2010 Wyoming GRC Overview

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Contents

- Case overview
- Witness introduction and topic
- Test period
- Comparison to previous case
- 2010 rate case drivers
- Treatment of other specific items
- Cost of service and rate spread
- Demand response programs
- Line extension policy

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Rate Case Overview

- **Filed November 22, 2010**
- **Proposed price increase of $97.9 million, or 17.3%**
  - Requested effective date September 22, 2011
  - Hearing late May or early June 2011
- **Eighteen Company witnesses**
- **Forecast test period ending December 31, 2011**
  - Average rate base
- **Base net power cost update; RECs excluded from case (included in PCAM or ECAM)**
- **Inter-jurisdictional allocation based on 2010 Protocol**
  - Results also provided using Revised Protocol
- **Requested return on equity 10.60%, return on rate base 8.36%**
- **Major drivers in the case:**
  - Plant additions ($1.4b (total Company) over the plant included in current rates)
  - Net power costs (coal costs and contract replacement)
- **Wyoming load growth**
  - Sales in 2011 are forecast to be 6.7% greater than forecasted 2010 sales
- **Rate spread based on 99-101% of cost of service**
- **Rate impacts vary from increase of 21.54% to decrease of 3.53%**
- **Proposed changes to line extension policy**
- **Company is actively pursuing communicating the rate case impact to customers**

Witness Introduction

Witness	Topic
– **A. Richard Walje,** President, Rocky Mountain Power…………………………	General overview
– **Bruce N. Williams**, Vice President and Treasurer……………………………..	Cost of debt, preferred stock and capital
– **Dr. Samuel C. Hadaway**, FINANCO, Inc…………………………….……….	Return on equity
– **Stefan A. Bird**, Senior Vice President, Commercial and Trading……... ……	Dunlap Ranch, wind capacity factors
– **Chad A. Teply,** Vice President Resource Construction………………………	Environmental improvements
– **John A Cupparo,** Vice President Transmission………………………………..	Energy Gateway Project
– **Darrell T. Gerrard,** Vice President Transmission Planning………………….	Ben Lomond-Populus 345 kV trans. line
– **Douglas N. Bennion,** Vice President, Engineering……………………………	T and D plant investments
– **Dean S. Brockbank,** Vice President and General Counsel…………………..	Klamath hydro agreement
– **Dr. Peter C. Eelkema,** Senior Consultant, Load and Revenue Forecasting……	Test period loads and sales
– **Gregory N. Duvall**, Director, Long Range Planning and Net Power Costs……	Total net power costs
– **Cindy A. Crane**, Vice-President of Interwest Mining…………………………	Coal costs
– **Erich D. Wilson,** Director, Human Resources…………………………………	Compensation and benefit plans
– **Jeffery W. Bumgarner,** Director of Demand Side Management……………..	Demand response market
– **Brian S. Dickman**, Manager, Revenue Requirement…………………………..	Revenue requirement
– **C. Craig Paice,** Regulatory Consultant, Pricing and Cost of Service………..	Class cost of service study
– **William R. Griffith,** Director, Pricing and Cost of Service……………………	Rate spread and rate design proposal
– **F. Robert Stewart,** Regulatory Consultant…………………………………..	Line extension policy and lighting

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Test Period

- **Historical base year: Twelve months ended June 2010 (Dickman)**
- **Forecast test period: Forecast year ending December 2011 (Dickman)**
  - Test period ends 13 months after filing date
  - Average rate base
    - Electric plant in service on 13 month average over the test period
    - Effectively a June 2011 plant balance
  - Consistent with 2009 general rate case order
- **Normalized historical results (Dickman)**
  - Provided consistent with Commission order and stipulation in 2009 case
  - Limited normalizing adjustments, year end rate base
  - Historical revenue shortfall of approximately $86.9 million

Comparison to Previous Wyoming GRC

Wyoming Rate Case Comparison
Previous General Rate Case vs. Current General Rate Case
($ Thousands)

	(1) Settlement 2009 WY GRC	(2) Filed 2010 WY GRC	(2) - (1) Variance
General Business Revenues	(537.0)	(566.8)	(29.8)
Other Revenues	(41.9)	(20.3)	21.7
Net Power Costs	178.9	241.4	62.5
Embedded Cost Differential	(9.4)	(2.5)	7.0
Operations and Maintenance	106.7	120.8	14.1
Administrative and General	24.0	21.9	(2.1)
Depreciation & Amortization	77.6	85.6	8.0
Pre Tax Return on Rate Base	196.2	215.1	18.9
Taxes Other Than Income	16.8	19.4	2.7
Income Taxes	(11.9)	(16.9)	(5.0)
Revenue Shortfall	**$0.0**	**$97.9**	**$97.9**
Rate Base:			
Gross EPIS	3,004.7	3,217.5	212.8
Accum. Depr. & Amort.	(1,053.7)	(1,076.8)	(23.1)
Net EPIS	$1,951.0	$2,140.8	$189.7
Allocation Factors:			
System Generation (SG)	15.79%	15.84%	0.05%
System Energy (SE)	17.61%	17.67%	0.06%
ROE	NA	10.60%	
Total ROR (%)	8.33%	8.36%	0.02%
100 bp on Equity	$14.0	$15.5	$1.5

2010 WY GRC Drivers

- **Net power costs ($62.5m of the overall rate increase)**
  - Total company NPC in CY 2011 is $1.377 billion (Duvall)
    - $241.4 million Wyoming allocated
    - Sets base for power cost adjustment mechanism
  - 2009 GRC NPC settlement for CY 2010 is $1.003 billion
    - $178.9 million Wyoming allocated
  - Increase of $374 million total Company or $62.5 million to Wyoming (37% increase)
- **Plant additions not currently in rates ($18.9m of the overall rate increase due to higher rate base)**
  - Dunlap I 111MW wind generation plant north of Medicine Bow, WY ~$253.4m (Bird)
  - Populus to Ben Lomond 345 kV transmission line segment ~$553.4m (Cupparo and Gerrard)
  - Naughton Unit 2 scrubber (near Kemmerer, WY) ~$153.1m (Teply)
  - Environmental projects (scrubbers, bag houses and control systems) at Wyodak, Huntington, Hunter, and Bridger (Teply)
  - Paradise sub in the Upper Green River Basin and other WY situs distribution projects (Bennion)
  - Total pro forma capital additions (Dickman)

    July – December 2010…………………… $1,424 million
    January – December 2011……………….. $1,218 million

Coal Costs

- **Coal costs and contracts have significant impact on net power costs (Crane)**
  - Third-party coal contract revisions are driving the majority of the increase in coal costs in this case
  - Although the Company's affiliate mine supply represents approximately 33 percent of the plant supply requirements, it accounts for 10 percent of the overall coal cost increase
  - Relative to the affiliate mines, third-party coal supply costs have increased primarily due to the timing of long-term coal contract reopeners
  - Details of the coal supply costs in Ms. Crane's testimony are confidential and available only to the Commission, PSC staff, OCA and individuals who sign the confidentiality agreement

Sales Growth

- **Sales growth in Wyoming is increasing at a faster rate than sales growth on a total Company basis (Eelkema)**
- Comparing the sales levels that were used to establish existing rates in the 2009 general rate case to the forecast developed for the current rate case:
  - Total Company 2011 sales are forecast to be 5.9% greater than forecasted 2010 sales.
  - Wyoming 2011 sales are forecast to be 6.7% greater than forecasted 2010 sales.
- Comparing the first 8 months of weather normalized sales in 2010 and forecasted sales for the last 4 months of 2010 to the forecast developed for the current rate case:
  - Total Company sales in 2011 are forecast to be 3.2% greater.
  - Wyoming sales are forecast to be 3.3% greater.

Electric Plant in Service

– Comparison of EPIS by function between cases (Dickman)

Wyoming Rate Case Comparison
Electric Plant In Service Summary
($ Millions)

	Year End Rate Base 2009 WY GRC	Average Rate Base 2010 WY GRC	Variance
Electric Plant In Service:			
Steam	951.0	976.0	25.0
Hydro	107.2	117.4	10.2
Other	480.2	523.7	43.5
Transmission	561.0	704.1	143.1
Distribution	573.8	571.6	(2.2)
General/Mining	231.1	223.1	(8.0)
Intangible	100.3	101.5	1.2
Total Electric Plant In Service	**3,004.7**	**3,217.5**	**212.8**
Accumulated Depr. & Amort:			
Steam	(407.2)	(406.9)	0.3
Hydro	(41.6)	(43.3)	(1.7)
Other	(47.5)	(67.2)	(19.7)
Transmission	(190.3)	(192.0)	(1.7)
Distribution	(225.3)	(229.0)	(3.7)
General	(76.0)	(73.6)	2.4
Intangible	(65.9)	(64.8)	1.1
Total Accumulated Depr. & Amort.	**(1,053.7)**	**(1,076.8)**	**(23.1)**
Net Plant			
Steam	543.8	569.1	25.3
Hydro	65.6	74.1	8.5
Other	432.8	456.6	23.8
Transmission	370.7	512.1	141.4
Distribution	348.5	342.6	(5.9)
General	155.2	149.5	(5.6)
Intangible	34.5	36.8	2.3
Total NET EPIS	**1,951.0**	**2,140.8**	**189.7**

Cost of Capital

- **Requested 10.60% return on equity (Hadaway)**
  - 53.1% equity, 8.36% overall return on rate base (Williams)
- **Previous case settled at 8.33% return on rate base**
  - No specific return on equity called out in settlement

Cost of Capital Comparison

	Capital Structure	Cost of Capital	WACC
Current Rate Case			
Debt	46.60%	5.82%	2.71%
Preferred	0.30%	5.43%	0.02%
Common Equity	53.10%	10.60%	5.63%
Total			8.36%
Prior Rate Case (Settled)			8.33%

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Renewable Energy Credits

- **REC revenue will be accounted for in net power cost filings (Dickman and Bird)**
  - REC revenue is removed from the 2010 general rate case
    - Returned to customers in NPC filing (ECAM or other mechanism)
    - Consistent with Company's ECAM application
  - $98.5m total Company REC revenue in base year
    - Excluded from test period revenue requirement
    - Causes 'Other Revenue' to be reduced compared to previous filing
    - Approximately $20.3m Wyoming-allocated
      - Wyoming is allocated approximately 21% of RECs sold due to Oregon and California treatment

Insurance Expense

– **Merger Commitment Wy10 expires December 31, 2010 (Dickman)**
  - Committed to use captive insurance company and limit premiums to $7.4m annually
  - MEHC captive insurance coverage terminates March 21, 2011
  - Replaced with self-insurance accruals for liability and property insurance based on historical claims

Current Insurance Coverage

3rd Party Liability	Company Property: Non T&D & Substations	Company Property: T&D Lines
		No Commercial Insurance Self Insurance Account 924
	Commercial $400.0m	
Commerical $175.0m		
Captive $750k	Captive $6.0m	Captive $10.0m aggregate
Self Insurance $250k Account 925	Self Insurance $1.5m Account 924	Self Insurance $5m aggregate Account 924
	$25k per event Remains in project	$25k per event Remains in project

Pro Forma Insurance Coverage

3rd Party Liability	Company Property: Non T&D & Substations	Company Property: T&D Lines
	Commercial $400.0m	
Commerical $175.0m		No Commercial Insurance Self Insurance Account 924
Self Insurance $1.0m Account 925	Self Insurance $7.5m Account 924	
	$1.0m O&M per event Remains in project	Per event: $250k O&M distribution $1.0m O&M transmission Remains in project

Wyoming Reliability

- **Case includes additional funding beginning in 2011 (Bennion)**
  - $1.5m operation and maintenance annually
  - $2.5m capital annually
- **Company commitment to increase reliability in Wyoming (Bennion)**
  - Focus on communities of Buffalo, Casper, Laramie, Rock Springs and Pinedale
  - Projects include hardening feeders, replacing sections of poor performing underground cable and increasing the replacement of distribution poles which include raptor safe design standards

MEHC Cross Charge

- **Charges for MEHC administrative services (Dickman)**
  - Direct charges from someone doing work directly for PacifiCorp
  - Allocated charges for costs incurred that benefit the entire group
    - Senior management oversight of common corporate functions
- **Merger Commitment 9 caps the amount in rates at $7.3m (Dickman)**
  - Expires December 31, 2010
- **Case includes $7.0m (Dickman)**
  - Actual amount booked July 2009 – June 2010
  - Does not include charges for long term incentive plan, legislative costs, and excess air travel costs above commercial equivalent

Klamath Hydroelectric Settlement Agreement

- **Klamath hydroelectric settlement agreement impacts included beginning CY 2011 (Brockbank)**
  - $5.0m incremental operations and maintenance expense
  - $73.8m asset for relicensing and settlement process costs
    - Amortized through 2019
  - Accelerated depreciation on existing facilities
    - Accelerated depreciation starting January 1, 2011
    - Complete depreciation by December 2019
    - Increases annual depreciation expense $4.5m
    - Additional $2.3m capital additions through 2011
  - Oregon and California surcharge treated consistent with 2010 Protocol allocation

Cost of Service and Rate Spread

- **No proposed changes to Cost of Service Study (Paice)**
- **Rate spread within 99% to 101% of cost of service results (Griffith)**

Customer Class	**Proposed Percentage Change**
Residential	
Schedule 2	21.54%
General Service	
Schedule 25	19.50%
Schedule 28	9.44%
Large General Service	
Schedule 33	15.62%
Schedule 46	14.18%
Schedule 48T	21.54%
Irrigation	
Schedule 40	7.41%
Schedule 210	-3.53%
Public Street Lighting Schedules	17.40%
Overall	17.27%

Demand Response

- **Commission Order in Docket No. 20000-352-ER-09 Paragraph 179, directs the Company to address the creation of a demand response market in its next general rate case (Bumgarner)**
  - Testimony explains how the Company identifies, selects and prioritizes initiatives designed to control peak usage
  - Describes how program development occurs and how programs are moved from development to implementation
  - Explains the status of the Company's current resource planning process with respect to load control

Line Extension Policy

- **Comprehensive review of Rule 12 Line Extension Policy (Stewart)**
  - Docket No. 20000-162-ER-00 requires Rocky Mountain Power to file an update of the extension allowance in Rule 12 every three years
  - Last update was filed in 2008, next update is due in 2011
  - Line extension is a policy matter ultimately established by the Commission
  - The Company is not proposing to change the residential and non-residential extension allowances at this time
    - Based solely on the cost of service analysis, the residential allowance should increase and the general service allowance should decrease
  - Several proposed changes to the policy:
    - Timeliness of responses on power availability
    - Number of customers eligible for refunds
    - Cost breakdown availability
    - Customer built extensions and transfer of ownership