current schedule and current PSC rules. The Parties acknowledge that, to account for changes in the electric industry over time, the IRP rules may need to be updated and revised. ScottishPower/PacifiCorp commits to work with the Intervenors and other relevant bodies to address this issue at the relevant tme.

b. **Renewable Resources**

ScottishPower/PacifiCorp confirms its commitment to develop an additional 50 MW of renewable resources across its entire system within five years of the approval of the merger, as set out in the direct testimony of Mr. Alan Richardson. ScottishPower/PacifiCorp is interested in developing cost effective renewable energy programs and projects in Utah. ScottishPower/PacifiCorp will use the Integrated Resource Planning process and other mechanisms to evaluate renewable resources and work with the Intervenors and other interested parties, including the Energy Efficiency and Renewable Energy Task Force, in designing, developing, implementing and evaluating specific programs to most effectively deploy renewable energy technology in Utah. Pilot programs may be used to ascertain the effectiveness of program design and implementation. Nothing in this Stipulation, however, would provide ScottishPower/PacifiCorp with a finding of prudency in regard to these renewable resource investments prior to a future rate case. Rather, when PacifiCorp or ScottishPower seek to include these renewable resource costs in rates, they must demonstrate at that time that these costs have been prudently incurred.

In its testimony, ScottishPower/PacifiCorp also committed to filing a green resource tariff within 60 days of the approval of the merger. To ensure that the green pricing tariff filed in Utah addresses issues and opportunities specific to Utah, ScottishPower/PacifiCorp commits to incorporating, where appropriate, the recommendations of the Energy Efficiency and Renewable Energy Task Force in the design of the tariff. The Parties recognize that any green pricing tariff implemented in Utah is subject to Commission approval.

c. **Conservation and Energy Efficiency Programs**

At the meeting of the parties, ScottishPower/PacifiCorp explained that the lack of specific testimony relating to Utah-specific energy efficiency programs was due to uncertainty regarding the outcome of the investigation currently being undertaken by the Commission's Energy Efficiency and Renewable Energy Task Force. ScottishPower/PacifiCorp commits to continue to support funding for cost effective and prudent energy efficiency in Utah and will continue to use the Integrated Resource Planning process and other mechanisms to establish Utah energy efficiency targets. In determining the appropriate cost effective programs and investments, aspects such as market transformation, removing barriers to self-sustaining energy efficiency markets, technical potential, achievable potential, program design, leverage of additional funds, administration costs, timing of implementation, portfolio and risk diversification value, and environmental benefits will be considered. The prudency of investment will be determined according to Utah Commission guidelines.

The Parties believe that conservation and energy efficiency programs are more than merely an alternative to increasing generation plant. If properly constituted there programs can deliver real benefits to customers by:

- reducing the energy used;
- increasing comfort;
- lowering the total cost of energy;
- reducing risk by diversifying the electric resource mix; and
- reducing environmental impacts.

ScottishPower/PacifiCorp commits to work with the Energy Efficiency and Renewable energy Task Force, and assist in establishing a technical database and in designing, developing, implementing and evaluating specific Utah programs that can most effectively deliver the benefits of energy efficiency programs to Utah customers. Pilots may be used to ascertain the effectiveness of program design and implementation.

The overall objective will be to maximize the benefits from cost effective and prudent investment in conservation and energy efficiency programs in Utah.

The tariffs associated with these conservation and energy efficiency programs will be subject to Commission approval prior to implementation.

d. **Environmental Forum**

As described in its testimony and discovery responses, ScottishPower has committed to establishing an Environmental Forum, similar to the Forum it uses in the UK In the UK, the Forum is a consultative body incorporating representatives of academic, industry, and advocacy organizations in the field of environmental issues, together with senior ScottishPower management. It provides ScottishPower with external expertise and perspective on strategic issues related to the environment.

e. **Other Issues**

The Parties recognize that there are environmental, energy efficiency, and renewable energy issues not covered in ScottishPower/PacifiCorp's direct testimony (e.g. impacts of distributed generation, issues related to the state sponsored energy programs for National Parks and public lands management agencies, public buildings, and regional haze).

With respect to distributed generation and state sponsored energy programs, ScottishPower/PacifiCorp commit to work with the Energy Efficiency and Renewable Energy Task Force and/or other appropriate working groups to develop a framework to address these issues as they relate to Utah. This approach will ensure that a balance is struck between addressing the issues on a regional basis and being able to tackle issues which specifically relate to PacifiCorp's Utah customers.

With respect to regional haze, the Parties recognize that ScottishPower/PacifiCorp intends to support PacifiCorp's continued involvement in the Western Regional Air Partnership's work to develop a regional haze strategy for the Western states, including Utah. The Parties point out that ScottishPower's merger related commitments to renewable energy and energy efficiency could be a component of Utah's state implementation planning requirements for regional haze as outlined in Section 51.309(d)(8) of EPA's final regional haze rule.

4. **General Terms and Conditions**

a. The Parties agree that this Stipulation represents a compromise in the positions of the Parties. As such, evidence or conduct or statements made in the negotiation and discussion phases of this Stipulation shall not be admissible as evidence in any proceeding before the Commission or a court. All negotiations relating to this Stipulation are privileged and confidential.

b. The Parties have negotiated this Stipulation as an integrated document. Accordingly, the Parties recommend that the Commission adopt the Stipulation in its entirety.

c. The Parties shall cooperate in submitting this Stipulation promptly to the Commission for acceptance, and shall support adoption of the Stipulation in the proceedings, relative to this Docket. Each Party shall make available a witness in support of the Stipulation at which time other parties to the proceeding would have an opportunity to cross-examine such witness. In the event the Commission rejects all or any material portion of this Stipulation or imposes additional material conditions in approving the Application, each Party reserves the right, upon written notice to the Commission and all parties to the proceeding within 15 days of the date of the Commission's Order, to withdraw from this Stipulation. In such case, no Party to this Stipulation shall be bound or prejudiced by the terms of this Stipulation and each Party shall be entitled to seek reconsideration of the Commission Order, file any testimony it chooses, to cross-examine witnesses and in general to put on such case as it deems appropriate.

d. The Parties agree that this Stipulation is in the public interest and that all of its terms and conditions are fair, just and reasonable.

e. No Party shall be bound by any position asserted in the negotiations, except to the extent expressly stated in this Stipulation. Execution of this Stipulation shall not be deemed to constitute an acknowledgment by any Party of the validity or invalidity of any particular method, theory or principle of regulation, and no party shall be deemed to have agreed that any method, theory or principle of regulation employed in arriving at this Stipulation is appropriate for resolving any issues in any other proceeding. No findings of fact or conclusions of law other than those stated herein shall be deemed to be implicit in this Stipulation.

f. The obligations of ScottishPower/PacifiCorp under this Stipulation are subject to the Commission's approval of the Application in this Docket on terms and conditions acceptable to ScottishPower and PacifiCorp, in their sole discretion, and the closing of the merger transaction between ScottishPower and PacifiCorp.

Dated: July 26, 1999

PacifiCorp

By: /s/ Edward A. Hunter
Its: Attorney

ScottishPower plc

By: /s/ Michael Marron
Its: Customer Relations Director

The Office of Energy and Resource Planning, Utah Department of Natural Resources

By: /s/ Jeffrey S. Burks
Its: Director

The Land and Water Fund of the Rockies

By: /s/ Eric Blank
Its: Energy Project Director

APPENDIX 3

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of PacifiCorp and Scottish Power plc for an Order Approving the Issuance of PacifiCorp Common Stock	))))	Docket No. 98-2035-04 Stipulation and Settlement of Issues Related to Low-Income Customers

This Stipulation ("Stipulation") is entered into among PacifiCorp, Scottish Power plc, Crossroads Urban Center ("Crossroads"), and Salt Lake Community Action Program ("CAP") (together, the "Parties").

The purpose of this Stipulation is to resolve all issues in this Docket relating to the impact of the merger of PacifiCorp and ScottishPower plc on low-income customers. PacifiCorp and ScottishPower have publicly committed to funding certain kinds of programs on a system-wide basis, as set out in direct testimony of Mr. Jack Kelly filed on February 26, 1999. In this Stipulation, ScottishPower and PacifiCorp agree to actions specifically applicable to the Utah jurisdiction in respect of those testimony commitments, as a negotiated resolution of issues between the parties.

1. <u>Terms of Stipulation</u>

The terms and conditions of this Stipulation are set forth below. Upon acceptance of these terms and conditions by PacifiCorp/ScottishPower, CAP and Crossroads will, as soon as possible within the procedural limits of this Docket, recommend that the Commission approve the Application in this docket, in so far as low income issues are concerned and shall not adversely comment on any other issue in this Docket. CAP and Crossroads will include this recommendation in its prefiled direct testimony and will support its recommendation in this Docket.

2. Background

In Utah PSC Docket No. 97-035-01, CAP and Crossroads proposed implementation of a lifeline rate for certain low-income customers and asked that the Utah Public Service Commission institute a Docket to address other issues related to low-income customers of PacifiCorp. In its Order, the Commission established a Low-Income Task Force to address a number of issues related to problems of low-income customers. The Commission also concluded that it had the authority to adopt a lifeline rate and identified four criteria that a lifeline rate would have to meet to satisfy the Commission that it was in the public interest. In addressing each of the four criteria, the Commission observed that there was no evidence that the proposed lifeline rate was not in the public interest and concluded that "a lifeline rate may be in the public interest." However, it had several unanswered questions that were referred to the Low-Income Task Force to provide recommendations to the Commission.

3. Lifeline Rate

As a participant on the Utah Low-Income Task Force, PacifiCorp will support the implementation of a lifeline rate in the Utah jurisdiction, either the rate proposed by Crossroads and CAP in Utah PSC Docket No. 97-035-01, or some appropriate rate agreed by the parties, to be funded by ratepayers. PacifiCorp will also support extension of the lifeline rate in Utah to provide an additional discount to disabled and other vulnerable customers, both in the Utah Low-

Income Task Force and any future Utah PSC docket in which such an extension is introduced. ScottishPower shall support PacifiCorp in these regards.

4. Low-Income Task Force

PacifiCorp will be an active participant in the Utah Low-Income Task Force to seek means of initiating appropriate programs that will make electric utility service more affordable for low-income customers in Utah. ScottishPower shall support PacifiCorp in this regard.

5. Low Income Programs

PacifiCorp/ScottishPower are committed to working with the appropriate partners to identify innovative, cost-effective programs that provide sustained benefit to low income customers through decreasing energy usage and improving their ability to pay current and past electric bills.

To this end, PacifiCorp, supported by ScottishPower, will work with the Task Force to identify programs that incorporate a range of measures including:

Energy Efficiency Advice

Budget management & Debt Counseling plus

Implementation of energy efficiency measures

The objective of PacifiCorp/ScottishPower, is to deliver real benefit (i.e. reducing the energy used; increasing comfort; lowering the total cost of energy and/or reducing debt burden) to Low Income and other vulnerable customers by accomplishing the following to the extent practicable:

Helping to stimulate the provision of cost-effective programs.

Identifying the objectives of each program and how achievement of objectives can be measured

Identifying the customer groups who will benefit from each individual program.

Identifying possible sources of funding which can provide additional leverage.

Identifying the most effective method of funding, managing and delivering each program.

Establishing pilot projects to prove the effectiveness of appropriate programs.

Identifying the data required to confirm the effectiveness of pilot programs and whether they should be rolled out.

Provided the appropriate programs can be identified, developed and financially structured to ensure they are cost-effective and meet all regulatory and business requirements, PacifiCorp/ScottishPower will make additional funds available. This commitment of additional funding will be shareholder's funds to the value of $300,000 per annum in Utah for three years after approval of the merger, over and above what was spent on similar programs in the State of Utah in 1998. After this 3 year period this funding shall be subject to review by the parties. All parties will use their reasonable endeavors to work together and identify appropriate programs for this funding as set out in this paragraph.

6. General Terms and Conditions

a. The Parties agree that this Stipulation represents a compromise in the positions of the Parties. As such, evidence or conduct or statements made in the negotiation and discussion phases of this Stipulation shall not be admissible as evidence in any proceeding before the Commission or a court. All negotiations relating to this Stipulation are privileged and confidential.

b. The Parties have negotiated this Stipulation as an integrated document. Accordingly, the parties recommend that the Commission adopt the Stipulation in its entirety.

c. The Parties shall cooperate in submitting this Stipulation promptly to the Commission for acceptance, and shall support adoption of the Stipulation in prefiled testimony submitted in this proceeding. If a hearing is scheduled for presentation of the Stipulation, each Party shall make available a witness in support of the Stipulation. At which time other parties to the proceeding would have an opportunity to cross-examine such witness. In the event the Commission rejects all or any material portion of this Stipulation or imposes additional material conditions in approving the Application, each Party reserves the right, upon written notice to the Commission and all parties to the proceeding within 15 days of the date of the Commission's Order, to withdraw from this Stipulation. In such case, no Party to this Stipulation shall be bound or prejudiced by the terms of this Stipulation and each Party shall be entitled to seek reconsideration of the Commission Order, file any testimony it chooses, to cross-examine witnesses and in general to put on such case as it deems appropriate.

d. The Parties agree that this Stipulation is in the public interest and that all of its terms and conditions are fair, just and reasonable.

e. No Party shall be bound by any position asserted in the negotiations, except to the extent expressly stated in this Stipulation. Execution of this Stipulation shall not be deemed to constitute an acknowledgment by any Party of the validity or invalidity of any particular method, theory or principle of regulation, and no Party shall be deemed to have agreed that any method, theory or principle of regulation employed in arriving at this Stipulation is appropriate for resolving any issue in any other proceeding. No findings of fact or conclusions of law other than those stated herein shall be deemed to be implicit in this Stipulation.

Dated: June 18, 1999

Community Action Program

By: Catherine Hoskins
Its: Executive Director

Crossroads Urban Center

By: Glenn L. Bailey
Its: Executive Director

PacifiCorp

By: Timothy E. Meier
Its: V.P., CIO

Scottish Power plc

By: Robert Moir
Its: General Manager, Metering Business

APPENDIX 4

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of PacifiCorp and Scottish Power plc for an Order Approving the Issuance of PacifiCorp Common Stock.	))))	**DOCKET NO. 98-2035-04** **STIPULATION**

This Stipulation ("Stipulation") is entered into between PacifiCorp ("PacifiCorp"), Scottish Power plc ("ScottishPower") and Deseret Generation and Transmission Cooperative, Inc. ("Deseret"). PacifiCorp, ScottishPower and Deseret are referred to collectively as the "Parties". PacifiCorp and ScottishPower are referred to jointly as "Applicants".

BACKGROUND

A. PacifiCorp is an Oregon corporation and an electric public utility in the state of Utah. PacifiCorp provides retail electric service in the states of California, Idaho, Oregon, Utah, Washington and Wyoming.

B. Scottish Power is a public limited company in Scotland. Scottish Power provides retail electric service in the United Kingdom and, through it subsidiaries, also provides telecommunications and water and wastewater services.

C. Deseret is a wholesale electric generation and transmission cooperative that provides electric generation, transmission and related services to its rural electric cooperative members in the states of Arizona, Colorado, Nevada, Utah and Wyoming.

D. On June 17, 1999, Deseret filed testimony in this proceeding raising reliability and contract issues and recommending that the Commission reject the proposed merger unless adequate conditions were agreed to by the Applicants.

E. This Stipulation constitutes the negotiated settlement of all the issues raised by Deseret in this docket. Based on the terms of this Stipulation, Deseret recommends that the Commission approve the Application.

TERMS OF STIPULATION

The terms and conditions of this Stipulation are set forth below.

1. Applicants and Deseret agree that they will address the issues raised by Deseret regarding service reliability at the Middleton delivery point or other service reliability issues in Commission Docket No. 99-2035-01 and not in this docket.

2. Applicants agree that, within 30 days after the closing date of the merger, they will meet with representatives of Deseret to discuss and try to resolve service reliability problems at the Middleton delivery point. To the extent the Middleton reliability issues can be resolved or improved through commercially feasible engineering or technical improvements to PacifiCorp's system, PacifiCorp will, upon mutually satisfactory agreement with Deseret regarding payments for the improvements, use its commercially reasonable efforts to pursue those solutions without undue delay.

3. Applicants and Deseret agree that they will evaluate and discuss in good faith with each other all reasonable proposals that provide benefits to the companies and their respective customers.

4. ScottishPower and PacifiCorp agree that the items described in Attachment 1 will not be included in the calculation of the administrative and general expense for Deseret under the provisions of Section 5.3(l) and Exhibit E of the Hunter II Ownership and Management Agreement ("Agreement") between Deseret and Utah Power & Light Company.

GENERAL TERMS AND CONDITIONS

1. The Parties agree that this Stipulation has been reached through settlement negotiations. As such, evidence or conduct or statements made in the negotiation and discussion phases of this Stipulation shall not be admissible in any proceedings before the Commission or any other regulatory agency or court.

2. This Stipulation will be submitted to the Commission for filing and not for approval.

3. Execution of this Stipulation shall not be deemed to constitute an acknowledgment by any party of the validity or invalidity of any particular method, theory or principle of regulation, and no party shall be deemed to have agreed that any principle, method or theory of regulation employed in arriving at this Stipulation is appropriate for resolving any issue in any other proceeding. No findings of fact or conclusions of law other than those stated herein shall be deemed to be implicit in this Stipulation.

4. While this Stipulation constitutes the negotiated resolution of all issues raised by Deseret in this Docket, this Stipulation is not intended to resolve all issues that exist or which may arise in the future between those parties concerning the Agreement, reliability issues, or otherwise. Each party reserves without limitation or waiver any or all other rights, remedies and

defenses otherwise available to each such party at law, pursuant to contract, or in equity except as expressly provided pursuant to this Stipulation.

5. The obligations of the Parties under this Stipulation are subject to the Commission's approval of the Application in this docket on terms and conditions acceptable to ScottishPower and PacifiCorp, in their sole discretion, and the closing of the merger between ScottishPower and PacifiCorp.

Dated: August 2,1999

DESERET GENERATION & TRANSMISSION COOPERATIVE

By: /s/ David F. Crabtree

PACIFICORP

By: /s/ Edward A. Hunter

SCOTTISH POWER PLC

By: /s/ Brian W. Burnett

August 2, 1999 Stipulation - Attachment No. 1
Scottish Power/PacifiCorp (Proposed Treatment of Merger Related Costs)

SCOTTISH POWER/PACIFICORP - PROPOSED TREATMENT OF MERGER RELATED COSTS

Cost Item	$	Above the Line	Below the Line	Ref.	Comment
Goodwill	1,800m (£1124.7m)		X	SP Listing Particulars page 107	Goodwill represents the difference between the purchase price and fair value of the net assets of PacifiCorp. Goodwill is sometimes referred to as the aquisition adjustment for accounting purposes. The calculation of goodwill varies with fluctuations in ScottishPower share price.
Acquisition Costs 1)Share Issues Costs 2)Preferred Stock Redemption 3)Investment, legal, accounting, etc. **Total Acquisition Cost**	104m (£65m) 26m (£15m) 109m **239m**		X X X **X**	SP Listing Particulars pages 107 & 145	This is an estimate only. However, all such costs incurred directly in completing the acquisition will be charged below the line.
Preferred Stockholder Merger Approval Payments	2.5m (maximum)		X	PC Proxy Statement page 138	Special payments made to preferred Stockholders of 1% to obtain merger approval.
Payments to Directors	0.4m		X	SP Listing Particulars page 166	$50,000 payment made to non-executive directors.
Change in Control 1)Enhanced Executive Severance 2)PacifiCorp Stock Plans 3)Supplemental Executive Retirement Plan (SERP)	8.3m (maximum) minimal cost 2.6m		X X X	SP Listing Particulars page 163-165	Only enhanced payments resulting from the application of change in control conditions are included. To the extent that a net benefit in costs going forward can be demonstrated then such costs will be treated above the line. Final change in control costs can only be determined 24 months after closure. Numbers quoted are upper limit amounts if all eligible employees receive maximum amounts due. They include payments due to two executives who have already retired. There is no material cost associated with PacifiCorp employee stock option provisions.
Retention Incentive Payments	7m (maximum)		X	SP Listing Particulars page 166, WIEC 3.5	Payments to retain key employees during period prior to merger completion.
Bonus Pool - Merger related portion	Not known		X	SP Listing Particulars page 166	To the extent that any such payments are made in connection with "extraordinary efforts" to accomplish the successful completion of the merger only. No quantification of this portion can be determined at this time.

APPENDIX 5

(logo)

Scottish Power Inc

Alan Richardson
Chief Executive Officer

August 3, 1999

Mr. David Winder
Executive Director
Dept. of Community and
Economic Development
State of Utah
324 S. State Street, Suite 500
Salt Lake City, UT 84111

Mr. Rick Mayfield
Director
Division of Business and
Economic Development
State of Utah
324 S. State Street, Suite 500
Salt Lake City, UT 84111

Dear Mr. Winder and Mr. Mayfield

I am writing to you following several discussions we have had since Mr. Winder's testimony was filed on 18 June. I have always found these discussions useful and constructive and believe it would be helpful if I set down ScottishPower's intended approach on several matters following approval of the proposed merger with PacifiCorp.

Utah Presence

1. I believe you well understand ScottishPower's commitment to all its customers and communities. We have always intended to provide strong leadership in Utah, particularly given the very significant customer base and broad range of assets in the State. In recognition of this, ScottishPower will relocate a senior executive from the Group to take up residence in Utah. The executive will report directly to the CEO of PacifiCorp. As a member of the executive team, this person will have broad influence over PacifiCorp's operations in Utah including, but not limited to, authority to approve corporate involvement in economic development and corporate citizenship activities. The executive will be able to assure the best decisions in the interests of Utah.

2. This executive will provide a strong ScottishPower presence in Utah, setting a high standard and representing Utah Power and Light in all communities across the state. For the medium-to-long term, the executive will need to groom a successor so that there is a good guarantee of successful representation well into the future.

3. The corporate offices of PacifiCorp will not be moved outside the states of PacifiCorp's service area and the Utah Power & Light Division headquarters will be located in Utah. ScottishPower will strengthen the Utah presence of PacifiCorp and in this regard, will

work towards having a fair proportionality compared to other PacifiCorp service areas, insofar as is commercially reasonable. We confirm that we view Utah as a location from which to base new opportunities for the future.

4. ScottishPower plc will endeavor to maintain on its Board of Directors a non-executive director from the Utah Power service area.

Economic Development

5. ScottishPower's instincts and track record are to support economic development in some depth. I understand very well from my discussions with you, Mr. Winder, your Board, and others that this is a major consideration. At this time, I am not able to be specific on just how we will deliver support in this important area. However, I am very clear in my mind that this will be a significant task for the senior executive mentioned above, and that economic development staff in Utah will report directly to that executive. We will make a strong commitment to economic and community development the details of which will be completed by a transition team after the completion of the merger. We will work closely with your Department to ensure success in this area.

6. I would intend that there will be increased support of Utah businesses and that, where commercially reasonable, and to the extent permitted under the procurement policy of PacifiCorp which has been approved by the Commission, those businesses will be considered favorably to supply goods and services to PacifiCorp.

PacifiCorp Foundation

7. I well understand your comments that the allocation of grants from the Foundation should be equitable. At present, ScottishPower is twice removed from the Foundation, because it is independent of PacifiCorp, who are themselves still not yet part of ScottishPower. Following completion of the merger, I intend to work with the Foundation to agree on rules that assure equitable treatment across the service territories of PacifiCorp and provide for open reporting of the allocation of funds from the Foundation. I do have a concern that the Foundation Board is not constrained in its ability to make good decisions by a slavish adherence to strict allocation rules but it should target an equitable allocation over the period of a few years.

General

8. ScottishPower and PacifiCorp will work with the aim of ensuring that resources and attentions given to Utah in the following areas shall be just and proportional when compared to any other area or jurisdiction in which PacifiCorp operates:

- Foundation gifts
- Training
- Representation on boards and committees
- Economic development

I understand that this letter adequately addresses the concerns raised by DCED and the DBED Board in their direct testimony filed with the Public Service Commission and that based on the foregoing commitments and the Stipulation with the Division of Public Utilities and the Committee of Consumer Services, DCED and the DBED Board will recommend approval of the proposed merger transaction as it relates to issues raised by DCED and the DBED Board. We do, however acknowledge that you have raised the issue of special contracts and that your concerns are not yet resolved on that issue, and that this letter does not prevent any party from expressing its views on this and any other issue raised by another party.

I assure you that ScottishPower's intentions for Utah are of the highest order. We want to set a standard of which we can all be proud. I hope this letter allows you to better understand our commitment and to be able to support and encourage us to achieve those high standards in practice.

Yours sincerely,

/s/ Alan Richardson

AR:lrs

We acknowledge receipt of this letter and agree with its content and terms.

/s/ Rick Mayfield	/s/ David B. Winder
For and on behalf of	For and on behalf of
Division of Business and	Department of Community and
Economic Development, Utah	Economic Development, Utah

I hereby certify that on Thursday, December 2, 1999, I served a true copy of the hereto attached REPORT AND ORDER on the persons whose names are set forth below by mailing such copy on said date in a post office in Salt Lake City, Utah, properly enclosed in a sealed envelope with postage prepaid thereon, legibly addressed to the addresses shown:

* See attached Mailing Lists and "E" Mailing Lists

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THOMAS M. ZARR, P.C.
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P.O. BOX 17635
SALT LAKE CITY UT 84117-0635

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LAND AND WATER FUND OF THE ROCKIES
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BOULDER CO 80302

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UTAH ASSOCIATION OF COUNTIES
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Letter to the Editor
Scottish Vs Pacific Corp: A Bad Idea

If it is too good to be true, It probably is. This is an overused adage but, is it possible that the reverse is true. If it sounds like a bad idea, it probably is. A foreign country taking control of the electrical power in Utah. To the reader, take one minute, stand in the center of your home and review all of the services provided by your electric system. Then trace the lines back to a foreign country and read your feelings. Now remember back, if possible, to the electric service you received when UP&L was your electric provider. This change has come about merely by transferring ownership out of the state. Think about the instability of European countries in general. Is it possible that Iraq could have it's eyes on it's neighbors? - Iran - or any of the dictatorial led nations and you will say immediately, no way! Then be reminded that is exactly what the British said after the fall of Poland. Whoever is in control of our electrical supply has the strongest of holds on our lives. Think of all the critical defense installations in these Western States that are connected by Pacific Corps transmission lines and then put them subservient to an adversarial country. When a country, any country, is in the hands of men and women of integrity and good standing, no problem. We know what has happened to our country when the reverse is true.

Remember Pearl Harbor? The single biggest tactical error was made by the Japanese when they left the electrical facilities intact. Thus being, we were able to regroup far faster than though possible because the maintenance factories and etc., were up and running again over night. Now suppose that sometime previously, the Japanese had acquired ownership of said electric facilities? The whole complexity would have been entirely different and I'm sure, disastrous.

So again, our electric systems in the hands of a Foreign Country, "If it sounds like a bad idea, it is!" If it sounds like a bad idea to you, call the Public Service Commission and so express your feelings.

Jay F. Gardner,
Retired Regional Manager Utah Power & Light Co.

submitted from
(Jay F. Gardner 385 East Center Richfield, UT. 1-435-896-6093)
-----Original Message-----
From: Marjorie Cortez <marjorie@desnews.com>
To: Martin R. Mangum <eolaman@infowest.com>
Date: Monday, October 04, 1999 7:57 AM
Subject: Re: scottish power vs pacific corp

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>Thank you.
>Marjorie Cortez
>Deseret News Editorial Board
>
>At 11:27 PM 10/3/99 -0600, you wrote:
>> My name is; Jay F. Gardner 385 East Center Richfield, UT
>>84701 (435) 896-6093 Thankyou, Jay Gardner Attachment Converted:
>>"c:\eudora\attach\dadup
>
>

18150

MICHAEL L. GINSBERG (#4516)
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Salt Lake City, Utah 84114-0857
Telephone: (801) 366-0335

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF PACIFICORP AND SCOTTISH POWER PLC FOR AN ORDER APPROVING THE ISSUANCE OF PACIFICORP COMMON STOCK	DOCKET NO. 98-2035-04

JOINT REPLY MEMORANDUM OF THE DIVISION OF PUBLIC UTILITIES AND THE COMMITTEE OF CONSUMER SERVICES

The following constitutes a reply memorandum of the Division of Public Utilities (DPU) and the Committee of Consumer Services (CCS) to the initial briefs of the parties filed in this proceeding.

I.

INTRODUCTION

After reading the reply briefs of the various parties in this proceeding, the DPU and CCS continue to believe that their stipulation provides net positive benefits to Utah's ratepayers and is in the public interest. Therefore, the DPU and CCS continue to recommend the Commission approve the merger. With very few exceptions, the issues raised by the parties in their initial briefs were addressed adequately by the DPU and CCS in its initial brief. This memorandum, therefore, will address certain issues not addressed initially or issues we believe need further clarification.

II.

THE REQUEST OF MAGNESIUM CORPORATION OF AMERICA TO BE DECERTIFIED SHOULD NOT BE CONSIDERED IN THIS PROCEEDING

MagCorp has requested that the Commission as a condition to the merger decertify it from PacifiCorp's "exclusive retail service territory effective upon the termination of its existing contract with PacifiCorp."[1] MagCorp gives various reasons why decertification should take place including the failure of PacifiCorp to extend the existing contract beyond its current

[1] Initial brief of MagCorp p. 3.

termination date. The DPU and CCS oppose the Commission in this proceeding decertifying a customer from the exclusive service territory of PacifiCorp. The issue of whether a customer should have direct access to other suppliers of electricity is not an issue that should be decided in this merger proceeding. MagCorp, by its request to decertify PacifiCorp, is in essence answering the direct access question. An action to decertify a utility from its exclusive service territory should be in a proceeding where all applicable issues can be fully heard. As a merger case, the proposal to condition such a transaction with an order of decertification appears to go well beyond relevant issues that flow directly from the merger. As a basis of MagCorp's request they state that PacifiCorp has failed to negotiate a new contract. During the proceeding, PacifiCorp indicated they understood the need for customers to consider alternatives and committed to negotiate new contracts promptly in good faith. Therefore MagCorp's claim that PacifiCorp has not negotiated a new contract with it appears premature. Nor is there a right of MagCorp to have a new contract. If one can be negotiated that meets the Commission-established criteria, then PacifiCorp has committed it will do so. If a qualifying contract cannot be negotiated, MagCorp certainly has the option of taking tariffed service or seeking other remedies.

III.

EMERY COUNTY'S REQUEST FOR A SPECIFIC FINDING BY THE COMMISSION ON PROPERTY TAXES SHOULD BE REJECTED

Emery County has requested that the Commission issue a specific finding that the Utah Tax Commission has exclusive jurisdiction over "all questions of property valuation which are a significant component of property tax paid by PacifiCorp."[2] In addition, Emery County requests that the Commission adopt a finding that all valuation matters be deferred to the Utah State Tax Commission because it is impossible to accurately isolate and predict specific impacts of the merger on property valuation and taxes of PacifiCorp. They conclude that "any attempt by the Public Service Commission to contain or influence valuation by the Utah State Tax Commission may produce unanticipated results and certainly would transgress the jurisdiction of the Tax Commission to make the assessments required by Utah law."[3] The DPU and CCS oppose such conditions. Clearly, the Utah State Tax Commission has jurisdiction over PacifiCorp's property tax. The Utah Public Service Commission has jurisdiction over the rates charged by PacifiCorp to its customers. During a rate case property taxes paid by PacifiCorp are reviewed by the DPU and CCS. Property taxes became an issue in this proceeding because of the possibility of higher property tax caused by the premium paid by Scottish Power for PacifiCorp's stock. No specific condition was included in the stipulation dealing directly with property taxes. However, the stipulation does provide conditions dealing with the premium paid by Scottish Power. In addition, conditions exist which state that rates will not be higher than they would absent the merger. Obviously, it might be difficult to determine the cause of increased property taxes for PacifiCorp. This proceeding, however, should not eliminate issues relating to future property tax increases from future rate cases. A condition that would automatically force the Commission to

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[2]Emery County's initial brief, p. 2.

[3]Initial brief of Emery County, p. 3.

rely on the property tax assessment by the Utah State Tax Commission without reference to the merger conditions in the stipulation would reduce protections in the stipulation intended to protect Utah ratepayers from potential property tax increases that result from the revaluation of assets due to the merger.

The conditions in the stipulation provide the DPU and the CCS opportunities to raise issues if they believe that increased property taxes violates one of the conditions in the merger. Those issues should be left for a future day. Emery County's proposed findings appear to be an attempt to eliminate the Commission's ability to address future property tax increase issues in future rate cases. Instead, their findings would require the Commission to accept any property tax increase without reference to the conditions agreed to in the stipulation.

IV.

NOT AUTOMATICALLY GRANTING AN EXTENSION OF EXISTING CONTRACTS FOR SPECIAL CONTRACT CUSTOMERS IS NOT DISCRIMINATORY

A number of the briefs[4] argue that it would be discriminatory for the merger to be approved without "insuring comparable benefits and protections for special contract customers."[5] The DPU and CCS do not agree that an issue of discrimination exists between special contract customers and retail customers particularly with the proposed rate credit in the stipulation.

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[4]Large customer group, p. 14, NuCor Steel, p. 33.

[5]Large customer group brief, p. 14. Mr. Goins states "I'm recommending the special contract customer be given the same protection as non-special contract customers covered by the stipulation. That's all. I'm not asking for any special treatment, any more favorable treatment than any customers. I'm simply saying, let those customers have the same protections from merger related risk as non-special contracts customers are given under the stipulation. That's all. (Initial brief of NuCorp, p.33.)

Under the rate credit proposal special contract customers are protected from changes in rates during the contract period. They are promised good faith negotiations for extensions of their contracts in sufficient time for them to pursue alternatives if negotiations fail. They are promised that those negotiations will recognize the contributions that these customers make to the economic well-being of Utah and that those contracts will be negotiated in accordance with Commission standards in effect at the time. No such comparable treatment is guaranteed for retail ratepayers. PacifiCorp has indicated that it plans to file for a significant rate increase in the near future. Any resulting rate increase would not affect the special contract customers. Therefore, there is no comparability between a retail customer and a special contract customer. One should note that the special contract customers are not asking for comparable treatment. They are not asking to have their rates subject to the rate increase filed this year or the future rate credits.

The promises that Scottish Power has made to negotiate extensions to the special contracts did not exist as a public commitment by PacifiCorp. There was no guarantee that PacifiCorp would extend these special contracts beyond the contract period. What appears to be happening in this proceeding is that the special contract customers are using the opportunity of a merger to force new contract terms on PacifiCorp without negotiations. The assurances by PacifiCorp that negotiations will be concluded in ample time for the special contract customers to seek alternatives should be sufficient. The task force on special contracts has held a number of meetings. The DPU and the CCS do not oppose extensions of special contracts assuming they meet the criteria established by the Commission to show that those contracts are in the public interest. Automatic extension of contracts without reference to criteria established by the Commission may have the unwanted affect of causing harm to other ratepayers. That must be avoided. Using the legal argument of "discrimination" is not a valid basis to force extensions of these contracts.

V.

ADDITIONAL COMMENTS

A. RATE CAP

UIEC's brief (p. 22) implies that the DPU has backed off of a rate cap proposal by agreeing to the rate credit included in the stipulation. Further, UIEC points to the Wyoming agreement as an example of a rate cap that Scottish Power has agreed to that apparently they believe is more beneficial than the $48 million credit. The rate cap in Wyoming was for only two years. There was not a cap on rates but a limitation on rate increases to $12 million in the first year and $8 million in the second, plus any depreciation change. The DPU's original proposal was to consider an alternative similar to Wyoming or other mechanisms like a GDP limitation on rate increases. It was never for an absolute rate cap for a five year period.

The rate credit provides anticipated merger benefits up front and insures that management has a pecuniary stake in merger-related outcomes. It allows general rate cases to proceed without artificial limitations being placed on the results. We believe that the merger credit and protections provided by other provisions in the stipulation[6] adequately protect customers from risk associated with the merger making a rate cap unnecessary.

B. DIFFICULTIES IN CALCULATING MERGER BENEFITS

UIEC and others claim that an advantage of the rate cap makes it unnecessary to attempt to determine what costs are merger-related and what savings could have been achieved absent the merger. As with any merger of two utilities the difficulties associated with calculating merger savings is present. That problem existed when Utah Power & Light and PacifiCorp merged. It will be present with this merger. What is clear is that the burden of proof to show that there are merger savings rests with the utility and not with regulators. Understanding that this difficulty exists does not appear, in and of itself, to warrant a rate cap or present a basis for denying the merger.

C. THE DPU AND CCS WERE NOT CO-OPTED AND CAPTURED

UIEC, presumably not in a pejorative manner, tells the Commission the DPU and CCS have been "captured and co-opted by those they regulate." (UIEC initial brief, p. 13.) Presumably how the DPU and CCS were captured and co-opted was to enter into a stipulation that provides retail customers with a $48 million merger credit and provides all of the protections the DPU and CCS identified as necessary in their investigations. Even the tax issue received

[6]These other provisions include paragraph 3 eliminating merger transaction cost from rates, paragraph 19 requiring the use of hypothetical capital structures, paragraph 25 stating that increased cost of capital will not be allowed in rates, paragraph 26 prohibiting the inclusion of the premium Scottish Power is paying in rates, paragraph 28 requiring funding of network expenditures required to implement service quality standards from redirected internal funding, paragraph 41 requiring a specific showing of prudency prior to the inclusion of any renewable resources in rate base, and paragraph 44 stating that rates in Utah will not increase as a result of the merger.

sufficient consideration by the DPU and CCS to determine that such an issue could be heard in a future rate proceeding.[7]

We do not believe that we have been taken in by Scottish Power. Instead, both the DPU and CCS adequately performed investigations leading to the stipulation and independently determined that, with the terms of the stipulation in place, the merger is in the public interest. Two days of cross-examination of representatives of the DPU and CCS by counsel for the industrials certainly punctuated that point.

D. ADDITIONAL CONDITIONS

The UIEC makes the blanket assertion that "the Division and Committee appear to have no objection to additional conditions." The assertion is made in the context of the tax savings issue, but appears to be a blanket statement. As the DPU and CCS have set out in their original post-hearing brief in this matter, they do object to all conditions having to do with restructuring issues, including RTO's and stranded costs, and the forced extension of special contracts.

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[7]The UIEC states that the DPU and CCS were operating in a climate of information deficit and did not know of the tax savings when the stipulation was signed.. UIEC brief, pp. 13, 15. It should be noted that the industrials cite CCS witness Talbot's testimony when talking about the tax issue. The confidential exhibits that were used during the hearings on this issue were also in response to a CCS data request. It seems that the DPU and CCS had at least as much information as the industrials.

The industrials also complain about the confidential status of documents as part of their information deficit argument. These are the same industrials that sought, and received, confidential treatment of the only exhibit introduced during the hearings that showed the names of the special contract customers, and the revenue from each. The industrials apparently do not have a problem with attempting to keep their information confidential.

VI.

CONCLUSION

The DPU and CCS continue to believe that if the terms and conditions of the stipulation are adopted, the proposed merger is in the public interest. The DPU and CCS continue to recommend the Commission approve the merger.

DATED this 17th day of September, 1999.

By______________________
Michael Ginsberg
Assistant Attorney General

By______________________
Douglas C. Tingey
Assistant Attorney General

CERTIFICATE OF SERVICE

I hereby certify that I caused the foregoing Joint Reply Memorandum of the Division of Public Utilities and the Committee of Consumer Services to be served upon the following persons by mailing a true and correct copy of the same, postage prepaid, to the following on the 17th day of September, 1999:

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SERVICE COMMISSION

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

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In the Matter of the Application of PACIFICORP and SCOTTISH POWER PLC for an Order Approving the Issuance of PACIFICORP Common Stock	**DOCKET NO. 98-2035-04** **UIEC'S POST HEARING REPLY BRIEF**

* * * * *

The Utah Industrial Energy Consumers ("UIEC") hereby submit this Post-Hearing Reply Brief to respond to the opening Brief of ScottishPower PLC and PacifiCorp, and the Joint Brief of the Division of Public Utilities ("DPU" or "Division") and the Committee of Consumer Services ("CCS" or "Committee").

INTRODUCTION

From the outset of these proceedings, the industrial customers have expressed concern that under ScottishPower's merger proposal, the operating utility's capital structure would be weakened, its cost of capital would increase, cash would flow upstream from the regulated utility to holding companies, and rates would be forced upward in an effort to recover inflated acquisition premiums and to shore up certain UK returns. See, e.g., Brubaker Direct, Ex. UIEC 1.1 at 33-39; Anderson Direct, Ex. LCG-1 at 63. Those concern are even greater today than they were three weeks ago during the hearings. On August 12, 1999, (three days after the hearings concluded), the UK office of Gas & Electricity Markets proposed price reductions in ScottishPower's distribution prices of 12 to 17%, and for Manweb, 23 to 28%. See Electric Utility Week, August 16, 1999 at 1 (Steep Distribution Price Reductions in U.K. Stuns Utilities; Moody's Eyes Downgrades). As a result of the announcement of the proposed reduction, Moody's investor service placed many UK regional electric companies on review for possible downgrade. ScottishPower was one of those utilities placed under review. Id. at 4.

The risks that the merged Company will require an ever increasing supply of money, and thus may be forced to increase rates, cannot be overemphasized. It is crucial, therefore, that the Commission require iron-clad assurances that Utah rate payers will not be harmed by this merger. The proposed Stipulation falls far short of providing the necessary protections. The UIEC contend that the only effective method of ensuring that the merger is in the public interest, is to cap rates and impose conditions that have the force of law in future proceedings. A rate cap could be financed by the reductions in income tax and by the savings anticipated from corporate consolidation. It would alleviate the regulatory burden of administering the merger credit and enforcing a vague and ambiguous stipulation.

A rate cap would also serve to bring some semblance of finality to these proceedings. ScottishPower has discouraged the Commission at every turn from reaching any decision in this case other than granting the approval it desires. It has refused to submit a transition plan, hoping to avoid scrutiny about whether cost savings will materialize. It has proposed that the Commission delay the establishment of a benchmark from which to measure those savings. It has sought to defer a decision on the treatment of upstream tax savings in hopes that the Commission will be deprived of authority to address the issue later. It has asked the Commission to wait for task forces, the Utah Legislature, and the FERC before making any decisions on special contracts, stranded costs or participation in a regional transmission organization. At the same time, ScottishPower has fostered these delays by refusing to produce or make reasonably available the information necessary for regulators to perform their duty.

The UIEC submit that under the circumstances, the Commission should not approve this merger without imposing a rate cap, strengthening and clarifying the terms of the Stipulation, and imposing additional conditions that will ensure not only that rates will not increase as a result of the merger, but that the merger will result in a net positive benefit to Utah customers.

ARGUMENT

I. Standard For Approval of the Application.

Section 54-4-28 requires that the Utah Public Service Commission ("Commission") find the merger to be in the public interest before approving it. The Division and Committee advocate a "net positive benefit test" that was adopted by the Commission in 1988 as a standard for determining whether the public interest is served. (Docket No. 87-035-27). ScottishPower and PacifiCorp[1] take issue with that standard and advocate instead that the Commission adopt a "no harm" standard. They ask the Commission in effect to lower the bar. The UIEC contend that the standard is "public interest" which may be inferred when there is a net positive benefit to customers. Even if ScottishPower's "no harm" standard were applied, this merger would not be in the public interest unless additional conditions are imposed. As discussed in UIEC's opening brief, Applicants have not shown that the rate payers will suffer no harm as a result of the merger or that the Stipulation adequately mitigates the risk of such harm.

II. Few If Any Benefits Will Result From the Proposed Merger Unless Additional Conditions are Imposed.

It is not as, ScottishPower contends, "abundantly clear" that the merger carries a net benefit for rate payers. (Applicants' Brief at 3). While ScottishPower has offered certain concessions such as the merger credit, there are also numerous and substantial risks of the merger. The Stipulation among ScottishPower, PacifiCorp, the Division and the Committee ("Stipulation") mitigates some of those risks, but it does not sufficiently mitigate the risks for all rate payers, especially special contract customers. In addition, it does not capture certain benefits

[1] For the sake of simplicity, ScottishPower and PacifiCorp are collectively referred to as ScottishPower or the "Company" unless the context requires that PacifiCorp be separately identified.

unknown at the time the Stipulation was signed and it creates a significant additional administrative burden for the Commission.

In this Post-Hearing Reply Brief, the UIEC respond to the arguments offered in ScottishPower's Brief ("Applicants' Brief") and the Joint Brief of the DPU and CCS ("Joint Brief").

A. Merger Credit.

ScottishPower argues that the $12 million annual merger credit is guaranteed to the Utah tariff rate payers for the entire four-year period. (Applicants' Brief at 3.) During the third and fourth years, however, the $12 million is subject to offset by achieved cost savings. Under ScottishPower's proposal, the baseline from which cost savings will be measured will be set in ScottishPower's transition plan (not subject to approval by the Commission). Wright, Tr. 203, 209-210. The Company thus is in a position to unduly influence the determination of whether there will be any cost savings in the third or fourth year. The Commission has no reliable, objective baseline from which to measure cost savings.

In addition to the diminution of the merger credit through cost savings, the merger credit may also be overwhelmed by increasing rates. PacifiCorp has already stated that it will seek a $100 million rate increase based on a 1998 test year. If the Company is not able to achieve its projected level of cost savings thereafter and must seek further rate increases, the entire merger credit could be consumed in the increased rates. Without a moratorium on rate cases, it is possible that ScottishPower could continue to claim greater cost increases than the amount of the merger credit for every year the credit is in effect.

Although ScottishPower has promised that rates will not go up "as a result of the merger," determining what is a result of the merger is virtually an impossible task. Alt, Tr. 209.

ScottishPower already has testified that if rates go up due to new management practices, for example, ScottishPower will contend that the increase is not "due to the merger." Wright, Tr. 493-96. If rising costs can somehow be characterized as non-merger related, the risk remains, despite the Stipulation, that the merger will result in a net rate increase to rate payers.

The only way to be sure that rates will not increase as a result of the merger, is to impose a rate cap. The Division and Committee do not seem as certain as ScottishPower that merger credit and Stipulation will provide the necessary protection. Rather, the DPU and CCS warn that the Commission "will need to answer for itself" whether adequate protection is provided under the Stipulation. (Joint Brief at 8). The DPU and CCS agree that a rate cap for a five-year period, even allowing for a 1999 rate case, "would provide protection for retail customers from cost increases caused by the merger." Id.

The Division and Committee see only one possible disadvantage to a rate cap: if there is an "absolute rate cap for a five-year period, the merger will not take place." Id. That may not be the worst outcome of this case considering there are other domestic utilities who may be more suitable candidates for a merger with PacifiCorp. See Cross Exh. 4 at 34; O'Brien, Tr. at 683-84 (acknowledging previous merger offer). In any event, it is unlikely ScottishPower would not consummate the merger if the Commission imposed a rate cap. ScottishPower agreed to a rate cap in Wyoming even though it was earning below its authorized return on equity in that state. Moreover, it appears that in Wyoming, rates were not only capped, but the Company agreed to a 1.7% rate cut just as they have agreed in Utah. (See Electric Utility Week, August 30, 1999 at 10 (ScottishPower, PacifiCorp agree to 1.7% rate cut in Wyoming)). If a rate cap was acceptable to the Company in Wyoming, it should be acceptable in Utah.

ScottishPower has not been forthcoming on how it intends achieve the promised cost savings. Since it has not proffered the transition plan, it must be assumed that it cannot deliver the promised savings. It is evident, nevertheless, that ScottishPower will enjoy savings from reduced tax costs and from corporate consolidation. If it is able to achieve the predicted additional savings estimated to be $200 million, it will not be harmed by a rate cap in Utah. Moreover, if the Commission were to impose a rate cap, it would not have to rely upon the transition plan to tell it whether cost savings have been achieved, and it would not have to determine whether any purported cost savings are "as a result of the merger." Given ScottishPower's persistent affirmations that it will achieve cost savings, and given the uncertainty it has created by failing to produce information showing how it intends to do so, the Commission would be prudent to cap rates and place the risk of savings on ScottishPower.

B. <u>Promise to Pass Additional Cost Savings Through to Customers</u>.

ScottishPower has promised that it will pass cost savings on to customers. It claims those intended savings are a direct benefit of the merger because PacifiCorp had no specific plans to achieve cost savings. (Applicant's Brief at 4). This is inaccurate. When talks with ScottishPower were in process, PacifiCorp already had proposed its refocus plan which included $30 million in savings for the year 1999. Larsen, Tr. at 53, 201. Unless PacifiCorp's refocus plan is to be considered a result of the merger, it is clear PacifiCorp did have a specific plan to save costs. In addition, evidence presented at hearing demonstrated that PacifiCorp very likely could have realized some level of savings over the next four years. <u>E.g.</u>, Cross Ex. 23.

ScottishPower's plans for savings are virtually unknown. The best it can offer is that cost savings will be identified in the transition plan. (Applicants' Brief at 4). When the transition plan is filed, ScottishPower contends, the Commission will "clearly see what cost savings initiatives will be implemented by ScottishPower." Id. Obviously, at present, the cost savings are *not* there for the Commission to see. Until they are, they cannot be evidence of any net benefit.[2]

C. Improvements in Network Performance and Customer Service.

ScottishPower, the Division and the Committee count it as a benefit that ScottishPower has promised network performance and customer service guarantees. Certainly, any improvements in performance in customer service would be welcome. But such improvements, if they occur, would not be uniquely due to ScottishPower's takeover of PacifiCorp. ScottishPower argues that "PacifiCorp has no plan for improvements to be undertaken on its own." (Brief at 7). Again, that is not true unless the refocus plan is to be considered a product of the merger.[3] Moreover, PacifiCorp is obligated under current law to achieve adequate levels of performance and customer service. Theoretically, the Commission has the authority to deny approval of the merger and then to require PacifiCorp to achieve the same performance level that has been proposed by ScottishPower. There is very little benefit to rate payers in ScottishPower agreeing to do what the regulators already may compel it to do and what it is obligated by law to do.

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2 ScottishPower's promise to "pass additional cost savings through to its customers" is disingenuous in light of its resistance to agree to pass tax savings through to rate payers. As discussed below in this Reply Brief, a condition to capture tax savings for the benefit of Utah customers (along with certain other conditions) should be imposed before the merger is found to be in the public interest. The Division and Committee point out the advantage in a merger credit "designed to capture benefits associated with the merger up-front rather than waiting until those benefits are achieved in future rate cases." Joint Brief at 8. If this is a virtue for the merger credit, why is it not a virtue for tax benefits?

3 ScottishPower has resisted any suggestion that PacifiCorp's refocus plan is in any way related to the discussions between PacifiCorp and ScottishPower that were in progress at the same time the refocus plan was developed. Larsen, Tr. 53, 203.

ScottishPower argues that it will spend "approximately $55 million" over the next five years on improving service standards.[4] It states that these costs will not be passed on to rate payers *unless* the Commission approves them in a rate case. (Brief at 8). As discussed above, if improvements to service quality are needed, then the Commission could order PacifiCorp to invest the same $55 million. Such investments, if prudent, could be recovered in rates whether by ScottishPower after the merger or by PacifiCorp in the absence of the merger. Thus, even if the $55 million investment represents a benefit, it is not a benefit resulting from the merger. Moreover, we can be sure that ScottishPower intends to seek approval to pass on the $55 million to rate payers just as PacifiCorp would.

Improvements in service should not be counted as a benefit of the merger because PacifiCorp could be required to make the same investment and because prudent costs are recoverable by ScottishPower as they would be by PacifiCorp.

III. **The Risks Associated With the Transaction Are Not Adequately Mitigated by the Stipulation**.

The Stipulation was developed before the Division and Committee had the benefit of hearing and analyzing certain important evidence that came to light during hearings. It was also fashioned without any accommodation to the industrial customers. For those reasons, the Stipulation is incomplete protection against the risks of the merger. The UIEC have urged the Commission to require additional conditions of Scottish Power.

ScottishPower contends that the Stipulation's conditions "effectively neutralize" all risks associated with the merger. (Applicants' Brief at 14). Despite the assurances of

[4] While ScottishPower would like us to think that $55 million is a substantial investment, compare it to the $250 million that ScottishPower has spent on lawyers and consultants in this merger. Richardson, Tr.

ScottishPower, however, it has admitted that the rate payers still bear the risk that ScottishPower's new management will cause costs to increase. Wright, Tr. 493-496. The very existence of new management brings a number of risks that have not been addressed in the Stipulation. The new Company's information management policy places a burden on the regulatory system. While the Stipulation provides that regulators will have access to "necessary" books and records, it was evident in this proceeding that ScottishPower has a different view than the regulators about what is necessary. The Division and the Committee did not have the necessary information to ascertain the level of tax savings to ScottishPower or the confidential cost projections of ScottishPower and PacifiCorp. (See UIEC Opening Brief at 11-12).

The Stipulation also fails to neutralize the risk of prolonged and expensive litigation that likely will occur as a result of ambiguities or omissions in the Stipulation.[5] In addition, the uncertainties remaining as a result of ScottishPower's refusal to file a transition plan leaves a substantial risk that ScottishPower will not be able to achieve any level of cost savings or operate this company more efficiently than PacifiCorp could have. Rate payers are still faced with the risk that rates will increase if the savings do not materialize. In short, the Stipulation does not neutralize the risks of the merger. Additional conditions are necessary to ensure that it is in the public interest.

618-19; O'Brien, Tr. 697-99.

[5] Condition No. 22, for example, is ambiguous as to the meaning of "inter-company" loans; paragraph 9 is ambiguous about whether notification and approval is required if the Company places transmission distribution or generation into a separate subsidiary; paragraph 10 and 11 addressing access to information may be insufficient to require the Company to cooperate in timely disclosing essential information; paragraph 13 requiring the filing of a transition plan that need not be approved by the Commission invites future litigation over claimed savings as a result of the merger, the Commission's right to adjust the benchmark for those savings, and the Division's right to audit the amount of merger savings claimed. (Tr. 194-202; 209-212).

A. <u>Taxes</u>.

The Commission should determine in the present case that potential income tax savings resulting from the merger must flow through to PacifiCorp's Utah customers. The Division and the Committee agree that the tax savings associated with the transaction should be credited to rate payers "if appropriate," (Joint Brief at 10), but they are unwilling to ask the Commission to decide at present what the amount might be. ScottishPower claims that even though there is potential for upstream tax savings, it is "not clear that tax savings will be available." (Applicants' Brief at 18). The Company, the Division and the Committee thus advocate that specific treatment of those tax savings should be decided in a future proceeding. (Joint Brief at 11; Applicant's Brief at 18). The UIEC do not ask the Commission to determine whether or in what amount tax savings will be achieved, or what a reasonable allocation to the Utah jurisdiction might be. It is essential, however, that the Commission clearly impose the condition in this docket that those tax savings, if any, will accrue to the benefit of Utah rate payers.

Both the Division and the Committee argue that the language contained in Cross Exhibit 2 adequately "preserves the issue" for a future proceeding and "resolves all concerns" regarding the tax question. (Joint Brief at 11; Applicants' Brief at 19). They are mistaken. Cross Exhibit 2 states:

> The parties to this Docket preserve their right to raise the issue of the treatment of upstream tax savings and costs in future rate cases. <u>All parties preserve their positions and have not waived their rights on the issue</u>. ScottishPower commits to retain records regarding upstream tax savings and costs relating to the merger and make those records available to the DPU, CCS and other parties in accordance with the Stipulation. Ex. 1 and the discovery rules of the Commission.

Cross Exhibit 2 (emphasis added). The language of Cross Exhibit 2 does not amount to an acknowledgment that the Commission may address the treatment in a later proceeding and may order that tax savings be credited to Utah rate payers. To the contrary, it preserves the right of ScottishPower to argue in a future case that the Commission has no jurisdiction to address the tax issue at all, or to compel upstream entities to pass along the tax savings to Utah rate payers. Fell, Tr. 979; Larsen, Tr. 93; Wright Tr. 106 (refusing to acknowledge PSC has jurisdiction to decide issue of future case). Neither ScottishPower nor the Joint Brief explicitly address the problem of the Commission's jurisdiction to capture the tax benefits. Either they have overlooked the issue or they have chosen to divert the Commission's attention away from it, contending that cross Exhibit 2 adequately preserves the issue for future determination.

Whether or not ScottishPower could succeed in preventing the Commission from addressing the tax issue in a future case is not known. It is obvious, however, that ScottishPower does not ever intend to submit the merits of the matter to the Commission. Fell, Tr. 979; Larsen, Tr. 93; Wright Tr. 106. Its promise in Cross Exhibit 2 is nothing more than an attempt to momentarily placate regulators now that the tax issue has been uncovered. It simply sets the stage for litigation. The only way the Commission can ensure that the issue will be preserved for a later case is to determine now that as a condition of the merger, ScottishPower must acknowledge the Commission's authority to decide the issue, and must agree that the tax benefits, whatever they may be, will flow through to Utah rate payers. The Commission should impose such a condition now that will carry the force of law in future proceedings.

B. <u>Utah Presence</u>.

The UIEC have emphasized the importance of having ScottishPower agents present in Utah capable of binding PacifiCorp and making decisions regarding Utah operations.

The Stipulation does not address the topic. Both ScottishPower and the Division rely on a letter sent to DCED and DBED, in which ScottishPower committed to have an individual in Utah who would report directly to PacifiCorp's CEO. (SP Exh.1R.1; Joint Brief at 13; Applicants' Brief at 20). The commitments that ScottishPower makes in that letter do not include a commitment that a representative located in Utah will have authority to make decisions and bind the company regarding Utah operations. Instead, the letter states:

> The [Utah] executive will report directly to the CEO of PacifiCorp. As a member of the executive team, this person will have broad influence over PacifiCorp's operation in Utah including, but not limited to, authority to approve corporate involvement in economic development and corporate citizenship activities. The executive will be able to assure the best decisions in the interests of Utah.

SP1 R.1. The language of the condition allows ScottishPower to place a CEO in Utah with "authority to approve corporate involvement in economic development issues," but not necessarily with authority to bind the Company in its Utah contracts or operations. The UIEC urge the Commission to require a straightforward, unambiguous commitment from ScottishPower so regulators and customers will have access to someone in Utah with decision-making authority.

C. <u>Existing Evidence</u>.

The UIEC have requested that the confidential information currently in the possession of ScottishPower and PacifiCorp be preserved for future cases. ScottishPower contends that "these documents have been entered into the record and are governed by the terms and conditions to the protective order in this docket." (Applicants' Brief at 21). It believes that no additional provisions are required. It is evident, however, that certain data in work papers backing up some of those documents were not produced in response to data requests, yet were referred to by ScottishPower witnesses during the hearings. Tr. 1475-81. The UIEC request that the Commission order that information to be produced and made available for use in future proceedings.

D. Stranded Costs.

The UIEC have advocated in this proceeding that ScottishPower should be required to waive any claim for stranded costs as a result of the premium paid for the acquisition of PacifiCorp stock. The Division and Committee evidently understand the Stipulation to mean that ScottishPower shall make no attempt to recover the premium or transaction costs as stranded costs or to include them in any stranded cost calculation. (Joint Brief at 14.) While ScottishPower apparently agreed with that position, (Tr. 136-146), it has not acknowledged such a concession in the Stipulation or in its Brief. (See Applicants' Brief at 21 (omitting any reference to a waiver of premium and transaction costs as stranded costs)). The UIEC propose, therefore, that the commitment of ScottishPower in that regard be incorporated as a formal condition of the merger.

ScottishPower, the Division and the Committee contend that the stranded cost issue is more appropriately addressed in a later proceeding. None of them identify any substantive reason that the Commission should defer the issue, or explain the nature of the "complexities" they claim would preclude a decision in this docket. (Joint Brief at 14; Applicants' Brief at 21). Evidence of the premium is uncontested and there is ample evidence on record on which the Commission could reach a decision that PacifiCorp's shareholders have been compensated for stranded costs. (See UIEC Opening Brief at 26-27).

ScottishPower also claims the Commission should not decide the issue because the Utah Legislature is reviewing restructuring issues in a task force. ScottishPower suggests that the question of stranded costs may be more appropriately handled in that forum. (Applicants' Brief at 21). If the Commission defers a decision on stranded costs in this case, it should enter findings that will assist the Legislature in its debate. The Commission should find that ScottishPower is a sophisticated buyer, that an independent appraisal company established that ScottishPower is paying 1.4 to 1.8 times the value of PacifiCorp's stock, that such payment reflects the value of the generation assets, and that PacifiCorp shareholders have received a premium over book value in this transaction. (See UIEC Opening Brief at 27).

E. **Regional Transmission Organization**.

The UIEC have requested that the Commission require as a condition of the merger that ScottishPower participate in the organization and operation of a regional transmission organization within a time certain after approval of the merger. (UIEC Brief at 28-29). The Division and Committee believe that the issue should be decided by the FERC and that it does not have any direct relationship with the merger. (Joint Brief at 15). ScottishPower remarks that the only occasions where commissions have required a commitment to join an RTO as a condition to a merger is when market power was affected by the merger. (Applicant's Brief at 22). It also argues that competitive issues were reviewed by the FERC and the FTC for the purposes of the proposed merger, and these entities did not impose the requirement of joining an RTO. Id.

If the Division, Committee, and ScottishPower's suggestions are adopted, the Utah Public Service Commission would be precluded from exercising any control or input over the development of a regional transmission organization in the western United States. The Commission must impose the obligation as part of this merger or be preempted from ever doing so in the future. (See UIEC Opening Brief at 28-29). The fact that the FERC did not require participation in an RTO is not surprising since the FERC will retain jurisdiction to compel an RTO in the future. But the issue in the present docket is not whether FERC can compel a RTO, whether the FERC imposed similar conditions on this merger, or whether there is a direct relationship between the merger and the proposed condition. It is whether the state of Utah can preserve its right to direct the development of an RTO.

The UIEC believe it is important for the Commission to retain authority to deal with regional transmission issues. This concern was recently underscored when NARUC mounted an opposition to a federal bill that would create a national organization to develop and enforce national reliability standards under FERC oversight. See Electric Utility Week, September 13, 1999, at 4 (State Regulator Group Demands Bigger Role in Reliability Regime"). State regulators, concerned that the bill "might strip them [of] what they consider their police power over local utilities to ensure reliable service to customers," refused to endorse the measure unless it is revised to preserve a meaningful role for the states in ensuring reliability. Id.[6] Likewise, unless the Utah Commission imposes conditions on the merger, it will be stripped of its power to influence the development of a regional transmission system.

The Commission has the opportunity in this docket to remain involved and retain some control over regional transmission issues to ensure reliable service to Utah customers. As discussed in UIEC's Opening Brief, the Commission should take advantage of the opportunity by crafting a merger condition requiring ScottishPower's participation in an RTO.

6 NARUC also recently petitioned the 8th Circuit Court of Appeals to uphold a decision that limited the FERC's authority to compel curtailments in native load and network service when transmission constraints forced the local utility to cut point-to-point deals. (Power Markets Week, September 13, 1999 at 9).

F. Special Contracts.

ScottishPower has offered the following assurances to special contract customers: (a) all existing contracts will be honored; (b) PacifiCorp will allow ScottishPower representatives to join the PacifiCorp negotiating team ahead of completion of this transaction, if the customers so wish; (c) ScottishPower/PacifiCorp will negotiate all contracts in good faith; (d) complete such negotiations promptly (understanding the possible needs for customers to pursue alternatives); (e) negotiate contracts recognizing the contributions these customers make to the economic well being of Utah; and (f) negotiate in accordance with the Commission rules in effect at that time. (ScottishPower Brief at 24; DPU Brief at 19).

None of these concessions represents a net benefit to special contract customers or offers them significant protection from future rate increases. The first concession, that all existing contracts will be honored, is nothing more than a statement of ScottishPower's obligation under current law. Special contract customers are not concerned that their current contracts will not be honored, but that they will not be able to extend or renegotiate those contracts under acceptable terms. (See UIEC Opening Brief at 22-23). The second concession, that PacifiCorp will allow ScottishPower representatives to join negotiating teams before the completion of the merger, is not of any significant benefit to special contract customers, especially in view of the fact that ScottishPower has been less willing to negotiate than PacifiCorp.[7] The third concession, that contracts will be negotiated in good faith, again, is no more than the law requires currently. The fourth concession, that negotiations will commence as

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[7] When the application for approval of this merger was filed, special contract negotiations with PacifiCorp were halted. ScottishPower refused to negotiate. Brown, Tr. 1233-34. After the hearings, ScottishPower invited some industrial customers to discuss special contracts, but the customers are not optimistic that they can obtain suitable contracts under the circumstances.

early as practical and be completed promptly, has little meaning to customers who have already requested discussions with ScottishPower and have been refused. ScottishPower's fifth concession is that it will "recognize the contribution" that special contract customers make to the economic well being of Utah. Without more definite terms, this concession is meaningless. Finally, the concession that contracts will be negotiated in accordance with Commission rules is merely another statement that ScottishPower will comply with the law. In sum, ScottishPower's hollow promises do not offer special contract customers any protection from increasing rates or any guarantee that acceptable terms can be negotiated. Under the Stipulation, special contract customers are the victims of the utility's discrimination, having been selected as the only group of customers to whom no merger benefit or protection is offered.

ScottishPower attempts to justify its exclusion of special contracts customers by citing the work of the Commission's task force on special contracts. (ScottishPower Brief at 23-24). It argues that it will participate in this "procedure to examine the issue of special incentive contracts" but that prior to the completion of the task force's work, "the discussion regarding special contracts is premature and should not be an issue in this docket." (Brief at 24 citing SP Exhibit 1S, page 17-18). ScottishPower's attempt to delay and stall the negotiation of special contracts is a thinly veiled effort to raise special contract rates. In fact, the results of the task force will not be helpful for setting guidelines in the future. As discussed in UIEC's Initial Brief, the task force deals only with firm contracts, while all of the special contracts represented in the merger docket are interruptible contracts. The task force's anticipated guidelines will be inapplicable.

The Division and Committee have stated:

> The Division and Committee do not oppose extension of these contracts if they are in the public interest. In other words, the Division and Committee do oppose the automatic extension of these contracts unless they are submitted for approval to the Commission and pass muster showing that they continue to in the public interest under the standards and criteria adopted by the Commission [when the task force's report is submitted].

Division Brief at 17-18. Like ScottishPower, the Division and Committee misconstrue the objective of the task force. Those criteria will not apply to interruptible contracts. At present, all special contracts have been approved and are subject to continuing jurisdiction of the Public Service Commission. The UIEC do not expect to operate under contracts that are inimical to the public interest. (See UIEC Opening Brief at 24-25).

ScottishPower, the Division and Committee have urged the Commission to wait for the results of the task force, evidently hoping to gain some insight as to whether special contract prices will remain above costs, and whether terms and conditions of existing contracts will be reasonable in the future. (Applicants' Brief at 24-25; Joint Brief at 17-18). Because the results of the task force will largely be irrelevant to those questions, however, perhaps the best indicator of whether it would be reasonable to extend special contracts is ScottishPower's non-existent transition plan. Ironically, ScottishPower, claiming that there is insufficient information to determine future costs, is asking Commission to presume that special contracts will become uneconomic if extended. That approach, of course, is backward. Because ScottishPower itself has created the information deficit by its refusal to file the transition plan, the Commission must presume just the opposite: that the information ScottishPower has refused to provide would be adverse to ScottishPower if it were available.[8] Hence, the Commission must conclude that the transition plan would show that special contracts will remain economic through the transition period.

Even based solely on the evidence available this proceeding, there is every indication that ScottishPower's projected costs would remain below the rates set in the current special contracts. There is no reason that the Commission cannot decide on the current record that special contracts must be extended. The UIEC have advocated that the Commission impose a rate cap as the most effective way of ensuring the public interest is met in this merger. Capping rates also eliminates all risk that special contracts will become uneconomical or that rate payers would be harmed by extending them.

ScottishPower claims: "We value our relationship with all of our customer classes." (Brief at 23 quoting SP Exhibit 1S). The UIEC's perception is that ScottishPower has alienated every industrial customer in every state in which it has applied for merger approval. The industrial customers are extremely apprehensive that unless there are enforceable conditions in place prior to approval of the merger, ScottishPower will be disinclined to treat special contract customers fairly.

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8 See 2 Wigmore, Evidence § 285 (1991)(the failure of a party to bring before the tribunal a document or witness that might elucidate the facts is evidence that such document or witness if brought, would have exposed facts unfavorable to that party).

CONCLUSION

This case has been presented to the Commission without sufficient information for the Commission to determine that the merger is in the public interest. ScottishPower, largely through its refusal to submit a reasonable transition plan, simply has not borne its burden to show quantifiable, actual net benefits of the merger. At the same time, it has been immensely successful in securing the cooperation of the Division and the Committee who were virtually ambushed by the information deficit. Under these circumstances, the Commission should look carefully at evidence, closely evaluate the tangible benefits and risks of this transaction and, as the Division and Committee recommend, "answer for itself" whether the Stipulation alone ensures the public interest.

The UIEC recommend that the Application of PacifiCorp and ScottishPower PLC be denied unless ScottishPower agrees to the amendments necessary to clarify the Stipulation and unless it accepts the following additional conditions: (1) Utah rate payers are entitled to the tax savings resulting from merger and the Utah Public Service Commission has jurisdiction and authority to order that those savings be credited to Utah rate payers; (2) rates will be capped through the transition period (either before or after a rate case using a 1998 test year); (3) special contracts shall be extended through the transition, in accordance with the terms set out in the UIEC's comments to the proposed Stipulation (August 2, 1999); (4) intervenors, customers and regulators must have access to essential information in the possession of ScottishPower or its affiliates; (5) the merged company must waive any future claim for stranded costs; and (6) ScottishPower must present a plan to the Commission for the formation of a regional

CERTIFICATE OF SERVICE

I hereby certify that on this 17th day of September, 1999, I caused to be mailed, first class, postage prepaid, a true and correct copy of the foregoing **UIEC'S POST HEARING REPLY BRIEF**, to:

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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of PacifiCorp and Scottish Power plc for an Order Approving the Issuance of PacifiCorp Common Stock.	**DOCKET NO. 98-2035-04**

REPLY BRIEF
OF APPLICANTS
SCOTTISH POWER PLC AND PACIFICORP

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Scottish Power plc ("ScottishPower") and PacifiCorp (together, "Applicants"), respectively submit this Reply Brief pursuant to the schedule established by the Public Service Commission of Utah ("Commission") in this docket.

INTRODUCTION

The record in this case establishes that the Application of PacifiCorp and Scottish Power plc for an Order Approving the Issuance of PacifiCorp Common Stock ("Application"), pursuant to Utah Code Ann. § 54-4-31 will be in the public interest and should be approved by the Commission.

The only active opponents to the Application are: the Utah Industrial Energy Consumers ("UIEC"), the Large Customer Group ("LCG") and Nucor Steel ("Nucor"). These parties are collectively referred to as the "Industrial Customers". The Industrial Customers failed to raise any issues in their Post-Hearing Briefs that are sufficient to justify the Commission's rejecting the Application or imposing any conditions beyond those already agreed to by the Applicants. The Industrial Customers have suggested that the fact that they are opposing the merger should give the Commission "tremendous pause" in approving the transaction. (LCG Brief, page 3.) The fact remains that the transaction benefits all of the 622,250 residential, commercial and industrial customers of PacifiCorp as well as the eight special contract customers located in Utah. (Hearing Transcript ("Tr.") 1483.) The entities which represent the overwhelming majority of Utah customers support the merger and only a handful of customers continue to oppose the transaction.

For all the reasons stated below, Applicants respectfully request that the Commission approve the Application with the conditions agreed to by the Applicants.

ARGUMENT

I. STANDARD FOR APPROVAL OF THE APPLICATION

The standard for approving the ScottishPower/PacifiCorp transaction is whether the transaction is in the "public interest." UTAH CODE ANN. § 54-4-31. The Utah Supreme Court has interpreted this standard to mean that no harm will come to the public (the "no harm" standard). See Milne Truck Lines, Inc. v. Public Service Comm'n, 720 P.2d 1373, 1380 (Utah 1986) (citing to Collett v. Public Service Comm'n, 211 P.2d 185, 187 (Utah 1949)). The Commission, however, has interpreted the "public interest" to be a "positive benefits" standard. See Re CP National Corp., 43 PUR 4th 315 (Utah PSC 1981) and Re Utah Power & Light Co., 90 PUR 555 (Utah PSC 1987).

While Applicants believe the "no harm" standard to be the appropriate standard, the evidence presented in this docket meets the higher "positive benefits" standard used by the Commission in CP National Corp. and Utah Power & Light.

In its Post-Hearing Brief, the LCG fashioned, a new interpretation of "public interest." According to the LCG the "public interest" standard imposes a heavy burden on the Applicant to show by substantial evidence, with paramount considerations on rate and reliability issues, that any demonstrable and measurable benefits of the proposed acquisition will clearly outweigh any potential risk or negatives. (LCG Post-Hearing Brief, pages 4-5.)

The LCG created this new standard by inappropriately relying on two cases. First, the LCG relied upon White River Shale Oil Corp. v. Public Service Comm'n, 700 P.2d 1088 (Utah 1985), to support that the "public interest" standard should be interpreted in the context of the Public Utilities Act and thus rate and reliability issues should be paramount considerations. (LCG Post-Hearing Brief, page 4.) The White River case related to the Commission's authority to issue a Cease and Desist Order, stopping construction of a transmission line extension. White

River does not support the LCG's assertion, and instead, holds that the term "public interest" is a sufficient standard for a legislative delegation of authority when read in light of the entire Public Utilities Act. See White River, 700 P.2d at 1091-92 (stating: "'Public interest' certainly falls within this class of standards and, when read in light of the entire Public Utilities Act, is not so broad as to result in an improper delegation of authority."). White River says nothing about giving rate and reliability issues paramount consideration when contemplating the positive benefits or negative impacts of a proposed acquisition.

LCG then relies upon Utah Dept. of Business Regulation, Div. of Public Utilities v. Public Service Comm'n, 614 P.2d 1242 (Utah 1980) to support the assertion that the Applicants have a heavy burden of showing by substantial evidence that any demonstrable and measurable benefits will clearly outweigh any potential risks or negatives. The Utah Dept. of Business case involved a utility asking for a rate increase to pass through increased wage costs, a single item of cost of service. The procedures to be followed, and the standard applied in approving a rate increase are substantially different from those involved in approving the merger of a public utility. The standard is not the same as approving a rate increase, as LCG would have the Commission believe. There is no statutory or case law stating that the Applicants in a merger have a "heavy burden" or that they must produce "substantial evidence". The Commission has previously stated: "Our task is to consider them all [positive benefits and negative impacts], giving each its proper weight, and determine whether on balance the merger is beneficial or detrimental to the public." Re: Utah Power & Light, 90 PUR 4th 555 (Utah PSC 1987). The evidence set forth in this proceeding demonstrates that the Application meets both the "no harm" standard and the "positive benefits" standard. Applicants ask the Commission to reject the newly fashioned and inappropriate standard presented by the LCG.

In their discussion of the legal standard, the Industrial Customers fail to mention their burden in this case. In its May 10, 1999 Order, the Commission directed each party to demonstrate why each issue raised by it should be considered in this docket, indicating specifically how those issues could be affected by the proposed merger, and identifying the remedy the party seeks to achieve by its condition. The Commission should consider this standard in its analysis of the conditions proposed other parties in this proceeding.

II. NET BENEFITS WILL RESULT FROM THE TRANSACTION

The Applicants have made significant commitments in the four stipulations and the letter agreement reached in this proceeding. It is abundantly clear that net benefits for PacifiCorp's Utah customers will result from approval of this transaction. Many of the criticism of the transaction listed in the Industrial Customers Post Hearing briefs cite to the Division of Public Utilities ("DPU") and the Committee of Consumer Services ("CCS") witnesses' testimony which was filed prior to execution of the Stipulation, defined below, and as a result of which these witnesses now fully support the merger. Some of the issues relating to benefits are categorized and discussed below.

A. Merger Credit

The DPU, the CCS, ScottishPower and PacifiCorp, entered into a stipulation dated July 28, 1999, Joint Exhibit No. 1 (the "Stipulation") which provides for a merger credit as detailed in the Applicants' Post Hearing Brief. The Industrial Customers have criticized the merger credit as being insignificant and not much greater than the net present value of the annual corporate cost savings proposed in the Applicants initial filings. (LCG Brief, page 9; Nucor Brief, page 11; UIEC Brief, page 6.) The fact is that the merge credit at $12 million per year begins immediately. (Hearing Transcript ("Tr.") 869.) The $48 million merger credit is therefore guaranteed to the Utah tariff ratepayers for the entire four-year period. UIEC has confused the merger credit with a PacifiCorp rate case that will be filed based upon a 1998 test year. (UIEC Brief, page 6.) However, UIEC later agrees that a rate case may be appropriate for the 1998 test year. (UIEC Brief, page 21, footnote 14.)

No rate case is required for the merger credit to be reflected in rates. Except for the merger, PacifiCorp had no plans to offer this credit to customer bills or do any of the other things promised by ScottishPower. (Tr. 36, 672.)

B. Transition Plan

The Industrial Customers have suggested that final approval of the transaction should be delayed pending the filing of the transition plan. That condition is both impractical and unnecessary. The record shows that prior to the closing of the transaction, ScottishPower has significant legal and practical impediments to the development of a meaningful plan. (Tr. 930-932.) The record also shows that, even if the transition plan condition was achievable, the Stipulation addresses any legitimate concerns regarding the public interest benefits of the merger, making a transition plan condition unnecessary.

Nucor express concern regarding the difficulty in identifying whether costs or savings are merger related. (Nucor Brief, page 19.) The transition plan will set forth a list of initiatives showing costs and benefits over the transition period. (Tr. 1490.) Cost savings will be identified in the transition plan which the Applicants will file with the Commission six months after closing of the transaction which will enable the Commission to clearly see what cost saving initiatives will be implemented by ScottishPower as a result of the merger. (Stipulation, Condition 13.) The Commission should not delay final approval of the merger pending filing of the transition plan.

C. Improvements in Network Performance and Customer Service

The Applicants have voluntarily committed to provide the most comprehensive set of performance standards and customer guarantees for any U.S. electric utility. (SP Exhibit 2, page 19; Tr. 1483.)

The Industrial Customers have taken conflicting positions in this proceeding regarding ScottishPower's plans for network performance and customer service. The Industrial Customers have argued that:

- The benefits of improved network performance are not "desired, necessary or cost effective". (LCG Brief, page 9.)
- The benefits of improved network performance and customer service are of a speculative nature, that the proposed improvements are minimal, the costs unknown, and the benefits unsubstantiated. (Nucor Brief, pages 12-14.)
- PacifiCorp should be held to the same service quality standards. (UIEC Brief, page 9.)

At the same time, the Industrial Customers appear to be very concerned with service quality and have stated:

- Reliability issues should be a paramount consideration in this proceeding. (LCG Brief, page 4.)
- The merger may affect service quality and reliability. (Nucor Brief, page 8.)
- The potential financial detriment to special contract customers from decreased reliability is enormous. (LCG Brief, page 13.)
- The Industrial Customers are concerned that the service standards are not aimed at them. (LCG Brief, pages 13-14.)
- A single customer may not individually experience improvement in overall network performance. (UIEC Brief, page 10.)

Certainly the Industrial Customers value network performance and customer service. ScottishPower has offered a package that will make significant improvements in these areas. The facts on the record in this proceeding are as follows:

a. All customers benefit from improved network performance. (Tr. 866.)

b. ScottishPower's planned improvements will have an estimated dollar value of approximately $61 million annually and up to $600 million on a net present value basis. (SP Exhibit 1S, page 5.)

c. Other studies confirm the estimated dollar value of system performance improvements ranging from $31 million to $61 million. The studies with lower estimates excluded large commercial and industrial customers from the study base. (SP Exhibit 3R, pages 12-15; Tr. 821.)

d. Utah will benefit approximately $20 million per year from network performance. (Tr. 1483.)

e. ScottishPower has backed up its commitments with financial penalties. (SP Exhibit 2, page 9.)

f. ScottishPower witness Bob Moir discussed in detail ScottishPower's plans for improving and focusing upon customer service. (SP Exhibit 2, pages 3-5.)

g. DPU witness, Maloney, testified that "we'd probably work two to three years before we'd get anything close to what we've got on the table right now", referring to ScottishPower's proposal. Mr. Maloney also thought that ScottishPower's proposal will be more effective because it is voluntary. (Tr. 1459.)

h. The $55 million investment in improvements in customer service and system performance will come from a redirection of existing budgets and savings in other areas such that there will be no new incremental costs to ratepayers for the program. (SP Exhibit 1S, page 8.) In any event, these costs will not be passed on to ratepayers unless the Commission determines in a rate proceeding that they have been prudently incurred. (Tr. 864.)

i. In contrast to the detailed and comprehensive commitment made by ScottishPower to improvements in customer service and system performance, PacifiCorp has no plan for improvements to be undertaken on its own. (PacifiCorp Exhibit 1, pages 7-9 and PacifiCorp Exhibit 1R, page 5.) Without evidence of such plans, the value of ScottishPower's

> commitment cannot be fairly diminished on speculation that PacifiCorp might have achieved some of the same improvements on its own. Also ScottishPower's experience means greater certainty of delivery.

There is no evidence that any of the cost savings associated with the merger will affect safety and reliability. Indeed, the evidence is to the contrary. Improvements in customer service to which ScottishPower has committed have real value to customers, and should be given considerable weight by this Commission in its decision whether to approve the proposed merger. Such improvements clearly increase the adequacy and efficiency of the utility service and benefit the comfort and convenience of PacifiCorp's customers.

D. Summary

Approval of the merger between ScottishPower and PacifiCorp will bring a wide range of benefits to PacifiCorp's Utah customers, as listed in detail in Applicants' Post-Hearing Brief. The Industrial Customers' remarks have not diminished the benefits associated with the transaction. The benefits of the transaction are numerous and well documented in the record of this proceeding.

III. ANY RISKS ASSOCIATED WITH THE TRANSACTION ARE ADDRESSED BY CONDITIONS

The next issue to be addressed by the parties is whether there are any risks associated with the transaction that have not been adequately addressed by conditions in the Stipulation. ScottishPower, PacifiCorp, DPU and CCS agree that the Stipulation effectively addresses all material risks.

The Industrial Customers have identified risks associated with the transaction. In some circumstances, they cited to testimony of the DPU and the CCS which was filed before the Stipulation. The extensive set of conditions that Applicants have negotiated with DPU, CCS and others, effectively neutralize all these risks. (Tr. 476.) DPU Exhibit 1.0 SR lists every issue that the DPU was concerned about and demonstrates how these concerns were addressed. The Commission should take comfort that an extensive review of the issues in this docket has resulted in a comprehensive Stipulation which provides protection for Utah.

The UIEC has argued that the Stipulation is ambiguous and, as a result, the Commission may find it difficult to implement. (UIEC Brief, page 16.) The UIEC has tried to create the impression of ambiguity where there is no real question regarding the terms of the Stipulation.

For example, the UIEC states that there is confusion regarding whether Condition 14 of the Stipulation precludes loans from PacifiCorp to ScottishPower. As support for that statement, UIEC cites a transcript reference where Mr. Alt states that he is not the DPU expert on this condition. However, the UIEC ignores Mr. O'Brien's testimony that PacifiCorp could not lend money to anyone in the ScottishPower group above PacifiCorp. (Tr. 720.) There is no confusion here.

In any event, the Commission will, as the DPU and the CCS pointed out, have the authority to resolve disputes regarding these issues just as they resolve disputes about other issues on a regular basis.

Applicants have maintained throughout the proceeding that the risks, if any, of the merger are far outweighed by its benefits. The stock transaction is a very simple one, involving a change only in the shareholders of PacifiCorp. PacifiCorp will continue to operate on a stand-alone basis. The Commission will exercise a similar degree of regulatory oversight over PacifiCorp as it does today, and the Stipulation establishes a number of conditions designed to ensure that the Commission will not be hampered by the new corporate structure, including conditions relating to access to books and records (Condition 11), numerous reports filed by PacifiCorp (Condition 17), annual reports regarding merger savings for five years (Condition 12), as well as numerous other conditions outlined in Applicants' Post Hearing Brief. There is no basis on the record to support UIEC's assertions that the merger will somehow deprive the Commission of effective regulatory authority.

The Industrial Customers are concerned that the merger will lead to increased costs. There is no evidence to support this concern. ScottishPower's track record has demonstrated successful management. In addition, Applicants have agreed to several broad conditions in the Stipulation that guarantee that costs assigned to customers will not increase as a result of the merger as set forth in Applicants' Post Hearing Brief.

The 51 conditions, along with all of the other commitments the Applicants have agreed to, mitigate any risks associated with the ScottishPower/PacifiCorp transaction.

IV. INDUSTRIAL CUSTOMERS' ISSUES

A. Taxes

The Industrial Customers requested that any potential income tax savings resulting from the ownership of PacifiCorp flow through to PacifiCorp's customers and that this requirement be added as a condition to the Stipulation.

The Industrial Customers in their Post-Hearing Briefs referred to the potential tax savings that may accrue to upstream affiliates of $109.2 million from the transaction. (LCG Brief, pages 3, 16; UIEC Brief, pages 5, 18; Nucor Brief, page 35.) This reference is completely inaccurate. The source of this figure is testimony on an issue which is entirely unrelated to asserted tax savings. During the hearings, the testimony of CCS witness Neal H. Talbot was cited – incorrectly -- as containing an estimate of tax savings flowing from the transaction, and a figure of $109 million was used. In fact, this figure was generated by Talbot as a hypothetical intended to illustrate the impact of double leveraging the capital structure, and there is no mention of asserted "tax savings" flowing from the transaction. Mr. Talbot's testimony, CCS Exhibit 4, Pages 44-48, presents a hypothetical situation illustrating the application of double leveraging in determining the capital structure for ratemaking purposes. At page 48, line 20, he arrives at a revenue requirement of $109.2 million associated with this example.

ScottishPower testified that there is a potential for tax efficiency of the ownership structure upstream of PacifiCorp going forward, but that it is not clear that tax savings will be achievable. (Tr. 1505-1506.)

In fact, there may not be any tax savings whatsoever associated with the transaction. Tax savings do not arise from the transaction itself, but in the calculation of the tax liability on an ongoing basis following the transaction. Tax savings arising from a transaction of this sort are by their very nature speculative as they depend on the tax legislation in existence at the time the tax liability is calculated. For these reasons, the issue cannot properly be addressed in this proceeding. Rather, the issue should be addressed in a subsequent general rate proceeding when the facts are known regarding the tax liability after the transaction.

In this regard, the Applicants proposed the following condition at the hearing as a means of addressing this issue:

> The Parties to this Docket preserve their right to raise the issue of the treatment of upstream tax savings and costs in future rate cases. All parties preserve their positions and have not waived their rights on this issue. ScottishPower commits to retain records regarding upstream tax savings and costs relating to the merger and make these records available to the DPU, CCS and other parties in accordance with Stipulation Ex. 1 and the discovery rules of the Commission.
>
> (Cross Examination Exhibit 2.)

In subsequent general rate proceedings, it will be known whether any tax savings actually materialize. At that time, if tax savings materialize, the Commission will have an opportunity to consider the issue. Moreover, there is an associated policy question of whether the Commission wishes to adopt a practice of looking beyond the regulated utility operations for purposes of determining the tax liability for ratemaking purposes. If the Commission wants to include tax benefits associated with consolidated taxation, it must also consider the costs and risks of consolidated taxation. That issue is unrelated to this transaction; it arises whenever a regulated utility is part of a larger consolidated corporate structure where tax savings may be created from non-utility operations, thereby reducing the consolidated tax liability. Such a policy question need not, and should not, be examined in this proceeding. The Commission should not impose a condition requiring that any tax benefits of the merger be given to ratepayers. There is absolutely no evidence on the record related to the consolidated tax issue. There is no evidence on which to make a finding regarding consolidated taxes.

DPU witness, Lowell Alt, CCS witness, Dan Gimble, agreed that the consolidated tax issue could be addressed in a rate case. (Tr. 86-91.)

The proposed condition resolves all concerns regarding this issue. There are many complex considerations in respect of this matter and these can be adequately and fully addressed in a rate case and should be considered there.

The LCG suggests that the tax issue must be dealt with in this proceeding so that it is a merger benefit. The Applicants have clearly demonstrated that the merger is in the public interest without consideration of the tax issue.

B. Rate Cap

In their initial briefs, the Industrial Customers insist that a rate cap is required to ensure that the merger meets the public interest standard. That assertion is not supported by the record.

The Applicants provided evidence that a rate cap was not required to establish that there are net positive benefits for Utah customers from the merger. In their testimony, the Applicants identified significant benefits to customers from the merger, including the merger credit and the system performance and customer service commitments made by the Applicants, as well as their commitments to the environment, employees and communities. (SP Exhibit 1R, page 8.) The Applicants' testimony also explained that any legitimate risks associated with the merger, including rate related risks, have been adequately addressed by the Stipulation. (SP Exhibit 1R, page 8.) For example, the Stipulation includes commitments that rates will never rise as a result of the merger (Condition 44), and that no transaction related costs shall be allowed in rates (Condition 3). The Applicants have agreed to the use of a hypothetical capital structure for ratemaking purposes (Condition 19).

The Applicants also provided evidence that the rate cap takes no account of underlying business economics unrelated to the merger. (Tr. 1504.)

The two regulatory agencies with the statutory responsibility to represent the broad public interest also concluded that a rate cap was unnecessary. The DPU and the CCS testified that they had performed an exhaustive review and analysis of the potential risks of the transaction and, based on that review, reached the conclusion that the Stipulation protects customers against merger-related risks and provides customers with significant benefits. (Tr. 21-38, 360-362) As a result, they determined that a rate cap was not required to meet the public interest standard. (DPU/CCS Joint Brief, pages 8-9.) The DPU and CCS also expressed their view that the Industrial Customer's five year absolute rate cap would "more than likely do nothing more than assure all concerned that the transaction would not occur." (DPU/CCS Joint Brief, page 8.)

While the Industrial Customers' response to the DPU and CCS testimony was that they must have been "captured" or co-opted by those they regulate, the record supports their conclusion that a rate cap is not required for this merger to satisfy the public interest standard. (UIEC Brief, page 13.)

The Farm Bureau Federation requested a similar condition in its Brief. (Farm Bureau Brief, pages 3-4.) For the reasons discussed above, their proposed condition should also be rejected.

For all the reasons stated above, the rate cap or rate freeze proposals are inappropriate and the Commission should reject any suggestion of a condition relating thereto.

C. Special Contracts.

The Industrial Customers have recommended that, as a condition of the merger, the Commission should require the extension of special contracts through 2003. As support for their position, they make several assertions. The first is that "special contract negotiations stopped dead in their tracks" after the application in this docket was filed. (UIEC Brief, page 23.) There is no evidence in this record to support the assertion that the merger has influenced either the timing of negotiations, or the willingness to negotiate with the special contract customers.

A second assertion made by the Industrial Customers is that "there is no present indication that current costs (of the special contracts) will not be compensatory through the transition period." (UIEC Brief at 24) That assertion is also not supported by the record. DPU witness Powell testified that the current Utah special contracts were approved based on analyses that showed PacifiCorp did not need additional capacity during the term of those contracts. (Tr. 1402) Mr. Powell also testified that he was aware of changes in PacifiCorp's load and resource balance that could now require capacity additions. (Tr. 1403) That testimony certainly qualifies as the "present indication" referred to by the Industrial Customers.

A third assertion made by the Industrial Customers is that, as a result of the efficiencies in operation associated with the merger, "there will be very little risk of harm either to the company or its tariffed customers in extending special contracts through the transition period." (UIEC Brief page 24.) Since the need for new capacity is not impacted by the cost reductions contemplated under the merger, and since PacifiCorp is facing potential changes in its load and resource balances, it is difficult to see how merger related cost reductions could eliminate the risks associated with serving special contract customers at current prices through 2003. (Tr. 1403)

Another Industrial Customer assertion is that the special "contracts at issue in this docket are not firm." (UIEC Brief, page 24) That assertion is incorrect. Special contract customers in Utah do, in some instances, receive firm service under their existing contracts. (Tr. 1398-1399)

Finally, the Industrial Customers argue that special contract customers need protection against merger related risks and it would be discriminatory to deny them extensions of their contracts. That is in essence the same argument raised in Docket No. 87-035-27 (the Utah Power/PacifiCorp merger proceeding). In that case, the Commission rejected proposed contract amendment conditions, stating that:

> "in this era of increased competition and low energy prices the industrial customers have other options for power supply ... which they have been able to use to some advantage in negotiating power contracts with Company. It is therefore unlikely that these customers will be left "holding the bag" after the merger is consummated.

The Commission's reasoning in that prior merger case is equally applicable to the special contract customers in this case. The current special contract customers have special contracts because they had other options for power supply. (Tr. 1402) The merger does not alter either the risks those customers face, or the alternatives they have. In addition, the Applicants have made additional commitments to address special contract customer concerns, including commitments to honor all existing contracts, to negotiate all contracts in good faith and to complete negotiations promptly in recognition of the possible need for customers to pursue their alternatives. (Tr. 1487-1488)

Special contract customers benefit from many aspects of the transaction including benefits associated with network performance improvements and related cost reductions. The commitments included in the Stipulation, along with the assurances made on the record at the hearings, also provide protection against the perceived risks that the Industrial Customers claim exist for special contract customers. Any condition regarding extension of special contracts should be rejected by the Commission.

D. Stranded Costs

UIEC and Nucor recommend that as a condition to the merger that PacifiCorp and ScottishPower renounce any future claim to any stranded costs relating to PacifiCorp because of the payment of a premium. (UIEC Brief, page 26; Nucor Brief, page 38.) UIEC witness, Maurice Brubaker, admitted that:

- He was unaware of any merger proceeding where a merger approval was conditioned upon the merged company agreeing not to make a claim for stranded cost recovery. (Tr. 1315.)
- All of the acquisitions of electric utilities reflected in Exhibit 25 included a premium. (Tr. 1310.)
- The premium in this transaction is at the lower value end of the scale compared to other premiums in the exhibit. (Tr. 1319.)

Stranded cost issues are not appropriate for this proceeding and the evidence shows that a waiver of stranded cost claims is unprecedented in U.S. mergers. Rather, the Utah Legislature is reviewing industry restructuring issues through its Electric Deregulation and Customer Choice Task Force and the Applicants are prepared to contribute to discussions in that forum. (SP Exhibit 1R, pages 12-13.)

E. Regional Transmission Organization ("RTO")

UIEC recommended that the Commission require, as a condition of the merger, that the Applicants "make a commitment about planning and participating in a regional transmission organization ("RTO")". (UIEC Brief, page 28.)

UIEC has attempted to interject completely irrelevant issues into this proceeding by referring to issues in the U.K. which are not germane to this docket. The laws, regulations and level of regulation in the U.K. differ from the situation in Utah and are not relevant to the establishment of a RTO. UIEC's reference to the U.K. government's "special share" has no relevance to any future RTO formation proposed by PacifiCorp.

> As explained in Alan Richardson's Supplemental Testimony:
> The practical effect of the "special share" is to require government approval before control of ScottishPower may be transferred, much like the regulatory statutes in many of the states which require utility commission approval before control of a regulated utility passes to another. It comes into play only if a transfer of ownership of ScottishPower is involved, and does not in any way impose any restrictions on the actions which ScottishPower may take with respect to its own business or PacifiCorp.
> (SP Exhibit 1S, page 18.)

Membership in a RTO does not require the sale of transmission assets, only that operation be turned over. Thus, even if the special share would otherwise have implications with respect to a sale of ScottishPower, it has no relevance whatsoever to the formation of a RTO as no sale or transfer of facilities is involved. The Commission should reject the request of UIEC to impose a RTO as a condition of approval of the transaction. The following summary of the testimony on the RTO issue at the hearing sheds light on this matter.

UIEC witness, Brubaker, admitted that:

- The Utah Commission is not required to apply the Department of Justice/Federal Trade Commission ("FTC") guidelines. (Tr. 1288.)
- The Federal Energy Regulatory Commission ("FERC") adopted the horizontal merger guidelines of the FTC. (Tr. 1289.)
- UIEC intervened at FERC and argued that ScottishPower/PacifiCorp transaction would have an adverse impact on competition. (Tr. 1290.)
- FERC found that because ScottishPower and PacifiCorp did not compete in common geographic markets, there was no change in concentration of the market and therefore no transaction related effect on competition. ("Tr. 1290.)
- FERC found no competitive harm from the transaction and rejected UIEC's argument. (Tr. 1290-1291.)
- UIEC requested that FERC condition approval of this transaction on the Applicants participating in the formation of and joining a RTO. (Tr. 1295.)
- FERC has the authority to condition the approval of the transaction on joining a RTO. (Tr. 1295.)
- FERC concluded that there was no basis for conditioning the transaction on transmission related requirements. (Tr. 1296.)
- The Utah Commission does not have the authority to directly order PacifiCorp to participate in a RTO. (Tr. 1297.)
- Every situation cited where the requirement on participating in a RTO or independent system operator was imposed involved a concern regarding market power. (Tr. 1297-1303.)

ScottishPower is simply obtaining the stock of PacifiCorp. PacifiCorp will continue to operate in its existing service territory. Competitive issues were reviewed by the Federal Energy Regulatory Commission ("FERC"). FERC has established a Notice of Proposed Rulemaking, Docket RM99-2 regarding "Regional Transmission Organizations" and proposes to establish fundamental characteristics and functions for appropriate retail transmission organizations. (UIEC Exhibit 1, page 40.) That is the place where this issue should be reviewed.

F. Magnesium Corporation of America ("Magcorp") Issues

Magcorp requested that the Commission condition the merger by removing Magcorp from PacifiCorp's exclusive service area. (Magcorp Brief, page 1.) In effect, Magcorp is requesting that the Commission revoke PacifiCorp's certificate and create a retail access zone for Magcorp. Magcorp has not and could not provide evidence which would justify the revocation of PacifiCorp's certificate. See e.g. Silver Beehive Tele. Co. v. PSC, 512 P2d 1327 (Utah 1973). Magcorp has also failed to cite any case or statute which would justify the creation of a separate regulatory structure for Magcorp. Retail access is currently under review by the Utah Legislature in its Electric Deregulation and Customer Choice Task Force and should be considered there. In any event, the issues raised by Magcorp are not merger related and are not relevant to this docket.

G. Summary

The Industrial Customers have not identified any risks or issues arising from this transaction that are not adequately addressed by conditions and the evidence on this record. None of the additional conditions proposed by the Industrial Customers should be required by the Commission. As shown above, these conditions either do not address risks that are merger-related issues or they are unnecessary.

Magcorp's issues are similarly not appropriate for this proceeding.

CONCLUSION

Approval of this transaction will deliver net benefits to PacifiCorp's Utah customers. ScottishPower has committed to improve system performance and customer service with an unmatched package of initiatives that will benefit all of PacifiCorp's customers. The merger credit of $48 million establishes a guaranteed financial benefit to customers, which places the value of the transaction beyond any reasonable dispute. Scottish Power intends to deliver cost savings that can be passed through to customers in rates. The conditions that Scottish Power, PacifiCorp, DPU and CCS have agreed to ensure that these benefits will be delivered and that customers will not be harmed. The conditions proposed by the Industrial Customers and Magcorp should be rejected.

In sum, approval of this transaction will serve PacifiCorp's customers in the public interest. For the reasons set forth above, the Commission should approve the Application.

DATED this 17th day of September, 1999.

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CALLISTER NEBEKER & MCCULLOUGH

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CERTIFICATE OF SERVICE

I hereby certify that I caused the foregoing ***REPLY BRIEF OF APPLICANTS SCOTTISH POWER PLC AND PACIFICORP*** to be served upon the following persons via Federal Express or by mailing a true and correct copy of the same, postage prepaid, to the following on September 17, 1999:

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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of PacifiCorp and Scottish Power plc for an Order Approving the Issuance of PacifiCorp Common Stock	Docket No. 98-2035-04 **LARGE CUSTOMER GROUP'S REPLY BRIEF**

INTRODUCTION

In its Opening Brief, the Large Customer Group ("LCG") cited extensive testimony in the record showing that the claimed benefits of the proposed acquisition of PacifiCorp by ScottishPower are uncertain, speculative and relatively insignificant, while the risks are significant and inadequately mitigated. The Applicants' Brief repeats the well-worn, largely discredited, argument that Utah customers will receive significant benefits at no risk. Ignoring self-serving, unverifiable claims, the Applicants' Brief fails to adduce substantial credible evidence that the public interest of the State of Utah will be best served by approval of the acquisition as currently proposed. The applicants have simply not carried their heavy burden of proof.

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A. The Commission Need Not Approve the Acquisition as Proposed.

The Opening Briefs of the Applicants and the DPU/CCS seem to assume that this Commission is essentially obligated to approve the proposed acquisition because the Stipulation, with its relatively meager "merger credit," supposedly pushes the proposed acquisition over some illusory "net positive benefits" line. [Applicants' Brief at 26; DPU/CCS Brief at 6-7]. Such an assumption is devoid of logic or merit. ScottishPower does not have a **right** to acquire control over Utah's monopoly electric service facilities, and it certainly cannot buy such a right with vague, short-term promises. ScottishPower can acquire PacifiCorp only if it first satisfies its heavy burden of making a substantial, verifiable showing that the proposed acquisition will be in the long-term best interests of the State of Utah. The proper question before this Commission is not whether the Applicants have managed to put just enough on the table to push the proposal over a nebulous "net positive benefits" line, but rather whether there are other reasonable conditions that should be required to better assure Utah electric consumers of long-term, verifiable benefits and protections against risk. The LCG submits that additional protections are both appropriate and necessary to protect the interests of Utah consumers.

B. Absent a Rate Cap, Claimed Benefits of the Acquisition are Uncertain, Speculative and of Limited Value.

As explained by a number of diverse witnesses, the benefits of the acquisition as proposed are largely uncertain and speculative and produce few significant, verifiable or long-term benefits, while the risks are significant and inadequately mitigated. In tacit acknowledgment of the limited value of assured benefits, the Applicants continue to offer tantalizing assurances--although not guarantees--of significant cost savings: "ScottishPower *will achieve* cost savings in the operations of PacifiCorp beyond that which PacifiCorp could achieve on a standalone basis." [Applicants' Brief at 4 (emphasis added)]. While this language may sound a lot like a guarantee to the untrained ear, the Applicants have carefully structured the transaction in an effort to avoid any possibility of guaranteed cost-reduction commitments to back up their tantalizing projections. A rate cap--a remedy supported by substantial testimony on the record--affords the Applicants the clear opportunity either to back up their bravado with guarantees or to cease causing misleading expectations.

The DPU/CCS Brief dismisses the $10 million per year in guaranteed cost savings committed to by the Applicants in their initial filing (with a net present value to Utah estimated by Applicants at $35 million) as "minimal" [DPU/CCS Brief at 3], yet embraces a "merger credit" with a net present value of under $40 million, drawing the unsupported conclusion that the "merger credit" will provide adequate protections against the risks associated with the transaction. [DPU/CCS Brief at 8]. The merger credit is insufficient to ensure that Utah customers are adequately protected against the significant risks of the transaction. Only a rate cap will adequately mitigate those risks.

C. The Commission Must Take Affirmative Steps Now to Ensure that Merger Benefits in the form of Upstream Tax Savings Can be Shared with Utah Consumers.

The Applicants have proposed a condition that all parties preserve their rights and arguments on the issue of tax savings. The Applicants' Brief makes the astonishing claim that this proposed condition "would resolve all concerns regarding this issue." [Applicants' Brief at 19]. To the contrary, and as explained in detail in the briefs of the LCG, the UIEC and Nucor Steel, the Applicants' proposed condition falls far short of resolving the significant concerns on this issue.

The Applicants clearly hope to escape this approval process with no specific order addressing the issue of taxes. They hope to be able to argue in the future that, having failed to establish its jurisdiction as a condition of the acquisition, the Commission has no legal basis to capture upstream tax savings as merger benefits to be shared with Utah electric consumers.

According to the DPU/CCS Brief, the state agencies "do not disagree with the industrial customers that the tax savings associated with the transaction ... should be available to flow through to ratepayers if appropriate." [DPU/CCS Brief at 10], but they take a giant unsupported leap in logic in concluding that the condition proposed by the Applicants "adequately preserves the upstream tax savings associated with the acquisition ... and that the Commission need not decide the issue on its merits in this proceeding." [DPU/CCS Brief at 11]. The state agencies either wholly miss the point or are remarkably confident in their legal opinions (reached without any research or analysis shared on the record). Unless the Commission acts affirmatively in its Order to ensure its jurisdiction to even *consider* the merits of this issue, it may never get the chance to address the merits. The Applicants have made it abundantly clear that they intend to stand on their legal argument that the Commission lacks jurisdiction to capture the benefits of upstream tax savings for Utah consumers in rate proceedings. The Commission will reach the merits of the argument only if it first wins the legal battles, including probable appeals.

All legal disputes over this issue can be easily avoided by a requirement that the Applicants agree as a condition of approval that the Commission has full and adequate power and jurisdiction to decide, on the merits, whether and what amounts of tax savings realized by ScottishPower affiliates as a result of the acquisition should be considered merger benefits that should flow to Utah electric consumers. No one has offered a logical reason why the Commission should not diffuse this debate once and for all in this proceeding.

D. Absent a Rate Cap, Special Contract Extensions are Necessary to Produce Equitable, Non-Discriminatory Results.

The Applicants and state agencies suggest that a promise by PacifiCorp to negotiate in good faith with special contract customers is adequate to mitigate risks faced by these customers. To the contrary, such a promise is illusory and inadequate. No one has offered any adequately explanation why this one class of customers should be denied any meaningful protections against risks of the proposed acquisition. Discriminatory and inequitable results can be avoided only by providing all customers with comparable protections—preferably through a rate cap for all customers; alternatively through short-term contract extensions.

Special contract customers have not asked for preferential treatment or contract modifications.[1] Rather, they seek a modicum of protection against the significant identified risks of the proposed acquisition. A rate cap applied to all customers, or alternatively, a short-term contract extension, would provide special contract customers with reasonable time to explore other

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[1] Issues raised by special contract customers in this case are nothing like the issues raised in the PacifiCorp/Utah Power merger by certain interruptible customers who requested modifications of contractual interruption priorities. The special contract customers here have not requested contractual amendments or preferential treatment, but rather reasonable protections against identified risks commensurate with the protections offered to other customers.

alternatives.

The DPU and CCS state that they will not oppose extensions of contracts that are in the public interest. [DPU/CCS Brief at 17]. The special contract customers ask for nothing more. Either all rates should be capped or special contracts should be extended, subject to the Commission's jurisdiction to determine, upon appropriate request, whether each contract is in the public interest. The requested extensions are not intended to evade Commission review or public interest considerations, but rather to mitigate against delays, vagaries and uncertainties caused by the takeover of PacifiCorp.

PacifiCorp's promise to negotiate in good faith does nothing to ease the risks or concerns faced by special contract customers. Absent aggressive requirements imposed on the utility,[2] the remaining time before contracts expire is simply not adequate to accommodate typical negotiations and reasonable pursuit of alternative supply options.

CONCLUSION

The Applicants have not met their heavy burden of demonstrating by substantial evidence that the proposed transfer of control to ScottishPower over essential electric facilities and exclusive service rights would be in the public interest of the State of Utah. The risks are too great and the benefits too speculative. Despite efforts by the Division and Committee, the Stipulation simply does

[2]For example, under an approach utilized by some regulatory agencies, the Commission could reserve ruling on the special contract issues or the request for contract extensions for a period of 90 days with directions to the parties to attempt to negotiate satisfactory extensions during that period. If the parties reach agreement, the contracts would be submitted for Commission approval. Failing agreement, the Commission would enter rulings on the reserved issues.

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not go nearly far enough to provide meaningful protections to Utah electric consumers. The Commission should require the Applicants to accept further conditions. At a minimum, the commission should require a rate cap for all Utah customers to provide meaningful protections against rate risks and a waiver of any claims or arguments that the Commission lacks power or jurisdiction to require that tax savings realized by ScottishPower affiliates stemming from the acquisition be shared with Utah electric consumers as benefits of the transaction.

DATED this 17th day of September, 1999.

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Re: PacifiCorp/ScottishPower - Docket No. 98-2035-04

Dear Commissioners:

Enclosed please find for filing an original and three copies of PacifiCorp/ScottishPower's Confidential Reply Brief in the above-referenced docket. The original Confidential Reply Brief should be kept under seal and each Commissioner should receive a copy. I am also providing an electronic copy of the Confidential Reply Brief as required by the Commission's rules.

Thank you for your cooperation in this regard. If you have any questions, please feel free to contact me.

Sincerely yours,

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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of PACIFICORP and SCOTTISH POWER PLC for an Order Approving the Issuance of PACIFICORP Common Stock	Docket No. 98-2035-04 REPLY BRIEF OF NUCOR STEEL, A DIVISION OF NUCOR CORPORATION

PacifiCorp, ScottishPower (collectively the "Applicants"), the Division of Public Utilities (the "DPU" or the "Division"), and the Committee of Consumer Services (the "CCS" or the "Committee") urge a view that this is a risk-free merger with substantial benefits for Utah. It is not. The Applicants, Division and Committee find merger benefits where there are none, and ignore merger-related risk. The principal points raised in the *Post-Hearing Brief of Applicants Scottish Power PLC and PacifiCorp* ("Applicants' Initial Brief") and the *Joint Brief of the Division of Public Utilities and the Committee of Consumer Services* ("DPU/CCS Initial Brief") were discredited in the *Initial Brief of Nucor Steel, a Division of Nucor Corporation* ("Nucor Initial Brief"), as well as the initial briefs of the other industrial customers in this docket, the Utah Industrial Energy Consumers ("UIEC") and the Large Customer Group ("LCG"). This Reply Brief[1] is thus not intended to address all matters raised in the initial briefs of the

[1] This Reply Brief is filed pursuant to the Commission's order from the bench in this proceeding. Tr. 1536 at 3-9.

Applicants and the Division and Committee, but only those Nucor believes warrant additional comment. Simply because Nucor chose not to reply to certain comments should not be interpreted as agreement with or acquiescence in the substance of those comments. Nucor encourages the Commission to look carefully at claimed benefits and mitigation measures, and to focus on whether the merger creates real benefits that outweigh the real risks imposed by the merger. Upon review of the initial briefs of the parties, Nucor believes more strongly than ever that additional conditions are necessary to ensure that the merger is in the public interest.

I. THE REAL MERGER-RELATED BENEFITS IDENTIFIED BY THE APPLICANTS, DIVISION AND COMMITTEE REMAIN MINIMAL

As the Commission has formulated the public interest standard, a merger is in the public interest if "the expected benefits of the merger to the Utah jurisdiction outweigh the costs and potential detriments associated with it." *Re Utah Power and Light Company,* 97 PUR 4th 79, 125 (Utah P.S.C. 1988) ("*UP&L II*"). The burden is on the applicants to show that the merger will result in benefits that could not be achieved without the merger. *Id.* Moreover, the Commission has made it clear that the applicants must *quantify* the savings resulting from the merger. *UP&L II*, 97 PUR 4th at 101.

In their initial briefs, both the Applicants and the Division and Committee assert that a variety of non-quantified and not necessarily merger-related benefits should be attributed to the proposed merger. Nucor urges the Commission to resist the entreaties to encompass every positive thing PacifiCorp might do in the future from being included in the determination of whether or not to approve this merger.

The Applicants broadly assert six merger benefits: (1) the merger credit, (2) the "ability to pass additional cost savings through to customers," (3) network performance and customer service improvements, (4) community-related commitments, (5) environmental commitments and (6) wholesale customer commitments. Applicants' Initial Brief at 3-13. Of these, the only truly quantified benefit that could not be achieved without the merger is the $12 million per year merger credit. The other claimed benefits do not warrant being included in the public interest assessment for a variety of reasons. *See* Nucor Initial Brief at 10-18. The Applicants' attempt to categorize their "ability" to pass through cost savings and "intention" to achieve cost savings as being "benefits" barely deserves comment. *See* Applicants' Initial Brief at 4. It is of course not the ability to pass-through benefits or the intent to achieve savings that matter – it is the quantifiable benefits created by the proposed merger that matter. As to the network performance and service quality improvements, the Division and Committee claim that the promised network improvements and service quality standards "will produce measurable benefits to Utah customers," and that "nobody can seriously dispute that those benefits are not significant." DPU/CCS Initial Brief at 9, 10. The Committee's own witness testified as to the "significance" of these claimed benefits:

> My most important recommendation with regard to the application in this proceeding is that nothing that ScottishPower has offered with respect to the performance standards and customer guarantees demonstrates any significant benefit from the merger.[2]

Various witnesses concurred with Mr. Chernick's conclusion. Division witness Alt testified that the Division "didn't really count on [the $60 million benefit] because, to me, we saw a

2 Direct Testimony of Paul Chernick, Ex. CCS-3 ("Chernick Direct"), p. 42 at 17-20.

probability that it could go the other way."[3] As Dr. Richard Anderson testified "[n]o weight should be given to this weak attempt to quantify claimed benefits."[4]

Numerous other cited benefits are no more than commitments to live by existing obligations, to continue to support various programs, or to continue to follow current practice. For the community-related, environmental and wholesale commitments identified by the Applicants, no attempt has been made to make the required showing that the benefits could not be achieved without the merger. Virtually none of the "benefits" have been meaningfully quantified.[5]

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[3] Tr. 472 at 16-18 (Alt).

[4] Direct Testimony of Richard M. Anderson, Ex. LCG-1 ("Anderson Direct"), p. 13 at 36-37; *see also* Direct Testimony of Dennis W. Goins, Ex. Nucor-1 ("Goins Direct"), p. 8 at 21 to p. 9 at 3; Direct Testimony of Maurice Brubaker, Ex. UIEC-1 ("Brubaker Direct"), p. 14 at 5-14. Moreover, Dr. Anderson notes that customers will largely be expected to pay for all of the system reliability enhancements. ScottishPower can hardly claim merger benefits stemming from system improvements funded by the customers. Anderson Direct, pp. 13-14.

The Applicants' confirm Dr. Anderson's concerns. The Applicants state that "these costs [$55 million] will not be passed on to ratepayers unless the Commission determines in a rate proceeding that they have been prudently incurred." Applicants' Initial Brief at 8. This statement, coming in the same paragraph as the statement that "there will be no new incremental cost to ratepayers for the program," should vividly highlight for the Commission the coming debates over the costs and benefits of this merger.

[5] As to the "benefit" of adding another manager in Utah, Nucor notes that the insertion of an additional manager without authority is not necessarily in the special contract customers' best interests. *See* DPU/CCS Initial Brief at 13; Applicants Initial Brief at 20 (both suggesting that the addition of a Utah manager will, in some unspecified way, satisfy industrial customers' "concerns"). The potential for the insertion of another level of management is the precise concern expressed by contract customers. While it may solve problems perceived by the Department of Community and Economic Development and the Division of Business and Economic Development, it may be counterproductive with respect to contract customers.

Despite the recognized lack of substantial benefits (*see* Nucor Initial Brief at 10-11), the Division and Committee are discouraging the Commission from capturing all potential benefits for ratepayers. The Division and Committee suggest that the Commission "need not capture all possible future benefits that may arise out of the transaction in order to satisfy the 'public interest' test." DPU/CCS Initial Brief at 6. This misses several principal points raised by various intervenors. First, the identified benefits are extremely slight when compared to the benefits being achieved by shareholders and management. The minimal level of benefits makes it imperative that, if the merger produces benefits, the ratepayers share in those benefits. Second, as to the potential tax benefits identified, the issue is whether the Commission will have any authority whatsoever to take action in the future to capture this benefit. If the Commission does not act to ensure its jurisdiction, it may never be able to capture the benefit.

Nucor addressed at length the alleged benefits of the merger in its Initial Brief, and will not belabor the issue here. For all the benefits claimed, Division and Committee witnesses recognized that the benefits are so minimal that without the merger credit even they could not claim a net benefit for this merger. *See* Tr. 361 at 25 to 362 at 6 (Alt); Tr. 362 at 16-22 (Gimble). The Division and Committee seem more concerned with ensuring the consummation of the merger than with the impact of the merger on ratepayers. *See* DPU/CCS Initial Brief at 8 (while a rate cap is desirable from a customer's standpoint, it would likely mean the merger wouldn't occur – therefore such a cap is bad). Nucor urges the Commission to take the necessary steps to assure that ratepayers receive real, significant benefits from the merger, commensurate with the risks they are asked to bear.

II. THE APPLICANTS, DIVISION AND COMMITTEE INCORRECTLY ASSERT THAT MERGER-RELATED RISK IS SUFFICIENTLY MITIGATED

The Applicants, the Division and the Committee continue to claim in their initial briefs that the risks posed by the merger are mitigated by the Stipulation. *See* Applicants' Initial Brief at 13-26; DPU/CCS Initial Brief at 2. The Division and Committee go to great pains to justify rejecting additional conditions. Yet, as Nucor and others discussed in initial briefs in this docket, the claim that all risks have been perfectly mitigated by the Stipulation was defused at hearing:

> Q: Okay. And as I understand the rationale, it's because the risks couldn't be perfectly mitigated, you want to have some guarantee of benefits that essentially put this over the top in terms of meeting the net benefit standard?
>
> A: That's right.[6]

See Nucor Initial Brief at 19. In addition, certain risks imposed on special contract customers are not addressed in any way by the Stipulation (*see* Nucor Initial Brief at 23-26) – this despite the pains taken to assure the provision of data and information and protect the potential risks facing other groups and interests, such as environmental, low-income, wholesale, and community and economic development.

The Division and Committee cite enforcement problems as one reason not to add additional conditions to the merger approval. In their initial brief, the Division and Committee urge the Commission to focus on, among other things, the Commission's ability to enforce proposed conditions as a prerequisite to imposing conditions on the merger. *See* DPU/CCS

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[6] Tr. 361 at 25 to 362 at 6 (Alt). *See also* Tr. 362 at 16-22 (Gimble); Tr. 175 at 20-22 (Wright).

Initial Brief at 6.[7] If the Commission approves the merger on the basis of conditions concerning future behavior, the new PacifiCorp will be bound by those conditions. The Commission's powers under section 54-725 are available to enforce the conditions suggested by the intervenors. The Commission's enforcement abilities are thus identical for virtually every paragraph in the Stipulation. *See* Tr. 75 at 8-13.[8] The Division and Committee's vague concerns in this regard are not well placed and should be disregarded.

One of the Division's "tests" of suggested conditions, whether the condition is "outside of the Commission's traditional jurisdiction or the Commission's role," is not a test for the appropriateness of a condition. Rather, the answer to the question determines the placement of the burden of proof necessary to establish the need for a condition. In language quoted by the Division and Committee, the Commission in the UP&L/PP&L merger stated that in areas "outside our normal regulatory jurisdiction and enforcement powers" parties other than the merger applicants bear the burden of demonstrating a benefit or harm that necessitates a condition. *Re Utah Power & Light Company*, 90 PUR 4th 555, 556 (Utah P.S.C. 1987) (*UP&L*

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7 It is interesting that enforcement risk related to additional conditions is such a grave concern of the Division and Committee. The Division and the Committee are more than willing to ignore the risk that the Commission may lack jurisdiction to enforce a claim as to tax-related merger benefits.

8 The exchange between Commission White and ScottishPower witness Wright was instructive on this point:

> COMMISSIONER WHITE: Okay. So if the Commission believed that PacifiCorp or ScottishPower had not lived up to any of the terms and conditions, I take it we would be expected to proceed under section 54-725.
>
> MR. WRIGHT: Right.

Tr. 75 at 8-13.

I"). The Commission did not there establish a jurisdictional or enforcement "test," and should not accept the Division and Committee's apparent suggestion to do so here.

The Division and Committee also note that conditions must address items directly related to the merger. DPU/CCS Initial Brief at 3. While the Division and Committee do not clearly specify which particular conditions they believe run afoul of this "test," Nucor surmises that they are attempting to attack intervenor positions related to stranded costs, in that the Division and Committee state their opinion, without elaboration, that the merger case is not "the proper forum to resolve the complexities attendant to the stranded cost issue." DPU/CCS Initial Brief at 14. To the contrary, the merger creates and implicates stranded cost issues, and this case is the most appropriate forum to address those issues. Not only does the merger create potential stranded cost claims related to the premium being paid and the transaction costs (*see* Nucor Initial Brief at 38), but the very fact of the high premium creates greater incentive within the new PacifiCorp to vigorously seek all potential avenues of income to satisfy investors. The new PacifiCorp will be in a materially different position as a result of the merger, and the risk this creates is appropriately dealt with now.

The Stipulation goes to great pains to protect rights to information and data, and in some instances provides what amounts to a belt and suspenders to ensure that the merged company will continue to do what it is already obligated to do. *See* Nucor Initial Brief at 22. As to ensuring that actual benefits go to ratepayers, few protections are in place. When it comes to protecting vital ratepayer interests, we are told to rely on vague promises and assumptions about the law and the future. This is not only unnecessary it is unacceptable. The Stipulation does not mitigate all risks to all customers. Additional conditions are necessary to protect all customers (including special contract customers) from merger-related risks, and to preserve merger-related benefits.

III. The Division and Committee's Position as to Potential Tax Benefits is Instructive of Their Approach to Reviewing this Merger

While at one point the Division and Committee confidently claim that any tax benefits "will be subject to future proceedings and decisions of the Commission," (DPU/CCS Initial Brief at 7), they later express their belief that the tax savings "*should* be available to flow through to ratepayers if appropriate." DPU/CCS Initial Brief at 10 (emphasis added). Yet the Division and Committee do not recommend any additional conditions to protect ratepayer interests. This stands in stark contrast to the approach in the Stipulation of providing assurances that the Applicants would do what they are already obligated to do. *See* Nucor Initial Brief at 22. Indeed, the Division and Committee's less than firm commitment provides little solace to ratepayers who are receiving scant benefit from the merger.

Nucor agrees that the amount of tax savings and the manner in which any savings will be passed through to ratepayers can be left for another day. What cannot be left for another day is a determination by this Commission that any tax benefits created as a result of this transaction are by definition "merger-related," and an agreement by the Applicants (through a condition) that this Commission has the jurisdiction to determine that merger-related tax benefits should be used for the benefit of ratepayers. *See* Nucor Initial Brief at 34-37.

IV. The Applicants, Division and Committee Continue to Inappropriately Ignore Special Contract Customers in the Evaluation of the Public Interest Standard

The Division and Committee base their decision to ignore the impact of the merger on special contract customers on the Commission's order in the UP&L/PP&L merger and the "striking" similarities between the cases. DPU/CCS Initial Brief at 15-17. There are unquestionably similarities. Both cases involve mergers; they both involve requests by special contract customers, and at the time of both cases there were task forces assessing various special contract issues. The similarities are irrelevant to whether the relief requested in this case by special contract customers has merit.

The difference between these two cases that has escaped the Division and Committee is that the UP&L/PP&L merger promised tremendous benefits to ratepayers, and came at a time when utility costs were declining. In that case, the industrial customers sought to share in these benefits through an improvement in their priority of service. The Commission declined to provide the requested enhancements to the contracts, on the grounds that doing so would provide those customers with preferential treatment. *See UP&L II* at 114. Here, however, special contract customers do not seek preferential treatment, or enhancements in the pricing provisions at the heart of each contract. Rather, special contract customers seek protection from the risks imposed by the merger – protection that should be provided to all customers.

The Division, Committee and the Applicants cite the existence of the special contract task force as an additional reason for ignoring special contract customers, on the notion that the task force is "looking at the appropriate criteria for extensions of these contracts" and that a report to the Commission will be submitted by the end of the year. *See* DPU/CCS Initial Brief at 17;

Applicants' Initial Brief at 23-24. Given the expiration dates of the contracts (Tr. 1385 at 2-4 (K. Powell)) and the timing required by special contract customers for the consideration of alternatives, those customers need to make decisions now. Tr. 1212 at 20-23 (Anderson). A task force report will not be filed until the end of the year – no guidance will be provided until the Commission acts on the report. With contracts expiring in the near future, this sort of a "wait and see" attitude espoused by the Applicants, Division and Committee will force the hand of special contract customers.

As to Nucor's request that if contracts are not extended customers be given the option of taking service from other suppliers (*see* Nucor Initial Brief at 34), the Division and Committee suggest that "[i]t seems unreasonable for the Commission to require PacifiCorp to waive any legal rights it may have." DPU/CCS Initial Brief at 18. This is an unusual comment, given that that seems to be the very purpose of merger conditions – to require the merging companies to do things they otherwise would not be obligated to do. Arguing that the Commission should not adopt a condition because the Applicants would otherwise be free of that condition is absurd.

The promises made by ScottishPower with respect to the conduct of negotiations with special contract customers was fully addressed in Nucor's Initial Brief, at 27-28. As was explained there, these promises represent nothing more than a commitment by ScottishPower to do (1) what they are otherwise required to do,[9] and (2) what common business sense would tell them to do,[10] and are largely, if not wholly, unenforceable. The promises are nothing less than what Nucor would expect of all of its suppliers. In fact, Nucor is troubled by the implicit notion

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9 *E.g.*, honor existing contracts and abide by Commission rules.

10 *E.g.*, allow ScottishPower to be involved in negotiations, negotiate in good faith and in a timely manner, and recognize the contributions made by special contract customers.

that without such a "commitment," ScottishPower intended to (1) refuse to honor the existing contracts, (2) prevent its representatives from joining in negotiations prior to the merger, (3) negotiate in bad faith, (4) attempt to drag out negotiations, (5) refuse to recognize the contribution the customer makes to the economy of Utah, and (6) ignore Commission rules. These commitments typify the "benefits" espoused by the Applicants, the Division and the Committee in this case, and are insufficient to mitigate the merger-related risks facing special contract customers.

V. ADDITIONAL CONDITIONS REMAIN NECESSARY TO ENSURE THAT THE MERGER IS IN THE PUBLIC INTEREST

As Nucor stated in its Initial Brief, at least four additional conditions are required to ensure that the proposed merger is in the public interest:

(1) Rates of all Utah tariff customers should be capped and all provisions of the Stipulation should be adopted as conditions of merger approval;

(2) Current Utah special contract customers should have the option of having their contracts extended through the transition period on current terms and conditions, subject to Commission approval (or, in the alternative, to buy power from alternate suppliers);

(3) The Applicants should be required to acknowledge that if the Commission determines that tax savings result from the merger, then those tax savings will go to benefit customers, through rate reductions. Whether tax savings are created and the amount of any savings should be left for a future proceeding; and

(4) The Applicants should be required to waive any and all future claims to stranded costs relating to existing generation- and transmission-related assets, as well as claims relating to the merger premium and/or merger transaction costs, in any proceeding.[11]

[11] Nucor concurs with the UIEC that, at a minimum, the Commission should include in its order a finding that will permit the Legislature (or a future Commission) to conclude that any claim for stranded cost has been satisfied as a result of this transaction. *See* UIEC Initial Brief at 27.

After reviewing the initial briefs of the Division and Committee and the Applicants, Nucor recommends that the Commission take steps now to ensure that merger-related risk is placed appropriately on the Applicants and that identified merger-related benefits are preserved. Moreover, the Commission should recognize that Applicants, the Division and the Committee propose no protection for special contract customers comparable to the merger credit, in spite of the significant merger-related risk facing those customers. Given that these customers represent a significant portion the Utah customer base, the impact of the merger on these customers cannot be ignored for purposes of assessing the public interest.

WHEREFORE, for the reasons set forth herein, as well as in Nucor's Initial Brief, the Commission should adopt the conditions suggested by Nucor Steel, impose such additional conditions as it deems appropriate, and make such modifications to the Stipulation as it believes are necessary to clarify the protections meant to be provided therein.

DATED this 17th day of September 1999.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that on this 16th day of September, 1999, I caused via mail, first class, postage prepaid, a true and correct copy of the foregoing **REPLY BRIEF OF NUCOR STEEL, A DIVISION OF NUCOR CORPORATION** to:

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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

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SERVICE COMMISSION

In the Matter of the Application of PacifiCorp	**)**	
And ScottishPower plc for an Order Approving	**)**	**Docket No. 98-2035-04**
And Issuance of PacifiCorp Common Stock	**)**	
	)	

REVIEWED BY COMMISSIONERS
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REPLY BRIEF OF INTERVENOR MAGNESIUM CORPORATION OF AMERICA ON THE PROPOSED MERGER OF SCOTTISHPOWER PLC AND PACIFICORP

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Dated: September 17, 1999

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of PacifiCorp And ScottishPower plc for an Order Approving And Issuance of PacifiCorp Common Stock	))))	**Docket No. 98-2035-04**

REPLY BRIEF OF INTERVENOR MAGNESIUM CORPORATION OF AMERICA ON THE PROPOSED MERGER OF SCOTTISHPOWER PLC AND PACIFICORP

Pursuant to the briefing schedule established by the Commission in the above-referenced proceeding, Magnesium Corporation of America ("Magcorp")[1] hereby submits its Reply Brief.

ARGUMENT

In their Initial Briefs, the Division of Public Utilities (the "DPU"), joined by the Committee of Consumer Services ("CCS"), and the Applicants maintain their painstaking and consistent efforts to exclude industrial customers from any merger benefits. Under their interpretation of the "net benefits test," so long as residential and small commercial customers receive some benefit, it is of no importance in determining whether the Applicants meet the "net benefits" test that the backbone of the Utah manufacturing economy -- the large industrial customers -- have been excluded from the Proposed Settlement Stipulation ("Stipulation") in either its negotiation or terms.

As Magcorp has noted, however, it does not attempt to impose upon the economic benefits parceled out to others in the Stipulation. Magcorp does not seek any modification of its existing contract, either through early termination or regulated

[1] All references to Magcorp and to Applicants herein include, by incorporation, references to their respective predecessor-in-interest, as appropriate.

extension; Magcorp will abide by its contracts and assumes PacifiCorp will continue to do likewise. Nor does it seek any regulatory requirement that Applicant be required to negotiate with it in "good faith," since any such requirement is meaningless because it is so easily evaded: who is to say whether a party has negotiated in "good faith"?

What Magcorp does seek is simply a condition that would allow it to contract with the most economic power supplier effective upon termination of its current contract with PacifiCorp by decertifying Magcorp from PacifiCorp's exclusive service territory.[2] By this condition, Magcorp does not seek to exclude PacifiCorp from being its power supplier. But this condition, more than anything else the Commission could do, will effectively enforce PacifiCorp's volunteered undertaking to negotiate with Magcorp in good faith. Consequently, this condition is appropriate in any event as to Magcorp -- the only party and only class requesting the condition -- to implement PacifiCorp's volunteered undertaking.[3]

Thus, all of the arguments advanced against the position of the "industrial customers" by the DPU, the CCS and Applicants simply have no applicability to Magcorp. And once the testimony of Lowell Alt is examined, there appears to be no basis for the DPU to oppose Magcorp's requested condition.

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[2] By order dated April 19, 1968 in Case No. 5639, *et al.*, PacifiCorp was authorized to expand its service territory to include Magcorp. If in so doing, the Commission did not thereby render PacifiCorp's service rights therein exclusive as to Magcorp, but only permissive to the extent it had a contract with Magcorp, then in such event, Magcorp's requested condition would be rendered moot, since PacifiCorp would not have the exclusive right to serve Magcorp, which is the relief requested by Magcorp in its condition.

[3] Magcorp's request was first made in comments on the Stipulation prior to the hearing on August 6, 1999 to remedy its exclusion from the negotiation of the Stipulation or from any benefits under the Stipulation.

As to Applicants, in their Initial Brief they either misrepresent the record or attempt to avoid it. Interestingly, Applicants make no claim that Magcorp was included in the negotiation process for the Stipulation. Further, notwithstanding Applicants repeated claims, the unchallenged testimony of Magcorp was that despite its repeated requests to PacifiCorp over a six-month period, PacifiCorp refused to negotiate with Magcorp on a new contract, most recently as June 1999 when its representatives personally informed Mr. Lee Brown that they had no proposal to make nor would any proposal be forthcoming. It was only after Magcorp's August 6th filing and Mr. Brown's August 6th testimony that Applicants changed their tune. But although correspondence has now been received setting out Applicants' intent to negotiate with Magcorp, to date -- some 6 weeks after Mr. Brown's testimony -- there has neither been a proposal forwarded nor even a telephone call to set up a meeting. Given this "slow play" state of affairs, effectively jamming Magcorp into a time squeeze where it has no options or alternatives, imposition of the merger condition to assure that Applicants abide by their undertakings is fully appropriate.

"Trust me" may be a comforting assurance if confirmed by positive actions over time. But no such positive actions are reflected on this record. As Magcorp pointed out -- unchallenged, PacifiCorp explicitly refused negotiation with it over a new contract. Given this state of the record, there simply is no predicate in the record for affording Applicants' assertion any credibility. Magcorp's requested condition provides it with the certainty of options and alternatives compared to the hollow ring of Applicants' "trust me."

Magcorp will not repeat here the arguments in its Initial Brief of how its proposed condition is fully warranted; inures to the benefit of Utah, Applicants and other ratepayers; and satisfies the public interest standard. Rather, Magcorp would simply point out that given the marginal and parsimonious nature of the "net benefits" accruing under the Stipulation, as admitted even by the DPU and the CCS, adopting Magcorp's proposed condition only serves to make the Stipulation more inclusive and representative, in satisfaction of the public interest requirements for approving a merger.

Respectfully submitted,

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Dated: September 17, 1999

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I hereby certify that a true and correct copy of the Reply Brief of Intervenor submitted by Magnesium Corporation of America dated September 17, 1999 on the Proposed Merger of ScottishPower PLC, and Pacificorp, was sent first class mail, postage prepaid to the parties set forth below on this 17th day of September, 1999.

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SERVICE COMMISSION

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SEPT. 12, 1999

CHAIRMAN,
PUBIC SERVICE COMMISSION
160 E 300 SOUTH
SLC UT 84111

DEAR SIR:

WE ARE WRITING YOU CONCERNING PACIFICORP (UP&L) AND THE PROPOSED ACQUSITION BY A SCOTTISH COMPANY. WE ARE JUST A COUPLE OF THE THOUSAND'S OF UP&L CUSTOMERS, BUT FEEL THAT THIS IS NOT IN THE BEST INTEREST OF THE UTILITY USER'S.

WE HAVE LIVED IN THE STANSBURY PARK AREA FOR 11 YEARS. MOST OF THE TIME WE HAVE EXPERIENCED GOOD POWER SERVICE. WITH TREMENDOUS GROWTH IN EASTERN TOOELE COUNTY, WE ARE EXPERIENCING VERY POOR SERVICE. THE PAST 3-4 YEARS ARE POWER HAS HAD MANY DISRUPTIONS MOST ARE VERY SHORT IN DURATION, BUT DO CAUSE US THE INCONVIENIENCE OF HAVING TO RESET EVERYTHING THAT IS DIGITAL OR POWER DIRECTED. ABOUT 3 WEEKS AGO OUR POWER WENT OUT. AFTER 3 HOURS, I CALLED CUSTOMER SERVICE AND WAS TOLD "THE OUTAGE WAS REPORTED AND HAD BEEN FIXED. WE TOLD CUSTOMER SERVICE, NOT SO, WE DID NOT HAVE POWER IN OUR AREA. THE PLACED AN OTHER CALL FOR SERVICE. 2 PLUS HOURS LATER, I CALLED AGAIN, DUE TO NO POWER. CUSTOMER SERVICE ADVISED US THAT THE PROBLEM HAD BEEN REPORTED TO HER AS FIXED. NOT SO, AND SHE AGAIN PLACED A SERVICE CALL. 3 MORE HOURS, WE CALLED AGAIN TO ADVISE NO POWER. THE YOUNG MAN WHO ANSWER WAS NOT PLEASANT, BUT WOULD PLACE ANOTHER REQUEST FOR SERVICE.

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SERVICE COMMISSION
COMMISSIONERS
STE... Sen 9/8/99
CONSTANCE B. WH... CBW 9/8
CLARK D. JONES CDJ 9/9

August 30, 1999
4141 Colt Haven Circle
Salt Lake City, Utah 84124

Public Service Commission
Heber M. Wells Bldg, 4th Floor
160 E. 300 S.
Salt Lake City, Utah 84111

Dear Sirs:

I am writing to strongly oppose approval of the Scottish Power acquisition of Pacificorp. This merger is not in the interest of Utah customers, and it is insulting that Scottish Power believes that it can buy off our concerns with pennies a month for a few years. Electric power supply should not be entrusted to a foreign company with no accountability to the citizens of this country. Beyond this strategic concern, we will end up with an unjust situation where we will be paying both utility taxes to our government and (indirectly) Scottish Power business taxes to Scotland. I can see no benefit to Utah to counter these concerns. If this sale goes through, the only beneficiaries will be Pacificorp shareholders. The PSC should oppose this merger in the interest of Utah consumers.

Sincerely,

Kyle Polychronis

Kyle Polychronis

18052

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SERVICE COMMISSION

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of PacifiCorp and Scottish Power plc for an Order Approving the Issuance of PacifiCorp Common Stock.	**DOCKET NO. 98-2035-04**

POST-HEARING BRIEF
OF APPLICANTS
SCOTTISH POWER PLC AND PACIFICORP

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Scottish Power plc ("ScottishPower") and PacifiCorp (together, "Applicants"), respectively submit this Post-Hearing Brief pursuant to the schedule established by the Public Service Commission of Utah ("Commission") in this docket.

INTRODUCTION

The record in this case establishes that the Application of PacifiCorp and Scottish Power plc for an Order Approving the Issuance of PacifiCorp Common Stock ("Application"), pursuant to Utah Code Ann. § 54-4-31 will be in the public interest and should be approved by the Commission. Through four separate stipulations with various parties, and a letter agreement with two parties, Applicants have made substantial commitments for the benefit of PacifiCorp's customers and employees in Utah, including a four-year merger credit totaling $48 million, new cost-savings initiatives, system performance and customer service improvements, low-income assistance, charitable contributions, community initiatives, commitments to employees, commitments to Utah, increased investments in renewable resources, conservation, and other environmental commitments. ScottishPower will maintain Utah Power & Light Division headquarters in Utah and will relocate a senior executive to take up residence in Utah with broad influence over the utility's operation in Utah including involvement in economic development and corporate citizenship activities. The myriad of terms and conditions set forth in the stipulations ensure that Applicants will deliver these benefits and that customers will be benefitted, not harmed, by the transaction.

The Application in this case was filed on December 31, 1998. Seven months and four Stipulations and a letter agreement later, the only active opponents to the Application are: the

Utah Industrial Energy Consumers ("UIEC"), the Large Customer Group and Nucor Steel (collectively "Industrial Customers"). The Industrial Customers failed to raise any issues that are sufficient to justify the Commission's rejecting the Application or imposing any conditions beyond those already agreed to by the Applicants.

In addition, the Utah League of Cities and Towns ("League") asked that certain conditions be required of the Applicants in connection with approval of the merger and Magnesium Corporation of America ("Magcorp") requested that as a condition of the merger that it be decertified from the ScottishPower/PacifiCorp service area upon the termination of its special contract.

For all the reasons stated below, Applicants respectfully request that the Commission approve the Application with the conditions agreed to by the Applicants.

ARGUMENT

I. STANDARD FOR APPROVAL OF THE APPLICATION

The Commission's task in this proceeding is to determine whether the ScottishPower/PacifiCorp transaction is in "the public interest" pursuant to Utah Code Ann. § 54-4-31. The Commission has previously interpreted this statutory language to mean that a transaction must meet a net "positive benefit" standard for the Commission to approve it. See CP National Corp., Case No. 80-023-01, Utah Power & Light Co./PacifiCorp, Case No. 87-035-27. Applicants believe the statute only requires a "no harm" standard. However, the DPU, the CCS and the Applicants all agree that the evidence shows that the Applicants meet the higher net benefit standards and that the ScottishPower/PacifiCorp transaction is in the public interest.

II. NET BENEFITS WILL RESULT FROM THE TRANSACTION

Based upon the range of commitments Applicants have made in the four stipulations and the letter agreement reached in this proceeding, it is abundantly clear that net benefits for PacifiCorp's Utah customers will result from approval of this transaction. These benefits are categorized and discussed below.

A. Merger Credit

The Division of Public Utilities ("DPU"), the Committee of Consumer Services ("CCS"), ScottishPower and PacifiCorp, entered into a stipulation dated July 28, 1999, Joint Exhibit No. 1 (the "Stipulation"). Condition 43 of the Stipulation sets forth Applicants' commitment to provide a merger credit to customers for a four-year period, from 2000 through 2003. The merger credit consists of $12 million per year for four years. Applicants have the ability to offset the credit for the third and the fourth years by filing a rate case to the extent that this filing reflects merger-related cost savings. Even if Applicants offset the merger credit with cost savings in the third or fourth year, those savings will be reflected in customer rates and therefore would be lower than they would have been absent the merger. (Hearing Transcript ("Tr.") 869.) The $48 million merger credit is therefore guaranteed to the Utah tariff ratepayers for the entire four-year period.

B. Ability to Pass Additional Cost Savings Through to Customers

Based upon its track record of transforming utility companies in the U.K., ScottishPower will achieve cost savings in the operations of PacifiCorp beyond that which PacifiCorp could achieve on a standalone basis. (SP Exhibit 4, pages 4-6, Tr. 869-870.) ScottishPower's intention to achieve cost savings in PacifiCorp is a direct benefit of the merger, because PacifiCorp has no specific plans to achieve any additional cost savings. (PacifiCorp Exhibit 1R, page 4, Tr. 672.)

Cost savings will be identified in the transition plan which the Applicants will file with the Commission six months after closing of the transaction which will enable the Commission to clearly see what cost saving initiatives will be implemented by ScottishPower as a result of this merger. (Stipulation, Condition 13.) In addition, to ensure that the increased potential for cost savings is a concrete merger benefit, Applicants agreed to Condition 43 of the Stipulation; the merger credit is therefore essentially a down-payment on expected merger savings.

C. Improvements in Network Performance and Customer Service

1. Network Performance

The Applicants have voluntarily committed to provide the most comprehensive set of performance standards and customer guarantees for any U.S. electric utility. (SP Exhibit 2, page 19, Tr. 1483.)

System performance will be improved by reducing the System Average Interruption Duration Index ("SAIDI") in Utah by 10% by 2005, reducing the System Average Interruption Frequency Index ("SAIFI") in Utah by 10% by 2005 and reducing the Momentary Average Interruption Frequency Index ("MAIFI") in Utah by 5% over the same time period. Additionally, PacifiCorp will identify the five worst performing circuits in Utah in each year, and will take corrective measures within two years of identification of those circuits to make a 20% improvement in each such circuit. For power outages because of a fault or damage on PacifiCorp's system, Applicants will restore supplies on average to 80% of customers within three hours. (SP Exhibit 2. pages 3-4, Joint Exhibit Attachment No. 1.)

The evidence also shows that ScottishPower will bring important experience to its effort to increase service quality and system performance and achieve these standards. In the U.K., ScottishPower has achieved high levels of customer satisfaction at Manweb and Southern Water, and has dramatically improved the quality of service and system performance in those companies, following their acquisition by ScottishPower. (SP Exhibit 2, pages 17-19.)

While the value of increases in service quality is difficult to identify in dollars, their value is nevertheless substantial. ScottishPower has estimated that these planned improvements will have a dollar value of approximately $61 million annually and up to $600 million on a net present value basis. (SP Exhibit 1S, page 5.) This value is underpinned by other studies which range from $31 million to $61 million, with the lower value excluding large customers within the study base. (SP Exhibit 3R.2, Tr. 821.) We expect Utah benefits will approximate $20 million per year. (Tr. 1483.) DPU witness, Robert Maloney, stated that the $60 million benefit from improvement of system performance was understated and the value did not account for secondary economic impacts or customers of companies affected by power outages. Moreover, this calculation covered the three network performance standards, SAIDI, SAIFI and MAIFI, and did not account for the additional benefits associated with the entire package of performance standards and customer guarantees. (Tr. 1455-1456.)

ScottishPower has committed that in the event that it fails to meet its targets for increasing performance on the network in Utah, it will pay $1 for each of its customers in Utah. These funds would be returned to the community as determined by the Commission. (SP Exhibit 2, page 9.) This is a commitment that is without precedent in Utah.

2. Customer Service

ScottishPower witness Bob Moir discussed in detail ScottishPower's plans for improving and focusing upon customer service. (SP Exhibit 2, pages 3-5.) ScottishPower will focus its efforts on a number of areas that have been demonstrated to be of particular concern to consumers, and will increase its quality of service in each of those areas and has made eight guaranteed commitments to customers in this regard. ScottishPower will reduce the time to answer telephone calls to PacifiCorp's business centers, and will shorten the time necessary to resolve customer complaints received through the Commission. ScottishPower will make guarantees to individual customers regarding restoration of power supply, kept appointments, service installation, response to bill inquiries, clarification of planned interruptions and handling of power quality complaints. Guarantees will also be extended regarding estimates for installations of new service. As to each of these guarantees, ScottishPower will make payments of $50 or $100, depending upon whether the customer is residential or commercial, directly to individual customers for each failure to meet these guarantees. (SP Exhibit 2, pages 14-15.)

ScottishPower's willingness to voluntarily make guarantees backed by payments to individual customers in the event of failure of the company to meet those guarantees gives unique evidence of the strong commitment of ScottishPower to the customers it serves.

It is noteworthy that, in contrast to the detailed and comprehensive commitment made by ScottishPower to improvements in customer service and system performance, PacifiCorp has no plan for improvements to be undertaken on its own. (PacifiCorp Exhibit 1, pages 7-9 and PacifiCorp Exhibit 1R, page 5.) Without evidence of such plans, the value of ScottishPower's commitment cannot fairly be diminished on speculation that PacifiCorp might have achieved some of the same improvements on its own. Also, ScottishPower's experience means greater deliverability.

Improvements in customer service to which ScottishPower has committed have real value to customers, and should be given considerable weight by this Commission in its decision whether to approve the proposed merger. Such improvements clearly increase the adequacy and efficiency of the utility service and benefit the comfort and convenience of the company's customers.

ScottishPower estimates that it will spend approximately $55 million during the five year implementation for its proposed service standards package. ScottishPower has committed that the $55 million investment in improvements to customer service and system performance will come from the redirection of existing budgets and savings in other areas such that there will be no new incremental cost to ratepayers for the program. (SP Exhibit 1S, page 8.) In any event, these costs will not be passed on to ratepayers unless the Commission determines in a rate proceeding that they have been prudently incurred. (Tr. 864.)

D. Commitments to Communities

1. Low-Income Customers

ScottishPower has made a number of commitments to the communities that PacifiCorp serves, which Applicants believe will deliver merger benefits to PacifiCorp's Utah customers. A number of these have been memorialized in the Stipulation and Settlement of Issues Related to Low-Income Customers ("Low-Income Stipulation"). (SP Exhibit No. 8.)

The Low-Income Stipulation was entered into by ScottishPower, PacifiCorp, the Salt Lake Community Action Program and the Crossroads Urban Center. In the Low-Income Stipulation, Applicants have agreed to support the implementation of a lifeline rate in the Utah jurisdiction to be funded by ratepayers and to support extension of the lifeline rate in Utah to provide additional discounts to the disabled and other vulnerable customers. PacifiCorp/ScottishPower are committed to working with the appropriate partners (as ScottishPower has successfully done in the U.K.) to identify innovative, cost-effective programs that provide sustained benefit to low-income customers through decreasing energy usage and improving their ability to pay current and past electric bills. The Applicants also committed to fund low-income initiatives in Utah, with shareholder funds, for three years at a level of $300,000 over and above what was spent by PacifiCorp on similar programs in the State of Utah in 1998. The parties to the Low-Income Stipulation agreed that its provisions are in the public interest and beneficial to PacifiCorp's Utah customers. (Low Income Stipulation, page 1, SP Exhibit 8.)

2. Charitable Contributions

ScottishPower has also made a commitment to contribute $5 million, funded by shareholders, to the PacifiCorp Foundation upon completion of the transaction. In addition, ScottishPower will maintain the existing level of PacifiCorp's other community-related contributions, both in terms of monetary and in-kind contributions. (SP Exhibit 1, page 11, lines 19-23.)

3. Commitments to Employees

ScottishPower has committed to honor PacifiCorp's existing labor agreements. (SP Exhibit 1, page 16, lines 13-19.) ScottishPower will promote and support access to life-long learning for its employees through its Open Learning network, similar to its U.K. programs, and has committed to develop high quality training facilities for PacifiCorp's employees, and will locate one of those facilities in Utah. (SP Exhibit 6, page 4, lines 12-18.) ScottishPower will also develop other training and educational opportunities for employees and, ultimately, their families and communities. (SP Exhibit 6, page 4, lines 19-26.) The Applicants have also agreed to comply with the provisions of the Merger Agreement in respect of employee benefit plans. (Joint Exhibit No. 1, Condition 42.)

4. Community Learning

ScottishPower has made additional commitments to deliver ongoing educational and training opportunities to the communities PacifiCorp serves. ScottishPower will develop a "School to Work" initiative, similar to programs it has successfully developed in the U.K. ScottishPower also intends, through time, to provide community access to the Open Learning network. Skill development opportunities will be made available through the Open Learning Centers, work experience mentoring, and work shadowing. (SP Exhibit 6, page 9, lines 15-22.)

5. Commitment to Utah

ScottishPower has had detailed discussions with the Department of Community and Economic Development ("DCED") and the Division of Business and Economic Development ("DBED") in Utah and by letter agreement with them, has committed to locate a senior executive to take up residence in Utah. The executive will report directly to the CEO of PacifiCorp and this person will have broad influence over PacifiCorp's operation in Utah including, but not limited to, authority to approve corporate involvement in economic development and corporate citizenship activities. The other commitments include, inter alia, a commitment that Utah Power & Light Division headquarters will be located in Utah and that ScottishPower will work to assure that Utah is treated fairly and equitably across the service territories of PacifiCorp in respect of employees, resources, training, foundation gifts, corporate representation and economic development. (SP Exhibit 1R.1.)

E. Environmental Commitments

ScottishPower has made a number of important commitments to the environment which are incorporated in the Stipulation and Settlement of Issues related to Public Purpose Program between PacifiCorp, ScottishPower, the Office of Energy and Resource Planning, and the Land and Water Fund of the Rockies. (SP Exhibit 7.)

1. Integrated Resource Planning

ScottishPower and PacifiCorp commit to produce Integrated Resource Plans every two years according to the current schedule and the then current Commission rules. (SP Exhibit 7, page 3, Joint Exhibit No. 1, Condition 40.)

2. Renewable Resources

Applicants have committed to develop or acquire an additional 50 MW of system-wide renewable resources. ScottishPower/PacifiCorp will use the Integrated Resource Planning process to evaluate renewable resources and work with interested parties including the Energy Efficiency and Renewable Energy Task Force in designing, developing, implementing and evaluating specific programs to most effectively deploy renewable energy technology in Utah. (SP Exhibit 7, pages 3-4.) PacifiCorp shall make a showing in a rate proceeding that the addition of those renewable resources to the rate base for the revenue requirement first appearing in that rate proceeding are prudent investments. (Joint Exhibit 1, Condition 41.)

Applicants have also committed to file a "green resource" tariff within 60 days after completion of the transaction. (SP Exhibit 7, pages 3-4.)

3. Conservation and Energy Efficiency Programs

ScottishPower/PacifiCorp commit to continue to support funding for cost effective and prudent energy efficiency in Utah which focus on reducing the energy used, increasing comfort, lowering the total cost of energy, reducing risk by diversifying the electric resource mix and reducing environmental impacts. (SP Exhibit 7, pages 4-6.)

4. Other Environmental Commitments

ScottishPower has made a number of other environmental commitments. PacifiCorp will contribute $100,000, funded by shareholders, to the Bonneville Environmental Foundation for use in the development of new renewable resources and fish mitigation projects. ScottishPower has committed to establish an environmental forum which will provide ScottishPower with external expertise and perspective on strategic issues related to the environment. In addition, PacifiCorp will continue its involvement in the Western Regional Air Partnerships work to develop a regional haze strategy for the western states including Utah.

(SP Exhibit 7, pages 6-7.) PacifiCorp will also have environmental management systems in place that are self-certified to ISO 14001 standards at all PacifiCorp operated thermal generation by the end of 2000. (Joint Exhibit 1, Attachment 1, page 8.)

F. Commitments to Wholesale Customers

The Applicants and Deseret Generation & Transmission ("Deseret") have entered into a stipulation which settles the issues raised by Deseret in the case. In that stipulation, the Applicants and Deseret have agreed on a framework for the resolution of the reliability and other issues between the parties. As a result, Deseret has recommended that the Commission approve the Application.

G. Summary

Approval of the merger between ScottishPower and PacifiCorp will bring a wide range of benefits to PacifiCorp's Utah customers. These include: financial benefits through a merger credit and cost savings; enhanced customer service through specific improvements in network performance and customer service guarantees; and commitments to the communities, environment and employees. Together, these initiatives establish net benefits for PacifiCorp's Utah customers resulting from this transaction.

III. ANY RISKS ASSOCIATED WITH THE TRANSACTION ARE ADDRESSED BY CONDITIONS

The next issue to be addressed by the parties is whether there are any risks associated with the transaction that have not been adequately addressed by conditions in the Stipulation.

ScottishPower, PacifiCorp, DPU and CCS agree that the Stipulation effectively addresses all material risk.

A. There is No Risk That Costs to Customers Will Increase as Result of the Transaction

Applicants have maintained throughout the proceeding that there are minimal or no risks, and primarily benefits, associated with the merger. The stock transaction is a very simple one, involving a change only in the shareholders of PacifiCorp. PacifiCorp will continue to operate on a stand-alone basis. The Commission will exercise a similar degree of regulatory oversight over PacifiCorp as it does today, and the Stipulation establishes a number of conditions designed to ensure that the Commission will not be hampered by the new corporate structure. Moreover, ScottishPower is an experienced operator of regulated utility businesses, which has a goal of raising the standards of PacifiCorp's service. The service standards that ScottishPower committed to introduce, with more accurate performance measurements and reporting of results, should beneficially increase this Commission's ability to monitor PacifiCorp's service performance. (Joint Exhibit 1, Conditions 16, 27-39.) For example, DPU witness, Robert Maloney, testified that more progress had been achieved relating to service standards in six weeks than in the prior three years. (Tr. 1459.)

On the other hand, DPU, CCS and other parties have identified risks associated with the transaction during the course of this proceeding. The extensive set of conditions that Applicants have negotiated with DPU, CCS and others, effectively neutralize all these risks. (Tr. 476.)

Originally some Intervenors were concerned that the merger would lead to increased costs. However, Applicants have agreed to several broad conditions that guarantee that costs assigned to customers will not increase as a result of the merger. Condition 44 of the Stipulation provides that "Rates in Utah shall not increase as a result of the merger". Condition 3 of the Stipulation requires that "No merger transaction related costs shall be allowed in rates". Furthermore, Condition 19 provides that the "Applicants agree to the use of hypothetical capital structure to determine the correct cost of capital for ratemaking purposes in Utah". Other conditions require Applicants to maintain separate PacifiCorp long-term debt (Stipulation, Condition 21), and to obtain Commission approval regarding debt issuances. (Stipulation, Condition 22.)

In addition to the merger credit set forth in Condition 43 and the commitments set forth in Attachment 1 as agreed to in Condition 1, the Stipulation conditions can be categorized generally as follows:

Financial Conditions

Condition No.	General Description
2	Corporate cost allocation methodology and agreement
3	Transaction/transition costs rate treatment
15	Conditions on payment of dividends
18	Will follow FASB52 for U.S. regulatory reporting
19	Will use hypothetical capital structure - A rated
21	Maintenance of separate long-term debt of PacifiCorp
22	PacifiCorp debt issuances need Commission approval (except inter-company loans)
25	Increased/lower cost of capital impacts

Financial Conditions

Condition No.	General Description
26	Rates set using original, not revalued costs and premiums disregarded
44	Rates will not increase as a result of merger
45	Inter-jurisdictional allocation differences and different merger conditions in different states
48	PacifiCorp will not guarantee obligations of ScottishPower. ScottishPower will not pledge assets of PacifiCorp as security

Affiliate Transactions/Corporate Structure

Condition No.	General Description
4	Diversified holdings or investments not to be held by PacifiCorp (electric company) or a subsidiary
7	New affiliates/affiliate transactions with PacifiCorp
10	Officers and employees of all companies in new ScottishPower group to be available to testify
11	Access to necessary books and records
14	Inter-company loans will be subject to existing Umbrella Loan Agreement
20	Will file report detailing PacifiCorp's percentage of group re: assets, expenditure, employees, etc.
47	Notification of Commission of corporate structure changes

Reporting Requirements

Condition No.	General Description
12	Annual Report re: merger savings for five years
17	Numerous reports to be filed re: PacifiCorp
23	Waiver of right to argue preemption re: PUHCA
24	Will give DPU and CCS copies of SEC filed lobbying reports

Conditions re: Acquisitions/Disposals, etc.

Condition No.	General Description
5	Notification of large acquisitions by ScottishPower or merger sale of PacifiCorp as soon as possible after announcement
8	Notification of sale, etc. of utility assets
9	Commission approval for sale, etc. of utility function of PacifiCorp

Environment

Condition No.	General Description
40	Produce integrated resource plan
41	Renewable resources must be prudent investments to be included in rate base

Ongoing Business

Condition No.	General Description
6	Continue to comply with Transfer Pricing Policy of PacifiCorp
46	Continue to comply with procurement policy and competitive bidding requirements of PacifiCorp
49	Provide adequate management and financial resources for PacifiCorp to carry out its obligations

Transition Plan

Condition No.	General Description
13	File within six months of closing

Network Performance

Condition No.	General Description
16	Penalties for failure of network performance standards will be paid as directed by the Commission
27-39	Network performance and service quality standard clarifications and reporting requirements

Employees

Condition No.	General Description
42	Comply with the merger agreement for two years re: employee benefits (i.e., they will not change for two years)

These 51 conditions, along with all of the other commitments the Applicants have agreed to, mitigate any risks associated with the ScottishPower/PacifiCorp transaction.

The most recent position statement from the Industrial Customers was filed on Monday, August 2, 1999. It urged the Commission to consider the following issues:

B. Taxes

The Industrial Customers requested that any potential income tax savings resulting from the ownership of PacifiCorp flow through to PacifiCorp's customers and that this requirement be added as a condition to the Stipulation.

ScottishPower testified that there is a potential for tax efficiency of the ownership structure upstream of PacifiCorp going forward, but that it is not clear that tax savings will be achievable. (Tr. 1505-1506.)

DPU witness, Lowell Alt, testified that historically DPU has not looked at consolidated operations regarding taxes, but that this could be a rate case issue. (Tr. 86-87.) CCS witness, Dan Gimble, agreed that the consolidated tax issue could be addressed in a rate case. (Tr. 89-91.)

To the extent there is any question regarding the existing authority of the Commission to review tax issues, the Applicants offered the following language set forth in Cross Examination Exhibit 2 regarding the consolidated tax issue which could be added as a condition of the merger.

> ScottishPower and PacifiCorp agree to an additional Condition to approval of this merger that states:
>
> "The parties to this Docket preserve their right to raise the issue of the treatment of upstream tax savings and costs in future rate cases. All parties preserve their positions and have not waived their rights on this issue. ScottishPower commits to retain records regarding upstream tax savings and costs relating to the merger and make these records available to the DPU, CCS and other parties in accordance with Stipulation Ex. 1 and the discovery rules of the Commission."

This condition would resolve all concerns regarding this issue. There are many complex considerations in respect of this matter and these can be adequately and fully addressed in a rate case.

C. PacifiCorp Cash

The Industrial Customers have raised a concern regarding cash held in PacifiCorp and whether adequate conditions are in place to preclude the upstream movement of cash until service quality in Utah has been found adequate. There are currently in the Stipulation several conditions which address this issue. First, ScottishPower/PacifiCorp have agreed to the provisions of the Umbrella Loan Agreement which places limits on short term loans. In addition, the Commission will approve the issuance of PacifiCorp debt as set forth in Condition 22. The provisions of Condition 15 govern dividend policies. Condition 49 provides that there will be adequate financial resources to enable PacifiCorp to meet its commitments, activities and public service obligations. Conditions 16 and 27-39 deal with service quality issues, in addition to the commitments in the direct testimony of Bob Moir. These conditions provide assurance that PacifiCorp will be adequately funded while at the same time service quality will be improved.

D. Access to Employees and Records

The Industrial Customers requested that access to employees and records be the same for Intervenors as for representatives of the DPU and the CCS. Condition 11 provides for adequate access to relevant books, records and officials of ScottishPower entities. Corporate records will be available for inspection in Utah or Portland, Oregon, and Intervenors will have, as is the current practice, access to books and records in Utah and Portland, Oregon. (Tr. 58-61.) Also, ScottishPower and PacifiCorp and all affiliates shall make their employees, officers, directors and agents available to testify and provide information. (Stipulation, Condition 10.)

E. Utah Presence

The Industrial Customers have requested that as a condition of this merger, the Commission should require that ScottishPower/PacifiCorp provide agents in Utah capable of binding PacifiCorp and making decisions regarding Utah operations. In the letter agreement with the DCED and DBED (SP Exhibit 1R.1), ScottishPower agreed to relocate a senior executive to take up residence in Utah. The executive will report directly to the CEO of PacifiCorp. As a member of the executive team, this person will have broad influence over PacifiCorp's operations in Utah. In addition, Utah Power & Light Division headquarters will be located in Utah. These commitments along with all of the other commitments in this Docket adequately address the Industrial Customers' concern regarding this matter.

F. Existing Evidence

The Industrial Customers requested that highly sensitive Confidential Information be filed with the Commission relating to tax savings and projections for PacifiCorp's operations. These documents have been entered into the record and are governed by the terms and conditions of the Protective Order in this Docket. No additional provisions are required.

G. Stranded Costs

The Industrial Customers recommended that as a condition to the merger that PacifiCorp and ScottishPower renounce any future claim to any stranded costs relating to PacifiCorp because of the payment of a premium. UIEC witness, Maurice Brubaker, admitted that he was unaware of any merger proceeding where a merger approval was conditioned upon the merged company agreeing not to make a claim for stranded cost recovery. (Tr. 1315.) In addition, Mr. Brubaker, in reviewing Cross Examination Exhibit 25, admitted that all of the acquisitions of electric utilities reflected in that exhibit included a premium. Indeed, the premium in this transaction is at the lower value end of the scale compared to other premiums in the exhibit. (Tr. 1310.) Stranded cost issues are not appropriate for this proceeding and the evidence shows that a waiver of stranded cost claims is unprecedented in U.S. mergers. Rather, the Utah Legislature is reviewing industry restructuring issues through its Electric Deregulation and Customer Choice Task Force and the Applicants are prepared to contribute to discussions in that forum. (SP Exhibit 1R, pages 12-13.)

H. Regional Transmission Organization ("RTO")

The Industrial Customers have recommended that the Commission require, as a condition of the merger, that the Applicants agree to join a RTO within 24 months after approval of the merger. In the alternative, Industrial Customers requested a condition that the Applicants file within 18 months after the approval of the merger, a definitive plan outlining how they would place transmission assets in the hands of an independent and capable third-party administrator. Nucor witness, Dennis Goins, testified that he has previously criticized a recommendation that a utility join a non-existent mid-west Independent System Operator ("ISO") as a remedy for competitive issues for variety of reasons including issues regarding the ISO's membership structure. (Tr. 1028-1032.) UIEC witness, Maurice Brubaker, admitted that mergers which required a commitment to join a RTO had situations where market power was impacted as a result of the merger. (Tr. 1287-1303.) Mr. Brubaker testified as follows:

> Q. When FERC applied the guideline ..., it found, did it not, because ScottishPower and PacifiCorp do not compete in common geographic markets, there's no change in the concentration of the market and therefore no transaction related effect on the competition?
>
> A. That's correct.
>
> Q. And then basically, FERC found that there was no competitive harm resulting from the transaction and rejected that argument?
>
> A. Correct.

(Tr. 1290-1291.)

ScottishPower is simply purchasing the stock of PacifiCorp. PacifiCorp will continue to operate in its existing service territory. Competitive issues were reviewed by the Federal Energy Regulatory Commission ("FERC"). The Federal Trade Commission performed a Hart/Scott/Rodino review and cleared the transaction. These entities did not impose any requirement regarding a RTO. FERC has established a Notice of Proposed Rulemaking, Docket RM99-2 regarding "Regional Transmission Organizations" and proposes to establish fundamental characteristics and functions for appropriate retail transmission organizations. (UIEC Exhibit 1, page 40.) That is the place where this issue should be reviewed.

I. Special Contracts.

The Industrial Customers have recommended that special contracts that expire during the merger credit period be extended through December 31, 2003, if desired by the customer.

Relating to special contracts, ScottishPower testified as follows:

> As we have stated previously, after the transaction, PacifiCorp will honor all of its contractual obligations. We value our relationship with all our customer classes, and it may be appropriate to evaluate the issue of special contracts following completion of the transaction. This evaluation must be done in parallel with the work of the task force recently appointed by the Commission to examine this issue. The Public Service Commission of Utah issued a Report and Order on March 4, 1999 in Docket No. 97-035-01 ("Order") establishing a task force to study the standards the Commission should employ in approving special contracts and the regulatory treatment of all special contracts stating that:
>
>> We conclude that the Task Force desired by the Company and the Division, which we herein establish, should re-examine the previous Task

> Force guidelines and definitions for regulatory treatment of special incentive contracts, with particular emphasis on how risk should be shared between the Company and its customers. We also want an evaluation of the appropriateness of the confidential treatment customarily given to the rates and terms of service in Utah special contracts in an increasingly competitive environment. (Order, Section V.B.)

The Commission has therefore established a procedure to examine the issue of special incentive contracts. PacifiCorp will participate in this process and add its resources to the task force. Prior to completion of the transaction and until the Commission's task force has finished its work, however, the discussion regarding special contracts is premature and should not be an issue in this docket.

(SP Exhibit 1S, pages 17-18.)

ScottishPower witness, Andrew MacRitchie, testified regarding special contracts that: (1) ScottishPower will honor all existing contracts; (2) PacifiCorp will allow ScottishPower representatives to join the PacifiCorp negotiating team ahead of completion of this transaction, if the customers so wish; and (3) ScottishPower/ PacifiCorp will negotiate all contracts in good faith, complete such negotiations promptly (understanding the possible needs for customers to pursue alternatives), negotiate contracts recognizing the contribution these customers make to the economic well-being of Utah and negotiate in accordance with Commission rules in effect at that time. (Tr. 1487-1488.)

This proceeding should not be the place where special contract issues are decided. The Commission's task force is reviewing special contract issues. ScottishPower's purchase of PacifiCorp's stock does not alter special contract customers' situations. Any condition regarding extension of special contracts should be rejected by the Commission.

At public witness day on August 6, 1999, Magcorp submitted its request that it be "decertified from PacifiCorp's retail service area" as a condition of the approval of the Stipulation. That proposed condition is neither merger related nor supported by the evidence in this record and should be rejected.

Magcorp argues that it has "been excluded" from any of the benefits of the Stipulation and "denied the opportunity to negotiate a future supply arrangement" and, as a result, decertification is an appropriate remedy. Contrary to those assertions, Magcorp, like the other special contract customers, will receive benefits, including the system reliability and performance guarantees.

In addition, the Applicants have committed, as described in this section, to commence and complete negotiations regarding supply arrangements promptly. Magcorp's assertions are not supported in this record and its proposed condition should be rejected.

J. Franchise Issues

The League has requested that the Applicants be required, as a condition of merger approval, to "reopen current franchise agreements". As the Applicants noted in their testimony and motion to strike, the abrogation of contracts, including franchise agreements, is not an appropriate condition of the transaction.

K. Summary

The Industrial Customers have not identified any risks or issues arising from this transaction that are not adequately addressed by conditions. None of the additional conditions proposed by the Industrial Customers should be required by the Commission. As shown above, these conditions either do not address risks that are merger-related issues or they are unnecessary.

The League and Magcorp's issues are similarly not appropriate for this proceeding.

CONCLUSION

Approval of this transaction will deliver net benefits to PacifiCorp's Utah customers. ScottishPower has committed to improve system performance and customer service with an unmatched package of initiatives that will benefit all of PacifiCorp's customers. The merger credit of $48 million establishes a guaranteed financial benefit to customers, which places the value of the transaction beyond any reasonable dispute. Scottish Power intends to deliver cost savings that can be passed through to customers in rates. ScottishPower will also deliver benefits from its environmental commitments and other commitments to communities and employees. The conditions that Scottish Power, PacifiCorp, DPU and CCS have agreed to ensure that these benefits will be delivered and that customers will not be harmed.

In sum, approval of this transaction will serve PacifiCorp's customers in the public interest. For the reasons set forth above, the Commission should approve the Application.

DATED this 3rd day of September, 1999.

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CERTIFICATE OF SERVICE

I hereby certify that I caused the foregoing ***POST-HEARING BRIEF OF APPLICANTS SCOTTISH POWER PLC AND PACIFICORP*** to be served upon the following persons via Federal Express or by mailing a true and correct copy of the same, postage prepaid, to the following on September 3, 1999:

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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of PacifiCorp and Scottish Power plc for an Order Approving the Issuance of PacifiCorp Common Stock	))))))))	Docket No. 98-2035-04 OPENING BRIEF OF DESERET GENERATION & TRANSMISSION CO-OPERATIVE AND MEMBER CO-OPERATIVES

Deseret Generation & Transmission Co-operative ("Deseret") and its Member co-operatives ("Members") (Deseret and Members are referred to collectively as the "Cooperatives") submit this opening brief to summarize their position on issues raised by the proposed merger, as that position now stands in light of the stipulation entered into between Deseret and Applicants.

SUMMARY OF POSITION

Deseret and the Applicants have entered into a Stipulation dated August 2, 1999, a copy of which has been entered into the record in this proceeding and is attached hereto as Exhibit "A". The terms of the Stipulation speak for themselves.

Based on Applicants' undertakings in the Stipulation, and in reliance upon those undertakings, Deseret and the Members have agreed to recommend that the Commission approve the Application.

As noted in the Stipulation, Deseret and the Member Cooperatives continue to discuss with PacifiCorp various issues relating to the reliability, efficiency, and cost of assuring adequate electric service to rural areas of the state. In a few parts of the state isolated segments of PacifiCorp's service area are virtually surrounded by Cooperatives' service territory. Where that is the case there exists legitimate opportunity to reduce overall cost and boost reliability of service through sensible reallocation of responsibility to those local Cooperatives that are more intensely invested in serving local communities and the sparsely populated surrounding areas. In other places, needed maintenance and improvements must be made to existing PacifiCorp facilities on which both Deseret and PacifiCorp customers currently depend. As appropriate, Deseret and the Cooperatives will request the assistance and oversight of the Commission with respect to any issues of this nature which cannot be fairly addressed by the parties through good faith negotiation.

CONCLUSION

Deseret and the Cooperatives do not necessarily concur with all of the expressed opinions or the testimony of the witnesses proferred by the Applicants, nor with certain of the opinions expressed by Division witnesses in support of the merger. The position Deseret has taken in support of the merger is based in reliance upon the good faith adherence by the Applicants to the undertakings set forth in the Stipulation. Pursuant to the terms of the Stipulation, the Cooperatives will continue to work diligently to ensure that no potential adverse consequences of the merger attend or fall upon those Utah residents which they serve.

DATED this 3rd day of September, 1999.

David F. Crabtree,
Counsel for Deseret and its Members

EXHIBIT "A"
TO
OPENING BRIEF OF
DESERET GENERATION & TRANSMISSION CO-OPERATIVE

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of PacifiCorp and Scottish Power plc for an Order Approving the Issuance of PacifiCorp Common Stock.	))))))	**DOCKET NO. 98-2035-04** **STIPULATION**

This Stipulation ("Stipulation") is entered into between PacifiCorp ("PacifiCorp"), Scottish Power plc ("ScottishPower") and Deseret Generation and Transmission Cooperative, Inc. ("Deseret"). PacifiCorp, ScottishPower and Deseret are referred to collectively as the "Parties". PacifiCorp and ScottishPower are referred to jointly as "Applicants".

BACKGROUND

A. PacifiCorp is an Oregon corporation and an electric public utility in the state of Utah. PacifiCorp provides retail electric service in the states of California, Idaho, Oregon, Utah, Washington and Wyoming.

B. Scottish Power is a public limited company in Scotland. Scottish Power provides retail electric service in the United Kingdom and, through it subsidiaries, also provides telecommunications and water and wastewater services.

C. Deseret is a wholesale electric generation and transmission cooperative that provides electric generation, transmission and related services to its rural electric cooperative members in the states of Arizona, Colorado, Nevada, Utah and Wyoming.

D. On June 17, 1999, Deseret filed testimony in this proceeding raising reliability and contract issues and recommending that the Commission reject the proposed merger unless adequate conditions were agreed to by the Applicants.

E. This Stipulation constitutes the negotiated settlement of all the issues raised by Deseret in this docket. Based on the terms of this Stipulation, Deseret recommends that the Commission approve the Application.

TERMS OF STIPULATION

The terms and conditions of this Stipulation are set forth below.

1. Applicants and Deseret agree that they will address the issues raised by Deseret regarding service reliability at the Middleton delivery point or other service reliability issues in Commission Docket No. 99-2035-01 and not in this docket.

2. Applicants agree that, within 30 days after the closing date of the merger, they will meet with representatives of Deseret to discuss and try to resolve service reliability problems at the Middleton delivery point. To the extent the Middleton reliability issues can be resolved or improved through commercially feasible engineering or technical improvements to PacifiCorp's system, PacifiCorp will, upon mutually satisfactory agreement with Deseret regarding payments for the improvements, use its commercially reasonable efforts to pursue those solutions without undue delay.

3. Applicants and Deseret agree that they will evaluate and discuss in good faith with each other all reasonable proposals that provide benefits to the companies and their respective customers.

4. ScottishPower and PacifiCorp agree that the items described in Attachment 1 will not be included in the calculation of the administrative and general expense for Deseret under the provisions of Section 5.3(l) and Exhibit E of the Hunter II Ownership and Management Agreement ("Agreement") between Deseret and Utah Power & Light Company.

GENERAL TERMS AND CONDITIONS

1. The Parties agree that this Stipulation has been reached through settlement negotiations. As such, evidence or conduct or statements made in the negotiation and discussion phases of this Stipulation shall not be admissible in any proceedings before the Commission or any other regulatory agency or court.

2. This Stipulation will be submitted to the Commission for filing and not for approval.

3. Execution of this Stipulation shall not be deemed to constitute an acknowledgment by any party of the validity or invalidity of any particular method, theory or principle of regulation, and no party shall be deemed to have agreed that any principle, method or theory of regulation employed in arriving at this Stipulation is appropriate for resolving any issue in any other proceeding. No findings of fact or conclusions of law other than those stated herein shall be deemed to be implicit in this Stipulation.

4. While this Stipulation constitutes the negotiated resolution of all issues raised by Deseret in this Docket, this Stipulation is not intended to resolve all issues that exist or which may arise in the future between those parties concerning the Agreement, reliability issues, or otherwise. Each party reserves without limitation or waiver any or all other rights, remedies and

defenses otherwise available to each such party at law, pursuant to contract, or in equity except as expressly provided pursuant to this Stipulation.

5. The obligations of the Parties under this Stipulation are subject to the Commission's approval of the Application in this docket on terms and conditions acceptable to ScottishPower and PacifiCorp, in their sole discretion, and the closing of the merger between ScottishPower and PacifiCorp.

Dated: August 2 ,1999

DESERET GENERATION & TRANSMISSION COOPERATIVE

By: _______________________

David F. Crabtree
General Counsel/Asst. Gen'l Mgr.

SCOTTISH POWER PLC

By: _______________________

PACIFICORP

By: _______________________

Attorney

ATTACHMENT 1

ScottishPower/PacifiCorp
Proposed Treatment of Merger Related Costs

Cost Item	$	Above the line	Below the line	Ref.	Comment
Goodwill	1,800m (£1124.7m)		X	SP Listing Particulars page 107	Goodwill represents the difference between the purchase price and fair value of the net assets of PacifiCorp. Goodwill is sometimes referred to as the acquisition adjustment for accounting purposes. The calculation of goodwill varies with fluctuations in ScottishPower share price.
Acquisition Costs					
1)Share Issue Costs	**104m (£65m)**		X	SP Listing Particulars pages 107 & 145	This is an estimate only. However, all such costs incurred directly in completing the acquisition will be charged below the line.
2)Preferred Stock Redemption	**26m (£15m)**		X		
3)Investment, legal, accounting etc	**109m**		X		
Total Acquisition Cost	**239m**		X		
Preferred Stockholder Merger Approval Payments	2.5m (maximum)		X	PC Proxy Statement page 138	Special payments made to preferred Stockholders of 1% to obtain merger approval.
Payments to Directors	0.4m		X	SP Listing Particulars page 166	$50,000 payment made to non-executive directors.
Change in Control					Only enhanced payments resulting from the application of change in control conditions are included. To the extent that a net benefit in costs going forward can be demonstrated then such costs will be treated above the line. Final change in control costs can only be determined 24 months after closure. Numbers quoted are upper limit amounts if all eligible employees receive maximum amounts due. They include payments due to two executives who have already retired. There is no material cost associated with PacifiCorp employee stock option provisions.
1)Enhanced Executive Severance	8.3m (maximum)		X	SP Listing Particulars page 163-165	
2)PacifiCorp Stock Plans	minimal cost		X		
3)Supplemental Executive Retirement Plan (SERP)	2.6m		X		
Retention Incentive Payments	7m (maximum)		X	SP Listing Particulars page 166, WIEC 3.5	Payments to retain key employees during period prior to merger completion.
Bonus Pool- Merger related portion	Not known		X	SP Listing Particulars page 166	To the extent that any such payments are made in connection with "extraordinary efforts" to accomplish the successful completion of the merger only. No quantification of this portion can be determined at this time.

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was mailed, postage prepaid, this 3 day of September 1999, to the following:

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