The energy markets in the Western region continue to evolve at an extraordinary pace. The Western Chapter of the Energy Bar Association is presenting an outstanding program of panels and speakers sure to engage industry professionals as well as lawyers looking to gain a wealth of insight in a focused, one-day session. As in past years, the Western Chapter is hosting a reception for speakers and attendees the evening prior to the meeting at 5:30 p.m. on Thursday, February 23. The reception will benefit Grid Alternatives, a non-profit that empowers communities in need through renewable energy and energy efficiency services, equipment and training, through Chapter’s work with the Charitable Foundation of the Energy Bar Association.

### PROGRAM SCHEDULE

**THURSDAY, FEBRUARY 23, 2012**

<table>
<thead>
<tr>
<th>Time</th>
<th>Event</th>
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<tbody>
<tr>
<td>5:30 -</td>
<td><strong>Opening Reception and Wine Auction</strong></td>
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<tr>
<td>7:30 p.m.</td>
<td><strong>Benefit for the Charitable Foundation of the Energy Bar Association</strong></td>
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</tbody>
</table>

**FRIDAY, FEBRUARY 24, 2012**

<table>
<thead>
<tr>
<th>Time</th>
<th>Event</th>
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<tbody>
<tr>
<td>7:30 -</td>
<td><strong>REGISTRATION &amp; CONTINENTAL BREAKFAST</strong></td>
</tr>
<tr>
<td>8:30 a.m.</td>
<td><strong>WELCOME AND INTRODUCTION OF KEYNOTE SPEAKER</strong></td>
</tr>
<tr>
<td>8:30 -</td>
<td>Derek A. Dyson</td>
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<tr>
<td>8:45 a.m.</td>
<td>President, Energy Bar Association</td>
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<tr>
<td></td>
<td>Duncan, Weinberg, Genzer &amp; Pembroke, P.C.</td>
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<tr>
<td></td>
<td>Michael S. Hindus</td>
</tr>
<tr>
<td></td>
<td>President, Western Chapter of the Energy Bar Association</td>
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<td></td>
<td>Pillsbury Winthrop Shaw Pittman LLP</td>
</tr>
<tr>
<td>8:45 -</td>
<td><strong>KEYNOTE SPEAKER</strong></td>
</tr>
<tr>
<td>9:20 a.m.</td>
<td>The Honorable Cheryl A. LaFleur</td>
</tr>
<tr>
<td></td>
<td>Commissioner</td>
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<td>Federal Energy Regulatory Commission</td>
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<tr>
<td>9:30 -</td>
<td>Renewable Energy Markets in the West</td>
</tr>
<tr>
<td>10:45 a.m.</td>
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<tr>
<td></td>
<td>Given the significant megawatts of renewable generation current available in the Western region and the additional megawatts proposed, market mechanisms for renewable energy in the region are of utmost importance to all industry participants. This panel will focus on the market mechanisms including cap and trade, TREC's, renewable auction mechanisms as well as on the opportunities, challenges and limitations of procuring renewable energy across the Western region.</td>
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<tr>
<td></td>
<td>Moderator: Pamela J. Anderson</td>
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<td>Perkins Coie LLP</td>
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<td></td>
<td>Speakers: David Falck</td>
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<tr>
<td></td>
<td>General Counsel</td>
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<td>Pinnacle West Capital Corporation</td>
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<td></td>
<td>Ron Binz</td>
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<tr>
<td></td>
<td>Senior Policy Advisor, Center for the New Energy Economy</td>
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<td></td>
<td>Colorado State University</td>
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<td></td>
<td>Rachel Shimshak</td>
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<td></td>
<td>Director</td>
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<td>Renewable Northwest Project</td>
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<td>Brian White</td>
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<td>Director, West Coast Governmental Affairs</td>
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<td>SunEdison</td>
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<td>Time</td>
<td>Event</td>
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<tr>
<td>10:45 - 11:00</td>
<td>BREAK</td>
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<tr>
<td>11:00 - 11:30</td>
<td><strong>Legal and Policy Challenges for Bilateral Trade in Energy Between Canada and the United States</strong>&lt;br&gt;Ms. Doyle, the current Consul General of Canada and former Deputy Minister of Energy for Canada, will address the current legal and policy challenges to bilateral energy trading between Canada and the Western United States, including current oil, natural gas, and renewable issues that Canada faces in the Western U.S. and what this means for the future as the Western states move towards diversification of their energy resources.  &lt;br&gt;<strong>Speaker:</strong> The Honorable Cassie Doyle&lt;br&gt;Consul General, Consulate General of Canada, San Francisco/Silicon Valley</td>
</tr>
<tr>
<td>11:30 a.m. - 12:30 p.m.</td>
<td><strong>New Issues in Natural Gas in the West</strong>&lt;br&gt;This panel will address how fracking and new pipeline infrastructure are likely to reshape the flow and cost of gas in the region and what this means for use of gas in the region, including its place as a competitor to wind and solar for electric generation.  &lt;br&gt;<strong>Moderator:</strong> Carl M. Fink&lt;br&gt;K&amp;L Gates LLP&lt;br&gt;<strong>Speakers:</strong> Robert J. Cupina&lt;br&gt;Brown, Williams, Moorhead &amp; Quinn, Inc.&lt;br&gt;James P. Harrigan&lt;br&gt;Vice President, Gas Acquisitions&lt;br&gt;Southern California Gas Company&lt;br&gt;Lynn Dahlberg&lt;br&gt;Director, Marketing Services&lt;br&gt;Williams Northwest Pipeline</td>
</tr>
<tr>
<td>12:30 - 1:45</td>
<td><strong>LUNCHEON SPEAKER</strong>&lt;br&gt;Frank Wolak&lt;br&gt;Holbrook Working Professor of Commodity Price Studies, Department of Economics&lt;br&gt;Stanford University</td>
</tr>
<tr>
<td>1:45 - 2:00</td>
<td>BREAK</td>
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<tr>
<td>2:00 - 3:30</td>
<td><strong>State Commissioner Panel</strong> A popular tradition at the Annual Meeting of EBA's Western Chapter, this panel of speakers from various states throughout the West will discuss emerging issues in energy regulation before their respective commissions that may also affect the region, other states’ regulatory responsibilities and FERC policy and authority.  &lt;br&gt;<strong>Moderator:</strong> David L. Huard&lt;br&gt;Manatt, Phelps &amp; Phillips, LLP&lt;br&gt;<strong>Panelists:</strong> The Honorable Catherine J.K. Sandoval&lt;br&gt;Commissioner&lt;br&gt;California Public Utilities Commission&lt;br&gt;The Honorable Jeffrey Goltz&lt;br&gt;Chairman&lt;br&gt;Washington Utilities and Transportation Commission&lt;br&gt;The Honorable David S. Noble&lt;br&gt;Commissioner&lt;br&gt;Nevada Public Utilities Commission&lt;br&gt;The Honorable Marsha H. Smith&lt;br&gt;Commissioner&lt;br&gt;Idaho Public Utilities Commission</td>
</tr>
<tr>
<td>3:30 - 3:40</td>
<td><strong>CONCLUSION</strong></td>
</tr>
<tr>
<td>3:40 - 4:00</td>
<td><strong>EBA WESTERN CHAPTER BUSINESS MEETING</strong></td>
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Keynote Speaker
NOTES
Renewable Energy Markets in the West
A Decade of Renewable Energy Growth
<table>
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<tr>
<th></th>
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<tbody>
<tr>
<td>resource/technology</td>
<td>solar testing sites and distributed solar</td>
<td>distributed and utility scale solar (PV and concentrating solar power)</td>
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<tr>
<td></td>
<td></td>
<td>• wind</td>
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<td>• geothermal</td>
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<tr>
<td></td>
<td></td>
<td>• biomass</td>
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<tr>
<td></td>
<td></td>
<td>• biogas</td>
</tr>
<tr>
<td>MWs (installed or under contract)</td>
<td>&lt; 1MW</td>
<td>• 206 MW solar</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• 190 MW wind</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• 27 MW geothermal, biomass, biogas</td>
</tr>
<tr>
<td># customers served</td>
<td>&lt;250</td>
<td>106,000</td>
</tr>
<tr>
<td>% of load served</td>
<td>--</td>
<td>3.5%</td>
</tr>
<tr>
<td>purchased vs. owned</td>
<td>purchased under PPAs</td>
<td>• 232 MW under PPA</td>
</tr>
<tr>
<td></td>
<td>distributed solar</td>
<td>• 55 MW owned and operated by APS</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• 136 MW distributed generation</td>
</tr>
<tr>
<td>form of agreement</td>
<td>EEI Master Agreement with transaction confirmation</td>
<td>• renewable energy purchase and sale agreement</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• turnkey agreement for renewable energy facility</td>
</tr>
</tbody>
</table>
Threshold Considerations for a Utility

- Fair and transparent solicitation process
  - best value for ratepayers
- Capture of environmental attributes and renewable energy credits
  - utility retains regardless of ownership model for project
  - some jurisdictions permit unbundling of energy and RECs
- Regulatory compliance
- ROFR/ROFO for solar projects
  - right of offtaker to buy the project
- Interconnection
  - risk and cost allocation
Key Contract Terms

• Performance Requirements
  – eliminate original “take or pay” model
  – development milestones
  – minimum availability, production/delivery
  – narrow performance band – quantity and timing both critical
  – performance testing

• Remedies
  – seller may pay to extend performance deadlines
  – shortfall damages; cure periods; catastrophic failure
  – termination rights
  – draw on credit

• Force Majeure
  – very narrowly defined; does not include loss of supply or weather adjustments
  – determine duration of qualifying event and right to terminate
Key Contract Terms Cont’d.

• **Credit Support**
  – significant increases in levels of credit support required of seller
  – development period vs. post-development security
  – may be used to satisfy damages prior to termination
  – credit support not necessarily cap on liability

• **Assignment and/or Sale of Facility**
  – assignment generally requires utility consent; notice to utility of potential sale
  – change of control of project company can trigger same provisions

• **Project Finance Considerations**
  – lenders no longer distant third parties in transaction
  – lender consent often heavily negotiated
  • notice, cure periods, step-in rights, bankruptcy issues
Specific Considerations for Ownership

- **Development milestones**
  - timing of project completion impacts resource planning and regulatory compliance
- **Performance testing**
  - generally longer than with conventional facility
  - warranty period
  - challenges with facilities built in phases
- **Performance Shortfall**
  - utility may allow developer right to “buy down” performance shortfall
- **Credit support**
  - maintained through construction and extended performance guarantee period
- **Termination rights**
  - will include step-in rights for utility
Renewable Energy Markets in the West
Energy Bar Association
February 24, 2012

Rachel Shimshak
Renewable Northwest Project
503-223-4544
www.RNP.org
Renewable Northwest Project (RNP)

Objectives:
Proper siting, advance policies that promote new renewables, expand retail markets.

Geography: OR, WA, ID, MT

Members: Business, non-profit, educational
Lessons from the NW System:

- Renewable resources have few emissions.
- Renewables create economic vitality.
- Renewable resources are capital intensive, but stabilize rates over the long term.

- Vansycle
- Foote Creek Rim
- Wind - Operating
Renewable Projects in the Northwest 2012

Map Legend
- Wind
- Solar
- Wave
- Geothermal
Accomplishments

• Over 5000 MW
• RESs in OR, WA, MT
• Incentives in states
• 1.7 billion kWh in retail green power sales
Renewable Energy Standards

- Montana – 15% by 2015
- Oregon - 25% by 2025
  - 1500 aMW
- Washington - 15% by 2020
  - 1200 aMW
- OR, WA, MT utilities on track to meet standards cost effectively
<table>
<thead>
<tr>
<th>Key Issues</th>
<th>The Economy</th>
<th>People</th>
<th>EPA emissions regulation</th>
<th>Transmission</th>
<th>“Oversupply” – low prices</th>
<th>Siting issues</th>
</tr>
</thead>
</table>
Energy Subsidies Black, Not Green

A soon-to-be-released study of federal energy subsidies by the Environmental Law Institute, a nonpartisan research and policy organization, shows that the federal government has provided substantially larger subsidies to fossil fuels than to renewables. Subsidies to fossil fuels totaled approximately $72 billion over the seven-year study period, while subsidies for renewable fuels totaled $29 billion over the same period. The vast majority of subsidies support energy sources that emit high levels of greenhouse gases when used as fuel. Moreover, just a handful of tax breaks make up the largest portion of subsidies for fossil fuels, with the most significant of these, the Foreign Tax Credit, supporting the overseas production of oil. More than half of the subsidies for renewables are attributable to corn-based ethanol, the use of which, while decreasing American reliance on foreign oil, has generated concern about climate effects. These figures raise the question of whether scarce government funds might be better allocated to move the United States towards a low-carbon economy.

Federal Subsidies (2002-08)

- **Fossil Fuels**: $72.5 billion
  - $2.3 billion for Carbon Capture and Storage
- **Renewable Energy**: $29.0 billion
  - $12.2 billion for Traditional Renewables
  - $16.8 billion for Corn Ethanol

Notes:
- Carbon capture and storage is a developing technology that uses older existing power plants to capture and store their carbon dioxide emissions. Although this technology does not make coal a renewable fuel, it could help reduce greenhouse gas emissions compared to coal plants that do not use this technology.
- Recognizing that the production and use of corn-based ethanol may generate significant greenhouse gas emissions, the data depict separate subsidies both with and without ethanol subsidies.

Sources:
Transmission proposals serving Northwest wind resource areas
Dreams

• Comprehensive planning approach
• Stable, long-term federal and state renewable policy.
• People
• Transmission from renewable-rich areas.
• Regulators, legislators who “get it” and lead.
• Large customer support due to stable prices.
Renewable Energy Markets in the West

Energy Bar Association

2-24-12

Brian White, Director, West Coast Government Affairs
SunEdison Overview

Headquarters: Belmont, CA

**Capabilities**
- Development and asset management of solar power plants
- Commercialization of clean energy, financing through global investment funds, sale of turnkey assets
- Energy services (operations and maintenance, energy management)

**Customers**
- Small, large commercial and utility scale
- Federal, state or local government
- North America, Europe, and Emerging Markets

**Technology**
- Energy and system fleet analytics enable high performing systems
- 24 x 7 system service capabilities drive >100% investor performance
- Actively testing multiple technologies
- Aligned balance of systems and module roadmap

SunEdison is an industry cost leader with a presence in each market segment. By staying close to its customers, SunEdison can respond quickly to changing market conditions.
Solar PV system costs have declined sharply over the past few years, and are poised to decline at an accelerating pace in the coming year.
Solar costs have steadily declined over the last 20 years and the trend is projected to continue into the future.

**Drivers**
- Increased cell efficiency/scale
- Supply/demand imbalance
- Tech innovation, margin compression

**Assumptions:**
- WACC = 8%, 10% ITC 2000-2008, 30% ITC 2008-2018
- EIA Commercial rates 2009
- 1% increase in production efficiency; 3% annual rate escalation

Source: GTM, Navigant adjusted for DG
Most financial evaluations only look at the cost of solar for ratepayer, overlooking the benefits.

**Financial cost of solar**

- Cost of purchasing solar Renewable Energy Credits (SRECs) or paying the Alternative Compliance Payment (ACP)

**Tangible**

- Lowering rates for all ratepayers by taking expensive peaking plants offline
- Potential to mitigate new transmission and/or distribution costs

**Tangible but difficult to quantify:**

- Administrative costs for regulated utilities and deregulated electricity suppliers to comply with the RPS
- Potential risk of investing now in solar technology that might be lower cost in the future

**Financial benefit of solar**

**Tangible**

- Environment benefits
- National security benefit of diversified fuel sources

**Non-tangible**

- Hedge against fuel price volatility
- Scalability

- Environmental benefits
- National security benefit of diversified fuel sources
Distributed generation (DG) = distributed benefits – DG by definition is dispersed throughout the electricity grid which means the jobs and economic benefits of DG are not concentrated, but shared by all Californians.

Typically involves projects less than 20 MW in size and interconnected to the distribution grid. Most less than 3 MW.

Governor Brown’s 12,000 MW DG goal by 2020. Not in statute but it needs more detail tied to specific policies.

California Solar Initiative (CSI) – incentives for solar systems under 1 MW (includes residential, commercial, industrial, non-profit, government, and agricultural projects). Goal: 3,000 MW by 2016.

Self Generation Incentive Program (SGIP) – provides financial incentives to encourage deployment of new self generation equipment.

New Solar Homes Partnership – creates a self-sustaining market for energy efficient, new solar homes.

Net Energy Metering (NEM) – billing arrangement that ensures consumers with self-generation of eligible renewable energy receive proper credit (at retail rates) from utilities for any electricity they generate in excess of the amount consumed over a 12-month period. 5% net metering cap will be reached as soon as 2013 in some IOU territories.

These programs have increased private capital investment in renewables, especially PV solar, which has spawned the rise of new financing mechanisms (third party leasing) to diversify the solar customer base.
Recent DG and Solar News Stories

• “California Has Solar Job Lessons For Other States” – Earth Techling (2-17-12)
• “Wholesale Distributed generation ‘Set To Crank’ In California” – AOL Energy (2/13/12)
• “California Saw Record Number in January for Homeowners, Business Who Turned to Solar for Electricity” – PV Tech (2/8/12)
• “San Diego Leads State in Solar Power Generation” – San Diego Union Tribune (1/25/12)
Users of Net Energy Metering (NEM)

Approximately 1,000 MW of installed NEM solar capacity to date!

- Homes
- Schools
- Businesses
- Government
Benefits of Net Energy Metering

- Substantial job creation and private investment benefits are occurring. Over 50,000 Californians work in the solar industry (roughly 25,000 attributed to DG solar projects).
- Empowers individual electricity users to manage their electricity use and costs by providing a clean self-generation option.
- Acts like energy efficiency reducing on-site electricity use but with greater predictability and additionally provides clean power generation to the local grid without the need for new transmission lines.
- Helps meet energy and climate change goals.
- NEM solar systems are providing substantial direct savings for public agencies and schools in a time of shrinking budgets.
Ratepayer Impacts of NEM?

• A 2009 CPUC study conducted by E3 examined costs of NEM but significantly overstated the costs and concerns about potential “cost shifts” to non-solar ratepayers.

• A more recent 2011 study conducted by Crossborder Energy found that NEM does not impose costs on non-NEM customers when viewed across the entire customer base.

• The Crossborder study also found that the majority of the costs from the E3 study were shown to be an artifact of the steeply tiered rate structure that existed at the time in PG & E territory. Those tiered rates have since been lowered.

• On balance, a small net cost imposed by residential NEM customers is offset by a net benefit provided by non-residential solar customers.

• As California’s rate structure changes over time, the economics of NEM will correspond.
California has capped NEM, while many other states have not.

- 43 States have adopted NEM Policies
- 22 of 43 States have NO limits on NEM

<table>
<thead>
<tr>
<th>State</th>
<th>NEM Aggregate Capacity Limit</th>
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<tbody>
<tr>
<td>AZ</td>
<td>No Limit</td>
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<tr>
<td>AK</td>
<td>No Limit</td>
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<td>CO</td>
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<td>WY</td>
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<tr>
<td>UT</td>
<td>20% '07 peak demand: Rk Mt Pwr</td>
</tr>
<tr>
<td>MO</td>
<td>5% of single-hour peak load</td>
</tr>
<tr>
<td>CA</td>
<td>5% of aggregate customer peak demand</td>
</tr>
<tr>
<td>DE</td>
<td>5% of peak demand</td>
</tr>
<tr>
<td>VT</td>
<td>4% of utility's '96 peak demand</td>
</tr>
<tr>
<td>WV</td>
<td>3% of peak demand</td>
</tr>
<tr>
<td>RI</td>
<td>2% of utility's peak load</td>
</tr>
<tr>
<td>NV</td>
<td>2% of total peak capacity</td>
</tr>
</tbody>
</table>

Source: www.dsireusa.org
Key Takeaways

- **Solar costs are declining.** Cost-competitive with grid electricity. California needs to define a policy pathway that will endure beyond 2020.

- **Solar industry is a significant employer in California:** Solar jobs are driven by strong policies like NEM.

- **More solar jobs on the horizon.** 18,000 to 24,000 solar jobs will be added in California over the next three years, an increase of up to 49% from 2012. — Center of Excellence Employer Survey (February 2012)

- **Promote DG at schools and government facilities.** Public agencies will save billions from solar investments over the 30 year life of the systems. The energy savings helps save taxpayer dollars.

- **Some programs will soon expire.** Several existing DG policies and programs (NEM and CSI) will expire in the next several years.

- **Certainty helps lower solar costs.** Long-term market certainty is essential for sustained investment. Any new or additional costs imposed on solar customers will disrupt the market.
California Leading the Way

As California Goes, So Goes the Nation . . .
Legal and Policy Challenges for Bilateral Trade in Energy Between Canada and the United States
Canada-California Energy Relationship
Canada – US Trading Relationship

• $645 billion in bilateral trade

• $1.77 billion worth of goods and services crosses the Canada – US border daily

• $80 billion in bilateral trade Energy Bar Association, Western Chapter states
Three Pillars of Energy Public Policy

Affordability

Reliability

Sustainability
Canada: Largest Supplier of Energy to the US

Canadian exports accounted for 9% of total US demand (2010)

Electricity: 1% of US Market, $2.1 B
Crude Oil: 13% of US Market, $53.6 B
Natural Gas: 14% of US Market, $16.5 B
Uranium: 22% of US Market, $714 M

Canadian exports:
- Electricity: 19 M MWh, 44 M MWh
- Crude Oil: 701 MMb
- Natural Gas: 3.3 TcF, 0.7 TcF
- Uranium: 2600 tU

Total US exports: $2.1 B, $53.6 B, $16.5 B, $714 M
Canada: Third-largest oil reserves

- Saudi Arabia
- Venezuela
- Canada
- Iran
- Iraq
- Kuwait
- UAE
- Russia
- Libya
- Nigeria
- Kazakhstan
- Qatar
- China
- United States

• OPEC member  Source: EIA, 2009 data
Canada’s Innovation Priorities in Cleantech
In-Situ Extraction Site
New Issues in Natural Gas in the West
New Issues in Natural Gas in the West

Carl Fink
K&L Gates
April, 2012
Carl.Fink@KLGates.com
“We have a supply of natural gas that can last America nearly one hundred years, and my Administration will take every possible action to safely develop this energy. Experts believe this will support more than 600,000 jobs by the end of the decade.”

Barack Obama, State of the Union, January 24, 2012
What Shale We Do?

Impacts of the Shale Gas Boom on the North American Pipeline Network

Energy Bar Association Eleventh Annual Western Chapter Meeting
San Francisco, California
February 24, 2012

Robert J. Cupina
Shale Gas Plays in the United States
Growth in Shale Supply

Since 2000, U.S. shale gas production has increased 17-fold and now comprises about 30 percent of total U.S. dry production annual shale gas production (dry) trillion cubic feet

Source: Lippman Consulting, Inc. gross withdrawal estimates as of November 2011 and converted to dry production estimates with EIA-calculated average gross-to-dry shrinkage factors by state and/or shale play. Note: Data as of December 2011.
Traditional Supply Areas

- Mid Continent (Hugoton, Anadarko, San Juan)
- Gulf Coast and OCS
- Western Canada
- Long-distance pipelines constructed from supply areas to destination/consumption markets (Upper Midwest, Northeast and California)
Outlook for Shale Production

Source: North American Electric Reliability Corporation
Offshore to Onshore Supply Shift

Figure 1. Long-term growth in the lower-48 States and long-term declines offshore continued in 2010

billion cubic feet per day

Source: U.S. Energy Information Administration, Natural Gas Monthly

The dip in production in the fall of 2008 reflects production shut-ins (mainly in the Gulf of Mexico) resulting from Hurricanes Gustav and Ike.
Imports Down; Exports Up

General Impacts of Shifting Supply

- Pipeline expansions in shale areas.
- Upstream long-haul pipes underused.
- Commodity prices declining.
- Coal to gas for power generation.
- Pipeline exports increasing; LNG exports in the air.
# Projects Impacting the Shale Basins

## FERC Related Projects

<table>
<thead>
<tr>
<th>Natural Gas Basin</th>
<th>Capacity (MMcf/d)</th>
<th>Miles of Pipe</th>
<th>Compression (HP)</th>
<th>Cost (Millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Barnett</td>
<td>2,027</td>
<td>230</td>
<td>91,940</td>
<td>$602</td>
</tr>
<tr>
<td>Total Barnett, Woodford &amp; Fayetteville</td>
<td>3,532</td>
<td>877</td>
<td>290,070</td>
<td>$3,517</td>
</tr>
<tr>
<td>Total Fayetteville</td>
<td>6,032</td>
<td>448</td>
<td>122,107</td>
<td>$2,240</td>
</tr>
<tr>
<td>Total Woodford</td>
<td>638</td>
<td>50</td>
<td>19,500</td>
<td>$134</td>
</tr>
<tr>
<td>Total Haynesville</td>
<td>3,230</td>
<td>196</td>
<td>229,716</td>
<td>$1,618</td>
</tr>
<tr>
<td>Total Marcellus</td>
<td>6,776</td>
<td>640</td>
<td>426,657</td>
<td>$3,535</td>
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<tr>
<td>Total Bakken</td>
<td>120</td>
<td>77</td>
<td>4,500</td>
<td>0</td>
</tr>
<tr>
<td>Total Various Supplies</td>
<td>3,910</td>
<td>638</td>
<td>283,334</td>
<td>$2,168</td>
</tr>
<tr>
<td>Grand Total</td>
<td>26,265</td>
<td>3,156</td>
<td>1,467,824</td>
<td>$13,814</td>
</tr>
</tbody>
</table>

## Potential Projects

<table>
<thead>
<tr>
<th>Natural Gas Basin</th>
<th>Capacity (MMcf/d)</th>
<th>Miles of Pipe</th>
<th>Compression (HP)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Barnett</td>
<td>2,139</td>
<td>40</td>
<td>9,500</td>
</tr>
<tr>
<td>Total Barnett &amp; Woodford</td>
<td>1,800</td>
<td>175</td>
<td>70,000</td>
</tr>
<tr>
<td>Total Fayetteville</td>
<td>1,100</td>
<td>346</td>
<td>100,000</td>
</tr>
<tr>
<td>Total Bakken</td>
<td>130</td>
<td>100</td>
<td>0</td>
</tr>
<tr>
<td>Total Haynesville</td>
<td>1,100</td>
<td>0</td>
<td>20,260</td>
</tr>
<tr>
<td>Total Marcellus</td>
<td>4,988</td>
<td>962</td>
<td>0</td>
</tr>
<tr>
<td>Grand Total</td>
<td>11,257</td>
<td>1,623</td>
<td>199,760</td>
</tr>
</tbody>
</table>

Source: Federal Energy Regulatory Commission
Marcellus Shale Projects

Approved or Pending Projects

- Appalachian Expansion (NiSource)
- Line 300 Exp (Tennessee)
- NiSource/MarkWest & NiSource
- N Bridge, TIME 3, TEMAX (TETCO)
- Appalachian Gateway (Dominion)
- Line N & N, R & I Projects (NFG)
- Tioga County Extension (Empire)
- NSD Project (Tennessee) & Ellisburg to Craigs (Dominion)
- Northern Access & Station 230C (NFG & Tennessee)
- Sunrise Project (Equitrans)
- TEAM 2012 Project (TETCO)
- Northeast Upgrade (Tennessee)
- Marc I (Central NY)
- Low Pressure East-West (Equitrans)
- East-West - Overbeck to Leidy (NFG)
- NJ-NY Project (TETCO & Algonquin)
- Northeast Expansion (Dominion)
- Northeast Supply Link (Transco)

Potential Projects

- New Penn (NiSource)
- Marcellus to Manhattan (Millennium)
- Appalachian to Market Expansion & TEAM 2013 (TETCO)
- Keystone (Dominion/Williams)
- West to East Connector (NFG)
- NiSource & UGI
- Northeast Supply (Williams)*
  * Combined Transco’s Rockaway Lateral and Northeast Connector Projects

Source: Federal Energy Regulatory Commission
2007 Basis (pre-shale boom) to Henry Hub

$6.94

$0.34

$1.53

-$2.88
2011 Basis Differentials
Developing Issues

• Traditional pipeline destination markets are no longer captive markets.
• Spot price basis differentials between Henry Hub and Chicago or New York no longer support cost of pipeline transportation.
• Large number of good, competitive, low-cost alternatives - do not allow for recovery of traditional mileage-based zone rates in historic destination markets.
• Increases in Marcellus and other shale production has the potential to strand significant quantities of traditional interstate pipeline capacity.
Price Declines

Natural gas spot prices (Henry Hub)

Source: Natural Gas Intelligence
Natural Gas Use by Sector

2000 Natural Gas Demand by Sector

- Transportation: 0.1%
- Secondary: 7.7%
- Electric: 22.3%
- Commercial: 13.6%
- Industrial: 34.9%
- Residential: 21.4%

2010 Natural Gas Demand by Sector

- Transportation: 0.1%
- Secondary: 7.7%
- Electric: 30.6%
- Commercial: 13.3%
- Industrial: 27.3%
- Residential: 20.5%

1. Secondary Demand includes Lease and Plant Fuel, and Pipeline Fuel

Source: EIA
Growth in Electric Sector Gas Demand

Source: North American Electricity Reliability Corporation
Scenarios for Future Electric Demand

Source: North American Electricity Reliability Corporation
Electricity Generation by Fuel
Energy Consumption by Other Sectors

Source: EIA AEO2012
Western Impacts

- Fundamentals turn on hydro.
- Rockies gas displacing Canadian.
- Surface transportation apps.
- Gas/electric interdependence.
- Alaska pipeline window opened and closed again.
Hydro Critical in Pacific West/Northwest

Top Hydropower Producing States, 2010

Rockies Production

Note: Bars represent annual production levels (BCFD), while diamonds symbols represent quarterly production levels (TCF).

Source: North American Electric Reliability Corporation
Net Canadian Transactions

Source: North American Electric Reliability Corporation
Estimated Impact of Coal-to-Gas Fuel Displacement on Gas Consumption – Monthly Displacement by Natural Gas

Source: North American Electric Reliability Corporation
Total U.S. Energy Production and Consumption (quadrillion Btu)

Source: EIA AEO2012
Energy Production by Fuel

Source: EIA AEO2012
Takeaways

- Shifting supply affecting the entire country.
- Traditional supply pipelines facing underutilized capacity while new supply projects proliferate.
- Canadian gas displaced in the East by Marcellus gas and in the West and Midwest by Rockies gas.
- Increases in U.S. shale production to continue toward a surplus situation.
- Electric and industrial growth will absorb some of the surplus.
- U.S. will become a net exporter of natural gas.
Links to the individual FERC Orders:

https://mail.bwmq.com/fercorders/Bison.pdf

https://mail.bwmq.com/fercorders/ColumbiaGulfSettlement.pdf

https://mail.bmwq.com/fercorders/DominionAppalachianGateway.pdf


https://mail.bwmq.com/fercorders/MidContinent%20Express%20Certificate.pdf

https://mail.bwmq.com/fercorders/RockiesEast.pdf

https://mail.bwmq.com/fercorders/RockiesWest.pdf

https://mail.bwmq.com/fercorders/Ruby.pdf

https://mail.bwmq.com/fercorders/Tennessee300Line.pdf

https://mail.bwmq.com/fercorders/TennesseeRateSettlement.pdf

https://mail.bwmq.com/fercorders/TetcoTime3andTEMAX.pdf
Perspective on Gas Markets
from an LDC

Energy Bar Association
February 24, 2012
Outline

- Background on Core Procurement at SoCalGas
  - Core Procurement Function
  - Management Approach
  - Regulatory Framework

- Opportunities/Challenges in Current Environment
California Utilities

- SDG&E
  - Provider of electric and natural gas services
  - 3.5 million consumers
  - 4,100 square miles of service territory
  - 2.3 million electric & gas meters
  - Ratebase of $4.7 billion

- SoCalGas
  - Provider of natural gas services
  - 20.9 million consumers
  - 20,000 square miles of service territory
  - 5.8 million gas meters
  - Ratebase of $2.9 billion

Note: Data as of December 31, 2010.
### Southern California Gas Company
**System Assets and Load**

<table>
<thead>
<tr>
<th></th>
<th>Non-Core/</th>
<th>Total</th>
<th>Core</th>
<th>Wholesale</th>
</tr>
</thead>
<tbody>
<tr>
<td>Throughput (Bcf/d)</td>
<td></td>
<td>2.6</td>
<td>1.1</td>
<td>1.5</td>
</tr>
<tr>
<td>Storage Capacity (Bcf)</td>
<td></td>
<td>134</td>
<td>81</td>
<td>53</td>
</tr>
</tbody>
</table>

**Core Interstate Pipeline Capacity (Bcf/d)**
- Transwestern
- El Paso
- Kern
- GTN

1.0 – 1.3
Core Procurement

- Gas Acquisition Department acquires gas for residential and small commercial customers (core customers).

- Acts on behalf of SoCalGas core customers and SDG&E core customers.

- Transport to SoCalGas Citygate and utilizes storage on SoCalGas’ system.

- Commodity and transportation costs are passed through to customers on monthly bills.

- Acts independently of SoCalGas system operator like any other shipper.

- The SoCalGas system operator provides only transport and storage service to the non core and core aggregation customers.
Order of Gas Acquisition Priorities

1. Reliability
2. Low Cost Gas with limited rate volatility
3. Shareholder Award through Gas Cost Incentive Mechanism (GCIM)
Current Approach

- Core customer bills generally move with market prices.
- Rely primarily on Storage, Interstate Capacity for price protection.
- Optimize Storage and Interstate Capacity Assets.
- Hedge to protect against major price spikes. Generally seasonal.

Supply Diversity:
- Pipelines
- Basins
- Term
- Suppliers
- Balance diversity objective with low cost objective

- Frequent Contact with CPUC Staff
Regulatory Framework

- **Core Commodity Cost.** Gas Cost Incentive Mechanism (GCIM).

- **Core Interstate Capacity Cost.** Advice Letter approvals for capacity. Required to hold 90% to 120% of demand.

- **SoCalGas Storage and Transportation.** Determined in the Triennial Cost Allocation Proceeding (TCAP).

- **Hedging.** GCIM.

- **Dealings with SoCalGas System Operator and Affiliates.** Remedial Measures and Affiliate Rules approved by CPUC.
Opportunities/Challenges in the Current Gas Markets

- **Commodity Prices**
  - Are low prices here to stay?
  - Producer profitability/health?
  - Reduced drilling and production in the West /impact on basis?
  - LNG exports?
  - Hedging?

- **Storage and Pipeline Commitments**
  - Long term vs. short term contracting?
  - What happens when markets indicate only a partial recovery of fixed costs?
  - FERC rates vs. commercial reality?
  - Scheduling complexity on pipelines.
  - Impacts of Abandonment/Mothballing?
Energy Bar Association Meeting

Lynn Dahlberg, Director Marketing Services
Williams Northwest Pipeline

San Francisco, CA
February 24, 2012
Agenda

1. Western Natural Gas Supply Options
2. Market Outlook – Pipeline Reality
   - Supply
   - Demand
   - Infrastructure
3. Impact of Excess Pipeline Capacity
   - Displacement
   - De-contracting
4. Safety and Compliance Update
5. Conclusion
Major Western United States Natural Gas Supply Options

> Rockies
  - 11 Bcf/d export capacity out of the region
  - >4 Bcf/d added since 2008

> Western Canada
  - 4.1 Bcf/d of import capacity from Western Canada

> San Juan
  - 4.7 Bcf/d of export capacity

> Permian/Midcon
  - 3.5 Bcf/d of export capacity
Northwest Pipeline - Backbone of the Northwest

- 55 years of continuous, reliable service
  - 3,900-mile system
  - 3.7 Bcf/d peak design capacity
  - 13.0 Bcf storage capacity
  - 709 MMcf/d storage deliverability
- System expansion to meet customer growth needs
  - Completed 4 major expansions since 2003
- Prolific supply sources
  - Rockies, San Juan, WCSB, emerging shales
- Low-cost, primary service provider in the pacific northwest
- Postage – stamp rates
- Average contract life of 9.9 years as of January 1, 2012
Market Outlook... Pipeline Reality
February 2008 Pipeline Reality

Supply
- Liquefied Natural Gas (LNG) Imports was going to be the natural gas supply savior
  - Billions of $$$ was being invested in domestic LNG infrastructure additions
- Rockies natural gas supply potential was the lone beacon of hope for domestic supply
- Traditional Western Canadian supply was in a perpetual state of decline

Demand
- From a market standpoint, the economy was strong and supporting energy demand fundamentals
  - The DOW was trading close to 13,000

Infrastructure
- Gas was constrained in the Rockies region and traded as low $.12 Dth in September 2007
  - REX was under construction to move gas from the Rockies to the east
  - There were three competing projects to move Rockies gas west (Ruby, Sunstone and Bronco)
Fast forward to February 2012

Supply
- Natural gas supply is plentiful
  - Shale technology has been proven successful and is the quintessential game changer in domestic natural gas supply
- Those billions of $$$ stranded on LNG regasification capacity are now attracting new investment in liquefaction technology (export instead of import)
- In Western Canada the decline in traditional Alberta supply has been offset by new British Columbia Shale potential

Demand
- On the demand front, the economy is still recovering after what has been duped the great recession
  - Demand for natural gas has been stymied by the economic conditions, an intense build out of renewable electric generation and demand-side management programs
  - The DOW is trading close to 13,000

Infrastructure
- REX and Ruby are both in-service adding over 3 Bcf/d of additional export capacity out of the region
  - Additional capacity has been added on Kern River and Bison
Impact of Excess Pipeline Capacity
What is the impact of adding Ruby Pipeline?

- Pre-Ruby: 2,000,000
- Post-Ruby: 3,000,000

Pre-Ruby Post-Ruby

PG&E GT Northwest

REX East

REX West

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De-contracting risk embedded in excess capacity market

> Transfer of risk to fewer customers
> Shorter term contracts
> Pipeline’s scramble to rationalize capacity to existing market
  - New services
  - Abandon facilities
  - Cost management
> Increased risk for pancaked rate case scenarios
Safety and Compliance Update
Safety Compliance Update

Pipeline Safety, Regulatory Certainty, and Job Creation Act

Signed into law by Obama on January 3, 2011

PHMSA Proposed Rule Making Legislation AKA – ANOPR

INGAA provided policy level Commitments on Nov 3/11. Final comments due on January 20/12

Some of the 33 sections of the Act are effective now, such as increased violation limits.

Probably only 3 of the Sections are of Consequence:

1. Operators to verify MAOP within 18 months.
2. Study the use of auto/remote valves in new const.
3. Expand IMP principles.

15 areas of interest.

3 areas of real focus for INGAA:
1. Fitness for purpose of pre-regulation pipelines.
2. Auto/remote valves with greater than 1 response time (retrofit).
3. Expand IMP into non HCA areas.
Conclusion
Doubled-edged conclusion

> Western pipeline infrastructure is robust, dynamic and versatile to serve current market needs
  – There are peaking requirements and small bottlenecks that will require near-term solutions

> There is excess capacity in the Rockies and Western Canada
  – Significant rationalization of regional capacity is underway that will subject some pipelines to significant contractual risks

> To add more price pressure, pipelines have undetermined increases in pipeline safety costs associated with new and proposed requirements

> The confluence of these two realities may:
  – Increase overall pipeline reservation rates
  – Require collaboration with all parties to manage the overall risk scenario; and
  – Most certainly keep lawyers and policy makers gainfully employed
State Commissioner Panel
I. INTRODUCTION

The purpose of this paper is to provide an overview of a number of energy issues facing the State of Washington, with a focus on the issues facing the Washington Utilities and Transportation Commission (UTC or Commission) involving regulation of investor-owned utilities (IOUs) providing electric service.¹

II. ROLE OF THE UTC IN ENCOURAGING CONSERVATION

State law places a high priority on cost-effective conservation and energy efficiency. Washington’s Energy Independence Act (I-937) requires that qualifying utilities “pursue all available conservation that is cost-effective, reliable, and feasible.”² In legislation requiring an update to Washington’s energy strategy, the Legislature required that the strategy be guided by the principle to “[p]ursue all cost-effective energy efficiency and conservation as the state’s preferred energy resource, consistent with state law.”³ Indeed, the Legislature has emphasized the utility of conservation numerous times in various legislative “findings.”⁴ The UTC has

¹ The UTC regulates three IOUs: Puget Sound Energy (PSE), Avista Utilities (Avista), and PacifiCorp. Collectively, these utilities provide electric service to approximately 46% of Washington’s electricity consumers. The remaining 54% receive service from municipal utilities, public utility districts, or rural electric cooperatives. The UTC has no jurisdiction over the rates and services of those publicly-owned and operated utilities. RCW 80.04.500 (municipal utilities); RCW 54.16.040 (public utility districts); RCW 54.48.040 (cooperatives); see RCW 80.04.110 (definition of “electric company”).

² RCW 19.285.040(1).

³ RCW 43.21F.088(1)(a); Laws of 2010, §403.

⁴ E.g., Laws of 2009, ch. 423, § 1 (“The legislature finds that energy efficiency is the cheapest, quickest, and cleanest way to meet rising energy needs, confront climate change, and boost our economy.”); Laws of 2009, ch 379, § 1 (“The legislature finds that improving energy efficiency in structures is one of the most cost-effective means to meet energy requirements, and that while there have been significant efficiency savings achieved in the state over the past quarter century, there remains enormous potential to achieve ever greater savings.”); Laws of 2008, ch. 284, § 1 (“The legislature finds that improving energy efficiency is key to achieving the state's goals to reduce greenhouse gas emissions to 1990 levels by 2020.”); Laws of 1991, ch. 122, § 1 (“The legislature further finds that energy efficiency improvement is the single most effective near term measure to lessen the risk of energy shortage”); Laws of 1990, ch. 2. § 1 (“using energy efficiently in housing is one of the lowest cost ways to meet consumer demand for energy . . . [and] helps protect the citizens of the state from negative impacts due to changes in energy supply and cost”); RCW 43.21F.015 (“It is the policy of the state of Washington that: . . . (4) Energy conservation and elimination of wasteful and uneconomic uses of energy and materials shall be encouraged”).
reinforced this legislative direction by requiring electric IOUs to prepare integrated resource plans (IRPs) that “describe[] the mix of energy supply resources and conservation that will meet current and future needs at the lowest reasonable cost to the utility and its ratepayers.”\(^5\) As part of such a plan, the IOU must conduct “[a]n assessment of commercially available conservation, including load management, as well as an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.”\(^6\)

A. Implementing the Conservation Mandates of the Energy Independence Act (I-937)

In addition to overseeing the IRP process, the UTC also implements the legislative conservation mandates through I-937.\(^7\) Enacted by the voters in 2006, I-937 requires that each “qualifying utility” (one that serves more than 25,000 customers\(^8\)) every two years identify its achievable, cost-effective ten-year “conservation potential” and set a biennial “acquisition target for cost-effective conservation potential.”\(^9\) In determining its cost-effective conservation “potential,” the utility must use methodologies “consistent with those used by the Pacific Northwest electric power and conservation planning council in its most recently published regional power plan.”\(^10\) The Commission must review and approve the conservation targets and “may rely on its standard practice” for such review and approval.\(^11\)

In early 2010, the Commission considered targets for three electric IOUs and approved them all, though in one case the matter went to an adjudicative proceeding.\(^12\) That first biennial period closed at the end of December 2011. The IOUs must file reports with the Commission on its progress in meeting the targets by June 1, 2012.\(^13\) To determine whether the utilities have met their targets, or whether they will be subject to the statutory penalties of $50 per megawatt hour

\(^5\) WAC 480-100-238(2)(a).

\(^6\) WAC 480-100-238(3)(b).


\(^8\) RCW 19.285.030(16).

\(^9\) RCW 19.285.040(1)(a)-(b).


\(^12\) Pacific Power & Light Co., UTC Dkt. No. UE-100170 (Order 02, July 29, 2010) (approving biennial target of 74,460 MWh); Avista Utilities, UTC Dkt. No. UE100176 (Order 01, May 13, 2010) (approving biennial target of 128,603 MWh); Puget Sound Energy, UTC Dkt. No. UE 100177 (Order 05 (amended), October 13, 2010) (approving biennial target of 622,000 MWh). All Commission decisions or dockets referenced in this paper may be accessed through Commission’s website, [www.utc.wa.gov](http://www.utc.wa.gov).

of shortfall, the Commission will take public comments and then either consider the issues at an open meeting or in an adjudication.

Because the target-setting and approval process for the 2010-11 period was somewhat prolonged, the Commission, in its orders approving the initial targets, required a number of reporting and procedural requirements for the 2012-13 period. In part as a result of this earlier action, all three of the IOUs filed their 2012-13 proposed targets with the Commission in late 2011. Because of this early (or more timely) filing and the early work by the utility, Commission staff, Public Counsel, and stakeholders, the Commission was able to hear proposed conservation targets of PSE and Avista at its December 15, 2011, open meeting. The utilities’ targets were agreed to by all the stakeholders participating at the meeting.

Setting the conservation targets is just one part of the overall effort to implement the I-937 conservation mandates. Utilities also file, and the Commission must approve, tariffs that implement the programs and conservation budgets that also include the tariff riders that provide the customer source of funding for the programs. The following graphic shows this planning, tariff, and budget cycle.

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14 RCW 19.285.060(1). The statutory penalty amount must be adjusted for inflation. *Id.*

15 WAC 480-109-040(2).

16 *E.g., Avista Utilities*, UTC Dkt. No. UE-100176, ¶¶64-65 (Order 01, May 13, 2010).

17 *Pacific Power & Light Co.*, UTC Dkt. No. UE-111880 (filed September 15, 2011) (setting a target of 77,964 MWh); *Puget Sound Energy*, UTC Dkt. No. UE-111881 (filed October 28, 2011) (setting a target of 666,000 MWh); *Avista Utilities*, UTC Dkt. No. UE-111882 (filed November 1, 2011) (setting a target within a range of 76,202 and 137,410 MWh).


19 The Commission heard, and allowed to take effect, PSE’s electric energy efficiency program tariffs at its December 29, 2011, open meeting. *Puget Sound Energy*, UTC Dkt. No. UE-111860.

20 Deborah Reynolds of the Commission Staff is responsible for this graphic that summarizes the multitude of conservation-related filings and processes.
In this diagram:

1. The Biennial Conservation Plan presents biennial conservation targets and 10-year potential as required by statute. It includes program tariffs, budgets, EM&V (Evaluation, Measurement & Verification) plans and any other details necessary to demonstrate how the company plans to achieve its targets. These details may be updated annually.

2. The Conservation Rider Tariff is the recovery filing. It relies on the support of the Biennial Conservation Plan to justify the expenditures made by the company in the previous year. In most cases, the resulting rates also incorporate the budgets proposed by the company.

3. The Biennial Report provides the details of whether the company met its targets in the previous biennium. Third-party evaluation of the entire portfolio is required.

4. Progress reports are required every 6 months. These 6-Month and Annual reports detail the expenditures made by the company and company estimates of conservation savings. They also include any EM&V completed during the period.
One new program offered by PSE is a commercial and industrial demand response program in Schedule 271. Based on a successful pilot program, PSE is initiating an incentive-based demand reduction during peak periods for commercial and industrial customers. The Commission approved the Request for Proposal for this program in early December.\textsuperscript{21}

**B. Decoupling and Related Proposals**

A number of utilities and conservation advocates tout “revenue decoupling” as a means to “break the link” between revenue and profits so that utilities have no disincentive to implement conservation programs. The Legislature has authorized the Commission to implement such a program. RCW 80.28.260(3) provides:

> The commission shall consider and may adopt other policies to protect a company from a reduction of short-term earnings that may be a direct result of utility programs to increase the efficiency of energy use. These policies may include allowing a periodic rate adjustment for investments in end use efficiency or allowing changes in price structure designed to produce additional new revenue.

The Legislature has also authorized the Commission to adopt incentives for utilities to exceed their I-937 conservation targets,\textsuperscript{22} as well as incentive rates of return to encourage utility investment in conservation.\textsuperscript{23}

The Commission was one of the first commissions in the country to implement a decoupling mechanism,\textsuperscript{24} though that program was later terminated at the request of the parties.\textsuperscript{25} In December 2009, the Commission approved a “limited decoupling” program for Avista’s gas utility designed to allow the utility to recover revenue lost due to the utility’s implementation of its conservation programs, including its educational programs.\textsuperscript{26}

In response to a 2010 legislative proposal that would have required a type of decoupling mechanism,\textsuperscript{27} the Commission initiated an inquiry into improving performance of investor-owned utilities in the delivery of conservation resources to their customers by filing, pursuant to the administrative procedure act, a Preproposal Statement of Inquiry

\textsuperscript{21} Puget Sound Energy, UTC Dkt. No. UE-111799 (Order 01, December 15, 2011).

\textsuperscript{22} RCW 19.285.060(4).

\textsuperscript{23} RCW 80.28.260(2).


\textsuperscript{25} See Puget Sound Power & Light Co., UTC Dkt. No. UE-921262, Joint Report and Proposal Regarding Termination of the Periodic Rate Adjustment Rate Mechanism (April 20, 1995).

\textsuperscript{26} WUTC v. Avista Corp., UTC Dkt. No. UE-090135, Order 10 (Dec. 22, 2009). Avista had sought to make permanent its pilot decoupling that the Commission had approved in 2007.

\textsuperscript{27} SB 6656, §8, 61\textsuperscript{st} Leg (2010); HB 2853, §8, 61\textsuperscript{st} Leg (2010).
(CR-101)\textsuperscript{28} with the Code Reviser. After receiving several rounds of comments and conducting two stakeholder workshops, the Commission issued a Report and Policy Statement setting forth its current thinking on regulatory mechanisms, including decoupling, to encourage utilities to meet or exceed their I-937 conservation targets.\textsuperscript{29} In the statement, the Commission discussed the history of decoupling in Washington and stated a policy that was receptive to various types of proposals.

First, the Commission continued to express receptiveness to limited decoupling for gas utilities, similar to the proposal it approved for Avista.\textsuperscript{30} Second, the Commission expressed receptiveness to full decoupling for either gas or electric utilities.\textsuperscript{31} Though recognizing that relatively few jurisdictions had adopted such full decoupling for electric utilities, the Commission stated:

Nevertheless, while a close call, we believe that a properly constructed full decoupling mechanism that is intended, between rate cases, to balance out both lost and found margin from any source can be a tool that benefits both the company and ratepayers.\textsuperscript{32}

Finally, though the Commission articulated a number of details of an acceptable decoupling proposal, it was clear that it is open to other proposals. The Commission stated:

The guidance provided in this policy statement does not imply that the Commission would not consider other mechanisms in the context of a general rate case, including an appropriate attrition adjustment designed to protect the company from lost margin due to any reason.\textsuperscript{33}

The Commission currently is considering decoupling proposals in cases involving Avista and PSE.\textsuperscript{34}

\textsuperscript{28} RCW 34.05.230(1) states: “An agency is encouraged to advise the public of its current opinions, approaches, and likely courses of actions by means of interpretive or policy statements. Current interpretive and policy statements are advisory only. To better inform and involve the public, an agency is encouraged to convert long-standing interpretive and policy statements into rules.”


\textsuperscript{30} Decoupling Policy Statement ¶¶18-24.

\textsuperscript{31} Id. ¶¶25-29.

\textsuperscript{32} Id. ¶27.

\textsuperscript{33} Id. ¶34. The Commission also indicated it would consider direct incentives for conservation. Id. ¶¶30-33. The Commission had previously approved such a program for Puget Sound Energy. Puget Sound Energy, UTC Dkt. Nos. UE-060266, UG-060267 (consolidated), Order 08, ¶156 (Jan. 5, 2007).

\textsuperscript{34} Avista Utilities, UTC Dkt. No. UE-111086; Puget Sound Energy, UTC Dkt. No. UE-111048.
III. ROLE OF THE UTC IN FOSTERING THE DEVELOPMENT OF RENEWABLE ENERGY

A. Implementing the Renewable Portfolio Standards in the Energy Independence Act (I-937)

In addition to the conservation mandate, I-937 established for “qualifying utilities” an obligation to meet a renewable portfolio standard (RPS). Each qualifying utility must meet the following targets for acquiring renewable resources (or use renewable energy credits): three percent of load by January 1, 2012; nine percent of load by January 1, 2016; and fifteen percent of load by January 1, 2020. A utility may meet this target using “eligible resources” or renewable energy credits (RECs) or a combination of the two.

As is the case for conservation targets, investor-owned utilities must report to the Commission by June 1 on their progress in meeting the standards, and the Commission must determine whether the standards have been met and, if not, assess penalties. A utility that falls short of the target must pay a penalty of $50 MWh of shortfall.

Because some utilities have expressed uncertainty as to how some provisions of the RPS provisions will be implemented or enforced, the Commission has issued a pair of policy statements under the administrative procedure act to provide guidance on how the Commission will apply the Act.

In January 2011, the Commission issued a policy statement that set forth its policies on four issues. First, the Commission described the standards it would apply to determine the prudence

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35 RCW 19.285.040(2).

36 “Eligible resources” include renewable resources such as wind; solar energy; geothermal energy; landfill gas; wave, ocean, or tidal power; gas from sewage treatment facilities; and biodiesel. RCW 19.285.030(10), (18). It does not include hydroelectric power except “[i]ncremental electricity produced as a result of efficiency improvements completed after March 31, 1999” that is located in the Pacific Northwest and is delivered on a “real-time” basis.” Id. (10)(b).

37 There are alternate means for compliance. A utility may invest at least four percent of its total annual retail revenue requirement on the incremental cost of renewable resources or RECs (RCW 19.285.040(1)(a)), or the utility can show that its weather-adjusted load for the previous three years did not increase, any new acquisitions of energy from non-renewable sources were offset by purchase of RECs, and the utility invested at least one percent of its total annual retail revenue requirement on renewable resources or RECs. RCW 19.285.040(2)(d).

38 RCW 19.285.060(6).

39 RCW 19.285.060(1).

of the acquisition of a renewable resource, as well as whether such a resource is “used and useful,” when the resource is being acquired at or near the time of the RPS deadlines.

Second, the Commission described the standards it would apply to determine the same issues when the resource is acquired in advance of the RPS deadline. In the proceeding that the Commission conducted leading up to the issuance of the policy statement, some utility representatives expressed concern that if the utility acquired a renewable resource too far in advance of the RPS deadline it could risk disallowance of the costs in a subsequent rate proceeding. The Commission advised that acquisition in advance of need would be perfectly acceptable, provided that the “early acquisition can be cost-justified.”

Third, the Commission discussed how it would approach evaluating utility acquisition of renewable resources that would produce renewable energy that is not needed to comply with the RPS. The Commission recognized that comparing the economics of renewables with non-renewables can be difficult because, at present, there is no set cost of carbon designed to take into account the externalities of non-renewable resources. However, recognizing that utilities must consider possible costs of carbon in their integrated resource plans, the Commission stated that “it would seem incongruous if they did not also consider such costs in making resource decisions.” Accordingly, the Commission concluded:

Therefore, if a utility seeks to acquire resources to meet loads, and it has already acquired renewable resources to meet its RPS, it may assume in its economic analysis a cost of carbon consistent with the range of assumptions in its IRP. The Commission will not second-guess adding such carbon cost assumptions. Indeed, we read state law as permitting us to encourage an evaluation of environmental impacts of resource acquisition in our approval process.

Finally, because of the difficulties in analyzing the economics of renewable resources and recognizing that a utility may fear disallowance of an acquisition of such a resource, which in turn could impact perceived risk to investors, the Commission indicated receptiveness to petitions for preapproval of acquisition of renewable resources. In such a preapproval proceeding, the utility can obtain a determination both of the prudence of the acquisition and that the resource when operating would be considered “used and useful.” However, the

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41 In Washington, as in most jurisdictions, a utility may include an asset in rate base and therefore recover its costs and a return on the investment when the resource is “used and useful for service in this state.” RCW 80.04.250.

42 Renewables Policy Statement ¶51, n.65.

43 Id. ¶52.

44 Id. ¶62.

45 Id. ¶62.

46 Id. ¶¶65-69. However, the Commission noted that it was not articulating a receptiveness to preapproval with regard to conventional resources. Id. ¶66, n.79.
determination of prudency would be limited to the acquisition of the resource. The Commission still would review costs to determine if all of the costs were prudently incurred.\textsuperscript{47}

In addition to the regulatory issues addressed in the Renewables Policy Statement, the Commission addressed in another policy statement issues of whether certain resources would qualify under I-937.\textsuperscript{48} In it, the Commission describes two processes it will use to assist utilities and developers assurance about whether given proposed projects will be considered eligible under I-937. One is informal, technical assistance that would be non-binding.\textsuperscript{49} The other is a formal process to obtain a binding declaratory order from the Commission.\textsuperscript{50}

\textbf{B. Encouraging Development of Renewable Energy Beyond the RPS}

I-937 authorizes the Commission to “consider providing positive incentives for an investor-owned utility to exceed the [RPS] targets . . .”\textsuperscript{51} In the order adopting the rules implementing I-937, the Commission invited utilities to “propose incentives and the Commission will consider them on a case-by-case basis.”\textsuperscript{52}

Though the Commission has not adopted any such incentives (and none have been proposed), in its policy statements, described above, the Commission has attempted to at least remove disincentives to additional investment in renewable technologies by providing mechanisms for pre-certification of eligibility and preapproval of acquisition for purposes of cost recovery.

\textbf{C. Distributed Generation}

In Summer 2011, the Commission, pursuant to a legislative request, commenced inquiry into another aspect of renewable energy: distributed generation. In the interim between the 2011 and 2012 legislative sessions, the Technology, Energy and Communications Committee of the Washington House of Representatives undertook an effort to “identify and develop a set of policy actions to advance distributed energy in Washington, including potential legislation to encourage the growth of distributed energy in the state.” The Committee requested that the Commission assist by “conducting a study of distributed generation issues applicable to investor-owned utilities.” Specifically, the Commission was asked to discuss “available options to encourage the development of cost-effective distributed generation in areas served by investor-owned utilities.”

\begin{footnotes}
\footnotetext{47} Id. ¶72.
\footnotetext{49} Id. ¶8. The Commission, like all regulatory agencies, has the authority to provide such technical assistance. RCW 43.05.020.
\footnotetext{50} Eligibility Policy Statement ¶¶9-13. This procedure is authorized by the Administrative Procedure Act. RCW 34.05.240.
\footnotetext{51} RCW 19.2805.060(6).
\footnotetext{52} UTC Dkt. No. UE-061895, General Order R-546 ¶44.
\end{footnotes}
owned utilities, as well as the opportunities and challenges facing investor-owned utilities and their ratepayers in developing distributed generation..."53

To assist the Committee, the Commission provided stakeholders with two opportunities to submit comments and hosted a workshop to gather additional perspectives. The Commission also worked closely with the Washington Department of Commerce, which was developing an updated State Energy Strategy54 as well as the National Renewable Energy Laboratory (NREL). The Commission published its report in October 2011.55

There are already in place a number of statutes that facilitate distributed generation.56 For example:

- I-937 allows a utility to acquire additional credit for distributed generation where the “generation facility or any cluster of such facilities has a generating capacity of not more than five megawatts.” In such a case, the utility may count the output of such facilities at double the output under certain circumstances.57

- Utilities must allow “customer-generators” with a generating capacity of no more than 100kW to interconnect with the utility’s distribution facilities through a “net-metering” system.58 A “net-metering system” is a generation facility on the customer’s premises that is “intended primarily to offset part or all of the customer’s requirements for electricity.”59 The Commission has adopted rules governing interconnection of such customer-generators with the distribution grid.60

- Under federal law, utilities must purchase the output of “qualifying small power production facilities.” Pursuant to section 210 of the Public Utility Regulatory Policies Act (PURPA), state regulators implement rules of the Federal Energy Regulatory Commission (FERC) that require utilities to offer to purchase electricity from such small

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53 Letter from Representative Deborah Eddy on behalf of the House Technology, Energy and Communications Committee to Jeffrey Goltz, Chairman, UTC (June 9, 2011).

54 The Department of Commerce has now published its revised Energy Strategy. It devotes a significant amount of attention to fostering the development of distributed generation. See http://www.commerce.wa.gov/site/1327/default.aspx.


56 “Distributed generation” has been defined in one place in state law as “electric generation connected to the distribution level of the transmission and distribution grid, which is usually located at or near the intended place of use.” RCW 80.80.010(10).


58 RCW 80.60.

59 RCW 80.60.010(10).

60 WAC 480-108.
power production facilities. The UTC has implemented PURPA section 210 by adopting by rule a competitive contracting process in which IOUs solicit bids from qualifying facilities. Under the rules, PURPA qualifying facilities with a generation capacity of one megawatt or less may accept a utility’s standard offer contract without a bid.

After reviewing the law and the concerns of utilities and stakeholders, the Commission, in its Distributed Generation Report made several recommendations on actions it could take administratively, including:

- Update and simplify the Commission’s interconnection rules in light of technological advances and to consider their simplification.
- Clarify whether utilities purchasing energy from a qualifying generator under PURPA also receive any renewable energy credits (RECs) produced by the facility. Though this legal issue has been resolved in other states (with differing results), it has not been resolved in Washington. The Commission could resolve this administratively.
- Provide greater certainty for developers of distributed generation through longer duration standard offer PURPA contracts established under utility tariffs.

The Commission has commenced the rule-making proceeding to review the interconnection rules.

In addition, the Commission recommended several possible actions for the Legislature. These included:

- Legislation to increase the cap for net metering to more than the existing 100kW and clarify whether third party ownership of generation of facilities results in the third-party owner being an electric company subject to UTC generation.
- Legislation to clarify the definition of “eligible renewable resource” to include combined heat and power resources.
- A review existing tax incentives for distributed generation.
- Gathering better information on the costs and benefits of varying levels of distributed generation.

61 16 U.S.C. §824a-3(f); see 18 C.F.R. Pt. 292.
62 WAC 480-170.
63 Distributed Generation Report at 18.
64 Id. at 24-25.
D. Electric Vehicles

State policy favors the development of infrastructure for electric vehicles, and the Legislature has included improvement in “efficiency of transportation energy use through advances in vehicle technology . . . [and] development of electricity . . . and other clean fuels” in the State’s energy strategy.

To assist in the furtherance of these state policies, in 2010, the Commission opened a proceeding to consider a number of regulatory issues that could be implicated by increased penetration of electric vehicles. The Commission listed the following issues as topics for consideration:

- Whether the resale of electricity at public charging stations is, or should be, subject to economic regulation;
- The extent to which existing laws will protect consumers who purchase electricity for recharging of vehicles from unfair or deceptive practices; and
- Whether there are any ratemaking considerations for investor-owned utilities that need be addressed by the Commission, such as time-of-use tariffs.

The Commission ascertained that because there was some uncertainty about whether vehicle charging stations would be, under the then existing law, subject to Commission jurisdiction over “electric plant,” it proposed, and the Legislature enacted, legislation to clarify that the owner of such charging stations, if not otherwise an electric company, would not have to file tariffs and otherwise be subject to Commission rate regulation.

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60 In 2009, the Legislature stated:

The legislature finds the development of electric vehicle infrastructure to be a critical step in creating jobs, fostering economic growth, reducing greenhouse gas emissions, reducing our reliance on foreign fuels, and reducing the pollution of Puget Sound attributable to the operation of petroleum-based vehicles on streets and highways . . . .”


68 Notice of Open Meeting and Opportunity to Submit Written Comments, Regulatory Issues Related to Electric Vehicles, UTC Dkt. No. UE-101521 (Sept. 27, 2010).

69 See RCW 80.04.010; Inland Empire Rural Electrification, Inc. v. Dep’t of Public Service, 199 Wash. 527, 92 P.2d 258 (1939).

70 Laws of 2011, ch. 28, §2, codified as RCW 80.28.320, states:

The commission shall not regulate the rates, services, facilities, and practices of an entity that offers battery charging facilities to the public for hire; if: (1) That entity is not otherwise subject to commission jurisdiction as an electrical company; or (2) that entity is otherwise subject to commission jurisdiction as an electrical company, but its battery charging facilities and services are not subsidized by any regulated service. An electrical company may offer battery charging facilities as a regulated service, subject to commission approval.
E. Coal Plant Legislation

In 2011, the Legislature enacted legislation designed to phase out the existing coal plant at Centralia. Under preexisting law, utilities may not enter into a long-term financial commitment for baseload electric generation unless the generating plant meets certain emissions performance standards (EPS). The legislation recognizes an exception to this requirement for a contract for “coal transition power” if the Governor and a “coal-fired baseload facility” enter into a memorandum of agreement by December 31, 2011. The Commission must approve any contract for such coal transition power if it meets certain conditions. The Governor entered into such an agreement on December 23, 2011.

IV. Issues in Setting Rates by the UTC

The Commission continues to have a high volume of rate cases. Indeed, according to Regulatory Research Associates (RRA), only five state commissions have had more rate cases than the Washington Commission has had in the past three years. The issues in these cases can be numerous, and range from the significant to the symbolic. A few deserve mention.

A. Tracker Mechanisms

In the past, the Commission has approved a number of “tracker” mechanisms by which utilities may pass on costs to ratepayers. Generally, these are costs that are substantially out of the control of the company, and a tracker mechanism makes more sense than frequent rate proceedings. For gas utilities, a typical mechanism, and one used in Washington, is a purchased gas adjustment (PGA) mechanism. However, the Commission has approved a number of mechanisms for electric utilities as well. Sometimes these involve a tariff charge...

71 Laws of 2011, ch. 180, codified at RCW 80.80.
72 RCW 80.80.040.
73 RCW 80.80.100.
74 RCW 80.04.570.
75 Regulatory Research Associates provides this information to subscribers. See www.snl.com/interactivex/CommissionProfiles.aspx.
76 This discussion is necessarily abbreviated because many rate issues are included in two pending rate cases, one involving PSE (UTC Dkt. Nos. UE-111048, UG-111049) and the other involving PacifiCorp (UTC Dkt. No. 111190).
79 For example, the Commission has approved tracking mechanisms relating to the residential exchange tariffs of the Bonneville Power Administration (see UTC Dkt. No. UE-112050); the receipt of federal tax incentives received for...
designed to recover the anticipated costs with the tariff being adjusted periodically to “true-up”
the expenses and the revenues. In other cases, such a mechanism may involve a deferral of costs
for possible later recovery. In the Commission’s recent approval of an all-party settlement of the
Avista rate case, the Commission approved “provisionally” a new deferral mechanism for
maintenance costs associated with the Coyote Springs 2 natural gas generating plant and the
company’s fifteen percent share of the Colstip 3 and 4 coal-fired generating plants. \(^{80}\)

**B. Rate of Return**

In rate cases, much of the difference involves the rate of return issues, both return on equity and
capital structure. For example, in the last litigated PacifiCorp rate case decided by the
Commission, the company proposed a 10.6% return on equity (ROE), with a capital structure
comprised of 52.1% common equity. In contrast, the Commission staff advocated for a 9.5%
ROE, with a capital structure comprised of 46.5% common equity. The Industrial Customers of
Northwest Utilities proposed an ROE of 9.5%, but with a capital structure comprised of 49.1%
common equity. \(^{81}\) The Commission’s final rate order was based on a 9.8% ROE, with a capital
structure containing 49.1% common equity. \(^{82}\)

**C. Treatment of Revenues from Sale of Renewable Energy Credits**

Renewable Energy Credits (RECs) are intangible assets that represent the right to claim the
environmental attributes of a renewable generation facility associated with electricity generated
from that facility. In Washington, utilities may purchase RECs to meet their I-937 RPS
obligations. \(^{83}\) Utilities may also sell RECs when they are not needed for RPS compliance. How
utilities should treat revenues from such sales was the subject of a Commission decision
involving PSE. \(^{84}\) In that case, the Commission stated the general principle that the benefits of
REC revenues “should go to all of PSE’s retail ratepayers, because they are the ones burdened
with the responsibility of paying rates sufficient for PSE to recover all of the costs of the
resources that generate RECs . . . including a reasonable return on the Company’s investment.” \(^{85}\)

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\(^{81}\) *PacifiCorp*, UTC Dkt. No. UE-100749, Order 06 ¶22 (March 25, 2011).

\(^{82}\) Id. ¶100.

\(^{83}\) RCW 19.285.040(2)(d).

\(^{84}\) *Puget Sound Energy*, UTC Dkt. No. UE-0707025, Order 03 (May 20, 2010) (PSE REC Case). There currently is
pending before the Commission another case involving REC proceeds. *PacifiCorp*, UTC Dkt. No. UE-100749.

\(^{85}\) PSE REC Case ¶59. However, having stated this general principle, the Commission did allow some of the REC
proceeds to be used by PSE as a credit against amounts arguably owed to PSE by several California utilities for
power purchased from PSE during the 2000-01 energy crisis and some to be used to fund additional low-income
energy efficiency efforts. *Id.* ¶¶46-47, 59-61.
The Commission established a mechanism by which future REC revenues will be used for the benefit of ratepayers.86

D. Low Income Support

Under Washington law, the Commission may approve discounted rates for low income customers, with the costs being recovered from other customers.87 The recent approval of the Avista rate case included an increase such funding.88

V. WASHINGTON’S REVISED ENERGY STRATEGY

In 2010, Washington’s Legislature directed the Department of Commerce to produce an energy strategy for the State, the first such comprehensive effort since 1993.89 The Legislature provided Commerce with some guidance on how to proceed, stating three goals for the Strategy:

Maintain competitive energy prices that are fair and reasonable for consumers and businesses and support Washington’s continued economic success;

Increase competitiveness by fostering a clean energy economy and jobs through business and workforce development; and

Meet the state’s obligations to reduce greenhouse gas emissions.

In addition, the Legislature provided Commerce with nine guiding principles:

(a) Pursue all cost-effective energy efficiency and conservation as the state’s preferred energy resource, consistent with state law;
(b) Ensure that the state’s energy system meets the health, welfare, and economic needs of its citizens with particular emphasis on meeting the needs of low-income and vulnerable populations;
(c) Maintain and enhance economic competitiveness by ensuring an affordable and reliable supply of energy resources and by supporting clean energy technology innovation, access to clean energy markets worldwide, and clean energy business and workforce development;
(d) Reduce dependence on fossil fuel energy sources through improved efficiency and development of cleaner energy sources, such as bioenergy, low-carbon energy sources, and natural gas, and leveraging the indigenous resources of the state for the production of clean energy;

86 Id. ¶¶66-68.

87 RCW 80.28.068.

88 Avista Utilities, UTC Docket No. UE-110876, Order 06, ¶¶27, 32, n. 73 (December, 16 2011). In approving the settlement, the Commission stated: “Of particular note, we are pleased with the increased monies dedicated to LIRAP funding. With the ever-growing number of households seeking assistance with their energy bills, these additional funds come at a critical time when charities and community organizations are stretching every dollar to help aid the public.” Id.

89 Laws of 2010, ch. 271 (E2SHB 2658), codified in RCW 43.21F.
(e) Improve efficiency of transportation energy use through advances in vehicle technology, increased system efficiencies, development of electricity, biofuels, and other clean fuels, and regional transportation planning to improve transportation choices;

(f) Meet the state’s greenhouse gas limits and environmental requirements as the state develops and uses energy resources;

(g) Building on the advantage provided by the state’s regional electrical grid by expanding and integrating additional carbon-free and carbon-neutral generation, and improving the transmission capacity serving the state;

(h) Make state government a model for energy efficiency, use of clean and renewable energy, and greenhouse gas-neutral operations; and

(i) Maintain and enhance our state’s existing energy infrastructure.\(^{90}\)

To implement the Legislature’s directive, Commerce established both an Advisory Committee and a Technical Experts Panel to assist in the development of the Strategy. In January 2011, Commerce decided to focus the 2012 Energy Strategy on the transportation sector. Accordingly, it convened a third group of stakeholder experts to advise on transportation topics.

The Department published the 2012 Energy Strategy in December 2011.\(^{91}\) Its highlights include:

- An overview of Washington’s resources and usage;
- A summary of strategies for “advancing transportation efficiency,” including support of electric vehicles; proposals for renewable fuels standards and commute trip reduction program expansion; and discussion of possible longer-term policy options such as new vehicle fuel efficiency and road pricing;
- Proposals for increased conservation savings, including new financing mechanisms and low income weatherization programs;
- Proposals to encourage more distributed energy, including updated interconnection standards and revised net metering policies; and
- A discussion of possible options for carbon pricing.

**VI. REGIONAL ISSUES**

There are a number of regional issues that, though not jurisdictional to the UTC, involve the Commission.\(^{92}\) Most such issues are under the jurisdiction of federal agencies, either the Bonneville Power Administration (BPA) or FERC. For example, FERC has promulgated Order 1000 setting up a revised framework for transmission planning that contemplates, or at least

\(^{90}\) RCW 43.21F.088(1).


\(^{92}\) RCW 80.04.075 gives the Commission the authority to “participate in proceedings before federal administrative agencies in which there is at issue the authority, rates or practices for transportation or utility services affecting the interests of the State of Washington, its businesses and general public . . . .”
acknowledges, some potential role for state regulators,\textsuperscript{93} and state officials from western states have been involved in WECC-wide planning efforts through the United States Department of Energy.\textsuperscript{94} State regulators also have been involved in wind integration and other issues being addressed by the BPA and the Northwest Power and Conservation Council.\textsuperscript{95} The Commission works closely with the Energy Office of the Department of Commerce on these issues.

VII. PIPELINE SAFETY

A. Overview

Washington’s pipeline safety program dates back to 1955, when the Commission began inspecting natural gas systems.\textsuperscript{96} In 2000, the Legislature approved the Pipeline Safety Act.\textsuperscript{97} It directed the Commission to seek federal delegation of authority to inspect interstate pipelines,\textsuperscript{98} which the Commission later received from the United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA). In 2001, the Legislature authorized fees on gas and pipeline companies to fund the Commission’s safety program.\textsuperscript{99}

B. State Pipeline Legislation (“Call-Before-You-Dig”)

In 2011, the Legislature enacted the “Underground Utility Damage Prevention Act” that strengthened Washington’s existing “call-before-you-dig” law.\textsuperscript{100} Among other things, it clarified obligations of excavators and facility owners, enhanced penalty amounts for violations, and clarified and expanded the Commission’s enforcement powers.

C. Pipeline Integrity Program (“PIP”) Proceeding

Pipeline explosions in other states has resulted in substantial focus on the safety of Washington’s existing pipeline infrastructure. There is pending before the Commission a proposal by Puget

\textsuperscript{93} See Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 136 FERC P61,051, Order 1000 §162 (July 21, 2011).

\textsuperscript{94} See \url{http://www.wecc.biz/Planning/TransmissionExpansion/Pages/default.aspx}. The Western Electricity Coordinating Council has adopted an interconnection-wide transmission plan. \url{http://www.wecc.biz/library/StudyReport/Wiki%20Pages/Home.aspx}.

\textsuperscript{95} See \url{http://www.nwcouncil.org/energy/wind/Default.asp}.

\textsuperscript{96} Laws of 1955, ch. 316.

\textsuperscript{97} Laws of 2000, ch. 191.

\textsuperscript{98} \textit{Id.} §9.


\textsuperscript{100} Laws of 2011, ch. 263.
Sound Energy for a “pipeline integrity program” (PIP) that would include a tracking mechanism for accelerated recovery of costs of replacing some existing pipeline deemed to be higher risk.\textsuperscript{101}
Eleventh Annual Meeting of the Western Chapter of the Energy Bar Association

Friday, February 24, 2012 / San Francisco, California

State Commissioner Panel
David Noble, Commissioner
Public Utilities Commission of Nevada

Cost Causers Pay Rate Design Principle
Cost Causers Pay Rate Design Principle

“Cost causers pay for the costs they impose on the system.”

Transmission/Distribution Undergrounding:

PUCN Docket No. 07-12001, Order issued June 27, 2008 at ¶¶ 370-404
District Court Case No. CV08-2470 and CV08-2493
Supreme Court Case No. 57584 (Oral Argument scheduled for March 14, 2012)

PUCN Docket No. 10-06001, Order issued December 23, 2010 at ¶¶449-498

Nevada Administrative Code 704.660—“The Commission will consider a utility’s marginal (incremental) cost of service to each class of customer in determining the revenue required from that class.”

Utility Tariff, Rule No. 9 (Line Extensions)

Appeal of Oncor from an Ordinance of the City of Allen, 2002 WL 31947857 (TX)
Chesapeake and Potomac Telephone Co. of Maryland, 1994 WL 810630 (MD)
General Telephone Co. v. City of Bothell, 716 P.2d 879 (WA 1986)
Baltimore Gas and Electric Co., 77 Md. PSC 21 (1986)

Smart Meters (Opt-Out Provisions):

PUCN Docket No. 11-10007

February 29, 2012 (9:30 a.m. in Carson City and Las Vegas, Nevada)

Judicial Review of PUCN Decisions:

Assembly Bill 17 (2011)—fast tracks PUCN decisions at district court level
Assembly Bill No. 17–Committee
on Government Affairs

CHAPTER...........

AN ACT relating to administrative procedure; exempting the
judicial review of decisions of the Public Utilities
Commission of Nevada from the requirements of the Nevada
Administrative Procedure Act; revising provisions governing
the procedure for the judicial review of decisions of the
Commission; and providing other matters properly relating
thereto.

Legislative Counsel's Digest:

Existing law provides that the provisions of chapter 703 of NRS that relate to
the judicial review of decisions of the Public Utilities Commission of Nevada
prevail over the general provisions of the Nevada Administrative Procedure Act,
which is contained in chapter 233B of NRS. (NRS 233B.039) Section 1 of this bill
removes that existing provision and instead provides that the provisions of the
Nevada Administrative Procedure Act do not apply to the judicial review of
decisions of the Commission.

Existing law also sets forth provisions relating to the procedure for the judicial
review of decisions of the Commission. (NRS 703.373) Section 1.7 of this bill
revises various provisions relating to that procedure and: (1) requires a party
seeking judicial review to exhaust all administrative remedies before the party is
entitled to seek judicial review of a final decision of the Commission; (2) specifies
certain periods in which certain documents must be filed with the court and served
upon the parties involved in the judicial review; and (3) provides that a final
decision of the Commission is deemed reasonable and lawful until reversed or set
aside in whole or in part by the court.

EXPLANATION – Matter in bolded italics is new; matter between brackets [existing-material] is material to be omitted.

THE PEOPLE OF THE STATE OF NEVADA, REPRESENTED IN
SENATE AND ASSEMBLY, DO ENACT AS FOLLOWS:

Section 1. NRS 233B.039 is hereby amended to read as follows:

233B.039 1. The following agencies are entirely exempted
from the requirements of this chapter:
(a) The Governor.
(b) Except as otherwise provided in NRS 209.221, the
Department of Corrections.
(c) The Nevada System of Higher Education.
(d) The Office of the Military.
(e) The State Gaming Control Board.
(f) Except as otherwise provided in NRS 368A.140, the Nevada
Gaming Commission.
(g) The Division of Welfare and Supportive Services of the Department of Health and Human Services.

(h) Except as otherwise provided in NRS 422.390, the Division of Health Care Financing and Policy of the Department of Health and Human Services.

(i) The State Board of Examiners acting pursuant to chapter 217 of NRS.

(j) Except as otherwise provided in NRS 533.365, the Office of the State Engineer.

(k) The Division of Industrial Relations of the Department of Business and Industry acting to enforce the provisions of NRS 618.375.

(l) The Administrator of the Division of Industrial Relations of the Department of Business and Industry in establishing and adjusting the schedule of fees and charges for accident benefits pursuant to subsection 2 of NRS 616C.260.

(m) The Board to Review Claims in adopting resolutions to carry out its duties pursuant to NRS 590.830.

2. Except as otherwise provided in subsection 5 and NRS 391.323, the Department of Education, the Board of the Public Employees' Benefits Program and the Commission on Professional Standards in Education are subject to the provisions of this chapter for the purpose of adopting regulations but not with respect to any contested case.

3. The special provisions of:

(a) Chapter 612 of NRS for the distribution of regulations by and the judicial review of decisions of the Employment Security Division of the Department of Employment, Training and Rehabilitation;

(b) Chapters 616A to 617, inclusive, of NRS for the determination of contested claims;

(c) Chapter 703 of NRS for the judicial review of decisions of the Public Utilities Commission of Nevada;

(d) Chapter 91 of NRS for the judicial review of decisions of the Administrator of the Securities Division of the Office of the Secretary of State; and

(e) NRS 90.800 for the use of summary orders in contested cases, prevail over the general provisions of this chapter.

4. The provisions of NRS 233B.122, 233B.124, 233B.125 and 233B.126 do not apply to the Department of Health and Human Services in the adjudication of contested cases involving the issuance of letters of approval for health facilities and agencies.

5. The provisions of this chapter do not apply to:
(a) Any order for immediate action, including, but not limited to, quarantine and the treatment or cleansing of infected or infested animals, objects or premises, made under the authority of the State Board of Agriculture, the State Board of Health, or any other agency of this State in the discharge of a responsibility for the preservation of human or animal health or for insect or pest control;

(b) An extraordinary regulation of the State Board of Pharmacy adopted pursuant to NRS 453.2184; or

(c) A regulation adopted by the State Board of Education pursuant to NRS 392.644 or 394.1694; or

(d) The judicial review of decisions of the Public Utilities Commission of Nevada.

6. The State Board of Parole Commissioners is subject to the provisions of this chapter for the purpose of adopting regulations but not with respect to any contested case.

Sec. 1.3. NRS 703.330 is hereby amended to read as follows:

703.330 1. A complete record must be kept of all hearings before the Commission. All testimony at such hearings must be taken down by the stenographer appointed by the Commission or, under the direction of any competent person appointed by the Commission, must be reported by sound recording equipment in the manner authorized for reporting testimony in district courts. The testimony reported by a stenographer must be transcribed, and the transcript filed with the record in the matter. The Commission may by regulation provide for the transcription or safekeeping of sound recordings. The costs of recording and transcribing testimony at any hearing, except those hearings ordered pursuant to NRS 703.310, must be paid by the applicant. If a complaint is made pursuant to NRS 703.310 by a customer or by a political subdivision of the State or municipal organization, the complainant is not liable for any costs. Otherwise, if there are several applicants or parties to any hearing, the Commission may apportion the costs among them in its discretion.

2. If a petition is served upon the Commission as provided in NRS 703.373 for the bringing of an action against the Commission, before the action is reached for trial, the Commission shall file a certified copy of all proceedings and testimony taken with the clerk of the court in which the action is pending.

3. A copy of the proceedings and testimony must be furnished to any party, on payment of a reasonable amount to be fixed by the Commission, and the amount must be the same for all parties.

4. The provisions of this section do not prohibit the Commission from:
(a) Restricting access to the records and transcripts of a hearing pursuant to paragraph (a) of subsection 3 of NRS 703.196.

(b) Protecting the confidentiality of information pursuant to NRS 704B.310, 704B.320 or 704B.325.

Sec. 17. NRS 703.373 is hereby amended to read as follows:

703.373 1. Any party of record to a proceeding before the Commission is entitled to judicial review of the final decision upon the exhaustion of all administrative remedies by the party of record seeking judicial review.

2. Proceedings for review may be instituted by filing a petition for judicial review in the District Court in and for Carson City, in and for the county in which the party of record seeking judicial review resides, or in and for the county where the act on which the proceeding is based occurred.

3. A petition for judicial review must be filed within 30 days after the service of the final decision action by the Commission on reconsideration or, if a hearing is held, or if the Commission takes no action on reconsideration or rehearing, within 30 days after the date on which reconsideration or rehearing is deemed denied. Copies of the petition for judicial review must be served upon the Commission and all other parties of record.

4. The Commission shall participate in the judicial review. Any party of record desiring to participate in the judicial review must file a statement of intent to participate in the petition for judicial review and serve the statement upon the Commission and every party within 15 days after service of the petition for judicial review.

5. Within 30 days after the service of the petition for judicial review or such time as is allowed by the court, the Commission shall transmit to the reviewing court a certified copy of the entire record of the proceeding under review, including a transcript of the evidence resulting in the final decision of the Commission. The record may be shortened by stipulation of the parties to the proceedings.

6. A petitioner who is seeking judicial review must serve and file a memorandum of points and authorities within 30 days after the Commission gives written notice to the parties that the record of the proceeding under review has been filed with the court.

7. The Commission and any other defendants respondents shall serve and file their answers to the petition a reply memorandum of points and authorities within 30 days after the service thereof of the memorandum of points and authorities,
whereupon the action is at issue and [they] the parties must be ready for a hearing upon 20 days' notice. [to each party.]

4. The

8. Judicial review of a final decision of the Commission must be [conducted] :
   (a) Conducted by the court without a jury; and [be confined] 
   (b) Confined to the record.

In cases [of] concerning alleged irregularities in procedure before the Commission [that are] not shown in the record, [proof thereon may be taken in] the court []. The court, upon request, shall hear oral argument and receive written briefs.

5. [may receive evidence concerning the irregularities.]

9. The final decision of the Commission shall be deemed reasonable and lawful until reversed or set aside in whole or in part by the court. The burden of proof is on the petitioner to show that the final decision is invalid pursuant to subsection 11.

10. All actions brought under this section have precedence over any civil action of a different nature pending in the court.

11. The court shall not substitute its judgment for that of the Commission as to the weight of the evidence on questions of fact. The court may affirm the decision of the Commission or set it aside in whole or in part if substantial rights of the [appellant] petitioner have been prejudiced because the [administrative findings, inferences, conclusions or decisions are] final decision of the Commission is:
   (a) In violation of constitutional or statutory provisions;
   (b) In excess of the statutory authority of the Commission;
   (c) Made upon unlawful procedure;
   (d) Affected by other error of law;
   (e) Clearly erroneous in view of the reliable, probative and substantial evidence on the whole record; or
   (f) Arbitrary or capricious or characterized by abuse of discretion.

Sec. 2. This act becomes effective upon passage and approval.
The Honorable Marsha H. Smith, Commissioner
Idaho Public Utilities Commission
Energy Bar Association’s
Twelfth Annual Western Chapter Meeting
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE PETITION OF
IDAHO POWER COMPANY FOR A DECLARATORY ORDER REGARDING PURPA JURISDICTION.

CASE NO. IPC-E-11-14
ORDER NO. 32453

On July 8, 2011, Idaho Power Company filed a Petition for a Declaratory Order asking the Commission to exercise its jurisdiction over Public Utility Regulatory Policies Act of 1978 (PURPA) transactions proposed by Western Desert Energy and Tumbleweed Energy II (the “Projects”). Idaho Power is a regulated electric utility serving primarily Idaho and portions of eastern Oregon (revenue by jurisdiction: 95% Idaho and 5% Oregon). Idaho Power requests that the Commission issue an Order determining that the Commission will exercise jurisdiction over the proposed PURPA qualifying facility (QF) transactions proposed by Western Desert Energy 1, LLC (Western Desert) and Tumbleweed Energy II, LLC (Tumbleweed).

On July 29, 2011, the Projects filed a Joint Answer and Motion to Dismiss Idaho Power’s Petition. On August 18, 2011, the Commission issued a Notice of Petition and set a comment deadline of September 8, 2011. Rule 102, IDAPA 31.01.01.102. Idaho Power and PacifiCorp dba Rocky Mountain Power filed comments. Two public comments were also received.

Based upon our review of the facts and the arguments presented by the parties, we partially grant Idaho Power’s Petition. Given the facts of this case, we find that Idaho is the more appropriate jurisdiction to exercise authority over the QF transactions proposed by Western Desert and Tumbleweed. However, we cannot and will not order the Projects to submit themselves to this Commission’s jurisdiction.

IDAHO POWER’S PETITION

Western Desert is a proposed 5 MW wind QF project located in Owyhee County, Idaho. Tumbleweed is a proposed 10 MW wind QF project located in Elmore County, Idaho. Each project requested from Idaho Power a PURPA QF contract in the State of Oregon – specifically, an Energy Sales Agreement pursuant to the Public Utility Commission of Oregon’s rate Schedule 85-4. Each project also requested “Firm Point-to-Point Transmission Service”
from its interconnection with Idaho Power in the State of Idaho for delivery to “Idaho Power’s Oregon jurisdiction.” Presently, in Oregon, QFs with a nameplate capacity of 10 MW or less are eligible for a “standard” contract with SAR-based published rates. Currently in Idaho, the published avoided cost rates for wind QF projects are limited to QFs generating no more than 100 kW. Order No. 32262.

Idaho Power’s Petition explains that both Western Desert and Tumbleweed are QFs located in the State of Idaho, interconnecting with Idaho Power in the State of Idaho, and Idaho Power is a regulated utility that provides retail electric service in Idaho. Idaho Power further argues that the Idaho Commission has a regulatory framework for PURPA QF projects for Idaho Power in Idaho. Idaho Power maintains that common sense would dictate that Western Desert and Tumbleweed must contract with Idaho Power pursuant to the Idaho Commission’s PURPA rates, rules and regulations. Idaho Power states that these Projects “submit this veiled attempt to seek the same published rate SAR-based contracts that they are ineligible for in Idaho by concocting a scheme to attempt delivery to Idaho Power in its Oregon service territory, from Idaho Power’s Idaho service territory, entirely over Idaho Power’s own system.” Petition at 10-11. Idaho Power describes the Projects’ actions as a “blatant attempt to manipulate and avoid the Idaho Commission’s rates, rules, and regulations that are designed to implement PURPA and protect Idaho Power’s customers.” Id. at 11.

THE PROJECTS’ ANSWER AND MOTION

The Projects filed their Answer and Motion to Dismiss arguing that Idaho Power’s Petition is fatally flawed for several reasons. First, the Projects state that Idaho Power fails to cite to any Order, law or rule upon which the Petition is based. Second, the Projects maintain that the Commission is prohibited by federal law from regulating QFs – as such, the Commission does not have the authority to restrict their access to markets. Finally, the Projects argue that granting Idaho Power’s Petition would violate the Commerce Clause of the U.S. Constitution by restricting QFs from access to markets outside of the boundaries of Idaho. Moreover, the Projects state that FERC rules “specifically require utilities to wheel (even involuntarily) QF output to third party purchasers and prohibit utility-type regulation of QFs.” Id. at 3.

Western Desert maintains that it investigated the possibility of obtaining a PURPA contract in Idaho utilizing IRP-based avoided cost rates. However, the Project concluded that “IRP modeling results are not favorable for the development of wind projects in Idaho.” Answer
at 2. Consequently, the Projects state that they have no interest in selling output from their QF wind projects “to any utility that is operating under the jurisdiction of the Idaho Public Utilities Commission.” Id.

**PACIFICORP’S COMMENTS**

PacifiCorp insists that the Commission has authority and proper jurisdiction over the subject of Idaho Power’s Petition. PacifiCorp argues that FERC’s implementation of PURPA provides two ways a QF may impose a PURPA purchase obligation on a utility. QFs have the right to interconnect with a public utility and sell the net output of the QF to the directly interconnected utility. 18 C.F.R. § 292.303(a)(1). Alternatively, a QF may forego the right to sell to the directly interconnected utility and instead compel another utility to purchase its net output if the QF can “wheel” its net output to the second utility. 18 C.F.R. § 292.303(d), (a)(2). In this second scenario, PacifiCorp argues that the plain language of FERC’s regulations makes clear that the indirect purchase obligation under subsection 292.303(d) only applies to a utility that is not the wheeling utility. PacifiCorp argues that “by choosing to have a directly interconnected utility wheel net output, the QF developer thereby waives its right to obligate the directly interconnected utility to purchase net output.” Comments at 5. PacifiCorp maintains that, under FERC’s PURPA regulations, a QF developer cannot obligate a utility to wheel its net output and purchase its net output. Id. at 7.

In the alternative, if the Commission finds that a PURPA purchase obligation exists under the proposed transaction, PacifiCorp argues that the Projects “should receive the avoided cost rate they would have received if they sold to Idaho Power in Idaho because the wheel from the point of interconnection in Idaho to the point of delivery in Oregon is a contrivance aimed only at obtaining Oregon’s avoided cost rates.” Id. at 8.

**FINDINGS AND CONCLUSIONS**

The Commission has jurisdiction over Idaho Power, an electric utility, and the issues raised in this matter pursuant to the authority and power granted it under Title 61 of the Idaho Code and the Public Utility Regulatory Policies Act of 1978 (PURPA). *Rosebud Enterprises, Inc., v. Idaho Public Utilities Commission*, 128 Idaho 609, 614, 917 P.2d 766, 771 (1996). “Although FERC promulgated the general scheme and rules, it left implementation of PURPA to state regulatory authorities.” Id. at 614, 917 P.2d at 771. The Projects argue that this Commission does not have jurisdiction to consider Idaho Power’s Petition. However, the
Projects acknowledge in their Answer that “State utility regulatory commissions such as the Idaho PUC implement FERC’s regulations on the purchases and sales of power between utilities and QFs.” Answer at 7. Moreover, this Commission has previously addressed our authority to assert jurisdiction over PURPA matters. See Earth Power Energy and Minerals, Inc. v. Idaho Power Company (Order No. 25174); Island Power Company, Inc. v. PacifiCorp (Order No. 25245); Vaagen Bros. Lumber, Inc. v. Washington Water Power Company (Order No. 25716); Idaho Power Company v. Clark Canyon, LLC (Order No. 32294).

Jurisdiction is shared by all state regulatory authorities that exercise “ratemaking authority” over multi-jurisdictional utilities. PURPA Section 210, 18 U.S.C. § 824a-3(f)(1). The Projects’ assertion that Idaho Power failed to cite to any Order, law or rule upon which its Petition is based is erroneous. Idaho Power did, in fact, note this Commission’s jurisdiction pursuant to PURPA and citations to several pertinent Commission Orders were included. Because Idaho Power is a regulated utility serving customers in both Idaho and Oregon, both this Commission and the Public Utility Commission of Oregon (OPUC) have jurisdiction over these PURPA transactions. However, the question presented in this Petition is which Commission has primary jurisdiction. Based upon the particular facts of this case, we find that Idaho Power’s Petition is properly before this Commission and the underlying transaction is appropriately subject to the Idaho Commission’s primary jurisdiction for the reasons set out below.

First, Western Desert is a PURPA QF developing a 5 megawatt (MW) wind project in Owyhee County, Idaho. Tumbleweed is a PURPA QF developing a 10 MW wind project in Elmore County, Idaho. Both Projects will interconnect with Idaho Power’s system in Idaho. Under these facts alone it is obvious that Idaho would be the appropriate state to exercise primary jurisdiction over the transactions proposed by Western Desert and Tumbleweed. Projects located in Idaho, interconnecting with Idaho Power’s system in Idaho should reasonably expect to be governed by Idaho’s rules and regulations regarding the sale and purchase of QF power to Idaho’s regulated utilities.

Second, the Projects’ reliance on PURPA and FERC’s PURPA regulations to justify their transactions is misplaced. FERC’s regulations specifically address the sale and purchase of power between QFs and utilities:

(a) Obligation to purchase from qualifying facilities. Each electric utility shall purchase . . . any energy and capacity which is made available from a qualifying facility:
(1) Directly to the electric utility; or

(2) Indirectly to the electric utility in accordance with paragraph (d) of this section.

. . . .

(d) Transmission to other electric utilities. If a qualifying facility agrees, an electric utility which would otherwise be obligated to purchase energy or capacity from such qualifying facility may transmit the energy or capacity to any other electric utility. Any electric utility to which such energy or capacity is transmitted shall purchase such energy or capacity under this subpart as if the qualifying facility were supplying energy or capacity directly to such electric utility.

18 C.F.R. § 292.303(a) and (d) (emphases added). Thus, FERC’s regulations allow a QF two distinct paths for imposing a PURPA purchase obligation on a utility: (1) selling directly to the interconnected utility or (2) selling indirectly, by requesting that the directly interconnected utility transmit the QF output to any other electric utility.

Western Desert and Tumbleweed do not propose either of the transactions contemplated by the PURPA regulations. The Projects seek to interconnect with Idaho Power in Idaho and compel the same utility to transmit the output for delivery to a substation located in another state that has preferable avoided cost rates. This transaction is contrary to what is permissible under FERC regulations and pursuant to FERC Orders. FERC has stated that “[i]nterconnection service or an interconnection by itself does not confer any delivery rights from the generating facility to any points of delivery.” FERC Order No. 2003, 104 FERC 61,103 (2003) at ¶ 23. FERC goes on to state that “[w]hen an electric utility is obligated to interconnect under Section 292.303 of [FERC’s] Regulations, that is, when it purchases the QF’s total output, the relevant state authority exercises authority over the interconnection. . . .” Id. at ¶ 813.

Third, the Projects argue that FERC rules require utilities to wheel – even involuntarily – QF output to “third party purchasers.” Idaho Power’s ability to provide electric service in two states does not negate the fact that the Company is a single entity. Notwithstanding the fact that there is no third party utility purchaser in the Projects’ proposed transactions, FERC has specifically stated that no utility can be forced to wheel. “It is clear that the provisions of 18 C.F.R. § 292.303(d) can only be invoked with the consent of the QF, as well
as the consent of the electric utility with which the QF is interconnected.” Utah Power and Light, 57 FERC ¶ 61,363 at ¶ 62,188 (1991); Consumer Power Company, 133 P.U.R. 4th 497, 516 (Mich, PSC 1992) (the interconnecting utility must agree to wheel the power). In other words, the first utility must agree to wheel the QF power to a second utility. Id.; Re Association of Businesses Advocating Tariff Equity, 135 P.U.R. 4th 553, 557 (Mich. PSC 1992). In the present case, there is no “other” utility and the interconnecting utility (Idaho Power) has not agreed to wheel. Involuntary wheeling must be gained under provisions of the Federal Power Act (FPA).

Although a facility may meet the requirements for QF status, its owner nevertheless may elect to be an electric utility as defined in section 3(22) of the FPA rather than have the facility be treated as a QF. If such a facility sells electric energy at wholesale in interstate commerce, the owner is also a public utility. If the owner of the facility elects electric utility status, it may then request wheeling under section 211 of the FPA. Thus, a QF owner has the option to remain a QF and seek voluntary transmission from its local utility or in effect to waive its PURPA rights by electing to be an electric utility and thereby obtaining the ability to seek involuntary wheeling under the FPA.

Id. at ¶ 62,190. Therefore, a QF seeking to involuntarily wheel its power waives its PURPA rights and is subject to regulation pursuant to the FPA. The Projects’ assertion that a utility must involuntarily wheel QF power is erroneous. “QFs [have] no statutory right (under PURPA or otherwise) to wheeling.” Id.

Finally, sound public policy suggests that the Idaho Commission should exercise primary jurisdiction over the two transactions. Western Desert and Tumbleweed are projects located within Idaho seeking to interconnect with Idaho Power in Idaho Power’s Idaho service territory. The costs associated with PURPA transactions – regardless of the jurisdiction approving the agreements and avoided cost rates – are borne primarily by Idaho ratepayers (95%) as compared to Oregon ratepayers (5%). To allow the Projects to seek higher avoided cost rates from Oregon for Projects located and interconnecting in Idaho with an illusory wheel of the Projects’ output would be an arbitrage of federal and state regulations regarding PURPA. Consequently, we find that a QF located in Idaho, seeking to interconnect to a regulated utility in Idaho is most appropriately subject to Idaho’s rules and regulations regarding PURPA. Furthermore, FERC regulations do not allow a QF to impose the type of transaction that the Projects’ propose on a regulated utility.
This Commission is neither subjecting Western Desert or Tumbleweed to utility-type regulation nor is it attempting to compel the Projects to sell their output to Idaho Power pursuant to Idaho’s PURPA rules and regulations. This Commission cannot compel the Projects to enter into contracts for the sale of their energy. Finally, this Commission is not attempting to prohibit the Projects from selling their output to eligible customers in other states. The commerce cases cited by the Projects are not applicable and are distinguishable. The Projects may voluntarily negotiate to sell their output to any utility in any state that they wish. However, if the Projects wish to sell their output as a PURPA QF, then they must abide by FERC’s PURPA regulations that govern such transactions. The transactions proposed by Western Desert and Tumbleweed do not meet FERC’s criteria. 18 C.F.R. § 292.303(d).

ORDER

IT IS HEREBY ORDERED that Idaho Power’s Petition for a Declaratory Order is partially granted.

IT IS FURTHER ORDERED that the Idaho Public Utilities Commission has proper jurisdiction to address the Petition for Declaratory Order filed on July 8, 2011, by Idaho Power. It is further determined that Idaho is the more appropriate jurisdiction to exercise primary jurisdiction over the QF transactions proposed by Western Desert and Tumbleweed.

IT IS FURTHER ORDERED that the Projects’ Motion to Dismiss the Petition is denied.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See Idaho Code § 61-626.
DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 10th day of February 2012.

[Signatures]

PAUL KJELLANDER, PRESIDENT

MACK A. REDFORD, COMMISSIONER

MARSHA H. SMITH, COMMISSIONER

ATTEST:

[Signature]

Jean D. Jewell
Commission Secretary

ORDER NO. 32453
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF
PACIFICORP DBA ROCKY MOUNTAIN
POWER FOR A DETERMINATION
REGARDING A FIRM ENERGY SALES
AGREEMENT BETWEEN ROCKY
MOUNTAIN POWER AND CEDAR CREEK
WIND, LLC (RATTERLISNAKE CANYON
PROJECT (11-01), COYOTE HILL PROJECT
(11-02), NORTH POINT PROJECT (11-03),
STEEP RIDGE PROJECT (11-04), AND FIVE
PINE PROJECT (11-05)).

CEDAR CREEK WIND, LLC,

Petitioner/Appellant,

v.

IDAHO PUBLIC UTILITIES COMMISSION,

Respondent, Respondent on Appeal,

and

PACIFICORP DBA ROCKY MOUNTAIN
POWER,

Respondent.

SUPREME COURT
DOCKET NO. 39134-2011

IPUC CASE NOS. PAC-E-11-01
PAC-E-11-02
PAC-E-11-03
PAC-E-11-04
PAC-E-11-05

On July 27, 2011, the Commission issued Final Order on Reconsideration No. 32302
affirming its prior decision to not approve five Power Purchase Agreements (PPAs or
Agreements) entered into between Cedar Creek Wind and PacifiCorp dba Rocky Mountain
Power pursuant to the federal Public Utility Regulatory Policies Act of 1978 (PURPA). Based
upon the expressed terms of the five Agreements, the Commission found that the PPAs were not
effective prior to December 14, 2010 – the date on which the eligibility for PURPA published
avoided cost rates in Idaho changed from 10 average megawatts (aMW) to 100 kilowatts (kW)
for wind and solar qualifying facilities (QFs). Order No. 32260. Because each of the PPAs

ORDER NO. 32419
requested published avoided cost rates but the projects were in excess of 100 kW, the Commission found that the published rate was no longer available to the projects.

On August 5, 2011, Cedar Creek filed a Petition with the Federal Energy Regulatory Commission (FERC) claiming that the Commission’s Order No. 32302 was inconsistent with FERC’s regulations implementing PURPA. While its Petition to FERC was pending, Cedar Creek, on August 31, 2011, also appealed the Commission’s Order to the Idaho Supreme Court. On October 4, 2011, FERC issued an Order concluding that the Commission’s Order was inconsistent with PURPA and FERC’s PURPA regulations.

On October 24, 2011, the Commission and Cedar Creek filed a Stipulated Motion with the Idaho Supreme Court that the appeal be temporarily suspended and the matter remanded to the Commission.¹ Suspending the appeal would allow the Commission to reconsider its Order No. 32302 in light of the FERC Order and provide the parties with an opportunity to discuss the possibility of resolving the dispute. I.A.R. 13.3. On November 9, 2011, the Court issued an Order suspending the appeal and remanding the matter to the Commission for further review. On remand, the Commission invited settlement of the entire dispute and authorized the Commission Staff to participate in the settlement negotiations. Order No. 32386 citing Rules 352 and 353. Cedar Creek, Rocky Mountain and Staff (collectively the “Parties”) convened four settlement conferences. On December 15, 2011, the Parties filed a Motion to approve a “Stipulation of Settlement and Request for Approval of Power Purchase Agreements” (“Settlement Stipulation”) that proposed to settle all the disputed issues.

Having reviewed the underlying administrative record, the FERC Order and the Settlement Stipulation, the Commission issues this final Reconsideration Order on Remand. As explained in greater detail below, the Commission approves the Settlement Stipulation and approves the three modified PPAs. Accordingly, the Commission amends and clarifies its prior Order No. 32302 to be consistent with this Order. Idaho Code § 61-624.

¹ When the Stipulated Motion was filed, Rocky Mountain had not yet been granted intervention by the Court. Nevertheless, Rocky Mountain supported the suspension and remand.
BACKGROUND

A. Eligibility Cap Case

Prior to the filing of the five Cedar Creek PPAs, Avista Corporation, Idaho Power Company, and Rocky Mountain (collectively "the Utilities") petitioned the Commission on November 5, 2010, to initiate a generic investigation to address various PURPA issues. The Utilities also requested that while the investigation was underway, the Commission "immediately" reduce the eligibility cap or ceiling for the "published" avoided cost rate from 10 aMW per month to 100 kW per month. Order Nos. 32212 and 32302. The Commission issued a Notice and Order opening a separate investigation (GNR-E-10-04), solicited initial and reply comments, and convened an oral argument to address the proposed reduction in the eligibility cap. Order No. 32131 at 6-7.

The Commission subsequently found that the Utilities had made a convincing case to temporarily "reduce the eligibility cap for published avoided cost rates from 10 aMW to 100 kW for wind and solar [QFs] only while the Commission further investigates" other PURPA issues. Order No. 32176 at 9 (emphasis original). Consistent with its prior Notice, the Commission ordered that the eligibility cap for the published rate be reduced from 10 aMW to 100 kW for wind and solar projects effective December 14, 2010. Order Nos. 32176, 32212, 32302. No party, including Cedar Creek, appealed the Commission's decision to reduce the eligibility cap. Order No. 32302 at 5, 14-15.

B. The Five Original Agreements

The procedural history of this consolidated case is complex and lengthy, but the pertinent points are summarized here. On December 22, 2010, Rocky Mountain Power and Cedar Creek executed five separate PPAs for five wind QF projects.3 Because of the similarity between each of the five Agreements, the Commission found it reasonable and appropriate to consolidate the cases and issue a consolidated Order. Order No. 32260 at n.1.

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2 Pursuant to FERC's PURPA regulations, state commissions must "publish" an avoided cost rate for small QFs with the design capacity of 100 kW or less. 18 C.F.R. § 292.304(c)(1). However, PURPA regulations also declare that state commissions "may" set standards or published rates at a higher capacity amount. 18 C.F.R. § 292.304(c)(1-2). In February 2008, the Commission established the eligibility cap for published avoided cost rates for each of the three utilities at 10 aMW. Order No. 30488 at 17.

3 Because of the similarity between each of the five Agreements, the Commission found it reasonable and appropriate to consolidate the cases and issue a consolidated Order. Order No. 32260 at n.1.
nameplate capacity of 133.4 MW. Under normal and/or average conditions, each wind project was to have sold its output of not more than 10 aMW per month to Rocky Mountain at the published rate. The projects all selected October 1, 2012 as the scheduled commercial operation date (COD). Order No. 32302 at 3.

On January 10, 2011, Rocky Mountain filed the Applications requesting that the Commission issue an Order “accepting or rejecting” the five Cedar Creek PPAs. On February 24, 2011, the Commission issued a consolidated Notice of Application and Notice of Modified Procedure for the five Applications. Cedar Creek and Commission Staff filed timely comments in response to the Notice of Modified Procedure. Rocky Mountain and Cedar Creek both filed reply comments.

In its final Order No. 32260 issued June 8, 2011, the Commission declared that “the primary issue to be determined in these [Cedar Creek] cases is whether the Agreements were executed before the eligibility cap for published rates was lowered to 100 kW on December 14, 2010.” Order No. 32260 at 9. The Commission found that the five PPAs were not fully-executed (i.e., signed by both parties) prior to December 14, 2010. Relying on the actual terms of the PPAs, the Commission found that each PPA stated that “the ‘Effective Date’ of [each] Agreement is ‘after execution by both Parties and after approval by the Commission.’” Id. citing PPA ¶¶ 1.13, 2.1. (emphasis added). Because the Commission had previously reduced the eligibility cap for the published avoided cost rate from 10 aMW to 100 kW, the five PPAs “contained an essential term that was no longer available to the Projects.” Order No. 32302 at 2.

Cedar Creek timely filed a Joint Petition for Reconsideration of the Commission’s final Order No. 32260. On reconsideration, Cedar Creek argued that the Commission’s Order was erroneous because a “legally enforceable obligation” existed between Cedar Creek and Rocky Mountain prior to the reduction in the eligibility cap on December 14, 2010. As a result, Cedar Creek maintained that it was entitled to published avoided cost rates and urged the Commission to “expeditiously approve the Agreements as submitted.” Order No. 32302 at 2.

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4 The Applications for Rattlesnake Canyon, Coyote Hill and North Point indicated that each of these projects would have a maximum nameplate capacity of 27.6 MW, while Steep Ridge and Five Pine would each have a maximum nameplate capacity of 25.3 MW.

5 The Commission also observed that the opening paragraph of each Agreement states that the Agreement is “entered into this 22nd day of December 2010.” Id.
On reconsideration, the Commission affirmed its prior decision that the five PPAs all contained express language that the effective date of each Agreement is when both parties signed the PPAs – December 22, 2010. The Commission noted that it was undisputed that Cedar Creek signed the PPAs on December 13, 2010, and Rocky Mountain signed on December 22, 2010. *Id.* Agreements ¶¶ 1.13, 2.1, Order No. 32302 at 4, 6, 8. Given the agreed upon effective date, the Commission affirmed that each Agreement did not become effective until after execution by both Parties. Order No. 32302 at 9. The Commission also found that it is not in the public interest to allow parties with contracts executed on or after December 14, 2010, to avail themselves of an eligibility cap, and thus published rates, that are no longer applicable. Order No. 32302 at 12, 16.

D. The FERC Case and the Appeal

On August 5, 2011, Cedar Creek filed a Petition with FERC requesting that the federal agency bring an enforcement action against the Commission pursuant to 16 U.S.C. § 824a-3(h)(2) or, in the alternative, to make certain findings related to the Commission’s decision. Cedar Creek claimed that the Commission’s Order is inconsistent with FERC’s regulations implementing PURPA. On October 4, 2011, FERC issued an Order declining to bring an enforcement action against the Commission. However, FERC determined that the Commission’s Order was inconsistent with PURPA and FERC’s implementing regulations. *Notice of Intent not to Act and Declaratory Order*, 137 FERC ¶ 61,006 (Oct. 4, 2011). In particular, FERC construed the Commission’s final Order No. 32260 as “limiting the creation of a legally enforceable obligation only to QFs that have [PPAs] . . . signed by both parties to the agreement.” *Id.* at ¶ 26. FERC interpreted the Commission’s Order as requiring a fully-executed contract as a condition precedent to the creation of a legally enforceable obligation between the parties. *Id.* at ¶¶ 30, 35. Although this Commission has a long line of cases to the contrary, FERC concluded that the Commission did not recognize that “a legally enforceable obligation may be incurred before the formal memorialization of a contract to writing.” *Id.* at ¶ 36.

FERC did not rule whether Cedar Creek had perfected a legally enforceable obligation for the five projects. *Id.* at ¶¶ 38 (whether there is a “legally enforceable obligation . . . is not before us.”); 39. Given the issuance of the FERC Order and Cedar Creek’s appeal to the Idaho Supreme Court, Cedar Creek and the Commission filed a Stipulated Motion for the appeal to be temporarily suspended and the matter remanded to the Commission.
THE SETTLEMENT STIPULATION

Cedar Creek, Rocky Mountain and Staff (collectively the “Parties”) convened four settlement conferences on October 20 and 27, November 16, and December 1, 2011. As a result of these settlement discussions, the Parties on December 15, 2011, filed a Motion to Approve the Settlement Stipulation and Request for Approval of Power Purchase Agreements (the “Settlement Stipulation”). The Parties disclosed that they have resolved all disputes between and among themselves.

The Parties requested that the Commission modify its Order on Reconsideration No. 32302 and approve three of the five original PPAs as amended in the Settlement Stipulation. More specifically, the Parties requested that the Commission approve the amendments to the North Point project (Case No. PAC-E-11-03); the Five Pine project (Case No. PAC-E-11-05); and the Coyote Hill project (Case No. PAC-E-11-02) (together, the “Agreements”). In addition, Cedar Creek and Rocky Mountain agreed to withdraw the remaining two Applications and accompanying PPAs. Stipulation at § 2.

The Parties agreed that Cedar Creek had established a legally enforceable obligation under PURPA no later than December 13, 2010. Stipulation at §§ 1, 4. Because such obligation arose prior to December 14, 2010, the Parties agree that the surviving PPAs should be approved by the Commission at the avoided cost rates contained in the Original Agreements. Id. at § 5. Thus, Cedar Creek and Rocky Mountain are restored to their relative positions under the original PPAs. The three surviving PPAs will have a combined nameplate capacity not to exceed 133.4 MW and Rocky Mountain shall not be required to purchase more than 438,000 MWh (i.e., approximately 50 aMW) of output in any given calendar year. Id. at § 7; PPAs at 1.30, 1.43, 4.1. The North Point PPA will be modified to have an 80 MW nameplate capacity, while the Five Pine and Coyote Hill PPAs will have a total nameplate capacity not to exceed 53.4 MW. Stipulation, Exh. A, B, C.

Both the North Point and Five Pine PPAs provide that these PPAs may be assigned to Ridgeline at its Meadow Creek site. Id. at § 21.2. Because the Meadow Creek facility already has its transmission interconnection with PacifiCorp, assignment to Ridgeline would allow the scheduled commercial operation date (COD) for both facilities to be December 31, 2012.

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6 The two Applications and PPAs to be withdrawn are: the Steep Ridge project (Case No. PAC-E-11-04) and the Rattlesnake Canyon project (Case No. PAC-E-11-01) (together, the “Withdrawn Agreements”). Stipulation at 2.
Utilizing the Meadow Creek facility would allow Cedar Creek/Ridgeline to obtain Treasury grants and other tax incentives before they are set to expire on December 31, 2012. Any assignment of North Point and Five Pine to Ridgeline must occur within 90 days of the effective date of the PPAs as modified, approximately on or before March 31, 2012. Exh. A, B, C § 21.2.\(^7\)

The Coyote Hill project is contemplated at the original Cedar Creek site.

In addition, the PPAs further provide that Cedar Creek and Rocky Mountain shall share the “Environmental Attributes” (including but not limited to renewable energy credits (RECs) and Green Tags) attributed to the surviving PPAs. More specifically, Cedar Creek shall be entitled to the environmental attributes for the first 10 years of operation, while Rocky Mountain shall be entitled to the environmental attributes for the last 10 years of the 20-year Agreements. Exh. A, B, C at §§ 1.17, 1.26, 4.6.

The Parties assert that the settlement of their dispute including the modifications of the surviving PPAs represents a fair, just and reasonable resolution of the disputed claims, and are consistent with applicable law and regulatory policies. Stipulation at §§ 1, 6, 12. The Parties further maintain that the settlement represents a negotiated compromise between the Parties and is in the public interest. The Parties agree that the Settlement Stipulation “resolves all issues raised by any party in the captioned [Commission] dockets, in the FERC Proceeding, and in Cedar Creek’s appeal to the Idaho Supreme Court. If the Commission adopts the Settlement Stipulation, each waives, releases and discharges the other Parties from any and all causes of action, suits, claims, demands, and liability whatsoever in law or equity.” Id. at § 17. The Parties urge the Commission to approve this Settlement Stipulation and the PPAs in their entirety and they stand ready to support the Stipulation. Id. at § 13.

**COMMISSION FINDINGS**

At the outset, we commend the Parties for their diligence and efforts at resolving the underlying disputes. Consistent with our authority under *Idaho Code* § 61-624 and Rules 352 and 353, we invited settlement of all of the disputes arising from our Order Nos. 32260 and 32302. Order No. 32386 at 2.

\(^7\) Although the Ridgeline/Meadow Creek transmission line is already completed, this line may have capacity limitations. Consequently, the PPAs allow for a combination of generation sizes at the Five Pine and Coyote Hill projects so long as the total generation for all the projects not exceed 438,000 MWh. This purchase cap shall be trued-up annually. Stipulation at § 7.
Rule 356 provides that the Commission is not bound by the Parties’ Settlement Agreement. IDAPA 31.01.01.356. The Commission will “independently review any settlement proposed to it to determine whether the settlement is just, fair and reasonable, in the public interest or otherwise in accordance with law or regulatory policy.” Id. The Commission may accept, reject, or modify settlement provisions. Moreover, proponents of settlements on appeal carry the burden of showing that the settlement is reasonable and in the public interest. Rule 355. When a settlement of an appeal – such as this case – calls for Commission action, the Commission will prescribe an appropriate procedure to examine a proposed settlement. In this case, the Parties to the appeal have asked the Commission to amend Reconsideration Order No. 32302 issued July 27, 2011, and approve three modified PPAs. Idaho Code § 61-624 provides that the Commission “may at any time, upon notice to the public utility affected, . . . rescind, alter or amend any order or decision made by it.”

After having reviewed the record in this case, the FERC Order, the Stipulation of Settlement and Request for Approval of Power Purchase Agreements, and the modified PPAs, we find the record is comprehensive and further proceedings are not necessary. Rule 354. Based upon our review of the entire record and the particular facts of this case, we find that the Settlement is fair, just and reasonable, and in the public interest. As noted by the Parties, the Stipulation represents a reasonable compromise of the positions held by the Parties.

In our initial decision, this Commission made a determination about whether to approve the Agreements based on the express terms contained within each Agreement. In our past experience, when a QF wants a determination that there is a legally enforceable obligation, it files a complaint against a utility that it alleges has failed to negotiate. This is the first time the Commission has reviewed the facts of this case for evidence regarding the existence of a legally enforceable obligation outside the express terms of the original five Agreements entered into by Rocky Mountain and Cedar Creek.

There are several reasons supporting our determination that the settlement is fair and reasonable to Cedar Creek, Rocky Mountain, and ratepayers. First, the Stipulation returns Cedar Creek and Rocky Mountain to their respective positions prior to the issuance of our Orders disapproving the PPAs. Based upon the Parties’ assertions in the Settlement Stipulation and our review of the record, we find that the record reveals that Cedar Creek had perfected a legally enforceable obligation no later than December 13, 2010. As such, Cedar Creek was entitled to
the published avoided cost rates available to 10 aMW QFs in effect as of December 13, 2010. The three modified PPAs equate to the original five PPAs.

Second, PacifiCorp and ratepayers are protected under the settlement and the three modified PPAs by being obligated to purchase no more than the total equivalent of 50 aMW of net output as originally contemplated under the five PPAs. Assignment also allows the COD date to advance, thereby providing benefit to Cedar Creek.

Third, ratepayers and Rocky Mountain are further advantaged because the modified PPAs recognize that the environmental attributes produced by the three modified projects will be equally apportioned between Rocky Mountain and Cedar Creek. Under the PPAs, Cedar Creek will be entitled to the environmental attributes for the first 10 years of the Agreements and Rocky Mountain will be entitled to the environmental attributes for the last 10 years of the Agreements. This is an improvement over the original PPAs because the assignment of the environmental attributes or RECs was not clearly delineated in the original Agreements. Moreover, subsequent revenues derived from the environmental attributes will offset Rocky Mountain’s purchase of the output from the surviving PPAs over the last 10 years of the Agreements.

Finally, we find that resolution of this matter will avoid uncertainty and conserve resources (both time and money). This is beneficial to Cedar Creek, Rocky Mountain and ratepayers. The settlement avoids the likelihood of litigation in multiple forums and represents a significant benefit to all Parties. Here the settlement brings the dispute to a reasonable conclusion and benefits Cedar Creek, Rocky Mountain and ratepayers. Rules 354-355; Aguirre v. Hamlin, 80 Idaho 176, 327 P.2d 349 (1958).

ORDER

IT IS HEREBY ORDERED that the Motion for Approval of the Stipulation of Settlement and Request for Approval of Power Purchase Agreements filed by the Parties is granted. In addition, we approve the three modified Agreements identified in Exhibit A (North Point), Exhibit B (Five Pine), and Exhibit C (Coyote Hill).

IT IS FURTHER ORDERED that Rocky Mountain Power’s request to withdraw the Steep Ridge Application and Agreement (Case No. PAC-E-11-04) and the Rattlesnake Canyon Application and Agreement (Case No. PAC-E-11-01) is granted.
IT IS FURTHER ORDERED that Order No. 32302 issued July 27, 2011, is amended consistent with the findings and discussions set out in this Order pursuant to Idaho Code § 61-624.

THIS IS A FINAL RECONSIDERATION ORDER ON REMAND. Any party aggrieved by this Order may appeal to the Supreme Court of Idaho as provided by the Public Utilities Law and the Idaho Appellate Rules. See Idaho Code § 61-627.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 21st day of December 2011.

P A U L  K J E L L A N D E R , P R E S I D E N T


ATTEST:

B a r b a r a  B a r r o w s
Barbara Barrows
Assistant Commission Secretary

bs/O:PAC-E-11-01_PAC-E-11-02_PAC-E-11-03_PAC-E-11-04_PAC-E-11-05_dh3
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA ROCKY MOUNTAIN POWER FOR A DETERMINATION REGARDING A FIRM ENERGY SALES AGREEMENT BETWEEN ROCKY MOUNTAIN POWER AND CEDAR CREEK WIND, LLC (RATTLESNAKE CANYON PROJECT) CASE NO. PAC-E-11-01

IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA ROCKY MOUNTAIN POWER FOR A DETERMINATION REGARDING A FIRM ENERGY SALES AGREEMENT BETWEEN ROCKY MOUNTAIN POWER AND CEDAR CREEK WIND, LLC (COYOTE HILL PROJECT) CASE NO. PAC-E-11-02

IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA ROCKY MOUNTAIN POWER FOR A DETERMINATION REGARDING A FIRM ENERGY SALES AGREEMENT BETWEEN ROCKY MOUNTAIN POWER AND CEDAR CREEK WIND, LLC (NORTH POINT PROJECT) CASE NO. PAC-E-11-03

IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA ROCKY MOUNTAIN POWER FOR A DETERMINATION REGARDING A FIRM ENERGY SALES AGREEMENT BETWEEN ROCKY MOUNTAIN POWER AND CEDAR CREEK WIND, LLC (STEEP RIDGE PROJECT) CASE NO. PAC-E-11-04

IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA ROCKY MOUNTAIN POWER FOR A DETERMINATION REGARDING A FIRM ENERGY SALES AGREEMENT BETWEEN ROCKY MOUNTAIN POWER AND CEDAR CREEK WIND, LLC (FIVE PINE PROJECT) ORDER NO. 32302

On January 10, 2011, PacifiCorp dba Rocky Mountain Power filed five Applications each requesting acceptance or rejection of a 20-year Firm Energy Sales Agreement

ORDER NO. 32302
(“Agreements”) between Rocky Mountain Power and Cedar Creek Wind, LLC, for its Rattlesnake Canyon, Coyote Hill, North Point, Steep Ridge and Five Pine wind projects (collectively “the Projects”). On February 24, 2011, the Commission issued a consolidated Notice of Application and Notice of Modified Procedure for the five Applications. Timely comments in response to the Notice of Modified Procedure were filed by the Commission Staff and the Projects. On March 31, 2011, Rocky Mountain Power filed reply comments. On June 8, 2011, the Commission issued a consolidated final Order disapproving each of the five Agreements. The Commission found that the Agreements “were not fully executed (signed by both parties) prior to December 14, 2010” – the date that the Commission lowered the eligibility cap for the published avoided cost rate from 10 aMW to 100 kW. Order No. 32260 at 10. Thus, the Agreements contained an essential term that was no longer available to the Projects. Id.

On June 29, 2011, the Projects timely filed a Joint Petition for Reconsideration of the Commission’s final Order. The Projects allege that the Commission’s final Order is erroneous and is not in conformity with the law because a legally enforceable obligation existed between Rocky Mountain Power and the Cedar Creek projects prior to December 14, 2010. As a result, Cedar Creek maintains that they are entitled to published avoided cost rates under the previous 10 aMW eligibility cap. The Projects further argue that not considering grandfathering criteria is a departure from the Commission’s past precedent and the Commission did not give proper notice to the parties regarding its intent to depart from precedent.

On July 6, 2011, Rocky Mountain Power filed an answer to the Projects’ Petition. Rocky Mountain Power maintains that the Commission’s final Order is consistent with federal and state law. Rocky Mountain Power contends that the Commission had good cause to act as it did. Further, the Commission was acting within its discretion and, therefore, reconsideration should be denied.

This matter was fully submitted for the Commission’s consideration on the July 11, 2011, decision meeting agenda. On July 12, 2011, the Projects filed a reply to Rocky Mountain Power’s answer. On July 21, 2011, Rocky Mountain Power filed a sur-reply to the Projects’ reply. The Commission finds that the record in this case closed on July 11, 2011, when the matter became fully submitted. Furthermore, Commission Rule 331 does not provide parties the opportunity for a reply and sur-reply to the initial petition for reconsideration and answer.
Therefore, the Commission will not consider the arguments addressed in the Projects’ July 12 reply or Rocky Mountain Power’s July 21 sur-reply.

BACKGROUND

A. The Agreements

On December 22, 2010, Rocky Mountain Power and the five wind projects entered into their respective Agreements. Under the terms of the Agreements, each wind project agrees to sell electric energy to Rocky Mountain Power for a 20-year term using the 10 aMW non-levelized published avoided cost rates. Applications at 8-9. The Applications recite that Rattlesnake Canyon, Coyote Hill and North Point will each have a maximum capacity of 27.6 MW, and Steep Ridge and Five Pine will each have a maximum capacity of 25.2 MW. Under normal and/or average conditions, each QF will not generate more than 10 aMW on a monthly basis. Rocky Mountain Power warrants that the Agreements comport with the terms and conditions of the various Commission Orders applicable to PURPA agreements for a wind resource. Id. at ¶ 6 citing Order Nos. 30415, 30488, 30738 and 31025.

The projects all selected October 1, 2012, as the Scheduled Commercial Operation Date. Applications at 9. Rocky Mountain Power asserts that various requirements have been placed upon the projects in order for Rocky Mountain Power to accept the project’s energy deliveries. Rocky Mountain Power states that it will monitor each project’s compliance with initial and ongoing requirements through the term of the Agreement. The parties have each agreed to liquidated damage and security provisions. Agreements ¶¶ 2.5.1, 11.1.2.

Rocky Mountain Power asserts that it advised each project of the project’s responsibility to work with Rocky Mountain Power’s delivery transmission unit to ensure that sufficient time and resources will be available for the delivery unit to construct the interconnection facilities, and transmission upgrades if required, in time to allow the projects to achieve their October 1, 2012, Scheduled Commercial Operation Date. The Applications state that the projects have been advised that delays in the interconnection or transmission process do not constitute excusable delays and if a project fails to achieve its Scheduled Commercial Operation Date, delay damages will be assessed. Applications at 11. The Applications further maintain that each project has acknowledged and accepted the risk inherent in proceeding with its Agreement without knowledge of the requirements of interconnection and possible transmission upgrades. Id.
Rocky Mountain Power states that each project has also been made aware of and accepted the provisions in each Agreement regarding curtailment or disconnection of its facility should certain operating conditions develop on Rocky Mountain Power’s system. Agreements ¶ 6.3.

By their own terms, the “effective date” of each agreement is “after execution by both parties and after approval by the Commission.” Agreement ¶ 2.1; 1.13. The Agreements are dated December 22, 2010. Id. at p. 1. The Agreements further provide that the Agreements will not become effective until the Commission has approved all of the terms and conditions and declares that all payments made by Rocky Mountain Power to each project for purchases of energy “are just and reasonable, in the public interest, and that the costs incurred by [Rocky Mountain Power] for purchases of capacity and energy from [Cedar Creek] are legitimate expenses, all of which the Commission will allow [Rocky Mountain Power] to recover in rates in Idaho in the event other jurisdictions deny recovery of their proportionate share of said expenses.” Agreements ¶ 2.1.

B. The Utilities’ Joint Petition

On November 5, 2010, prior to the date that Rocky Mountain Power and the Projects entered into their Agreements, Idaho Power, Avista Corporation, and PacifiCorp dba Rocky Mountain Power filed a Joint Petition requesting that the Commission initiate an investigation to address various avoided cost issues related to the Commission’s implementation of PURPA. Case No. GNR-E-10-04. On December 3, 2010, the Commission issued Order No. 32131 declining a motion made by the utilities to immediately reduce the published avoided cost rate eligibility cap from 10 aMW to 100 kW. Order No. 32131 at 5. However, the Order did notify parties that the Commission’s decision regarding whether to reduce the published avoided cost eligibility cap would become effective on December 14, 2010. Id. at 5-6, 9.

Section 210 of PURPA generally requires electric utilities to purchase power produced by QFs at “avoided cost” rates set by the Commission. “Avoided costs” are those costs which a public utility would otherwise incur for electric power, whether that power was purchased from another source or generated by the utility itself.” 18 C.F.R. § 292.101(b)(6). Order No. 32176 at 1. Under PURPA regulations issued by the Federal Energy Regulatory Commission (FERC), the Commission must “publish” avoided cost rates for small QFs with a design capacity of 100 kW or less. Order No. 32176 at 1. However, the Commission has the
discretion to set eligibility for the published avoided cost rate at a higher capacity amount — commonly referred to as the “eligibility cap.” 18 C.F.R. § 292.304(c)(1-2). When a QF project is larger than the Commission-established eligibility cap the avoided cost rate for the project must be individually negotiated by the QF and the utility using the Integrated Resource Plan (IRP) Methodology. Order No. 32176.

The purpose of utilizing the IRP Methodology for large QF projects is to more precisely value the energy being delivered. Id. at 10. The IRP Methodology recognizes the individual generation characteristics of each project by assessing when the QF is capable of delivering its resources against when the utility is most in need of such resources. The resultant pricing is reflective of the value of QF energy to the utility. Utilization of the IRP Methodology does not negate the requirement under PURPA that the utility purchase the QF energy.

Based upon the record in the GNR-E-10-04 case, the Commission subsequently found that a “convincing case has been made to temporarily reduce the eligibility cap for published avoided cost rates from 10 aMW to 100 kW for wind and solar only while the Commission further investigates” other avoided cost issues. Order No. 32176 at 9 (emphasis original). On reconsideration, the Commission affirmed its decision to temporarily reduce the eligibility cap for published avoided cost rates from 10 aMW to 100 kW. Order No. 32212. Thus, the eligibility cap for the published avoided cost rate for wind and solar QF projects was set at 100 kW effective December 14, 2010. No party appealed from the Orders in Case No. GNR-E-10-04.

C. The Prior Final Order in this Case

On June 8, 2011, the Commission issued Order No. 32260 disapproving the Agreements between Rocky Mountain Power and each of the five wind projects — Rattlesnake Canyon, Coyote Hill, North Point, Steep Ridge and Five Pine. The Commission determined that the Agreements were not fully executed (signed by both parties) prior to December 14, 2010, the date upon which the eligibility for published avoided cost rates changed from 10 aMW to 100 kW for wind and solar projects. Consequently, the Commission found that the rates contained in the Agreements did not comply with Order No. 32176 because each of the projects

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1 The five projects had previously filed consolidated comments because the relevant facts for each of these five projects are substantially similar. Consequently, the Commission found it reasonable and appropriate to consolidate the cases and issue a consolidated final Order. Order No. 32260 n.1.
requesting published avoided cost rates is in excess of 100 kW. Order No. 32260 at 10. The "old" 10 aMW published rate is available only to non-wind and non-solar QFs.

The Projects signed the Agreements on December 13, 2010, and Rocky Mountain Power signed on December 22, 2010. The Commission noted that the Agreements contain language regarding the effective date. The terms of the Agreements unequivocally state that the "Effective Date" of the Agreements is "after execution by both Parties and after approval by the Commission." Agreements ¶ 1.13, 2.1 (emphasis added). The Agreement is dated "this 22nd day of December, 2010" and Rocky Mountain Power stated that it executed the Agreements on December 22, 2010. Applications at ¶ 9; Reply Comments at 4. We stated that "[t]he Commission does not consider a utility and its ratepayers obligated until both parties have completed their final reviews and signed the agreement." Order No. 32260 at 9. We found that "a thorough review is appropriate and necessary prior to signing Agreements that obligate ratepayers to payments in excess of $685 million" over the 20-year term of the Agreements. Id. at 8. The Commission established a bright line rule that for a wind or solar QF larger than 100 kW to be eligible for published avoided cost rates, a Firm Energy Sales Agreement/Power Purchase Agreement must have been executed, i.e., signed by both parties, prior to the December 14, 2010, effective date of the change in eligibility criteria. Id. at 10. The Commission additionally found that it was "not in the public interest to allow parties with contracts executed on or after December 14, 2010, to avail themselves of an eligibility cap that is no longer applicable." Id. at 9.

PETITION FOR RECONSIDERATION

On June 29, 2011, the Projects filed a timely Joint Petition for Reconsideration. Idaho Code § 61-626. The Projects allege that the Commission's Order is erroneous and violates federal and state law. Specifically, the Projects argue that (1) the Commission's bright line rule requiring an executed contract in order for a wind facility to qualify for a 10 aMW eligibility cap violates federal law; (2) the Commission arbitrarily departed from past precedent by not utilizing grandfathering criteria to allow projects an opportunity to qualify under the 10 aMW eligibility cap; and (3) the Commission did not give proper notice prior to deviating from past precedent with regard to grandfathering. Ultimately, the Projects contend that their Agreements should be approved because a legally enforceable obligation existed prior to December 14, 2010. The Projects request that the Commission "expeditiously grant this petition for reconsideration and,
by August 5, 2011, approve the Agreements without further briefing, hearing, or other proceedings.” Reconsideration at 18.

Rocky Mountain Power filed an answer to the Projects’ Petition for Reconsideration. Rocky Mountain Power states that the Commission properly applied the controlling legal standard for determining when a legally enforceable obligation arises under Idaho and federal law. Rocky Mountain Power asserts that “there is no contract until Rocky Mountain Power has completed its internal review, and signified its acceptance by executing the Agreement.” Answer at 16. The Company maintains that it executed the Agreement after the eligibility cap was reduced to 100 kW — i.e., on December 22, 2010. Id. at 15. The Company further argues that the Commission may, in its discretion, determine whether to utilize grandfathering criteria. Finally, Rocky Mountain Power maintains that the Projects have failed to demonstrate that the Commission’s Order is legally flawed.

**ISSUES ON RECONSIDERATION**

**A. Legal Standards**

Reconsideration provides an opportunity for a party to bring to the Commission’s attention any question previously determined and thereby affords the Commission an opportunity to rectify any mistake or omission. *Washington Water Power Co. v. Kootenai Environmental Alliance*, 99 Idaho 875, 879, 591 P.2d 122, 126 (1979). The Commission may grant reconsideration by reviewing the existing record, by written briefs, or by evidentiary hearing. IDAPA 31.01.01.311.03. If reconsideration is granted, the Commission must complete its reconsideration within 13 weeks after the deadline for filing petitions for reconsideration. *Idaho Code* § 61-626(2).

Consistent with the purpose of reconsideration, the Commission’s Rules of Procedure require that petitions for reconsideration “set forth specifically the ground or grounds why the petitioner contends that the order or any issue decided in the order is unreasonable, unlawful, erroneous or not in conformity with the law.” Rule 331.01, IDAPA 31.01.01.331.01. Rule 331 further requires that the petitioner provide a “statement of the nature and quantity of evidence or argument the petitioner will offer if reconsideration is granted.” Id.

**B. Legally Enforceable Obligation**

The Projects argue that, pursuant to 18 C.F.R. § 292.304(d)(2), a QF is entitled to the rates that are in effect on the date the QF incurred a legally enforceable obligation to provide
energy. The Projects maintain that the key consideration is "whether, as was true here for Cedar Creek, the QF has committed through a legally enforceable obligation to sell power to the utility or, as also was the case here for Rocky Mountain Power, the utility is committed to entering into a legally enforceable obligation to buy that power." Reconsideration Petition at 5. The Projects argue that the Commission committed reversible error by requiring a fully executed contract to establish a legally enforceable obligation.

**Commission Findings:** The Idaho Supreme Court has held that "[t]he implementation of PURPA as it relates to cogeneration and small power producers, and the regulations promulgated by FERC, have been largely left to the regulatory authorities of the individual states." A.W. Brown Company, Inc. v. Idaho Power Company, 121 Idaho 812, 816, 828 P.2d 841, 845 (1992). "FERC regulations grant the states latitude in implementing the regulation of sales and purchases between QFs and electric utilities." Order No. 32262 citing Federal Energy Regulatory Commission v. Mississippi, 456 U.S. 742, 102 S.Ct. 2126, 72 L.Ed.2d 532 (1982). As we stated in our final Order, "[a]ccording to the FERC, 'it is up to the States, not [FERC] to determine the specific parameters of individual QF power purchase agreements, including the date at which a legally enforceable obligation is incurred under State law.'" Order No. 32260 at 9 citing Rosebud Enterprises v. Idaho PUC, 128 Idaho 609, 623-624, 917 P.2d 766, 780-781 (1996) citing West Penn Power Co., 71 FERC ¶ 61,153 (1995).

The premise of the Projects’ argument is correct: QFs have the right to choose to have rates calculated at the time that a legally enforceable obligation is incurred. Reconsideration at 5. However, this Commission determined that the parties entered into a legally enforceable obligation at the time that both parties executed the power purchase agreement. We find that, for each of these five projects, a legally enforceable obligation was incurred on December 22, 2010 – the date that Rocky Mountain Power executed the Agreements. By their very terms the Agreements were not effective until December 22, 2010, and after approval by this Commission. Agreements ¶¶ 1.13, 2.1. On December 14, 2010, wind projects larger than 100 kW were no longer entitled to the 10 MW published avoided cost rate. In determining when the parties incurred a legally enforceable obligation, we properly exercised the authority granted us by FERC. "For purposes of [FERC] regulations, the critical date is the date on which a legally enforceable obligation is incurred, and choosing that date for a specific QF is

In their Petition for Reconsideration, the Projects reference FERC regulations and *JD Wind 1, LLC*, 130 FERC ¶ 61,127 (2010), in support of their proposition that an executed contract is not necessarily required in order for a legally enforceable obligation to exist. In *JD Wind*, six separate QFs developed by John Deere Renewables petitioned FERC to overturn a Texas PUC decision denying the projects long-term contracts at avoided cost rates calculated at the beginning of the contract. The Texas PUC found that wind QFs were not entitled to long-term legally enforceable obligations because of the intermittent, or non-firm, nature of the resource. FERC concluded that the Texas PUC’s Order, limiting the award of a legally enforceable obligation to only those QFs that provide firm power, was inconsistent with FERC regulations implementing PURPA. *JD Wind* does not consider or analyze when a legally enforceable obligation is incurred under PURPA. The Projects’ use of this FERC case as instructive on the issues of contract formation and timing of a legally enforceable obligation is misleading and without merit. *JD Wind* contemplates whether a legally enforceable obligation must be entered into by a utility for intermittent/non-firm resources – nothing more.

Nothing cited by the Projects demonstrates that the Commission’s Order is erroneous or inconsistent with federal law. On the contrary, the Projects admit, “[n]o doubt, FERC leaves it to the discretion of state commissions to establish the date on which a legally enforceable PURPA obligation is created.” Reconsideration at 6 (emphasis in original). We find that, in this case, a legally enforceable obligation was incurred when the contracts were fully executed – upon obtaining the signature of both parties – December 22, 2010. Rocky Mountain Power executed the Agreements on December 22, 2010. Applications at ¶ 9; Reply Comments at 4; Answer at 16. This finding is based on substantial and competent evidence and supported by the record. The Commission’s finding is also in the public interest and strikes a balance between “the local public interest of a utility’s electric consumers and the national public interest in development of alternative energy sources.” *Rosebud Enterprises*, 128 Idaho at 613, 917 P.2d at 770. Allowing a project to avail itself of an eligibility cap (and therefore published rates) that is no longer applicable could cause ratepayers to pay more than the utility’s avoided cost which “would be in direct violation of PURPA policies.” *A.W. Brown Company v. Idaho Power*
Company, 121 Idaho 812, 818, 828 P.2d 841, 847 (1992). Based on the foregoing, the Projects’ request for reconsideration on this issue is denied.

Prior to signing, Rocky Mountain Power performs a thorough review of the terms of the contract. As we stated in our final Order, a comprehensive review of a power purchase agreement is consistent with this Commission’s directive to utilities that they assist the Commission in its gatekeeper role when reviewing QF contracts. Order No. 32260 at 8. We find that it is reasonable and consistent with the authority granted us under PURPA, and that the public interest requires that each party have a full and final review of the contract before signing and obligating the utility and its ratepayers to hundreds of millions of dollars in energy payments over the 20-year life of the Agreements. The Projects were given unrestricted time to adequately review the contracts before signing. Rocky Mountain Power is obligated to be as diligent in its review prior to asking the Commission to commit ratepayer dollars.

We further note that, unlike standard offer and acceptance contracts, PURPA agreements are subject to review and approval by this Commission pursuant to Idaho statutes. Idaho Code §§ 61-502 and 61-503. “The Commission, as part of its statutory duties, determines reasonable rates and investigates and reviews contracts.” A.W. Brown Company v. Idaho Power Company, 121 Idaho 812, 816, 828 P.2d 841, 845 (1992). The Agreements acknowledge this statutory duty of the Commission by providing that each Agreement will not become effective until the Commission has approved all of the terms and conditions and declares that all payments made by Rocky Mountain Power to the Projects for purchases of energy are just and reasonable and in the public interest. Agreements ¶ 2.1. An effective date based on Commission approval of the Agreement has been supported on Idaho Supreme Court review. Here, no one has argued that the legally enforceable obligation arises only after the Commission has approved the Agreements. Therefore, based upon this record and pursuant to the discretion granted us by PURPA and FERC regulations, we find that a legally enforceable obligation was incurred between Rocky Mountain Power and the Projects on the date that the parties executed the Agreements and agreed to be bound by the terms contained therein. Our Order presented

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2 “Rosebud is not entitled to a lock-in of an avoided cost rate until it has entered into a legally enforceable and IPUC approved obligation for the delivery of energy and capacity.” Rosebud Enterprises, 128 Idaho at 620, 917 P.2d at 777 (emphasis added).
sufficient facts to show that we did not act arbitrarily. Furthermore, the Projects have failed to demonstrate that we were not regularly pursuing our authority.

C. Application of Grandfathering Criteria

The Projects also argue that the Commission’s decision to not consider the application of grandfathering criteria is erroneous and contrary to Commission precedent. Specifically, the Projects argue that, “when previously considering whether QFs were eligible to receive published avoided cost rates, the Commission identified indicative criteria to determine whether such a legally enforceable obligation existed prior to the effective date of its decision on the eligibility cap.” Reconsideration at 7 (emphasis in original). In cases where the criteria were met, projects were grandfathered and permitted to use rates previously in effect. The Projects contend that they satisfied the requirements of the Commission’s grandfathering precedent before the effective date of the eligibility cap reduction.

Commission Findings: The Projects’ reliance on previously utilized grandfathering criteria is misplaced. First, this Commission has explicitly stated that “we look at the totality of the facts” in assessing entitlement to grandfathering status. Order No. 29954 at 2. In these Agreements, the “effective date” of each Agreement – the date when both parties executed the Agreement and agreed to be bound by its terms – is well after the Commission lowered the eligibility cap for the published avoided cost rate to 100 kW. Thus, the Projects’ Agreements do not support that use of grandfathering. Second, the Idaho Supreme Court has stated that “[c]onferment of grandfathered status on [a] qualifying facility is essentially an IPUC finding that a legally enforceable obligation to sell power existed by a given date. Such a finding is within the discretion of the state regulatory agency.” Rosebud Enterprises, 128 Idaho 624, 917 P.2d at 781 (emphasis added). In this consolidated case, we found that each of the five projects incurred a legally enforceable obligation on December 22, 2010. Thus, there is no occasion to resort to the use of grandfathering criteria. We further find that the time Rocky Mountain Power took to complete its final review of the Agreements was reasonable. This finding is consistent with our authority under federal and state law.

Third, our Supreme Court has noted, “Because regulatory bodies perform legislative as well as judicial functions in their proceedings, they are not so rigorously bound by the doctrine of stare decisis that they must decide all future cases in the same way as they have decided similar cases in the past.” Rosebud Enterprises v. Idaho PUC, 128 Idaho 609, 618, 917
P.2d 766, 775 (1996) citing Intermountain Gas Co. v. Idaho PUC, 97 Idaho 113, 119, 540 P.2d 775, 781 (1975). “So long as the Commission enters sufficient findings to show that its action is not arbitrary and capricious, the Commission can alter its decisions.” Washington Water Power v. Idaho PUC, 101 Idaho 567, 579, 617 P.2d 1242, 1254 (1980). Therefore, simply because grandfathering criteria have been used in consideration of QF eligibility to published rates in the past does not mean that this Commission must decide all future QF eligibility cases in the same manner.

Regardless of whether it is a change in the eligibility cap for access to published rates or a change in the rates themselves, the Commission is not bound by prior grandfathering treatment decisions so long as our decision is based on substantial and competent evidence in the record and we enter sufficient findings to demonstrate that is the case. The decision of whether to use grandfathering criteria is within the Commission’s discretion. In contrast to the change in eligibility for published rates in 2005, no criteria were enunciated or established by this Commission to determine project eligibility through the use of grandfathering for QF agreements executed on or after December 14, 2010. As stated in our final Order, it is adverse to the public interest to allow parties who have not executed contracts to avail themselves of an eligibility cap that is no longer in place. Order No. 32260 at 9. Grandfathering contracts that were executed on or after December 14, 2010, and allowing them to utilize an eligibility cap that is no longer applicable would be contrary to our determination regarding what the public interest requires. This finding is supported by substantial and competent evidence in the record and is explained in our Orders. Because the Commission’s decision to not utilize grandfathering criteria was not arbitrary and/or capricious, we deny reconsideration on this issue.

D. December 14, 2010, Effective Date

The Projects next argue that the Commission did not give proper notice of its intention to require that QFs have fully executed contracts by December 14, 2010, in order for 10 aMW projects to be eligible for published avoided cost rates. Reconsideration at 10. Specifically, the Projects maintain that the Commission did not “state, imply, or otherwise lead one reasonably to conclude that the Commission would or even might reject its own precedent,

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3 The Commission outlined criteria that it would consider in determining whether a project was eligible for the previous, no longer applicable, eligibility cap for published avoided cost rates, i.e., whether a project would be “grandfathered” and permitted to utilize the old eligibility cap. Order No. 29839.
much less violate PURPA, by requiring that a QF have a fully-executed contract in order to receive published rates.” *Id.* at 11. The Projects insist that by failing to provide proper notice, the Commission has acted in an unreasonable and unlawful manner.

**Commission Findings:** Contrary to the assertion of the Projects, the Commission provided actual notice to the Projects on December 3, 2010, that its decision regarding the published avoided cost rate eligibility cap would become effective December 14, 2010. Order No. 32131 at 5-6, 9, granting Cedar Creek’s Petition to Intervene. The Commission’s Order No. 32131 states that “it is our intent that our decision regarding the ‘Joint Motion’ to reduce the published avoided cost eligibility cap shall become effective on December 14, 2010.” *Id.* at 5-6 (emphasis added). Moreover, the ordering section of the Order states: “IT IS FURTHER ORDERED that the Commission’s decision regarding whether to reduce the published avoided cost eligibility cap become effective on December 14, 2010.” *Id.* at 9 (capitals in original). Because this is the very same Order that granted intervention to Cedar Creek, the Projects (i.e., Cedar Creek) were provided actual notice. Consequently, we find that the Commission provided adequate notice to all parties that the eligibility cap was subject to change and that any change would become effective on December 14, 2010.

In the Commission’s final Order in the case establishing the December 14, 2010, effective date for the 100 kW eligibility cap for wind and solar’s access to published rates (GNR-E-10-04), we unequivocally stated that “[a]rguments that the Commission is without authority to implement its eligibility cap reduction on December 14 are unpersuasive. . . .” Order No. 32176 at 10. We noted FERC’s determination that the filed rate doctrine and rule against retroactive ratemaking do not extend “to cases in which [parties] are on adequate notice that resolution of some specific issue may cause a later adjustment to the rate being collected at the time of service.” *Natural Gas Clearinghouse v. FERC*, 965 F.2d 1066, 1075 (D.C. Cir. 1992) (emphasis added). We further confirmed that “[t]he goals of equity and predictability are not undermined when the Commission warns all parties involved that a change in rates is only tentative and might be disallowed.” *OXY USA, Inc., v. FERC*, 64 F.3d 679, 699 (D.C. Cir. 1995).

The Projects insist that by failing to provide proper notice, “regardless of whether the appropriate notice period was simply the 30-day notice required when the Commission is performing its legislative function of setting rates, or the more extensive notice required under Idaho’s Administrative Procedure Act, the Commission has acted in an unreasonable and
unlawful manner. . . .” Id. at 12. The Projects’ argument regarding notice is without merit for several reasons. First, as mentioned above, the Projects had actual notice that the Commission intended the effective date for the lowered eligibility cap to be December 14, 2010. The Projects (i.e., Cedar Creek) petitioned to intervene in the GNR-E-10-04 case on November 10, 2010 – five days after the three utilities petitioned the Commission to immediately reduce the eligibility cap from 10 MW to 100 kW and more than a month before the Commission’s stated effective date. Cedar Creek Wind Petition at 1 (Case No.GNR-E-10-04). Second, “[t]he Commission, as part of its statutory duties, determines reasonable rates and investigates and reviews contracts.” A.W. Brown Company v. Idaho Power Company, 121 Idaho 812, 816, 828 P.2d 841, 845 (1992) (emphasis added). These duties are legislative, not adjudicative, in nature. The Commission, as an agency of the legislative branch of government, exercises delegated legislative powers to make rates. Id. Idaho Code § 61-502 defines “Determination of rates” as

Whenever the commission, after a hearing had upon its own motion or upon complaint, shall find that . . . the rules, regulations, practices, or contracts [by any public utility] affecting such rates . . . are unjust, unreasonable, discriminatory or preferential, or in any wise in violation of any provision of law . . . the commission shall determine the just, reasonable or sufficient rates, fares, tolls, rentals, charges, classifications, rules, regulations, practices or contracts to be thereafter observed and in force . . . .

Review of contracts or agreements that contain PURPA rates falls clearly within the Commission’s ratesetting, i.e., legislative, function. Moreover, the APA does not apply to contested cases before the Commission. Idaho Code § 67-5240. There is no question that the Projects and others were contesting the proposed reduction in the eligibility cap. “The APA specifically does not apply to ‘those in the legislative or judicial branch.’ I.C. § 67-5201.” A.W. Brown Company v. Idaho Power Company, 121 Idaho 812, 819, 828 P.2d 841, 848 (1992).

Finally, Idaho Code § 61-625 prohibits collateral attacks of Commission Orders that are final and conclusive. “A different rule would lead to endless consideration of matters previously presented to the Commission and confusion about the effectiveness of Commission orders.” Utah-Idaho Sugar Co. v. Intermountain Gas Co., 100 Idaho 368, 373, 597 P.2d 1028, 1063 (1979). The Projects argue that the Commission’s final Order disapproving the Agreements retroactively applies the reduced 100 kW eligibility cap without notice or due process. Reconsideration at 12. This argument amounts to a collateral attack of the Commission’s prior Order reducing the eligibility cap. No party to the GNR-E-10-04 case that
lowered the eligibility cap — including the Projects — timely appealed the Commission’s decision to lower the eligibility cap effective December 14, 2010. Case No. GNR-E-10-04; Order Nos. 32176 and 32212. Therefore, the Commission’s decision to lower the eligibility cap from 10 aMW to 100 kW for wind and solar projects effective December 14, 2010, is a final and conclusive Order of the Commission that is not subject to collateral attack. The Projects’ failure to appeal the Commission’s decision to temporarily reduce the cap effective on December 14, 2010, cannot be revived by seeking reconsideration of the Commission’s final Order in this case. Therefore, reconsideration of these issues is denied.

Although in this particular case we have established that Cedar Creek had actual notice, in the alternative, the Commission, “for good cause shown, may allow changes without requiring the thirty (30) days’ notice herein provided for, by an order specifying the changes so to be made and the time when they shall take effect. . . .” Idaho Code § 61-307. The utilities had requested an immediate reduction for access to published rates from 10 aMW to 100 kW claiming that the combined megawatts, the dollar impacts, and the potential adverse consequences to the system and to customers was enormous. Order No. 32131 at 2. On December 3, 2010, the Commission declared that any changes to the published avoided cost rate eligibility cap would be effective December 14, 2010. Id. Although the Commission declined to immediately reduce QF projects’ access to published rates, we declared that any change would become effective December 14, 2010, based on the assertions in the Utilities’ Joint Petition. Absent actual notice, the notice provided would have otherwise met the “good cause” exception to the 30 days’ notice requirement of Idaho Code § 61-307.

CONCLUSION

The Commission has jurisdiction over PacifiCorp dba Rocky Mountain Power, an electric utility, and the issues raised in this matter pursuant to the authority and power granted it under Title 61 of the Idaho Code and the Public Utility Regulatory Policies Act of 1978 (PURPA). The Commission has authority under PURPA and the implementing regulations of the Federal Energy Regulatory Commission (FERC) to set avoided cost rates, to order electric utilities to enter into fixed-term obligations for the purchase of energy from qualified facilities (QFs) and to implement FERC rules. Rosebud Enterprises, Inc. v. Idaho Public Utilities Commission, 128 Idaho 609, 612, 917 P.2d 766, 769 (1996).
Although FERC promulgated the general scheme and rules, it left the actual implementation of PURPA to the state regulatory authorities. *Id.*, 128 Idaho at 614, 917 P.2d 771. FERC rules insist that rates for purchases from QFs be just and reasonable to ratepayers, in the public interest, and not discriminatory against QFs. 18 C.F.R. § 292.304(a)(1). Notably, PURPA and the implementing regulations require only that published/standard avoided cost rates be established and made available to QFs with a design capacity of 100 kW or less. 18 C.F.R. § 292.304(c). When this Commission reduced wind and solar projects’ eligibility to published avoided cost rates we unequivocally stated that continuing to allow large wind and solar projects access to published avoided cost rates for projects greater than 100 kW was “clearly not in the public interest.” Order No. 32262. We reaffirmed that determination in the present case by finding that “it is not in the public interest to allow parties with contracts executed on or after December 14, 2010, to avail themselves of an eligibility cap that is no longer applicable.” Order No. 32260 at 9. The Projects have failed to demonstrate that the Commission’s findings are unreasonable, unlawful, erroneous, or not in conformity with the law. Rule of Procedure 331, IDAPA 31.01.01.331.01.

The Firm Energy Sales Agreements between Rocky Mountain Power and the five projects were executed on December 22, 2010. The Agreements recite that Rattlesnake Canyon, Coyote Hill and North Point will each have a maximum capacity of 27.6 MW. Steep Ridge and Rive Pine will each have a maximum capacity amount of 25.2 MW. Under normal and/or average conditions, each project will not exceed 10 aMW on a monthly basis. Because the size of each of these wind projects exceeds 100 kW, they are not eligible to receive the published avoided cost rate. Nevertheless, the Projects are entitled to PURPA contracts with avoided cost rates calculated using the IRP Methodology.

**ORDER**

IT IS HEREBY ORDERED that the Joint Petition for Reconsideration filed by Rattlesnake Canyon, Coyote Hill, North Point, Steep Ridge and Five Pine wind projects is denied.

THIS IS A FINAL ORDER ON RECONSIDERATION. Any party aggrieved by this Order or other final or interlocutory Orders previously issued in this Case Nos. PAC-E-11-01, PAC-E-11-02, PAC-E-11-03, PAC-E-11-04, and PAC-E-11-05 may appeal to the Supreme Court.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 27th day of July 2011.

Paul Kellander, President

Mack A. Redford, Commissioner

Marsha H. Smith, Commissioner

ATTEST:

Jean D. Jewell
Commission Secretary

ORDER NO. 32302 17
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA ROCKY MOUNTAIN POWER FOR A DETERMINATION REGARDING A FIRM ENERGY SALES AGREEMENT BETWEEN ROCKY MOUNTAIN POWER AND CEDAR CREEK WIND, LLC (RATTLESNAKE CANYON PROJECT) CASE NO. PAC-E-11-01

IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA ROCKY MOUNTAIN POWER FOR A DETERMINATION REGARDING A FIRM ENERGY SALES AGREEMENT BETWEEN ROCKY MOUNTAIN POWER AND CEDAR CREEK WIND, LLC (COYOTE HILL PROJECT) CASE NO. PAC-E-11-02

IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA ROCKY MOUNTAIN POWER FOR A DETERMINATION REGARDING A FIRM ENERGY SALES AGREEMENT BETWEEN ROCKY MOUNTAIN POWER AND CEDAR CREEK WIND, LLC (NORTH POINT PROJECT) CASE NO. PAC-E-11-03

IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA ROCKY MOUNTAIN POWER FOR A DETERMINATION REGARDING A FIRM ENERGY SALES AGREEMENT BETWEEN ROCKY MOUNTAIN POWER AND CEDAR CREEK WIND, LLC (STEEP RIDGE PROJECT) CASE NO. PAC-E-11-04

IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA ROCKY MOUNTAIN POWER FOR A DETERMINATION REGARDING A FIRM ENERGY SALES AGREEMENT BETWEEN ROCKY MOUNTAIN POWER AND CEDAR CREEK WIND, LLC (FIVE PINE PROJECT) CASE NO. PAC-E-11-05

ERRATA TO ORDER NO. 32260
On June 8, 2011, IPUC Order No. 32260 was issued by this Commission. The following change should be made to that Order:

Page 10, Order Section, Paragraph 1

READS:

“IT IS HEREBY ORDERED that the five December 22, 2010, Firm Energy Sales Agreements between Idaho Power and Cedar Creek Wind, LLC (for its Rattlesnake Canyon, Coyote Hill, North Point, Steep Ridge and Five Pine projects) are disapproved.”

SHOULD READ:

“IT IS HEREBY ORDERED that the five December 22, 2010, Firm Energy Sales Agreements between PacifiCorp dba Rocky Mountain Power and Cedar Creek Wind, LLC (for its Rattlesnake Canyon, Coyote Hill, North Point, Steep Ridge and Five Pine projects) are disapproved.”

DATED at Boise, Idaho this 4th day of June 2011.

Jean D. Jewell
Commission Secretary
BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF
PACIFICORP DBA ROCKY MOUNTAIN
POWER FOR A DETERMINATION
REGARDING A FIRM ENERGY SALES AGREEMENT BETWEEN ROCKY MOUNTAIN POWER AND CEDAR CREEK WIND, LLC (RATTLESNAKE CANYON PROJECT)

CASE NO. PAC-E-11-01

IN THE MATTER OF THE APPLICATION OF
PACIFICORP DBA ROCKY MOUNTAIN
POWER FOR A DETERMINATION
REGARDING A FIRM ENERGY SALES AGREEMENT BETWEEN ROCKY MOUNTAIN POWER AND CEDAR CREEK WIND, LLC (COYOTE HILL PROJECT)

CASE NO. PAC-E-11-02

IN THE MATTER OF THE APPLICATION OF
PACIFICORP DBA ROCKY MOUNTAIN
POWER FOR A DETERMINATION
REGARDING A FIRM ENERGY SALES AGREEMENT BETWEEN ROCKY MOUNTAIN POWER AND CEDAR CREEK WIND, LLC (NORTH POINT PROJECT)

CASE NO. PAC-E-11-03

IN THE MATTER OF THE APPLICATION OF
PACIFICORP DBA ROCKY MOUNTAIN
POWER FOR A DETERMINATION
REGARDING A FIRM ENERGY SALES AGREEMENT BETWEEN ROCKY MOUNTAIN POWER AND CEDAR CREEK WIND, LLC (STEEP RIDGE PROJECT)

CASE NO. PAC-E-11-04

IN THE MATTER OF THE APPLICATION OF
PACIFICORP DBA ROCKY MOUNTAIN
POWER FOR A DETERMINATION
REGARDING A FIRM ENERGY SALES AGREEMENT BETWEEN ROCKY MOUNTAIN POWER AND CEDAR CREEK WIND, LLC (FIVE PINE PROJECT)

ORDER NO. 32260

On January 10, 2011, PacifiCorp dba Rocky Mountain Power filed five Applications each requesting acceptance or rejection of a 20-year Firm Energy Sales Agreement
between Rocky Mountain Power and Cedar Creek Wind, LLC for its Rattlesnake Canyon, Coyote Hill, North Point, Steep Ridge, and Five Pine wind projects. All five projects are located near Bingham County, Idaho, and are managed by Cedar Creek Wind, LLC. The Projects have self-certified as “qualifying facilities” (QFs) under the applicable provisions of the federal Public Utility Regulatory Policies Act of 1978 (PURPA). Rocky Mountain Power requested that its Applications be processed by Modified Procedure.

On February 24, 2011, the Commission issued a Notice of Application and Notice of Modified Procedure setting a March 24, 2011, comment deadline and a March 31, 2011, deadline for reply comments. Comments were filed by the Commission Staff, the Company, and Cedar Creek Wind on behalf of the five projects. Numerous public comments were also received by the Commission. As set out in greater detail below, the Commission declines to approve the Firm Energy Sales Agreements.

BACKGROUND

On November 5, 2010, Idaho Power, Avista Corporation, and PacifiCorp dba Rocky Mountain Power filed a Joint Petition requesting that the Commission initiate an investigation to address various avoided cost issues related to the Commission’s implementation of PURPA. Section 210 of PURPA generally requires electric utilities to purchase power produced by QFs at “avoided cost” rates set by the Commission. “Avoided costs” are those costs which a public utility would otherwise incur for electric power, whether that power was purchased from another source or generated by the utility itself.” 18 C.F.R. § 292.101(b)(6). Order No. 32176 at 1.

While the Commission pursues its investigation, the utilities also moved the Commission to “lower the published avoided cost rate eligibility cap from 10 aMW to 100 kW [to] be effective immediately. . . .” Id. citing Joint Petition at 7. Under PURPA regulations issued by the Federal Energy Regulatory Commission (FERC), the Commission must “publish” avoided cost rates for small QFs with a design capacity of 100 kW or less. Order No. 32176 at 1. However, the Commission has the discretion to set the published avoided cost rate at a higher capacity amount – commonly referred to as the “eligibility cap.” 18 C.F.R. § 292.304(c)(1-2). When a QF project is larger than the published eligibility cap the avoided cost rate for the project.

The parties in these five cases have all filed consolidated comments because the relevant facts for each of these five projects are substantially similar. Consequently, the Commission finds it reasonable and appropriate to consolidate these cases and issue this consolidated final Order. Rule 247, IDAPA 31.01.01.247.

ORDER NO. 32260
must be individually negotiated by the QF and the utility using the Integrated Resource Plan (IRP) Methodology. Order No. 32176.

The purpose of utilizing the IRP Methodology for large QF projects is to more precisely value the energy being delivered. Id. at 10. The IRP Methodology recognizes the individual generation characteristics of each project by assessing when the QF is capable of delivering its resources against when the utility is most in need of such resources. The resultant pricing is reflective of the value of QF energy to the utility. Utilization of the IRP Methodology does not negate the requirement under PURPA that the utility purchase the QF energy.

On December 3, 2010, the Commission issued Order No. 32131 declining the utilities’ motion to immediately reduce the published avoided cost rate eligibility cap from 10 aMW to 100 kW. Order No. 32131 at 5. However, the Order did notify parties that the Commission’s decision regarding the motion to reduce the published avoided cost eligibility cap would become effective on December 14, 2010. Id. at 5-6, 9.

Based upon the record in the GNR-E-10-04 case, the Commission subsequently found that a “convincing case has been made to temporarily reduce the eligibility cap for published avoided cost rates from 10 aMW to 100 kW for wind and solar only while the Commission further investigates” other avoided cost issues. Order No. 32176 at 9 (emphasis original). On reconsideration, the Commission affirmed its decision to temporarily reduce the eligibility cap for published avoided cost rates from 10 aMW to 100 kW. Order No. 32212. Thus, the eligibility cap for the published avoided cost rate for wind and solar QF projects was set at 100 kW effective December 14, 2010.

THE AGREEMENTS

On December 22, 2010, Rocky Mountain Power and each of the five wind projects entered into their respective Agreements. Under the terms of the Agreements, each wind project agrees to sell electric energy to Rocky Mountain Power for a 20-year term using the 10 aMW non-levelized published avoided cost rates. Applications at 8-9. The Applications recite that Rattlesnake Canyon, Coyote Hill and North Point will each have a maximum capacity amount of 27.6 MW, and Steep Ridge and Five Pine will each have a maximum capacity of 25.2 MW. Under normal and/or average conditions, each QF will not generate more than 10 aMW on a monthly basis. Rocky Mountain Power warrants that the Agreements comport with the terms
and conditions of the various Commission Orders applicable to PURPA agreements for a wind resource. *Id.* at ¶ 6 citing Order Nos. 30415, 30488, 30738 and 31025.

The projects have all selected October 1, 2012, as the Scheduled Commercial Operation Date. Applications at 9. Rocky Mountain Power asserts that various requirements have been placed upon the Facilities in order for Rocky Mountain Power to accept the Facilities’ energy deliveries. Rocky Mountain Power states that it will monitor each Facility’s compliance with initial and ongoing requirements through the term of the Agreements. Rocky Mountain Power asserts that it has advised each Facility of the Facility’s responsibility to work with Rocky Mountain Power’s transmission unit to ensure that sufficient time and resources will be available for delivery to construct the interconnection facilities, and transmission upgrades if required, in time to allow each Facility to achieve its October 1, 2012, Scheduled Commercial Operation Date.

Rocky Mountain Power asserts that each Facility has been advised that delays in the interconnection or transmission process do not constitute excusable delays and if a Facility fails to achieve its Scheduled Commercial Operation Date delay damages will be assessed. *Id.* at 11. The Applications further maintain that each Facility has acknowledged and accepted the risk inherent in proceeding with its Agreement without knowledge of the requirements of interconnection and possible transmission upgrades. *Id.* The parties have each agreed to delay liquidated damages and security provisions. Agreements ¶¶ 2.5.1, 11.1.2. Rocky Mountain Power states that each Facility has also been made aware of and accepted the provisions in each Agreement regarding curtailment or disconnection of its Facility should certain operating conditions develop on Rocky Mountain Power’s system. Agreements ¶ 6.3.

By their own terms, the Agreements will not become effective until the Commission has approved all of the terms and conditions and declares that all payments made by Rocky Mountain Power to the Facilities for purchases of energy “are just and reasonable, in the public interest, and that the costs incurred by [Rocky Mountain Power] for purchases of capacity and energy from [Cedar Creek] are legitimate expenses, all of which the Commission will allow [Rocky Mountain Power] to recover in rates in Idaho in the event other jurisdictions deny recovery of their proportionate share of said expenses.” Agreements ¶ 2.1.
THE COMMENTS

A. Staff Comments

Staff observed that the five Agreements are nearly identical. All five of the projects are proposed to be built in the same general vicinity. Staff calculated that the five projects collectively are expected to generate 375,503 MWh annually. Under the non-levelized rates in the Agreements, the annual energy payments by Rocky Mountain Power for the expected generation will be approximately $23.6 million in 2013 increasing to approximately $45.2 million in 2031, or a cumulative total of $685.4 million over the 20-year term of the Agreements. The collective net present value of the energy payments over the life of the Agreements will be approximately $265.2 million.

The five Agreements were signed by the project developer on December 13, 2010, and signed by Rocky Mountain Power on December 22, 2010. The Agreements were filed with the Commission on January 10, 2011. The Agreements contain the published avoided cost rates from Order No. 31025. However, Staff observed that Order No. 32176 lowered the availability of published avoided cost rates for wind and solar QF projects to 100 kW, effective December 14, 2010. As a matter of law, Staff considers the effective date of the contract to be the date upon which both parties signed the agreement. A signature by only one party, Staff believes, does not create an enforceable contract nor establish the effective date of the Agreement. Consequently, Staff considers the effective date for the five Agreements to be December 22, 2010.

Staff acknowledged the comments submitted by Cedar Creek in support of the Agreements, as well as the affidavit of Dana Zentz, filed with the Commission on January 26, 2011. The comments and affidavit allege that the parties had reached full agreement as to the rates, terms and conditions of a PPA for the projects on November 29, 2010, and that Cedar Creek signed and delivered copies of the Agreements to Rocky Mountain Power on December 13, 2010. Nevertheless, the effective date of each Agreement is shown as December 22, 2010, on page 1 of each Agreement, clearly after the December 14, 2010, effective date established by Order No. 32176.

Because the Agreements were executed after the date upon which the 100 kW eligibility cap became effective for wind and solar projects and because the size of each proposed wind project clearly exceeds 100 kW, Staff maintains that approval of the Agreements
is prohibited by Order No. 32176. Staff believes that the avoided cost rate for these Agreements must be negotiated using the IRP methodology. Consequently, Staff recommended denial of the Agreements as submitted.

B. Cedar Creek Wind Comments and Reply

Cedar Creek states that after it unsuccessfully bid in Rocky Mountain Power's 2008/2009 Request for Proposal (RFP), Cedar Creek and Rocky Mountain Power discussed the possibility of two 78 MW PURPA wind projects. Cedar Creek determined that the avoided cost calculated by Rocky Mountain Power's integrated resource model was "uneconomic and unfinanceable for purposes of developing the Cedar Creek" wind projects. Comments at 2. Cedar Creek subsequently decided to "reduce the amount of gross generation and sacrifice the economies of scale associated with two 78 MW wind projects and reconfigure into five separate PURPA projects not greater than 10 aMW, in order to qualify for Surrogate Avoided Resource ("SAR") based avoided cost rates." Id. at 2, 3.

Cedar Creek argued that each of its five Agreements were mature contracts with a meeting of the minds between the parties prior to December 14, 2010. The Projects maintain that they had fully perfected their right to a published avoided cost rate power purchase agreement with Rocky Mountain Power prior to the Commission's reduction of the eligibility threshold for wind and solar projects.

On April 5, 2011, Cedar Creek filed reply comments.2 Cedar Creek asserted that "[t]he standard articulated by Staff – that December 14, 2010 is an ‘absolute’ cut-off date – is both a misreading of the Commission Order 32176 in Case No. GNR-E-10-4 and is contrary to established law regarding PURPA rates and contract requirements.” Reply at 4. Cedar Creek argues that the Commission does not require, or even speak to, December 14 as the date by which both counterparties must have signed an agreement. Id. Cedar Creek maintained that, because Rocky Mountain Power and Cedar Creek agreed that the five projects were eligible for published rates prior to December 14, 2010, and both parties agreed that all contract terms and conditions, including price, had been agreed to prior to that date, Cedar Creek has proven entitlement to published avoided cost rates. Id.

Cedar Creek states that Staff’s recommendation is wrong, misguided, bad public policy and "contrary to PURPA’s federal mandate that utilities execute power purchase

2 Pursuant to Commission Order No. 32192, reply comments were to be filed no later than March 31, 2011.
agreements with QF projects that are mature and are ready, willing and able to deliver qualifying power to the utility at the avoided cost applicable at that time.” *Id.* at 6.

**C. Rocky Mountain Power Reply**

Rocky Mountain Power filed reply comments on April 11, 2011.

Rocky Mountain Power acknowledged that it had completed negotiation of all terms of the Agreements for Cedar Creek’s five projects prior to December 14, 2010. *Reply* at 2. Rocky Mountain explained that the Company’s review and execution procedures must comply with Sarbanes Oxley (‘SOX’) regulatory requirements. “Once the parties agree to a final draft, the final draft then undergoes a detailed review and sign-off by management, merchant transmission, accounting, financial reporting (FAS133, Fin 46, etc.), credit, legal, billing, and delegation of signing authority by the appropriate Company executive for execution of the agreement.” *Id.* at 3. Rocky Mountain Power asserted that it acted “with reasonable speed to execute the PPAs given the number of documents and complexity of review of the multiple transactions requested by Cedar Creek Wind.” *Id.*

Rocky Mountain Power stated that Cedar Creek returned signed Agreements to Rocky Mountain’s Portland office “late on the afternoon of December 13, 2010. Cedar Creek did not deliver final conformed exhibits for each PPA until December 14, 2010. . . . During the review, the Company identified discrepancies in several of the PPA exhibits which were corrected and confirmed by Cedar Creek Wind on December 16, 2010.” *Id.* at 3, 4. Rocky Mountain completed its final review and received executive approval of the Agreements on December 22, 2010. *Id.* “It is unlikely that Rocky Mountain Power could have completed its review in a timelier manner and in no event could the Company have been diligent and still executed the contracts prior to December 14, having received signed PPAs with no conformed exhibits from Cedar Creek Wind at the end of the business day on December 13, 2010.” *Id.*

Rocky Mountain notes that, by their own terms, the Agreements are not effective until approved by the Commission. *Id.* at 6. Rocky Mountain also maintains that, although Cedar Creek argues for “grandfathering” treatment, the Projects do not meet the bright line rule for grandfathering – a fully executed PPA by December 14 or a meritorious complaint filed with

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3 Rocky Mountain acknowledged that its reply, as well as Cedar Creek’s reply, was untimely. As a result, Rocky Mountain requested that the Commission either strike both replies or accept both replies.
the Commission by December 14. *Id.* at 7. Rocky Mountain concedes that the parties reached agreement on all terms of their Agreements prior to December 14, 2010. “This fact alone does not, however, compel the Commission to approve those contracts.” *Id.* at 8.

**D. Public Comments**

More than 40 public comments were received regarding the Cedar Creek projects. Approximately 36 comments supported approval of the 5 wind projects. The majority of commenters who support approval believe that the projects would stimulate the local economy and provide economic growth at a time when jobs and industry is greatly needed. Several commenters stressed the need for Idaho to capture and develop its natural resources. A few commenters believed that utilizing wind energy would reduce the cost of electricity to Idahoans.

Approximately seven comments opposed the five wind projects. Commenters in opposition stated that utility customers cannot afford another increase in electricity rates. Several commenters cited the intermittent nature of wind as being an unreliable resource that is heavily subsidized to make it economically feasible.

**DISCUSSION AND FINDINGS**

The Commission has jurisdiction over Rocky Mountain Power, an electric utility, and the issues raised in this matter pursuant to the authority and power granted it under Title 61 of the Idaho Code and the Public Utility Regulatory Policies Act of 1978 (PURPA). The Commission has authority under PURPA and the implementing regulations of the Federal Energy Regulatory Commission (FERC) to set avoided cost rates, to order electric utilities to enter into fixed-term obligations for the purchase of energy from qualified facilities (QFs) and to implement FERC rules. *Rosebud Enterprises, Inc., v. Idaho Public Utilities Commission*, 128 Idaho 609, 612, 917 P.2d 766, 769 (1996).

The Commission has reviewed the record in this case, including the Applications, the Firm Energy Sales Agreements, and the comments of Commission Staff, Rocky Mountain Power, the wind projects, and the public. It is clear from the record that extensive review of PPAs is conducted by both parties prior to signing an agreement. From the Commission’s perspective, a thorough review is appropriate and necessary prior to signing Agreements that obligate ratepayers to payments in excess of $685 million over the 20-year term of these Agreements. Indeed, the Commission has directed the utilities to assist the Commission in its gatekeeper role when reviewing QF contracts.
The primary issue to be determined in these cases is whether the Agreements – which utilize the published avoided cost rate – were executed before the eligibility cap for published rates was lowered to 100 kW on December 14, 2010, for wind and solar projects. “According to the FERC, ‘it is up to the States, not [FERC] to determine the specific parameters of individual QF power purchase agreements, including the date at which a legally enforceable obligation is incurred under State law.’” Rosebud Enterprises, 128 Idaho at 780-781, 917 P.2d at 623-624, citing West Penn Power Co., 71 FERC ¶ 61, 153 (1995). We find that the Agreements were not fully executed (signed by both parties) prior to December 14, 2010. More specifically, each Firm Energy Sales Agreement states that the “Effective Date” of the Agreement is “after execution by both Parties and after approval by the Commission.” Agreements ¶ 1.13, 2.1. The opening paragraph is dated “this 22nd day of December, 2010.” Agreements at 1. It is not disputed that the projects signed the Agreements on December 13, and Rocky Mountain Power signed on December 22, 2010. Thus, on the date the five Agreements became effective, published avoided cost rates were available only to wind and solar projects with a design capacity of 100 kW or less.

The proposed change in the eligibility cap was clearly noticed in our Order No. 32131 issued on December 3, 2010. As we observed in Order No. 32176: “One need look no further than the abundance of firm energy sales agreements filed with the Commission [between the notice and December 14] to realize that the parties took the Commission’s notice of its effective date seriously.” Order No. 32176 at 11. The Commission does not consider a utility and its ratepayers obligated until both parties have completed their final reviews and signed the agreement. In other words, in order for the 10 aMW eligibility cap to be available to wind and solar QFs, the agreement must have been effective prior to December 14, 2010. The Idaho Supreme Court has recognized that “a balance must be struck between the local public interest of a utility’s electric consumers and the national public interest in development of alternative energy sources.” Rosebud Enterprises, 128 Idaho at 613, 917 P.2d at 770. We find that it is not in the public interest to allow parties with contracts executed on or after December 14, 2010, to avail themselves of an eligibility cap that is no longer applicable.

The published avoided cost rates established in Order No. 31025 have not changed. What has changed is the size at which wind and solar projects can avail themselves of the published avoided cost rates. Consistent with FERC regulations, and as set out in Order No.
32176, published rates are available to wind and solar QFs with a design capacity of 100 kW or less. 18 C.F.R. § 292.304(c)(1-2). Wind and solar projects larger than 100 kW are still entitled to PURPA contracts at avoided cost rates calculated using the IRP Methodology. Because published avoided cost rates remain unchanged and only the eligibility size has changed, grandfathering criteria applied to rate changes are not applicable here. Regarding the application of a change in the eligibility cap, we adopt a bright line rule: a Firm Energy Sales Agreement/Power Purchase Agreement must be executed, i.e., signed by both parties to the agreement, prior to the effective date of the change in eligibility criteria.

The Firm Energy Sales Agreements between Rocky Mountain Power and the five projects were executed on December 22, 2010. The Agreements recite that Rattlesnake Canyon, Coyote Hill and North Point will each have a maximum capacity amount of 27.6 MW, and Steep Ridge and Five Pine will each have a maximum capacity of 25.2 MW. Because the size of each of these wind projects exceeds 100 kW, they are not eligible to receive published rate contracts. Simply put, the rates contained in the Agreements do not comply with Order No. 32176. Therefore, we disapprove the five Firm Energy Sales Agreements.

ORDER

IT IS HEREBY ORDERED that the five December 22, 2010, Firm Energy Sales Agreements between Idaho Power and Cedar Creek Wind, LLC (for its Rattlesnake Canyon, Coyote Hill, North Point, Steep Ridge and Five Pine projects) are disapproved.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See Idaho Code § 61-626.
DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 8th day of June 2011.

PAUL KJELLANDER, PRESIDENT

MACK A. REDFORD, COMMISSIONER

MARSHA H. SMITH, COMMISSIONER

ATTEST:

Jean D. Jewell
Commission Secretary

O:PAC-E-11-01_PAC-E-11-02_PAC-E-11-03_PAC-E-11-04_PAC-E-11-05_ks2
NOTES
BIOGRAPHIES
Pamela J. Anderson

Partner

Pam Anderson, a partner in the Environment, Energy & Resources practice, represents utilities, local distribution companies, energy markets, producers and natural gas, crude oil and products pipelines throughout the country. A certified public accountant, she combines her legal and financial experience to help clients negotiate complex business transactions and conduct due diligence.

Pam advises energy companies on both reactive and proactive measures to ensure regulatory compliance and establish best practices in corporate governance and risk management. She also represents natural gas clients across the spectrum of federal regulatory issues, including all matters associated with regulatory compliance, rate litigation, certificates, and new construction and expansions, as well as oil pipeline clients and crude oil marketers on regulatory compliance and rate and tariff matters.

In addition to her energy and power clients, Pam works with electric utility clients, public power clients and joint action agencies advising on reliability compliance, transmission tariff issues and fuel sourcing for gas-fired generation, renewable energy standards, power purchase agreements, and electric generation and transmission construction.

Professional Leadership

- Energy Bar Association
- Washington State Bar Association

Related Employment

- Van Ness Feldman, Seattle, WA; Washington, D.C., Member
BIOGRAPHY

ROBERT J. CUPINA

Robert J. (Rob) Cupina has been a Vice President at Brown, Williams, Moorhead & Quinn, Inc. (BWMQ) in Washington, DC. since 2010 following a distinguished 36-year career at the Federal Energy Regulatory Commission and the Federal Power Commission. BWMQ is a leading energy consulting firm that has been providing comprehensive energy-related services to hundreds of clients, including electric utilities, natural gas and oil pipeline companies, local distribution companies, energy producers, trade associations, shippers and federal and state agencies for over 25 years. BWMQ’s mission statement is to satisfy its client’s needs through quality work and a close working relationship. Through its extensive experience, knowledge and technical resources, BWMQ is well suited to provide expert advice and assistance on key economic, business, financial and regulatory matters.

Mr. Cupina was the Principal Deputy Director of the Office of Energy Projects from 2001 to 2009. He directed a staff of 330 engineers and physical scientists responsible for processing applications for the construction and operation of natural gas pipeline and storage facilities for interstate and foreign commerce, including liquefied natural gas (LNG), and licenses for non-federal hydroelectric projects, as well as managing the license compliance and dam safety programs and the supplemental siting authority for interstate electric transmission facilities under EPAct 2005. Mr. Cupina's many major energy infrastructure accomplishments include: issuing an open season rule as a prerequisite to an Alaska natural gas pipeline, significant expansion of LNG terminals and the interstate pipeline grid, rules for electric transmission siting and organization of the infrastructure policy group and the hydrokinetics program.

Prior to that, Mr. Cupina held other senior-level positions at FERC including Director of the Division of Tariffs and Rates - Central in the Office of Markets, Tariffs and Rates in 2000 to 2001 and Deputy Director of the Office of Pipeline Regulation from 1989 to 1999. Among his major accomplishments were implementing Order No. 2000 to establish regional transmission organizations (RTOs) and Independent System Operators (ISOs), pipeline expansions to California and the Northeast and issuing and implementing Order No. 636 to restructure the gas industry.

Mr. Cupina is thoroughly familiar with the Commission's licensing and certification process improvements embodied in the Integrated Licensing Process (ILP) for hydroelectric projects and the Pre-Filing Process (PF) for natural gas and electric transmission projects. They are based on three essential components: early identification and resolution of issues by stakeholders, coincident rather than sequential action by the myriad agencies involved using a single administrative record, and meeting specific, predictable milestones and overall processing timeframes. Compared to the traditional approaches, these processes place a premium on flexibility and collaboration. Mr. Cupina has been a tireless advocate for expediting the process and enhancing the quality of deliverables throughout his career.

Mr. Cupina’s educational background includes an MPA in Public Management from George Mason University, a BS in Technology Management from the University of Maryland, Senior Managers in Government at Harvard’s Kennedy School and Petroleum and Natural Gas Engineering at Penn State. He is married with two grown children and three grandchildren.
Lynn Dahlberg is Director of Marketing for Williams’ Northwest Pipeline. Williams owns and operates 15,000 miles of interstate natural gas pipelines, which deliver approximately 12 percent of the natural gas consumed in United States. It also owns and operates 1,000 miles of NGL transportation pipelines, and more than 10,000 miles of oil and gas gathering pipelines.

Dahlberg has served in her current position since 2010. She is responsible for the commercial transactions on Northwest Pipeline, which include business development, contract negotiation and administration, gas scheduling, revenue accounting/invoicing and customer service. Previous positions have included Manager of Tariffs and Certificates and Manager of Marketing for Northwest Pipeline.

Previous positions outside of Northwest Pipeline include Controller of Kern River Gas Transmission Company and various financial positions with Arthur Andersen & Company.

Dahlberg holds a Bachelor of Arts degree from the University of Southeast Missouri State College, with a major in accounting and a minor in management.
Ms. Cassie Doyle was appointed as Consul General of Canada with accreditation for northern California, Nevada, Hawaii and Guam, effective January 10, 2011.

A native of Canada’s west coast, Ms. Cassie Doyle has served at the executive level of all three orders of government including as Deputy Minister with both the governments of Canada and British Columbia. Over the past 15 years, she has led departments that have focused on advancing Canada’s energy, natural resource and environmental agendas. Ms. Doyle achieved notable success in the development of clean energy innovation and efficiency programs, improvements in the performance of the government’s regulatory system for major projects and the transformation of the forest industry. She has a proven track record of collaborating effectively with stakeholders from across the spectrum of public, private and non-governmental sectors.

Ms. Doyle served as Canada’s Deputy Minister of Natural Resources from 2006 to 2010 after three years as the Associate Deputy Minister of Environment Canada. She was also a member of the Board of Directors for the Atomic Energy Corporation of Canada. Prior to joining the federal government in 2002, Ms. Doyle held a number of senior positions with the British Columbia Government including the CEO of the BC Assets and Land Corporation, Deputy Minister of Environment, Lands and Parks and Deputy Minister of Small Business, Tourism and Culture. Ms. Doyle started her career with the City of Ottawa working in housing and urban development.

Ms. Doyle holds a Master’s degree in Social Policy and Administration from Carleton University and a Bachelor’s degree in Sociology from the University of Victoria. She has served as the Chair of Oxfam Canada, the chair of the 2010 Community Campaign and a member of the Board of Directors of the Ottawa United Way.
DAVID P. FALCK
Executive Vice President, General Counsel and Secretary
Pinnacle West Capital Corporation and Arizona Public Service Company

David Falck is executive vice president, general counsel and secretary of Pinnacle West Capital Corporation and its primary subsidiary, Arizona Public Service Company (APS).

Falck is responsible for overseeing all facets of the company’s legal affairs as well as the company’s state and federal Public Affairs groups.

Falck joined Pinnacle West in 2009 and has more than 30 years of experience as a legal advisor to public and private companies. Prior to joining Pinnacle West, he was Senior Vice President-Law for New Jersey-based Public Service Enterprise Group Inc., and served as a member of its executive officer group.

Before his employment with PSEG, Falck was a partner in the New York office of national law firm Pillsbury Winthrop Shaw Pittman LLP. His practice concentrated in mergers and acquisitions, financing and strategic advice for a range of clients in the energy, manufacturing and telecommunications industries in the U.S. and abroad. Falck served on the Managing Board of Pillsbury and as co-head of its national corporate and securities practice group.

Falck is chair of the corporate subcommittee of the Edison Electric Institute Legal Committee and a frequent speaker on legal issues affecting public companies. He is a member of the Board of Directors of the Northern Arizona University Foundation, the Working Board of the National Institute for Civil Discourse and the President’s Cabinet of the Musical Instrument Museum.

Falck is a magna cum laude graduate of Colgate University, and earned his law degree summa cum laude from Washington & Lee University School of Law. He is a member of Phi Beta Kappa and Order of the Coif.
Carl Fink is a partner in the Portland office of K&L Gates. Carl has more than twenty-five years experience in the energy industry, including representing interstate pipeline and storage companies, electric transmission companies, independent power projects, energy marketing companies and gas and electric utilities in complex commercial negotiations and in regulatory matters before the Federal Energy Regulatory Commission (FERC), state public service commissions and appellate courts.

Carl's transactional experience includes a wide variety of energy-related transactions, including interstate pipeline transportation contracts on behalf of both pipelines and their customers; interconnection agreements, negotiations with domestic and international natural gas suppliers and LNG companies; electric transmission contracts; mergers, acquisitions and due diligence; joint venture agreements, shipper and vendor contract negotiations; complex credit and risk negotiations; financing, and all aspects of major greenfield infrastructure development. In the regulatory arena, Carl's experience includes federal and state permitting of major projects; rate and certificate proceedings; compliance matters; securing market based rates; and advising clients with respect to all issues arising under the Natural Gas Act, Natural Gas Policy Act, and Federal Power Act.
Jeffrey Goltz was appointed chairman of the Washington Utilities and Transportation Commission by Gov. Chris Gregoire in February 2009.

Before coming to the commission, Mr. Goltz practiced law for 34 years, 30 of which were in the Washington Attorney General’s Office (AGO), most recently as one of four supervising deputy attorneys general, both under Attorney General Rob McKenna and former Attorney General Chris Gregoire. Prior to that, he served as head of the AGO’s Utilities and Transportation Division for 11 years, serving as chief counsel to the commission; as head of the Ecology Division; and as an assistant attorney general both in the Ecology and Revenue Divisions. He also was in private practice and worked on environmental and energy issues as a legislative assistant in Washington, D.C. He currently serves on the Electricity and Consumer Affairs Committees of the National Association of Regulatory Utility Commissioners (NARUC) and is the representative of the Washington UTC on the State-Provincial Steering Committee, an advisory committee to the Western Electricity Coordinating Council on regional transmission issues.

After growing up in Bellingham, Washington, Goltz attended Macalester College in St. Paul, Minnesota, receiving his B.A. cum laude in 1971. He received his law degree from the University of Oregon School of Law in 1974.
James P. Harrigan is Vice President of Gas Acquisition for the Southern California Gas Company (SoCalGas), one of Sempra Energy’s two regulated California utilities. Sempra Energy is a San Diego-based Fortune 500 energy services holding company whose subsidiaries provide electricity, natural gas and value-added products and services.

SoCalGas is the nation’s largest natural gas distribution utility serving 20.9 million consumers through 5.8 million gas meters.

Harrigan has served in his current position since 2005. He is responsible for the acquisition of natural gas supplies for residential and commercial customers of SoCalGas and San Diego Gas and Electric. Previous positions included Assistant Controller for both Pacific Enterprises Oil Company and Pacific Enterprises.

Prior to joining the company, Harrigan held various operational and financial positions with Tenneco, Coastal Corporation, Phillips Petroleum and Ernst and Young.

Harrigan holds both a bachelor’s degree in mechanical engineering and a master’s degree in professional accounting from the University of Texas, Austin. He also is a certified public accountant.
Biography

David L. Huard
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Professional Experience

Mr. Huard is the Co-Chair of the firm’s Energy, Environment and Natural Resources practice group, and partner responsible for the Climate Change Solutions group and the Solar and Renewables Project Development team.

He specializes in commercial, administrative and appellate matters related to the energy industry and maintains offices in Los Angeles and San Francisco. He has advised and represented natural gas pipelines, electric and natural gas distributors, gas and power marketers, municipalities, counties, special districts, governmental organizations, large consumers, natural gas and oil producers, co-generators, electric generators, clean fuel vehicle groups, solar panel manufacturers, renewable power producers and project developers, and distributed generation manufacturers and customers. His concentration is on project development, sales and purchase of products and services, and regulatory considerations and procedures.

Following a judicial clerkship, Mr. Huard served as a trial attorney and legal advisor to a commissioner at the Federal Energy Regulatory Commission and as an in-house attorney at the nation's largest natural gas distribution company. He has testified as an expert witness on utility rate design, gas transportation and supply issues, and affiliate transaction rules.

Education

Georgetown University Law Center, J.D., 1976.
University of Santa Clara, B.A., 1972.
National Association of Regulatory Utility Commissioners Annual Regulatory Studies Program; and others.

Memberships & Activities

Member, State Bar of California.
Member, District of Columbia Bar.
Admitted to the United States Supreme Court and the United States Courts of Appeals for the Third through Tenth and District of Columbia Circuits

Member, American Bar Association.

Member, Energy Bar Association (EBA).

Founder and President (twice past,) Western Chapter.

Past member, Board of Directors of the Energy Bar Association.


Director, Charitable Foundation of the Energy Bar Association.

Member, Conference of California Public Utility Counsel.


Representative for the San Francisco office on the firm’s Pro Bono Committee and, as part of his pro bono activities, has served since 2007 as a judge pro tem in both San Francisco and Los Angeles counties.

**Honors & Awards**

Recognized as a Leading Lawyer, *Chambers USA*.

Preeminent AV-Rated, Martindale-Hubbell.

**Publications**


**Speaking Engagements**

Mr. Huard is a frequent commentator on energy issues addressing groups as diverse as the International Bar Association, State Bar of California, Energy Bar Association, Institute of Gas Technology, Infocast, Law Seminars International, Platt’s Conferences, Southern California Association of Governments, Los Angeles County Economic Development Corporation, the Arizona Chamber of Commerce, California Counties General Services Association, and Community College League of California.
Commissioner Cheryl A. LaFleur

Commissioner Cheryl A. LaFleur was nominated by President Barack Obama to serve as a member of the Federal Energy Regulatory Commission and confirmed by the U.S. Senate for a term that ends in June 2014.

Commissioner LaFleur has more than 20 years experience as a leader in the electric and natural gas industry. She retired in 2007 as executive vice president and acting CEO of National Grid USA, responsible for the delivery of electricity to 3.4 million customers in the Northeast. Her previous positions at National Grid USA and its predecessor New England Electric System included chief operating officer, president of the New England distribution companies and general counsel. Earlier in her career, she was responsible for leading award-winning conservation and demand response programs for customers.

Commissioner LaFleur is a frequent speaker on energy issues, particularly reliability and grid security, transmission planning, and enabling clean energy resources. She is a member of the NARUC Committees on Electricity and Critical Infrastructure.

Commissioner LaFleur has been a nonprofit board member and leader, and has been honored by Bryant University, the Greater Boston Chamber of Commerce, and the YWCA of Central Massachusetts.

Commissioner LaFleur began her career as a lawyer at Ropes and Gray in Boston. She has a J.D. from Harvard Law School, where she was an editor of the Harvard Law Review, and an A.B. from Princeton University.

Commissioner LaFleur is married to William A. Kuncik, a retired attorney, and they are the parents of two grown children.
David Noble was appointed Commissioner of the Public Utilities Commission of Nevada by Governor Brian Sandoval in August 2011.

Commissioner Noble has been with the Commission since 1997, working as an administrative attorney, assistant staff counsel, assistant general counsel, and hearings officer. Commissioner Noble was also a Commission liaison to the Nevada Legislature on various utility and administrative matters over the last six regular legislative sessions.

Commissioner Noble earned his Bachelor of Arts degree in international relations and environmental studies from the University of Pennsylvania and his Juris Doctorate degree from Loyola Law School (Los Angeles).
Commissioner Catherine J.K. Sandoval

Catherine J.K. Sandoval, of Campbell, was appointed to the California Public Utilities Commission on January 25, 2011, by Governor Jerry Brown. She has worked as an associate professor at Santa Clara University School of Law since 2004. She previously served as undersecretary and senior policy advisor for housing with the Business, Transportation and Housing Agency from 2001 to 2004. She was vice president and general counsel with Z-Spanish Media Corporation from 1999 to 2001 and was the director of the Office of Communications Business Opportunities for the Federal Communications Commission from 1994 to 1999. Commissioner Sandoval was an associate with Munger, Tolles & Olson from 1991 to 1994. She earned a J.D. from Stanford Law School, a Master of Letters in political science from Oxford, where she was a Rhodes Scholar, and a B.A. from Yale.

You can contact Commissioner Sandoval at:

- Commissioner Catherine J.K. Sandoval
  California Public Utilities Commission
  505 Van Ness Avenue
  San Francisco, CA  94102
Rachel Shimshak

Rachel has been the Director of the Renewable Northwest Project since its inception in 1994. On her watch, RNP has supported the implementation of more than 4,100 MW of wind, geothermal and solar resources in the Northwest. In 2005, she was chosen by the Governor of Oregon to represent the state on the Western Governor’s Association Clean and Diversified Energy Advisory Committee, and she was chosen by the four Northwest Governors to serve on the Comprehensive Review of the Northwest Energy System in 1996. Before moving back to the Northwest, Rachel was the Policy Director for the Massachusetts Division of Energy Resources where she worked on electricity, natural gas, oil, conservation, renewables, and emergency planning issues. Prior to that, Rachel was the Legislative Director for a Massachusetts consumer group, and an advocate in Colorado and Washington, D.C. She has served on the Boards of several, non-profit, clean energy and educational organizations and is currently the Secretary of the Bonneville Environmental Foundation. Rachel graduated from the University of Oregon and is a native Oregonian.
Marsha H. Smith is serving her fourth term on the commission. Her current term expires in January 2015. Smith, a Democrat, served as commission president from November 1991 to April 1995.

Commissioner Smith is chair of the Western Electricity Coordinating Council (WECC) Board of Directors, chairs the WECC Compliance Committee and is a member of the Scenario Planning Steering Group for the Regional Transmission Expansion Planning Project. She represents Idaho on the Western Interconnection Regional Advisory Body and the State-Provincial Steering Committee. Smith is a past president of the National Association of Regulatory Utility Commissioners (NARUC), serves on the NARUC Board and is a member and past chair of NARUC’s Electricity Committee. She is a member of the Steering Committee of the Northern Tier Transmission Group, chaired the Western Interstate Energy Board’s Committee for Regional Electric Power Cooperation from October 1999 to October 2005 and is a member of the National Council on Electricity Policy Steering Committee, the Harvard Electricity Policy Group, the Idaho State Bar and the Log Cabin Literary Center board.

Smith received a bachelor of science degree in biology/education from Idaho State University, a master of library science degree from Brigham Young University and her law degree from the University of Washington.

Before her appointment to the commission, Commissioner Smith served as deputy attorney general in the business regulation/consumer affairs division of the Office of the Idaho Attorney General and as deputy attorney general for the Idaho Public Utilities Commission. She was the commission's director of Policy and External Affairs and chair of the NARUC Staff Subcommittee on Telecommunications.
Brian E. White

Brian White has over 15 years of experience in the legislative and public policy arenas. Brian is currently the West Coast Government Affairs Director for SunEdison, a California-based company and one of North America's largest solar energy services providers. SunEdison develops, installs, finances and operates small distributed generation projects for commercial, government, residential and utility customers, in addition to operating large scale utility solar projects. As SunEdison’s lead advocacy representative in the West, Brian works with executive, legislative, and regulatory officials to expand opportunities for SunEdison to grow its solar projects in Western markets.

Prior to coming to SunEdison, Brian served in a variety of private and public sector roles, including as the Director of California Government Affairs for BP America; Vice President of Legislative Affairs for the California Forestry Association; Assistant Director of Legislative Affairs for the California Department of Water Resources; legislative advocate for the California Building Industry Association; and Director of Education and Environment for the California Chamber of Commerce.

Brian received a B.A. in political science with honors from Morehouse College in Atlanta, Georgia.
Frank A. Wolak is the Holbrook Working Professor of Commodity Price Studies in the Economics Department and the Director of the Program on Energy and Sustainable Development at Stanford University. He received his undergraduate degree from Rice University, and an S.M. in Applied Mathematics and Ph.D. in Economics from Harvard University. His fields of research are industrial organization and empirical economic analysis. He specializes in the study of privatization, competition and regulation in network industries such as electricity, telecommunications, water supply, natural gas and postal delivery services. Professor Wolak has served as a consultant to the California and U.S. Departments of Justice on market power issues in the telecommunications, electricity, natural gas, and other energy markets. He has also served as a consultant to the Federal Communications Commission and Postal Rate Commission on issues relating to regulatory policy design in network industries.

From January 1, 1998 to March 30, 2011, Wolak was the Chair of the Market Surveillance Committee (MSC) of the California Independent System Operator. In this capacity, he prepared over 60 reports and opinions on the market design, performance, and oversight of the California electricity market for the management and Board of Governors of the California ISO and the Federal Energy Regulatory Commission (FERC). He has also testified numerous times at the FERC, and at various Committees of the US Senate and House of Representatives on issues relating to market monitoring and market power in energy markets. He has also provided Congressional testimony on the performance and regulation of the United States Postal Service.

Wolak has worked on the design and regulatory oversight of the electricity markets internationally in Europe in England and Wales, Italy, Norway and Sweden, and Spain; in Australia/Asia in New Zealand, Australia, Indonesia, Korea, Singapore, and the Philippines; in Latin American in Brazil, Chile, Colombia, El Salvador, Honduras, Peru, and Mexico; and the US and Canada in California, New York, PJM, Texas (ERCOT), and New England and Alberta and Ontario. He lectures internationally on issues related to electricity market monitoring and regulatory oversight.

Most recently, Wolak has worked on the design of transmission planning, expansion, and pricing protocols to enhance wholesale electricity competition and support the expansion of renewable energy resources in the United States and in the Australia, Canada, Chile, Peru, and the United Kingdom. He was involved in the development of the California ISO’s Transmission Economic Assessment Methodology (TEAM) and recently completed a study for the Office of Gas and Electricity Markets (Ofgem) on the re-design of the transmission protocols for the United Kingdom electricity supply industry.