CHALLENGES IN THE WEST

The pace of activity in the energy sector in Western North America has been extraordinary over the past year. This pace shows no signs of slowing – the year ahead promises to bring continuing challenges for businesses and lawyers alike. The Tenth Annual Meeting of EBA's Western Chapter, featuring an outstanding list of speakers and panels, will afford an exceptional opportunity for energy practitioners to catch up on key developments.

PROGRAM SCHEDULE

THURSDAY, FEBRUARY 24, 2011

6:00 - 8:00 p.m.  RECEPTION AND WINE AUCTION  
Benefit for the Charitable Foundation of the Energy Bar Association

FRIDAY, FEBRUARY 25, 2011

7:30 - 8:30 a.m.  REGISTRATION & CONTINENTAL BREAKFAST

8:30 - 8:45 a.m.  WELCOME AND INTRODUCTION
Susan N. Kelly
President, Energy Bar Association
American Public Power Association

8:45 - 9:30 a.m.  INTRODUCTION OF KEYNOTE SPEAKER
Frank R. Lindh
President, Western Chapter of the Energy Bar Association
General Counsel, California Public Utilities Commission

KEYNOTE SPEAKER
The Honorable Jon B. Wellinghoff
Chairman
Federal Energy Regulatory Commission

9:30 - 10:45 a.m.  INTEGRATING AND SELLING RENEWABLE POWER IN THE WEST

As California moves to a 33% renewable portfolio standard, with other western states not far behind, utilities, operators and traders are facing significant challenges throughout the region. This panel will discuss the challenges in meeting western RPS mandates, including planning for and building transmission, integrating large amounts of intermittent power, and creating a regional market in renewable power.

Chairs: Michael S. Hindus
Pillsbury Winthrop Shaw Pittman LLP

Brooks E. Harlow
Miller Nash LLP

Speakers: Nancy J. Saracino
General Counsel
California Independent System Operator Corporation

Marc L. Ulrich, Ph.D.
Vice President of Renewable and Alternative Power
Southern California Edison Company

Elliot Mainzer
Executive Vice President, Corporate Strategy
Bonneville Power Administration

Grady Mathai-Jackson
Attorney
Pacific Gas & Electric Company
10:45 - BREAK
11:00 a.m.

11:00 a.m. - ENERGY INFRASTRUCTURE
12:15 p.m. SAFETY AND CRISIS MANAGEMENT

Crisis management has moved to the forefront for energy infrastructure companies and legal practitioners in the wake of firestorms in southern California and the tragic San Bruno, California natural gas pipeline explosion. This panel of experts will explain basic principles of crisis management and root cause investigations in light of these and other recent experiences.

Chair: Charles R. Middlekauff
Pacific Gas and Electric Company

Speakers: Gary Halbert
General Counsel
National Transportation Safety Board

Mark Farley
Partner
Pillsbury Winthrop Shaw Pittman LLP

Ali Yari
Director, Electric Transmission & Distribution Engineering
San Diego Gas & Electric Company

12:30 - LUNCHEON SPEAKER
1:45 p.m.

The Honorable Michael R. Peevey
President
California Public Utilities Commission

1:45 - STATE COMMISSIONERS PANEL
3:15 p.m.

Always 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 the field of energy regulation, from the perspective of state regulatory commissions.

Panel Coordinator: David L. Huard
Manatt, Phelps & Phillips, LLP

Panel Chair: The Honorable Kristin K. Mayes
Former Commissioner and Former Chairman
Arizona Corporation Commission

Speakers: The Honorable Sue Ackerman
Commissioner
Oregon Public Utilities Commission

The Honorable Paul Newman
Commissioner
Arizona Corporation Commission

The Honorable Michel Peter Florio
Commissioner
California Public Utilities Commission

The Honorable Ted Boyer
Commissioner
Utah Public Service Commission

3:30 - EBA WESTERN CHAPTER
4:00 p.m. BUSINESS MEETING
KEYNOTE SPEAKER
NOTES
INTEGRATING AND SELLING RENEWABLE POWER IN THE WEST
Integrating and selling renewable power in the West

Energy Bar Association – Western Chapter Meeting
San Francisco – February 25, 2011

Nancy Saracino
Vice President General Counsel & Chief Administrative Officer
California Independent System Operator
California ISO by the numbers

- **55,027 MW** of power plant capacity
- **50,270 MW** record peak demand (July 24, 2006)
- **30,000** market transactions per day
- **25,526** circuit-miles of transmission lines
- **30 million** people served
- **286 million** megawatt-hours of electricity delivered annually
Tight margin for error matching supply and demand of electricity

For a power grid that can draw 50,000 megawatts of electricity

Electricity supply must be matched within a narrow bandwidth and is corrected every 4 seconds by automated generation control.
Supply profile

Source: 2010 Integration of Renewable Resources Operational Requirements and Generation Fleet Capability at 20% RPS
Operational challenges due to wind and solar variability

Weather now a critical factor

ISO must be able to serve load in the event of unexpected weather changes

Conventional generators must be available to adjust to the minute-to-minute variability and provide back up for unexpected weather.
Forecasted vs. actual wind output

Simulated spring day in 2012

Source: 2010 Integration of Renewable Resources Operational Requirements and Generation Fleet Capability at 20% RPS
California ISO wholesale markets are a platform for integrating renewable energy

- **Real-time imbalance energy market**
  - Short-term unit commitment every 15-minutes
  - Optimal dispatch and transparent prices every 5-minutes
- **Day-ahead and real-time ancillary service markets**
- **As more renewables come on line, the system needs more to balance the variability**
Needs for reliability services increase substantially with increasing levels of variable generation.

Combined cycle gas generation is essential but faces financial challenges

<table>
<thead>
<tr>
<th></th>
<th>2006</th>
<th>20% RPS</th>
<th>Percent Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of Starts</td>
<td>2,492</td>
<td>3,362</td>
<td>35%</td>
</tr>
<tr>
<td>On-Peak Energy (GWh)</td>
<td>36,259</td>
<td>32,421</td>
<td>-11%</td>
</tr>
<tr>
<td>Off-Peak Energy (GWh)</td>
<td>31,056</td>
<td>26,146</td>
<td>-16%</td>
</tr>
<tr>
<td>CO2 Emissions (Mmtons)</td>
<td>27.97</td>
<td>24.27</td>
<td>-13%</td>
</tr>
<tr>
<td>Revenue ($ Billion)</td>
<td>4.1</td>
<td>3.46</td>
<td>-16%</td>
</tr>
</tbody>
</table>

Increased wear and tear means higher maintenance costs
Emission reductions are less than hoped
Lower revenues, higher maintenance costs threaten viability

Interconnection studies for over 40,000 MW of renewable generation projects

Projects with completed studies

- Wind: 9,057 MW
- Conventional: 11,615 MW
- Solar: 10,245 MW
- Other Renewable: 1,126 MW

Total: 32,043 MW

Projects in study process

- Wind: 4,047 MW
- Conventional: 4,806 MW
- Other Renewable: 636 MW
- Solar: 21,391 MW

Total: 30,880 MW

6,967 MW of online renewable generation
Over $7 billion in approved transmission projects to support RPS goals

<table>
<thead>
<tr>
<th>Transmission Upgrade</th>
<th>Aproval Status</th>
<th>Renewable Potential</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>CAISO</td>
<td>MW</td>
</tr>
<tr>
<td>1 Carrizo-Midway</td>
<td>Pending LGIA</td>
<td>900</td>
</tr>
<tr>
<td>2 Sunrise Powerlink</td>
<td>Approved</td>
<td>1,700</td>
</tr>
<tr>
<td>3 Eldorado - Ivanpah</td>
<td>LGIA Decision Pending</td>
<td>1,400</td>
</tr>
<tr>
<td>4 Pisgah-Lugo</td>
<td>LGIA Not yet filed</td>
<td>1,750</td>
</tr>
<tr>
<td>5 Valley - Colorado River</td>
<td>Approved</td>
<td>4,700</td>
</tr>
<tr>
<td>6 West of Devers</td>
<td>Approved</td>
<td>4,500</td>
</tr>
<tr>
<td>7 Tehachapi</td>
<td>Approved</td>
<td>2,700</td>
</tr>
<tr>
<td>Other - CAISO Grid Upgrades</td>
<td>Mixed</td>
<td>N/A</td>
</tr>
<tr>
<td>Other - Outside of CAISO Grid</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td>53.3</td>
</tr>
</tbody>
</table>

*Petition to modify CPCN pending.

CAISO Balancing Area Needs for 33%: 44

Total Cost (Planning Estimate): $7.2 B
Agenda

- SCE’s Renewable Energy Portfolio
- Challenges to Achieving a Renewable Portfolio Standard (RPS)
- Current Topic: Transmission
- Current Topic: Integration
- Costs of Renewable Energy
SCE Delivers More Renewable Energy Than Any Company In The U.S.

2009 Renewable Resources
13.6 Billion kWh
~17% of SCE’s portfolio

- Biomass 7%
- Solar 6%
- Small Hydro 4%
- Wind 26%
- Geothermal 57%

2009-2010 (Billion kWh)

- 2009: 13.6
- 2010: 15.0

10% Increase
89% Increase

Renewable Resources
2009-2010 (Billion kWh)

SCE’s Role in U.S. Renewables Market

In 2009, SCE purchased roughly:
- 80% of all U.S. solar generation
- 50% of renewable energy generated in California
- 60% of total wind energy in California
- 60% of total geothermal energy in California

Sources: Energy Information Administration, SCE
Challenges to the RPS program

- Transmission delays
- Integrating intermittent renewable resources onto the grid
- Rate impact to retail customers (e.g., purchase and integration costs)
- Legislative barriers:
  - Regulatory inflexibility (e.g., Renewable Energy Credit limits)
  - Changing policy initiatives
  - Overly-prescriptive programs
- Permitting and siting
- Project failure (e.g., lack of financing, decertification of previously eligible resources)
- Uncertainty surrounding federal production and investment tax credits
Transmission of Renewables

- Power from SCE’s contracted renewables typically flows through its transmission system, which is operated by the California Independent System Operator (CAISO).
- Transmission constraints and generation oversupply can cause conditions in which SCE must pay the CAISO to take the excess energy.
- Without adequate transmission, some facilities are deemed only “partially deliverable” (i.e., not all power can be delivered).

Congestion (local overgen.)

Overgeneration (system overgen.)

Lack of demand/transmission = falling prices
## Transmission: Curtailment and Deliverability

<table>
<thead>
<tr>
<th>Problem</th>
<th>Concerns</th>
<th>SCE’s Solution</th>
</tr>
</thead>
<tbody>
<tr>
<td>In times of congestion and overgeneration, prices for renewable energy may fall so low as to require additional payment to the CAISO</td>
<td>SCE’s customers should not pay for energy that is not delivered</td>
<td>Worked with market participants to develop a “curtailment cap” option</td>
</tr>
<tr>
<td>Renewable generators who undergo transmission studies and only qualify as “partially deliverable” have a reduced capacity benefit</td>
<td>Generators argued that without guaranteed payment, they could not secure financing</td>
<td>Consider partially deliverable projects on an energy-only basis</td>
</tr>
<tr>
<td></td>
<td>SCE would prefer that the grid be fully built before generators are interconnected</td>
<td>Consider delays in online dates</td>
</tr>
<tr>
<td></td>
<td>Generators want partial credit for the dependable capacity they do provide</td>
<td>SCE will not execute contracts until phase 1 transmission study is complete</td>
</tr>
</tbody>
</table>
Integrating Renewables

- Many readily-available new renewable resources will be intermittent
- Ramping requirements must be met to maintain system operability
- Ancillary Service (AS) requirements increase with higher penetration of renewables

Annual Maximum Ancillary Service Requirements within CAISO

20% → 33% target: over 60% increase in AS reqs.

Source: Derived from CAISO 33% Renewable Integration Study Step 1 Results
Integrating Renewables: Emissions

While preliminary integration studies using increased RPS targets show a decrease in emissions WECC-wide, there is little change to emissions created within California.

From a 20% RPS to a 33% RPS, CO₂ emissions across the WECC drop by approximately 19 million metric tons.

Emission reduction comes from a lower import need, not a reduction in emissions from within California.

Source: CAISO 33% Renewable Integration Study
Purchase Costs of Renewable Energy

Levelized Cost of Energy by Technology, Q4 2009

- Solar Thermal
- Solar PV
- Biomass
- Wind
- Municipal Solid Waste
- Geothermal
- Landfill Gas
- Gas CCGT
- Coal

Sources: Bloomberg New Energy Finance 2/22/10 and SCE Internal 2/17/11
Effect of Renewable Energy Costs on Rates

- The prices of renewable energy significantly exceed those of conventional resources
  - Current generation rate in SCE: 9 cents/kWh (average rate)
  - Historical price paid for renewables: 10-15 cents/kWh
  - Current prices for renewables are lower than historical prices

- In addition to high renewable prices, additional charges, such as integration and federal incentives, may be required
  - Current BPA wind integration charge: 0.5 cents/kWh
  - This cost may rise as demand for integration services increases

Without taking steps to limit the costs incurred by expanding renewables, SCE's customers may face a significant rate increase.
Renewables Policy and System Operations

*The Case for Co-Evolution*

Energy Bar Association – Western Chapter Meeting
February 25, 2011
San Francisco, CA

Elliot Mainzer
EVP, Corporate Strategy
Bonneville Power Administration
Drivers of NW Wind Development

- State renewable portfolio standards (WA, OR, CA)
- Federal and state financial incentives
- Proximity to existing 500 KV lines and interties to California
- Relatively short construction lead time and quick siting & permitting (although there is growing pushback in some areas)
- Rural economic benefits + green tinge = strong political support
- Least-cost renewable available in bulk quantity
BPA Enablers of NW Wind Development

- Relaxed imbalance penalties (2001)
- Storage and Shaping Services (2004)
- 2007 NW Wind Integration Action Plan – “Yes We Can”
- BPA Network Open Seasons (2008-2010)
  - New twist on open access queue management
  - More efficient transmission planning
  - Federal financing for new lines
- Relatively low-cost wind integration rates (2009-11)
- BPA has evolved its business practices to incorporate Intra-hour scheduling, self-supply of generation imbalance, new wind forecasting systems, expanded dynamic transfer capacity.
The Result: Exponential Growth of Wind
Forecasted Wind Generation Connected to BPA’s Transmission System

![Graph showing forecasted wind generation](image)

**Notes:**
1. Projections beyond FY11 may be impacted or delayed due to a need for transmission system expansion.
2. Projected totals based on previous experience and present growth factors including Production Tax Credits and RPS Demand.
3. Generation shown is interconnected to BPA-T; amount within EPA Balancing Authority Area is not estimated.
Highly Concentrated Pattern of Wind Development
Volatile Ramping Behavior

BPA Balancing Authority Total Wind Generation and Wind Baseline, Last 7 days

MW

Based on 5-min readings from the BPA SCADA system for points 79687, 103349
Balancing Authority Wind Generation in Green, Wind Baseline in Red. Installed Wind Capacity = 337 MW
BPA Technical Operations (TOT-OpInfo@bpa.gov)
Limited Capacity Value

BPA Balancing Authority Area Load & Total Wind Generation
Jan. 1-11, 2011

Date/Time (5-min increments)

- BPA Total Wind Generation
- BPA Balancing Authority Area Load
Unintended Consequences

• The Federal Columbia River Power System is effectively tapped out. The next tranche of balancing capacity will need to come from conventional power plants or new technologies.

• Huge ramping requirements may diminish ultimate carbon reductions because of spinning reserve requirements for thermal generation.

• Confluence of high wind and high spring runoff leading to conflicts with the Endangered Species Act.

• Reductions in power prices from increased wind penetration perhaps good for many regional ratepayers, but degrading the economics of the capacity resources needed to maintain reliability (like hydro).
The Case for Co-Evolution

• The nation’s utility system operators are rightly being asked to adapt their operational practices to integrate increased amounts of renewable generation.

• As we scale up the nation’s renewable energy fleet, public policies supporting renewables should better acknowledge the operational realities of the power grid and the legitimate needs of LSEs.

• RPS legislation should be matched with substantive, coordinated implementation plans for transmission utilization/expansion and the provision of integration services.

• Important policy tools like Production Tax Credits (PTCs) and Renewable Energy Credits (RECs) are increasingly distorting markets and leading to unintended cost shifts. Is it time to take them off the margin and embed them in the capital base?

• Providers of reliability services need to be compensated through effective forward markets for balancing capacity.
Your Feedback is Welcome!

Elliot Mainzer
EVP, Corporate Strategy
Bonneville Power Administration
eemainzer@bpa.gov
503 230 4175
The Role of RECs in a Regional Renewable Electricity Market

California’s REC Policy Evolution

M. Grady Mathai-Jackson
Attorney, Energy Supply & Planning
PG&E

February 25, 2011
What are Tradable Renewable Energy Credits (TRECs)?

The details depend on the jurisdiction.

Fundamentally:

• A REC is the green (or renewable) attribute associated with one MWh of renewable generation.

• A TREC can “unbundled” from underlying generation and traded separately.

Diagram Credit: Andy Schwartz, CPUC, 2006
What are Tradable Renewable Energy Credits (TRECs)?

In California, some bundled purchases of electricity and RECs are considered “REC-only” and subject to limits on TREC procurement.

Example: Firmed and Shaped Out-of-State Purchase (illustrative delivery structure shown on next slide)
Example Firming and Shaping Structure

**Seller**

Step 1:
- Sell Energy (A) at busbar
- Retain Green Attributes

Step 2:
- Buy firm Energy (B)
- Deliver Energy (B) and Green Attributes to LSE

**Intermediary (Shaping Provider)**

- Buy all Energy (A) at busbar
- Sell firm Energy (B) back to RPS Seller at PPA delivery point

**RPS-obligated CA LSE**

- Buy firm Energy (B) and Green Attributes at CAISO delivery point
- Pay price for combined product
What are Tradable Renewable Energy Credits (TRECs)?

RECs used for compliance with California’s RPS Program must be tracked as certificates in the Western Regional Energy Generation System Information System (“WREGIS”)

• WREGIS is designed to ensure:
  – No double counting of RECs
  – That RECs actually represent renewable generation

• The California RPS statute required that WREGIS be operational before the CPUC could authorize the trading of unbundled RECs.
The Impact of RECs on the Regional Renewables Market

Increasing Market Efficiency
• Addresses Integration and Transmission Obstacles

  – Facilitates siting of renewable generation where:
    • Resource is most abundant
    • Land use conflicts are minimized

  – Can provide least-cost GHG reductions from avoided fossil emissions

  – Provide a fungible product that is easily and efficiently traded between regulated entities.
The Impact of RECs on the Regional Renewables Market

Social, Environmental, and Operational Impacts

• In-state vs. out-of-state benefits
  – Jobs, tax revenues, utilization of in-state transmission
  – Development of in-state clean tech industry

• Species impacts from geographically-concentrated development

• Potential displacement of in-state fossil-fueled generation

• Impacts on reliability and congestion
RPS Programs in Place

RPS Policies
www.d sireusa.org / February 2011

- WA: 15% x 2020 *
- MT: 15% x 2015
- MN: 25% x 2025
  (X6%: 30% x 2020)
- ND: 10% x 2015
- SD: 10% x 2015
- WI: varies by utility;
  10% x 2015 statewide
- MI: 10% + 1,100 MW
  x 2015 *
- VT: (1) RE meets any increase
  in retail sales x 2012;
  (2) 29% RE & P & P x 2017
- OR: 25% x 2025 (large utilities) *
- NV: 25% x 2025 *
- CO: 30% by 2020 (tours)
  10% by 2020 (co-ops & large munis) *
- IA: 105 MW
- IL: 25% x 2025
- OH: 25% x 2025
- WV: 25% x 2025 *
- VA: 15% x 2025 *
- NC: 12.5% x 2021 (tours)
  10% x 2018 (co-ops & munis)

29 states +
DC and PR have an RPS
(7 states have goals)

- Solar water heating eligible
- ☀️ Minimum solar or customer-sited requirement
- ✫ Extra credit for solar or customer-sited renewables
- + Includes non-renewable alternative resources
REC REGIMES IN U.S. PORTION OF THE WECC

- WA can use unbundled RECs generated in-state, or in ID or OR*
- OR can use bundled RECs generated within US portion of WECC
- CA can use out-of-state generated, WREGIS-tracked RECs for RPS compliance with temporary 25% and $50 caps
- AZ, CO, and UT: No participation in WREGIS at this time
- AZ, MT, NM, NV: Restricted to trading of RECs generated in-state
- Information based on DSIRE database as of 2/16/11
TRECs in California

California’s Renewables Portfolio Standard Statute

• Gave discretion to CPUC to authorize and create rules for use of TRECs.

• Delivery requirements for out-of-state RECs.
TRECs in California

California Public Utilities Commission Decisions

• March 2010 TREC Decision (D.10-03-021)
  – Temporary price ($50) and usage (25%) caps
• Petitions to Modify and Applications for Rehearing
• May 2010 Stay and Moratorium
• January 2011 Modification (D.11-01-025)
  – Back to the future.
  – CPUC summary of final rules included with handout.
TRECs in California

Proposed 33% Legislation (SB 23 / SBX1 2)

• Deletes language giving CPUC discretion to cap procurement of unbundled RECs, but places caps in statute.
• LSEs would have limited ability to use unbundled RECs and bundled out-of-state procurement to meet RPS compliance targets for each compliance period.
• Deletes delivery requirements from statute.
• Regulatory uncertainty has stymied the market.
  – PG&E Feb. 11, 2011 Letter to Legislators: Let’s codify the CPUC TREC decision.
## TRECs in California

### Proposed 33% Legislation (SB 23 / SBX1 2)

#### Out-of-State and Unbundled Limits

<table>
<thead>
<tr>
<th>RPS Compliance Period</th>
<th>Cap on Firmed and Shaped Incremental² Procurement (% of RPS Requirement in each period)¹</th>
<th>Cap on Incremental² Unbundled RECs (% of RPS Requirement in each period)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2011-2013</td>
<td>25%-50%</td>
<td>25%</td>
</tr>
<tr>
<td>2014-2016</td>
<td>20-35%</td>
<td>15%</td>
</tr>
<tr>
<td>2017-2020 and each year thereafter</td>
<td>15-25%</td>
<td>10%</td>
</tr>
</tbody>
</table>

¹ Range is from maximum allowed use to no use of unbundled RECs
² Applies to contracts executed after June 1, 2010
TREC Market Implementation Issues

Issues for Q&A and Panel Discussion

• Federal Commerce Clause challenges to in-state renewable generation requirements
  – Massachusetts Litigation
  – Regulatory retreat in Missouri
  – Applications for rehearing of CPUC TREC Decision

• Integrating and marketing null power

• Will (or should) firm transmission into CAISO count as bundled procurement?

• Trading and banking rules governing TRECs

• Inferring the price of RECs in bundled procurement
Thank You

M. Grady Mathai-Jackson
mgml@pge.com
APPENDIX B TO CPUC DECISION 11-01-025

Summary of TREC Rules Announced in D.10-03-021, and Compiled in Appendix D to D.10-03-021, as Modified by this Decision

This decision sets rules for the use of TRECs for RPS compliance and for the TREC market. The orders and guidance (while not limited by this summary) are summarized below. Other sources relevant to TRECs include D.08-08-028, the CEC’s RPS Eligibility Guidebook, and the WREGIS Operating Rules.

What is a tradable renewable energy credit (TREC) transaction?

1) A transaction in which an entity procures only a REC (and not the underlying energy) from another entity, or

2) A transaction conveying both RECs and energy that does not meet the Commission's criteria for bundled RPS procurement transactions. These REC-only transactions currently include all procurement from generators of RPS-eligible energy for which the first point of interconnection with the WECC interconnected transmission system is not a California balancing authority, and the transaction does not make use of dynamic transfer arrangements in a California balancing authority area.

Effective date of REC trading

- RPS-obligated load-serving entities may begin procuring and trading RECs on the effective date of this decision.

Eligibility of TREC

- All TRECs must be associated with RPS-eligible energy generated on or after January 1, 2008.

- All TRECs must be tracked in WREGIS to be used for RPS compliance.

- The RECs from bundled contracts currently delivering RPS-eligible energy may be unbundled and traded separately from the associated energy, subject to the exceptions below.

Load-serving entities (LSEs) include: investor-owned utilities (IOUs), energy service providers (ESP), and community choice aggregators (CCAs).
• The RECs from bundled contracts scheduled to deliver RPS-eligible energy in the future may be unbundled and traded on a forward basis separately from the associated energy, subject to the exceptions below.

• Exceptions:
  1. RECs associated with RPS-eligible energy delivered under procurement contracts signed prior to 2005 with California RPS-obligated LSEs or publicly owned utilities cannot be traded unless the contract explicitly assigns ownership or disposition of the RECs.
  2. RECs associated with RPS-eligible energy delivered to California utilities under procurement contracts pursuant to the Federal Public Utility Regulatory Policies Act of 1978 with qualifying facilities signed after January 1, 2005 cannot be traded.

Flexible compliance rules for TREC

Commitment and Banking
• In order to be used for RPS compliance, TREC may be retained in active sub-accounts in WREGIS for no more than three calendar years (inclusive of the year in which the electricity associated with the RECs was generated) after the electricity associated with the RECs was generated.
• Once RECs are retired in WREGIS for RPS compliance, they may be banked for RPS compliance in future years in accordance with the RPS flexible compliance rules.

Earmarking
• TREC contracts between an LSE and one RPS-eligible generator may be earmarked for RPS compliance purposes, but no other types of TREC contracts may be earmarked.
• An LSE may not unbundle and trade RECs associated with energy generated in the first three years of an RPS contract (whether bundled or REC-only) that is being used for earmarking.

Filling compliance shortfalls
REC-only contracts may be used to make up shortfalls in APT, so long as the total use of TREC for the year of the shortfall does not exceed the applicable limit on TREC usage.
Temporary limit on use of TRECs for RPS compliance

- PG&E, SCE, and SDG&E may meet no more than 25% of their APT with TRECs. This limitation will sunset December 31, 2013.

Contract review and approval of TREC transactions

- IOUs may submit TREC contracts for CPUC review and approval by advice letter starting April 1, 2010.

- Energy Division staff may use present methods of analyzing advice letters for bundled contracts, and make any adaptations necessary, for reviewing REC-only contracts, except that the fast-track process set out in D.09-06-050 does not apply to TRECs. These methods may be reviewed in R.08-08-009.

- TRECs for which an IOU pays more than $50/TREC may not be used for RPS compliance. This price cap will sunset December 31, 2013.

- The temporary $50/TREC price cap does not make a TREC priced at or below $50 reasonable. A utility will still have to provide sufficient information in its advice letter filing to demonstrate that the TREC contract is reasonable.

- All REC-only contracts must contain the following three non-modifiable standard terms and conditions: (1) Transfer of renewable energy credits; (2) Tracking of RECs in WREGIS; (3) Applicable Law.

- REC-only contracts of California IOUs other than MJUs must contain a fourth STC: Commission Approval.

- IOUs may enter into voluntary TREC transactions even if their cost limitation pursuant to § 399.15(d) has been reached, so long as they comply with the requirements of this decision.

Delivery rules for TREC transactions

The CEC decides whether a TREC contract satisfies RPS delivery rules. For bundled contracts, the Energy Division may request written confirmation from the CEC about whether the contract complies with RPS delivery rules.
SECTIONS 21 AND 22 OF SBX1 2
(PROPOSED 33% RPS LEGISLATION IN CALIFORNIA)
(As bill was introduced on February 1, 2011)

[NOTE: Section 21 amends the existing RPS Statute’s provisions regarding the use of RECs to meet RPS compliance targets.

Section 22 would create product category requirements that generally correspond to in-state bundled generation, out-of-state procurement using firming and shaping arrangements, and out-of-state procurement of unbundled RECs. It would then require the LSEs to meet the RPS requirements in each compliance period using certain percentages of each product category.]

SEC. 21. Section 399.16 of the Public Utilities Code is amended and renumbered to read:

399.16. 399.21. (a) The commission, by rule, may authorize the use of renewable energy credits to satisfy the requirements of the renewables portfolio standard procurement requirements established pursuant to this article, subject to the following conditions:

(1) Prior to authorizing any renewable energy credit to be used toward satisfying annual procurement targets, the commission and the Energy Commission shall conclude that the tracking system established pursuant to subdivision (c) of Section 399.13, is operational, is capable of independently verifying that electricity earning the credit is generated by an eligible renewable energy resource and delivered to the retail seller, and can ensure that renewable energy credits shall not be double counted by any seller of electricity within the service territory of the Western Electricity Coordinating Council (WECC). Each renewable energy credit shall be counted only once for compliance with the renewables portfolio standard of this state or any other state, or for verifying retail product claims in this state or any other state. (3) The electricity is delivered to a retail seller, the Independent System Operator, or a local publicly owned electric utility.

(4) All revenues received by an electrical corporation for the sale of a renewable energy credit shall be credited to the benefit of ratepayers.

(5) No renewable

(4) Renewable energy credits shall not be created for electricity generated pursuant to any electricity purchase contract with a retail seller or a local publicly owned electric utility executed before January 1, 2005, unless the contract contains explicit terms and conditions specifying the ownership or disposition of those credits. Deliveries under those contracts shall be tracked through the accounting system described in subdivision (b) of Section 399.13 and included in the baseline.
quantity of eligible renewable energy resources of the purchasing retail seller pursuant to Section 399.15.

(6) A renewable energy credit shall not be eligible for compliance with a renewables portfolio standard procurement requirement unless it is retired in the tracking system established pursuant to subdivision (c) of Section 399.25 by the retail seller or local publicly owned electric utility within 36 months from the initial date of generation of the associated electricity.

(b) The commission shall allow an electrical corporation to recover the reasonable costs of purchasing renewable energy credits, selling, and administering renewable energy credit contracts in rates.

SEC. 22. Section 399.16 is added to the Public Utilities Code, to read:

399.16. (a) Various electricity products from eligible renewable energy resources located within the WECC transmission network service area shall be eligible to comply with the renewables portfolio standard procurement requirements in Section 399.15. These electricity products may be differentiated by their impacts on the operation of the grid in supplying electricity, as well as, meeting the requirements of this article.

(b) Consistent with the goals of procuring the least-cost and best-fit electricity products from eligible renewable energy resources that meet project viability principles adopted by the commission pursuant to paragraph (4) of subdivision (a) of Section 399.13 and that provide the benefits set forth in Section 399.11, a balanced portfolio of eligible renewable energy resources shall be procured consisting of the following portfolio content categories:

(1) Eligible renewable energy resource electricity products that meet either of the following criteria:
(A) Have a first point of interconnection with a California balancing authority, have a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area, or are scheduled from the eligible renewable energy resource into a California balancing authority without substituting electricity from
another source. The use of another source to provide real-time ancillary services required to maintain an hourly or subhourly import schedule into a California balancing authority shall be permitted, but only the fraction of the schedule actually generated by the eligible renewable energy resource shall count toward this portfolio content category.

(B) Have an agreement to dynamically transfer electricity to a California balancing authority.

(2) Firmed and shaped eligible renewable energy resource electricity products providing incremental electricity and scheduled into a California balancing authority.

(3) Eligible renewable energy resource electricity products, or any fraction of the electricity generated, including unbundled renewable energy credits, that do not qualify under the criteria of paragraph (1) or (2).

(c) In order to achieve a balanced portfolio, all retail sellers shall meet the following requirements for all procurement credited towards each compliance period:

(1) Not less than 50 percent for the compliance period ending December 31, 2013, 65 percent for the compliance period ending December 31, 2016, and 75 percent thereafter of the eligible renewable energy resource electricity products associated with contracts executed after June 1, 2010, shall meet the product content requirements of paragraph (1) of subdivision (b).

(2) Not more than 25 percent for the compliance period ending December 31, 2013, 15 percent for the compliance period ending December 31, 2016, and 10 percent thereafter of the eligible renewable energy resource electricity products associated with contracts executed after June 1, 2010, shall meet the product content requirements of paragraph (3) of subdivision (b).

(3) Any renewable energy resources contracts executed on or after June 1, 2010, not subject to the limitations of paragraph (1) or (2), shall meet the product content requirements of paragraph (2) of subdivision (b).

(d) Any contract or ownership agreement originally executed prior to June 1, 2010, shall count in full towards the procurement requirements established pursuant to this article, if all of the following conditions are met:

(1) The renewable energy resource was eligible under the rules in place as of the date when the contract was executed.

(2) For an electrical corporation, the contract has been approved by the commission, even if that approval occurs after June 1, 2010.

(3) Any contract amendments or modifications occurring after June 1, 2010, do not increase the nameplate capacity or expected quantities of annual generation, or substitute a different renewable energy resource. The duration of the contract may be extended if the original contract specified a procurement commitment of 15 or more years.

(e) A retail seller may apply to the commission for a reduction of a procurement content requirement of subdivision (c). The commission may reduce a procurement content requirement of subdivision (c) to the extent the retail seller demonstrates that it cannot comply with that subdivision because of conditions beyond the control of the retail seller as provided in paragraph (5) of subdivision (b) of Section 399.15. The commission shall not, under any circumstance, reduce the obligation specified in paragraph (1) of subdivision (c) below 65 percent for any compliance obligation after December 31, 2016.
NOTES
ENERGY INFRASTRUCTURE SAFETY
AND CRISIS MANAGEMENT
THE ANATOMY
OF AN
NTSB PIPELINE INVESTIGATION

I. INTRODUCTION TO BOARD/BOARD MAKEUP

A. Chairman Deborah A.P. Hersman sworn in as Chairman on July 28, 2009.

1. Serving her second 5-year term as Board Member; Member since 2004.

2. Previously served as a Senior Professional Staff Member of the U.S. Senate Committee on Commerce, Science and Transportation, 1999–2004.

3. Prior to that served as a Staff Director and Senior Legislative Aide to Congressman Bob Wise of West Virginia.

4. On-scene spokesperson for crash at Fort Totten station between two Washington Metropolitan Area Transit Authority Trains in 2009; the allision of the container ship Cosco Busan with the San Francisco Bay Bridge in 2007; crash of COMAIR 5191 in Lexington, Kentucky, in 2006; and the head-on collision of two freight trains in Anding, Mississippi, in 2005; among others.

5. Commercial Drivers License (CDL) holder with passenger, school bus, and air brake endorsements; motorcycle basic course and motorcycle endorsement; certified Child Passenger Safety Technician.

B. Vice Chairman Christopher A. Hart sworn in as a Member on August 12, 2009.

1. Designated as Vice Chairman on August 18, 2009; 2-year term.

2. Lengthy career in transportation safety.

3. Previously Deputy Director for Air Traffic Safety Oversight at the FAA.

4. Prior to that, was FAA Assistant Administrator for Office of System Safety.


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1 Prepared by the General Counsel, NTSB, for the Tenth Annual Energy Bar Association (EBA), Western Chapter, February 24–25, 2011, San Francisco, California. These remarks were not approved by the Board and reflect the personal views of the author.

1. Served 2 years as Vice Chairman.


3. 14,000 flight hours; type ratings in 5 aircraft; retired in 2005.


7. Author of approximately 100 articles and papers in aviation trade publications.

D. Member (Dr.) Mark R. Rosekind joined NTSB June 30, 2010.

1. Previously President and Chief Scientist of Alertness Solutions, a scientific consulting firm that specializes in fatigue management. He has divested his interests in this entity.

2. Before that, directed the Fatigue Countermeasures Program and served as Chief of the Aviation Operations Branch in the Flight Management and Human Factors Division at the NASA Ames Research Center.

3. Prior to that, was Director of the Center for Human Sleep Research at the Stanford University Sleep Disorders and Research Center.

4. Internationally recognized sleep expert; published over 150 scientific, technical, and industry papers.

5. Industry fatigue management consultant; previously assisted NTSB.

E. Member (Dr.) Earl F. Weener (way'ner) joined NTSB June 30, 2010.

1. 25-year career with The Boeing Company—held series of leadership positions with The Boeing Company, including 3 Chief Engineer positions, in Airworthiness, Reliability, and Maintainability, and Safety; in System Engineering; and in Safety Technology Development.

2. Served 4 years as Boeing’s Manager of Government Affairs.

3. Licensed pilot, general aviation flight instructor, and Part 135 pilot.

4. All 3 academic degrees, including Ph.D., in Aerospace Engineering at the University of Michigan.

5. Awards include 1994 Laurel Award from Aviation Week and Space Technology magazine; 2005 Honeywell Bendix Trophy for Aviation Safety.

6. Most recently, consultant and fellow for the Flight Safety Foundation.

II. NTSB JURISDICTION/STATUTORY MANDATE

A. Accident investigation responsibilities/authority of the Safety Board.

1. Aviation.

   a. “The National Transportation Safety Board shall investigate or have investigated (in detail the Board describes) and establish the facts, circumstances, and cause or probable cause of—(A) an aircraft accident the Board has authority to investigate under section 1132 of this title or an aircraft accident involving a public aircraft as defined by section 40102(a)(41) of this title other than an aircraft operated by the Armed Forces or by an intelligence agency of the United States.” 49 U.S.C. § 1131(a)(1)(A).

   b. “The Board is responsible for the organization, conduct, and control of all accident and incident investigations within the United States, its territories and possessions, where the accident or incident involves any civil aircraft or certain public aircraft….” 49 C.F.R. § 831.2(a).

2. Surface.

   a. “The National Transportation Safety Board shall investigate or have investigated (in detail the Board prescribes) and establish the facts, circumstances, and cause or probable cause of—”
b. “(B) a highway accident, including a railroad grade crossing accident, the Board selects in cooperation with a State.” 49 U.S.C. § 1131(a)(1)(B).

c. “(C) a railroad accident in which there is a fatality or substantial property damage, or that involves a passenger train.” 49 U.S.C. § 1131(a)(1)(C).

d. “(D) a pipeline accident in which there is a fatality, substantial property damage, or significant injury to the environment.” 49 U.S.C. § 1131(a)(1)(D).

e. “(E) a major marine casualty (except a casualty involving only public vessels) occurring on or under the navigable waters, internal waters, or the territorial sea of the United States as described in Presidential Proclamation No. 5928 of December 27, 1988 [12-mile limit]; or involving a vessel of the United States (as defined in section 2101(46) of title 46), under regulations prescribed jointly by the Board and the head of the department in which the Coast Guard is operating.” 49 U.S.C. § 1131(a)(1)(E).

3. “(F) any other accident related to the transportation of individuals or property when the Board decides – (i) the accident is catastrophic; (ii) the accident involves problems of a recurring character; or (iii) the investigation of the accident would carry out this chapter.” 49 U.S.C. § 1131(a)(1)(F).

4. Aside: Authority of Directors [of the NTSB’s modal investigative offices].

a. “The Directors, Office of Aviation Safety, Office of Railroad, [Pipeline, and Hazardous Materials Investigations], Office of Highway Safety, [and] Office of Marine Safety [. . .], subject to the provisions of § 831.2 and part 800 of this chapter, may order an investigation into any accident or incident.” 49 C.F.R. § 831.3.

B. Authority of the U.S. Pipeline and Hazardous Materials Safety Administration (PHMSA) to participate

1. Federal Aviation Administration is “required” participant and regulatory “party” to NTSB aviation accident investigations. 49 U.S.C. § 1132(c). (more on party status later)

2. However, it is the consistent practice of the NTSB to offer party status to PHMSA. 49 U.S.C. § 1131(a)(2)(A).

3. Some ongoing discussions to provide similar requirement to Coast Guard in marine casualty investigations. Possible reauthorization amendment at 49 U.S.C. 1131 or 1132 that would grant Coast Guard the same participation as the FAA.
C. Nature of an NTSB investigation—what it is and what it is not.

1. “Accident and incident investigations are conducted by the Board to determine the facts, conditions, and circumstances relating to an accident or incident and the probable cause(s) thereof. These results are then used to ascertain measures that would best tend to prevent similar accidents or incidents in the future.” 49 C.F.R § 831.4.

2. “Accident/incident investigations are fact-finding proceedings with no formal issues and no adverse parties. They are not subject to the provisions of the Administrative Procedure Act (5 U.S.C. § 504 et seq.), and are not conducted for the purpose of determining the rights or liabilities of any person.” (emphasis added) 49 C.F.R. § 831.4.

3. Priority of Board investigations.

a. “Subject to the requirements of this paragraph, an investigation by the Board under paragraph (1)(A)-(D) or (F) of this subsection has priority over any investigation by another department, agency, or instrumentality of the United States Government.” 49 U.S.C. § 1131(a)(2)(A).

b. “Any investigation of an accident or incident conducted by the Safety Board directly or pursuant to the appendix to part 800 of this chapter (except major marine investigations conducted under 49 U.S.C. § 1131(a)(1)(E)) has priority over all other investigations of such accident or incident conducted by other Federal agencies.” (emphasis added) 49 C.F.R. § 831.5.

c. “The Board shall provide for appropriate participation by other departments, agencies, or instrumentalities in the investigation. However, those departments, agencies, or instrumentalities may not participate in the decision of the Board about the probable cause of the accident.” (emphasis added) 49 U.S.C. § 1131(a)(2)(A).

d. “If the Attorney General, in consultation with the Chairman of the Board, determines and notifies the Board that circumstances reasonably indicate that the accident may have been caused by an intentional criminal act, the Board shall relinquish investigative priority to the Federal Bureau of Investigation. The relinquishment of investigative priority by the Board shall not otherwise affect the authority of the Board to continue its investigation under this section.” 49 U.S.C. § 1131(a)(2)(B).
4. The Federal Bureau of Investigation (FBI) supports major accident investigations conducted by the NTSB (Colgan Air flight 3407); when a criminal act is suspected and lead status is turned over to the FBI, the NTSB supports the FBI (Austin, Texas plane crash into IRS facility). The FBI often provides Evidence Response Team (ERT) Unit.

5. Local law enforcement agencies may work in parallel with NTSB where local law enforcement has an interest (for example, single fatality, Boston Tunnel Collapse, July 2006, had FBI, U.S. Attorney’s Office, Massachusetts State Police, Massachusetts Attorney General’s Office, and other agencies involved), requiring coordination and investigation protocol(s).

III. ACCIDENT INVESTIGATION PROCEDURES

A. Initiation of NTSB investigations.

1. Report/news of accident collected from variety of sources: required notifications, citizen calls, state and local authorities, other federal agencies, news reports, etc.

2. Modal Office Director makes decision whether and how to launch—in reality, a group decision at Headquarters with Chairman, Managing Director (in effect the COO of agency), Office Director, and others participating.

3. If a “major” accident, a “Go Team” is launched. Includes: Board Member as agency on-scene spokesperson, Investigator-in-Charge (IIC), investigative specialists, Public Affairs, Family Assistance, and some support staff.

4. Launch in 1–2 hours via FAA jet or commercial travel.

B. An NTSB investigation, in addition to its statutory and regulatory purpose:

1. Assumes responsibility for the accident site, subject to the needs of first responders;

2. In most instances, preserves key components;

3. Normally results in an initial on-scene survey;

4. Provides an objective examination of facts and circumstances; and

5. Provides for release of wreckage under formal procedures.
C. Role of the NTSB IIC.

1. “The designated investigator-in-charge (IIC) organizes, conducts, controls, and manages the field phase of the investigation, regardless of whether a Board Member is also on-scene at the accident or incident site.” 49 C.F.R. § 831.8.

2. “The IIC has the responsibility and authority to supervise and coordinate all resources and activities of all personnel, both Board and non-Board, involved in the on-site investigation.” 49 C.F.R. § 831.8.

3. “The IIC continues to have considerable organizational and management responsibilities throughout later phases of the investigation, up to and including Board consideration and adoption of a report or brief of probable cause(s).” 49 C.F.R. § 831.8.

4. “The role of the Board Member at the scene of an accident investigation is as the official spokesperson for the Safety Board.” 49 C.F.R. § 831.8.

D. NTSB investigations and “parties” to those investigations.


2. “Parties shall be limited to those persons, government agencies, companies, and associations whose employees, functions, activities, or products were involved in the accident or incident and who can provide suitable qualified technical personnel actively to assist in the investigation.” (emphasis added) 49 C.F.R. § 831.11(a)(1).

3. “Other than the FAA in aviation cases, no other entity is afforded the right to participate in Board investigations.” (emphasis added) 49 C.F.R. § 831.11(a)(1). See 49 U.S.C. § 1132(c).

4. Customary practice to offer party status to other regulatory agencies such as PHMSA.

5. “Participants in the investigation (i.e., party representatives, party coordinators, and/or the larger party organization) shall be responsive to the direction of Board representatives and may lose party status if they do not comply with their assigned duties and activity proscriptions or instructions, or if they conduct themselves in a manner prejudicial to the investigation.” 49 C.F.R. § 831.11(a)(2).
6. Activity that can be considered a violation of party obligations and grounds for loss of party status:

a. Disreputable conduct within the investigation;

b. Spoilage, destruction, loss of evidence (along with likely prosecution);

c. Compromise/disclosure of the NTSB’s investigative activity or focus;

d. In public statements, purporting to address the findings, cause, probable cause, or contributing factors of a pending investigation (this includes statements by company headquarters, officers, or designated spokespersons);

e. Any other violation of the agreed upon “Statement [Certification] of Party Representative” to NTSB investigations and the associated “Information and Guidance for Parties to NTSB Accident and Incident Investigations.”

7. “No party to the investigation shall be represented in any aspect of the NTSB investigation by any person who also represents claimants or insurers. No party representative may occupy a legal position (see § 845.13 of this chapter). Failure to comply with these provisions may result in sanctions, including loss of status as a party.” 49 C.F.R. § 831.11(a)(3).

8. Law firms may need to create firewall during the fact-finding phase of an NTSB investigation—counsel supporting party “coordinator” or “representatives” and/or corporate entity as a party during NTSB investigation vs. counsel retained purely for purposes of litigation defense. This permits party representatives to have access to counsel during fact-finding without risk of violating party agreement with premature disclosures of investigative information to litigation counsel.

9. Typical parties to NTSB rail accident investigations: 1) pipeline operator, 2) equipment manufacturers (pipeline, components, control systems, etc.), 3) unions and/or labor representatives, 4) maintenance or operations contractors, 5) local government authorities, 6) law enforcement, 7) first responders, 8) state regulatory agencies, and 9) Federal regulator(s) (PHMSA).

10. Party status is not a right, and NTSB staff expects party representatives to focus on transportation safety as the primary concern during the fact-finding investigation. What staff needs:

a. Responsive, cooperative, technically accurate interactions.

b. Forthrightness—party expected to volunteer relevant information discovered by party, before or after the accident.
c. Truthfulness—an exceedingly, and to the credit of the transportation industry, remarkably rare problem.

d. Very important that counsel and client recognize that submissions and letters to the staff and Board Members are generally placed in the public docket.

E. Issues for counsel to parties (should consider these at the beginning of representation).

1. If there is the potential for criminal liability, will the law firm represent entity in both criminal and civil proceedings? Can it under state rules of professional conduct?

2. Who or what to represent—every witness in NTSB investigation entitled to “representation.” 49 C.F.R. § 831.7.

3. Should counsel represent individual company witnesses? Potential for conflicts of interest between company “employee” and company itself—classic ethics conundrum. “Could we lose the ability to represent the corporate party?”

4. Issues can apply to in-house counsel. Are communications with company personnel privileged for purposes of civil litigation under applicable law? Can in-house counsel serve as counsel for criminal matters? May in-house counsel prevent (counsel against) employee “client” from giving statement to law enforcement authorities such as FBI?

5. A careful reading of 18 U.S.C. § 1513(e) may be in order: “Whoever knowingly, with intent to retaliate, takes any action harmful to any person, including interference with the lawful employment or livelihood of any person, for providing to a law enforcement officer any truthful information related to the commission or possible commission of any Federal offense, shall be fined under this title or imprisoned not more than 10 years, or both.” (emphasis added)

6. A careful reading of 18 U.S.C. § 1001 is advisable when representing a party itself during the NTSB investigation.

F. Party Participation: Why? What is really involved?

1. Parties augment the limited resources of the NTSB, enable a more efficient accident investigation, make needed technical expertise readily available, and provide a ready “peer” or “expert” review of the factual information being collected.

   a. Technical expertise in “functions, activities, or products” involved in the accident. 49 C.F.R. § 831.11(a)(1). “[The] party coordinator must have sufficient status and authority within his/her organization to effect a complete and timely response with minimal need for higher approval or coordination in response to a request of the IIC.” Certification of Party Representative Form, section III.

   b. Parties assist in the fact-finding stage of the investigation, not in analysis or deliberations (other than through opportunity to make formal submissions under the rules). Parties may make submissions (including recommended findings), and even comment on the inputs and submissions by other parties.

   c. Illustration: “The Board shall provide for the participation of the Secretary of Transportation (FAA) in the investigation of an aircraft accident under this chapter when participation is necessary to carry out the duties and powers of the Secretary. However, the Secretary may not participate in establishing probable cause.” 49 U.S.C. § 1132(c).

   d. Party status places party representatives inside the fact-gathering activities, but does not alter the obligation of the party to provide accurate information in a responsive manner to NTSB investigators.

   e. NTSB staff recognizes fully that there may be tensions, or differing and conflicting organizational objectives, among the parties—staff is trained to be vigilant for this, manage the issues, and consider this in weighing inputs from the parties.

2. Parties “shall be responsive” to reasonable requests from investigators. 49 C.F.R. § 831.11(a)(2).

   a. Typical requests include: to view records; for copies of records, computers and/or hard drives; cell phone numbers of employees killed or involved in the accident; copies of written policies and procedures, employee interviews, maintenance records/logs, system schematics, equipment design drawings, employee disciplinary records, etc.
b. NTSB possesses broad subpoena authority: “...may conduct hearings to carry out this chapter, administer oaths, and require, by subpoena or otherwise, necessary witnesses and evidence.” 49 U.S.C. § 1113(a)(1).

c. Established practice and custom: No subpoena is required of parties; full cooperation is expected and customarily readily provided.

d. If subpoena required of a party, party may lose party status for lack of cooperation.

e. Proprietary information submitted to the NTSB must be appropriately marked. “Information submitted to the Board that the submitter believes qualifies as a trade secret or confidential commercial information subject either to the Trade Secrets Act or FOIA Exemption 4 [trade secrets and commercial or financial information] shall be so identified by the submitter on each and every page of such document.” 49 C.F.R. § 831.6(a)(2).

f. While the NTSB has authority to publicly disclose proprietary information, must engage in consultation process with the submitter prior to doing so, and uses the FOIA Exemption 4 consultation process as a model.

g. Expect similar markings for materials protected by International Traffic in Arms Regulations (ITAR) and Export Administration Regulations (EAR), and NTSB will consult with the party prior to release of such materials in the same manner as for proprietary information.

3. Consequence of prohibition against attorneys as party representatives.

a. Attorneys may not join the fact-finding activities on scene, even if retained solely to support the NTSB safety investigation. May not sit in on organizational meetings.

b. May counsel organization and party representative on matters related to investigation such as NTSB process, proprietary information, ITAR/EAR matters, and NTSB public hearing process.

c. NTSB rules will likely mean a division of responsibilities between legal support of party in NTSB investigation and immediate post-accident litigation preparation and defense.
d. Duration of limitation on party representatives sharing investigative information within company and with counsel for purposes of litigation—until the fact-finding phase of investigation is over (usually defined as all group factual reports completed or Technical Review completed—IIC determines).

e. NTSB Office of General Counsel routinely advises counsel for parties to NTSB investigations on the rules applicable to parties under Part 831—please feel free to make the call!

d. Bottom line: NTSB must protect the integrity of the independent NTSB investigative authority and processes—current congressional interest in party process.


1. NTSB has published a formal policy setting out a standard “Certification of Party Representative” and “Information and Guidance for Parties to NTSB Accident and Incident Investigations.”

2. “Certification of Party Representative” form must be signed by each party’s Party Coordinator and each Party Representative serving on an investigative group (regulatory bodies and law enforcement exempted).

3. Party Coordinator represents the entire party organization (company, association, or other entity) and signs the form “on behalf of” or “for” the entity.

4. All other party representatives sign only for themselves—this is a recent change based on party (stakeholder) feedback—but NTSB does insist on someone signing for the party organization and employees as a whole.

5. On form, party acknowledges:

   a. Its representatives and management have familiarized themselves with the “Guidance” and with 49 C.F.R. Part 831, “Accident/Incident Investigation Procedures.”

   b. Party’s representatives do not hold a legal or claim settlement function.

   c. Participation will be solely to assist the NTSB safety investigation and “not for the purposes of preparing for litigation.”

   d. Important constraint contained in the form and guidance, as well as NTSB rules, specifically, “limitations on the dissemination of investigative information.” Certification of Party Representative Form, para 2; see 49
C.F.R. § 831.13, “Flow and dissemination of accident or incident information.”

H. Time limit for bar on dissemination of information outside of the fact-finding investigation.

1. Again, duration of limitation on party representatives sharing investigative information within company and with counsel for purposes of litigation—until the fact-finding phase of investigation is over (usually defined as all group factual reports completed or Technical Review completed—IIC determines).

2. At any time, may readily get IIC approval to notify appropriate parts of company of urgent safety considerations that need to be addressed immediately with regulators, customers, manufacturers, etc.

3. Public statements related to possible findings and cause(s).
   a. Prohibited by party until the final report is issued.
   b. Do not want the matter litigated in the media while the NTSB investigation is ongoing, and do not want the public misled or “whiplashed.”
   c. Violations may be grounds for loss of party status.

I. Party participation in factual determinations.

1. Parties assist in factual development, not analysis.

2. Within an investigative group, a party representative may comment on findings, suggest additional lines of inquiry, and review and propose edits to the group factual report.

3. Party may comment on NTSB factual report(s).

4. Party may propose findings, probable cause and safety recommendations. 49 C.F.R. § 831.14, and also 49 C.F.R. § 845.27 following hearing.

J. Docket(s).

1. Docket of investigative records created, and investigative staff begin populating it as early as possible.

2. Records released into the “public docket.”
3. Records not released are retained in non-public docket. Remember to ask for both when seeking copy.

3. Public docket will be substantially populated for public hearing to ensure hearing exhibits are available.

4. Items rarely “removed” from public docket, although errata to exhibits are placed in the public docket.

IV. NTSB PUBLIC HEARINGS AND SPECIAL CONSIDERATIONS

A. What is an NTSB public hearing?

1. Primarily a fact-finding hearing with sworn testimony from witnesses having relevant information related to the accident or to the industry or regulatory structure underpinning the operations at issue in the accident investigation.

2. 49 C.F.R. Part 845, Rules of Practice in Transportation Accident/Incident Hearings and Reports—note: NTSB hearings normally open to the public, and in fact are webcast.

3. “Transportation accident hearings are convened to assist the Board in determining cause or probable cause of an accident, in reporting the facts, conditions, and circumstances of the accident, and in ascertaining measures which will tend to prevent accidents and promote transportation safety.” 49 C.F.R. § 845.2.

4. “Such hearings are fact-finding proceedings with no formal issues and no adverse parties and are not subject to the provisions of the Administrative Procedure Act.” 49 C.F.R. § 845.2.

5. Hearing generally occurs 2–6 months into investigation during the fact-finding stage of investigation.

B. Hearing process.

1. “The chairman of the board of inquiry [normally an assigned Board Member] shall designate as parties to the hearing those persons, agencies, companies, and associations whose participation in the hearing is deemed necessary in the public interest and whose special knowledge will contribute to the development of pertinent evidence.” 49 C.F.R. § 845.13(a).

   a. Parties to investigation generally are invited to be parties to the hearing, but that is not a requirement.
b. Parties to the investigation may decline to participate as parties to the hearing, but may still be compelled to provide witnesses via subpoena or otherwise. 49 U.S.C. § 1113(a). For subpoenaed witnesses, fees and travel expenses will be paid. 49 C.F.R. § 845.29.

2. “Parties shall be represented by suitable qualified technical employees or members who do not occupy legal positions.” 49 C.F.R. § 845.13(a).

3. Prehearing conference, usually the week prior to the hearing. “At such prehearing conference, the parties shall be advised of the witnesses to be called at the hearing, the areas in which they will be examined, and the exhibits which will be offered in evidence.” 49 C.F.R. § 845.23(a).

4. Witnesses are sworn in by the Hearing Officer. 49 C.F.R. § 845.21.

5. Sequence of questioning: Technical Panel (49 C.F.R. § 845.22—NTSB staff); Parties; and then Board of Inquiry. Chairman of the Board of Inquiry may give either group multiple rounds, but second round expected to be short. 49 C.F.R. § 845.25.

6. “Materiality, relevancy, and competency of witness testimony, exhibits, or physical evidence shall not be the subject of objections in the legal sense by a party to the hearing or any other person.” 49 C.F.R. § 845.25(b).

7. “Such matters shall be controlled by rulings of the chairman of the board of inquiry on his own motion.” 49 C.F.R. § 845.25(b).

8. “[The chairman] may exclude any testimony or exhibits which are not pertinent to the investigation or are merely cumulative.” 49 C.F.R. § 845.26.

9. In addition to no formal objections to the chairman’s rulings, there is no “record” to protect—the matters are politely and calmly discussed with the chairman in open session.

C. Hearing practice and technique.

1. Attorney may not be spokesperson, but may be at table and help formulate questions.

2. Attorney may, and usually does, help prepare witnesses.

3. While one party to a table preferred, usually two “parties” at table, with three people each.

4. Wireless or other connectivity may be useful.
5. Third member at table should usually be a non-attorney, and should be a technical person able to substitute as party spokesperson.

6. May want second attorney to sit behind a party witness as witness’ “representative” under Board rules. 49 C.F.R. § 845.24, Right of [to] representation.

7. Opportunity for proposed findings after the hearing, usually within 60 days. 49 C.F.R. § 845.27. Unless correcting testimony or record of hearing, most parties file one submission under section 831.14 after investigation’s Technical Review.

V. THE ACCIDENT REPORT

A. Staff does not publish the “report” of the Board in major accident investigations—the Board votes on the report.

1. Staff proposes draft report to the Board.

2. Vote generally held in Sunshine Act public meeting—“Board Meeting.”

3. Some lesser reports may be voted on in a “notation” process—a paper vote sanctioned by the Government in the Sunshine Act.

4. Staff delegated the authority to issue, in the name of the Board, certain lesser investigation briefs on lesser accidents and regional aviation accidents.

5. Board may, and frequently does, amend the final report in the Board Meeting.

6. Shortly after Board Meeting, approved findings, probable cause, and recommendations are publicly released, but not the full report.

   a. It may take 2–6 weeks for the report to be formatted, edited in accordance with Board member changes, and published.

   b. Staff may not issue preliminary or courtesy version before formal publication.

B. See limitations on use of investigation report in litigation below. Key rules:

1. Board accident investigation reports shall not be admitted into evidence in civil proceedings. 49 C.F.R. § 835.3(a). More below.

2. There is a distinction between factual report and Board “accident” report.
VI. THE NTSB INVESTIGATIVE PROCESS AND LITIGATING ENTITIES

A. Testimony of Board Employees.

1. “[I]n lawsuits or actions for damages and criminal proceedings arising out of transportation accidents when such testimony is in an official capacity and arises out of or is related to accident investigation,” the presumption is against testimony by NTSB employees, unless there is no other way for litigating parties to obtain factual information. See 49 C.F.R. § 835.1.

2. “The purpose of this part is to ensure that the time of Board employees is used only for official purposes, to avoid embroiling the Board in controversial issues that are not related to its duties, to avoid spending public funds for non-Board purposes, to preserve the impartiality of the Board, and to prohibit the discovery of opinion testimony.” 49 C.F.R. § 835.1.

3. “Section 701(e) of the FA Act and section 304(c) of the Safety Act preclude the use or admission into evidence of Board accident reports in any suit or action for damages arising from accidents. These sections reflect Congress’ ‘strong . . . desire to keep the Board free of the entanglement of such suits’, Rep. No. 93-1192, 93d Cong., 2d Sess., 44 (1974), and serve to ensure that the Board does not exert undue influence on litigation.” 49 C.F.R. § 835.3(a).

4. “The purposes of these sanctions would be defeated if expert opinion testimony of Board employees, which may be reflected in the views of the Board expressed in its reports, were admitted in evidence or used in litigation arising out of an accident . . . . [T]he use of Board employees as experts to give opinion testimony would impose a significant administrative burden on the Board’s investigative staff. Litigants must obtain their expert witnesses from other sources.” 49 C.F.R. § 835.3(a).


   b. Annual budget (although subject to special appropriations): $100.0 mil.

   c. It is a major consideration for Congress to contemplate an extra $2 mil annually for 11 additional investigators.

5. “…Board employees may only testify as to the factual information they obtained during the course of an investigation, including factual evaluations embodied in their factual accident reports.” 49 C.F.R. § 835.3(b).
6. “Manner in which testimony is given in civil litigation. (a) Testimony of Board employees with unique, firsthand information may be made available for use in civil actions or civil suits for damages arising out of accidents through depositions or written interrogatories. Board employees are not permitted to appear and testify in court in such actions.” 49 C.F.R. § 835.5(a).

a. “Normally, depositions will be taken and interrogatories answered at the Board’s office to which the employee is assigned, and at a time arranged with the employee reasonably fixed to avoid substantial interference with the performance of his duties.” 49 C.F.R. § 835.5(b).

b. “Board employees are authorized to testify only once in connection with any investigation they have made of an accident.” 49 C.F.R. § 835.5(c).

c. “Consequently, when more than one civil lawsuit arises as a result of an accident, it shall be the duty of counsel seeking the employee’s deposition to ascertain the identity of all parties to the multiple lawsuits and their counsel, and to advise them of the fact that a deposition has been granted, so that all interested parties may be afforded the opportunity to participate therein.” 49 C.F.R. § 835.5(c).

7. Prohibition against use of accident reports in deposition.

a. “Use of reports. (a) As a testimonial aid and to refresh their memories, Board employees may use copies of the factual accident report they prepared, and may refer to and cite from that report during testimony.” (emphasis added) 49 C.F.R. § 835.4(a).

b. “Consistent with section 701(e) of the FA Act and section 304(c) of the Safety Act, a Board employee may not use the Board’s accident report for any purpose during his testimony.” (emphasis added) 49 C.F.R. § 835.4(b).

c. NTSB counsel and NTSB employees will prevent efforts to get an accident report in effect admitted into evidence through the deposition testimony of an NTSB investigator or other staff member by having the employee read the report or testify regarding it.

8. Request for testimony in civil litigation.

a. “A written request for testimony by deposition or interrogatories of a Board employee relating to an accident shall be addressed to the General Counsel, who may approve or deny the request consistent with this part.” (emphasis added) 49 C.F.R. § 835.6(a).
b. “Such request shall set forth the title of the civil case, the court, the type of accident (aviation, railroad, etc.), the date and place of the accident, the reasons for desiring the testimony, and a showing that the information desired is not reasonably available from other sources.” (emphasis added) 49 C.F.R. § 835.6(a).

c. “Where testimony is sought in connection with civil litigation, the General Counsel shall not approve it until the factual accident report is issued (i.e., in the public docket).” 49 C.F.R. § 835.6(b).

d. “In the case of major accident investigations where there are multiple factual reports issued and testimony of group chairmen is sought, the General Counsel may approve depositions regarding completed group factual reports at any time after incorporation of the report in the public docket. However, no deposition will be approved prior to the Board’s public hearing, where one is scheduled or contemplated.” (emphasis added) 49 C.F.R. § 835.6(b).

e. “A subpoena shall not be served upon a Board employee in connection with the taking of a deposition in civil litigation.” (emphasis added) 49 C.F.R. § 835.6(d).

f. “If the Board employee has received a subpoena to appear and testify in connection with civil litigation, a request for his deposition shall not be approved until the subpoena has been withdrawn.” (emphasis added) 49 C.F.R. § 835.9(a).

B. Production of NTSB records in legal proceedings.

1. “Demands for material contained in the NTSB’s official public docket files of its accident investigations, or its computerized accident databases(s) shall be submitted, in writing, to the Public Inquiries Branch.” 49 C.F.R. § 837.3(a).

2. “Demands for information collected in particular accident investigations and made part of the public docket should be submitted to the Public Inquiries Branch or, directly, to [the NTSB] contractor.” 49 C.F.R. § 837.3(a).

3. “No subpoena shall be issued to obtain materials subject to this paragraph, and any subpoena issued shall be required to be withdrawn prior to release of the requested information.” 49 C.F.R. § 837.3(b).
4. “Other material. (a) Production prohibited unless approved. Except in the case of the material referenced in § 837.3, no employee or former employee of NTSB shall, in response to a demand of a private litigant, court, or other authority, produce any material contained in the files of the NTSB (whether or not agency records under 5 U.S.C. 552) or produce any material acquired as part of the performance of the person’s official duties or because of the person’s official status, without the prior written approval of the General Counsel.” 49 C.F.R. § 837.4(a).

5. “Each demand must contain an affidavit by the party seeking the material or his attorney setting forth the material sought and its relevance to the proceeding, and containing a certification, with support, that the information is not available from other sources, including Board materials described in § 837.3 and part 801 of this chapter.” (emphasis added) 49 C.F.R. § 837.4(b)(2).

6. “The General Counsel shall advise the requester of approval or denial of the demand, and may attach whatever conditions to approval considered appropriate or necessary to promote the purposes of this part.” 49 C.F.R. § 837.4(b)(4).
Safety After *Deepwater Horizon*

*Mark L. Farley*
Introduction

- 2010 was challenging year for energy industry
  - Feb. 2010 – Kleen Energy
    - Natural gas cleanout of new fuel-gas piping; 6 fatalities
  - Apr. 2010 – Tesoro Refinery
    - Heat exchanger failure led to explosion and fire; 7 fatalities
  - Apr. 2010 – Massey Energy
    - Methane explosion; 29 fatalities
  - Apr. 2010 – Deepwater Horizon
    - Blowout during well completion activities; 11 fatalities
Impact of *Deepwater Horizon*

- **Watershed event for upstream operations**
  - Will have impact similar to *Piper Alpha*
  - Ultimately will prove to be single most expensive incident in energy industry
  - Aside from direct cost of incident which likely will exceed $10-15 billion, companies involved in incident lost billions of dollars in market capitalization
  - Will affect upstream operations in the same manner as BP Texas City impacted downstream operations
  - Department of Interior aggressively moving to increase off-shore safety oversight and enforcement

- **Occurs at time of continued scrutiny of corporate oversight of safety, health, and environmental systems and performance**
  - Investigation of incident ultimately will lead to questions on compliance programs and management systems oversight
Oversight of EHS Performance

Board of Directors

Management Review

ACT

PLAN

Culture and Values

Risk Identification and Mitigation

EHS Management Systems

CHECK

DO

Performance Evaluation

Implementation and Operation
CSB Will Conduct Root Cause Investigation

- Congressional request cited CSB's unique position to address BP's safety culture and practices because of BP Texas City investigation.

- What to expect from CSB:
  - Investigation as opportunity to renew focus on safety culture and oversight.
  - View of upstream operations through Baker Panel lens.
  - Also expect CSB to make recommendations with respect to regulatory scheme.
    - CSB held public hearing on December 15, 2010 on how off-shore safety is regulated in other countries.
    - Possible push for concept of “safety case”.
  - Possible focus on contractor oversight.
    - Assuring that third parties (contractors, non-operating joint ventures) are properly managing risk.
Possible CSB Repeat Themes

- **Process Safety Leadership**
  - Process safety not a core value
  - Ineffective leadership regarding process safety performance
  - Emphasis on personal safety but not process safety

- **Employee Empowerment**
  - Absence of positive / trusting environment with effective lines of communication

- **Incorporation of Process Safety into Decision-Making**
  - Decentralized management system without clearly defined process safety expectations, responsibilities, or accountabilities
  - Lack of accountability for process safety performance
Possible CSB Repeat Themes (cont.)

- **Correction of Identified Deficiencies**
  - Identified process safety deficiencies not always addressed promptly and tracked to correction

- **Corporate Oversight**
  - Neither executive management nor its refining line management has ensured the implementation of an integrated, comprehensive, and effective process safety management system

- **Board Oversight**
  - Board has not ensured, as a best practice, that management has implemented an integrated, comprehensive, and effective process safety management system
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Mark Farley’s practice concentrates on internal investigations and crisis response. He advises clients with respect to process safety incidents, workplace fatalities, government inspections, and enforcement. He also has an extensive regulatory counseling practice. Farley was one of the lead attorneys supporting the work of the BP U.S. Refineries Independent Safety Review Panel, which investigated corporate safety culture and oversight at BP’s North American refineries on behalf of an independent panel of experts.

Farley directs Pillsbury’s Health and Safety Working Group, a safety issues and benchmarking forum designed for corporate safety managers and lawyers. Over 20 companies presently are members of the Working Group.
NOTES
STATE COMMISSIONERS PANEL
Western Energy Bar Association  
San Francisco, California  
February 25, 2011  

Outline of Remarks by Susan K. Ackerman  
Commissioner, Oregon Public Utility Commission  

I. State Decision Making, Despite Uncertainty  

Biggest source of uncertainty is climate change, the potential for greenhouse gas regulation, and environmental rulemakings at the Environmental Protection Agency (EPA) that affect electric generation. E.g., see FERC charts of (1) Bloomberg’s SO2 and NOX Seasonal allowance spot prices, and (2) Chicago Climate Exchange CO2 Index. (charts provided with materials, or go to: http://www.ferc.gov/market-oversight/mkt-snp-sht/2011/02-2011-snapshot-west.pdf)  

A. EPA Rulemakings  

At the federal level, current source of uncertainty are the EPA rulemakings affecting the existing and new electric generation fleet:  


(3) Power Plant Cooling Water Intake Structure Rule under section 316(b) of the Clean Water Act:  
(4) Interstate Transport Proposed Rule (to replace the Clean Air Interstate Rule)(applicable only in the eastern United States):
http://www.gpo.gov/fdsys/pkg/FR-2010-08-02/pdf/2010-17007.pdf#page=1

B. Oregon Legislative Activities:

(1) Renewable Portfolio Standards: Oregon Revised Statutes Chapter 469A (469A.005 – 469A.205); See: http://www.leg.state.or.us/ors/469a.html

Qualifying renewable energy sources include: wind, solar photovoltaic and solar thermal energy, wave, tidal and ocean thermal energy, geothermal energy, and certain biomass facilities and certain small hydro facilities. ORS 469A.025.

Standards for renewable electricity sold (by large electric utilities) to retail electric customers: 15% of sales in 2015; 20% of sales in 2020; and 25% of sales in 2025 and thereafter. ORS 469A.052. Separate (smaller) standards for small electric utilities. ORS 469A.055. Statutes contain an exemption from complying with the standards when the incremental costs of compliance exceed 4% of utility’s annual revenue requirement.

(2) Oregon Solar “Feed In” Tariff: Oregon Revised Statutes Chapter 757 (757.360 – 757.380); See: http://www.leg.state.or.us/ors/757.html

Directs the OPUC to conduct a pilot program to demonstrate the “use and effectiveness of volumetric incentive rates for electricity delivered from solar photovoltaic energy systems that are permanently installed in this state by retail electricity consumers [.]” ORS 757.365(1). The commission has authority to limit the pilot so that “the rate impact of the pilot program for any customer class does not exceed 0.25 percent of the electric company’s revenue requirement for the class [.]” ORS 757.365(7).

OPUC Order Implementing the pilot program: Order No. 10-198 (May 28, 2010); See http://apps.puc.state.or.us/orders/2010ords/10-198.pdf
C. Early Closure of PGE’s Boardman Coal Plant

Portland General Electric (PGE) conducted an integrated resource planning process under the OPUC’s IRP rules. The single largest issue was the question of whether the utility should retrofit the company’s coal plant located in Boardman, Oregon, to comply with Oregon’s EQC-approved (at a total projected cost of $510 million and keep the plant running until 2040, or alternatively install a more limited suite of retrofits and close earlier. Coalition led by the Sierra Club sought closure of the Boardman plant in 2014.

The PUC agreed with the utility’s plan to install a more limited retrofit and close by the end of 2020: (1) lowest cost option; (2) mitigates risk of future carbon regulation; (3) mitigates risk of acquiring replacement resources in time, and (4) provides flexibility to test new technologies. OPUC Order No. 10-457 (November 23, 2010) (page 15); See http://apps.puc.state.or.us/orders/2010ords/10-457.pdf

II. “Smart Grid” and State Decision Making:


(2) Docket No. UM 1460 (Development of Smart Grid Objectives and Action Items for 2010-2014)(ongoing). See: http://apps.puc.state.or.us/edockets/docket.asp?DocketID=15928


B. Portland General Electric’s AMI Investments:

PGE receives regulatory authority to install solid-state electronic meters with fixed two-way communications on the premises of all customers. The
project had a projected net present value benefit to customers of $33 million over 20 years, with the analysis assuming accelerated depreciation of existing meters and operational savings to the utility only. OPUC Order No. 08-245 (copy provided with materials, or go to: http://apps.puc.state.or.us/orders/2008ords/08-245.pdf)

Consumers (Citizens’ Utility Board) opposed on the grounds that the technology was not mature, that the savings were too slim to inspire confidence, and that other (future) benefits such as demand response tariffs or direct load control options require additional upgrades & costs.

Commission approved the company’s plan to move forward, based on the utility’s commitments to pursue other benefits from the meters, but stated that future prudence reviews were not ruled out.

III. Rates & Consumer Costs

A. For energy consumers, a parade of horribles:
   - Aging infrastructure that needs replacement (gas & electric)
   - Lack of new investment in generation and transmission (particularly transmission) in the last two decades & need for new investment as economy strengthens
   - Climate concerns and push for more costly but cleaner resources
   - Smart grid investments
   - Reliability standards & cyber security concerns: utility investment required.

B. Bottom line for consumers: frequent rate adjustments and increasing consumer costs, at levels that exceed inflation and expectations.

IV. The Graying Workforce

Not just a problem for the utilities; a problem for regulators, too.
BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 48

In the Matter of

PORTLAND GENERAL ELECTRIC COMPANY, ORDER


DISPOSITION: PLAN ACKNOWLEDGED WITH REQUIREMENTS

I. INTRODUCTION

Portland General Electric Company (PGE or the Company) seeks acknowledgment of its 2009 Integrated Resources Plan (IRP) and 2010 Addendum. In this order we acknowledge the plan subject to certain requirements that are discussed below.

A. IRP Guidelines

We require regulated energy utilities to engage in integrated resource planning and to file an IRP every two years. We review the filed plans to determine whether they adhere to our IRP guidelines and either “acknowledge” them, or return to the utility with comments. Acknowledgement does not guarantee favorable ratemaking treatment, but means that the plan seems reasonable at the time of Commission review.

The Commission has adopted thirteen IRP guidelines. The first guideline includes substantive requirements under which the utility must (1) evaluate all resources on a consistent and comparable basis; (2) consider risk and uncertainty; (3) have as its primary goal the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers; and (4) draft a plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies.¹ The remaining twelve guidelines include procedural requirements that provide direction on how to prepare and update the plan, and other provisions that address specific resources such as transmission and conservation.

¹ Docket UM 1056, Order No. 07-002 (Jan 8, 2007).
B. Effect of Acknowledgement of an IRP on Future Ratemaking Actions

The Commission’s role in reviewing an IRP is to determine whether the IRP meets the substantive and procedural guidelines in Order Nos. 89-507 and 07-002. The Commission generally does not address the need for specific resources, but rather determines whether the utility has proposed a portfolio of resources to meet its energy demand that presents the best combination of cost and risk. Commission acknowledgement of an IRP means only that the Commission finds that the utility’s preferred portfolio is reasonable at the time of acknowledgement.

In Order No. 89-507, the Commission described its role in reviewing and acknowledging a utility’s least-cost plan:

The establishment of Least-Cost Planning in Oregon is not intended to alter the basic roles of the Commission and the utility in the regulatory process. The Commission does not intend to usurp the role of utility decision-maker. Utility management will retain full responsibility for making decisions and for accepting the consequences of the decisions. Thus, the utilities will retain their autonomy while having the benefit of the information and opinion contributed by the public and the Commission.

* * * * *

Acknowledgment of a plan means only that the plan seems reasonable to the Commission at the time the acknowledgment is given. As is noted elsewhere in this order, favorable rate-making treatment is not guaranteed by acknowledgment of a plan.

This order does not constitute a determination on the ratemaking treatment of any resource acquisitions or other utility expenditures. As a legal matter, the Commission must reserve judgment on all ratemaking issues. Notwithstanding these legal requirements, we consider the integrated resource planning process to complement the ratemaking process. In ratemaking proceedings, in which the reasonableness of resource acquisitions is considered, the Commission will give considerable weight to utility actions that are consistent with acknowledged plans. A utility is expected to explain actions they take that are inconsistent with Commission-acknowledged plans.

C. Procedural History

PGE filed its 2009 Integrated Resource Plan on November 5, 2009. In that filing, PGE proposed to invest over $500 million to retrofit its Boardman coal-fired plant

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2 See Order No. 07-002 at 25.
3 See Id. at 16.
4 See Order No. 89-507 at 6, 11 (Docket UM 180). The Commission affirmed these principles in Docket UM 1056. See Order No. 07-002 at 24.
(Boardman) to meet requirements of the Oregon Environmental Quality Commission’s (EQC) Regional Haze Plan and operate the plant until 2040. Following a prehearing conference on December 1, 2009, an administrative law judge issued a procedural schedule that included a presentation to the Commission on January 19, 2010.

On January 14, 2010, PGE asked the Commission to postpone PGE’s presentation to the Commission scheduled for January 19, 2010. PGE explained that it intended to meet with stakeholders to assess whether PGE could devise alternatives to its proposal to retrofit the Boardman plant and operate it until 2040 in a manner that would be acceptable to the EQC and other stakeholders. On January 15, 2010, the Commission stayed all proceedings in this docket.

On April 9, 2010, PGE filed an addendum to its IRP that included a revised operating plan for Boardman. Following the adoption of a new procedural schedule, however, we delayed proceedings to allow PGE, intervenors, and Commission Staff (Staff) the opportunity to consider whether certain EQC and Department of Environmental Quality (DEQ) actions might impact PGE’s revised IRP. Staff noted that EQC would soon consider (1) PGE’s request to modify the EQC’s 2009 Regional Haze Plan in a manner that would allow PGE to pursue its revised operating plan for Boardman, and (2) DEQ’s recommendation that the EQC direct DEQ to base analysis regarding potential revisions to the Regional Haze Plan on a range of operating options for Boardman, rather than on the single operating plan underlying PGE’s proposed rule change.

A final procedural schedule was subsequently adopted that required PGE to file reply comments analyzing three DEQ-proposed alternatives for Boardman retrofits and operation and responding to earlier filed comments. The procedural schedule gave intervenors the opportunity to respond to PGE’s supplemental comments, PGE the opportunity to file reply comments on September 27, 2010, and directed Staff to file recommendations and a proposed order. On September 21, 2010, the Commission issued a Bench Request directing PGE to file additional analysis regarding the three DEQ retrofit and operation scenarios, and allowing intervenors the opportunity to reply to PGE’s response.

In sum, the procedural schedule in this docket included multiple opportunities for the parties to address PGE’s IRP. This included three rounds of written comments; three public meetings; two technical workshops (to address Cascade Crossing and Boardman); and public comment hearings in Portland and Boardman, Oregon.

D. Parties and Comments

The following entities intervened in this proceeding: the Northwest and Intermountain Power Producers Coalition; the Citizens’ Utility Board of Oregon (CUB); NW Energy Coalition (NWEC); Ecumenical Ministries of Oregon (EMO); Oregon Environmental Council, PacifiCorp, dba Pacific Power; Iberdrola Renewables, Inc.; Oregon Department of Energy (ODOE); the Sierra Club, Columbia Riverkeeper, Friends of the Columbia Gorge, and the Northwest Environmental Defense Center; Renewable Northwest Project (RNP); Physicians for Social Responsibility; Northwest Pipeline GP; the City of
Portland; Industrial Customers of Northwest Utilities; Turlock Irrigation District; International Brotherhood of Electrical Workers, Local 125 (IBEW Local 125); Northwest Food Processors Association; Portland Metropolitan Building Owners and Managers Association; Oregon Forest Industries Council, Oregon Cattlemen’s Association; Willard Rural Association; Power Resources Cooperative; Salem Area Chamber of Commerce (Salem Chamber); Strategic Economic Development Corporation; Clackamas County Business Alliance; Columbia Corridor Association; Associated Oregon Industries; Westside Economic Alliance; Portland Business Alliance; Association of Oregon Counties; the Wilsonville Chamber of Commerce; SEDCOR, Morrow County; Oregonians for Food and Shelter; Oregon Farm Bureau Federation; Community Action Partnership of Oregon; and Pareto Energy, LTD.

In addition, well over one thousand people filed written public comments with the Commission. Many of the comments are form letters that the Commission received at the public comment hearings held in Boardman and Portland, Oregon. More than 800 form letters support closure of Boardman by 2014. More than 250 form letters support operating Boardman through 2040, or at the minimum, through 2020.

II. DISCUSSION

A. Load Forecast and Resource Need

1. Parties’ Positions

The Sierra Club, Columbia Riverkeeper, Friends of the Columbia Gorge, and the Northwest Environmental Defense Center (NEDC) (collectively referred to as the Coalition), as well as NW Energy Coalition (NWEC); Willard Rural Association (WRA); and Ecumenical Ministries of Oregon (EMO) argue that PGE has overstated its reference case load forecasts and, therefore, its future energy and capacity needs. Many of these parties argue that this has a direct bearing on the options for shutdown of Boardman.

The Coalition, NWEC, and EMO all argue that PGE’s load forecasts are inconsistent with recent historical load growth in PGE’s service territory. The Coalition emphasizes that since 2000 the yearly growth in sales has exceeded PGE’s March 2009 projected growth rate of 1.9 percent per year for 2010 through 2030 only once. NWEC points to analysis by WRA that shows PGE’s load growth has been essentially flat over the past ten years and questions why the next ten years should be projected to be any different.

The Coalition urges the Commission to consider the differences between the Company’s March 2009 load forecasts used in the IRP and its more recent December 2009 load forecasts. The Coalition provides the year-by-year reductions in peak load and annual average energy and argues that the forecast reductions are significant and material. For

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5 Coalition’s Sept 1, 2010 Comments at 17-18 (Schlissel Technical Consulting, Inc. (Schlissel))
6 NWEC’s May 14, 2010 Comments at 5.
7 Coalition’s Sept 1, 2010 Comments at 16-17 (Schlissel).
example, the December 2009 forecasts show reductions of 157 megawatts (MW) in peak load and 152 average MW (MWA) in annual energy during 2015.

NWEC, the Coalition, and EMO all argue that PGE’s load forecasts are inconsistent with those of independent forecasters. NWEC takes issue with PGE’s comparison of its projected load growth of 1.72 percent for the period 2010–2015, assuming a continuation of historic levels of embedded energy efficiency, to the Northwest Power and Conservation Council’s (NPCC) Draft Sixth Plan projected load growth for Oregon of 1.96 percent. NWEC argues that the appropriate comparison is to an adjusted load growth forecast for Oregon of 0.47 percent per year. NWEC calculated this adjusted growth rate after subtracting the NPCC’s forecast of future energy efficiency from its medium-load forecast.\(^8\)

Staff argues that PGE’s reference case forecast is too high because it does not adequately account for the continued effect of the 2007–2009 recession.\(^9\) Staff contends that the NPCC’s Final Sixth Plan projected annual load growth of 1.4 percent for 2010–2015 is more reasonable than PGE’s projected 1.7 percent. Staff indicates that this level of growth is consistent with PGE’s low-case forecasts. Staff also attempts to put this adjustment into the context of PGE’s overall resource need. Staff indicates that under PGE’s reference case load forecast, with Boardman operating, PGE is short 952 annual MWA of energy in 2016. Staff notes that shutting down Boardman in late 2015 would push that deficit to 1,266 MWA in 2016. Updating PGE’s model to include its low-load scenario, with Boardman shutdown in 2015, the resource deficit would be 1,158 MWA in 2016. Under this low load scenario, the winter and summer capacity deficits are 1,979 MW and 1,788 MW, respectively, in 2016. Staff asserts that these resource gaps under the low load forecasts are still significant and would be challenging to fill if Boardman were shut down in 2016.

PGE responds that its forecasts appropriately incorporate data from both the recent and distant historical past. PGE acknowledges that load growth exceeded the forecasted average rate of 1.9 percent only once since 2000, but adds that that historic annual growth exceeded 1.9 percent during sixteen of the last twenty-eight years.\(^10\) PGE also notes that the differences between its March 2009 and December 2009 load forecasts can be explained in part by different accounting treatment of Senate Bill 838 energy efficiency and by recession-driven reductions in a very limited set of large industrial customer loads. PGE emphasizes that the load reduction of 152 average MW in 2015 needs to be put into the context of PGE’s overall forecasted resource need of 873 average MW in 2015.\(^11\)

2. Commission Resolution

We agree that PGE’s reference case load forecast for the 2010-2015 period is likely too high because it fails to account for the lingering effect of the 2007-2009 recession. We also agree with PGE and Staff that we must consider this within

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\(^8\) NWEC’s May 14, 2010 Comments at 5.
\(^10\) PGE’s Sept 28, 2010 Comments at 14.
\(^11\) Id at 13.
the context of PGE’s overall resource needs. Even under the low-load scenarios, and even if Boardman keeps operating, PGE has significant resource needs. PGE’s future resource needs are driven not just by growing demand, but also by the expiration of key power purchase contracts held by the Company.

In an IRP, we require utilities to evaluate alternative resource portfolios across a wide range of potential futures, including those with low, medium, and high demand for electricity. PGE’s range of load forecasts appears reasonable. PGE evaluated its resource portfolios across this range of load forecasts. Our finding that PGE’s reference case load forecast is likely overstated does not change our decision regarding Boardman and the best resource options for ratepayers, as discussed in the next sections.

We do not agree with NWEC that PGE’s projected average annual growth in load is significantly higher than that projected by NPCC. PGE correctly compares its forecasts with embedded energy efficiency to NPCC’s “frozen efficiency” forecasts. This “apples-to-apples” comparison is consistent with the IRP objective of measuring resource need prior to the addition of any demand- or supply-side resource actions. More fundamentally, we agree with PGE that this comparison is founded on the faulty premise that the Pacific Northwest is one large homogeneous region in terms of economics and demographics. As PGE points out, for example, its service territory is more urban and has more high-technology customers than the rest of the region. There are many good reasons why load growth rates will differ by area within a state and within the region.

B. Natural Gas Price Forecast Method

1. Parties’ Positions

The Coalition argues that PGE uses unreasonably high natural gas prices in its IRP modeling and biases the results in favor of continued operation of the Boardman plant and against the early shutdown scenarios. The Coalition compares PGE’s reference case natural gas prices forecasts to those of the NPCC, Staff, and the U.S. Energy Information Administration (EIA).\(^\text{12}\) The Coalition argues that it is critically important that planning analyses and decisions be based on current information. The Coalition recommends that the Commission require PGE to update its reference case natural gas price forecast before accepting the modeling results.\(^\text{13}\)

Staff agrees also with the Coalition that PGE’s reference case natural gas price is slightly overstated. Staff argues that PGE’s forecasting methodology is flawed because the Company only relies on a single source, PIRA Energy Group, for its long-term natural gas price forecast. Staff also argues that PGE’s short-term price forecast is flawed because it only relies on NYMEX futures prices, and does not include fundamentals based price forecast. Staff recommends that the Commission require PGE to obtain natural gas prices forecast from multiple third party sources.

\(^\text{12}\) Coalition’s May 19, 2010 Comments at 4-10 (Schlissel).
\(^\text{13}\) Coalition’s Sept 1, 2010 Comments at 12 (Schlissel).
In response to Staff’s analysis and recommendations, PGE states that it is unaware of any bias in PIRA’s forecasts. PGE also notes that it appears that Staff compared the IRP’s August 2009 PIRA forecast to the 2010 forecasts of EIA and Wood MacKenzie Research and Consulting. PGE notes that comparing PIRA’s 2009 forecast to these 2010 forecasts is misleading because most forecasters reflected a downturn in prices for 2010. With respect to Staff’s observations regarding PGE’s use of NYMEX future prices for near-term forecasting, PGE maintains that using prices from actual trades reflects the most current and accurate information that is available in the market.

2. Commission Resolution

We agree that PGE’s reference case natural gas price forecast is likely overstated because of the lingering effect of the 2007-2009 recession and recent developments related to shale gas production. In IRPs, we require utilities to evaluate alternative resource portfolios across a wide range of potential futures, including those with low, medium, and high prices for natural gas. PGE’s range of natural gas prices appears reasonable. PGE’s natural gas forecasts satisfy IRP Guidelines 1b and 4g. Our finding that PGE’s reference case natural gas prices are likely overstated does not change our decision regarding Boardman. We decline to require PGE to use multiple forecasting sources in future IRPs. We expect PGE to continue to update its natural gas price forecasts in future IRPs and IRP Updates.

C. Boardman

1. Parties’ Positions

PGE requests that the Commission acknowledge continued coal-fired operations at Boardman as outlined in the Company’s BART III proposal submitted to the DEQ on July 30, 2010. PGE argues that its BART III compliance actions, when combined with its energy efficiency, renewable energy, and other resource actions, comprise a portfolio of resources that provide the best combination of cost and associated risk for ratepayers over the IRP planning period.

As part of its BART III proposal, PGE proposes the following compliance actions to meet Oregon Regional Haze Plan and Oregon Utility Mercury Rule standards:

1. Installation of low-nitrogen oxide (NOx) burners with a modified overfire air control system in July 2011;

2. Installation of mercury controls in July 2012;

3. Installation of selective non-catalytic reduction (SNCR) in July 2014;

4. Operation using reduced sulfur coal beginning in July 2014;

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14 PGE’s Nov 1, 2010 Comments at 13-14.
15 Id.
5. Installation and pilot testing of a Dry Sorbent Injection (DSI) system in July 2014; and

6. Cessation of coal-fired operations at the end of 2020.16

Contingent on the results of the DSI pilot testing, PGE would commit to meeting a 0.4 lb. sulfur dioxide (SO₂) per million British thermal unit (MMBtu) emission limit through 2020, using DSI. If the pilot testing demonstrated that operating the plant with DSI technology is incapable of achieving this level of SO₂ emissions without triggering an increase in emissions of particulate matter, then PGE proposes to meet an alternative SO₂ limit established by DEQ procedure based on the DSI testing. It is unclear whether the EQC will adopt PGE’s BART III proposal.

PGE analyzed its BART III proposal, as well as three alternative DEQ options, using its IRP portfolio modeling. DEQ Option 3 calls for installation of a low-NOx burner system in 2011 and mercury controls in 2012; but would require the shutdown of Boardman by late 2015 or early 2016. DEQ Option 2 is similar to PGE’s BART III proposal, but would result in cessation of coal-fired operations in 2018. DEQ Option 1 includes the low-NOx burner system in 2011, the mercury controls in 2012, adds installation of semi-dry flue gas desulfurization (dry scrubbers) in 2014 to control SO₂ emissions, and would cease coal-fired operations at Boardman in 2020. Based on its IRP modeling, PGE concludes that its BART III resource portfolio is both less costly and less risky than the three DEQ options.17

PGE contends that its BART III proposal is superior to these alternatives, and observes that among the early closure options, those that keep Boardman operating longer perform better. PGE suggests that DEQ Option 1 is unacceptable because the dry scrubbers are a very costly additional layer of control. PGE questions the regulatory implementation of DEQ Option 2, which does not include pilot testing of the DSI technology, and therefore fails to account for the possibility that achieving the SO₂ emission limit may simultaneously trigger a violation of particulate matter limits. Finally, PGE argues that DEQ Option 3, which would shutdown Boardman in late 2015 or early 2016, offers an extremely poor outcome for ratepayers in terms of cost and risk.

PGE concedes that its BART III proposal does not guarantee that future regulation of hazardous air pollutants or the resolution of pending litigation in United States District Court will not require PGE to install additional controls at Boardman prior to 2020. However, PGE no longer makes its acknowledgment request contingent upon obtaining a reasonable assurance by March 31, 2011 that it will be able to operate Boardman through 2020 without installing additional emission control technologies. PGE asks the Commission to acknowledge its BART III compliance actions despite these risks.18

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16 PGE’s Aug 10, 2010 Comments at 8-9.
17 Id. at 10-13.
18 Id. at 16.
PGE does, however, make its acknowledgement request contingent on EQC approval of its BART III proposal by March 31, 2011. In the event that the EQC fails to approve BART III, PGE requests acknowledgement of a backstop proposal. PGE's backstop is full implementation of BART I controls and continued operation of Boardman through at least 2040. Based on incremental rate impact analysis, PGE concludes that the BART I emission controls, as modeled in the Diversified Thermal with Green portfolio, outperform the three DEQ early shutdown options and is the second best option for ratepayers.\(^{19}\)

PGE argues that the backstop proposal acknowledgment is necessary because any delay in ordering the equipment needed to implement BART I will subject ratepayers to increased costs and risks associated with a compressed Engineering, Procurement and Construction (EPC) schedule and with a potential temporary shutdown of Boardman in 2014 as a result of failure to install the dry scrubbers by the BART I deadline.\(^ {20}\) PGE has continuously emphasized throughout this proceeding that failure to comply with the Oregon Regional Haze Plan is not an option. The Boardman plant must meet the emissions requirements by either installing the required controls or by ceasing coal-fired operations.

In its comments on Staff's proposed draft order, PGE states that it asked DEQ to reopen the record in the ongoing DEQ rulemaking proceeding to allow PGE to make a refinement to the BART III plan. PGE noted that CUB, RNP, Angus Duncan,\(^ {21}\) Oregon Environmental Council (OEC), and NWEC support the refined BART III plan. PGE also informed the Commission that PGE has committed to work with stakeholders in the Company's next IRP to evaluate and consider carbon-reduction options for replacement power.\(^ {22}\)

The following parties submitted opening comments that largely support PGE's BART III proposal without qualification: Morrow County, Portland Business Alliance, Oregon Forest Industries Council, Associated Oregon Industries (AOI), Oregon Cattlemen's Association, the Community Action Partnership of Oregon, Strategic Economic Development Corporation, Association of Oregon Counties, Salem Area Chamber of Commerce (Salem Chamber), Wilsonville Chamber of Commerce, Clackamas County Business Association, Columbia Corridor Association, Oregon Farm Bureau, and Oregonians for Food and Shelter. In their reply comments, AOI, Salem Chamber, West Side Economic Alliance, Oregon Forest Industries Council, Association of Oregon Counties, Columbia Corridor Association, and Morrow County strongly suggest the Commission acknowledge PGE's 2040 option as a backstop alternative.

IBEW Local 125 urges the Commission to acknowledge operation of the Boardman plant until 2040 and beyond, with nothing less than 2020 as a backstop.

\(^{19}\) Id. at 15.
\(^{20}\) Id. at 5; IRP Addendum at 124 (April 9, 2010).
\(^{21}\) Angus Duncan, an interested person in this docket, is the President and CEO of the Bonneville Environmental Foundation.
\(^{22}\) PGE's Oct 29, 2010 Comments at 3.
The Physicians for Social Responsibility implored the Commission to consider the serious health concerns and costs associated with continued operation of Boardman beyond 2014.

Other parties submitted comments that challenge PGE’s analysis of the Boardman compliance options and contained alternative recommendations for the Commission. We summarize these parties’ positions below, as well as some reply comments.

a. The Coalition

The Coalition characterizes PGE’s proposed compliance actions as a plan to transition off coal in 2020—or never.23 The Coalition argues that PGE’s proposed BART III is virtually identical to its BART II proposal that was already rejected by the EQC. The Coalition recommends that the Commission order PGE to start over and develop a balanced and reasonable outcome for Boardman that is consistent with clean air laws and Oregon’s greenhouse gas emissions reduction goals.

The Coalition argues that PGE’s own modeling shows that compared to PGE’s BART I backstop both DEQ Option 2, with early shutdown in 2018, and DEQ Option 3, with early shutdown in late 2015, are lower-cost alternatives.24

The Coalition further argues that PGE uses unreasonably high natural gas prices in its IRP modeling and biases the results in favor of continued operation of Boardman and against early shutdown scenarios.25 The Coalition concedes that it did not prepare its own natural gas prices forecasts, but instead relied upon the forecasts provided in the record of this proceeding by other parties. However, the Coalition argues that it is critically important that planning analyses and decisions be based on current information. The Coalition recommends that the Commission require PGE to update its reference case natural gas price forecast before accepting the modeling results.

The Coalition also believes that PGE has overstated its energy and capacity needs.26 Again, emphasizing the importance of current information, the Coalition argues that PGE should use its December 2009 peak and average energy load forecasts in its IRP modeling. The Coalition argues that the differences between the December 2009 forecasts and the March 2009 forecasts used in PGE’s IRP modeling are significant and material to the development of PGE’s IRP Action Plan.

The Coalition opines that contrary to PGE’s assertions, a natural gas-fired combined-cycle combustion turbine (CCCT) can be built in two, to two-and-a-half years.27

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23 Coalition’s Sept 1, 2010 Comments at 1-2.
24 Id. at 2-6 (Schlissel).
25 Id. at 7-16.
26 Id. at 16-18.
27 Id. at 18.
Given actual construction times, the Coalition believes that a CCCT could be built and ready to replace Boardman by 2016.

The Coalition states that PGE has completely failed to evaluate the economic costs and benefits of replacing some or all of Boardman’s output with a mid-term power purchase agreement (PPA). According to the Coalition a mid-term PPA strategy could be used to implement DEQ Options 2 & 3.

The Coalition points to PGE’s IRP modeling which shows Boardman operating as an intermediate-load resource in the future, and questions the prudence of investing in emissions controls at the plant if it would no longer operate as a baseload resource.

b. The Joint Parties

CUB, RNP, NWEC, OEC, Angus Duncan, EMO, Sierra Club, and NEDC, (collectively referred to as the Joint Parties) view the proposal to install BART I emissions controls to allow the continued operation of Boardman through 2040 as the most objectionable option before this Commission. They request the Commission not acknowledge the BART I emission controls, as modeled in the Diversified Thermal with Green portfolio or any other portfolio, even as a backstop plan.

The Joint Parties support closing Boardman as early as possible, yet indicate that they would prefer a broadly supported plan, even if the plan closed the plant at a somewhat later date. Therefore, PGE and DEQ are urged to use DEQ’s Option 2 and PGE’s BART III proposals as the basis for achieving convergence on a broadly supported plan. The Commission is urged to only acknowledge the pollution controls that are immediately necessary and to leave the door open for further amendments to this IRP. According to the Joint Parties these actions will allow room for PGE, DEQ, and other regional stakeholders to agree on a comprehensive plan to achieve the responsible closure of Boardman.

The Joint Parties argue that the replacement of Boardman should be significantly cleaner and more flexible resource than replacement with only a base load natural gas plant. The Joint Parties are confident that PGE could replace Boardman in the 2015/2016 timeframe with a diverse mix of resources. The Joint Parties concede the risk, however, that early closure would likely result in replacing the plant with a natural gas resource and its associated carbon emissions. Again, the Joint Parties urge the Commission to create space for stakeholders to develop a clean and diverse replacement strategy.

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28 Id. at 19.
29 Id. at 20-21.
30 Joint Parties’ Sept 1, 2010 Comments at 1.
31 Id. at 2.
c. The NW Energy Coalition

The NW Energy Coalition (NWEC) joins the Joint Parties in recommending shutdown of Boardman no later than 2020. Like the Joint Parties, NWEC prefers an agreement between PGE, DEQ, and regional stakeholders on a mutually acceptable plan. As a result, NWEC recommends that the Commission only indicate the boundaries of an acceptable closure plan. According to NWEC, formal acknowledgement should only occur after an actual agreement to close Boardman is achieved.\(^{32}\)

NWEC opines that not enough effort has been put into developing a resource strategy to replace Boardman.\(^{33}\) NWEC urges the Commission to consider the state’s carbon reduction goals and in the next IRP cycle to begin work on a comprehensive plan to achieve significant reductions in emissions. NWEC repeatedly argues that the risk metrics used by PGE in its IRP portfolio analysis assign no weight to the risk of carbon regulation because they average scenarios with high and low carbon costs. NWEC recommends that the Commission require future IRPs to include a risk metric that directly measures carbon dioxide emissions.

NWEC is most forceful in its objection to PGE’s request for backstop acknowledgment of the BART I compliance actions.\(^{34}\) NWEC argues the DEQ Option 3 with closure of Boardman in late 2015 or early 2016 is the better backstop. According to NWEC a comparison of the modeling results of PGE’s BART I backstop proposal to DEQ Option 3 shows no significant difference on a cost basis. NWEC argues that the lower carbon dioxide emissions of DEQ Option 3 should be used to break this tie. NWEC suggests that the advantage in emissions could be even larger if Boardman is replaced with power sources cleaner than a natural gas-fired CCCT. NWEC scolds PGE for introducing new tie-breaking criteria, such as near-term rate impacts, inadequate time to develop replacement resources, and insufficient transition time for its employees and the Boardman community.

Although NWEC joins the Coalition in questioning PGE’s timeline for construction of a CCCT, it more fundamentally questions the need for immediate and full replacement of Boardman’s capacity and energy output.\(^{35}\) NWEC has repeatedly argued that the load forecast used by PGE in its IRP modeling is higher than the NPCC forecast. NWEC also asserts that PGE has overstated its resource need by deciding to lower its exposure to the wholesale power market. NWEC criticizes PGE for not analyzing its level of market exposure in this IRP. NWEC concludes that there is little need for quick and full replacement of Boardman by 2015.

Finally, NWEC concedes that over reliance on the wholesale power market can be risky and detrimental to ratepayers. It then points to a healthy surplus of generating capacity in the Northwest and the area covered by the Western Electricity Coordinating Council and concludes this risk is worth taking to close Boardman in late 2015 or early 2016.

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\(^{32}\) NWEC’s Sept 1, 2010 Comments at 1.
\(^{33}\) Id. at 1-2.
\(^{34}\) Id. at 2-6.
\(^{35}\) Id. at 4.
NWEC argues that reliance on the market can provide the space needed in time to acquire a clean mix of replacement resources.

d. **NIPPC**

The Northwest and Intermountain Power Producers Coalition (NIPPC) offers no opinion regarding the cessation of coal-fired operations at the Boardman plant.\(^{36}\) NIPPC emphasizes, however, that the shutdown risks being debated in this proceeding are largely ratepayer risks, and believes that diversifying ownership of generation resources is in the best interest of ratepayers. NIPPC says it is well established that PPAs lower a utility’s business risk. Contrasting PGE’s Boardman ownership with PGE’s PPA with TransAlta for a portion of the output of the coal-fired Centralia plant, NIPPC concludes that power secured through a PPA with an independent power producer is far less risky for ratepayers.\(^{37}\)

NIPPC offers more detailed criticism of PGE’s analysis of the potential replacement resources for Boardman. NIPPC argues that PGE has not adequately evaluated the costs and risks, including the reliability risks, of entering into PPAs with independent power producers. NIPPC’s criticism is not limited to the evaluation of PPAs for long-term replacement of Boardman, but also covers the evaluation of short-term PPAs that could temporarily bridge the capacity and energy need until a permanent replacement is built or purchased. According to NIPPC, PGE’s repeated assertions that this type of analysis is more appropriate in a competitive procurement proceeding are misplaced. Commission IRP Guideline 1 requires utilities to evaluate all resources on a consistent and comparable basis.\(^{38}\) NIPPC argues that postponement of the evaluation of PPAs to the competitive bidding process makes PGE’s IRP noncompliant with this guideline.

NIPPC has specific recommendations to remedy PGE’s lack of analysis of the PPA option. NIPPC asks the Commission to require PGE to issue a Request for Information (RFI) to potential suppliers of replacement power.\(^{39}\) This streamlined information gathering process would allow PGE to adequately consider the PPA resource and to re-evaluate its replacement options. NIPPC states that PGE should be required to file an IRP addendum explaining the results of the RFI and to allow parties to fully vet the merits of the PPA replacement option.

NIPPC also has recommendations for improving PGE’s upcoming Request for Proposals (RFP) process.\(^{40}\) Concerned that PGE intends to favor its own self-built benchmark resources, NIPPC recommends the Commission encourage PGE to identify the actual amount of nameplate megawatts that it intends to acquire through unit contingent PPAs linked to resources that PGE does not intend to build or subsequently acquire. NIPPC also recommends that the Commission strongly encourage PGE to solicit bids that include build-to-own replacement options at PGE’s sites, long-term PPAs linked to replacement

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\(^{36}\) *Id.* at 2.
\(^{37}\) *Id.* at 7.
\(^{38}\) Order No. 07-002 at 3.
\(^{39}\) NIPPC’s Sept 1, 2010 Comments at 5.
\(^{40}\) *Id.* at 8-9.
resources located at non-PGE sites, as well as sales of existing assets from independent power producers.

e. **Staff**

Staff recommends that the Commission acknowledge PGE’s BART III proposal. Staff adds that the Commission should not acknowledge PGE’s BART I backstop proposal, but instead require PGE to present an alternative proposal and supporting analysis in its next IRP Update if EQC denies its request to revise the Regional Haze Plan to facilitate PGE’s BART III proposal.

Staff primarily focuses its analysis of PGE’s portfolio modeling on three metrics: (1) expected cost; (2) the average of the four worst deterministic futures; and (3) the stochastic TailVar90 risk metric. Staff also reviewed the analysis and comments of the other parties in this case. Based on this analysis, Staff agrees with PGE that its BART III proposal represents the portfolio with the best combination of cost and risk for PGE’s ratepayers. The BART I portfolios, including Diversified Thermal with Green, would impose too great of a risk on ratepayers from future federal and state regulation of carbon emissions. Staff also agrees with PGE that the execution risks associated with implementing the earlier shutdown scenarios are significant.

Staff agrees with NIPPC and NWEC that power purchases from independent power producers or the wholesale power market could be used to bridge the early energy and capacity deficits associated with these scenarios. Staff concludes, however, that the risk associated with the deliverability and cost of such power is not in the best interest of ratepayers.

Staff agrees with comments of other parties that that there is evidence that PGE’s reference case load forecast may overstate future demand. However, Staff’s analysis indicates that PGE’s energy and capacity need remains significant even under a lower load scenario. As previously discussed, Staff believes that PGE’s resource gaps are significant and would be challenging to fill if Boardman were shut down in 2016.

Staff also agrees with the Coalition and NWEC that PGE’s reference case natural gas price is slightly overstated. Staff notes, however, that PGE’s response to the Commission’s Bench Request, which tested a combined low natural gas price and low load forecast scenario, continues to show very little difference between the shutdown scenarios on an expected cost basis. Staff prefers PGE’s BART III proposal because it allows adequate time to implement a lower-risk replacement resource strategy.

f. **Reply Comments**

In its reply comments, CUB agrees with Staff that of the options presented in the IRP, BART III is the best performer from a least cost/least risk basis. Nonetheless, CUB believes that the Commission should not specifically acknowledge BART III in the event the
EQC adopts a rule that is substantially similar to BART III, but with a different off-ramp for the DSI technology. CUB recommends the Commission use the following language:

*If the EQC adopts the BART III compliance actions or compliance actions that are substantially similar to BART III, then this combination of pollution control investments and commitment to cease operation at Boardman no later than 2020 provides the best combination of expected costs and risks for customers. We acknowledge compliance actions that are substantially similar to BART III for the Boardman plant.*\(^{41}\) (emphasis in original).

NWEC also recommends that the Commission should broaden the scope of its acknowledgment regarding Boardman to allow PGE to proceed with its proposed refinements to BART III, should the EQC and the EPA allow it.\(^{42}\)

CUB, NWEC, RNP, Angus Duncan, and the OEC also filed joint comments urging the Commission to issue an acknowledgment order “flexible enough to accommodate the refinements that PGE have worked to make possible.” These parties also urge the Commission impose a requirement on PGE that tracks with the commitment PGE has made to certain parties to develop low-carbon portfolios for evaluation in PGE’s next IRP.\(^{43}\)

2. Commission Resolution

There are six Boardman options currently under consideration:

- The BART I option with shutdown targeted for 2040
- The Boardman through 2014 option
- PGE’s proposed BART III option with shutdown targeted for 2020
- DEQ Option 1 with shutdown targeted for 2020
- DEQ Option 2 with shutdown targeted for 2018; and
- DEQ Option 3 with shutdown targeted for 2015/2016

Of these options, PGE’s proposed BART III option offers the best combination of cost and risk for ratepayers. We consider PGE’s BART III to be the superior option because (1) it is a low-cost option for ratepayers; (2) it mitigates the risk of future carbon regulation by closing the plant at the end of 2020; (3) it mitigates the risk of acquiring replacement resources by providing the time needed to evaluate and implement a reasonable replacement strategy; and (4) it provides the flexibility needed to test the effectiveness of DSI technology and to adapt the plant’s operation to control both SO₂ and particulate matter (PM) emissions prior to the plant’s closure.

\(^{41}\) CUB’s Oct 29, 2010 Comments at 4.
\(^{42}\) NWEC’s Oct 29, 2010 Comments at 2.
\(^{43}\) Group Comments at 2 (Oct 29, 2010).
The BART I option, which requires a $510 million investment in pollution control equipment in order to operate the plant through 2040, is too costly and too risky. The risk of future carbon regulation, whether it takes the form of cap-and-trade regulation, carbon taxation, or the mandated closure of specific coal plants, makes this an inferior option for ratepayers. Under a worst-case scenario, PGE’s ratepayers could potentially pay the cost of replacing Boardman with low carbon emission resources while continuing to pay for pollution control equipment at a plant that no longer operates.

DEQ Option 3, which calls for shutdown of the Boardman plant in late 2015 or early 2016, does not allow enough time for PGE and interested parties to develop and implement a reasonable resource replacement strategy. PGE has argued that any replacement for Boardman needs to be a base load resource and has modeled replacement with a natural gas CCCT. The Joint Parties and others have indicated a strong preference for replacing Boardman with a mix of renewable resources. The choice of the best replacement resources is a complex decision that should be considered in PGE’s IRP process. Closing Boardman in late 2015 or early 2016 does not allow enough time to fully consider and develop alternative replacement options and could result in ratepayers bearing higher costs in the long-run. The same logic and conclusion applies to the Boardman through 2014 option.

DEQ Option 1, which requires a $343 million investment in pollution control equipment and closes the Boardman plant in 2020, is simply too costly for ratepayers. In PGE’s IRP modeling, this option and the BART I option are consistently the highest cost options over a wide range of potential futures, including both PGE’s reference case scenario and our Bench Request scenario.

DEQ Option 2 lacks the flexibility needed to test the effectiveness of DSI technology and to adapt the plant’s operation to control both SO2 and PM emissions prior to shutdown in 2018. This lack of flexibility makes operating the plant to 2018 a more risky endeavor. If DSI technology is incapable of controlling SO2 emissions without simultaneously violating PM emission standards, then PGE and its ratepayers would be confronted with the choice of making an expensive investment in additional pollution control equipment or closing the plant prior to the 2018 target. The increased risk of shutdown prior to 2018 raises the issue of having enough time fully develop and implement a reasonable resource replacement strategy. For these reasons, we find PGE’s BART III option to be superior to DEQ Option 2.

As noted, PGE requested that DEQ re-open its BART rulemaking to consider a refinement to PGE’s BART III option. The refinement consists of a lower SO2 emissions requirement beginning July 2018 and a request to repeal the existing BART I option if PGE’s BART III option is ultimately approved by the EQC and the EPA. With this refinement, and a PGE commitment to work with regional stakeholders to develop low-carbon resource portfolios for consideration in its next IRP, CUB, NWEC, OEC, and RNP now support Boardman shutdown no later than 2020.

PGE proposes to reach the lower SO2 emissions standard with increased use of DSI beginning in July 2018. This change increases the total expected net present value
cost of the BART III option by $10 million. This change in cost is not significant enough to alter our finding that BART III is the best option for ratepayers. We acknowledge both PGE's original and refined BART III options.

We decline, however, to adopt CUB’s recommendation to acknowledge other compliance actions that are “substantially similar” to BART III for the Boardman plant. Although we share CUB’s preference to not be involved in an IRP Update proceeding that is comparing small differences in BART compliance actions, the evaluation of differences in resource portfolios is complex and the determination that two options are equivalent is not amenable to allowing parties to interpret the phrase “substantially similar.”

We also decline to acknowledge BART I as a backstop option. The acknowledgement of a backstop option would require us to predict or prejudge which compliance options might remain if the EQC denies PGE’s BART III proposal. If the EQC denies the Company’s BART III proposal, then PGE has the ability to present its next preferred option, and ask for Commission acknowledgment, in an IRP Update. There is no limit on the frequency of IRP Updates and, if needed PGE can expeditiously file a Boardman-Only Update and also file a general IRP Update a year from now.

We also decline to not acknowledge BART I. We will wait for the EQC to make its decision on BART III before we consider any backstop option. Our decisions do not address the question of the prudence of pursuing the BART I compliance actions; they simply mean that we refuse to prejudge the EQC’s actions.

Finally, our acknowledgement of PGE’s BART III, conditional on EQC approval, does signal our intention to address the replacement strategy for Boardman in PGE’s next IRP.

D. Cascade Crossing

The Cascade Crossing Transmission Project (Cascade Crossing) is a proposed 500 kV transmission line connecting PGE’s Boardman and Coyote Springs plants to the southern portion of the Company’s service territory. The proposed project would begin at the Coyote Springs’ substation, go to the Boardman plant, and terminate at PGE’s Bethel substation. The project would parallel existing utility lines for the first 106 miles from the Boardman substation toward Bethel, and parallel PGE’s existing Bethel-to-Round Butte 230 kV line over the Cascades for the last 77 miles. The project will require the construction of a 500/230 kV substation, 500/230 kV transformer, and 500/230 kV transformer bank, as well as improvements to two existing substations.44

PGE asserts that Cascade Crossing will (1) directly connect west-side load to existing and new resources on the east side of the Cascade; (2) add transfer capacity to the Cross-Cascades South and West of Slatt cutplanes; (3) reduce stress on the I-5 cutplanes by providing another path to its system from the south; (4) provide firm transmission service for

44 IRP at 187.
existing generators as an alternate to service furnished by the Bonneville Power Administration (BPA); and (5) improve reliability by providing additional transmission and reducing load on transfer paths parallel to Cascade Crossing, thus reducing the severity of currently limiting contingencies.\textsuperscript{45}

PGE conducted a benefit-cost analysis of the Cascade Crossing transmission project to determine whether it should include Cascade Crossing in its IRP Action Plan and continue to invest in the project. The choice analyzed was whether it is preferable for PGE’s ratepayers to continue to purchase transmission capacity from the BPA or to obtain transmission capacity by building Cascade Crossing. PGE’s analysis consisted of five case studies with different assumptions regarding third party equity participation in Cascade Crossing and different assumptions regarding the growth of BPA’s transmission rates after 2025.

PGE analyzed both a single-circuit and double-circuit configuration of the Cascade Crossing. For the single-circuit configuration, PGE estimated total project costs to be $613 million and assumed a path rating of 1,500 MW of transfer capability. For the double-circuit configuration, PGE estimated total costs of $823 million and assumed a transfer capability of 2,200 MW. Under Case 3, its mid-point case study, PGE further assumed that it would partner with a third party to share the costs of the 17-mile segment of transmission line from Coyote Springs to Boardman and for the expansion of the Coyote Springs’ substation.

PGE estimated the cost of continued service from BPA by assuming that BPA’s current transmission rates experience a one-time increase of 10 percent in 2015 and grow at an average nominal rate of 4 percent from 2011 to 2025. Under its mid-point case study, PGE further assumed that BPA transmission rates grow at a rate of 3.2 percent from 2025 to 2082. In all five of the case studies, PGE included approximately $65.5 million for new transmission substations and radial lines needed to connect PGE’s planned resources to the BPA transmission system.

PGE, through its case studies, considered higher and lower levels of equity participation and higher and lower growth of BPA’s transmission rates after 2025. For example, in Case 1, PGE assumed no equity participation in the 17-mile line segment from Coyote Springs to Boardman and a growth rate of 2.5 percent in BPA’s transmission rates after 2025. In Case 5, PGE assumed an additional third party equity share equivalent to 209 MW of transfer capability under the single-circuit configuration (or 300 MW under the double-circuit configuration) and a growth rate of 3.5 percent in BPA’s transmission rates after 2025.

PGE seeks acknowledgment to build Cascade Crossing as a double-circuit 500 kV and alternatively, as a single-circuit 500 kV facility. PGE states that whether it proceeds with Cascade Crossing, as either a double-circuit or single-circuit, will depend on future economic analysis incorporating refined cost estimates, updated information regarding path rating, the level of equity participation from third parties, transmission service requests

\textsuperscript{45} Id. at 189-190.
received by PGE, and updated information regarding PGE’s generation facilities that would utilize the project.

1. **Parties’ Positions**

RNP believes Cascade Crossing will directly facilitate wind interconnections and will provide links between eastern Oregon wind, solar, and geothermal resources with western load centers. RNP supports acknowledgment of Cascade Crossing so long as it can be responsibly sited and developed within parameters of a sensible and timely cost-benefit analysis. RNP recommends that the Commission require PGE to update its analysis regarding Cascade Crossing in a future IRP or IRP Update.\(^\text{46}\)

CUB does not recommend against acknowledging Cascade Crossing, but raises numerous questions and concerns. These include: (1) Why does the expected closure of Boardman not affect PGE’s plan for Cascade Crossing; (2) Why aren’t BPA transmission services sufficient to serve PGE’s needs; (3) Does PGE have sufficient experience to manage construction of Cascade Crossing without incurring significant cost overruns; and (4) Should new transmission be a top priority for PGE?

Willard Rural Association (WRA) recommends that the Commission not acknowledge Cascade Crossing. WRA asserts that PGE made many forecasting errors, including: (1) overstating its load forecast; (2) understating the amount of transmission BPA will have in the future; (3) overstating the cost of BPA transmission; (4) underestimating the cost to acquire right of way for Cascade Crossing; and (5) understating the risk associated with an $823 million investment.

Staff recommends that the Commission acknowledge Cascade Crossing in the double-circuit configuration, subject to the requirement that PGE provide the Commission certain information and updated analysis in its next IRP Update. Staff asserts that PGE’s proposal to acquire a transmission resource is supported by analysis under IRP Guideline 8. Staff agrees with PGE’s conclusions that adding transmission to PGE’s system will allow additional purchases and sales, access to less costly resources in remote locations, access to renewable resources developed on the east side of the state, and will improve reliability.

Staff also asserts that PGE’s financial and qualitative analyses (some done in response to a Staff data request) support PGE’s proposal to build Cascade Crossing, as opposed to acquiring transmission in another manner.

2. **Commission Resolution**

The primary benefit of Cascade Crossing is that PGE can avoid future increases in BPA’s transmission rates. Cascade Crossing can achieve these savings by connecting PGE’s existing Boardman and Coyote Springs plants, and any new generation located in eastern Oregon, directly to PGE’s load. PGE’s analysis shows that the single-circuit configuration of Cascade Crossing provides net benefits to ratepayer under the mid-

\(^{46}\) RNP’s Sept 1, 2010 Comments at 3.
point and high equity participation cases. The double-circuit configuration only shows net benefits under the high equity participation cases.

PGE did not attempt to quantify all of the potential benefits of Cascade Crossing in its benefit-cost analysis. For example, in all cases PGE assumed zero revenues from transmission sales or use in the west-to-east direction. PGE also did not estimate the potential reliability benefits or the savings in energy losses that would accrue to PGE ratepayers from building Cascade Crossing.

Further, under both the single- and double-circuit configurations, Cascade Crossing would provide other load serving entities the opportunity to access new renewable resources located east of the Cascade Mountains. Pacific Power recently signed a Memorandum of Understanding with PGE to explore obtaining an equity share in the line equivalent to 600 MW of bi-directional transfer capability.

PGE’s benefit-cost analysis is sufficiently robust, and shows sufficient net benefits under certain scenarios, to allow us to acknowledge Cascade Crossing at this time. However, when developing an IRP, we always expect utilities to update their assessments of previously acknowledged projects that are still in the planning or development stages. We make this updating requirement explicit for the Cascade Crossing project because of the current uncertainty regarding equity participation and other key factors. We expect PGE to provide a thorough update of the Cascade Crossing benefit-cost analysis in its next IRP, with the understanding that Commission acknowledgment of the Company’s next IRP will depend on the outcome of that updated analysis. Therefore, we acknowledge Cascade Crossing with the following requirement:

PGE shall include an updated benefit-cost analysis of the Cascade Crossing transmission project in its next IRP. For the updated analysis, PGE shall update its assumptions about project configuration, capital cost, path rating, wheeling revenues, and equity participation and conduct sensitivity analyses that address any uncertainty about capital cost, path rating, levels of equity participation, and levels of wheeling revenues.

Finally, we reiterate that, at the time of ratemaking, each utility is required to show that its investment was a prudent decision. At that time, the utility will be expected to address any significant changes in construction cost, path rating, equity partnership, or third-party subscription and how these changes influenced the Company’s decision to continue with the project.

E. Demand Response

1. Parties’ Positions

Staff contends that PGE did not comply with IRP Guideline 7 regarding demand response (DR) because the Company failed to evaluate DR “on par” with other
options for meeting energy, capacity, and transmission needs. Staff notes that PGE included 60 MW of firm DR in its portfolios in 2012 through 2016 (50 MW from an RFP and 10 MW from a curtailment tariff option for large industrial customers) but that the Company did not explain why those were the only DR resources projected in that time period. Staff recommends that the Commission direct PGE to meet Guideline 7 and provide certain information on projected amounts and costs of DR in its next IRP Update.\textsuperscript{47}

CUB notes that PGE has not made much progress towards acquiring significant DR since the Commission approved the company’s Advanced Metering Infrastructure (AMI) proposal in 2008. CUB agrees with Staff that PGE did not adequately analyze DR in the IRP and recommends that Commission require the company to report in the next IRP Update what steps it will be taking to evaluate DR programs in the Company’s next full IRP.\textsuperscript{48}

In response, PGE contends that it did comply with the guideline, pointing out in particular that it evaluated DR on par with other resource options by assessing and selecting DR using a benefit/cost ratio based on an alternative capacity resource (a simple cycle combustion turbine or SCCT).\textsuperscript{49}

2. \textit{Commission Resolution}

We share the concerns expressed by Staff and CUB. PGE evaluated DR against an SCCT but did not provide DR cost information in the IRP. The Company included 10 MW from a critical peak pricing (CPP) program as a capacity resource in its last (2007) IRP but did not do so in its 2009 IRP, without really explaining the change (other than to say now that it primarily assumes acquisition of firm DR resources). PGE has not made the progress we expected on acquisition of DR, e.g., it has delayed its CPP pilot for a year, and its RFP for direct load control resources was unsuccessful.

We believe that DR can be a significant resource but realize that there is still much to learn about the potential for and reliability of different types of DR (mainly through pilot programs by PGE and other electric utilities). We adopt a combination of the proposals made by Staff and CUB and will require PGE to provide information and show the steps it is taking, and intends to take, to assess and acquire DR. Also, we agree with the timing of these requirements recommended by CUB and Staff and direct PGE to comply with the following directives at the time of its IRP update:

\textsuperscript{47} Staff’s Oct 15, 2010 Comments at 9-10.
\textsuperscript{48} CUB’s Oct 29, 2010 Comments at 5-7. CUB expressed concern about waiting two years to address DR, apparently because it understood Staff to be proposing a condition for the next IRP. But Staff, like CUB, recommends that PGE report on DR in the next IRP update (which should be filed a year after this order is issued).
\textsuperscript{49} PGE’s Oct 29, 2010 Comments at 7-8.
In its next IRP update, PGE must provide the following:

a. Its estimated cost per MW of capacity savings by demand response (DR) type (i.e., firm vs. non-firm resources), and projected MW acquisitions by DR type for the next 5 years;

b. A discussion of the steps it is and will be taking to evaluate DR in the Company’s next IRP, and

c. An updated action plan for assessing (e.g., plans for pilot programs) and acquiring DR for the next 3 years.

F. Energy Efficiency

1. Parties’ Positions

Staff concludes that PGE met the IRP guideline for conservation (IRP Guideline 6) with two exceptions. First, Staff states that PGE did not treat conservation voltage reduction (CVR) as a resource. Second, Staff states that PGE did not consider whether to include CVR in the action plan. Staff notes that the Energy Trust of Oregon identified technical potential for 19 MWe of savings from CVR in the Company’s service territory.\(^{50}\)

PGE replies that it views CVR as an operational efficiency, not a long-term resource planning issue. The Commission found that PGE complied with IRP Guideline 6 (except with respect to the planning horizon) in the Company’s last IRP, even though its treatment of CVR was the same as in the current IRP. PGE also points out that potential CVR savings are small and would not have a material impact on its resource requirements or action plan.\(^{51}\)

2. Commission Resolution

We agree with Staff that PGE should consider CVR in its resource planning and adopt the following requirement:

In its next IRP, PGE should consider conservation voltage reduction (CVR) for inclusion in its best cost/risk portfolio and identify in its action plan steps it will take to achieve any targeted savings.

\(^{50}\) Staff’s Oct 15, 2010 Comments at 10-11.
\(^{51}\) PGE’s Oct 29, 2010 Comments at 8-9.
G. Renewable Portfolio Standard Requirements

1. Parties’ Positions

PGE proposes to acquire 122 MWa of renewable wind generation by the end of 2012 to achieve physical compliance with the Renewable Portfolio Standard (RPS) requirement for 2015. PGE asserts that banking renewable energy credits (RECs) from early renewable resource actions provides a significant cushion for “meeting RPS compliance.”

Staff is concerned that PGE did not model the use of unbundled RECs to comply with the RPS requirements for the entire planning period. Staff notes that PGE’s analysis is predicated on an assumption that PGE would comply with the RPS requirement with physical resources, rather than unbundled RECs. Staff recommends that the Commission require to PGE “relax” the assumption that PGE must be in physical compliance with the 2015 RPS requirement. In other words, Staff recommends that PGE’s analysis include the possibility that PGE will use unbundled RECs to comply with the 2015 RPS requirement.

In support of this recommendation, Staff notes that several factors could result in a situation in which it is more cost effective to acquire physical resources later, rather than sooner, such as the later availability of emerging technology. Staff also notes that PGE’s concerns regarding penalties for non-compliance appear to be overstated.

The Oregon Department of Energy (ODOE) notes that PGE’s plan for physical RPS compliance overemphasizes the near term. ODOE finds the plan appropriate where short-term REC sales provide value to current utility customers at the same time prudent banking reduces RPS compliance risk beyond 2020. ODOE notes, however, that PGE should address the substantial REC output to be made available in 2011 due to the recent passage of House Bill 3674. ODOE reports that the bill makes a number of pre-1995 biomass facilities eligible for the RPS with the condition that REC output from those facilities cannot be used until 2026. ODOE notes that these facilities are expected to produce over 7 million RECs.

ODOE also notes that PGE’s IRP contains an incorrect conclusion regarding the penalty risk associated with failure to meet the RPS requirement. ODOE notes that the Alternative Compliance Payment is not a direct penalty as the RPS allows a variety of paths for a utility to invest those payments toward future project development.

PGE disagrees with Staff’s recommendation that PGE should project future prices and availability for unbundled RECs to assess the potential for acquiring unbundled RECs to meet Oregon’s RPS. PGE states, “[w]e believe that, given the lack of liquidity and transparency in the REC markets, it would not be prudent to rely on such projections.”

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52 IRP at 114.
53 ODOE’s May 14, 2010 Comments at 3.
54 Id. at 4.
2. Commission Resolution

We see no reason that PGE’s analysis of the least cost and least risk method to comply with RPS requirements should exclude the possibility of using unbundled RECs to meet RPS requirements at any point in the planning period, including the early years. Both Staff and ODOE identify circumstances that could lead to the conclusion that relying on unbundled RECs in early years of the planning period could be least cost and least risk. Accordingly, we adopt the following requirement

In its next IRP Update and in the next planning cycle, PGE must evaluate:

(1) The use of unbundled renewable energy credits (RECs) in its strategy to meet RPS Requirements for the entire planning period; and

(2) Alternatives to physical compliance with renewable portfolio standard (RPS) requirements in a given year, including meeting the RPS requirements in the most cost-effective/least risk manner that takes into consideration technological innovations, expiration or extension of production tax credits, and different levels of integration costs for renewable resources.

H. Wind Integration Study

1. Parties’ Positions

RNP recommends that the Commission not acknowledge the wind integration study PGE used to estimate costs to operate and acquire wind generation. RNP asserts that PGE’s study includes an unusually high cost of reserves and has not been provided for stakeholders and the Commission to evaluate.\(^{56}\) RNP recommends that the Commission order PGE to continue to use the BPA wind integration rate to model new wind resources until such time as PGE is prepared to fully engage with stakeholders in review of its methodology and results.

Staff agrees that PGE did not comply with the Commission’s order stemming from PGE’s last IRP to “include in the [next IRP] analysis a wind integration study that has been vetted by regional stakeholders.”\(^{57}\) Staff echoes RNP’s statements that PGE has not produced a study whose detailed methodology and results have been made available for review.

PGE disputes RNP’s assertion that the wind integration costs underlying PGE’s IRP analysis are unreasonably high. PGE notes that RNP’s assertions are largely based on comparisons to other utilities’ costs and to BPA’s Balancing Authority within-hour integration tariff. PGE notes that these comparisons are inappropriate because: (1) each

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\(^{56}\) RNP’s Sept 1, 2010 Comments at 1-3.

\(^{57}\) Docket LC 48, Order No. 08-246 at 10 (May 6, 2008).
utility's costs depend on the unique characteristics of the utility's system; and (2) PGE's wind integration costs is comprised of several components, only one of which is comparable to the within-hour integration tariff.  

PGE also disputes RNP's and Staff's criticisms of the wind integration study process. PGE states that it included several stakeholders on its technical review committee to evaluate the Company's study approach, inputs and findings, and conducted a three-hour workshop to present the details of its wind integration study. PGE also notes that, in addition to the input it received from stakeholders the Company hired an independent examiner (IE) in late 2008 to “vet” the study for docket UM 1345, and that the IE concluded the study was a “thorough integration study.” Nonetheless, although it believes it has already complied with the requirement to produce a vetted wind integration study, PGE agrees with Staff's recommendation to include in its next IRP Update a wind integration study that has been vetted by regional stakeholders.

2. Commission Resolution

We agree with RNP that it is important that “vetting” by regional stakeholders of a wind integration study include opportunity for regional stakeholders to examine, in detail, the methodology of the study and the results. We also believe that when vetting PGE’s wind integration study, stakeholders should have the opportunity to comment on the methodology and make recommendations. Also, it is incumbent on PGE to respond to any such comments and, to the extent it does not adopt recommendations of stakeholders, explain why.

As PGE itself acknowledges, the stakeholder “vetting” consisted of preliminary input from a technical group and a workshop attended by PGE and interested parties. PGE’s presentation at the workshop, a hard copy of which PGE attached to its comments, reflects that PGE informed stakeholders how it intended to go about the study. As RNP and Staff note, such a presentation is not a substitute for an opportunity for regional stakeholders to evaluate the methodology that PGE actually used and the results obtained from the methodology. Accordingly, we impose the following requirement:

In its next IRP planning cycle, PGE must include a wind integration study that has been vetted by regional stakeholders.

1. Risk Metrics

1. Parties’ Positions

Staff cautions the Commission about the possible misinterpretation of two risk metrics used by PGE in its 2009 IRP. PGE calculated the “Average of Worst Four Futures

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58 PGE's Sept 27, 2010 Reply to Intervenor Response Comments at 18.
60 Id.
Less the Reference Case Cost61 and “TailVar90 Less the Mean” risk metrics by subtracting a resource portfolio’s reference case or mean cost from the average of its “worst-case” or highest-cost outcomes. According to Staff, these calculations can produce counter-intuitive and misleading results. The problem is that the risk metrics may assign a lower risk to a portfolio that has both a higher expected (or reference case) cost and a higher extreme (or worst case) cost. Staff recommends that the Commission rely on PGE’s “Average of Worst Four Futures” and “TailVar90” risk metrics that do not subtract the reference case or mean value from the high cost outcomes.

RNP and NWEC also take issue with these two risk metrics. NWEC asserts that these risk metrics are measures of spread or variability, and not measures of risk of bad outcomes. NWEC argues that “any metrics such as these that subtracts out the mean, in cases where the mean can be very different across tested portfolios, is faulty, since high variability in itself is not a bad outcome.” RNP asserts the metrics do not measure relevant risks. RNP and NWEC also object to PGE’s “Year-to-Year Variation” risk measure.64

RNP recommends that the Commission require PGE to revise its methodology in future IRPs to appropriately reflect relevant risk factors, dropping duplicative or irrelevant metrics and adding a risk metric proportional to emissions of pollutants, including carbon dioxide.65 NWEC urges the Commission to direct PGE to improve future IRPs to correct the flaws in its risk analysis and portfolio scoring.66 NWEC argues that the risk metrics used by PGE assign no weight to the risk of future carbon regulation because they average scenarios with high and low carbon costs. NWEC recommends that the Commission require future IRPs to include a risk metric that directly measures carbon dioxide emissions.

In response to NWEC’s and RNP’s criticisms, PGE asserts that the disputed risk metrics are required by IRP Guideline 1e, which require two measures of risk: one that measures the variability of costs, and one that measures the severity of bad outcomes. According to PGE, the disputed risk metrics satisfy the requirement to have a measure of the variability of costs. The Average of Worst Four Futures and TailVar90 risk measures satisfy the requirement to have a measure of the severity of bad outcomes. Finally, according to PGE, the “Year-to-Year Variance Metric,” is necessary because rate stability is important to customers. PGE also rebuts NWEC’s assertion its risk metrics assign no weight to future carbon regulation by indicating that the Average of Worst Four Futures and TailVar90 risk metrics do not combine or average high and low CO2 price futures.

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61 PGE also refers to this metric as the “Deterministic Portfolio Risk Variability vs. Reference Case.” See IRP at 249.
63 RNP’s May 20, 2010 Comments at 3.
64 Id.
65 Id.
66 NWEC’s May 14, 2010 Comments at 14.
67 PGE’s Aug 10, 2010 Comments at 46.
68 Id. at 47.
Staff agrees that the Year-to-Year Variance Metric is an important measure of the variability in costs.\textsuperscript{69} According to Staff this specific metric obviates the need for the disputed metrics that can be misleading.

2. **Commission Resolution**

In its 2009 IRP, PGE models the risk and uncertainty associated with load requirements, natural gas prices, electricity prices, plant forced outages, and the cost of compliance with the future regulation of greenhouse gas emissions. Although we share concerns about some of the specific measures used by PGE, PGE's 2009 IRP includes risk metrics that measure both the variability of costs and the severity of bad outcomes for each of the candidate resource portfolios considered in the plan. PGE's risk analysis is robust and satisfies the requirements of IRP Guidelines 1b, 1c, 4i, 4j and 8a.

We decline to adopt NWEC's and RNP's recommendations to require PGE to drop the disputed risk metrics as long as they continue to provide measures that comply with the IRP risk guidelines. We also decline to require PGE to add an additional metric that measures a portfolio's carbon dioxide emissions in its next IRP. PGE provided carbon dioxide emissions analysis, including total emissions in short tons and emissions in short tons per megawatt-hour, for each of the portfolios under consideration in its 2009 IRP. We encourage Staff and other parties to continue to identify risk metrics and results that require careful interpretation and to make resource recommendations based on the metrics and results they find to be most relevant.

J. **Reliability**

1. **Parties' Positions**

NWEC comments that PGE's expected unserved energy (EUE) reliability metric measures a resource portfolio's exposure to the wholesale power market and is independent of the portfolio's mix of resources. NWEC notes that, because the EUE metric is a measure of market exposure, it is possible to improve a portfolio's performance simply by adding additional resources. NWEC asserts that the EUE metric should not be used to judge the reliability of PGE's resource portfolios.\textsuperscript{70}

Staff also takes issue with PGE's reliability analysis. Staff notes Guideline 11 requires the utility to determine by year for top-performing portfolios (1) the loss of load probability (LOLP), (2) the expected planning reserve margin, and (3) the expected and worst-case unserved energy. Staff asserts that PGE included neither the LOLP metric nor conventional metrics for EUE and Worst-Case Unserved Energy in scoring of its resource portfolios.

Staff notes that instead of calculating a conventional EUE metric, PGE calculated a conditional EUE (CEUE) metric. CEUE is defined as the average amount of

\textsuperscript{69} IRP at 267; 285.

\textsuperscript{70} NWEC's Sept 1, 2010 Comments at 6-8.
unserved energy that occurs given the occurrence of an unserved energy event. Staff echoes NWEC’s concern with this metric. Staff notes that a portfolio can get a low CEUE score even if it has a high frequency of unserved energy events. In other words, a particular portfolio may suffer from frequent exposure to the wholesale power market, but due to a low purchase amounts during these events receive an overall favorable CEUE score. Staff recommends that the Commission require PGE to perform the analyses required by Guideline 11 in PGE’s next IRP Update.

PGE denies NWEC’s assertion that PGE’s EUE metric is independent of the resource mix of IRP portfolios. PGE asserts that this metric “addresses the relative reliability of the portfolios based on the particular resources in them, with their assumed associated forced outage rates and mean times to repair.”

2. Commission Resolution

IRP Guideline 11 specifically requires electric utilities to provide measures of expected and worst-case unserved energy for the top-performing resource portfolios. PGE’s EUE and CEUE metrics measure a portfolio’s overall exposure to the wholesale power market, not annual unserved energy. PGE correctly points out that its metrics also reflect the forced outage rates and mean times to repair of the resources included in the portfolios. However, we cannot tell whether differences in outage rates and repair times impact the likelihood and amount of unserved energy. It is important to be able clearly distinguish between a portfolio’s market exposure and its level of expected unserved energy.

This gap in the metrics used by PGE does not impact on our decisions in this IRP. In its 2009 IRP, PGE constructed its resource portfolios to meet specific energy and capacity targets. With a few noted exceptions, all of PGE’s resource portfolios reflect similar levels of wholesale market exposure. Since all the portfolios have roughly the same market exposure, differences in the EUE metric largely reflect difference in the portfolios’ overall generation outage rate.

We direct PGE to work with Staff, NWEC, and other parties in its next IRP cycle to develop reliability metrics that measure unserved energy. We recognize that this may require parties to estimate the depth of the wholesale power market over the IRP planning period.

71 PGE’s Aug 10, 2010 at 34, citing its 2009 IRP at 245-247.
III. CONCLUSION

PGE's 2009 IRP reasonably adheres to the principles of resource planning established in Orders No. 89-507 and 07-002 and is acknowledged with the following requirements:

_In its next IRP, PGE must:_

1. Include an updated benefit-cost analysis of the Cascade Crossing transmission project. For the updated analysis, PGE shall update its assumptions about project configuration, capital cost, path rating, wheeling revenues, and equity participation, and conduct sensitivity analyses that address any uncertainty about capital cost, path rating, levels of equity participation, and levels of wheeling revenues.

2. Provide the following:
   (a) Its estimated cost per MW of capacity savings by Demand Response (DR) type (i.e., firm vs. non-firm resources), and projected MW acquisitions by DR type for the next 5 years,
   (b) A discussion of the steps it is and will be taking to evaluate DR in the next IRP, and
   (c) An updated action plan for assessing (e.g., plans for pilot programs) and acquiring DR for the next 3 years.

3. Consider Conservation Voltage Reduction (CVR) for inclusion in its best cost/risk portfolio and identify in its action plan steps it will take to achieve any targeted savings.

_In its next IRP Update and in its next IRP planning cycle, PGE must:_

1. Include a Wind Integration Study that has been vetted by regional stakeholders.

2. Evaluate the use of unbundled RECs in its strategy to meet RPS requirements for the entire planning period.

3. Evaluate alternatives to physical compliance with RPS Requirements in a given year, including meeting the RPS Requirements in the most cost-effective/least risk manner that takes into consideration technological innovations, expiration or extension of production tax credits, and different levels of integration costs for renewable resources.
IV. ORDER

IT IS ORDERED that:

1. The 2009 Integrated Resource Plan filed by Portland General Electric Company is acknowledged with the requirements set forth in this order.


Made, entered, and effective ________ NOV 28 2010 ________

Ray Baum
Chairman

John Savage
Commissioner

Susan K. Ackerman
Commissioner
BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 189

In the Matter of )
) ) ORDER
PORTLAND GENERAL ELECTRIC COMPANY )
) )
Request to Add Schedule 111, Advanced )
Metering Infrastructure (AMI). )

DISPOSITION: APPLICATION GRANTED

I. INTRODUCTION

In this docket Portland General Electric Company (PGE or the Company) seeks authority to implement its proposed Schedule 111, "to reflect the net costs related to the deployment of an Advanced Metering Infrastructure (AMI)." Following workshops, settlement conferences, informal contacts, and the filing of prepared testimony, several parties have reached a settlement and stipulation. The stipulation is attached as Appendix A and incorporated by reference. Parties to the settlement are PGE, staff of the Public Utility Commission of Oregon (Staff), the Community Action Partnership of Oregon (formerly the Community Action Directors of Oregon) (CAPO), the Oregon Department of Energy (ODOE), and Northwest Natural Gas Company (Stipulating Parties). The Citizens' Utility Board of Oregon (CUB) opposes the settlement.

The AMI project includes installation of new solid-state electronic meters and a fixed two-way communications system that allows for the automated collection of metering data and for sending signals to the meter. The system is intended to reduce costs, improve service, and provide a platform for additional demand-side management programs. If approved, installation would begin promptly, to be completed in 2010.

II. PGE/STAFF/ODOE'S JOINT POSITION

PGE, Staff, and ODOE (Joint Parties) filed joint opening and reply briefs in support of their stipulation. They state that the financial projections and financial analysis of the AMI project have undergone "intense scrutiny." These projections show a net present value benefit to customers of approximately $33 million over 20 years. Other customer and system benefits attributable to the AMI platform are estimated to increase the net present value to a range of $37 million to $80 million over 20 years.
ORDER NO. 08-245

The stipulation includes 12 pages of proposed AMI conditions settling all issues raised by the stipulating parties. In their brief, the Joint Parties offer the section headings of the stipulation to illustrate its breadth:

Operational Implementation Plans  
Customer and System-Related Benefits  
Demand Response  
  IRP Capacity Planning  
  Voluntary Critical Peak Pricing  
  Appliance Market Transformation  
  Information-Drive Energy Savings  
Distribution Asset Utilization  
Avoided Service Transformer Failures  
Proper Transformer Sizing  
Delayed Feeder Conductor Work  
Outage Management  
  Avoided Trouble Calls  
  Faster One-Premise Outage Response  
  Improved Storm Management  
  Faster Fault Location Identification  
Regulatory Filings  
Coordination with Northwest Natural Gas Company in Joint Meter Reading Area  
Community Action Partnership of Oregon and Oregon Energy Coordinators  
  Association Conditions  
  Remote Disconnect/Reconnect  
  Leveraging Data  
  Long-Term Benefits of AMI Functionality  
  Limited Service Delivery  
  Pre-Paid Electric Metering  
  Status Reporting

The provisions of the stipulation were described and explained in the joint testimony in support of the AMI stipulation, sponsored by Lisa Schwartz and Carla Owings of Staff and Alex Tooman of PGE.

According to their testimony, the capital costs of AMI will be about $132.2 million, including radio frequency meters ($70 million), remote disconnect meters ($19.3 million), meter installations ($20.1 million), and system development ($9.0 million). The remaining costs are attributable to servers and storage, network installation, licenses, handelds, and other items.

PGE claims that AMI will provide two types of benefits. First, it provides operational costs savings, which PGE estimates at $18.2 million in the first full calendar year after deployment. These savings are calculated as follows:
<table>
<thead>
<tr>
<th>Item</th>
<th>Amount</th>
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<tbody>
<tr>
<td>Labor Cost</td>
<td>$10,967,000</td>
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<tr>
<td>Non-labor Cost</td>
<td>956,000</td>
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<tr>
<td>Late Fees</td>
<td>1,737,000</td>
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<tr>
<td>Energy Unaccounted For</td>
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<tr>
<td>Power Cost Savings</td>
<td>1,387,000</td>
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<tr>
<td>Other Savings</td>
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<tr>
<td><strong>Total Projected Savings</strong></td>
<td><strong>$18,164,000</strong></td>
</tr>
</tbody>
</table>

Second, PGE claims that AMI also provides customer and system benefits, derived from programs that the system supports, or may be developed. These would include demand response, distribution asset utilization, and outage management. While these benefits have the potential to produce significant cost savings, their implementation would require additional investment.

PGE’s proposed tariff reflects about $12.9 million for the net annual revenue requirement impact of the AMI, including accelerated depreciation of the old metering system, and operation and management (O&M) savings during the deployment period. That amount represents a 0.8 percent increase in PGE’s revenue requirement as determined by the Commission in PGE’s last general rate case.

For rate recovery, PGE allocated the total revenue requirement into three components: recovery of the costs of the new equipment, accelerated depreciation of existing meters, and O&M savings. PGE calculated the percent to which each of these three categories contributes to the total revenue requirement, and applied those percent contributions to the annualized revenue requirement. Using that method, PGE allocated $4.5 million to the existing system, $12.5 million to the deployment of the new AMI meters, offset by a $4.1 million reduction attributable to O&M savings. For residential customers, the percentage change in revenue requirement is 1.2 percent. For small non-residential customers, the percentage change is 1.4 percent. For most large customers the percentage change is a “fraction” of 1 percent.

The tariff proposal reflects the magnitude of the project and its associated accounting treatment. The plan will take over 2 ½ years to fully implement. Most of the costs will not be charged initially to construction work in progress and then closed to plant when the project is completed. In this case, the meters, which comprise over 80 percent of the investment, will “immediately close to plant” when received by PGE. Without either the tariff or annual rate cases, PGE would receive no recovery on the new system during deployment.

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1 Included in the accelerated depreciation of existing meters are Network Meter Reading (NMR) meters deployed as part of a network metering program approved in docket UE 115. The meters were intended to support direct-access or to provide cost-effective meter readings in remote areas.

Only part of the proposed system was deployed. The costs of that system have been included by PGE in its rates. Because the full system was not deployed, PGE refunded to customers the difference between the projected and actual costs, from 2003 to 2007.
The Joint Parties state that the accelerated depreciation of old meters is consistent with prior Commission orders. They cite earlier dockets where PGE proposed plans for its NMR system and began the accelerated depreciation of its older meters, in anticipation of full deployment. The AMI project's net benefit includes the cost of the accelerated depreciation of the old meters.

The AMI project is structured in a manner that the parties believe avoids conflicts with ORS 757.355. The recovery of the new system occurs slower than the rate of deployment, while the accelerated depreciation of old meters occurs faster than the rate of replacement.

The recovery of the new system incorporates a six-month lag in recovery of new AMI costs, with rate base adjusted monthly during the deployment period. The recovery of the old meters is accomplished by applying most of the accelerated depreciation of the old system at the front-end of the tariff. Together, these provisions allow for the revenue requirement to be levelized over the deployment period.

Through 2010, the AMI will be part of PGE's rate base. PGE also will be realizing the full operating benefits described above. After 2010, PGE will file a general rate case at the Commission's request that will capture the operating benefits on behalf of customers, if the Company is not already engaged in such a proceeding.

In reaching their settlement, the parties reached agreement on implementation issues raised by Staff. These include the ratemaking treatment of vehicles used for meter reading as AMI is deployed, while also revising PGE's vehicle purchasing strategy.

Staff raised an issue relating to updates to PGE's financial analysis. The parties agree that PGE performed those updates and that those updates provide the final estimates for AMI costs and benefits, and the net present value (NPV) of the project. Those values are adopted in the stipulation.

Staff raised an issue regarding the mitigation of AMI rate impacts during the deployment period. The proposed effective date of the AMI tariff coincides with the expected Senate Bill 408 credit (June 1, 2008), which is expected to offset the rate impact of the AMI tariff.

PGE provided Staff a draft scoping plan that identifies and quantifies additional customer and system benefits not included in the direct benefit analysis. The stipulated conditions address Staff's concerns regarding operational implementation plans, customer and system benefits, direct load control and time-varying pricing.

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ORS 757.355 provides, in relevant part: "a public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation or real or personal property not presently used for providing utility service to the customer."
programs, regulatory filings, and coordination with Northwest Natural in the joint meter-reading area.

PGE provided Staff with work papers that demonstrate that PGE used its signed AMI contacts as the basis for its cost estimates for meter equipment and installation in its financial analysis.

The Stipulating Parties agree that PGE has addressed all of CAPO’s issues relating to low-income customers, including each of the following: remote disconnect/reconnect, earlier reconnection than specified in the Oregon Administrative Rules, customer payment/agency commitment processing, limited service delivery, leveraging data, long-term benefits of AMI functionality, and pre-paid metering.

The Stipulating Parties agree that PGE has addressed issues raised by Northwest Natural relating to coordination in joint meter-reading areas.

III. CUB’S POSITION

CUB argues that PGE’s AMI project is not based on a mature technology. CUB cites developments in California, where utilities are proposing widespread deployment of AMI systems. According to CUB, the decisions in California are based on utility business cases that “dwarf” PGE’s in depth, and that rely on time-of-use pricing to achieve cost-effectiveness, unlike PGE’s. CUB argues that the California model supports a “deliberate” process in Oregon.

CUB is concerned that PGE’s AMI technology will not have the functionality to directly control load — “one of the more exciting opportunities that advanced meters could provide.” CUB cites testimony by the Joint Parties to the effect that PGE’s system can be updated to use a “standard protocol” for load control. However, CUB is concerned regarding the likely cost of such upgrades, particularly “given the slim margin of projected net benefit[s]” for the basic system. In CUB’s terms, such improvements would amount to PGE’s third advanced metering installation since late 2001.

CUB notes that inherent in every business plan is the risk that benefits may not materialize as foreseen. PGE and Staff appear to be comfortable that the net benefits will materialize, as planned – CUB is not. CUB claims that PGE intends that its customers will take all of the business risk of the AMI project, and pay for the premature replacement of the earlier advanced NMR meters.

CUB states that the projected net benefit of $33 million over 20 years “is a slim margin when compared to the risks of technology or price changes” associated with the project. CUB compares that total benefit to PGE’s projected net variable power cost for 2008 - $745 million – to make the point that “there is little wiggle room” for the projected favorable outcome.
CUB objects to any advanced approval for PGE’s prudence in undertaking the project. CUB notes that even the parties that have joined PGE in the stipulation relied on PGE’s business plan. CUB makes a distinction between agreeing that PGE’s business plan appears reasonable, and agreeing that the Company prudently formulated its business plan. CUB observes that this Commission cannot bind future commissions, in any event.

CUB objects to the write-off of the docket UE 115 advanced meters (UE 115 meters) as a ratepayer expense. CUB notes that PGE earns a rate of return to manage its business risks. PGE should be responsible for its past project choice.

CUB argues that customers should not pay for either the accelerated depreciation of the UE 115 meters, or for the annual O&M costs necessary to use those meters with the newer system. According to CUB, it would be “bad regulatory policy” to insulate PGE from the consequences of its investment choices. If the Commission were to decide to allow PGE to recover the UE 115 meter costs, CUB argues that the Commission should reduce PGE’s allowed return on equity, to reflect its lower risk.

CUB makes a distinction between the UE 115 meters and the conventional meters that otherwise are deployed across PGE’s system. In the one case, the utility is making a fundamental change in its metering “platform.” In the other case, the utility would be simply replacing older meters with newer ones — prematurely.

CUB notes that 60 percent of PGE’s projected operational savings in its business plan comes from the reduced labor costs resulting from no longer having to read meters manually. That savings already has been realized for the UE 115 meters.

CUB applies ORS 757.140(2) and argues that the proposed retirement of the UE 115 meters would not be in the public interest. CUB notes that premature retirement of the UE 115 meters would not be due to factors enumerated in ORS 757.140(2)(a), leaving the Commission only with the blanket provision: “[W]hen the commission finds that the retirement is in the public interest.”

CUB states that a measure of public interest is net benefit – if the continuing costs of operating the plant are greater than costs associated with retiring the plant, there is a net benefit to closure. However, net benefits themselves do not necessarily support full cost recovery from ratepayers.

ORS 757.140(2). In the following cases the commission may allow in rates, directly or indirectly, amounts on the utility’s books of account which the commission finds represent undepreciated investment in a utility plant, including that which has been retired from service:
(a) When the retirement is due to ordinary wear and tear, casualties, acts of God, acts of governmental authority, or
(b) When the commission finds that the retirement is in the public interest.
CUB cites the Commission’s Trojan decision (Order No. 95-322) to support its view that “net benefits” must encompass more than lower costs. The lower cost standard implies that a poorly run plant could be shut down as a least-cost option, allowing a utility to shift the capital or operating costs of its own imprudence to ratepayers.

According to CUB, PGE’s decision pursuant to UE 115 to go ahead with a “second-choice advanced metering system,” well before advanced metering technology had matured, only increased the likelihood that premature retirement of those meters would produce a net benefit in the current proceeding. The Commission should not “wash out” a poor management decision with a net benefit finding.

In that light, CUB argues that PGE has not proven a net benefit to replacing the UE 115 meters. CUB notes that none of the operational savings reported in PGE’s business plan would seem to apply to the retirement of the UE 115 meters, because all of those benefits also would be realized with the advanced meters already deployed.

Thus, CUB argues that the premature retirement of the UE 115 meters would not qualify for rate recovery under ORS 757.140(2)(b), even if the Commission were to approve PGE’s proposed AMI program. In CUB’s view, it is not in the public interest for the Commission to allow utilities to invest in new technology, only to replace that technology with newer versions.

CUB recommends the Commission reject the stipulation and decline PGE’s request for “pre-approval” of its proposed AMI project. If, however, the Commission approves the proposal, CUB recommends against accelerated depreciation of the UE 115 meters. Further, CUB recommends the Commission make clear that PGE’s business case and its execution are open to prudence examination in the future.

IV. PGE/STAFF/ODOE’S JOINT RESPONSE TO CUB

The Joint Parties dispute CUB’s claim that the proposed technology is not “mature.” They describe the expected deployment of AMI systems in other jurisdictions, including sales by PGE’s vendor, to show that California is not the only market for such products.

They note that it is highly likely that new features will be available in the future, but, if PGE were to wait for new technology, the AMI project might never be undertaken. The technology available for this project will provide the functionality and benefits projected.

The Joint Parties believe that CUB misunderstands their testimony regarding upgrading the system to incorporate a standard protocol that may be developed at a later date for communication with smart appliances. They state that PGE only would seek approval for cost-effective changes to the system, such as a “communication
bridge,” to incorporate a standard protocol. They cite their testimony to the effect that the proposed system would be able to communicate with load control switches on appliances and thermostats, even without the standard protocol.

The Joint Parties state that CUB’s comparison of the $33 million in net benefits to PGE’s projected 2008 net variable power costs “is a meaningless comparison.” The $33 million in savings is significant, and is “more noteworthy” because it incorporates the cost of paying off the old system. On its own, the AMI system is predicted to generate a net present value of over $66 million, not including any potential demand response benefits the AMI project enables.

The Joint Parties state that CUB misconstrues PGE’s position regarding prudence reviews. PGE cites its testimony to the effect that all parties have the right to address AMI costs and benefits and that “the costs and benefits will be subject to a prudence review.” The only decision before the Commission at this time is whether it would be prudent for PGE to proceed with the installation of the AMI system.

Regarding the write-off of the UE 115 meters, the Joint Parties suggest that CUB has ignored uncontested facts and basic ratemaking principles. The parties do not see a legal or policy reason why cost recovery of the meters on an accelerated basis would be improper but recovery over a longer period would be proper. Under recent court decisions, PGE believes that absent accelerated recovery, there would be an unfair impact because it would not be allowed to earn a return on the investment after it is removed from service. If those meters are not replaced, PGE’s annual O&M costs would be greater by $600,000. In addition, capital costs would increase to keep the components functional.

The Joint Parties state that only part of the NMR system approved in docket UE 115 was deployed due to changes in circumstances and that the UE 115 meters have been used and useful since their deployment. However, it is cost effective to replace those meters now, as evidenced by the $600,000 per year savings. They argue that their proposed treatment does meet the standard of ORS 757.140(2).

The Joint Parties note that CUB argued that PGE can proceed without Commission approval, if it is confident about its business case. However, they argue that, for PGE to be able to recover the remaining depreciation of existing meters, ORS 757.355 requires that the Company do so prior to the retirement of such equipment. Therefore, PGE must request such treatment before installing its new AMI system.

V. DISCUSSION

Whether to deploy automatic meter-reading technology to residential and business customers depends largely on whether such an investment would be cost effective. The Joint Parties believe that their analysis proves that PGE’s program would be cost effective and should be approved. CUB disputes their analysis.
In this case the “cost effective” test may be applied in two stages. In the first stage, the Joint Parties have shown that the investment in the AMI technology would be cost effective, even if it were simply a matter of substituting the new meters for the old (including the early retirement of the UE 115 meters). In the second stage, the technology may be used dynamically to generate much more substantial benefits through rate design and load control applications and other system and operational benefits. These benefits could not be realized without the deployment of the devices. To the extent that these measures likewise are cost effective, their realization likely would make the first stage economic, even if it were not cost effective by itself.

The Commission’s adoption of the settlement does not merely allow the AMI technology to be installed and the UE 115 meters to be written off. It also obligates PGE to meet the “Proposed AMI Conditions” set forth in Exhibit 101, sponsored by PGE witness Tooman and Staff witnesses Schwartz and Owings in support of the stipulation. Through PGE’s performance of the specified conditions, the benefits to be realized from adoption of the settlement may be much greater than the savings used to justify the first stage.

The section headings for the conditions are set forth above. As PGE moves ahead to meet those conditions, we will follow its progress. We expect that the parties to the stipulation (and CUB) will hold PGE to these performance standards, and we will entertain a complaint from any party that believes that any condition is not being met. Because the conditions are a material part of our order adopting the settlement, any material change in the terms of the conditions will require Commission approval.

Some of the conditions will require further action before they can be implemented. PGE has committed to filing a critical peak pricing tariff for the Commission’s consideration. Whether to approve such a tariff is a matter that will be taken up at the appropriate time. Other rate design refinements will be entertained as may be reasonable.

PGE has committed to investigating load control measures. Again, whether to implement such measures is a matter that will be taken up at the appropriate time. PGE will have the burden of proving that any such proposed measures are cost effective.

CUB requests that the Commission “make clear that PGE’s business case and the Company’s execution thereof are open to prudence examination in the future.” PGE’s business case has been examined in this docket and has been found adequate to support the deployment of PGE’s proposed AMI technology.

The Commission does not foreclose future consideration of the prudence of PGE’s actions taken in furtherance of its business plan. In the event that the projected benefits are not realized, parties may investigate the circumstances and propose appropriate measures for the Commission’s consideration.
ORDER NO. 08-245

However, premature early retirement of meters itself is not evidence of imprudence. The Commission's decision to allow for accelerated depreciation of the UE 115 meters does not suggest that PGE was imprudent in proceeding with the UE 115 metering project. Early retirement of plant for the benefit of the ratepayers is not evidence of imprudence.

The terms of the stipulation are reasonable.

The settlement is adopted.

ORDER

IT IS ORDERED that Portland General Electric Company's request to add Schedule 111, Advanced Metering Infrastructure, is approved. Advice No. 07-08, subject to the conditions of the stipulation attached as Appendix A, shall be allowed to go into effect June 1, 2008. PGE is granted leave to proceed with its planned deployment of AMI technology, subject to the terms of the settlement adopted in this order.

Made, entered, and effective

MAY 05 2008

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.
BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 189

In the Matter of
PORTLAND GENERAL ELECTRIC COMPANY
Request to Add Schedule 111, Advanced Metering Infrastructure (AMI)

STIPULATION

This Stipulation ("Stipulation") is among Portland General Electric Company ("PGE"), Staff of the Public Utility Commission of Oregon ("Staff"), the Community Action Partnership of Oregon (formerly the Community Action Directors of Oregon), the Oregon Department of Energy, and Northwest Natural (collectively, the "Stipulating Parties").

I. INTRODUCTION

On March 7, 2007, PGE filed Advice No. 07-08 to add Schedule 111, an adjustment schedule to collect costs related to deployment of an Advanced Metering Infrastructure ("AMI"). PGE has since requested an effective date of June 1, 2008, for Schedule 111. Pursuant to the schedule set by the ALJ in this matter, PGE filed testimony supporting its filing on July 27, 2007. That testimony, which incorporated some testimony filed in a previous docket, explained the costs and benefits of the AMI project. PGE has also provided to parties, and the parties relied on in entering into this Stipulation, draft Implementation Plans for the project, draft and signed contracts for AMI equipment purchase and installation, a draft scoping plan related to customer and system benefits, and an updated financial analysis and supporting work papers reflecting the latest estimates of costs and benefits for the AMI project. Workshops have been held and PGE has also responded to numerous data requests from the various parties.
Settlement Conferences were held on July 9, 2007, and October 26, 2007, open to all parties. As a result of those settlement discussions, the Stipulating Parties have agreed to certain conditions associated with the implementation of the AMI project, and with those conditions support for approval of Schedule 111. The Stipulating Parties submit this Stipulation to the Commission and request that the Commission adopt orders in this docket implementing the following.

II. TERMS OF STIPULATION

1. This Stipulation settles all issues raised by the Stipulating Parties.

2. Subject to the provisions below, the Stipulating Parties agree that based on the information provided by PGE to date, and known to the parties, it is prudent for PGE to proceed with implementation of the AMI project, and that PGE should implement the AMI project as set forth in this docket, including the meter purchase and installation contracts provided to the Parties.

3. Attached as Exhibit “A” to this Stipulation are Proposed AMI Conditions (the “Conditions”). The Stipulating Parties have drafted and agreed to the Conditions to address various concerns and issues of the parties. The Stipulating Parties support the adoption and implementation of Schedule 111 as filed by PGE, subject to the Conditions.

4. The Stipulating Parties request and recommend that the Commission approve Advice Filing No. 07-08 subject to the Conditions.

5. This Stipulation does not address PGE’s recovery of AMI-associated costs in any future proceeding.

6. The Stipulating Parties agree that this Stipulation represents a compromise of the positions of the parties for purposes of this docket. As such, conduct, statements, and documents
disclosed in the negotiation of this Stipulation shall not be admissible as evidence in this or any other proceeding.

7. The Stipulating Parties agree that this Stipulation is in the public interest and will result in rates that are fair, just and reasonable.

8. If this Stipulation is challenged by any other party to this proceeding, or any other party seeks a revenue requirement for PGE that departs from the terms of this Stipulation, the Stipulating Parties reserve the right to cross-examine witnesses and put in such evidence as they deem appropriate to respond fully to the issues presented, including the right to raise issues that are incorporated in the settlements embodied in this Stipulation. Notwithstanding this reservation of rights, the Stipulating Parties agree that they will continue to support the Commission’s adoption of the terms of this Stipulation.

9. If the Commission rejects all or any material part of this Stipulation, or adds any material condition to any final order which is not contemplated by this Stipulation, each Stipulating Party reserves the right to withdraw from this Stipulation upon written notice to the Commission and the other Stipulating Parties within five (5) business days of service of the final order that rejects this Stipulation or adds such material condition.

10. This Stipulation will be offered into the record in this proceeding as evidence pursuant to OAR § 860-14-0085. The Stipulating Parties agree to support this Stipulation throughout this proceeding and in any appeal, provide witnesses to sponsor this Stipulation at the hearing, and recommend that the Commission issue an order adopting the settlements contained herein. The Stipulating Parties also agree to cooperate in drafting and submitting the explanatory brief or written testimony required by OAR § 860-14-0085(4).

11. By entering into this Stipulation, no Stipulating Party shall be deemed to have
approved, admitted or consented to the facts, principles, methods or theories employed by any other Stipulating Party in arriving at the terms of this Stipulation. Except as provided in this Stipulation, no Stipulating Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

12. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

DATED this 21st day of November, 2007.
ORDER NO. 08-245

Cece L Coleman
PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

COMMUNITY ACTION PARTNERSHIP OF OREGON

NORTHWEST NATURAL

OREGON DEPARTMENT OF ENERGY
PORTLAND GENERAL ELECTRIC COMPANY

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COMMUNITY ACTION PARTNERSHIP OF OREGON

NORTHWEST NATURAL

[Signature] 11/20/07
OREGON DEPARTMENT OF ENERGY
Proposed AMI Conditions
November 2007

These AMI Conditions include specific timing that is based upon a tariff effective date of June 1, 2008. Should that date change, the specific times identified in this document may change accordingly.

Operational Implementation Plans

With respect to the detailed implementation plans PGE has provided regarding the operational improvements enabled by AMI, PGE has or will:

- Quarterly, beginning in April of 2008 and continuing throughout the deployment period, file with the Commission a status report detailing:
  - progress under the implementation plans, including any significant changes in timing, budget, or scope,
  - number of meters installed, and
  - actual costs by category
- If implementation plans are delayed, either due to significant changes made to the overall AMI project scope that affect implementation plans previously provided or to delays associated with the implementation plans themselves, immediately notify the Commission and provide revised implementation plans within 60 days of the notice provided under this condition.
- Filed draft copies of contracts for AMI equipment and equipment installation on July 2, 2007.
- On October 1, 2007 filed signed copies of contracts for AMI equipment and equipment installation, including a redline/strike-out version to highlight differences from draft copies.

Customer and System-Related Benefits

PGE believes that development of customer demand response capability and additional tools through which customers can increase their energy efficiency are of great value to our customers' and PGE's future. AMI is foundational to furthering our goals for demand response and greater energy efficiency. System-related benefits derived from deployment of AMI will also add value for customers through more efficient use of utility assets and reduction in costs associated with outages. To obtain the greatest benefit from proceeding with AMI, PGE has or will:

- Appointed a Project Manager to lead the effort in developing Project Charters and Project Plans (implementation plans) in each of the following benefit areas:
  - Information-driven Energy Savings
• Distribution Asset Utilization
• Outage Management

Demand Response initiatives are already being addressed by organizations within PGE and do not need additional project management.

• Provided to OPUC Staff and CUB the Project Charters on June 29, 2007. A meeting was conducted on July 9, 2007 to obtain input and feedback on the charters.

• By May 1, 2008, provide OPUC Staff and CUB the detailed implementation plans (Project Plans). The project plans will include the same level of detail as the implementation plans provided for the operational benefits, with specifics as detailed below.

• After the deployment period and continuing through the conclusion of the first general rate case following deployment, file quarterly status reports on customer and systems-related benefits with the Commission (within 30 days of each calendar quarter) showing savings, costs and operational progress to the previously filed implementation plans.

• Three months following the first and third year after each direct load control program is first offered, file with the Commission a report evaluating each program in the preceding year, including itemized program costs, estimated capacity and costs savings, consumer survey results, and the Company's recommendations for modifications.

• For CPP programs, six months following the first and second year after participants are first offered the pricing option, file an evaluation report with the Commission including program costs, estimated capacity savings, customer acceptance results, and the Company's recommendations on whether to continue, modify or terminate the programs.

Demand Response

PGE's initial efforts to develop incremental demand response will occur through:

• IRP Capacity Planning
• Voluntary Critical Peak Pricing
• Appliance Market Transformation

IRP Capacity Planning
In the IRP that PGE filed June 29, 2007, PGE included in its proposed capacity actions all estimated achievable potential firm direct load control\(^1\) by 2012, under the assumption that this will be the achievable, cost-effective potential that can be reached upon implementation of AMI. Specifically, it includes 23-25 MW of mass market direct load control (i.e., from air conditioning, water and space heat), and 80 MW of additional Dispatchable Standby Generation (DSG).

PGE has also included 35 MW by 2012 for firm curtailment among large customers, and critical peak pricing (CPP) tariffs, under the same assumptions of being achievable and cost effective.

To achieve this capability by 2012, PGE has set the following targeted schedule.

- Because our large customers have encouraged PGE to develop a dispatchable peak capacity reduction program, and because of the potential for greater MW among fewer customers more quickly than mass market programs, and because they have the requisite metering capability, the Company has under development a curtailment tariff for its largest customer class (1 MW or greater). The tariff will be proposed by year end 2007. The cost effectiveness of such a program will be determined as part of the investigation of the tariff.

- The next highest potential for cost effective firm demand side capacity during peak periods is among the remaining large business customers. To that end, and where the metering is available, the Company will issue a request to providers of peak demand side capacity to provide proposals under a peak capacity purchase agreement. The development of the RFP is underway and expected to be issued in second quarter 2008, with a tariff following when successful responses are apparent.

- PGE is projecting higher peak loads, in part by the increasing rate of central air conditioning among the residential class. The communications capability of the proposed advanced metering infrastructure will facilitate direct control of major residential appliances such as air conditioners and electric water heaters with additional hardware. Initially PGE planned to issue an RFP for mass market demand side capacity to track with the installation schedule of the advanced meters. This turns out to be cumbersome for direct load control providers as they will not be able to efficiently deploy their installation crews across a targeted customer set over a short duration. Even with a full year of meter installations, a provider may connect only 5-10 MW of their committed load, and would possibly take another year to double that. PGE realizes that mass market direct load

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\(^1\) Per Update of Demand Response Resource Potentials for PGE, Quanta, February 6, 2007.
control providers will respond more favorably to an RFP that is aligned with the AMI deployment schedule, that is, issued just prior to full deployment of the AMI. Therefore, the RFP will be issued eight months prior to the scheduled full installation of the AMI, or approximately first quarter 2010, with a tariff filed by the end of AMI deployment. In addition to the earlier commitment by large customers, this will provide the needed capacity by 2012.

Voluntary Critical Peak Pricing

AMI meters will support time varying pricing options. PGE is planning to implement an experimental tariff for critical peak pricing once the AMI infrastructure is in place. For a CPP program, PGE will or has:

- Provided to OPUC Staff and CUB, on May 1, 2007, a summary document on Critical Peak Pricing. The document addresses market monitoring of other utility efforts, including the California Statewide Pricing Pilot, examples of possible design parameters, and a sample implementation period. In subsequent discussions the implementation period has since been updated to include a phase for data gathering that was originally omitted.
- Engaged OPUC Staff, CUB and other interested stakeholders in review of program options at a July 9, 2007 meeting and through other discussions and electronic communications.
- The Company estimates that a sampling of meter data can be used for the data gathering phase of a proposed program. After the AMI SAT is completed, approximately 50,000 meters, among all customer classes, will be installed, enough to begin data sampling and gathering.
- Two months prior to 50,000 meters scheduled to be installed, or approximately first quarter 2009, PGE will file an experimental CPP tariff. At least two months prior to filing, the Company will provide a draft tariff to OPUC Staff, CUB, ODOE, CAPO and other stakeholders. The Company also will host workshops to explain the proposed program design and provide an opportunity for informal stakeholder comments.
- As PGE develops its CPP program, the company will evaluate the capability of any programmable communicating thermostats and other demand response technologies for use in both price responsive applications for customers and utility direct load control. The Company will discuss its findings in informal stakeholder workshops in advance of tariff filing and include its evaluation in CPP tariff work papers.

Appliance Market Transformation
PGE clearly understands that as a mid-sized utility in Oregon, we do not have the political power or resources to drive significant market transformation. However, we do believe we can assist in moving towards that transformation by working with an appliance manufacturer with whom we already have developed a relationship to modify an agreed upon appliance to (1) receive price and/or control signals from the utility, and (2) include a simple control so the customer can make a one-time decision about how much of the appliance function they are willing to give up when the price of electricity is high. To move this effort forward, PGE will or has:

- Engaged regional stakeholders and appliance manufacturers to identify interest in a technology trial for either water heaters or thermostats.
- Assembled a consortium consisting of PGE, our AMI vendor, an appliance or thermostat manufacturer, and other interested parties to develop a project to create a 5 - 10 MW demand response resource through an appliance market-transformation approach that will activate if awarded a USDOE grant by March of 2008. If the grant is not awarded to the consortium, provide a written report to OPUC Staff and CUB detailing barriers to proceeding by May 1, 2008.

**Information-Driven Energy Savings**

PGE believes that energy usage information derived from AMI interval data will reveal energy savings strategies that customers will value. To test this hypothesis, PGE has performed market research to determine energy usage information. PGE will or has:

- By the dates indicated above, in the Customer and System-Related Benefits section for Project Charters and Project Plans, prepare a Project Charter and Plan (implementation plan) to share the results of research to date, the plans for additional research to determine customer interest in energy usage information, and the plans to implement a program to meet customer interest.

**Distribution Asset Utilization**

The underlying assumption in the area of distribution asset utilization is that the availability of hourly interval data at every point of delivery will allow PGE to compile a detailed load profile on each component of our distribution infrastructure (e.g., every tap line, service transformer, feeder segment between switches) with the objective of improving asset management and overall system efficiencies. AMI can affect:

- Avoided Service Transformer Failures
- Proper Transformer Sizing
- Delayed Feeder Conductor Work, Including Load Balancing of Substation Transformers

**Avoided Service Transformer Failures**

PGE has approximately 300 service transformer failures per year, many of which result from overloading. PGE uses a regression tool to identify overloaded transformers based on estimated monthly kWh usage. The ability to collect interval data on 100% of PGE's service delivery points allows a new model to be developed based on actual hourly loadings which would enable PGE to identify transformers that are overloaded beyond normal tolerances on a more accurate and timely basis. PGE will or has:

- By the dates indicated above, in the Customer and System-Related Benefits section, for Project Charters and Project Plans, prepare a Project Charter and Plan (implementation plan) to develop this model and apply it to service transformers.

**Proper Transformer Sizing**

The new regression model described above could also be used to address oversized transformers currently used. PGE has a program today to analyze transformer loading and replace oversized transformers when the replacement is determined to be cost effective. This program uses monthly kWh usage data assembled in the company's TIVO database to estimate the peak loading of these transformers. Use of interval data to more accurately identify peak loading conditions could better determine oversized transformers leading to more effective use of these resources. PGE will or has:

- By the dates indicated above, in the Customer and System-Related Benefits section, for Project Charters and Project Plans, prepare a Project Charter and Plan (implementation plan) to develop this model and apply it to proper transformer sizing.

**Delayed Feeder Conductor Work**

PGE currently plans feeder reconductor work each year to resolve overloading conditions on sections of affected feeders. With better loading information from AMI interval data on sections and taplines associated with these feeders, some of this work could be deferred or delayed. The better data may allow loads to be shifted to other feeders which could result in a delay in the need to complete the reconductor work. PGE will or has:

- By the dates indicated above, in the Customer and System-Related Benefits section, for Project Charters and Project Plans, prepare a
Project Charter and Plan (implementation plan) to apply the loading information to feeder conductor work.

Outage Management

After the deployment of an AMI system (2010), PGE is planning to upgrade its current Outage Management System (OMS). To ensure proper consideration of outage management improvements enabled by AMI both before and after OMS replacement, PGE will:

- By 2010, develop AMI interface specifications needed to support integration with the new OMS.

Prior to the OMS upgrade, actions that can be taken to improve outage management using the new AMI system will be considered. These actions for consideration are addressed below.

Avoided Trouble Calls

PGE estimates that for a fraction of trouble calls from customers reporting that their power is out, it is subsequently discovered that no PGE outage occurred. These trouble calls could be avoided using the query function in the AMI meter which can determine whether or not power is being delivered to the meter (i.e., customer premise). PGE will or has:

- By the dates indicated above, in the Customer and System-Related Benefits section, for Project Charters and Project Plans, include in an overall Outage Management Project Charter and Plan (implementation plan) application of this query function to avoid trouble calls.

Faster One-Premise Outage Response

With isolated outages involving only one premise, the time between outage occurrence and notification at PGE is currently expected to be longer than for outages affecting multiple customers. This expectation is based on the likelihood of people being away from their homes during work hours and returning to find that their home is without power. With the proposed AMI system, Operators can identify instances of isolated outages and create a service order to initiate repairs without having to rely solely on notification from the customer. PGE will or has:

- By the dates indicated above, in the Customer and System-Related Benefits section, for Project Charters and Project Plans, include in an overall Outage Management Project Charter and Plan
Improved Storm Management

This benefit would avoid the costs to address customers who remain without power after a line crew restores power on their tap line, because the AMI system can detect any remaining, isolated customer outages before the crew leaves the area. Restoring the customer’s service without having to return later saves outage time and utility costs. PGE will or has:

- By the dates indicated above, in the Customer and System-Related Benefits section, for Project Charters and Project Plans, include in an overall Outage Management Project Charter and Plan (implementation plan) application of this detection function to improve storm management.

Faster Fault Location Identification

Approximately half of PGE’s SAIDI (System Average Interruption Duration Index) duration is the result of faults that occur when a substation feeder breaker locks open on a downstream fault. Finding the downstream fault, especially on long rural feeders, is a time-consuming process. A business partner of PGE’s selected AMI vendor is currently developing a fault detection device that would communicate through PGE’s proposed AMI system and help pinpoint the location of faults. Using these devices in conjunction with the AMI system would reduce the time to find these faults significantly and improve SAIDI statistics. PGE will or has:

- By the dates indicated above, in the Customer and System-Related Benefits section, for Project Charters and Project Plans, include in an overall Outage Management Project Charter and Plan (implementation plan) application of these fault detection devices.

Regulatory Filings

PGE commits that if it does not file a general rate case within 12 months of the termination of the UE 189 tariffs, PGE will provide Staff and any interested party a report showing final capture of O&M savings so that the comparison of ‘before’ and ‘after’ states does not become too difficult. In addition, after 2010, if PGE is not currently engaged in a general rate proceeding, the Commission may request no later than July 1, 2012, that PGE submit a general rate filing in Oregon no later than eight months thereafter. PGE shall bear the burden of proof in such filing, in accordance with ORS 757.210

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2 This condition does not apply in the event the tariff terminates under Special Condition No. 1 in proposed Schedule 111, Exhibit 202 in PGE's direct testimony filed July 27, 2007.
Coordination with Northwest Natural Gas Company (NWN) in Joint Meter Reading Area

PGE Revenue Operations management has had discussions with NWN management on a periodic basis to inform them of our plans and progress towards deployment of an AMI system and to ascertain their plans for automation within the joint meter reading area. PGE has shared with NWN the specific AMI technology vendor selected and NWN has had several meetings with that vendor to determine whether or not they might consider use of that vendor in the joint meter reading area. To assure coordination that has the least possible financial impact upon customers continues, PGE will:

- Quarterly, beginning in April of 2008 and throughout the deployment period, report to the OPUC Staff and CUB (with a copy provided to NWN) on ongoing coordination discussions between PGE and NWN and actions being taken to assure continued coordination with the least possible financial impact upon customers during deployment.
- Provide preliminary notification of dissolution of the Joint Meter Reading Agreement between PGE and NWN within 30 days of PGE receiving AMI tariff approval from the OPUC and PGE Board approval to move forward with the project.
- Notify NWN no later than 30 days, and as soon as is practicable, of any significant changes from the operational implementation plans that may affect the joint meter reading area.

Community Action Partnership of Oregon (CAPO) and Oregon Energy Coordinators Associations (OECA) Conditions

Discussions between CAPO and PGE have identified several areas of potential impact upon PGE’s low-income customers as a result of the implementation of AMI. Each of these areas is addressed below.

Remote Disconnect/Reconnect

Administrative Rules outline the specific communication requirements that PGE must meet in disconnecting and reconnecting a customer. CAPO and OECA want assurance that PGE’s low-income customers understand the rules ahead of their application using AMI Remote Disconnect/Reconnect functionality so that they can proactively seek the assistance they need in paying their utility bills. To assist in educating customers, PGE will:

- In coordination with Community Action Agencies (CAAs), by December 15, 2008, prior to the start of full AMI meter deployment, develop the following training materials:
- Train the trainer materials that CAA personnel could use in their interaction with low income clients,
- General training information that could be provided to low income customers and social service agencies that serve these customers,
- Workshop material that could be delivered by either PGE or CAA personnel,
- Training of CAA representatives to assure their understanding of the need to communicate only completed and authorized commitments to PGE in relation to reconnections,
- Communicate with CAAs their responsibility in meeting contract obligations by providing funds to PGE within 45 days of the commitment date.

Development of this material will take into account the best methods of communication, including DVDs. During the Systems Acceptance Test consideration will be given to testing communications methodologies with low income customers associated with remote disconnect/reconnect.

During the development of these Administrative Rules, PGE outlined plans to assure that reconnections would be done in a timely manner. To assure reconnections are completed in a timely manner, PGE will:

- Where AMI meters with the automatic disconnect/reconnect feature are deployed, PGE will commit to provide same day reconnections when payments are processed at authorized payment locations or commitments are made by CAAs and reconnection requirements are met by 5:00 PM on Monday through Thursday, and by 3:00 PM on Fridays. PGE will establish procedures to facilitate the customer’s required reapplication for service.

During the full deployment of meters across PGE’s service territory as part of the AMI Project, PGE plans to install approximately 238,000 remote disconnect/reconnect meters in non-owner-occupied residences. Subsequent to the AMI Project deployment, PGE may consider deployment of additional remote disconnect/reconnect meters as part of the general meter replacement activities and not as a specific incremental cost to customers receiving those meters. However, no formal process has yet been defined about how that deployment would be implemented. Prior to implementing a post-AMI Project deployment of remote disconnect/reconnect meters, PGE will:

- Meet with CAPO, CAAs, OPUC Staff and other interested parties to review the implementation plan, provide sufficient time for review, and address identified concerns.
Leveraging Data

AMI provides for the collection and assembly of AMI interval data for customers that will enable PGE to deliver benefits described in the Information Driven Energy Savings (IDES) portion of this document. To assist CAAs and low-income customers in accessing electricity usage information to manage their electric bills, PGE will:

- As part of the IDES Project, make AMI interval data available and accessible to low income customers and, with customer approval and specific training (developed jointly by PGE and CAPO/CAAs), to CAAs that serve these customers. The timing of this commitment will be driven through the development of specific implementation plans as part of the IDES Project.

Long-Term Benefits of AMI Functionality

As part of demand response and appliance market transformation programs discussed earlier in this document, there is the potential for new technologies to be made available in the market place in the form of “smart” appliances and in-home communications devices providing pricing information. To assure that low-income customers are provided equivalent access to these new technologies, PGE will:

- Propose critical peak pricing demand response programs as voluntary “opt-in” programs.
- Provide educational information on demand response programs to PGE Customer Service Representatives and CAA representatives so that they can explain to low-income customers the potential risks of higher bills should they choose to participate in such programs but not reduce energy usage at critical times.
- Support local, regional and national policy decisions that would provide the opportunity for low-income customers to have access to “smart” appliances and in-home communications devices providing pricing information if/when they become available in the market. This will enable low-income customers to have the opportunity to use these technologies to lower their energy usage and their bill.

Limited Service Delivery

CAPO and CAAs have expressed an interest in exploring the possibility of providing minimal, lifeline-like electricity service to customers who have been “disconnected”. Such a service could entail providing continuous operation of a refrigerator for the safety and stability of a household’s perishable food and/or medications and the operation of, for example, a
single standard household outlet. Because PGE is also interested in exploration of this possible service after completing the installation of the initial AMI system, PGE will:

- By March 31, 2009, enter into policy discussions with CAPO, CAAs and other interested parties about providing minimal, lifeline-like service to customers who have been “disconnected”. Technology discussions will proceed by September 30, 2009 and PGE will assure that technology decisions made by PGE will not preclude the opportunity for consideration of this program.

**Pre-Paid Electric Metering**

Pre-paid metering is not a program or functionality that will be included as part of the AMI deployment project. While PGE has discussed using the AMI technology to pilot a pre-paid metering program, no decision to proceed has been made. To assure that this potential program is applied appropriately, PGE will:

- Prior to proposing a pre-paid metering pilot program to the OPUC, meet with OPUC Staff, CAAs, CUB, and other parties to explore parameters associated with pre-paid metering.

**Status Reporting**

To keep all parties informed of activity in addressing the CAPO OECA conditions, PGE will:

- Semi-annually, beginning in April of 2008 and throughout the deployment period, report to CAPO, CUB the OPUC Staff on status of the development and implementation of discussions, materials and trainings related to the low-income (CAPO) conditions.
“(B) PAYMENT.—Any company against which the Administrator assesses costs under this paragraph shall pay such costs.
“(2) DEPOSIT OF FUNDS.—Funds collected under this section shall be deposited in the account for salaries and expenses of the Administration.

“SEC. 394. MISCELLANEOUS.

“To the extent such procedures are not inconsistent with the requirements of this part, the Administrator may take such action as set forth in sections 309, 311, 312, and 314 and an officer, director, employee, agent, or other participant in the management or conduct of the affairs of a Renewable Fuel Capital Investment company shall be subject to the requirements of such sections.

“SEC. 395. REMOVAL OR SUSPENSION OF DIRECTORS OR OFFICERS.

“Using the procedures for removing or suspending a director or an officer of a licensee set forth in section 313 (to the extent such procedures are not inconsistent with the requirements of this part), the Administrator may remove or suspend any director or officer of any Renewable Fuel Capital Investment company.

“SEC. 396. REGULATIONS.

“The Administrator may issue such regulations as the Administrator determines necessary to carry out the provisions of this part in accordance with its purposes.

“SEC. 397. AUTHORIZATIONS OF APPROPRIATIONS.

“(a) IN GENERAL.—Subject to the availability of appropriations, the Administrator is authorized to make $15,000,000 in operational assistance grants under section 389 for each of fiscal years 2008 and 2009.

“(b) FUNDS COLLECTED FOR EXAMINATIONS.—Funds deposited under section 393(c)(2) are authorized to be appropriated only for the costs of examinations under section 393 and for the costs of other oversight activities with respect to the program established under this part.

“SEC. 398. TERMINATION.

“The program under this part shall terminate at the end of the second full fiscal year after the date that the Administrator establishes the program under this part.”.

SEC. 1208. STUDY AND REPORT.

The Administrator of the Small Business Administration shall conduct a study of the Renewable Fuel Capital Investment Program under part C of title III of the Small Business Investment Act of 1958, as added by this Act. Not later than 3 years after the date of enactment of this Act, the Administrator shall complete the study under this section and submit to Congress a report regarding the results of the study.

TITLE XIII—SMART GRID

SEC. 1301. STATEMENT OF POLICY ON MODERNIZATION OF ELECTRICITY GRID.

It is the policy of the United States to support the modernization of the Nation’s electricity transmission and distribution system
to maintain a reliable and secure electricity infrastructure that can meet future demand growth and to achieve each of the following, which together characterize a Smart Grid:

1. Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid.
2. Dynamic optimization of grid operations and resources, with full cyber-security.
3. Deployment and integration of distributed resources and generation, including renewable resources.
4. Development and incorporation of demand response, demand-side resources, and energy-efficiency resources.
5. Deployment of “smart” technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications concerning grid operations and status, and distribution automation.
6. Integration of “smart” appliances and consumer devices.
7. Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air conditioning.
8. Provision to consumers of timely information and control options.
9. Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.
10. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.

SEC. 1302. SMART GRID SYSTEM REPORT.

The Secretary, acting through the Assistant Secretary of the Office of Electricity Delivery and Energy Reliability (referred to in this section as the “OEDER”) and through the Smart Grid Task Force established in section 1303, shall, after consulting with any interested individual or entity as appropriate, no later than 1 year after enactment, and every 2 years thereafter, report to Congress concerning the status of smart grid deployments nationwide and any regulatory or government barriers to continued deployment. The report shall provide the current status and prospects of smart grid development, including information on technology penetration, communications network capabilities, costs, and obstacles. It may include recommendations for State and Federal policies or actions helpful to facilitate the transition to a smart grid. To the extent appropriate, it should take a regional perspective. In preparing this report, the Secretary shall solicit advice and contributions from the Smart Grid Advisory Committee created in section 1303; from other involved Federal agencies including but not limited to the Federal Energy Regulatory Commission (“Commission”), the National Institute of Standards and Technology (“Institute”), and the Department of Homeland Security; and from other stakeholder groups not already represented on the Smart Grid Advisory Committee.

SEC. 1303. SMART GRID ADVISORY COMMITTEE AND SMART GRID TASK FORCE.

(a) SMART GRID ADVISORY COMMITTEE.—
(1) ESTABLISHMENT.—The Secretary shall establish, within 90 days of enactment of this Part, a Smart Grid Advisory Committee (either as an independent entity or as a designated sub-part of a larger advisory committee on electricity matters). The Smart Grid Advisory Committee shall include eight or more members appointed by the Secretary who have sufficient experience and expertise to represent the full range of smart grid technologies and services, to represent both private and non-Federal public sector stakeholders. One member shall be appointed by the Secretary to Chair the Smart Grid Advisory Committee.

(2) MISSION.—The mission of the Smart Grid Advisory Committee shall be to advise the Secretary, the Assistant Secretary, and other relevant Federal officials concerning the development of smart grid technologies, the progress of a national transition to the use of smart-grid technologies and services, the evolution of widely-accepted technical and practical standards and protocols to allow interoperability and inter-communication among smart-grid capable devices, and the optimum means of using Federal incentive authority to encourage such progress.

(3) APPLICABILITY OF FEDERAL ADVISORY COMMITTEE ACT.—The Federal Advisory Committee Act (5 U.S.C. App.) shall apply to the Smart Grid Advisory Committee.

(b) SMART GRID TASK FORCE.—

(1) ESTABLISHMENT.—The Assistant Secretary of the Office of Electricity Delivery and Energy Reliability shall establish, within 90 days of enactment of this Part, a Smart Grid Task Force composed of designated employees from the various divisions of that office who have responsibilities related to the transition to smart-grid technologies and practices. The Assistant Secretary or his designee shall be identified as the Director of the Smart Grid Task Force. The Chairman of the Federal Energy Regulatory Commission and the Director of the National Institute of Standards and Technology shall each designate at least one employee to participate on the Smart Grid Task Force. Other members may come from other agencies at the invitation of the Assistant Secretary or the nomination of the head of such other agency. The Smart Grid Task Force shall, without disrupting the work of the Divisions or Offices from which its members are drawn, provide an identifiable Federal entity to embody the Federal role in the national transition toward development and use of smart grid technologies.

(2) MISSION.—The mission of the Smart Grid Task Force shall be to insure awareness, coordination and integration of the diverse activities of the Office and elsewhere in the Federal Government related to smart-grid technologies and practices, including but not limited to: smart grid research and development; development of widely accepted smart-grid standards and protocols; the relationship of smart-grid technologies and practices to electric utility regulation; the relationship of smart-grid technologies and practices to infrastructure development, system reliability and security; and the relationship of smart-grid technologies and practices to other facets of electricity supply, demand, transmission, distribution, and policy. The Smart Grid Task Force shall collaborate with the Smart Grid Advisory Committee and other Federal agencies and offices.
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The Smart Grid Task Force shall meet at the call of its Director as necessary to accomplish its mission.

(c) AUTHORIZATION.—There are authorized to be appropriated for the purposes of this section such sums as are necessary to the Secretary to support the operations of the Smart Grid Advisory Committee and Smart Grid Task Force for each of fiscal years 2008 through 2020.

SEC. 1304. SMART GRID TECHNOLOGY RESEARCH, DEVELOPMENT, AND DEMONSTRATION.

(a) Power Grid Digital Information Technology.—The Secretary, in consultation with the Federal Energy Regulatory Commission and other appropriate agencies, electric utilities, the States, and other stakeholders, shall carry out a program—

(1) to develop advanced techniques for measuring peak load reductions and energy-efficiency savings from smart metering, demand response, distributed generation, and electricity storage systems;

(2) to investigate means for demand response, distributed generation, and storage to provide ancillary services;

(3) to conduct research to advance the use of wide-area measurement and control networks, including data mining, visualization, advanced computing, and secure and dependable communications in a highly-distributed environment;

(4) to test new reliability technologies, including those concerning communications network capabilities, in a grid control room environment against a representative set of local outage and wide area blackout scenarios;

(5) to identify communications network capacity needed to implement advanced technologies.

(6) to investigate the feasibility of a transition to time-of-use and real-time electricity pricing;

(7) to develop algorithms for use in electric transmission system software applications;

(8) to promote the use of underutilized electricity generation capacity in any substitution of electricity for liquid fuels in the transportation system of the United States; and

(9) in consultation with the Federal Energy Regulatory Commission, to propose interconnection protocols to enable electric utilities to access electricity stored in vehicles to help meet peak demand loads.

(b) Smart Grid Regional Demonstration Initiative.—

(1) In General.—The Secretary shall establish a smart grid regional demonstration initiative (referred to in this subsection as the “Initiative”) composed of demonstration projects specifically focused on advanced technologies for use in power grid sensing, communications, analysis, and power flow control. The Secretary shall seek to leverage existing smart grid deployments.

(2) Goals.—The goals of the Initiative shall be—

(A) to demonstrate the potential benefits of concentrated investments in advanced grid technologies on a regional grid;

(B) to facilitate the commercial transition from the current power transmission and distribution system technologies to advanced technologies;
(C) to facilitate the integration of advanced technologies in existing electric networks to improve system performance, power flow control, and reliability;

(D) to demonstrate protocols and standards that allow for the measurement and validation of the energy savings and fossil fuel emission reductions associated with the installation and use of energy efficiency and demand response technologies and practices; and

(E) to investigate differences in each region and regulatory environment regarding best practices in implementing smart grid technologies.

(3) DEMONSTRATION PROJECTS.—

(A) IN GENERAL.—In carrying out the initiative, the Secretary shall carry out smart grid demonstration projects in up to 5 electricity control areas, including rural areas and at least 1 area in which the majority of generation and transmission assets are controlled by a tax-exempt entity.

(B) COOPERATION.—A demonstration project under subparagraph (A) shall be carried out in cooperation with the electric utility that owns the grid facilities in the electricity control area in which the demonstration project is carried out.

(C) FEDERAL SHARE OF COST OF TECHNOLOGY INVESTMENTS.—The Secretary shall provide to an electric utility described in subparagraph (B) financial assistance for use in paying an amount equal to not more than 50 percent of the cost of qualifying advanced grid technology investments made by the electric utility to carry out a demonstration project.

(D) INELIGIBILITY FOR GRANTS.—No person or entity participating in any demonstration project conducted under this subsection shall be eligible for grants under section 1306 for otherwise qualifying investments made as part of that demonstration project.

(c) AUTHORIZATION OF APPROPRIATIONS.—There are authorized to be appropriated—

(1) to carry out subsection (a), such sums as are necessary for each of fiscal years 2008 through 2012; and

(2) to carry out subsection (b), $100,000,000 for each of fiscal years 2008 through 2012.

SEC. 1305. SMART GRID INTEROPERABILITY FRAMEWORK.

(a) INTEROPERABILITY FRAMEWORK.—The Director of the National Institute of Standards and Technology shall have primary responsibility to coordinate the development of a framework that includes protocols and model standards for information management to achieve interoperability of smart grid devices and systems. Such protocols and standards shall further align policy, business, and technology approaches in a manner that would enable all electric resources, including demand-side resources, to contribute to an efficient, reliable electricity network. In developing such protocols and standards—

(1) the Director shall seek input and cooperation from the Commission, OEDER and its Smart Grid Task Force, the Smart Grid Advisory Committee, other relevant Federal and State agencies; and
(2) the Director shall also solicit input and cooperation from private entities interested in such protocols and standards, including but not limited to the Gridwise Architecture Council, the International Electrical and Electronics Engineers, the National Electric Reliability Organization recognized by the Federal Energy Regulatory Commission, and National Electrical Manufacturer's Association.

(b) Scope of Framework.—The framework developed under subsection (a) shall be flexible, uniform and technology neutral, including but not limited to technologies for managing smart grid information, and designed—

(1) to accommodate traditional, centralized generation and transmission resources and consumer distributed resources, including distributed generation, renewable generation, energy storage, energy efficiency, and demand response and enabling devices and systems;

(2) to be flexible to incorporate—

(A) regional and organizational differences; and

(B) technological innovations;

(3) to consider the use of voluntary uniform standards for certain classes of mass-produced electric appliances and equipment for homes and businesses that enable customers, at their election and consistent with applicable State and Federal laws, and are manufactured with the ability to respond to electric grid emergencies and demand response signals by curtailing all, or a portion of, the electrical power consumed by the appliances or equipment in response to an emergency or demand response signal, including through—

(A) load reduction to reduce total electrical demand;

(B) adjustment of load to provide grid ancillary services; and

(C) in the event of a reliability crisis that threatens an outage, short-term load shedding to help preserve the stability of the grid; and

(4) such voluntary standards should incorporate appropriate manufacturer lead time.

(c) Timing of Framework Development.—The Institute shall begin work pursuant to this section within 60 days of enactment. The Institute shall provide and publish an initial report on progress toward recommended or consensus standards and protocols within 1 year after enactment, further reports at such times as developments warrant in the judgment of the Institute, and a final report when the Institute determines that the work is completed or that a Federal role is no longer necessary.

(d) Standards for Interoperability in Federal Jurisdiction.—At any time after the Institute’s work has led to sufficient consensus in the Commission’s judgment, the Commission shall institute a rulemaking proceeding to adopt such standards and protocols as may be necessary to insure smart-grid functionality and interoperability in interstate transmission of electric power, and regional and wholesale electricity markets.

(e) Authorization.—There are authorized to be appropriated for the purposes of this section $5,000,000 to the Institute to support the activities required by this subsection for each of fiscal years 2008 through 2012.
SEC. 1306. FEDERAL MATCHING FUND FOR SMART GRID INVESTMENT COSTS.

(a) MATCHING FUND.—The Secretary shall establish a Smart Grid Investment Matching Grant Program to provide reimbursement of one-fifth (20 percent) of qualifying Smart Grid investments.

(b) QUALIFYING INVESTMENTS.—Qualifying Smart Grid investments may include any of the following made on or after the date of enactment of this Act:

1. In the case of appliances covered for purposes of establishing energy conservation standards under part B of title III of the Energy Policy and Conservation Act of 1975 (42 U.S.C. 6291 et seq.), the documented expenditures incurred by a manufacturer of such appliances associated with purchasing or designing, creating the ability to manufacture, and manufacturing and installing for one calendar year, internal devices that allow the appliance to engage in Smart Grid functions.

2. In the case of specialized electricity-using equipment, including motors and drivers, installed in industrial or commercial applications, the documented expenditures incurred by its owner or its manufacturer of installing devices or modifying that equipment to engage in Smart Grid functions.

3. In the case of transmission and distribution equipment fitted with monitoring and communications devices to enable smart grid functions, the documented expenditures incurred by the electric utility to purchase and install such monitoring and communications devices.

4. In the case of metering devices, sensors, control devices, and other devices integrated with and attached to an electric utility system or retail distributor or marketer of electricity that are capable of engaging in Smart Grid functions, the documented expenditures incurred by the electric utility, distributor, or marketer and its customers to purchase and install such devices.

5. In the case of software that enables devices or computers to engage in Smart Grid functions, the documented purchase costs of the software.

6. In the case of entities that operate or coordinate operations of regional electric grids, the documented expenditures for purchasing and installing such equipment that allows Smart Grid functions to operate and be combined or coordinated among multiple electric utilities and between that region and other regions.

7. In the case of persons or entities other than electric utilities owning and operating a distributed electricity generator, the documented expenditures of enabling that generator to be monitored, controlled, or otherwise integrated into grid operations and electricity flows on the grid utilizing Smart Grid functions.

8. In the case of electric or hybrid-electric vehicles, the documented expenses for devices that allow the vehicle to engage in Smart Grid functions (but not the costs of electricity storage for the vehicle).

9. The documented expenditures related to purchasing and implementing Smart Grid functions in such other cases as the Secretary shall identify. In making such grants, the Secretary shall seek to reward innovation and early adaptation,
even if success is not complete, rather than deployment of proven and commercially viable technologies.

(c) INVESTMENTS NOT INCLUDED.—Qualifying Smart Grid investments do not include any of the following:

(1) Investments or expenditures for Smart Grid technologies, devices, or equipment that are eligible for specific tax credits or deductions under the Internal Revenue Code, as amended.

(2) Expenditures for electricity generation, transmission, or distribution infrastructure or equipment not directly related to enabling Smart Grid functions.

(3) After the final date for State consideration of the Smart Grid Information Standard under section 1307 (paragraph (17) of section 111(d) of the Public Utility Regulatory Policies Act of 1978), an investment that is not in compliance with such standard.

(4) After the development and publication by the Institute of protocols and model standards for interoperability of smart grid devices and technologies, an investment that fails to incorporate any of such protocols or model standards.

(5) Expenditures for physical interconnection of generators or other devices to the grid except those that are directly related to enabling Smart Grid functions.

(6) Expenditures for ongoing salaries, benefits, or personnel costs not incurred in the initial installation, training, or start up of smart grid functions.

(7) Expenditures for travel, lodging, meals or other personal costs.

(8) Ongoing or routine operation, billing, customer relations, security, and maintenance expenditures.

(9) Such other expenditures that the Secretary determines not to be Qualifying Smart Grid Investments by reason of the lack of the ability to perform Smart Grid functions or lack of direct relationship to Smart Grid functions.

(d) SMART GRID FUNCTIONS.—The term “smart grid functions” means any of the following:

(1) The ability to develop, store, send and receive digital information concerning electricity use, costs, time of use, nature of use, storage, or other information relevant to device, grid, or utility operations, to or from or by means of the electric utility system, through one or a combination of devices and technologies.

(2) The ability to develop, store, send and receive digital information concerning electricity use, costs, time of use, nature of use, storage, or other information relevant to device, grid, or utility operations to or from a computer or other control device.

(3) The ability to measure or monitor electricity use as a function of time of day, power quality characteristics such as voltage level, current, cycles per second, or source or type of generation and to store, synthesize or report that information by digital means.

(4) The ability to sense and localize disruptions or changes in power flows on the grid and communicate such information instantaneously and automatically for purposes of enabling automatic protective responses to sustain reliability and security of grid operations.
(5) The ability to detect, prevent, communicate with regard to, respond to, or recover from system security threats, including cyber-security threats and terrorism, using digital information, media, and devices.

(6) The ability of any appliance or machine to respond to such signals, measurements, or communications automatically or in a manner programmed by its owner or operator without independent human intervention.

(7) The ability to use digital information to operate functionalities on the electric utility grid that were previously electro-mechanical or manual.

(8) The ability to use digital controls to manage and modify electricity demand, enable congestion management, assist in voltage control, provide operating reserves, and provide frequency regulation.

(9) Such other functions as the Secretary may identify as being necessary or useful to the operation of a Smart Grid.

(e) The Secretary shall—

(1) establish and publish in the Federal Register, within 1 year after the enactment of this Act procedures by which applicants who have made qualifying Smart Grid investments can seek and obtain reimbursement of one-fifth of their documented expenditures;

(2) establish procedures to ensure that there is no duplication or multiple reimbursement for the same investment or costs, that the reimbursement goes to the party making the actual expenditures for Qualifying Smart Grid Investments, and that the grants made have significant effect in encouraging and facilitating the development of a smart grid;

(3) maintain public records of reimbursements made, recipients, and qualifying Smart Grid investments which have received reimbursements;

(4) establish procedures to provide, in cases deemed by the Secretary to be warranted, advance payment of moneys up to the full amount of the projected eventual reimbursement, to creditworthy applicants whose ability to make Qualifying Smart Grid Investments may be hindered by lack of initial capital, in lieu of any later reimbursement for which that applicant qualifies, and subject to full return of the advance payment in the event that the Qualifying Smart Grid investment is not made; and

(5) have and exercise the discretion to deny grants for investments that do not qualify in the reasonable judgment of the Secretary.

(f) AUTHORIZATION OF APPROPRIATIONS.—There are authorized to be appropriated to the Secretary such sums as are necessary for the administration of this section and the grants to be made pursuant to this section for fiscal years 2008 through 2012.

SEC. 1307. STATE CONSIDERATION OF SMART GRID.

(a) Section 111(d) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2621(d)) is amended by adding at the end the following:

“(16) CONSIDERATION OF SMART GRID INVESTMENTS.—

“(A) IN GENERAL.—Each State shall consider requiring that, prior to undertaking investments in nonadvanced grid technologies, an electric utility of the State demonstrate
to the State that the electric utility considered an investment in a qualified smart grid system based on appropriate factors, including—

“(i) total costs;
“(ii) cost-effectiveness;
“(iii) improved reliability;
“(iv) security;
“(v) system performance; and
“(vi) societal benefit.

“(B) RATE RECOVERY.—Each State shall consider authorizing each electric utility of the State to recover from ratepayers any capital, operating expenditure, or other costs of the electric utility relating to the deployment of a qualified smart grid system, including a reasonable rate of return on the capital expenditures of the electric utility for the deployment of the qualified smart grid system.

“(C) OBSOLETE EQUIPMENT.—Each State shall consider authorizing any electric utility or other party of the State to deploy a qualified smart grid system to recover in a timely manner the remaining book-value costs of any equipment rendered obsolete by the deployment of the qualified smart grid system, based on the remaining depreciable life of the obsolete equipment.

“(17) SMART GRID INFORMATION.—

“(A) STANDARD.—All electricity purchasers shall be provided direct access, in written or electronic machine-readable form as appropriate, to information from their electricity provider as provided in subparagraph (B).

“(B) INFORMATION.—Information provided under this section, to the extent practicable, shall include:

“(i) PRICES.—Purchasers and other interested persons shall be provided with information on—

“(I) time-based electricity prices in the wholesale electricity market; and

“(II) time-based electricity retail prices or rates that are available to the purchasers.

“(ii) USAGE.—Purchasers shall be provided with the number of electricity units, expressed in kwh, purchased by them.

“(iii) INTERVALS AND PROJECTIONS.—Updates of information on prices and usage shall be offered on not less than a daily basis, shall include hourly price and use information, where available, and shall include a day-ahead projection of such price information to the extent available.

“(iv) SOURCES.—Purchasers and other interested persons shall be provided annually with written information on the sources of the power provided by the utility, to the extent it can be determined, by type of generation, including greenhouse gas emissions associated with each type of generation, for intervals during which such information is available on a cost-effective basis.

“(C) ACCESS.—Purchasers shall be able to access their own information at any time through the Internet and on other means of communication elected by that utility
for Smart Grid applications. Other interested persons shall be able to access information not specific to any purchaser through the Internet. Information specific to any purchaser shall be provided solely to that purchaser.”.

(b) COMPLIANCE.—
(1) TIME LIMITATIONS.—Section 112(b) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2622(b)) is amended by adding the following at the end thereof:

“(6)(A) Not later than 1 year after the enactment of this paragraph, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated utility shall commence the consideration referred to in section 111, or set a hearing date for consideration, with respect to the standards established by paragraphs (17) through (18) of section 111(d).

“(B) Not later than 2 years after the date of the enactment of this paragraph, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority), and each nonregulated electric utility, shall complete the consideration, and shall make the determination, referred to in section 111 with respect to each standard established by paragraphs (17) through (18) of section 111(d).”.

(2) FAILURE TO COMPLY.—Section 112(c) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2622(c)) is amended by adding the following at the end:

“In the case of the standards established by paragraphs (16) through (19) of section 111(d), the reference contained in this subsection to the date of enactment of this Act shall be deemed to be a reference to the date of enactment of such paragraphs.”.

(3) PRIOR STATE ACTIONS.—Section 112(d) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2622(d)) is amended by inserting “and paragraphs (17) through (18)” before “of section 111(d)”.

SEC. 1308. STUDY OF THE EFFECT OF PRIVATE WIRE LAWS ON THE DEVELOPMENT OF COMBINED HEAT AND POWER FACILITIES.

(a) STUDY.—
(1) IN GENERAL.—The Secretary, in consultation with the States and other appropriate entities, shall conduct a study of the laws (including regulations) affecting the siting of privately owned electric distribution wires on and across public rights-of-way.

(2) REQUIREMENTS.—The study under paragraph (1) shall include—

(A) an evaluation of—
(i) the purposes of the laws; and
(ii) the effect the laws have on the development of combined heat and power facilities;

(B) a determination of whether a change in the laws would have any operating, reliability, cost, or other impacts on electric utilities and the customers of the electric utilities; and

(C) an assessment of—
(i) whether privately owned electric distribution wires would result in duplicative facilities; and
(ii) whether duplicative facilities are necessary or desirable.

(b) REPORT.—Not later than 1 year after the date of enactment of this Act, the Secretary shall submit to Congress a report that describes the results of the study conducted under subsection (a).

SEC. 1309. DOE STUDY OF SECURITY ATTRIBUTES OF SMART GRID SYSTEMS.

(a) DOE STUDY.—The Secretary shall, within 18 months after the date of enactment of this Act, submit a report to Congress that provides a quantitative assessment and determination of the existing and potential impacts of the deployment of Smart Grid systems on improving the security of the Nation’s electricity infrastructure and operating capability. The report shall include but not be limited to specific recommendations on each of the following:

(1) How smart grid systems can help in making the Nation’s electricity system less vulnerable to disruptions due to intentional acts against the system.

(2) How smart grid systems can help in restoring the integrity of the Nation’s electricity system subsequent to disruptions.

(3) How smart grid systems can facilitate nationwide, interoperable emergency communications and control of the Nation’s electricity system during times of localized, regional, or nationwide emergency.

(4) What risks must be taken into account that smart grid systems may, if not carefully created and managed, create vulnerability to security threats of any sort, and how such risks may be mitigated.

(b) CONSULTATION.—The Secretary shall consult with other Federal agencies in the development of the report under this section, including but not limited to the Secretary of Homeland Security, the Federal Energy Regulatory Commission, and the Electric Reliability Organization certified by the Commission under section 215(c) of the Federal Power Act (16 U.S.C. 824o) as added by section 1211 of the Energy Policy Act of 2005 (Public Law 109–58; 119 Stat. 941).

TITLE XIV—POOL AND SPA SAFETY

SEC. 1401. SHORT TITLE.

This title may be cited as the “Virginia Graeme Baker Pool and Spa Safety Act”.

SEC. 1402. FINDINGS.

Congress finds the following:

(1) Of injury-related deaths, drowning is the second leading cause of death in children aged 1 to 14 in the United States.

(2) In 2004, 761 children aged 14 and under died as a result of unintentional drowning.

(3) Adult supervision at all aquatic venues is a critical safety factor in preventing children from drowning.

(4) Research studies show that the installation and proper use of barriers or fencing, as well as additional layers of protection, could substantially reduce the number of childhood residential swimming pool drownings and near drownings.
Two Questions:

1. In light of the varying degrees of progress among the states regarding smart grid implementation, should the federal government act in lieu of the states to require smart grid implementation at a faster pace?

2. What tools should state regulators bring to the table when judging the merit (or prudence) of utility decisions that affect customers?
February 24, 25, 2011

Energy Bar

Arizona Energy Issues

Commissioner Paul Newman
Arizona Corporation Commission
pnewman@azcc.gov
602-542-36827
Agenda - Items to Discuss

• You asked for some ‘new ideas’ and I want to deliver!
• Energy: **net energy** is key
• How much AZ spends on fossil fuels
• Why solar is the best long-term investment AZ can make
• Externalities: what are they, and what are the estimated costs?
Net Energy is Key Concept

• **Net Energy** = the energy left after using energy to drill, mine, transport, compress, combust, build, etc.

• Also called **EROI** (Energy Return on Investment)

• **Energy costs are going to rise**: Should we invest in renewables, with higher capital (building) costs, or fossil fuel, with increasing fuel costs and high Operation and Maintenance (O&M)?

• “**Externalities**” increasingly important: global warming, water scarcity; also enormous health effects from fossil fuels we’ve ignored for decades

• Environmental justice issues: local, U.S., global
Energy balance (EROI) is critical

Input

- Ethanol from corn
- Kerogen from marlstone; oil from tar sands SAGD

Output

- U. S. oil industry today

What are other impacts, like Gulf Oil spill?
The easiest-to-get resources are extracted first. Example: deepwater v. onshore drilling for oil.
Why Solar Is Good for AZ

• AZ has high insolation, **25-27% Capacity Factor** in best locations and certain technologies

• AZ can generate power from many different types of solar technologies, including:
  – Concentrating Solar Power (solar thermal),
  – PV (photo voltaic panels),
  – Solar Tower (uses rising hot air to generate electricity, high CF, no water use, Google “EnviroMission,”
  – U of A Professor Roger Angel working on high Capacity Factor Concentrating PV (go Wildcats!)
Why Solar is Good for AZ

- AZ imports all its Natural Gas and 2/3 of coal
- AZ spent **$1.5 billion** importing **Natural Gas (NG) for electricity** in **2009**
  - Another $800 million spent on NG for heating
  - Shale gas has been a game-changer, brought the price of gas way down, but ultimately depleting
  - During Katrina, cost of NG doubled; also doubled from 2007 to 2008 when oil peaked at $147/barrel
- AZ spent **$500 million** in 2007 importing **coal**
AZ’s Current Electricity Mix

• AZ exports 25-30% of power generated in-state, so total power generated different than in-state consumption.

• AZ utilities currently required to get 3% of total kWh’s generated from clean sources (see next slide)
# AZ RES Percentage Requirements

<table>
<thead>
<tr>
<th>Year</th>
<th>Requirement</th>
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<tr>
<td>2008</td>
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<tr>
<td>2009</td>
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<tr>
<td>2010</td>
<td>2.50 %</td>
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<td>2011</td>
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<td>2024</td>
<td>14.00 %</td>
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<tr>
<td>After 2024</td>
<td>15.00 %</td>
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2008 Arizona-Based Generated Electrical Energy (GWh's)

- Coal: 43,840 (37%)
- Natural Gas: 29,251 (24%)
- Nuclear: 260 (0.2%)
- Hydro: 7,286 (6%)
- Other: 38,822 (33%)

**TOTAL AZ generation = ~120,000 GWhs**

because AZ exports 25-30% of power

Total = 119,459 GWh’s

Source: US Energy Information Agency

October 15, 2010
2009 APS, SRP, TEP + AEPCO Electrical Energy (GWh's)

- Coal: 49%
- Natural Gas: 16%
- Nuclear: 17%
- Purchased Power (likely NG): 18%
- Other: 0.6%

Total in-state Electricity use is 50% coal, 16% NG, 17% nuclear, 18% purchased Power (likely NG).

Total = 85,688 GWh’s

See attached pages for Data and Sources

October 15, 2010
Arizona: GHG Emissions

Does not include GHGs from exported power.
Two-thirds of Energy From Coal Plants Lost as Heat; Natural Gas Combined Cycle More Efficient

Source: A Micro-Grid with PV, Fuel Cells, and Energy Efficiency, Tom Hoff, Clean Power Research.com
Carbon dioxide on the rise
The amount of pollution from carbon dioxide has been growing faster in Arizona than any other state.

Power plants produce the largest share of carbon dioxide pollution in Arizona. Primary sources:

- Electricity generation: 54.4%
- Transportation: 36.4%
- Industrial: 4.8%
- Residential: 2.3%
- Commercial: 2.1%

Includes GHGs from exported power.

Cost of Natural Gas -
More Volatile Since 2000

Natural Gas Wellhead Price - In Current $

Price in $ adjusted by CPI Urban

APS’ RW Beck Study on the Value of Distributed Energy Operating Impacts and Valuation study

**Build-Up of Solar DE Value**

- **Distribution Savings**: 0 to 0.31 cents/kWh
- **Transmission Savings**: 0 to 0.51 cents/kWh
- **Generation Savings**: 0 to 1.85 cents/kWh
- **Fixed O&M Savings**: 0.81 to 3.22 cents/kWh
- **Fuel, Purchased Power, & Losses Savings**: 7.10 to 8.22 cents/kWh

**TOTAL SAVING**: 7.91 to 14.11 cents/kWh (79.1 to 141.1 $/MWh)

*Minimum and maximum value shown not reflective of any specific scenario as evaluated in this Study

RW Beck study says the value of distributed solar is 7.9 to 14.11 cents/kWh in avoided costs for fuel, transmission, line losses, etc.
The Effect of Much Higher EE Savings

- Energy efficiency becomes *one-fifth* of the energy “pie” in 2020
- Lower total costs, lower utility bills, more jobs, less pollution
- Deferral of three large baseload plants from early 2020’s to 2030’s (and by then more renewables, storage, electric vehicles)
  
  Plus $9 billion in lower customer bills (2011-2030; APS, TEP...
Coal Capacity Factor Much Higher Than Natural Gas: AZ Can Hybridize NG plants!

U.S. Natural Gas and Coal Fleet Capacity Factors, 1976-2007
“Externalities” in electricity

• Uncounted costs are called “externalities” and include:
  – Water use and pollution
  – Air pollution
  – Mercury contamination
  – Lost productivity
  – Morbidity and mortality
  – Health effects from fossil fuel burning

• Recent coal ash spill at TVA coal plant in TN will cost $1.2 billion

• Power plants are big water users: nuclear the most, then coal; solar PV and wind use zero water; Concentrating Solar Power can be wet or dry. Wet CSP that uses a steam turbine uses as much water as a coal plant but does not pollute the water.
$72.5 billion for Fossil Fuels

$12.2 billion for Wind and Solar
Pollutants from 406 Coal Plants Cause $68B/Year Damage

NOTE: CLIMATE CHANGE DAMAGES NOT INCLUDED, ONLY SO₂, NOₓ, PM 2.5 & 10

Damages from these plants exceed $500 million a year.
Water Intensity of Electricity Generation

Emerging Technologies

Conventional Generation

Renewables

Source: Western Resource Advocates
Solar in AZ Means Jobs!

• Over the past 3 decades, the U.S. has lost millions of manufacturing jobs
• The Feed-in Tariff in Germany has resulted in hundreds of thousands of clean energy jobs and a vibrant export market for clean energy components
  – Big export market to export solar panels
Financial services increased from less than 10% to nearly 50% of corporate profits.

Manufacturing declined from 60% to less than 10% of corporate profits.
PV has historically been a marginal power source, but incentives drove steep growth in demand from '01-'05. Foreign incentives and R&D programs have driven worldwide competition past U.S. producers.

U.S. was a major PV supplier until 1998; losing ground since 2000.
New Harvard Study Says Coal Health Costs are $345 billion/year

- US reliance on coal for electricity costs $345 billion a year in health problems in mine communities and pollution around power plants, a study has found. These expenses would add 18 cents per kWh, effectively tripling the price of coal electricity. "This is not borne by the coal industry, this is borne by us, in our taxes," says the study's lead author, Dr. Paul Epstein.
“With public sentiment nothing can fail; without it, nothing can succeed.”

•- Abraham Lincoln
Thank you!

Paul Newman
Arizona Corporation Commissioner
pnewman@azcc.gov
602-542-3682
The Honorable Michel Peter Florio
Commissioner
California Public Utilities Commission
Decision 11-01-025 January 13, 2011

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop Additional Methods to Implement the California Renewables Portfolio Standard Program. Rulemaking 06-02-012 (Filed February 16, 2006)

DECISION RESOLVING PETITIONS FOR MODIFICATION OF DECISION 10-03-021 AUTHORIZING USE OF RENEWABLE ENERGY CREDITS FOR COMPLIANCE WITH THE CALIFORNIA RENEWABLES PORTFOLIO STANDARD AND LIFTING STAY AND MORATORIUM IMPOSED BY DECISION 10-05-018
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1. Summary

This decision resolves two petitions for modification of Decision (D.)10-03-021, which authorizes the procurement and use of tradable renewable energy credits (TRECs) for compliance with the California renewables portfolio standard (RPS) program. D.10-03-021 also sets forth the structure and rules for a TREC market and for the integration of TRECs into the RPS flexible compliance system. This decision denies the Joint Petition of Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company for Modification of Decision 10-03-021, with the exception of one suggested technical correction to D.10-03-021. This decision also denies the Petition of the Independent Energy Producers Association for Modification of Decision 10-03-021 Authorizing Use of Renewable Energy Credits for RPS Compliance.

Based on the Commission's review of D.10-03-021, the petitions for modification, the alternate proposed decision of Commissioner Grueneich (mailed October 25, 2010), and several rounds of comments on this proposed decision and the alternate proposed decision, this decision also makes several clarifying modifications to D.10-03-021, as well as modifications related to the lapse of time between the issuance of D.10-03-021 and the issuance of this decision.

This decision modifies D.10-03-021 by:
1. Extending the expiration dates of the temporary limit on the use of TRECs for RPS compliance and the temporary TREC price cap to December 31, 2013.

2. Clarifying the process for Commission review of utilities’ contracts for procurement of TRECs that were submitted for review prior to the effective date of this decision.

3. Clarifying the role of the California Energy Commission with regard to several aspects of the RPS program.


D.10-03-021, as modified by this decision, is effective March 11, 2010.

Further, because this decision resolves the two petitions for modification of D.10-03-021, the stay of D.10-03-021 imposed in D.10-05-018 is no longer necessary. The stay is therefore lifted. Similarly, the moratorium on Commission approval of certain RPS contracts imposed in D.10-05-018 is no longer relevant, and is ended.

2. **Procedural Background**

California Edison Company and San Diego Gas & Electric Company for Stay of Decision 10-03-021 (joint stay motion).

On April 14, 2010, the assigned Commissioner issued the Assigned Commissioner’s Ruling Setting Schedule for Consideration of Joint Petition for Modification of Decision 10-03-021 and Joint Motion for Stay of Decision 10-03-021 (ACR). The ACR shortened the time for responses and replies to the joint stay motion and for responses and replies to the utility petition.


Responses to the joint stay motion were filed April 21, 2010.¹ SCE filed a reply to the responses to the joint stay motion on April 23, 2010. In D.10-05-018, the Commission stayed D.10-03-021 on its own motion, pending the resolution of the two petitions for modification. D.10-05-018 also instituted a temporary moratorium on approval of any RPS procurement contracts for compliance with

¹ Responses to the joint stay motion were filed by the Alliance for Retail Energy Markets (AReM); Center for Energy Efficiency and Renewable Technologies (CEERT); City and County of San Francisco (CCSF); PG&E; Shell Energy North America (Shell); Sierra Pacific Industries; The Utility Reform Network (TURN); Union of Concerned Scientists (UCS); and Western Power Trading Forum (WPTF).
the renewables portfolio standard program (RPS) signed after May 6, 2010 (the effective date of the stay decision) that would be defined under D.10-03-021 as transactions transferring only renewable energy credits (RECs).

Responses to the utility petition and the IEP petition were filed May 4, 2010.2 SCE, PG&E, and SDG&E filed a joint reply to the responses to the utility petition on May 10, 2010.

The proposed decision (PD) was mailed for comment August 25, 2010. The alternate proposed decision of Commission Grueneich (alternate PD) was mailed for comment October 25, 2010.

_______________________________
2 Responses to the petitions for modification were filed by AReM; Bloom Energy; California Independent System Operator (CAISO); California Wind Energy Association (CalWEA); CCSF; Division of Ratepayer Advocates (DRA); Green Power Institute (GPI); Iberdrola Renewables, Inc. (Iberdrola); LS Power Associates, L.P. (LS Power); Large Scale Solar Association (LSA); Mountain Utilities and Bear Valley Electric Service (jointly; collectively, MU); NextEra Energy Resources (Next Era); Renewable Energy Coalition; SCE; Sempra Generation; Shell; Sacramento Municipal Utility District (SMUD); Solar Alliance; TURN; UCS; WPTF; and Zephyr Power Transmission, LLC and Chinook Power Transmission, LLC (jointly; collectively, Zephyr).
3. Discussion

3.1. The Petitions for Modification

3.1.1. The Utility Petition

The utility petition proposes wide-ranging changes to the decision on tradable renewable energy credits (TRECs). It makes 12 specific proposals.3

1. The Commission should revise the criteria for determining what transactions are bundled transactions and what transactions are for RECs only by ratifying the characterization of the transaction in the contract. That is, if the contract states that only RECs are being conveyed, the transaction should be classified as REC-only. If the contract states that RECs and energy are being conveyed, the transaction should be classified as bundled, regardless of any other characteristics of the contract or the transaction.

3 As noted by CCSF, the utility petition fails to comply with Rule 16.4(b) of the Commission’s Rules of Practice and Procedure. That rule provides that:

A petition for modification of a Commission decision must concisely state the justification for the requested relief and must propose specific wording to carry out all requested modifications to the decision. Any factual allegations must be supported with specific citations to the record in the proceeding or to matters that may be officially noticed. Allegations of new or changed facts must be supported by an appropriate declaration or affidavit.

The utility petition proposes specific wording for only one of its requested modifications. It contains no citations to the record of the proceeding and does not propose that any matters be officially noticed. It does not provide any declarations or affidavits to present any factual material in the petition that is not the record of this proceeding.

Because the utility petition raises issues of significant importance to the RPS program, ratepayers, and the public, the Commission will consider the utility petition on the merits, despite its failure to comply with the rules governing petitions for modification.
2. The Commission should apply the criteria for classification of contracts as REC-only or bundled to contracts that are submitted for Commission approval after the effective date of the TREC decision. For all contracts submitted for approval prior to that date, the characterization of the contract that would have obtained prior to D.10-03-021 should be used.

3. The Commission should eliminate the temporary limit on the use of TREC for RPS compliance by the large utilities imposed by the TREC decision (a temporary limit of 25% of the RPS annual procurement target (APT) of a large utility, which expires on December 31, 2011 unless the Commission takes some action that would extend it, or would terminate it before that date).

4. If the Commission does not eliminate the temporary limit on the large utilities’ use of TREC for RPS compliance, it should extend that limit to all RPS-obligated retail sellers.

5. If the Commission does not eliminate the temporary limit on the large utilities’ use of TREC for RPS compliance, it should provide that the limit will unconditionally expire on December 31, 2011, without further review.

6. The Commission should eliminate the temporary cap of $50.00/TREC on the price that utilities are allowed pay for TREC.

7. If the Commission does not eliminate the temporary cap on the price utilities may pay for TREC for RPS compliance, it should extend that price cap to all RPS-obligated retail sellers.

8. If the Commission does not eliminate the temporary cap on the price utilities may pay for TREC for RPS compliance, it should provide that the cap will unconditionally expire on December 31, 2011, without further review.
9. The Commission should expand the rules for “earmarking” TREC contracts.\(^4\) Instead of allowing earmarking of contracts for TRECs only between an RPS-obligated retail seller and one generator that is the source of the TRECs and associated energy, the utility petition proposes that the Commission allow earmarking of contracts between a retail seller and one seller of all the TRECs in the contract.

10. The Commission should remove the requirement that the new standard terms and conditions set out in D.10-03-021 be added to RPS procurement contracts that were submitted for Commission approval, but not yet approved, prior to the effective date of the TRECs decision.

11. The Commission should expand and/or revise the rules for using TRECs for RPS compliance to:
   - allow the use of TRECs associated with energy generated in 2008 and 2009 to meet retail sellers’ APTs for 2008 and 2009;
   - allow earmarking of REC-only contracts entered into prior to 2010 to apply to APTs prior to 2010 (if the Commission does not adopt either the utility petition’s requested change to the criteria for classifying a contract as REC-only or the request to allow all deliveries from all previously approved contracts to be counted as bundled); and
   - allow use of TRECs for APTs for 2008 or 2009 without any usage limit (if the Commission does not eliminate the temporary TREC usage limit for large utilities).

---

\(^4\) Earmarking is a flexible compliance mechanism by which deliveries from a future RPS procurement contract may be designated to make up, within three years, shortfalls in RPS procurement in the same year in which the earmarked contract was signed.
12. The Commission should clarify the status of RECs associated with energy generated by qualifying facilities (QFs) not located in California that is under contract with a utility that is also not located in California.

3.1.2. The IEP Petition

The IEP petition proposes changes to the TREC's decision that are less sweeping than the changes suggested in the utility petition. The IEP petition makes proposals in two areas: criteria for classifying transactions as REC-only or bundled, and the methodology for least-cost best-fit (LCBF) analysis of RPS procurement options.

1. The Commission should revise the criteria for determining what transactions are bundled transactions and what transactions are REC-only transactions, creating a rebuttable presumption that three types of transactions will be considered bundled transactions:
   - transactions providing real-time delivery using firm transmission;
   - transactions using firm transmission in which firmed and shaped energy is delivered within 90 days of the generation of the energy associated with the RECs; and
   - firmed and shaped transactions using nonfirm transmission in which firmed and shaped energy is delivered within 90 days of the generation of the energy associated with the RECs.

2. The Commission should revise the LCBF methodology to provide for the explicit consideration of the geographic and related attributes that the Commission determines would increase the value of RPS transactions for California consumers.
3.2. Resolution of Petitions for Modification

3.2.1. The utility petition

D.10-03-021 was adopted by the Commission after a process of considering the use of TRECs for RPS compliance that began with a workshop held by Energy Division staff in September 2007. Parties have had many opportunities over that period to provide information and argument to inform the Commission's approach to TRECs. Despite this background of detailed consideration, the utility petition presents no new facts that would provide a basis for modifying D.10-03-021. This omission is significant, since it results in the utility petition taking positions and advancing arguments that were previously made, and were not adopted by the Commission. The utility petition does not persuade us that these positions would better advance the statutory goals of the RPS program, protect ratepayers, and further the sound administration of the RPS program than the policies and procedures adopted in D.10-03-021.

Some points raised in the utility petition are, at this point, hypothetical. The RPS program has a mature process for reporting and compliance, and a history of cooperation among parties and Energy Division staff to resolve problems. We anticipate that the issues of possible future problems raised in the utility petition can be resolved through existing processes, or, if not, brought up in R.08-08-009 or its successor.

The utility petition properly points out an ambiguity in the treatment of the status of RECs associated with energy generated by QFs not located in California that is under contract with a utility that is also not located in California, and proposes a solution which we adopt.
With the exception of the clarification on QFs discussed above, the utility petition is denied.

3.2.2. The IEP petition

The IEP petition essentially asks the Commission to short-circuit the process we adopted in Ordering Paragraph (OP) 26 of D.10-03-021, and declare in this decision on the petitions for modification of D.10-03-021 that certain transactions using firm transmission should be considered to be bundled.5 We decline to do so. Energy Division staff has set up a process for carrying out our direction in OP 26 of D.10-03-021 that appears to be thorough, fair, and able to provide sound information on which to base a conclusion. We prefer to let that process take its course, rather than modifying D.10-03-021 now to decree an outcome that we explicitly concluded would require further investigation.

IEP also asks the Commission to expand the review of LCBF methodology for RPS procurement that is ordered in OP 34 of D.10-03-021. IEP seeks to include additional issues in the review, and to impose a time limit by which the review should be complete. While these issues may be important and worthwhile, they are not appropriately addressed by modification of D.10-03-021. As already reflected in OP 34, the assigned Commissioner is authorized to initiate a review and revision of the LCBF methodology. IEP and other interested parties may, if they choose, file a motion for consideration of these issues in the LCBF review.

Because D.10-03-021 already has in place processes to address the two issues raised by IEP in its petition, the IEP petition is denied.

5 This position is supported by commenters including CalWEA, Iberdrola, LS Power, SMUD, Terra-Gen, TransWest, and Zephyr.
3.3. Modifications Made by the Commission

The filing of the petitions for modification initiated many rounds of party participation, including responses to the petitions, two rounds of comments and reply comments on this PD, and comments and reply comments on the alternate PD. The intense scrutiny to which D.10-03-021 has been subject has allowed the Commission to identify several clarifications and modifications to that decision which, while not compelled by the petitions for modification, are nevertheless desirable. These changes, like D.10-03-021, implement the Commission’s existing authority under Pub. Util. Code § 399.166 to authorize the use of RECs for compliance with RPS annual procurement targets. Pursuant to §§ 399.11 and 399.15(b)(c), these targets are currently 20% of the retail sales of each RPS-obligated retail seller.

The findings of fact, conclusion of law, and Order of D.10-03-021, as modified by this decision, are attached as Appendix A.

3.3.1. Sources of TREC

The text in section 4.3.2. of D.10-03-021 should be clarified with respect to the nature of the distributed generation (DG) being discussed and the role of the California Energy Commission (CEC). The original text could engender confusion about the relationship of this Commission’s discussion of TREC from DG sources to the CEC’s authority, pursuant to § 399.13, to determine what resources are RPS eligible. We clarify that our decision to authorize the use of TREC is not intended to imply that RECs associated with energy from customer-side DG installations generated prior to the effective date

6 All subsequent references to sections refer to the Public Utilities Code, unless otherwise noted.
of D.10-03-021 are (or are not) RPS-eligible. The CEC will make those eligibility determinations. Therefore, section 4.3.2. should be rewritten, as follows:

AReM, BVES, PG&E, SCE, and TURN suggest that various forms of DG may provide some available TREC, though not at a very large scale over the next few years.

There are several types of renewable DG projects. Customer-side DG projects may utilize a variety of renewable technologies. These include on-site RPS-eligible generation at customers; solar photovoltaic (PV) installations, largely constructed under the aegis of the California Solar Initiative (CSI) and the self-generation incentive program (SGIP) administered by this Commission, and the New Solar Homes Partnership (NSHP) administered by the CEC; generation using biodiesel or biogas; and small biomass facilities.8

7 This discussion considers generation on the customer side of the meter as DG, in accordance with the CEC’s RPS Eligibility Guidebook (3d ed., December 2007), at 17-19 (available at http://www.energy.ca.gov/2007publications/CEC-300-2007-006/CEC-300-2007-006-ED3-CMF.PDF). Generation projects on the system side of the meter that are developed to connect to the distribution system are not considered “distributed generation” for purposes of this discussion.

8 Formal determination of the RPS eligibility of types of generation or particular systems is made by the CEC. The most current statement of CEC guidance is the RPS Eligibility Guidebook, (3d ed., December 2007). The RPS Eligibility Guidebook provides that “[t]he Energy Commission will not certify distributed generation facilities as RPS-eligible unless the CPUC authorizes tradable RECs to be applied toward the RPS.” (at 18.) We anticipate that the CEC will review the issue of the RPS eligibility of DG during its next revision of the RPS Eligibility Guidebook.
The CEC will determine the eligibility of customer-side DG for the RPS. At this time, almost no customer-side DG is RPS-eligible. The RPS Eligibility Guidebook (at 18) explains that:

“The Energy Commission will not certify distributed generation PV and other forms of customer-sited renewable energy into the RPS at this time, with the following exception.

The Energy Commission will certify facilities that would have been considered distributed generation facilities except that they are participating in a standard contract/tariff executed pursuant to Public Utilities Code § 399.20, as implemented through the CPUC Decision 07-07-027 (R.06.05.027), executed pursuant to a comparable standard contract/tariff approved by a local publicly owned electric utility... or if the facility is owned by a utility and meets other requirements, to become certified as RPS-eligible...

The Energy Commission will not certify distributed generation facilities as RPS-eligible unless the CPUC authorizes tradable RECs to be applied toward the RPS.”

Thus, although there are technologies that can be used for customer-side renewable DG, most current installations are not in fact RPS-eligible because they have not been certified by the CEC and cannot be certified until the CEC revises its RPS Eligibility Guidebook.

In anticipation of the eventual use of customer-side DG for RPS compliance, both this Commission and the CEC have addressed the issue of the availability of TREC from such installations. The availability of TREC from such installations has been addressed in a variety of contexts. In D.07-01-018, the Commission determined that owners of customer-side DG installations own the RECs associated with the generation, and can therefore sell them, regardless of whether the DG owners
participate in net metering, CSI, or the SGIP.\(^9\) In D.07-07-027 and D.08-09-033, implementing § 399.20, the Commission provided for tariffs or standard contracts for utilities’ bundled purchase of RPS-eligible generation from DG of not more than 1.5 megawatt (MW) in size located at public water and wastewater facilities and other customers, with an overall statewide limit on such purchases. The generation so acquired counts toward the utilities’ RPS targets. In this program, customers may sell to the utility either the full output of the DG facility (energy and RECs) or only the excess (energy and RECs) not used for on-site consumption. In the latter case, the RECs associated with the energy used on-site remain with the system owner.\(^{10}\)

\(^9\) The CEC has likewise determined that the system owner of customer-side DG does not need to relinquish claim over the RECs in order to participate in the NSHP. See New Solar Homes Partnership Guidebook (3d edition April 2010) at 7. This guidebook is available at http://www.energy.ca.gov/2010publications/CEC-300-2010-001/CEC-300-2010-001-CMF-REV1.PDF.

\(^{10}\) TRECs from RPS-eligible DG installations that are tracked in WREGIS are, for RPS compliance purposes, the same as TRECs from RPS-eligible utility-scale generation. No matter the type of DG generation or the kind of transaction, RECs associated with RPS-eligible DG—like RECs from any other RPS-eligible generation—“shall be counted only once for compliance with the renewables portfolio standard of this state or any other state, or for verifying retail product claims in this state or any other state.” (§ 399.16(a)(2).)
ARem states that the CSI program estimates that the program will have installed about 800 gigawatt hours (GWh) of generation by 2010. ARem additionally estimates that CSI will have provided incentives for approximately 1,100 GWh by 2011. No other party provides quantitative DG estimates.\textsuperscript{11}

### 3.3.2. Caveats on treatment of REC-only transactions

In order to promote fairness and certainty in the treatment of RPS procurement contracts approved by the Commission prior to the effective date of D.10-03-021, as set forth in OP 18,\textsuperscript{12} two caveats should be added. The treatment set forth in OP 18:

- Does not apply to any extension of a given contract beyond the expiration date existing on the effective date of D.10-03-021; and

\textsuperscript{11} In D.09-06-049, the Commission approved a new SCE program to procure RPS-eligible energy from rooftop solar PV installations of one to two MW in size. Because the program is new, it is not currently possible to know what, if any, impact it will have on DG as a resource for RPS procurement over the next two to three years.

\textsuperscript{12} OP 18 provides:

The temporary limit on the use of tradable renewable energy credits for compliance with the California renewables portfolio standard shall not be applied to deliveries to a load-serving entity obligated under the California renewables portfolio standard from contracts that are classified by this decision as contracts for renewable energy credits only, but were approved by the Commission prior to the effective date of this decision, if such deliveries would cause that load-serving entity to exceed the annual limit on the use of tradable renewable energy credits for compliance with the California renewables portfolio standard. In this circumstance, the LSE may not use any tradable renewable energy credits associated with contracts that were not approved by the Commission prior to the effective date of this decision for compliance in that year that would exceed the 25\% annual limit.

We note and here correct the inadvertent omission of "renewable" near the end of the first sentence.
• It does not apply to any deliveries under a given contract beyond the maximum deliveries identified in the contract as the contract read on the effective date of D.10-03-021.

That is, if a contract that is given bundled treatment is subsequently amended to extend the expiration date or to increase the maximum allowable deliveries, the incremental deliveries after the effective date of the contract amendment will be treated according to the then-applicable classification of REC-only and bundled deliveries, as of the date the amendment is effective. In the case of an extension, this means deliveries after the date the original contract would have expired; in the case of augmented deliveries, it means the deliveries in excess of the previous maximum.\textsuperscript{13}

Implementing these caveats will preserve the intent of treating approved contracts as bundled, while allowing existing contracts to be amended to meet future contingencies. Since the legitimate commercial expectations of the parties to contracts approved before the effective date of this decision do not, by definition, extend to transactions after that date, the incremental deliveries secured by amending the contract do not need the shelter of the safe harbor granted to the original contract.

In light of the forgoing discussion and determinations, the following modifications of D.10-03-021 should be made:

1. Conclusion of Law 13 should be modified as follows:

13. In order to recognize the legitimate expectations of the parties to RPS contracts now classified as REC-only that were approved by the Commission prior to the effective date of this decision, the

\textsuperscript{13} A contract could also be both extended and augmented.
temporary limit on the use of TRECs for RPS compliance provided in this decision should not be applied to deliveries to an LSE from contracts classified as REC-only by this decision, but which were previously approved by the Commission, if the deliveries would cause the LSE to exceed the TREC usage limit. In this circumstance, the LSE should not be allowed to use any TRECs associated with contracts that were not approved by the Commission prior to the effective date of this decision for compliance in that year that would exceed the 25% limit. The LSE should also not be allowed to use any TRECs in that year that would exceed the 25% limit from incremental changes to approved contracts in the event that either of the following changes occurs with respect to such a contract previously approved by the Commission:

a. The expiration date of the contract is extended beyond the expiration date existing in the approved contract on March 11, 2010; or

b. The deliveries allowed under the contract are increased beyond the maximum deliveries identified in the contract as the approved contract read on March 11, 2010.

In either event, all deliveries after the effective date of the contract amendment that are incremental to the deliveries set forth in the approved contract should be treated according to the then-applicable classification of REC-only and bundled transactions, and associated rules, including any limitations on their use for RPS compliance.

Ordering Paragraph 18 should be revised as follows:

The temporary limit on the use of tradable renewable energy credits for compliance with the California renewables portfolio standard shall not be applied to deliveries to a load-serving entity
obligated under the California renewables portfolio standard from contracts that are classified by this decision as contracts for renewable energy credits only, but were approved by the Commission prior to the effective date of this decision, if such deliveries would cause that load-serving entity to exceed the annual limit on the use of tradable energy credits for compliance with the California renewables portfolio standard. In this circumstance, the LSE load-serving entity may not use any tradable renewable energy credits associated with contracts that were not approved by the Commission prior to the effective date of this decision for compliance in that year that would exceed the 25% annual limit.

The load-serving entity also may not use any tradable renewable energy credits in that year that would exceed the 25% limit from incremental changes to approved contracts in the event that either of the following changes occurs with respect to such a contract previously approved by the Commission:

a. The expiration date of the contract is extended beyond the expiration date existing in the approved contract on March 11, 2010; or

b. The deliveries allowed under the contract are increased beyond the maximum deliveries identified in the contract as the approved contract read on March 11, 2010.

In either event, all deliveries after the effective date of the contract amendment that are incremental to the deliveries set forth in the approved contract should be treated according to the then-applicable classification of renewable energy credits only and bundled transactions and associated rules, including any limitations on their use for renewables portfolio standard compliance.
3.3.3. Extending temporary limits on use of TREC\textsc{s}

Because of the substantial amount of time that has passed between the issuance of D.10-03-021 and this decision, we find that the termination dates of the temporary limit on the use of TREC\textsc{s} for RPS compliance and the temporary limit on the price any utility may pay for a TREC are now too close to allow the Commission to assess the new TREC market and the value of REC-only contracts relative to bundled contracts. The report from Energy Division identified in OP 31 also will require more time to research and develop than would remain if the temporary limits were to expire at the end of this year. Further, the Commission should also be able to take into consideration in its review any new legislatively-mandated RPS goal, as well as implementation of the Renewable Energy Standard adopted by the Air Resources Board in September 2010. Therefore, we extend the expiration date for these limits to December 31, 2013, to give Energy Division sufficient time to develop this evaluative framework and to prepare the report identified in OP 31. The timeframe for Energy Division's report should be commensurately extended. The report identified in OP 31 should be completed by December 31, 2012.

In light of the forgoing discussion and determinations, the following modifications should be made to D.10-03-021:

1. Section 4.6.3 should be modified by:
   
   A. inserting the following paragraph in the text, after the paragraph beginning, “This limit is enforceable through the existing RPS compliance process. . .”

   Although a REC-only transaction of a utility may fall within the temporary usage limit, the Commission is not obligated to approve it simply because it would not exceed the limit. This decision does not alter the Commission’s existing authority to approve or deny
utilities’ RPS contracts submitted for our approval. Nor does this decision state or imply that a REC-only transaction that does not exceed the usage limit is in the best interests of ratepayers, or that such a transaction would be considered per se reasonable. If a REC-only transaction, or series of REC-only transactions, has the potential to impede the achievement of policy goals with respect to renewable energy development, the Commission retains its ability to disapprove or modify such transactions.\footnote{For example, D.08-12-058 includes a commitment from SDG&E to ensure that a certain amount of RPS-eligible energy is delivered via the Sunrise Powerlink. Nothing in this decision removes or reduces that commitment. REC-only transactions that would have the potential to undermine the practical effectiveness of that commitment, or to impact similar commitments to RPS implementation goals shall receive a heightened level of scrutiny.}

B. revising the paragraph beginning “This limit on the use of TRECs for RPS compliance should be a temporary one” as follows:

This limit on the use of TRECs for RPS compliance should be a temporary one. This usage limit will terminate December 31, 2011 unless the Commission acts to review, extend, or modify it, or to terminate the limit prior to its expiration. If there is a new legally binding RPS goal, the usage limitation may be reviewed in light of the new goal. The usage limit may be reviewed if and when new legislation increases the RPS goal, as well as if and when the Air Resources Board adopts regulations to implement a renewable energy standard under AB 32 to lead to use of renewable energy for 33\% of retail sales in California by 2020, as directed by Executive Order S-21-09 (September 15, 2009).

3. A new Conclusion of Law 12 should be added, as follows:
12. The temporary limit on the proportion of annual RPS procurement obligations that can be met by using TREC\textsuperscript{s} should not be considered as a determination that any REC-only transaction that would not exceed the limit is a \textit{per se} reasonable transaction for a utility to undertake.

4. Conclusion of Law 26 should be revised as follows:

26. In order to provide the Commission with information about the initial period of the TREC market and the use of TREC\textsuperscript{s} for RPS compliance, the Director of Energy Division should prepare a report for the Commission within 16 months of the effective date of this order \textit{by December 31, 2012}, using information provided by all RPS-obligated LSEs. This report should include a recommendation to the Commission regarding whether or not the applicable TREC usage limit and price cap should be retained or allowed to sunset,\textsuperscript{2} taking into consideration, among other things, any legislation or regulation increasing the percentage of retail sales that must be met with renewable energy procurement.

5. Ordering Paragraph 20 should be revised as follows:

The temporary limit on the use of tradable renewable energy credits for compliance with the California renewables portfolio standard shall terminate December 31, 2011, unless the Commission acts to review, extend, or modify it, or to terminate the limit prior to its expiration.

6. Ordering Paragraph 31 should be revised as follows:

31. The Director of Energy Division shall review and compile information about the market for tradable renewable energy credits and the use of tradable renewable energy credits for compliance with the California renewables
portfolio standard provided by load-serving entities obligated under the California renewables portfolio standard in their advice letters or applications seeking approval of contracts for procurement of renewable energy credits only, in their semiannual compliance reports, and in response to other request for information made by Energy Division staff. The Director of Energy Division shall include analysis of this information in a report to be provided to the Commission not more than 16 months from the effective date of this decision by December 31, 2012. The report shall also include recommendations about whether the Commission should review, modify, or extend the annual limit on the use of tradable renewable energy credits for compliance with the California renewables portfolio standard program, or whether the Commission should let the limit expire. The report shall also include recommendations about whether the Commission should review, modify, or extend the limit on the price an investor-owned utility may pay for tradable renewable energy credits for compliance with the California renewables portfolio standard program, or whether the Commission should let the limit expire.

7. Conforming changes should be made to those sections of text which refer to the expiration date of the temporary limit on the use of RECs and the temporary price cap to reflect a December 31, 2013 expiration.

a. The reference in the summary should be changed to read:

Both limits will expire December 31, 2013.
b. All the references to December 31, 2011 as they pertain to the expiration of the temporary usage limit and the temporary price cap in sections 4.6.3 and 4.7.3. should be modified to “December 31, 2013.”

3.3.4. Transactions subject to §§ 399.16(a)(5) and (6)

The utilities identify what they characterize as an inconsistency between the text of section 4.8 in D.10-03-021 and the implementation of that discussion in OP 9. We agree that OP 9 does not reflect the Commission’s full intention, as set forth in the discussion. We therefore adopt the proposed modification of OP 9 to eliminate the reference to facilities located in California, as follows:

Renewable energy credits associated with electricity generation that is eligible for the California renewables portfolio standard delivered under procurement contracts of California utilities for both energy and renewable energy credits pursuant to the federal Public Utility Regulatory Policies Act of 1978 that were signed after January 1, 2005 with qualifying facilities located in California shall be used for compliance with the California renewables portfolio standard only if they are not transferred to an entity other than the original buyer in the Western Renewable Energy Generation Information System prior to being retired for compliance with the California renewables portfolio standard.

3.3.5. Reporting information about RPS procurement contracts

D.10-03-021, as modified by this decision, authorizes a new market in TRECes. It also provides rules for integration of TRECes into the existing RPS framework. Although the market and compliance rules are intended to be as simple and transparent as possible, inevitably issues will arise about their application.
In order to identify and resolve RPS compliance issues, Energy Division staff must have access to accurate RPS procurement information of all RPS-obligated retail sellers. The Commission’s ability to have access to accurate information applies to all forms of procurement. The Commission made the application of this general authority to RPS-obligated retail sellers that are not utilities clear in D.06-10-019 (OP 7, for ESPs; OP 15, for CCAs). To avoid creating the appearance of any gaps in reporting obligations, we will modify OP 27 of D.10-03-021 to add an express direction on the submission of RPS procurement contracts and related information:

27. The Director of Energy Division is authorized to review existing reporting formats and tools for the California renewables portfolio standard and undertake appropriate revisions to allow complete reporting and monitoring of the provisions of this order. All retail sellers obligated under the California renewables portfolio standard must provide copies of their contracts for procurement under the California renewables portfolio standard, as well as any other required information about their procurement to meet the California renewables portfolio standard, to Energy Division staff, as and when required by the Director of Energy Division.

3.3.6. Standard terms and conditions

In its comments on the PD, SCE identifies inconsistencies between the capitalization of the references to RECs in the new STCs and the capitalization in existing STCs. Because these are significant, defined terms in RPS contracts, the inconsistencies should be remedied. The relevant changes should be made to OPs 35 and 36 and carried forward in Appendix C of D.10-03-021.

OP 35 should be changed to read:
35. The following non-modifiable standard terms and conditions shall be included in all contracts for procurement for compliance with the California renewables portfolio standard, whether bundled contracts or purchases of renewable energy credits only:

a. STC REC-1. Transfer of renewable energy credits

Renewable Energy Credits

Seller and, if applicable, its successors, represents and warrants that throughout the Delivery Term of this Agreement the renewable energy credits \( \text{Renewable Energy Credits} \) transferred to Buyer conform to the definition and attributes required for compliance with the California Renewables Portfolio Standard, as set forth in California Public Utilities Commission Decision 08-08-028, and as may be modified by subsequent decision of the California Public Utilities Commission or by subsequent legislation. To the extent a change in law occurs after execution of this Agreement that causes this representation and warranty to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in law.

b. STC REC-2. Tracking of RECs in WREGIS.

Seller warrants that all necessary steps to allow the renewable energy credits \( \text{Renewable Energy Credits} \) transferred to Buyer to be tracked in the Western Renewable Energy Generation Information System will be taken prior to the first delivery under the contract.

OP 36 should be modified to read:

36. The following non-modifiable standard terms and conditions shall be included in all contracts for purchase of renewable energy credits only of regulated utilities other than multi-jurisdictional utilities:

STC REC-3. CPUC Approval
“CPUC Approval” means a final and non-appealable order of the CPUC, without conditions or modifications unacceptable to the Parties, or either of them, which contains the following terms:

(a) approves this Agreement in its entirety, including payments to be made by the Buyer, subject to CPUC review of the Buyer’s administration of the Agreement; and

(b) finds that any procurement pursuant to this Agreement is procurement of Renewable Energy Credits that conform to the definition and attributes required for compliance with the California Renewables Portfolio Standard, as set forth in California Public Utilities Commission Decision 08-08-028, and as may be modified by subsequent decision of the California Public Utilities Commission or by subsequent legislation, for purposes of determining Buyer’s compliance with any obligation that it may have to procure eligible renewable energy resources pursuant to the California Renewables Portfolio Standard (Public Utilities Code Section 399.11 et seq.), Decision 03-06-071, or other applicable law.

CPUC Approval will be deemed to have occurred on the date that a CPUC decision containing such findings becomes final and non-appealable.
STC 17. Applicable Law

Governing Law. This agreement and the rights and duties of the parties hereunder shall be governed by and construed, enforced and performed in accordance with the laws of the state of California, without regard to principles of conflicts of law. To the extent enforceable at such time, each party waives its respective right to any jury trial with respect to any litigation arising under or in connection with this agreement.

We also take this opportunity to remind all RPS-obligated retail sellers that all RPS contracts must contain the relevant standard terms and conditions. For ESPs and CCAs, these are the nonmodifiable terms on REC Definition, WREGIS tracking, and statement of governing law as that of California adopted in this decision, the non-modifiable term on Green Attributes, and the STCs on eligibility and assignment required by D.06-10-019 (OP 20).

3.3.7. Timing issues

We conclude that the text in D.10-03-021 inadvertently elided the role of the CEC in determining RPS eligibility. In order to avoid potential confusion, the first sentence of section 4.11 should be revised to read:

15 The STCs are compiled in D.08-04-009, as modified by D.08-08-028.
Beginning on the effective date of this decision, TREC
tacked in WREGIS and certified by the CEC as
associated with RPS-eligible electricity, for which the
RPS-eligible electricity associated with the TREC was
generated on or after January 1, 2008, may be procured,
traded, and used for RPS compliance.16

We also accept SCE’s suggestion that contracts that are classified as
REC-only by D.10-03-021, as modified by this decision, which have already been
submitted for Commission approval, but not yet approved, do not need to be
withdrawn and resubmitted. However, the Director of Energy Division is
authorized to require the utility to submit any additional information that is
necessary for the complete evaluation of the contract.

Conclusion of Law 24 should be revised as follows:

24. Utilities that are required to submit their RPS
procurement contracts for Commission approval
should submit contracts conveying only RECs and
not energy REC-only contracts for approval not
earlier than April 1, 2010. The Director of Energy
Division should be authorized to require the
submission of any additional information necessary
for the evaluation of such contracts.

Ordering Paragraph 38 should be revised as follows:

38. Not earlier than April 1, 2010, investor-owned
utilities may submit for Commission approval
contracts conveying only renewable energy credits
only and not energy that conform to the
requirements of this order. For any contracts
conveying renewable energy credits only that a

16 This date is used because 2008 is the first year that WREGIS issued certificates; it is
also the first year data from WREGIS is reported to the CEC to verify RPS procurement.
(RPS Eligibility Guidebook at 46.)
utility submitted prior to January 14, 2011 but that have not been approved by January 14, 2011 the utility shall make a supplemental filing, in the form and with the content prescribed by the Director of Energy Division.

3.3.8. Miscellaneous corrections

Finally, four related editorial errors should be corrected.

1. The last sentence in the second paragraph of section 4.10 should be revised to read:

Because RECs TRECs cannot be recognized for RPS compliance unless they are tracked in WREGIS, REC-only contracts must contain assurances that the seller has taken all steps necessary to ensure that the generation is properly registered and the RECs TRECs will be tracked in WREGIS.17

2. Conclusion of Law 4 should be revised to read:

4. Only RECs tracked in WREGIS should be allowed to be used for RPS compliance. In order to be used for RPS compliance, TRECs must be tracked in WREGIS.

3. OP 3 should be changed to clarify the roles of the CEC and WREGIS. It should be revised to read:

3. Only renewable energy credits tracked and retired in the Western Renewable Energy Generation Information System shall be used for compliance with the California renewables portfolio standard. In order to be used for compliance with the California renewables portfolio standard, tradable renewable energy

17 PG&E suggests in its comments on the RPD that the assurance of registration with WREGIS should apply at the time deliveries commence under the contract, not at the time the contract is signed. This suggestion is unopposed and simplifies contracting; we adopt it in this decision.
credits must be tracked and retired in the Western Renewable Energy Generation Information System, must conform to the requirements of Decision 08-08-028 and any subsequent Commission decision or any applicable California legislation characterizing renewable energy credits, and must meet the criteria for eligibility for the California renewables portfolio standard that are set by the California Energy Commission.

4. OP 4 should be modified to address only the restrictions on the use of RECs associated with RPS-eligible energy generated by QFs. It should be revised to read:

4. Any renewable energy credits tracked in the Western Renewable Energy Generation Information System that conform to the requirements of Decision 08-08-028 and any subsequent Commission decision or any applicable California legislation characterizing renewable energy credits, and that meet the criteria for eligibility set by the California Energy Commission, may be used for compliance with the California renewables portfolio standard, are subject to the restrictions in Ordering Paragraphs 8 and 9, below.

3.4. Next Steps

This decision modifies some aspects of D.10-03-021 and dissolves the stay imposed by D.10-05-018. As a result, RPS-obligated retail sellers will begin to use TRECs for RPS compliance in accordance with the rules and procedures set out in D.10-03-021, as modified by this decision. A market for TRECs will develop, in accordance with the structure set forth. Over time, the Commission will take the actions required to refine and further develop the place of TRECs in RPS compliance.
By lifting the stay of D.10-03-021, this decision also allows Energy Division staff to complete the work it began in April 2010 to determine how to characterize RPS-eligible transactions that use firm transmission arrangements, as authorized by OP 26 of D.10-03-021. In view of the strong interest in this issue shown by the comments on the PD, we urge Energy Division staff to complete this task as soon as practicable.

Because one community choice aggregator (CCA) is in active operation (Marin Energy Authority),\(^{18}\) it is now appropriate for the Commission to complete specification of the RPS rules for CCAs, as far as possible with only one active example.\(^{19}\) The assigned Commissioner in R.08-08-009 or its successor should promptly take up the task of filling in the RPS rules for CCAs. This will include whether the temporary TREC's usage limit and price cap should be applied to CCAs, but is not limited to those issues.

We will continue our work to collaborate with the CEC as it revises its *RPS Eligibility Guidebook*.

The Air Resources Board (ARB) has adopted a regulation to create a Renewable Energy Standard (RES) as part of ARB’s implementation of the Global Warming Solutions Act, AB 32 (Nunez), Stats. 2006, ch. 488.\(^{20}\) In adopting the RES regulation, ARB noted that this Commission, the CEC, and ARB should coordinate their roles and harmonize their policies with respect to renewable energy programs in California. We intend to work with ARB and the CEC to


\(^{19}\) The City and County of San Francisco has consistently participated in this proceeding as a potential CCA.

\(^{20}\) Resolution 10-23 (September 23, 2010).
maximize the benefit of the state’s renewable energy programs for California residents.

4. Comments on Proposed Decision

The proposed decision of Commissioner Peevey in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code, and comments were allowed under Rule 14.3 of the Commission’s Rules of Practice and Procedure. Comments were filed on September 24, 2010 by Bear Valley Electric Service (BVES); Bonneville Power Administration; BP Wind Energy North America, Inc.; CalWEA; CEERT; DRA; Evolution Markets; First Solar; GPI; Iberdrola; LS Power; LSA; Next Era; PacifiCorp; PG&E; Royal Bank of Scotland; SDG&E; Shell; Sierra Pacific Power Company (Sierra Pacific); SCE; Terra-Gen Power, LLC; Transwest Express, LLC; TURN; UCS; WPTF and AReM (jointly); and Zephyr. Reply comments were filed on October 4, 2010 by BVES, CCSF; Coalition of California Utility Employees; DRA; Iberdrola; Mountain Utilities; PG&E; SDG&E; SCE; Sierra Pacific; SMUD; Solar Alliance; TURN; USC; and WPTF.

Pursuant to the Administrative Law Judge's Ruling Granting Motion Requesting Comment Period for the Revised Proposed Decision of Commissioner Peevey (October 27, 2010), supplemental comments on section 3.9 and related ordering paragraphs of Revision 3 of the PD were filed on November 5, 2010 by AReM, Direct Access Customer Coalition, School Project for Utility Rate Reduction, California State University, Walmart Stores, Commerce Energy, 3 Phases Renewables, and WPTF (jointly) (collectively, joint ESP parties); City of Cerritos; IEP; PG&E; Pilot Power; SDG&E; Shell; SCE; TURN; and UCS. Supplemental reply comments were filed on
November 12, 2010 by CCSF; joint ESP parties; PG&E; PacifiCorp and Sierra Pacific (jointly); Shell; and SCE.

The Commission has carefully considered all comments, reply comments, supplemental comments, and supplemental reply comments on this PD, as well as comments and reply comments on the alternate PD. Revisions to the PD have been made in response to comments and are found throughout the text and in the ordering paragraphs. Modifications to the findings of fact, conclusions of law, and ordering paragraphs of D.10-03-021 are fully set out in OP 4 of this decision. The complete findings of fact, conclusions of law, and ordering paragraphs of D.10-03-021 as modified by this decision are set out in Appendix A.

In addition to changes made to the PD in response to comments, revisions have been made to improve clarity and consistency, and to correct minor errors.

5. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and Anne E. Simon is the assigned Administrative Law Judge for this portion of this proceeding.

Findings of Fact

1. The utility petition for modification presents no new facts for the Commission's consideration.

2. Many of the arguments in the utility petition have been made by parties over the two-and-one-half years of the Commission’s consideration of the use of TRECs for RPS compliance, and have previously been rejected by the Commission.

3. The RPS program provides numerous opportunities for parties to identify and resolve uncertainties or problems by consultation with Energy Division staff, or if necessary by motion in R.08-08-009 or its successor.
4. Energy Division staff has begun the investigation of the role of firm transmission in procurement for RPS compliance mandated by OP 26 of D.10-03-021.

Conclusions of Law

1. The utility petition for modification should be denied, with the exception of the requested clarification of OP 9 of D.10-03-021.

2. The IEP petition for modification should be denied.

3. Clarifying modifications and improvements to D.10-03-021 should be made as set forth in this decision.

4. In order to allow the use of TREC for RPS compliance as soon as practicable, this order should be effective immediately.

ORDER

IT IS ORDERED that:


3. The Discussion section of Decision (D.) 10-03-021 is modified as explained in this decision. The specific modifications to the text are set forth as follows:

   A. The text of the seventh paragraph of the Summary is modified to read:

      To maximize the benefit of RPS-eligible generation to California customers, this decision provides a temporary limit on the use of TREC to meet RPS procurement
obligations. Under this limit, the three large California utilities may use TREC\textsuperscript{s} to meet no more than 25 percent of their annual RPS procurement obligations. To protect ratepayers from excessive payments for TREC\textsuperscript{s} in the early stages of the TREC market, the decision imposes a transitional price cap of $50/REC in REC-only contracts used for RPS compliance by all investor-owned utilities. Both limits will expire December 31, 2013.

B. Section 4.3.2 of the text is modified to read:

AR\textit{eM, BVES, PG&E, SCE, and TURN suggest that various forms of DG may provide some available TREC\textsuperscript{s}, though not at a very large scale over the next few years.} [FOOTNOTE: This discussion considers generation on the customer side of the meter as DG, in accordance with the CEC\textsuperscript{\textit{\textquotesingle}s} \textit{RPS Eligibility Guidebook} (3d ed., December 2007), at 17-19 (available at \url{http://www.energy.ca.gov/2007publications/CEC-300-2007-006/CEC-300-2007-006-ED3-CMF.PDF}.) Generation projects on the system side of the meter that are developed to connect to the distribution system are not considered “distributed generation” for purposes of this discussion.]

Customer-side DG projects may utilize a variety of renewable technologies. These include solar photovoltaic (PV) installations, largely constructed under the aegis of the California Solar Initiative (CSI) and the self-generation incentive program (SGIP) administered by this Commission, and the New Solar Homes Partnership (NSHP) administered by the CEC; generation using biodiesel or biogas; and small biomass facilities. [FOOTNOTE: Formal determination of the RPS eligibility of types of generation or particular systems is made by the CEC. The most current statement of CEC guidance is the \textit{RPS Eligibility Guidebook}, (3d ed., December 2007). The \textit{RPS Eligibility Guidebook} provides that “[t]he Energy Commission will not certify distributed generation facilities as RPS-eligible unless the CPUC authorizes tradable RECs to be applied toward the RPS.” (At 18.) We anticipate that the CEC will review the issue of the RPS]
eligibility of DG during its next revision of the RPS Eligibility Guidebook.]

The CEC will determine the eligibility of customer-side DG for the RPS. At this time, almost no customer-side DG is RPS-eligible. The RPS Eligibility Guidebook (at 18) explains that:

“The Energy Commission will not certify distributed generation PV and other forms of customer-sited renewable energy into the RPS at this time, with the following exception.

The Energy Commission will certify facilities that would have been considered distributed generation facilities except that they are participating in a standard contract/tariff executed pursuant to Public Utilities Code § 399.20, as implemented through the CPUC Decision 07-07-027 (R.06.05.027), executed pursuant to a comparable standard contract/tariff approved by a local publicly owned electric utility . . . or if the facility is owned by a utility and meets other requirements, to become certified as RPS-eligible . . . .

The Energy Commission will not certify distributed generation facilities as RPS-eligible unless the CPUC authorizes tradable RECs to be applied toward the RPS.”

Thus, although there are technologies that can be used for customer-side renewable DG, most current installations are not in fact RPS-eligible because they have not been certified by the CEC and cannot be certified until the CEC revises its RPS Eligibility Guidebook.

In anticipation of the eventual use of customer-side DG for RPS compliance, both this Commission and the CEC have addressed the issue of the availability of TRECs from such installations. In D.07-01-018, the Commission determined that owners of customer-side DG installations own the RECs associated with the generation, and can therefore sell them, regardless of whether the DG owners participate in net metering, CSI, or the SGIP. [FOOTNOTE: The CEC
has likewise determined that the system owner of customer-side DG does not need to relinquish claim over the RECs in order to participate in the NSHP. See New Solar Homes Partnership Guidebook (3d edition April 2010) at 7. This guidebook is available at http://www.energy.ca.gov/2010publications/CEC-300-2010-001/CEC-300-2010-001-CMF-REV1.PDF.\] In D.07-07-027 and D.08-09-033, implementing § 399.20, the Commission provided for tariffs or standard contracts for utilities’ bundled purchase of RPS-eligible generation from DG of not more than 1.5 megawatt (MW) in size located at public water and wastewater facilities and other customers, with an overall statewide limit on such purchases. The generation so acquired counts toward the utilities’ RPS targets. In this program, customers may sell to the utility either the full output of the DG facility (energy and RECs) or only the excess (energy and RECs) not used for on-site consumption. In the latter case, the RECs associated with the energy used on-site remain with the system owner. [FOOTNOTE: TREC from RPS-eligible DG installations that are tracked in WREGIS are, for RPS compliance purposes, the same as TREC from RPS-eligible utility-scale generation. No matter the type of DG generation or the kind of transaction, RECs associated with RPS-eligible DG—like RECs from any other RPS-eligible generation—“shall be counted only once for compliance with the renewables portfolio standard of this state or any other state, or for verifying retail product claims in this state or any other state.” (§ 399.16(a)(2)).]\]

AReM states that the CSI program estimates that the program will have installed about 800 gigawatt hours (GWh) of generation by 2010. AReM additionally estimates that CSI will have provided incentives for approximately 1,100 GWh by 2011. No other party provides quantitative DG estimates. [FOOTNOTE: In D.09-06-049, the Commission approved a new SCE program to procure RPS-eligible energy from rooftop solar PV installations of one to two MW in size. Because the program is new, it is not currently possible to know what,
if any, impact it will have on DG as a resource for RPS procurement over the next two to three years.]

C. The twenty-second paragraph of Section 4.5 of the text is modified to read:

The fundamental characteristic of a bundled transaction is that the energy associated with the REC serves California load. Based on the record in this proceeding, we can say with assurance at this time that the following transactions belong in this bundled transaction classification:

1. Transactions where the RPS-eligible generator’s first point of interconnection with the WECC interconnected transmission system is with a California balancing authority;

2. Transactions in which the RPS-eligible energy from the transaction is dynamically transferred to a California balancing authority.

D. The last sentence in the second paragraph of section 4.10 is modified to read:

Because TRECs cannot be recognized for RPS compliance unless they are tracked in WREGIS, REC-only contracts must contain assurances that the seller has taken all steps necessary to ensure that the generation is properly registered and the TRECs will be tracked in WREGIS. [FOOTNOTE: PG&E suggests in its comments on the RPD that the assurance of registration with WREGIS should apply at the time deliveries commence under the contract, not at the time the contract is signed. This suggestion is unopposed and simplifies contracting; we adopt it in this decision.]

E. The first sentence of section 4.11 of the text is modified to read:

Beginning on the effective date of this decision, TRECs tracked in WREGIS and certified by the CEC as associated with RPS-eligible electricity, for which the RPS-eligible electricity associated with the TREC was generated on or after January 1, 2008 may be procured, traded, and used for RPS compliance. [FOOTNOTE: This date is used because
2008 is the first year that WREGIS issued certificates; it is also the first year data from WREGIS is reported to the CEC to verify RPS procurement. ([RPS Eligibility Guidebook at 46.])

F. All references to December 31, 2011 in section 4.6.3. and 4.7.3. as those references pertain to the expiration of the usage limit for tradable renewable energy credits and price cap on tradable renewable energy credits are modified to read: “December 31, 2013.”

4. The findings of fact, conclusions of law, and Order in D.10-03-021 are modified as explained in this decision. The specific modifications are set forth as follows:

A. Conclusion of Law 4 is modified to read:

4. In order to be used for RPS compliance, TRECs must be tracked in WREGIS.

B. A new Conclusion of Law 13 is added to read:

13. The temporary limit on the proportion of annual RPS procurement obligations that can be met by using TRECs should not be considered as a determination that any REC-only transaction that would not exceed the limit is a per se reasonable transaction for a utility to undertake.

C. Conclusion of Law 13 is renumbered as 14 and is modified to read:

14. In order to recognize the legitimate expectations of the parties to RPS contracts now classified as REC-only that were approved by the Commission prior to the effective date of this decision, the temporary limit on the use of TRECs for RPS compliance provided in this decision should not be applied to deliveries to an LSE from contracts classified as REC-only by this decision, but which were previously approved by the Commission, if the deliveries would cause the LSE to exceed the TREC usage limit. In this circumstance, the LSE should not be
allowed to use any TRECs associated with contracts that were not approved by the Commission prior to the effective date of this decision for compliance in that year that would exceed the 25% limit. The LSE should also not be allowed to use any TRECs in that year that would exceed the 25% limit from incremental changes to approved contracts in the event that either of the following changes occurs with respect to such a contract previously approved by the Commission:

a. The expiration date of the contract is extended beyond the expiration date existing in the approved contract on March 11, 2010; or

b. The deliveries allowed under the contract are increased beyond the maximum deliveries identified in the contract as the approved contract read on March 11, 2010.

In either event, all deliveries after the effective date of the contract amendment that are incremental to the deliveries set forth in the approved contract should be treated according to the then-applicable classification of REC-only and bundled transactions and associated rules, including any limitations on their use for RPS compliance.

D. Conclusions of Law 14, 15, 16, 17, 18, 19, 20, 21, 22, and 23 are renumbered as 15, 16, 17, 18, 19, 20, 21, 22, 23, and 24, respectively.

E. Conclusion of Law 24 is renumbered as 25 modified to read:

24. Utilities that are required to submit their RPS procurement contracts for Commission approval should submit REC-only contracts for approval not earlier than April 1, 2010. The Director of Energy Division should be authorized to require the submission of any additional information necessary for the evaluation of such contracts.

F. Conclusion of Law 25 is renumbered as 26.
G. Conclusion of Law 26 is renumbered as 27 and modified to read:

26. In order to provide the Commission with information about the initial period of the TREC market and the use of TREC's for RPS compliance, the Director of Energy Division should prepare a report for the Commission by December 31, 2012, using information provided by all RPS-obligated LSEs. This report should include a recommendation to the Commission regarding whether or not the applicable TREC usage limit and price cap should be retained or allowed to sunset, taking into consideration, among other things, any legislation or regulation increasing the percentage of retail sales that must be met with renewable energy procurement.

H. Ordering Paragraph 3 is modified to read:

3. In order to be used for compliance with the California renewables portfolio standard, tradable renewable energy credits must be tracked and retired in the Western Renewable Energy Generation Information System, must conform to the requirements of Decision 08-08-028 and any subsequent Commission decision or any applicable California legislation characterizing renewable energy credits, and must meet the criteria for eligibility for the California renewables portfolio standard that are set by the California Energy Commission.

I. Ordering Paragraph 4 is modified to read:

4. Any renewable energy credits used for compliance with the California renewables portfolio standard are subject to the restrictions in Ordering Paragraphs 8 and 9, below.

J. Ordering Paragraph 9 is modified to read:

9. Renewable energy credits associated with electricity generation that is eligible for the California renewables portfolio standard delivered under procurement
contracts of California utilities for both energy and renewable energy credits pursuant to the federal Public Utility Regulatory Policies Act of 1978 that were signed after January 1, 2005 shall be used for compliance with the California renewables portfolio standard only if they are not transferred to an entity other than the original buyer in the Western Renewable Energy Generation Information System prior to being retired for compliance with the California renewables portfolio standard.

K. Ordering Paragraph 18 is modified to read:

18. The temporary limit on the use of tradable renewable energy credits for compliance with the California renewables portfolio standard shall not be applied to deliveries to a load-serving entity obligated under the California renewables portfolio standard from contracts that are classified by this decision as contracts for renewable energy credits only, but were approved by the Commission prior to the effective date of this decision, if such deliveries would cause that load-serving entity to exceed the annual limit on the use of tradable energy credits for compliance with the California renewables portfolio standard. In this circumstance, the load-serving entity may not use any tradable renewable energy credits associated with contracts that were not approved by the Commission prior to the effective date of this decision for compliance in that year that would exceed the 25% annual limit.

The load-serving entity also may not use any tradable renewable energy credits in that year that would exceed the 25% limit from incremental changes to approved contracts in the event that either of the following changes occurs with respect to such a contract previously approved by the Commission:
a. The expiration date of the contract is extended beyond the expiration date existing in the approved contract on March 11, 2010; or

b. The deliveries allowed under the contract are increased beyond the maximum deliveries identified in the contract as the approved contract read on March 11, 2010.

In either event, all deliveries after the effective date of the contract amendment that are incremental to the deliveries set forth in the approved contract should be treated according to the then-applicable classification of renewable energy credits-only and bundled transactions and associated rules, including any limitations on their use for renewables portfolio standard compliance.

L. Ordering Paragraph 19 is modified to read:


M. Ordering Paragraph 21 is modified to read:

21. The temporary limit on the price paid by an investor-owned utility for tradable renewable energy credits procured through contracts for renewable energy credits only for compliance with the California renewables portfolio standard shall terminate on December 31, 2013.

N. Ordering Paragraph 27 is modified to read:

27. The Director of Energy Division is authorized to review existing reporting formats and tools for the California renewables portfolio standard and undertake appropriate revisions to allow complete reporting and monitoring of the provisions of this order. All retail sellers obligated under the California renewables portfolio standard must provide copies of their contracts for procurement under the California renewables portfolio standard, as well as any other
required information about their procurement to meet the California renewables portfolio standard, to Energy Division staff, as and when required by the Director of Energy Division.

O. Ordering Paragraph 31 is modified to read:

31. The Director of Energy Division shall review and compile information about the market for tradable renewable energy credits and the use of tradable renewable energy credits for compliance with the California renewables portfolio standard provided by load-serving entities obligated under the California renewables portfolio standard in their advice letters or applications seeking approval of contracts for procurement of renewable energy credits only, in their semiannual compliance reports, and in response to other request for information made by Energy Division staff. The Director of Energy Division shall include analysis of this information in a report to be provided to the Commission by December 31, 2012. The report shall also include recommendations about whether the Commission should review, modify, or extend the annual limit on the use of tradable renewable energy credits for compliance with the California renewables portfolio standard program, or whether the Commission should let the limit expire. The report shall also include recommendations about whether the Commission should review, modify, or extend the limit on the price an investor-owned utility may pay for tradable renewable energy credits for compliance with the California renewables portfolio standard program, or whether the Commission should let the limit expire.
P. Ordering Paragraph 35 is modified to read:

35. The following non-modifiable standard terms and conditions shall be included in all contracts for procurement for compliance with the California renewables portfolio standard, whether bundled contracts or purchases of renewable energy credits only:

STC REC-1. Transfer of Renewable Energy Credits

a. Seller and, if applicable, its successors, represents and warrants that throughout the Delivery Term of this Agreement the Renewable Energy Credits transferred to Buyer conform to the definition and attributes required for compliance with the California Renewables Portfolio Standard, as set forth in California Public Utilities Commission Decision 08-08-028, and as may be modified by subsequent decision of the California Public Utilities Commission or by subsequent legislation. To the extent a change in law occurs after execution of this Agreement that causes this representation and warranty to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in law.

b. STC REC-2. Tracking of RECs in WREGIS

Seller warrants that all necessary steps to allow the Renewable Energy Credits transferred to Buyer to be tracked in the Western Renewable Energy Generation Information System will be taken prior to the first delivery under the contract.
Q. Ordering Paragraph 36 is modified to read:

36. The following non-modifiable standard terms and conditions shall be included in all contracts for purchase of renewable energy credits only of regulated utilities other than multi-jurisdictional utilities:

a. STC REC-3. CPUC Approval

“CPUC Approval” means a final and non-appealable order of the CPUC, without conditions or modifications unacceptable to the Parties, or either of them, which contains the following terms:

(a) approves this Agreement in its entirety, including payments to be made by the Buyer, subject to CPUC review of the Buyer’s administration of the Agreement; and

(b) finds that any procurement pursuant to this Agreement is procurement of Renewable Energy Credits that conform to the definition and attributes required for compliance with the California Renewables Portfolio Standard, as set forth in California Public Utilities Commission Decision 08-08-028, and as may be modified by subsequent decision of the California Public Utilities Commission or by subsequent legislation, for purposes of determining Buyer’s compliance with any obligation that it may have to procure eligible renewable energy resources pursuant to the California Renewables Portfolio Standard (Public Utilities Code Section 399.11 et seq.), Decision 03-06-071, or other applicable law.

CPUC Approval will be deemed to have occurred on the date that a CPUC decision containing such findings becomes final and non-appealable.

b. STC 17. Applicable Law

Governing Law. This agreement and the rights and duties of the parties hereunder shall be governed by
and construed, enforced and performed in accordance with the laws of the state of California, without regard to principles of conflicts of law. To the extent enforceable at such time, each party waives its respective right to any jury trial with respect to any litigation arising under or in connection with this agreement.

R. Ordering Paragraph 38 is modified to read:

38. Not earlier than April 1, 2010, investor-owned utilities may submit for Commission approval contracts conveying renewable energy credits only that conform to the requirements of this order. For any contracts conveying renewable energy credits only that a utility submitted prior to January 14, 2011 but that have not been approved by January 14, 2011, the utility shall make a supplemental filing, in the form and with the content prescribed by the Director of Energy Division.

S. Appendix C to Decision (D.) 10-03-021, “New and Revised Standard Terms and Conditions,” is modified to replace each use of the phrase “renewable energy credits” with “Renewable Energy Credits.”

5. Appendix D to D.10-03-021, “Summary of TREC Rules Announced in this Decision,” is modified to reflect the modifications made in this decision. The modified Appendix D is attached to this decision as Appendix B.

6. The stay of D.10-03-021 imposed by D.10-05-018 is dissolved, as of the effective date of this decision.

7. The temporary moratorium imposed by D. 10-05-018 on Commission approval of any procurement contracts for compliance with the renewables portfolio standard program signed after May 6, 2010 that would have been defined under D.10-03-021 as transactions transferring renewable energy credits only is ended, as of the effective date of this decision.
8. The prompt further development of rules for compliance with the California renewables portfolio standard by community choice aggregators is assigned to Rulemaking 08-08-009 or its successor.

This order is effective today.

Dated January 13, 2011, at San Francisco, California.

MICHAEL R. PEEVEY
President
TIMOTHY ALAN SIMON
NANCY E. RYAN
Commissioners
(APPENDIX A)
APPENDIX A

FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER IN D.10-03-021 AS MODIFIED BY THIS DECISION

Findings of Fact

1. Allowing the use of TRECs for RPS compliance will give RPS-obligated LSEs increased options for RPS compliance, and may reduce complexity and costs of RPS procurement contracting.

2. The use of TRECs for RPS compliance will be substantially compatible with existing RPS flexible compliance rules.

3. As the California TREC market develops, it is likely to provide support for the development of new RPS-eligible generation.

4. In view of the benefits of the use of TRECs for RPS compliance and the development of a viable TREC market, it is reasonable to allow the use of TRECs for RPS compliance, subject to reasonable conditions.

5. This Commission adopted the report on the tracking system required by § 399.16(a)(1) by Res. E-4178 (November 21, 2008).

6. The CEC adopted the report on the tracking system required by § 399.16(a)(1) at its business meeting on December 3, 2008.

7. In order to maximize benefits to ratepayers, it is reasonable to classify RPS procurement transactions that convey energy and RECs as bundled transactions when these transactions serve California customer load without the substitution of energy from firming and/or shaping arrangements prior to the energy being scheduled in a California balancing authority.

8. Because the RPS-eligible energy is delivered directly to California's system, California customers receive the maximum benefit of RPS procurement transactions when the generator of the energy associated with a REC has its first
point of interconnection with the WECC transmission system with a California balancing authority area, or when the energy procured is dynamically transferred to a California balancing authority.

9. In the early years of a California TREC market, prior to LSEs' attaining the goal of 20% of retail sales from RPS-eligible generation resources, demand for TREC is likely to exceed supply.

10. REC-only contracts are likely to provide fewer potential benefits to ratepayers than contracts for RPS procurement that include both RECs and RPS-eligible energy. In light of this differential in potential benefits, it is reasonable to impose on the three large IOUs a temporary limit of 25% of APT annually on their use of TREC for RPS compliance.

11. In order to provide protections for ratepayers from the potential for volatility and spikes in TREC prices without damaging the basic structure of the TREC market or undermining the financial incentives for new renewable construction that are among the longer-term benefits of a TREC market, it is reasonable to impose a temporary price cap of $50/REC for TREC purchases by IOUs.

12. Solely for purposes of determining whether the contract price is reasonable and the price of TREC is at or below the reviewable price cap, it is reasonable to develop a method to infer the price for a TREC based on a forecast of the market price for the associated energy if the contract does not specifically identify the REC price.

13. In order to promote liquidity in the TREC market, it is reasonable to impose a limit on the period of time that TREC and REC associated with energy in bundled contracts may be held in an active WREGIS sub-account before being retired for RPS compliance.
14. Allowing LSEs to unbundle and sell RECs from bundled contracts for RPS-eligible energy, on both a spot and forward basis, will promote liquidity in the TREC market and provide RPS compliance flexibility.

15. Because it is not always possible for the viability of REC-only contracts to be assessed in the same way as bundled contracts, it is reasonable to limit the earmarking of REC-only contracts to those contracts between an RPS-obligated LSE and one RPS-eligible generator providing the TREC.

16. It is reasonable to allow REC-only transactions as well as bundled transactions to be used to make up shortfalls in RPS procurement in prior years in accordance with the flexible compliance rules and the limits on TREC usage set forth in this decision.

17. In order to preserve the Commission's ability to determine compliance with RPS obligations and to eliminate the potential for double-counting of some RECs, it is reasonable to prohibit the unbundling and trading of RECs from the first three years of deliveries of any RPS procurement contract, whether bundled or REC-only, that has been earmarked.

18. In view of the uncertainties involved in the early years of a new TREC market, it is reasonable to provide for regular reports by RPS-obligated LSEs of their purchases and sales of TREC including prices of the transactions. This information may be used in assessments of market performance by Energy Division staff and, as needed, review by the Commission of the market rules set forth in this order.

Conclusions of Law
1. The use of TRECs for RPS compliance should be authorized.
2. All statutory preconditions to this authorization have been met.
3. Procurement and trading of RECs that meet the requirements of D.08-08-028 and any subsequent Commission decision or any applicable legislation characterizing RECs should begin not earlier than the effective date of this decision.
4. In order to be used for RPS compliance, TRECs must be tracked in WREGIS.
5. LSEs should be allowed to unbundle and sell RECs from bundled contracts for RPS-eligible energy, on both a spot and forward basis, subject to conditions that promote RPS compliance and prevent double-counting.
6. Existing RPS flexible compliance rules should be applied to the use of TRECs for RPS compliance, with the following adjustments:
   a. REC-only contracts between an LSE and one RPS-eligible generator supplying the TRECs may be earmarked.
   b. RECs may not be unbundled or traded in the first three years of contracts (whether bundled or REC-only) that have been earmarked.
   c. REC-only contracts that are used for earmarking will count against any TREC usage limitation in the year the TRECs are used for RPS compliance.
7. RECs associated with RPS-eligible generation under contracts with California RPS-obligated LSEs or POUs signed prior to 2005 that do not allocate ownership or disposition of RECs as well as RECs associated with RPS-eligible generation under contracts pursuant to PURPA between QFs and California LSEs or POUs signed after January 1, 2005 may not be unbundled or used for RPS compliance separate from the associated energy.
8. A reasonable limit on the period of time that TREC\#s and REC\#s associated with energy delivered in bundled contracts used for RPS compliance may be held in an active WREGIS sub-account before being retired for RPS compliance should be imposed.

9. In order to allow flexibility in RPS procurement and compliance, IOUs should be able to enter into voluntary TREC transactions even if their cost limitation, as set out in § 399.15(d), has been reached, so long as the usage limit, price cap, and other requirements in this decision are met.

10. In order to maximize the benefit California consumers receive from the procurement of RPS-eligible energy and of TREC\#s, all procurement that does not meet the Commission's criteria for classification as bundled RPS transactions should be classified as REC-only transactions. Transactions in which REC\#s and energy are procured from RPS-eligible generators for which the first point of interconnection with the WECC interconnected transmission system is in a California balancing authority area, or transactions using dynamic transfer arrangements with a California balancing authority, should be considered bundled procurement for RPS compliance purposes. All other RPS procurement transactions should be considered REC-only at this time.

11. Transactions in which REC\#s and RPS-eligible energy are procured from a generator whose first point of interconnection with the WECC interconnected transmission system is not a California balancing authority, and the transaction does not make use of dynamic transfer arrangements with a California balancing authority, that were approved by the Commission prior to the effective date of this decision should be counted as REC-only transactions as of the effective date of this decision. All deliveries from such transactions that occurred prior to the effective date of this decision should count as bundled transactions.
12. A temporary limit on the proportion of annual RPS procurement obligations that can be met by using TRECs should be imposed on the three large IOUs.

13. The temporary limit on the proportion of annual RPS procurement obligations that can be met by using TRECs should not be considered as a determination that any REC-only transaction that would not exceed the limit is a *per se* reasonable transaction for a utility to undertake.

14. In order to recognize the legitimate expectations of the parties to RPS contracts now classified as REC-only that were approved by the Commission prior to the effective date of this decision, the temporary limit on the use of TRECs for RPS compliance provided in this decision should not be applied to deliveries to an LSE from contracts classified as REC-only by this decision, but which were previously approved by the Commission, if the deliveries would cause the LSE to exceed the TREC usage limit. The LSE should also not be allowed to use any TRECs in that year that would exceed the 25% limit from incremental changes to approved contracts in the event that either of the following changes occurs with respect to such a contract previously approved by the Commission:

   a. The expiration date of the contract is extended beyond the expiration date existing in the approved contract on March 11, 2010; or

   b. The deliveries allowed under the contract are increased beyond the maximum deliveries identified in the contract as the approved contract read on March 11, 2010.

In either event, all deliveries after the effective date of the contract amendment that are incremental to the deliveries set forth in the approved contract should be treated according to the then-applicable classification of REC-only and bundled...
transactions and associated rules, including any limitations on their use for RPS compliance.

15. A temporary cap on the price a utility may pay for a TREC should be imposed.

16. The temporary price cap for IOU purchases of TREC should not be treated as a per se reasonable price for a TREC.

17. IOUs should include proceeds of the sale of TREC in their ERRA or ECAC accounts, or equivalents (such as power purchase accounts) for the benefit of ratepayers. Any IOU not currently having an appropriate accounting method should file an advice letter within 90 days of the date of this decision proposing an accounting method.

18. In order to allow multi-jurisdictional utilities to recover the reasonable costs of REC-only contracts procured solely for California RPS compliance, such contracts should be submitted for Commission approval via advice letter.

19. In order to carry out the determinations in this decision, the Director of Energy Division should be authorized to develop methods, in consultation with the parties and CAISO and other California balancing authorities, if relevant, of reviewing and evaluating RPS procurement contracts in which a dynamic transfer is an element of the contract.

20. In order to provide the Commission with information to evaluate the role of firm transmission in RPS procurement, the Director of Energy Division should be authorized to investigate the use of firm transmission in accordance with the guidance provided in this decision.

21. In order to facilitate the integration of TREC into RPS procurement planning and practices, the assigned Commissioner in R.08-08-009 or its successor should be authorized to include in that proceeding consideration of
changes to RPS annual procurement plans, LCBF evaluation methodology, and RPS contract approval processes to include procurement of TREC.

22. In order to facilitate the integration of REC-only transactions into the RPS flexible compliance rules, the Director of Energy Division should be authorized, consistent with the ALJ’s Reporting Ruling, to make revisions to the RPS compliance spreadsheet and other RPS reporting formats to implement the requirements and conditions set forth in this order.

23. In order to facilitate the integration of REC-only transactions into the RPS procurement process, the Director of Energy Division should be authorized to apply current procedures and methods of review of bundled contracts to REC-only contracts, with the exception that the fast-track procedure authorized by D.09-06-050 should not now be applied to REC-only contracts.

24. In order to facilitate the integration of REC-only transactions into the RPS procurement process, utilities that have submitted RPS procurement contracts for Commission approval should, if necessary, amend all pending contracts to include the STCs related to RECs, and should amend their pending advice letters or applications to demonstrate that the contracts conform to the requirements for STCs related to RECs.

25. Utilities that are required to submit their RPS procurement contracts for Commission approval should submit REC-only contracts for approval not earlier than April 1, 2010. The Director of Energy Division should be authorized to require the submission of any additional information necessary for evaluation of such contracts.

26. In order to facilitate the integration of REC-only transactions into the RPS procurement process, the Director of Energy Division should be authorized to determine the price of the TREC in transactions for both RECs and energy in
which no separate price for RECs is indicated and where the RECs are associated with energy from generators of RPS-eligible energy for which the generator’s first point of interconnection with the WECC interconnected transmission system is not with a California balancing authority, and the transaction does not make use of dynamic transfer arrangements in a California balancing authority.

27. In order to provide the Commission with information about the initial period of the TREC market and the use of TRECs for RPS compliance, the Director of Energy Division should prepare a report for the Commission within 16 months of the effective date of this order, using information provided by all RPS-obligated LSEs. This report should include a recommendation to the Commission regarding whether or not the applicable TREC usage limit and price cap should be retained or allowed to sunset, taking into consideration, among other things, any legislation or regulation increasing the percentage of retail sales that must be met with renewable energy procurement.

28. In order to allow the use of TRECs for RPS compliance as soon as practicable, this order should be effective immediately.

ORDER
IT IS ORDERED that:

1. Renewable energy credits that are procured and traded separately from the associated energy generated by a facility that is eligible for the California renewables portfolio standard may be used for compliance with the California renewables portfolio standard in accordance with the rules set forth in this decision.

2. Procurement and trading of renewable energy credits for compliance with the California renewables portfolio standard in accordance with the rules set forth in this decision may commence on the effective date of this decision.

3. In order to be used for compliance with the California renewables portfolio standard, tradable renewable energy credits must be tracked and retired in the Western Renewable Energy Generation Information System, must conform to the requirements of Decision 08-08-028 and any subsequent Commission decision or any applicable California legislation characterizing renewable energy credits, and must meet the criteria for eligibility for the California renewables portfolio standard that are set by the California Energy Commission.

4. Any renewable energy credits tracked used for compliance with the California renewables portfolio standard are subject to the restrictions in Ordering Paragraphs 8 and 9, below.

5. Any renewable energy credits tracked in the Western Renewable Energy Generation Information System associated with electricity that is eligible for the California renewables portfolio standard that was generated on or after January 1, 2008 may be procured and traded separately from the associated energy, subject to the restrictions set forth in Ordering Paragraphs 8, 9, and 14 below.
6. As of the effective date of this decision, a transaction for purposes of compliance with the California renewables portfolio standard shall be considered a transaction that procures only renewable energy credits if that transaction either:

a. Expressly transfers only renewable energy credits and not energy from the seller to the buyer; or

b. Transfers both renewable energy credits and energy from the seller to the buyer but does not meet the Commission's criteria for considering a procurement transaction a bundled transaction for purposes of compliance with the California renewables portfolio standard.

All deliveries from transactions described in subsection b, above, made prior to the effective date of this decision will be counted as bundled deliveries of both renewable energy credits and energy for purposes of compliance with the California renewables portfolio standard.

7. The following types of transactions shall be treated as bundled transactions for purposes of compliance with the California renewables portfolio standard:

a. Transactions in which energy is acquired from a generator certified as eligible for the California renewables portfolio standard and the generator has its first point of interconnection with the Western Electricity Coordinating Council interconnected transmission system with a California balancing authority; and

b. Transactions in which energy is acquired from a generator certified as eligible for the California renewables portfolio standard and the energy from the transaction is dynamically transferred to a California balancing authority area.

8. Renewable energy credits associated with electricity generation that is eligible for the California renewables portfolio standard delivered under procurement contracts signed prior to 2005 with load-serving entities obligated
under the California renewables portfolio standard or with California publicly owned utilities that do not allocate ownership or disposition of the renewable energy credits shall be used for compliance with the California renewables portfolio standard only if they are not transferred to an entity other than the original buyer in the Western Renewable Energy Generation Information System prior to being retired for compliance with the California renewables portfolio standard.

9. Renewable energy credits associated with electricity generation that is eligible for the California renewables portfolio standard delivered under procurement contracts of California utilities for both energy and renewable energy credits pursuant to the federal Public Utility Regulatory Policies Act of 1978 that were signed after January 1, 2005 shall be used for compliance with the California renewables portfolio standard only if they are not transferred to an entity other than the original buyer in the Western Renewable Energy Generation Information System prior to being retired for compliance with the California renewables portfolio standard.

10. In order to be used for compliance with the California renewables portfolio standard, renewable energy credits may be retained in active sub-accounts in the Western Renewable Energy Generation Information System for no more than three compliance years (inclusive of the year in which the electricity associated with the renewable energy credits was generated) after the electricity associated with the renewable energy credits was generated before being transferred to the Western Renewable Energy Generation Information System retirement sub-account of a load-serving entity obligated under the California renewables portfolio standard.
11. Once renewable energy credits are retired in the Western Renewable Energy Generation Information System for use for compliance with the California renewables portfolio standard, they may be banked for compliance with the California renewables portfolio standard in future years in accordance with the flexible compliance rules for the California renewables portfolio standard.

12. Subject to the restrictions in Ordering Paragraphs 8, 9, and 14, the renewable energy credits from bundled contracts currently delivering energy eligible under the California renewables portfolio standard may be unbundled and traded separately from the associated energy in accordance with the rules set forth in this decision, so long as, once the renewable energy credits have been sold, the associated energy is not used for compliance with the California renewables portfolio standard.

13. Subject to the restrictions in Ordering Paragraphs 8, 9, and 14, the renewable energy credits from bundled contracts scheduled to deliver energy eligible for the California renewables portfolio standard in the future may be unbundled and traded on a forward basis separately from the associated energy, so long as, once the renewable energy credits are generated, they are tracked in the Western Renewable Energy Generation Information System and, once the renewable energy credits have been sold, the associated energy is not used for compliance with the California renewables portfolio standard.

14. Renewable energy credits may not be unbundled and traded from the first three years of deliveries under any bundled procurement contract for compliance with the California renewables portfolio standard that has been earmarked to apply to a shortfall in meeting the annual procurement target of a load-serving entity obligated under the California renewables portfolio standard in the year
the bundled contract was signed, subject to the restrictions in Ordering Paragraphs 8 and 9.

15. Contracts for delivery of renewable energy credits only between a load-serving entity and one generator of energy eligible under the California renewables portfolio standard that supplies all the renewable energy credits in the contract may be earmarked for purposes of compliance with the California renewables portfolio standard, but no other types of contracts for delivery of renewable energy credits only may be earmarked. The tradable renewable energy credits from such contracts shall count against any annual limit on the use of tradable renewable energy credits in the year that the tradable renewable energy credits are used for compliance with the California renewables portfolio standard.

16. Renewable energy credits may not be sold or traded from the first three years of deliveries from a procurement contract for renewable energy credits only that has been earmarked to apply to a shortfall in meeting the annual procurement target of a load-serving entity obligated under the California renewables portfolio standard in the year the contract for the delivery of renewable energy credits was signed.

17. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company may each use renewable energy credits procured from contracts for renewable energy credits only to meet no more than 25 percent of their annual procurement targets for the California renewables portfolio standard, beginning with the 2010 compliance year.

18. The temporary limit on the use of tradable renewable energy credits for compliance with the California renewables portfolio standard shall not be applied to deliveries to a load-serving entity obligated under the California
renewables portfolio standard from contracts that are classified by this decision as contracts for renewable energy credits only, but were approved by the Commission prior to the effective date of this decision, if such deliveries would cause that load-serving entity to exceed the annual limit on the use of tradable energy credits for compliance with the California renewables portfolio standard. In this circumstance, the load-serving entity may not use any tradable renewable energy credits associated with contracts that were not approved by the Commission prior to the effective date of this decision for compliance in that year that would exceed the 25% annual limit.

The load-serving entity also may not use any tradable renewable energy credits in that year that would exceed the 25% limit from incremental changes to approved contracts in the event that either of the following changes occurs with respect to such a contract previously approved by the Commission:

a. The expiration date of the contract is extended beyond the expiration date existing in the approved contract on March 11, 2010; or

b. The deliveries allowed under the contract are increased beyond the maximum deliveries identified in the contract as the approved contract read on March 11, 2010.

In either event, all deliveries after the effective date of the contract amendment that are incremental to the deliveries set forth in the approved contract should be treated according to the then-applicable classification of renewable energy credits-only and bundled transactions and associated rules, including any limitations on their use for renewables portfolio standard compliance.

19. The temporary limit on the use of tradable renewable energy credits for compliance with the California renewables portfolio standard shall terminate December 31, 2013.
20. No renewable energy credits procured through contracts for renewable energy credits only for which the levelized amount paid is greater than $50.00 per renewable energy credit may be used by any investor-owned utility for compliance with the California renewables portfolio standard. This limit applies only to those renewable energy credits procured by multi-jurisdictional utilities exclusively for use in complying with their California renewables portfolio standard procurement obligations.

21. The temporary limit on the price paid by an investor-owned utility for tradable renewable energy credits procured through contracts for tradable renewable energy credits only for compliance with the California renewables portfolio standard shall terminate December 31, 2013.

22. Investor-owned utilities that have reached the procurement cost limitation for compliance with the California renewables portfolio standard set forth in Public Utilities Code Section 399.15(d) may enter into voluntary transactions for renewable energy credits in accordance with the rules set forth in this decision.

23. Investor-owned utilities shall promptly set up an appropriate accounting method to apply proceeds of the sale of renewable energy credits for the benefit of ratepayers. Any investor-owned utility not currently having an appropriate accounting method shall file an advice letter within 90 days of the effective date of this decision proposing an accounting method.

24. Any contracts for renewable energy credits only that are procured solely for compliance with the California renewables portfolio standard for which a multi-jurisdictional utility seeks recovery of costs must be submitted for Commission approval by means of an advice letter.

25. The Director of Energy Division is authorized to develop methods, in consultation with the parties and California Independent System Operator, and
other California balancing authorities, if relevant, of reviewing and evaluating procurement contracts for compliance with the California renewables portfolio standard in which a dynamic transfer is an element of the contract.

26. The Director of Energy Division shall take appropriate steps to obtain information that will enable a definitive determination of how to classify transactions for RPS procurement that include firm transmission arrangements but not dynamic transfers to a California balancing authority and will allow the development of criteria for reviewing and evaluating such contracts that are presented for Commission approval. The Director of Energy Division may also, in the Director's discretion, provide recommendations to the Commission about the classification and evaluation of such transactions. Such recommendations may be in the form of a report, or in the form of a resolution prepared for the Commission's consideration.

27. The Director of Energy Division is authorized to review existing reporting formats and tools for the California renewables portfolio standard and undertake appropriate revisions to allow complete reporting and monitoring of the provisions in this order. All retail sellers obligated under the California renewables portfolio standard must provide copies of their contracts for procurement under the California renewables portfolio standard, as well as any other required information about their procurement to meet the California renewables portfolio standard, to Energy Division staff, as and when required by the Director of Energy Division.

28. The Director of Energy Division is authorized to apply current procedures and methods of review of bundled contracts for procurement under the California renewables portfolio standard by investor-owned utilities to contracts for renewable energy credits only, with the exception that the fast-track
procedure authorized by Decision 09-06-050 may not now be applied to procurement of renewable energy credits only.

29. The Director of Energy Division is authorized to develop and apply a method for inferring the price of renewable energy credits in transactions for both renewable energy credits and energy in which no separate price for the renewable energy credits is indicated and where the renewable energy credits are associated with energy from generators of energy eligible under the California renewables portfolio standard for which the first point of interconnection with the Western Electricity Coordinating Council interconnected transmission system is not a California balancing authority and a dynamic transfer with a California balancing authority is not an element of transaction.

30. The Director of Energy Division may require the submission of appropriate documentation to verify compliance with any of the requirements set forth in this Order, including but not limited to purchases, sales, and prices of renewable energy credits.

31. The Director of Energy Division shall review and compile information about the market for tradable renewable energy credits and the use of tradable renewable energy credits for compliance with the California renewables portfolio standard provided by load-serving entities obligated under the California renewables portfolio standard in their advice letters or applications seeking approval of contracts for procurement of renewable energy credits only, in their semiannual compliance reports, and in response to other request for information made by Energy Division staff. The Director of Energy Division shall include analysis of this information in a report to be provided to the Commission by December 31, 2012. The report shall also include recommendations about
whether the Commission should review, modify, or extend the annual limit on the use of tradable renewable energy credits for compliance with the California renewables portfolio standard program, or whether the Commission should let the limit expire. The report shall also include recommendations about whether the Commission should review, modify, or extend the limit on the price an investor-owned utility may pay for tradable renewable energy credits for compliance with the California renewables portfolio standard program, or whether the Commission should let the limit expire.

32. The Director of Energy Division shall include in the format for advice letters seeking Commission approval of contracts for procurement of tradable renewable energy credits for compliance with the California renewables portfolio standard the following information from the utility submitting the advice letter:

- Whether the generation facility or facilities producing the energy eligible for the California renewables portfolio standard that is associated with the renewable energy credits to be procured entered commercial operation prior to January 1, 2005, or after January 1, 2005, or was not in commercial operation at the time the contract was signed;

- the sum of all delivered and expected tradable renewable energy credits purchased through contracts executed by the utility to date and how this compares to any applicable annual limit on the use of tradable renewable energy credits for compliance with the California renewables portfolio standard;

- the sum of all delivered and expected tradable renewable energy credits purchased by that utility through contracts for the procurement of renewable energy credits only with facilities that are or were already online as of the execution date of their associated contract for procurement of tradable renewable energy credits, and how this compares to the applicable annual limit on the use of tradable
renewable energy credits for compliance with the California renewables portfolio standard;

- the sum of all delivered and expected tradable renewable energy credits purchased by that utility through contracts for the procurement of renewable energy credits only with facilities that are not or were not online as of the execution dates of their associated contracts, and how this compares to the applicable annual limit on the use of tradable renewable energy credits for compliance with the California renewables portfolio standard;

- a comparison of the price of the renewable energy credits in the contract that is the subject of the advice letter and the price of renewable energy credits from all contracts for the procurement of renewable energy credits only with facilities that were online as of the execution date of their associated contracts; and

- a comparison of the price of the renewable energy credits in the contract that is the subject of the advice letter and the price of renewable energy credits from all contracts for the procurement of renewable energy credits only with facilities that were not yet online as of the execution date of their associated contracts.

33. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall each file and serve amendments to their 2010 annual procurement plans for compliance with the California renewables portfolio standard that have been submitted in Rulemaking 08-08-009, on a schedule to be set by the assigned administrative law judge. The amendments shall address each utility's anticipated plans for the use of tradable renewable energy credits to meet their procurement obligations under the California renewables portfolio standard. The amendments shall include as much detail as currently possible on whether the utility intends to use long-term or short-term contracts, and whether the utility expects to contract
with newly constructed generation, or acquire tradable renewable energy credits from facilities that are currently on line. The amendments shall also explain how these transactions will promote the development of new renewable facilities in California and the area served by the Western Electricity Coordinating Council.

34. The assigned Commissioner in Rulemaking 08-08-009 is authorized to initiate review and revision of the methodology for identifying least cost and best-fit resources for procurement for compliance with the California renewables portfolio standard. The review shall include, among other issues, consideration of revisions to the least cost and best-fit methodology that will encourage greater reliance on procurement transactions that lead to the construction of additional capacity for generation that is eligible for procurement for compliance with the California renewables portfolio standard.

35. The following non-modifiable standard terms and conditions shall be included in all contracts for procurement for compliance with the California renewables portfolio standard, whether bundled contracts or purchases of renewable energy credits only:
a. **STC REC-1. Transfer of Renewable Energy Credits**

Sellar and, if applicable, its successors, represents and warrants that throughout the Delivery Term of this Agreement the renewable energy credits transferred to Buyer conform to the definition and attributes required for compliance with the California Renewables Portfolio Standard, as set forth in California Public Utilities Commission Decision 08-08-028, and as may be modified by subsequent decision of the California Public Utilities Commission or by subsequent legislation. To the extent a change in law occurs after execution of this Agreement that causes this representation and warranty to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in law.

b. **STC REC-2. Tracking of RECs in WREGIS**

Seller warrants that all necessary steps to allow the Renewable Energy Credits transferred to Buyer to be tracked in the Western Renewable Energy Generation Information System will be taken prior to the first delivery under the contract.

36. The following non-modifiable standard terms and conditions shall be included in all contracts for purchase of renewable energy credits only of regulated utilities other than multi-jurisdictional utilities:

**STC REC-3. CPUC Approval**

“CPUC Approval” means a final and non-appealable order of the CPUC, without conditions or modifications unacceptable to the Parties, or either of them, which contains the following terms:

(a) approves this Agreement in its entirety, including payments to be made by the Buyer, subject to CPUC review of the Buyer’s administration of the Agreement; and
(b) finds that any procurement pursuant to this Agreement is procurement of Renewable Energy Credits that conform to the definition and attributes required for compliance with the California Renewables Portfolio Standard, as set forth in California Public Utilities Commission Decision 08-08-028, and as may be modified by subsequent decision of the California Public Utilities Commission or by subsequent legislation, for purposes of determining Buyer’s compliance with any obligation that it may have to procure eligible renewable energy resources pursuant to the California Renewables Portfolio Standard (Public Utilities Code Section 399.11 et seq.), Decision 03-06-071, or other applicable law.

CPUC Approval will be deemed to have occurred on the date that a CPUC decision containing such findings becomes final and non-appealable.

STC 17. Applicable Law

Governing Law. This agreement and the rights and duties of the parties hereunder shall be governed by and construed, enforced and performed in accordance with the laws of the state of California, without regard to principles of conflicts of law. To the extent enforceable at such time, each party waives its respective right to any jury trial with respect to any litigation arising under or in connection with this agreement.

37. Utilities that have submitted for Commission approval contracts for procurement for compliance with the California renewables portfolio standard shall, if necessary, amend all pending contracts to include the standard terms and conditions related to renewable energy credits set forth in Ordering Paragraphs 35 and 36 above, and shall amend their pending advice letters or applications to demonstrate that the contracts conform to the requirements for standard terms and conditions related to renewable energy credits.
38. Not earlier than April 1, 2010, utilities may submit for Commission approval contracts conveying only renewable energy credits and not energy that conform to the requirements of this order. For any contracts conveying renewable energy credits only that a utility submitted prior to January 14, 2011 but that have not been approved by January 14, 2011 the utility shall make a supplemental filing, in the form and with the content prescribed by the Director of Energy Division.

39. The issues in the Second Amended Scoping Memo and Ruling of Assigned Commissioner (February 25, 2008) have either been transferred to Rulemaking (R.) 08-08-009 by the Assigned Commissioner's Ruling Transferring Consideration of Certain Issues from R.06-02-012 to R.08-08-009 (April 3, 2009) or resolved in this proceeding. This proceeding is therefore resolved for the purpose of compliance with Public Utilities Code Section 1701.5. However, the proceeding remains open to address the Petition for Modification of Decision 06-10-019, filed October 29, 2009.

(END OF APPENDIX A)
APPENDIX B
APPENDIX B

Summary of TREC Rules Announced in D.10-03-021, and Compiled in Appendix D to D.10-03-021, as Modified by this Decision

This decision sets rules for the use of TREC for RPS compliance and for the TREC market. The orders and guidance (while not limited by this summary) are summarized below. Other sources relevant to TREC include D.08-08-028, the CEC’s RPS Eligibility Guidebook, and the WREGIS Operating Rules.

What is a tradable renewable energy credit (TREC) transaction?

1) A transaction in which an entity procures only a REC (and not the underlying energy) from another entity, or

2) A transaction conveying both RECs and energy that does not meet the Commission’s criteria for bundled RPS procurement transactions. These REC-only transactions currently include all procurement from generators of RPS-eligible energy for which the first point of interconnection with the WECC interconnected transmission system is not a California balancing authority, and the transaction does not make use of dynamic transfer arrangements in a California balancing authority area.

Effective date of REC trading

- RPS-obligated load-serving entities\(^1\) may begin procuring and trading RECs on the effective date of this decision.

Eligibility of TREC

- All TREC must be associated with RPS-eligible energy generated on or after January 1, 2008.

- All TREC must be tracked in WREGIS to be used for RPS compliance.

- The RECs from bundled contracts currently delivering RPS-eligible energy may be unbundled and traded separately from the associated energy, subject to the exceptions below.

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\(^1\) Load-serving entities (LSEs) include: investor-owned utilities (IOUs), energy service providers (ESPs), and community choice aggregators (CCAs).
• The RECs from bundled contracts scheduled to deliver RPS-eligible energy in the future may be unbundled and traded on a forward basis separately from the associated energy, subject to the exceptions below.

• Exceptions:
  1. RECs associated with RPS-eligible energy delivered under procurement contracts signed prior to 2005 with California RPS-obligated LSEs or publicly owned utilities cannot be traded unless the contract explicitly assigns ownership or disposition of the RECs.
  2. RECs associated with RPS-eligible energy delivered to California utilities under procurement contracts pursuant to the Federal Public Utility Regulatory Policies Act of 1978 with qualifying facilities signed after January 1, 2005 cannot be traded.

Flexible compliance rules for TREC

Commitment and Banking
• In order to be used for RPS compliance, TREC may be retained in active sub-accounts in WREGIS for no more than three calendar years (inclusive of the year in which the electricity associated with the RECs was generated) after the electricity associated with the RECs was generated.
• Once RECs are retired in WREGIS for RPS compliance, they may be banked for RPS compliance in future years in accordance with the RPS flexible compliance rules.

Earmarking
• TREC contracts between an LSE and one RPS-eligible generator may be earmarked for RPS compliance purposes, but no other types of TREC contracts may be earmarked.
• An LSE may not unbundle and trade RECs associated with energy generated in the first three years of an RPS contract (whether bundled or REC-only) that is being used for earmarking.

Filling compliance shortfalls
REC-only contracts may be used to make up shortfalls in APT, so long as the total use of TREC for the year of the shortfall does not exceed the applicable limit on TREC usage.
Temporary limit on use of TRECs for RPS compliance

- PG&E, SCE, and SDG&E may meet no more than 25% of their APT with TRECs. This limitation will sunset December 31, 2013.

Contract review and approval of TREC transactions

- IOUs may submit TREC contracts for CPUC review and approval by advice letter starting April 1, 2010.

- Energy Division staff may use present methods of analyzing advice letters for bundled contracts, and make any adaptations necessary, for reviewing REC-only contracts, except that the fast-track process set out in D.09-06-050 does not apply to TRECs. These methods may be reviewed in R.08-08-009.

- TRECs for which an IOU pays more than $50/TREC may not be used for RPS compliance. This price cap will sunset December 31, 2013.

- The temporary $50/TREC price cap does not make a TREC priced at or below $50 reasonable. A utility will still have to provide sufficient information in its advice letter filing to demonstrate that the TREC contract is reasonable.

- All REC-only contracts must contain the following three non-modifiable standard terms and conditions: (1) Transfer of renewable energy credits; (2) Tracking of RECs in WREGIS; (3) Applicable Law.

- REC-only contracts of California IOUs other than MJUs must contain a fourth STC: Commission Approval.

- IOUs may enter into voluntary TREC transactions even if their cost limitation pursuant to § 399.15(d) has been reached, so long as they comply with the requirements of this decision.

Delivery rules for TREC transactions

The CEC decides whether a TREC contract satisfies RPS delivery rules. For bundled contracts, the Energy Division may request written confirmation from the CEC about whether the contract complies with RPS delivery rules.

(END OF APPENDIX B)
BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Applying the Market Index Formula and As-Available Capacity Prices adopted in D.07-09-040 to Calculate Short-Run Avoided Cost for Payments to Qualifying Facilities beginning July 2003 and Associated Relief.

Application 08-11-001
(Filed November 4, 2008)

And related matters

Rulemaking 06-02-013
Rulemaking 04-04-003
Rulemaking 04-04-025
Rulemaking 99-11-022

DECISION ADOPTING PROPOSED SETTLEMENT
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Appendix A - Links To Joint Motion and Attachments, Including Settlement Agreement, Term Sheet, And Exhibits
DECISION ADOPTING PROPOSED SETTLEMENT

1. Summary

After more than a year and a half of intensive negotiations, three investor-owned utilities, four representatives of qualifying facilities (QFs), and two ratepayer advocacy groups have developed, and now propose for our consideration, their “Qualifying Facility and Combined Heat and Power Program Settlement Agreement” (Proposed Settlement). In this decision the Commission reviews the Proposed Settlement, finds that it meets established criteria for approval of settlements, and therefore approves it.

The Proposed Settlement is comprehensive. It would resolve numerous outstanding QF issues involving disputes in several Commission, and provide for an orderly transition from the existing QF program to a new QF/Combined Heat and Power (CHP) program. This new program is designed to preserve resource diversity, fuel efficiency, greenhouse gas (GHG) emissions reductions, and other benefits and contributions of CHP. The Proposed Settlement is also designed to promote new, lower GHG-emitting CHP facilities and encourage the repowering, operational changes through utility-pre-scheduling, or retirement of existing, higher GHG-emitting CHP facilities. Additionally, the Commission finds that the Proposed Settlement provides for an appropriate allocation of the costs of the QF/CHP program to all customers in California who benefit from the CHP portfolio. The Proposed Settlement is comprehensive, but it does not resolve issues in numerous Commission proceedings implementing recent statutory requirements that pertain to QFs of 20 MW or less, such as new CHP systems under Assembly Bill 1613 (codified as Pub. Util. Code sections 2840-2845), except to acknowledge that the megawatt (MW) and GHG reductions will count toward the investor-owned utilities’ MW and GHG reduction targets.
While the Proposed Settlement is the result of compromise and agreement among representatives of diverse interests, several parties strongly object to aspects of it. Foremost among their concerns is the Proposed Settlement’s establishment of procurement and reporting requirements for community choice aggregators and electric service providers. We review the opponents’ arguments for either rejecting the Proposed Settlement or approving it only with modifications. We conclude that the Proposed Settlement meets the Commission’s standards for approval of settlements – it is reasonable in light of the record, consistent with the law, and in the public interest.

In approving the Proposed Settlement, we set in motion a series of steps that should lead to eventual closure of each of the captioned proceedings. However, we find that it is premature to close the proceedings. Accordingly, the proceedings will remain open at this time.

2. Background

2.1. Overview of Proceedings

Pursuant to Decision (D.) 08-07-048, Southern California Edison Company (SCE) filed Application (A.) 08-11-001 to obtain authority to retrospectively apply, for the period July 2003 through July 2008, the Qualifying Facility (QF) pricing adopted in D.07-09-040 for calculating short-run avoided costs (SRAC). This proceeding has been held in abeyance while the negotiations that led to the Proposed Settlement were in progress.

The Commission instituted Rulemaking (R.) 06-02-013 to ensure reliable and cost-effective electricity supply in California through integration of a comprehensive set of procurement policies and review of long-term procurement plans (LTPP). It is the successor proceeding to R.04-04-003 as to LTPP issues. Although most issues have been resolved, R.06-02-013 remains open for
consideration of a petition for modification of D.07-12-052 that pertains to treatment of QF capacity in the LTPP process.

R.04-04-003 is a multi-phase “umbrella” proceeding to promote policy and program coordination and integration in utility resource planning. Among other procurement issues, R.04-04-003 addresses development of a long-term policy for QFs with expiring contracts. The Commission instituted R.04-04-025 to develop avoided costs in a consistent and coordinated manner across Commission proceedings, including QF pricing issues. R.04-04-003 and R.04-04-025 were consolidated for purposes of testimony and hearings on QF policy and pricing issues by ruling issued in those proceedings on February 18, 2005. D.07-09-040, as modified, adopted specific policies and pricing mechanisms applicable to the utilities’ purchase of energy and capacity from QFs. D.07-09-040 has been the subject of several applications for rehearing and petitions for modification, some of which remain open, and a Petition for Writ of Review at the California Court of Appeal (Case 210398).

R.99-11-022 was instituted to implement Public Utilities Code Section 390, which governs energy prices paid by utilities to nonutility power generators. It remains open to consider an evidentiary matter remanded to the Commission by the California Court of Appeal, i.e., retrospective application of the SRAC formula adopted by D.01-03-067.1

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2.2. Policy Background

2.2.1. PURPA and the Commission’s QF Program

In 1978, Congress enacted the Public Utility Regulatory Policies Act\(^2\) (PURPA), which was part of a national effort to promote energy independence and efficiency. Under PURPA and subsequent implementing regulations of the Federal Energy Regulatory Commission (FERC), qualifying cogeneration and small power production facilities were provided certain benefits and exemptions. State regulatory agencies were delegated responsibility for developing QF programs and determining avoided-cost pricing. The Commission implemented PURPA in the early 1980s by adopting for the investor-owned utilities (IOUs) a number of standard form power purchase agreements (PPAs) that were available to QFs and establishing energy and capacity prices to be paid under these PPAs. Many QFs signed these PPAs and built cogeneration and small power production facilities to provide energy and capacity to the IOUs.

Since the Commission implemented the QF program in the 1980s, there have been disputes between the QFs, IOUs and ratepayer advocates involving contract terms, SRAC pricing, capacity payments, contract extensions and terminations, and the availability of new contracts. Many of these disputes are still pending at the Commission. These include retrospective adjustments to SRAC pricing, disputes over pricing and ability to execute PPA extensions, motions for prospective QF PPA options, SRAC disputes dating back to the 2000-2001 energy crisis, disputes concerning administrative heat rates used to

\(^2\) 16 U.S.C. § 796, \textit{et seq.}
calculate SRAC, and applications for rehearing and petitions for modification of numerous QF decisions.

Not only is the Commission faced with disputes regarding existing QF PPAs and the existing QF program, the Commission is also faced with challenges as to how to implement the QF program going forward. For example, in D.07-09-040, the Commission recognized that it would need to address the impact of the California Independent System Operator's (CAISO) Market Redesign and Technology Upgrade (MRTU) on SRAC and the QF program. The Commission also has before it disputes over the terms and conditions of the new QF Standard Offer Contract (SOC) and disputes over the amount of QF capacity to include in the LTPP.

On the federal level, recently there have been changes to the PURPA purchase obligation. In October 2006, FERC issued Order No. 688:

... revising its regulations governing utilities' obligations to purchase electric energy produced by QFs. Order No. 688 implements PURPA section 210(m), which provides for termination of the requirement that an electric utility enter into power purchase obligations or contracts to purchase electric energy from QFs, if the Commission finds the QFs have nondiscriminatory access to markets.3

Although the California IOUs have not yet sought from FERC a termination of their PURPA purchase obligation for QFs larger than 20 megawatts (MW), it is argued that the changes in PURPA support a reexamination of California's existing QF program.

3 New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation, 130 FERC ¶61,216 (2010) at 3 (footnotes omitted).
2.2.2. State Policy Favoring Combined Heat and Power (CHP)

Public Utilities Code Section 372(a) and Energy Action Plan II\(^4\) both demonstrate that state policy supports the development of “efficient, environmentally beneficial” CHP. In the 2009 Integrated Energy Policy Report (IEPR), the CEC recommended the continued support and development of CHP as a means to meet state greenhouse gas (GHG) goals and other policy objectives. In D.08-10-037 the Commission, joining with the CEC, recognized CHP as an emissions reduction strategy, provided for action to remove barriers to CHP penetration, and acknowledged the need for CHP policy review.

2.2.3. Climate Change Scoping Plan

On December 11, 2008, the California Air Resources Board (CARB) adopted the Climate Change Scoping Plan for California pursuant to Assembly Bill (AB) 32\(^5\) (the CARB Scoping Plan).\(^6\) In the CARB Scoping Plan, the CARB noted that:

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\(^4\) In 2003, the Commission, the California Energy Commission (CEC), and the California Power Authority adopted an Energy Action Plan (EAP), articulating a single, unified approach to meeting California’s electricity and natural gas needs. A key element was the “loading order” which specified California’s policy to invest first in energy efficiency and demand response, followed by renewable resources, and only then in clean conventional electricity supply. In 2005, the Commission and the CEC adopted a second plan, EAP II, to reflect policy changes and actions. Since then, the Commission and the CEC have updated the EAP. The 2008 EAP update is available at the Commission’s website using the following link:

http://www.cpuc.ca.gov/NR/rdonlyres/58ADCD6A-7FE6-4B32-8C70-7C85CB31E8E7/0/2008_EAP_UPDATE.PDF

\(^5\) Stats. 2006, Ch. 488.

\(^6\) The CARB Scoping Plan is posted at:

http://www.arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm
... combined heat and power (CHP), also referred to as cogeneration, produces electricity and useful thermal energy in an integrated system. The widespread development of efficient CHP systems would help displace the need to develop new, or expand existing, power plants. This measure sets a target of an additional 4,000 MW of installed CHP capacity by 2020, enough to displace approximately 30,000 [gigawatt hours] of demand from other power generation sources.7

2.3. Settlement Process Overview

Seeing a need to resolve outstanding disputes and to establish a new CHP program for California going forward, in May 2009 SCE, Pacific Gas and Electric Company, San Diego Gas & Electric Company, The Utility Reform Network, the California Cogeneration Council, the Independent Energy Producers Association, the Cogeneration Association of California, the Energy Producers and Users Coalition, and the Division of Ratepayer Advocates (Joint Parties) and Commission representatives met to lay out a settlement framework. From that time to the filing of the Joint Motion described below, the Joint Parties conducted what they describe as frequent and lengthy meetings to negotiate the Proposed Settlement. The Joint Parties had divergent interests, and unresolved disputes in proceedings at the Commission. As a result, the Joint Parties assert that the Proposed Settlement represents a compromise that should be evaluated as an integrated package. They note that the Proposed Settlement provides a detailed and comprehensive framework for a Qualifying Facility and Combined Heat and Power (QF/CHP) Program in California.

7 CARB Scoping Plan at 42-43 (footnotes omitted).
Pursuant to Rule 12.1(b) of the Rules of Practice and Procedure (Rules), on September 24, 2010 the Joint Parties provided notice of a formal settlement conference to the service lists in these proceedings. Because of widespread interest in matters at issue in these proceedings, Joint Parties also provided notice of potential settlement to the service lists in R.03-10-003 (regarding community choice aggregation), R.07-05-025 (consideration of the lifting of the suspension of direct access), and R.08-06-024 (combined heat and power). The settlement conference was conducted on October 7, 2010. An overview of the Proposed Settlement was presented, and participants were able to ask questions and provide comments. Those that were interested in joining to support the Proposed Settlement were invited to do so.

On October 8, 2010, after the settlement conference was completed and participants were given an opportunity to review and comment on the Proposed Settlement, Joint Parties filed a motion (Joint Motion) for approval of the “Qualifying Facility and Combined Heat and Power Program Settlement Agreement” (Proposed Settlement).

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8 R.08-06-024 is the Commission’s proceeding, in which the Commission has issued D.09-12-042, denying reh’g, as modified, D.10-04-055, implementing AB 1613 involving statutory requirements for feed-in tariffs for new CHP facilities of 20 MW or less. These Commission decisions have been the subject of cross-petitions for declaratory orders in litigation at the FERC. See, California Public Utilities Commission, et al. (2010) 132 FERC ¶ 61,047, request for clarification granted, 133 FERC ¶ 61,059. In a separate decision in R.08-06-024, currently scheduled for the December 16, 2010 agenda, the Commission will be further addressing issues resolving a pending petition for modification and new comments submitted by parties in light of the FERC’s orders.
2.4. Procedural History

Concurrently with the filing of the Joint Motion, the Joint Parties filed a motion for expedited consideration of the Proposed Settlement. The assigned Administrative Law Judge (ALJ) granted the motion by ruling issued in these proceedings on October 11, 2010 (October 11 Ruling). Among other things, the time for filing comments on the Proposed Settlement was shortened from 30 days, as set forth in Rule 12.2, to October 25, 2010. The time for filing reply comments was shortened from 15 days, as set by Rule 12.2, to November 1, 2010. The October 11 Ruling also consolidated the proceedings for purposes of considering the Proposed Settlement. The ALJ also directed service of the October 11 Ruling on the service lists for the proceedings for which Joint Parties had served notice of the settlement conference, i.e., R.03-10-003, R.07-05-025, and R.08-06-024, and on registered electric service providers (ESPs) and community choice aggregators (CCAs). On October 12, 2010 the ALJ directed the Joint Parties to serve notice of the Joint Motion on registered ESPs and CCAs. Joint Parties complied with this directive on October 13, 2010.

On October 19, 2010 the assigned Commissioner and the ALJ issued an amended scoping memo for the consolidated proceedings for purposes of considering the Proposed Settlement (Amended Scoping Memo). It provided

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10 See Administrative Law Judge’s Ruling Regarding Service of Joint Motion, Rulings, and Tendered Documents, dated October 18, 2010.

that, with respect to consideration of the Proposed Settlement, the issues to be addressed in this proceeding are:

1. Whether the Proposed Settlement is reasonable in light of the whole record of these proceedings;
2. Whether the Proposed Settlement is consistent with the law;
3. Whether the Proposed Settlement is in the public interest;
4. Whether the Proposed Settlement should be approved, and if so whether it should be approved in its entirety without change.

The Amended Scoping Memo also directed parties claiming that evidentiary hearings were necessary to state, in comments on the Proposed Settlement, “with specificity the disputed issues of material fact related to the Proposed Settlement that are claimed to require hearings and why the facts are material to the resolution of the motion.”

Comments on the Proposed Settlement were filed by six parties or party groups: the CAISO, CAlifornians for Renewable Energy, Inc. (CARE); City and County of San Francisco (CCSF); California Municipal Utilities Association (CMUA); Shell Energy North America (US), LP (Shell Energy); and jointly by the Marin Energy Authority, the Alliance for Retail Energy Markets, and the Direct Access Consumer Coalition (CCA/Direct Access Parties). The CAISO supports the Proposed Settlement. CARE opposes it on the grounds that it is preempted by federal law and FERC orders. CARE also raises concerns regarding the expedited consideration of the Proposed Settlement and other procedural matters. CCSF objects to the Proposed Settlement unless provisions regarding cost allocation and portfolio requirements applicable to CCAs are removed.

12 Amended Scoping Memo at 4.
CMUA supports the efforts of the Joint Parties in reaching the settlement and believes that it represents a major achievement, but recommends certain amendments, deletions, and a clarification regarding provisions of the Proposed Settlement that pertain to CCAs, publicly-owned utilities (POUs), and municipal departing load (MDL). Shell Energy opposes the Proposed Settlement, arguing that the process leading up to it was flawed insofar as it would impose affirmative procurement obligations on ESPs, CCAs, and their customers. Shell Energy contends that such provisions lack legal authority and should be severed from the Proposed Settlement if it is approved. CCA/Direct Access Parties oppose, on due process and other legal and policy grounds, the provisions of the Proposed Settlement that would impose new regulatory requirements and cost obligations on ESPs, CCAs, and their customers. CCA/Direct Access Parties contend that if the Commission is inclined to adopt the Proposed Settlement, the provisions that are applicable to ESPs, CCAs, and their customers should be deleted. CCA/Direct Access Parties contend that evidentiary hearings or workshops are required for certain cost allocation issues.

Joint Parties filed reply comments arguing, among other things, that modifying the Proposed Settlement as requested by the commenting parties would upset the balance of interests underlying the Proposed Settlement and could cause the Joint Parties to terminate it.

3. Summary of the Proposed Settlement

The Proposed Settlement comprises an 8-page “CHP Settlement Agreement,” a 76-page “CHP Program Settlement Agreement Term Sheet” (Term Sheet) with 17 sections, and 11 exhibits totaling more than 700 pages. The Term Sheet and exhibits are attached to, and incorporated by reference into, the CHP Settlement Agreement. Due to the length of the Proposed Settlement and
its attachments, we do not republish it with this decision. The Proposed Settlement in its entirety is permanently posted on the Commission’s website.13

Sections 3.1 through 3.17 below present a brief overview of the corresponding 17 sections of the Term Sheet as described in the Joint Motion. Section 3.18 lists the 11 exhibits that are attached to the Proposed Settlement, including the Pro Forma PPAs and the Pro Forma PPA amendments that are included with the Proposed Settlement. We note the Joint Parties’ caveat that any inconsistencies between their summary and the Term Sheet should be governed by the Term Sheet.

3.1. Goals and Objectives

Section 1 of the Term Sheet outlines the goals and objectives of the Proposed Settlement. The goals and objectives are addressed later in this decision.

3.2. Settlement Periods

Section 2 describes the three periods covered by the Proposed Settlement: the Transition Period, the Initial Program Period, and the Second Program Period. The Transition Period is designed to facilitate the transition from the existing QF Program to the new QF/CHP Program. During the Initial Program Period, which overlaps with the Transition Period, the IOUs have specific MW Targets (MW Targets) for entering into new PPAs with CHP and other facilities. In the Second Program Period, the IOUs procure any portion of the MW Targets that they did not procure during the Initial Program Period and

13 Appendix A to this decision contains links to the Commission’s website for each of the component documents of the Proposed Settlement as well as the joint motion for approval of the Proposed Settlement.
additional CHP capacity to meet GHG Emissions Reduction Targets (GHG Targets) or other CHP procurement targets established by the Commission. SDG&E has a target to procure an additional 51 MW during the Second Program Period.

### 3.3. Transition PPA

Section 3 describes the eligibility requirements for QF and CHP facilities for a PPA during the Transition Period and the pricing for Transition Period PPAs. The “Transition Standard Contract for Existing Qualifying Cogeneration Facilities” (Transition PPA) is included as an exhibit to the Term Sheet and is an attachment to the Proposed Settlement.

### 3.4. CHP Procurement Process

Section 4 of the Term Sheet describes the various aspects of the CHP procurement process under the new QF/CHP Program. First, Section 4.2 describes the new CHP Request for Offers (CHP RFO) process under which the IOUs will procure generation from CHP facilities to meet MW Targets and GHG Targets specified in the Proposed Settlement. Section 4.2 includes eligibility requirements for CHP participating in the RFOs (Section 4.2.2), the delivery terms of PPAs resulting from the RFOs (Section 4.2.3), pricing (Section 4.2.4), and RFO evaluation and selection criteria (Section 4.2.5). In addition, the Joint Parties developed a Pro Forma power purchase agreement for CHP RFOs (CHP RFO PPA) that is attached as an exhibit to the Term Sheet.

Section 4 also describes the procurement processes for CHP other than through CHP RFOs that will count towards meeting MW and GHG Targets. Specifically, Sections 4.3 - 4.6 describe bilaterally negotiated CHP PPAs, PPAs
under the AB 1613\textsuperscript{14} feed-in tariff, PPAs for QFs of 20 MW or less under PURPA, and Optional As-Available PPAs for certain large CHP facilities that have significant on-site load and specific operating characteristics. Section 4.7 addresses utility-owned CHP and limits the contribution of utility-owned facilities to ten percent (10\%) of each IOU’s GHG Target. IOU-owned facilities will not count toward the MW Targets in the Initial Program Period. Section 4.8 describes “utility prescheduled facilities” which are existing QF facilities that convert to IOU-dispatchable generating facilities. Finally, Section 4.9 addresses new behind-the-meter CHP facilities as one of the procurement options under the QF/CHP Program.

Section 4.10 specifies the Commission approval process required for new PPAs arising from the procurement options in the QF/CHP Program. This includes Tier 2 advice letter filings for existing CHP facilities that execute the CHP RFO PPA without material modification, and a Tier 3 advice letter process for all other CHP PPAs. CHP PPAs that are less than five years in duration do not require Commission pre-approval but will be reported in the IOUs’ Quarterly Compliance Reports and CHP Program Semi-Annual Report.

Section 4.11 specifies information that CHP facilities must provide to the IOUs on an annual basis for monitoring purposes and Section 4.12 specifies the timing for commencement of deliveries from a CHP facility that has entered into a new CHP PPA.

\textsuperscript{14} Stats. 2007, Ch. 713.
3.5. **MW Targets**

Section 5 establishes a total MW Target for the IOUs of 2,949 MW during the Initial Program Period and a total MW Target of 3,000 MW for the entire QF/CHP Program. Section 5.1.2 includes a chart allocating this MW Target to three target periods for each of the IOUs. For example, the first MW Targets for SCE, PG&E, and SDG&E are 630 MW, 630 MW, and 60 MW, respectively. SDG&E has a specified MW Target during the Second Program Period. If the IOUs have not fulfilled the MW Targets assigned to them for the Initial Program Period they will also need to procure MWs during the latter period to fulfill those targets.

Section 5.1.4 provides that the IOUs are required to conduct three CHP RFOs during the Initial Program Period to seek CHP PPAs to meet the MW Targets. The number of CHP RFOs during the Second Program Period will be established in the LTPP proceedings.

Section 5.2 includes detailed counting rules as to how CHP PPAs executed during the Initial Program Period, whether through a CHP RFO or another procurement process, count toward the MW Targets. Section 5.3 clarifies the appropriate use of the MW counting procedure.

Section 5.4 addresses justifications for an IOU's failure to meet its MW Target. These justifications include lack of sufficient offers in the RFOs, the efficiency of CHP participating in the procurement programs, excessive offer prices, and the amount of GHG reductions.

3.6. **GHG Emissions Reduction Targets**

The Joint Parties assert that one of the key benefits of the Proposed Settlement is the implementation of a CHP Program designed to reduce GHG, consistent with the CARB Scoping Plan. Section 6.1 describes the Proposed
Settlement strategy for reducing GHG, including maintaining existing, efficient CHP facilities, adding new, efficient CHP resources and achieving the GHG Targets by December 31, 2020. Section 6.2 addresses maintaining the GHG emissions reductions from existing CHP and establishing new targets for GHG reductions from new facilities. In particular, the Proposed Settlement establishes a GHG Emissions Reduction Target or “GHG Target” of 4.3 million-metric tons (MMT) for the IOUs and 0.5 MMT for ESPs\textsuperscript{15} and CCAs. These targets are based on the 6.7 MMT GHG reductions attributable to CHP in the CARB Scoping Plan. Based on the current percentage of retail sales in California, the 6.7 MMT would be allocated as follows: (1) 4.3 MMT to the IOUs; (2) 0.5 MMT to ESPs and CCAs; and (3) 1.9 MMT to POUs. Joint Parties note that the Commission does not have jurisdiction over POUs, but assert it can set GHG Emissions Reduction Targets for the IOUs, ESPs and CCAs (collectively, load-serving entities or LSEs).

Section 6.2.2.3.3 provides for the adjustment of the allocation of the GHG Targets based on changes in retail sales during the term of the Proposed Settlement. Thus, for example, if customers depart utility service for ESPs or CCAs, the GHG Targets for the IOUs will decrease and the targets for the ESPs and CCAs will increase. The GHG Targets can also be adjusted among the IOUs.

Section 6.3 identifies the GHG Target allocated to ESPs and CCAs and indicates that it is the preference of the Joint Parties that these non-IOU Load Serving Entities (LSEs) achieve these targets by entering into CHP PPAs. However, if these non-IOU LSEs are not required to enter into CHP PPAs, the IOUs will procure the appropriate amount of CHP for these LSEs to meet their

\textsuperscript{15} The Joint Parties use the term “energy service provider.” We use the statutory term “electric service provider.” (Pub. Util. Code Section 218.3.)
GHG Target and the costs of this procurement by the IOUs will then be allocated to the customers of non-IOU LSEs. The allocation of CHP PPA costs is addressed in Section 13 of the Proposed Settlement. Section 6.4 describes the methodology for establishing the GHG Targets for each of the IOUs. Section 6.5 requires each IOU to report its progress toward meeting its GHG Target in its semi-annual CHP Program Reports that are submitted to the Commission. Section 6.6 states that the GHG Targets for the Second Program Period are subject to review and revision in the LTPP process.

Section 6.7 provides for revisions to the GHG Targets if CARB modifies its CHP reduction goals and provides for GHG Targets to be adjusted in the LTPP if AB 32 compliance is suspended or delayed. In Section 6.8, the Joint Parties agree to advocate at CARB in support of the Proposed Settlement, subject to certain conditions.

Finally, Section 6.9 sets out the justifications for failing to meet the GHG Targets, including the efficiency of CHP facilities participating in the IOUs' procurement programs, excessive offer prices, and a lack of need for CHP resources.

3.7. GHG Emission Accounting Methodology

Section 7 establishes the accounting principles for determining the IOUs' progress toward meeting their GHG Targets. This section adopts a Double Benchmark methodology for determining GHG reductions and provides detailed accounting procedures for new, repowered, and existing CHP facilities to determine the amount of GHG emissions reductions that are attributable to these different types of facilities.
3.8. **Commission Jurisdictional Entities’ Reporting Requirements**

Section 8 establishes reporting requirements for Commission-jurisdictional LSEs. Each LSE must prepare a semi-annual report detailing progress toward meeting its MW Targets and GHG Targets. Sections 8.2 - 8.5 describe the contents of the semi-annual reports, and specify report content for different categories of CHP generation (e.g., new, legacy, terminated).

3.9. **CHP Auditor**

Section 9 provides for a CHP auditor (CHP Auditor) who is to act as an advocate for CHP interests regarding the implementation of the QF/CHP Program. The CHP Auditor is used in situations where an IOU provides notice that it does not anticipate meeting the MW Targets during a particular RFO or the GHG Targets. The CHP party or parties requesting a CHP Auditor bear the costs and the CHP Auditor is provided with an opportunity to receive and review confidential IOU information regarding the relevant QF/CHP RFO. Section 9 includes provisions for execution of a non-disclosure agreement by the CHP Auditor (Section 9.1.4), when an IOU notice triggers an audit (Section 9.2), the time period for an audit review (Section 9.3), receipt and review of confidential information (Section 9.4), and the number of CHP Auditors, as well as rules regarding any potential conflicts of interest (Section 9.5).

3.10. **SRAC Energy Pricing Structure**

Section 10 establishes methodologies and formulas for SRAC to be used in Transition PPAs, Legacy PPAs, other existing QF PPAs and Optional As-Available PPAs. Section 10.2 includes a methodology for transitioning, by January 1, 2015, SRAC pricing from a formula that is based in part on administratively-determined heat rates to a formula that uses solely market heat
rates. Section 10.4 includes a process for addressing market disruptions that may impact the market heat rate to be used in SRAC. Section 10.2 also includes IOU-specific time-of-use (TOU) factors to be applied to energy prices to encourage energy deliveries during the times when the energy is most needed by customers. The SRAC formula also includes a locational adjustment based on CAISO nodal prices. Section 10.2 also includes pricing options based on whether a cap-and-trade program or other form of GHG regulation is developed in California or nationally.

If and when such a cap-and-trade program initially is developed that applies to California, Section 10.2 establishes a floor test which compares an energy price developed with a market-based heat rate to an energy price developed with either a negotiated heat rate, or a heat rate from a period prior to the start of a cap-and-trade program, plus the market price of GHG allowances. The higher of the two energy prices is the one chosen as SRAC.

Section 10.3 requires the Seller under a CHP PPA to provide certain information to the IOU regarding GHG information that it has reported to CARB or another governmental authority, and information concerning the operation of its facility. Finally, Section 10.5 addresses the responsibility for GHG-related costs.

3.11. Legacy PPA Matters for Existing QFs

Under Section 11.1, QFs with existing standard offers or other PPAs (QF PPAs) at the time of the Settlement Effective Date will be paid for energy based on the SRAC formula specified in Section 10 (unless the QF PPA specifies a different price) or may elect to amend their standard offer QF PPA to choose one of the energy price options described in the Legacy QF Amendments, attached as an exhibit to the Proposed Settlement. Unless otherwise specified in the QF PPA,
capacity payments for QF PPAs will be based on the capacity price established by the Commission in D.07-09-040. Section 11.2 provides for the transition from a QF PPA to a new CHP PPA and ensures that delivery from an existing CHP facility continues uninterrupted during that period. The amendments are not available to QFs participating in the Renewables Portfolio Standard (RPS) program.

Section 11.3 provides that the Seller under an existing QF PPA shall make a good faith effort to provide forecasting information to the IOU so that the IOU can more accurately schedule QF generation in the CAISO markets. This section provides specific forecasting submittal procedures.

3.12. CAISO Tariff Compliance

Section 12 provides that all CHP facilities subject to the CAISO Tariff shall comply with CAISO requirements when the facility begins deliveries under a CHP PPA. Section 12 also includes requirements for the installation of metering and telemetry equipment at existing CHP facilities within six months of the execution of a CHP PPA. The Joint Parties also acknowledge that the CAISO may condition, waive or modify certain requirements for QF and CHP facilities.

3.13. IOU Cost Recovery for CHP PPAs

Section 13 addresses cost allocation if the Commission determines that IOUs should purchase CHP generation on behalf of ESPs and CCAs. In this circumstance, the IOUs are authorized to recover "net capacity costs" from all bundled, direct access (DA) and CCA customers on a non-by-passable basis. Net capacity costs are the total costs paid by the IOU under the QF/CHP Program less the value of the energy and ancillary services supplied to the IOU under the program.
Section 13.1.1 recognizes that PPAs under the QF/CHP Program may be greater than 10 years and requires that the Commission: (1) affirmatively supersede the 10-year limitation for stranded cost recovery established in D.04-12-048 and D.08-09-012, and (2) determine that all above-market or net capacity costs associated with the QF/CHP Program can be recovered for the entire duration of any CHP PPA.

Section 13.1.2.1 provides that if the Commission determines that ESPs and CCAs are responsible for procuring CHP generation for their customers, any above-market costs associated with the QF/CHP Program can be allocated to future departing load customers who depart for DA or CCA service.

In Sections 13.1.3 and 13.1.4, the Joint Parties agree that they will not advocate the imposition of QF/CHP Program costs on CHP customer generation departing load, and in Section 13.1.5 the Joint Parties agree to advocate that CHP PPAs entered into as a result of the QF/CHP Program not be included in the existing Competition Transition Charge.

Finally, Section 13.2 provides that all payments made by the IOUs under the QF/CHP Program can be recovered in the IOUs' respective Energy Resources Recovery Account.

3.14. Settlement of Pending and Anticipated Litigation

Section 14 addresses the settlement of pending as well as anticipated claims and litigation. In Section 14.1, the IOUs agree under certain conditions to withdraw with prejudice all SRAC retrospective price adjustment claims. The Joint Parties mutually agree not to raise any new SRAC retrospective adjustment claims under the Court’s remand as long as the PURPA purchase obligation remains suspended (as described in more detail in Section 15).
In Section 14.2, the Joint Parties agree to release or withdraw a number of pending claims, rehearing applications, or motions including claims and motions at the Commission (Sections 14.2.1 - 14.2.3, 14.2.5 - 14.2.12) and pending appeals at the Court of Appeal (Section 14.2.4).\(^\text{16}\) Section 14 does not affect the Joint Parties' rights to advocate their respective position regarding the confidentiality of IOU procurement information.

### 3.15. FERC Section 210(m) Application

Under Section 15, if the Commission approves the Proposed Settlement, the IOUs will then submit an application to FERC requesting termination of the IOUs' PURPA purchase requirement from QFs with net capacity in excess of 20 MW, consistent with Section 210(m) of PURPA. Section 15.1 establishes a process for the CHP representatives to review the IOUs' FERC application and provides that these parties can intervene and comment on, but not protest, the IOUs' application. Under Section 15.1.10, the CHP representatives can file at FERC for reinstatement of the PURPA purchase obligation if an IOU “breaches its obligations under the [Proposed Settlement] or the CHP Program adopted in the [Proposed Settlement] is not successfully implemented, based upon the IOU’s failure to meet the targets established by the Commission pursuant to the

\(^{16}\) There are pending appellate court cases in which the Commission is a party. (See Southern California Edison Company, et al. v. Public Utilities Commission of the State of California, California Court of Appeal, Second Appellate District, Division 8 (Case No. B210398).) We observe that the Joint Parties have no authority to settle a court case in which the Commission is a party, since the Commission is a decision maker in the review of this settlement rather than a party to the settlement. However, we note that the approval of the Proposed Settlement will have the effect of making moot issues raised in pending appellate court litigation. In an order filed October 13, 2010, the California Court of Appeal granted an abeyance of the appellate litigation pending regulatory approval of the settlement by the Commission and the FERC.
Section 15.2 addresses a circumstance where FERC reinstates the PURPA purchase obligation. In this case, SRAC pricing established under the Proposed Settlement stays in place until changed by the Commission (Section 15.2.1.1), although Joint Parties may advocate for a change to SRAC (Section 15.2.1.3). Joint Parties may also advocate for retrospective adjustments to SRAC pricing (Section 15.2.1.4). If the PURPA purchase obligation is reinstated, the IOUs' obligations to conduct CHP RFOs or to engage in alternative procurement processes and the MW Targets and GHG Targets are suspended “provided that the Commission may on grounds other than the Settlement [Agreement] direct the procurement of CHP resources.” (Section 15.2.1.7) Any procurement target to be established by the Commission in the LTPP remains in place unless and until modified by the Commission in a subsequent proceeding. The Joint Parties also agree in Section 15.2.1.8 that for purposes of Section 210(m), designated CHP PPAs constitute “legally enforceable obligations.”

3.16. Conditions Precedent and Settlement Effective Date

Section 16.2 specifies that the Proposed Settlement becomes effective upon satisfaction of the following conditions precedent: (1) a final and non-appealable FERC order approving the IOUs' application to terminate their PURPA purchase obligation (Section 16.2.1), (2) a final and non-appealable Commission decision approving the Settlement, including a determination that the Settlement supersedes certain portions of existing Commission decisions (Sections 16.2.2 and 16.2.4 -16.2.6), and (3) CARB support, in written form, for the Settlement (Section 16.2.3).
Section 16.3 provides that after the Proposed Settlement becomes effective, if CARB adopts regulations directly imposing a MW Target or GHG Emissions Target that differs from the Proposed Settlement for the Second Program Period, the IOUs' obligations to purchase from CHP to meet these targets will remain in place until such time as the Commission is able to consider such change in an LTPP or other pertinent proceeding.

3.17. Glossary
The section includes a glossary of the defined terms used in the Settlement.

3.18. Attachments to the Settlement
In addition to the Term Sheet, the Settlement Agreement attaches the following exhibits (Exhibits 1-11), as listed below:

1. Amendment to Legacy QF PPA for PG&E
2. Amendment to Legacy QF PPA for SCE
3. Amendment to Legacy QF PPA for SDG&E
4. Transition PPA for existing Qualifying Cogeneration Facilities
5. CHP RFO Pro Forma PPA for CHP Facilities Participating in Solicitations
6. QF PPA for QFs 20 MW or Less
7. Optional As-Available PPA for eligible As-Available Facilities
8. Non-Disclosure Agreement (NDA) for CHP Auditor
9. List of Members of CAC
10. List of Members of CCC
11. List of Members of EPUC
4. Discussion

4.1. Standard of Review of Settlements

Rule 12.1(d) provides that “[t]he Commission will not approve settlements, whether contested or uncontested, unless the settlement is reasonable in light of the whole record, consistent with law, and in the public interest.” The Commission has rejected (or provided for modification of) settlements when it does not find these criteria are met. Factors that the Commission has considered in reviewing settlements include: (1) the risk, expense, complexity and likely duration of further litigation, (2) whether the settlement negotiations were at arms-length, (3) whether major issues were addressed, and (4) whether the parties were adequately represented. The Commission needs to be assured that parties to a settlement were able to make informed choices in the settlement process. With respect to whether a settlement agreement is consistent with the law, the Commission must be assured that no term of the settlement agreement contravenes statutory provisions or prior Commission decisions. A settlement that implements or promotes state and Commission policy goals embodied in statutes or Commission decisions would be consistent with the law. To determine whether a settlement agreement is in the public interest, in addition to substantive public interest concerns associated with the circumstances of a particular proceeding, the Commission may inquire into whether a settlement expeditiously resolves issues that otherwise would have been litigated.

Noting that the Commission has rejected or modified settlements where the interests of parties affected by the settlement were not represented in the

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17 *Re Pacific Gas & Electric Company*, 30 CPUC 2d 189, 222.
settlement discussions, CCSF cites to D.96-01-011. There, the Commission considered a settlement that resulted from negotiations that excluded some parties. CCSF points out that the Commission applied a heightened standard of review, quoting the following passage:

> While the settling parties have met the strict letter of the settlement rules, they did not “bring to the table” those who are in a position to represent all affected groups. If the settling parties choose not to accommodate all affected interest groups, they run the risk of not achieving an all-party settlement, and thus heightening the Commission’s standard of review as they have done in this case.18

In the same decision, the Commission had explained the more stringent standard of review, distinguishing it from the standard for all-party settlements established in D.92-12-019. After noting that it was not considering an all-party settlement, the Commission stated that it would consider the settlement under the three criteria set forth in Rule 51.1(e):19

> However, the standard of review here is somewhat more stringent. Here, we consider whether the Settlement taken as a whole is in the public interest. In doing so, we consider the individual elements of the settlement in order to determine whether the settlement generally balances the various interests at stake as well as to assure that each element is consistent with our policy objectives and the law.20

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18 Re Southern California Edison Company 64 CPUC 2d 241, 267.

19 Id. Rule 51.1(e) is the predecessor of Rule 12.1(d). Nearly identical to its successor, Rule 51.1(e) provided that “[t]he Commission will not approve stipulations or settlements, whether contested or uncontested, unless the stipulation or settlement is reasonable in light of the whole record, consistent with law, and in the public interest.”

20 Id., quoting D.94-04-088 at 8.
We concur that it would be inappropriate to apply the standards for all-party settlements here, just as it was in Re Southern California Edison Company, supra, since we are reviewing a settlement that was not signed by all parties. We consider the Proposed Settlement as a whole and its individual elements, and whether it balances the various interests at stake. Before we review the Proposed Settlement and whether these settlement criteria are met, we address issues regarding the process of its development and submittal to the Commission.

4.2. Process Issues

4.2.1. Compliance With the Settlement Rules

We find that Joint Parties have complied with the relevant elements of the Commission’s settlement rules.\textsuperscript{21} In particular, they convened and provided timely notice of a settlement conference (Rule 12.1(b)), and they filed a motion for approval that provided a statement of the factual and legal considerations adequate to advise the Commission of the scope of the settlement and of the grounds on which adoption is urged (Rule 12.1(a)).

Noting that hearings in R.06-02-013 were held in 2007, CARE argues that, at least with respect to R.06-02-013, the Joint Parties’ filing of the Proposed Settlement on October 8, 2010 violates the Rule 12.1(a) provision that settlements may be proposed within 30 days after the last day of hearing. We find this to be an unreasonable, overly restrictive application of Rule 12.1(a). R.06-02-013 was litigated and largely resolved by 2007. It remains open for consideration of a petition for modification, for which a proposed decision is pending. There is no connection between the evidentiary hearings held in 2007 and the petition for

\textsuperscript{21} Article 12 (Rules 12.1 -12.7).
modification that would warrant the strict application of Rule 12.1(a) that CARE suggests. If we were to apply the rule as literally as CARE proposes in all circumstances, we would render the Commission’s settlement process unavailable in many proceedings, including those where petitions for modification are involved as well as proceedings where no evidentiary hearings are held. No purpose is served by such an outcome, and it would be contrary to our preference that parties have the opportunity to pursue settlements and other forms of alternative dispute resolution. We therefore reject CARE’s argument that the motion is untimely.

4.2.2. Shortened Comment Period

CARE contends that its due process rights were violated, “because an October 25, 2010 (12 days) comments due date and a November, 1, 2010 (7 days) reply comments due date is unreasonable and unjustified…” CCSF argues that CCAs have had “minimal time” to review and analyze the settlement. Shell Energy also raises concerns about the shortened comment period.

As explained in the October 11 Ruling, which adopted the expedited schedule for considering the Proposed Settlement, parties were given notice of the October 7 formal settlement conference on September 24, 2010. That notice also informed parties that settlement documents would be posted on the IOUs’ websites prior to the settlement conference. In accordance with the notice, the

22 CARE comments at 6. CARE misstates the date of the ALJ ruling that adopted the expedited schedule as October 13, 2010. The ruling was issued on October 11. Thus, there were 14 days from the date of the ruling to the date that comments were due, not 12 days as stated by CARE. Moreover, under Rule 12.2 the time for filing comments is calculated from the date the motion for adoption of the settlement was served, not the date of an ALJ’s ruling. The comments were due 17 days after the motion was filed.
Term Sheet, which sets forth in detail the elements of the Proposed Settlement, was posted on the IOUs’ respective websites on October 4, 2010, as were the pro forma agreements and amendments. At the October 7, 2010 settlement conference, parties had opportunity to participate and ask questions about the settlement. Parties also had the opportunity to propound data requests and one party, CMUA, did so.

We conclude that while this process was expedited, parties had adequate time and were not unreasonably burdened or prejudiced by the schedule. The thoughtful and substantive comments that were filed by the parties demonstrate that they had reasonable opportunity to review and respond to the Proposed Settlement.

CARE also argues that the settlement rules do not specify that the time for filing comments on proposed settlements and replies to such comments may be shortened from 30 and 15 days, respectively, and, therefore, that the expedited schedule shortening time for comments and replies violates its due process rights. This argument is without merit. While Rule 12.2 itself does not explicitly provide for such a reduction, it is subject to the application of Rule 1.2, which provides that:

These rules shall be liberally construed to secure just, speedy, and inexpensive determination of the issues presented. In special cases and for good cause shown, the Commission may permit deviations from the rules.

Based on the foregoing discussion, we affirm the October 11 Ruling’s provision for shortening time for comments and replies on the Proposed Settlement.
4.2.3. Adequacy of the Comment Process

Raising concerns similar to those regarding the shortened comment period, some parties contend, in effect, that the settlement rules’ provision for comments and replies on the Proposed Settlement is inadequate in this proceeding. CCSF asserts that it has had no meaningful opportunity to have its concerns considered or addressed. Shell Energy contends that the settlement review process was flawed because ESPs, CCAs, and their customers were not consulted about or invited to participate in the settlement process. CCA/Direct Access Parties raise due process concerns based on the grounds that negotiations leading to the Proposed Settlement were conducted without notice that DA and CCA issues were being discussed.

The settlement rules do not require that all parties participate in settlement discussions. In fact, the rules explicitly accommodate settlements among a limited number of parties to a proceeding by (1) providing that settlements need not be joined by all parties (Rule 12.1(a)), and (2) providing that, prior to signing a settlement, the settling parties shall convene at least one conference with notice and opportunity to participate provided to all parties (Rule 12.1(b)). As Joint Parties observe, the fact that some parties may not be invited to participate in settlement negotiations is the very reason why the rules allow for non-settling parties to file comments. Additionally, as the Commission has stated:

Our settlement rules do not require that all interested parties participate in the preliminary discussions leading to the settlement. Indeed, if that were the case, parties might find it difficult to reach settlements as it is often easier to reach consensus with a few parties.
first, and then attempt to get consensus from a broader array of parties.23

CCSF notes that in D.06-05-034, the Commission modified a settlement that would have allocated potential Competition Transition Charge costs to parties that were not represented in settlement discussions. However, in that case the affected parties were not parties to the proceeding. In this case, affected parties were given notice of the settlement, and six parties (or party groups) actively participated by submitting comments.

The process followed here is in conformance with the Commission’s settlement rules, and parties have had the opportunity to file comments and replies on the Proposed Settlement as well as file comments and replies on the proposed decision. We find that parties were given notice of the settlement and had the opportunity to be heard, and conclude that the process followed here meets due process requirements.

CCA/Direct Access Parties request that hearings or workshops on the Proposed Settlement be scheduled. CCA/Direct Access Parties request is limited to three issues:

1. Whether unbundled customers would derive any benefits from IOU procurement under the proposed QF/CHP program, and if so what costs are associated with these benefits.

2. Whether the current cost allocation under D.06-07-029 is appropriate for “above market” costs associated with the QF/CHP program.

3. Whether the current cost allocation under D.06-07-029 should be extended from 10 years to 12 years for purposes of the QF/CHP program.

23 Re Southern California Edison, 64 CPUC 2d 241, 267.
CCA/Direct Access Parties argue that these issues should be considered on a comprehensive basis along with other IOU procurement/cost allocation issues. We will address cost allocation issues later in this decision to the extent necessary for considering the Proposed Settlement. However, we are persuaded that these are policy and legal issues that are appropriately addressed by notice and comments. We find that neither hearings nor workshops on the Proposed Settlement are necessary.

4.2.4. **Scope of the Consolidated Proceedings**

CARE claims that the Proposed Settlement is not allowed within the scope of R.06-02-013 in light of a 2006 scoping ruling providing that that proceeding will not be the place to re-litigate procurement targets already established elsewhere. However, CARE fails to explain how approval of the Proposed Settlement would constitute relitigation of earlier proceedings. CARE’s claim is therefore without merit.

CCA/Direct Access Parties contend that the following three issues are outside the scope of the consolidated proceedings, contrary to Rule 12.1(a):24

1. Whether the Commission has the authority to establish GHG emissions reduction targets for ESPs and CCAs, and if so what those targets should be.

2. Whether the Commission has the authority to impose CHP procurement requirements on ESPs and CCAs, and if so, what those requirements should be.

3. Whether the Commission has the authority to allocate costs incurred by the IOUs under a CHP procurement program to all

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24 Rule 12.1(a) provides in part that “[r]esolution shall be limited to the issues in that proceeding and shall not extend to substantive issues which may come before the Commission in other or future proceedings.”
customers, and if so what costs should be allocated to all customers and how should that allocation be implemented.

We are not persuaded by these arguments. The issue of cost allocation to ESPs and CCAs is within the scope of R.06-02-013, a phase of which dealt with stranded costs, non-bypassable charges, and ESP/CCA customer responsibility for those charges. D.08-09-012, issued in R.06-02-013, addressed the allocation of QF contract costs to ESP and CCA customers. Also, in D.06-06-071, issued in R.04-04-003, the Commission determined that GHG-related issues for the IOUs, ESPs, and CCAs were within the noticed scope of R.04-04-003. Further, the question of Commission jurisdiction over CCAs and ESPs for purposes of GHG emissions reductions has been addressed in R.04-04-003 and is within the scope of that proceeding. Finally, we note that the Amended Scoping Memo provides that the Proposed Settlement is within the scope of the consolidated proceeding.

4.2.5. Staff Involvement in the Settlement Process

The joint motion for approval of the Proposed Settlement notes that Commission staff representatives were involved in the framing of settlement discussions in May 2009. In their reply comments, Joint Parties also note that during the actual settlement negotiations, staff representatives were involved in some but not all of the meetings. CARE states the following regarding staff participation:

CARE objects to [Commission] staff exercising undue influence on the settlement as specific evidence of constructive retaliatory action against CARE and its members. We believe this is because we represent low-income, people of color and native people ratepayers in our complaints and pleadings before the FERC and CPUC which is a protected activity under both the Federal and State Constitutions and civil rights statutes. The [Commission] continues to seek to
deny us our constitutional right to petition the government for grievances.25

CARE offers no evidence, argument, or other legal basis to support any allegation that staff involvement in the settlement discussions was in any way improper. In particular, CARE provides no evidence that staff exercised “undue influence,” has or had any intent to retaliate against CARE, or actually retaliated against CARE. Likewise, CARE offers no evidence, argument, or other legal basis to support the allegation that the Commission seeks or has sought to deny CARE’s right to petition government. CARE is admonished that making such groundless and frivolous claims is wholly inappropriate and may constitute a failure to maintain the respect that is due the Commission.

Therefore, we dismiss as baseless CARE’s claims regarding staff participation in the settlement process and the alleged denial of its rights.

4.3. Review of the Proposed Settlement

4.3.1. Overview

As discussed below, the Proposed Settlement is reasonable in light of the record. It is the result of lengthy, arms-length settlement negotiations and compromise among divergent interests. The settling parties are experienced with Commission processes and well-represented, and we are convinced that their respective decisions to sign the Proposed Settlement were, in each case, the product of informed choices. None of the Joint Parties received everything it wanted, and each of them was required to compromise in specific areas so that an overall settlement could be reached.

25 CARE comments at 8-9.
The Joint Parties addressed the major issues regarding the development and operation of CHP in California historically and going forward. The Proposed Settlement resolves numerous complex and contentious disputes pending at the Commission. These disputes involve QF pricing, QF SOC terms and conditions, the amount of QF/CHP capacity included in long-term planning, retrospective SRAC price adjustments dating back to 2000, and numerous other disputes concerning the implementation of the Commission's current QF Program. The Proposed Settlement effectively resolves pending disputes by requiring the Joint Parties to either withdraw pending motions and applications or release certain claims.

In addition, the Proposed Settlement precludes the Joint Parties from raising new retrospective SRAC adjustment claims as long as certain conditions are met. Thus, the Settlement not only resolves past disputes, but it also limits potential future disputes regarding SRAC energy prices.

Additionally, the Proposed Settlement provides a comprehensive framework for a QF/CHP Program in California that will encourage the development of efficient CHP, and provide environmental benefits through reduced GHG emissions.

From the standpoint of the IOUs, QF representatives, and ratepayer advocates that signed the Proposed Settlement, the case in favor of adopting it is compelling. The relationship among these parties has been contentious and litigious for most of the last 30 years. It is apparent that the disputes arising from this relationship impose large costs upon the parties as well as the Commission, the FERC, and the courts. The uncertainty may also be delaying implementation of state policy goals for CHP and GHG emissions reductions. It is clearly in the public interest to adopt a settlement framework that resolves the ongoing
controversies in a manner that is acceptable to the settling parties, provided that the settlement otherwise meets our criteria for approval. To the extent that consideration of the Proposed Settlement requires balancing the interests of various parties, including non-settling parties, we find that significant weight should be given to this public interest benefit.

4.3.2. Elements of the Proposed Settlement

4.3.2.1. CHP Goals and Objectives

The state policy objectives addressed by the Proposed Settlement include requirements of Pub. Util. Code Section 372(a):

It is the policy of the state to encourage and support the development of cogeneration technology as an efficient, environmentally beneficial, competitive energy resource that will enhance the reliability of local generation supply, and promote local business growth.

The Proposed Settlement is also intended to address the policy objective of the Energy Action Plan II, which states:

The loading order identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs. After cost effective efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications. To the extent efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy and capacity needs, we support clean and efficient fossil-fired generation.

The Proposed Settlement explicitly provides that the purpose of the State CHP Program is to encourage the continued operation of the state's existing CHP facilities, and the development, installation, and interconnection of new, clean and efficient CHP Facilities, in order to increase the diversity, reliability, and environmental benefits of the energy resources available to the State's electricity consumers. The State CHP Program is designed to retain existing efficient CHP,
support the change in operations of inefficient CHP to provide greater benefits to the State, and replace CHP that will no longer be under contract with the IOUs with new, efficient CHP. Thus, with respect to implementation of state policy objectives for CHP, the Proposed Settlement is consistent with state and Commission policy and law.

4.3.2.2. GHG Emissions Reductions from CHP Facilities

Enacting AB 32 to reduce California's GHG emissions, the Legislature declared that global warming caused by GHG emissions poses a serious threat to California.26 Since AB 32 was enacted, the Commission has repeatedly indicated that reduction in GHG emissions is a key policy objective for the utility industry.27 The Commission, CARB and the CEC have all recognized that efficient and clean CHP can reduce GHG emissions.28 CARB has made CHP one element in its Scoping Plan to implement AB 32 and reduce GHG emissions in California.

The State CHP Program created by the Proposed Settlement is both intended and designed to secure additional GHG emissions reduction benefits, consistent with the reduction targets of AB 32, by adding new, efficient CHP. It would do so by:

- Setting GHG Targets for all Commission-jurisdictional LSEs, including the IOUs, ESPs and CCAs. The targets are intended to facilitate LSEs meeting CARB's CHP goals by December 31, 2020.


27 See e.g., D.07-12-052 at 2-5, 243; D.08-10-037 at 2-3.

28 D.08-10-037 at 237-238, CARB Scoping Plan at 43-44, 2009 IEPR at 97-98.
To the extent CARB modifies its CHP goals, the Settlement provides flexibility to incorporate any modification in them.

- Creating incentives for upgrading existing, inefficient CHP facilities, or, alternatively, for facilities that cannot participate or are unsuccessful in the CHP Program, providing an orderly exit strategy. All CHP facilities will be able to participate in the CHP RFOs, and some will be able to participate in other procurement processes and obtain contracts that facilitate the financing, construction and operation of upgraded and/or new facilities. The CHP RFO PPA includes efficiency performance obligations.

- Requiring all Commission-jurisdictional LSEs to file semi-annual compliance reports that include GHG emissions information. This will allow the Commission and other interested parties to monitor the GHG emissions resulting from the QF/CHP Program and to determine if LSEs are obtaining the GHG benefits expected, and to address any shortfalls in expected GHG emission reduction benefits in a timely manner.

With respect to its design for achieving state policy objectives for GHG emissions reductions, the Proposed Settlement is consistent with the law. We address below claims that setting GHG Targets and reporting requirements for all LSEs contravenes the law in other respects.

### 4.3.2.3. Competitive Procurement

The Commission has repeatedly stated a policy preference for competitive wholesale energy markets and competitive solicitations to procure new resources in those markets.\(^29\) Yet, currently, CHP QF contracting is not conducted through a competitive solicitation process. The Commission's early QF Program involved the issuance of standard offer contracts that a QF of any technology could sign. In recent years, the CHP QF Program has primarily been sustained by extensions

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\(^{29}\) D.04-01-050 at 63, D.07-12-052 at 205, D.08-11-008 at 20.
of existing contracts and the availability of short-term contracting options. In D.07-09-040, however, the Commission ordered the IOUs to offer QFs five-year as-available and ten-year firm PPAs. Despite considerable efforts, those contracts have never been finalized or made available to QFs.

Under the Proposed Settlement, a new, competitive procurement process will be adopted in lieu of the Commission-ordered contracts. In particular, the Proposed Settlement creates a CHP RFO process that allows the IOUs to run competitive, transparent RFOs for CHP resources. This is a significant change in CHP procurement. It puts CHP resources into a process similar to the one currently used for conventional and RPS procurement. This process will result in competitive prices that are ultimately subject to Commission approval.

The Commission has also provided for other methods for utility procurement, such as bilateral contracting. The Proposed Settlement provides similar additional flexibility to the IOUs in the CHP procurement process by including not only RFOs, but also other processes such as bilateral contracting, AB 1613 feed-in tariffs, a PURPA Program for QFs under 20 MW, utility-ownership, and other procurement options. The Proposed Settlement also includes a regulatory approval process for CHP PPAs that result from these procurement options. In short, the Proposed Settlement adopts a procurement process for QF and CHP resources that is competitive, flexible, and allows for sufficient regulatory oversight to ensure that the IOUs are able to minimize costs and select appropriate resources for California customers. It is consistent with,

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30 See e.g. D.03-12-062 at 38-40.
and gives effect to, the Commission's preference for competitive procurement, and in this respect it is consistent with the law.

### 4.3.2.4. Energy and Capacity Prices

The Proposed Settlement has several pricing and contracting options. First, CHP PPA prices will be set on a contract-specific basis through a competitive RFO process subject to Commission approval. Allowing CHP developers to bid into the RFO will allow them to propose prices that are sufficient to finance and develop their facilities, while at the same time allowing the IOUs to pick the best offers based on a number of criteria, including price. An RFO procurement process, similar to the processes currently used for conventional and RPS contracts, will result in competitive prices that are ultimately subject to Commission approval. The Proposed Settlement expressly provides that an IOU may use excessive RFO prices as a justification for failing to meet the MW Targets and GHG Targets.

Second, the Proposed Settlement establishes SRAC prices for the Transition PPAs, Legacy PPAs, QF contracts that are still available under PURPA for facilities less than 20 MW, and the Optional As-Available PPAs. The SRAC included in the Proposed Settlement is based on the current Commission-approved SRAC pricing formula\(^{31}\) and achieves the goal of ultimately transitioning to a market heat rate to determine SRAC by January 1, 2015.\(^{32}\) The Joint Parties point out that there is a long history of setting SRAC prices through

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\(^{31}\) D.07-09-040 at 67, Resolution E-4246 (July 10, 2009) (adopting Market Index Formula).

\(^{32}\) D.07-09-040 at 68.
settlements, and that the Proposed Settlement resolves this very contentious issue through an arms-length negotiation among adverse parties. As such, we concur that the established SRAC prices are reasonable and in the public interest.

Finally, the Proposed Settlement includes capacity prices that have already been approved by the Commission in D.07-09-040 or are already incorporated in existing contracts.

We find that the energy and capacity pricing provisions of the Proposed Settlement are reasonable and consistent with recent commission decisions.

### 4.3.2.5. QF/CHP Targets

The Proposed Settlement establishes MW Targets for each IOU. In addition, it establishes a GHG Target for all Commission-jurisdictional LSEs. These targets are consistent with the CHP targets included in CARB's Scoping Plan, but they can be adjusted to reflect changes by CARB in CHP targets for GHG emissions reductions and if a lack of need is asserted by an IOU and determined by the Commission.

The Joint Parties state that the MW Targets are the result of heated and protracted negotiations among parties with divergent interests. As noted earlier, the Commission has recognized that a settlement of contested issues among parties with divergent interests is reasonable and in the public interest. That is the case here. We address concerns regarding the applicability of the targets to all LSEs below.
4.3.2.6. Reporting and Auditing

The Commission has encouraged transparency in RFO and procurement processes. The Proposed Settlement includes several provisions that promote such transparency. Commission-jurisdictional LSEs are required to submit semi-annual reports concerning their progress toward achieving the MW Targets and GHG Targets. The Proposed Settlement contains detailed requirements for the type of information to be included in the semi-annual reports. This will provide the Commission and interested parties with information concerning the progress of the QF/CHP Program, and do so with sufficient frequency that the Commission will have an opportunity to address issues and concerns as they arise, rather than waiting until the end of the program to address these issues.

The Proposed Settlement also provides for a CHP Auditor to be used for the CHP RFOs if an IOU does not or anticipates that it will not meet its MW Targets or GHG Targets. The CHP Auditor provisions provide the auditor with access to confidential IOU information, to review the CHP RFO process, while including appropriate safeguards to prevent the disclosure of confidential information. The CHP Auditor can review the results of the IOU CHP RFOs, and raise any concerns about the RFOs to the Commission or the Energy Division. This provides an additional level of transparency in the implementation of the QF/CHP Program.

The Proposed Settlement’s provision for semi-annual reports and a CHP Auditor Process are consistent with Commission policies supporting greater public information and transparency. We address concerns about applicability

33 See e.g. D.07-12-052 at 148-151.
of reporting requirements to all jurisdictional LSEs below. The first semi-annual progress report should be filed on the first business day of the month following the Settlement Effective Date.

### 4.3.2.7. Pro Forma PPAs and Legacy of QF PPA Amendment

The Commission has previously approved the use of *Pro Forma* PPAs for QFs, as well as for use in RFOs for conventional and RPS resources. The Proposed Settlement includes the following four *Pro Forma* PPAs that were developed for specific circumstances and a *Pro Forma* Legacy QF PPA Amendment for each IOU:

- **Legacy QF PPA Amendments:** These *Pro Forma* Amendments offer QFs under unexpired Legacy QF PPAs as of the Settlement Effective Date (Legacy QFs) the option of amending the energy payment terms of their QF PPAs by selecting one of several payment options and executing the Legacy Amendment within 180 days of the Settlement Effective Date.

- **Transition PPA:** This *Pro Forma* PPA offers an existing CHP facility whose existing QF PPA or extension thereof is scheduled to expire prior to 2015 the option to continue existing deliveries until July 1, 2015.

- **CHP RFO PPA:** This *Pro Forma* PPA will be issued in the CHP RFOs to procure deliveries from CHP and other eligible generators larger than five MW.

- **Optional As-Available CHP PPA:** This *Pro Forma* PPA offers gas-fired CHP facilities with nameplates greater than 20 MW, but annual average deliveries less than 131,400 megawatt-hours (MWh), the option to make as-available deliveries to meet criteria specified in the Proposed Settlement. The facilities procured under this contract would be subject to a program cap and measured on a deliver basis.

- **PPA for QFs of 20 MW or Less:** This *Pro Forma* PPA offers QFs of 20 MW or less, including small power producers and renewable energy resources, the option to make firm or as-available sales to the IOUs.
The establishment of these PPAs and amendments represents a significant achievement that provides the foundation for a new QF/CHP program. This element of the Proposed Settlement is consistent with Commission policy and in the public interest.

4.3.2.8. Operationally Flexible Resources

Recognizing the amount of intermittent, renewable resources that will be added in California as a result of the RPS requirements, the Commission has encouraged the development of operationally flexible conventional resources to assist with renewables integration.34 One of the challenges for CHP facilities is that they are often operated as baseload facilities and/or need to operate consistent with the needs of a thermal host. Accordingly, these facilities often lack significant operational flexibility. Under the Proposed Settlement, the IOUs can contract with a limited group of existing CHP facilities that convert from a QF facility to a dispatchable generation facility. The dispatchable generating facility is referred to in the Proposed Settlement as a “Utility Prescheduled Facility.”

This aspect of the Proposed Settlement has important benefits and thus is in the public interest. If an existing CHP facility converts to a dispatchable facility, it gives the IOU the ability to dispatch the resource when it is needed, rather than the facility providing baseload generation or operating based on a thermal host's needs. This is similar to the contracts the IOUs have with peaking and other existing conventional generation facilities. It should prevent any incentive to maintain a facility as a CHP resource, when a thermal need no

34 See e.g. D.07-12-052 at 106, 111-112, 115.
longer exists, simply because of an overall CHP program target. Also, conversion to a dispatchable facility may ultimately result in GHG emission reductions. If an existing CHP facility operates as a baseload facility and is not efficient, its GHG emissions may be higher than a new conventional facility or other resource options. By giving the IOU the flexibility to dispatch a facility, the utility can optimize its GHG emissions reductions by choosing to operate facilities with the lowest total GHG emissions.

4.3.3. Contested Issues

4.3.3.1. Introduction

Most elements of the Proposed Settlement are uncontested by most of the parties in these proceedings. Four of the five parties that filed comments in opposition to one or more aspects of the Proposed Settlement (CCSF, CMUA, Shell Energy, and CCA/Direct Access Parties) addressed those portions of the settlement that pertain to procurement requirements and reporting obligations for ESPs and CCAs, and cost allocation issues, including non-bypassable charges for departing load customers. These parties recommend rejection of the Proposed Settlement only if it is not modified to address their proposed changes. Only CARE urges rejection of the Proposed Settlement as a whole. In Section 4.3.3 we address the recommendations and arguments of these parties.

4.3.3.2. Commission Jurisdiction Regarding ESPs and CCAs

Under the Proposed Settlement, the CARB CHP goal is allocated among Commission-jurisdictional LSEs based on their respective percentage of total retail sales. This allocation is used to establish GHG Targets for all LSEs, including the IOUs, ESPs and CCAs. The Proposed Settlement provides that the Commission can require that ESPs and CCAs procure their portion of the GHG Emissions Reduction Targets for their own customers. While it does not dictate
the procurement method by which ESPs and CCAs will need to comply with this requirement, it does require semi-annual reporting to ensure that these Commission-jurisdictional entities are making progress toward their targets. Alternatively, the Proposed Settlement provides that the Commission can require the IOUs to procure the ESP and CCA customers’ portion of the GHG Emissions Reduction Targets, in which case the ESPs and CCAs will pay the net capacity costs associated with the CHP procured on their behalf.

Parties representing ESPs and CCAs contend that the Commission lacks jurisdiction to require them to participate in the QF/CHP Program or to procure a share of the GHG emissions reduction targets established under the Proposed Settlement. As explained below, there are several statutory provisions and other reasons that we have the requisite jurisdiction to require ESP and CCA participation in the QF/CHP Program.

First, the QF/CHP Program in part implements CARB’s CHP goals for the electrical sector. Under Pub. Util. Code Section 365.1(c)(1), enacted as part of Senate Bill (SB) 695, ESPs should be subject to the same GHG emissions net reduction requirements as the IOUs. The Proposed Settlement provides for this by requiring either that ESPs procure their share of CHP to meet the GHG Emissions Reduction Targets, or that the customers of the ESPs pay their share of the costs attributable to the IOUs’ procurement of CHP on the ESPs’ behalf.

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35 Stats. 2009, Ch. 337. Section 365.1(c), by its own terms, becomes effective “[o]nce the commission has authorized additional direct transactions pursuant to subdivision (b) … ” D.10-03-022 authorized and implemented a plan for increased limits in the allowed level of direct access transactions within the IOUs’ service territories.
Second, notwithstanding the opponents’ argument that SB 695 only applies to “requirements” adopted by CARB, and not to the CARB Scoping Plan, the Scoping Plan itself indicates (at ES-1) that “the measures in this Scoping Plan will be developed over the next two years and be in place by 2012.” To the extent that CARB modifies the CHP portion of the Scoping Plan in any final AB 32 rules or regulations, these changes will be reflected in adjustments to the GHG Emissions Reduction Targets. To the extent the GHG Emissions Reduction Targets are modified, the ESP and CCA obligations will also be modified to reflect any final CARB rules or regulations. Thus, whatever CHP-related rules and regulations CARB ultimately adopts for all LSEs as a part of its implementation of AB 32, the Proposed Settlement allows for the incorporation of these final rules and regulations for the IOUs, ESPs and CCAs.

Third, Pub. Util. Code section 365.1(c)(2), enacted as part of SB 695, requires the Commission to allocate the net capacity costs and resource adequacy benefits to all customers, including CCAs, ESP and CCA customers, when it authorizes or directs the IOUs “to obtain generation resources that the commission determines are needed to meet system or local area reliability needs for the benefit of all customers in the electrical corporation’s distribution service territory.” By approving the Proposed Settlement and directing the IOUs to meet the CHP procurement targets included on behalf of all retail customers in their service territories, the Commission would trigger this provision of SB 695, since CHP resources provide system and local area reliability benefits, commensurate with their Net Qualifying Capacity.

Fourth, under Pub. Util. Code Section 366.2(f)(2), the Commission is required to ensure that CCA customers reimburse the IOUs for their share of
procurement costs attributable to the customer. Accordingly, CCA customers should be responsible for their share of the costs of the QF/CHP Program.

Fifth, the Commission has determined that where DA and CCA customers benefit from procurement, these customers should pay their share of the procurement costs. For example, it has authorized the allocation of new generation resource costs to DA and CCA customers because these customers benefitted from the system reliability provided by the new generation resources.36 It has also allocated GHG compliance costs and certain locational costs associated with CHP facilities developed under AB 1613 to DA and CCA customers because these customers benefitted from the AB 1613 program.37

Finally, we note that in 2006 the Commission adopted a load-based cap for GHG emissions and indicated that it intended to develop a GHG reduction program in the longer term.38 At that time, ESPs asserted that the Commission did not have jurisdiction to apply GHG-related requirements to them.39 The Commission rejected these arguments, noting that “[a]s a general policy, we believe it is imperative that GHG reduction goals and responsibilities be shared as broadly as possible.”40 In addition, the Commission determined that it had “direct authority” to regulate CCA and ESP procurement activities related to GHG insofar as the determination of those targets is “germane to the regulation

36 D.06-07-029 at 7.
37 D.09-12-042 at 21-25, aff’d, D.10-04-055 at 11-18.
38 D.06-02-032 at 2-3.
39 Id. at 25-27
40 Id. at 26.
of public utilities” and promotes equity. On rehearing the Commission again rejected the argument that it has no jurisdiction over ESPs and CCAs on GHG-related issues, citing, in part, its general authority over “public utilities” in Public Utilities Code section 701. It also noted that exempting ESPs and CCAs from GHG-related requirements would give these LSEs an improper competitive advantage over the IOUs.

We concur with the Joint Parties that the same argument applies in this proceeding, and that if the ESPs and CCAs were exempted from the GHG Emissions Reduction Targets, they would potentially have an improper competitive advantage because they would not be required to procure CHP. For this reason we reject Shell Energy’s argument that the Proposed Settlement puts ESPs at a competitive disadvantage because they cannot compete with the IOUs for CHP resources. Similarly, we reject the CCA/Direct Access Parties’ assertion that the Proposed Settlement is “fundamentally unfair” because it imposes GHG Emissions Reduction Targets on the ESPs and CCAs and not just IOUs.

We conclude that both California statutory law and Commission precedent fully support the Commission’s jurisdiction to adopt the portions of the Proposed Settlement that are applicable to the ESPs and CCAs.

4.3.3.3. Cost Allocation Issues

The CCA/Direct Access Parties assert that if the Commission determines that the IOUs should procure CHP on behalf of the ESPs and CCAs, the

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41 Id.

42 D.06-06-071 at 20.

43 Id.
Proposed Settlement improperly applies the SB 695 cost allocation methodology set forth in Pub. Util. Code section 365.1(c)(2). According to the CCA/ Direct Access Parties, the statute requires a determination that a generation resource is needed for reliability, and such a determination has not been made for CHP. However, CHP resources count toward resource adequacy requirements and provide system and local reliability benefits commensurate with their Net Qualifying Capacity. The “Goals and Objectives” section of the Proposed Settlement specifically cites the reliability benefits of CHP procurement. Thus, a requirement for procurement of CHP by the IOUs fits squarely within the parameters of SB 695.

CCSF argues that the non-bypassable charge approved in D.08-09-012 should not be extended from 10 years to 12 years. In response, the Joint Parties note that they are not seeking a blanket modification of the D.08-09-012 requirements to expand the recovery period for all PPAs from 10 years to 12 years. Rather, because some PPAs under the QF/CHP Program can have a duration of up to 12 years, the Joint Parties contend that it is appropriate for purposes of the Proposed Settlement to permit extending the 10 years in D.08-09-012 to 12 years to ensure recovery of the QF/CHP program costs that will be incurred over the entire term of the PPAs. We concur that the extension is reasonable and will therefore approve it. The Commission has extended the 10-year non-bypassable charge limitation in other areas, most notably with RPS contracts, which are recovered over the life of the PPA and thus may be recovered for a period substantially longer than 10 years.44

44 D.04-12-048 at 63.
We conclude that the cost allocation provisions of the Proposed Settlement are fair, reasonable, and consistent with California law.

4.3.3.4. **CMUA’s Requested Modifications**

CMUA proposes modification to the language in Section 6.3.4 and the deletion of Section 6.3.5. We find these modifications to be unnecessary and decline to make them. The Proposed Settlement recognizes that the POUs are not subject to Commission jurisdiction, and it does not impose any GHG Emissions Reduction Targets on them. Section 6.3.4 simply acknowledges that entities not regulated by the Commission should be responsible for a portion of the GHG Emissions Reduction Targets. In approving the Proposed Settlement, the Commission will not be imposing a GHG Emissions Reduction Target on the POUs. Similarly, Section 6.3.5 simply states that the Joint Parties support GHG Emissions Reduction Targets for the POUs. Again, this does not impose an obligation on the POUs.

CMUA also proposes deleting provisions in the Proposed Settlement that would require IOU bundled customers who depart bundled service to become municipal utility customers (MDL) to bear a share of the IOU costs incurred on their behalf. CMUA bases its argument primarily on D.08-09-012. In the context of the Proposed Settlement, we concur with the Joint Parties that it is appropriate to permit a deviation from D.08-09-012 related to MDL as a part of our approval of the Proposed Settlement. In D.08-09-012, the Commission exempted MDL from stranded cost responsibility for new generation resources because the load forecast to determine new resource needs takes into account the departure of customers for municipal service. Here, however, the GHG Emissions Reduction Targets are not based on load forecasts that exclude MDL, but rather on actual retail sales data that includes all current bundled service customers, even if some
of those customers later depart for municipal service. Because the IOUs’ GHG Emissions Reduction Targets obligations are based on their current bundled service customers’ retail sales (as compared to future load forecasts that account for departing customers), to the extent that a customer departs, that customer should bear its share of the costs incurred on its behalf. The Proposed Settlement’s methodology for allocating the GHG Emissions Reduction Targets reflects a fair allocation of these targets among all customers.

As requested by CMUA, we clarify here that adoption of the Proposed Settlement does not alter existing non-bypassable charge (NBC) agreements between POUs and IOUs. NBC payment provisions in existing NBC agreements are deemed to cover all CHP Program costs and no additional NBCs or other CHP Program costs will be imposed on customers covered by existing NBC agreements.

4.3.3.5. Federal Preemption Claims

CARE reargues portions of a complaint that it recently filed at the FERC, asserting that the Commission does not have authority to approve the Proposed Settlement or any of the underlying *pro forma* PPAs or amendments. We find the arguments proffered by CARE unpersuasive and therefore reject them. The Proposed Settlement is intended to resolve disputes that are currently pending at the Commission, and CARE fails to explain why Commission review of a settlement to resolve these pending disputes is improper. Also, the Proposed Settlement establishes a QF/CHP Program for the State, consistent with California statutory law and policy, yet CARE provides no explanation as to why the Commission does not have jurisdiction to approve a settlement that establishes a QF/CHP Program pursuant to California statutes and policy.
CARE also claims that approval of the Proposed Settlement would constitute approval of a PPA without FERC approval and thus not be lawful. However, approval of the pro forma PPAs and amendments is clearly distinguishable from mandating that a contract’s rate be set at a specific price. Moreover, the prices included in the Proposed Settlement were negotiated between the Joint Parties and were not mandated by the Commission. In addition, the Commission’s preapproval of a PPA, which will be set at market rates, is pursuant to Pub. Util. Code sections 380 and 454.4(d), ensuring that the utilities’ resource adequacy needs are met and determining that the IOU will not later be subject to a reasonable review proceeding.

Finally, CARE asserts that the Proposed Settlement violates a recent FERC order, which granted the Commission’s request for clarification of the FERC’s declaratory order involving the AB 1613 feed-in tariffs. In particular, the FERC’s clarification order has recognized that states are allowed a “wide degree of latitude” in setting avoided cost rates. However, in terms of the SRAC terms of the Proposed Settlement, CARE fails to explain how the Proposed Settlement would violate the FERC’s regulations concerning avoided cost rates.

4.3.3.6. FERC Review of PURPA 210(m) Application

CARE asserts that FERC should review the Proposed Settlement before it is considered by the Commission. We reject this argument. The Proposed Settlement resolves certain state law disputes that are outstanding at the Commission and establishes a California QF/CHP Program, and is therefore

45 See, California Public Utilities Commission, et al., 133 FERC ¶ 61,059.

46 See, id. at 24.
appropriately subject to review by the Commission at this time.\textsuperscript{47} Also, the Joint Parties’ proposal to seek Commission approval of the Proposed Settlement first, before filing the PURPA termination application at FERC, is entirely appropriate. As a part of their PURPA termination application, the IOUs will reference the Proposed Settlement among other facts to demonstrate that the statutory requirements of Section 210(m) are satisfied. This Commission first needs an opportunity to review and approve the Proposed Settlement before it can be referenced in any PURPA application filed at FERC.

Finally, CARE asserts that its federal due process rights will be violated as a result of the Commission reviewing the Proposed Settlement before the PURPA application is filed at FERC. However, as we have discussed earlier in this decision, CARE has been provided due process in this proceeding to challenge the Proposed Settlement. If the Proposed Settlement is approved and the IOUs file their PURPA application at FERC, CARE will have an opportunity to challenge that application at FERC consistent with FERC’s rules and regulations. We find no basis for CARE’s assertion that its federal due process rights will be violated.

\textbf{4.3.4. Alternatives for Cost Allocation to ESPs and CCAs}

As noted earlier, the Proposed Settlement provides for the Commission to choose one of two alternative approaches for allocating CHP procurement costs to ESPs and CCAs. One alternative, preferred by the Joint Parties, is to require these entities to meet their portion of the GHG Target by procuring CHP

\textsuperscript{47} Under the Proposed Settlement, the Joint Parties agree that the IOUs may file an application to terminate the IOUs’ PURPA obligations for QFs exceeding 20 MW under Section 210(m) and 18 C.F.R. §§ 292.309 – 292.310.88.
resources. Alternatively, if it is found that ESPs or CCAs are unable or unwilling to meet their portion of the GHG Targets by contracting with CHP facilities, the IOUs have agreed under the terms of the Proposed Settlement to procure CHP resources on behalf of these entities. In this case, however, ESP and CCA customers would be responsible for the costs of CHP resources procured on their behalf by the IOUs. As noted above, this is consistent with the Commission's recent decisions on cost allocation when ESP and CCA customers benefit from IOU procurement on their behalf.

We are persuaded that, at this time, we should provide for IOU procurement of CHP resources on behalf of non-IOU LSEs and allocation of net capacity costs and associated benefits as described in Section 13.1.2.2 of the Term Sheet. This approach is reasonable as it addresses concerns regarding the ability of ESPs and CCAs to procure CHP resources. The administrative burden for the Commission would also be reduced since it would only need to monitor the IOUs for compliance. We remain open to consideration, in a future proceeding, of proposals whereby ESPs and CCAs may opt out of IOU procurement and procure CHP resources on their own behalf.

4.3.5. Conclusion

In the foregoing discussion we have touched upon several public interest benefits of the Proposed Settlement. We restate the benefits here.

- It resolves numerous pending disputes, motions and applications and will likely limit disputes in the future. Settlements of disputes benefit the public by reducing the costs and expense of litigation and conserving Commission resources.
- The Proposed Settlement creates a framework for a QF/CHP Program going forward that is aligned with other Commission-approved procurement processes. For example, under the Proposed Settlement, the IOUs will initiate a CHP RFO process,
which is similar to how conventional and RPS resources are now procured. The Proposed Settlement also includes Pro Forma PPAs, which will allow CHP developers and the IOUs to reduce transaction costs and resources, which they would otherwise be expended in the time-consuming process of negotiating individual PPAs.

- The Proposed Settlement will encourage the continued operation of the State's existing CHP facilities and the development, installation and interconnection of new, clean, and efficient CHP facilities in order to increase the diversity, reliability and environmental benefits of the CHP energy resources.

- The Proposed Settlement creates a framework for achieving CARB's current CHP goals for the reduction of GHG emissions. GHG emissions pose a serious threat to the California economy, environment and the health and welfare of California's citizens. By providing a framework for the implementation of one aspect of the CARB Scoping Plan, the Proposed Settlement will facilitate efforts for California to meet its ambitious AB 32 goals. It encourages the retirement of existing, inefficient CHP facilities or repowering existing CHP facilities to make them more clean and efficient, and the development of new, clean and efficient CHP.

- The Proposed Settlement adopts a methodology for determining SRAC energy prices that is consistent with Commission decisions. The Proposed Settlement also provides for CHP PPA energy prices that are determined as a part of a competitive process, so that the prices accurately reflect a market price. Customers will benefit from clearly established SRAC prices, or prices determined through a competitive process. In addition, the capacity prices adopted in the Proposed Settlement have already been approved by the Commission.

- The Proposed Settlement creates a transparent procurement process, benefitting the Commission, interested parties and the public.

- The Proposed Settlement establishes clear rules for pricing and treatment of existing QF PPAs. For example, under the Settlement, QFs with existing PPAs are encouraged to provide
forecasting information to the IOUs so that the IOUs can more accurately forecast QF generation. QFs also have greater certainty as the SRAC formula is clearly established rather than being subject to continued and ongoing disputes.

- The Proposed Settlement provides for the equitable allocation of costs associated with the QF/CHP program to all Commission-jurisdictional LSEs.

The Proposed Settlement resolves several past and ongoing disputes and will likely resolve potential future disputes among the settling parties. It establishes a framework for a QF/CHP Program going forward that advances state policies encouraging efficient CHP operations and promoting GHG emissions reductions. It provides for reasonable cost allocation of QF/CHP program compliance among all Commission-jurisdictional LSEs. Taken as a whole, it constitutes a reasonable and appropriate resolution of the many QF issues presently under consideration before the Commission and in other forums. We have reviewed the elements of the Proposed Settlement and find that it does not contravene any provision of law. The Commission has a long-standing policy of supporting settlements:

The Commission favors settlements because they generally support worthwhile goals, including reducing the expense of litigation, conserving scarce Commission resources, and allowing parties to reduce the risk that litigation will produce unacceptable results.48 We will therefore approve the Proposed Settlement without modification.

Rule 12.5 states the following regarding limits on the future applicability of a settlement:

48 D.10-06-031 at 12.
Commission adoption of a settlement is binding on all parties to the proceeding in which the settlement is proposed. Unless the Commission expressly provides otherwise, such adoption does not constitute approval of, or precedent regarding, any principle or issue in the proceeding or in any future proceeding.

The Joint Parties request that the Commission expressly find that the Term Sheet is precedential. For good cause shown, we do so here.

5. **Disposition of Proceedings**

In approving the Proposed Settlement, we set in motion a series of steps that should lead to eventual closure of each of the captioned proceedings. However, under the terms of the Proposed Settlement, these actions include approval by the FERC of a waiver of the IOUs’ obligations under Section 210(m) of PURPA following approval of the settlement by this commission as well as written support by the CARB. It is therefore premature to close the proceedings. Accordingly, the proceedings will remain open but, subject to the discretion of the assigned Commissioner or ALJs, held in abeyance at this time. When the conditions precedent to the settlement effective date have been met, Joint Parties should so inform the Commission by filing a motion(s) for closure of these proceedings.

6. **Comments on the Proposed Decision**

The proposed decision (PD) of ALJ Wetzell in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission’s Rules of Practice and Procedure. Comments were filed by the CAISO, CCA/Direct Access Parties, CCSF, CMUA, Joint Parties, and Shell Energy. Reply comments were filed by CCA/Direct Access Parties, CCSF, Joint Parties, and Shell Energy.
In response to the comments and replies, we have made several non-substantive revisions to the PD that do not affect the recommended outcome, i.e., approval of the Proposed Settlement. In addition, as discussed in Section 4.3.4 above, we have made one substantive change: where the PD adopted the alternative cost allocation method set forth in Section 13.1.2.1 of the Term Sheet, we instead adopt the alternative method set forth in Section 13.1.2.2 of the Term Sheet.

7. Assignment of Proceedings


Findings of Fact

1. Since the QF program was implemented in the 1980s, there have been numerous disputes between the QFs, IOUs, and ratepayer advocates involving contract terms, SRAC pricing, capacity payments, contract extensions and terminations, and the availability of new contracts. Many of these disputes are still pending at the Commission.

2. To implement the QF program going forward, the Commission must address the impact of the CAISO’s MRTU on SRAC and the QF program, disputes over the terms and conditions of the new QF Standard Offer Contract, and the amount of QF capacity to include in the LTPP.

3. State policy embodied in Pub. Util. Code Section 372(a) and Energy Action Plan II supports the development of efficient, environmentally beneficial CHP.
4. In adopting the CARB Scoping Plan pursuant to AB 32, the CARB noted that the widespread development of efficient CHP systems would help displace the need to develop new, or expand existing, power plants.

5. The CARB Scoping Plan sets a target of an additional 4,000 MW of installed CHP capacity by 2020, enough to displace approximately 30,000 GWh of demand from other power generation sources.

6. On September 24, 2010, parties in these proceedings and in R.03-10-003, R.07-05-025, and R.08-06-024 were given notice that a formal settlement conference would be convened on October 7, 2010 and that settlement documents would be posted on the IOUs’ websites prior to the settlement conference.

7. The Term Sheet setting forth in detail the elements of the Proposed Settlement was posted on the IOUs’ respective websites on October 4, 2010, as were the pro forma agreements and amendments.

8. Parties had opportunity to participate and ask questions about the Proposed Settlement at the October 7, 2010 settlement conference and to propound data requests.

9. The settlement rules do not require that all parties participate in settlement discussions.

10. The process followed in this proceeding for review of the Proposed Settlement is in conformance with the Commission’s settlement rules.

11. The issues of cost allocation to LSEs and GHG emissions reductions for the LSEs, including the question of Commission jurisdiction over CCAs and ESPs for purposes of GHG emissions reductions, were addressed in one or more of the consolidated proceedings.
12. The Proposed Settlement is the result of arms-length settlement negotiations and compromise among divergent interests.

13. The settling parties are experienced with Commission processes and well-represented, and their respective decisions to sign the Proposed Settlement were, in each case, the product of informed choices.

14. The Joint Parties addressed the major issues regarding the development and operation of CHP in California historically and going forward.

15. The Proposed Settlement resolves numerous complex and contentious disputes pending at the Commission.

16. The Proposed Settlement provides a comprehensive framework for a QF/CHP Program in California that will encourage the development of efficient CHP and provide environmental benefits through reduced GHG emissions, consistent with the reduction targets of AB 32.

17. The Proposed Settlement adopts a procurement process for QF and CHP resources that is competitive, flexible, and allows for sufficient regulatory oversight to ensure that the IOUs are able to minimize costs and select appropriate resources for California customers.

18. The Proposed Settlement includes several provisions that promote the Commission’s objective of transparency in RFO and procurement processes.

19. Converting an existing CHP facility to a dispatchable facility gives the IOU the ability to dispatch the resource when it is needed and may ultimately result in GHG emission reductions.

20. To the extent the GHG Emissions Reduction Targets are modified, the ESP and CCA obligations will also be modified to reflect any final CARB rules or regulations.
21. The Commission has determined that where DA and CCA customers benefit from procurement, these customers should pay their share of the procurement costs.

22. The Commission has allocated GHG compliance costs and certain locational costs associated with CHP facilities developed under AB 1613 to DA and CCA customers because these customers benefitted from the AB 1613 program.

23. The Commission has determined that GHG reduction goals and responsibilities be shared as broadly as possible.

24. The Commission has determined that it has authority to regulate CCA and ESP procurement activities related to GHG insofar as the determination of those targets is “germane to the regulation of public utilities” and promotes equity.

25. The Commission has determined that exempting ESPs and CCAs from GHG-related requirements would give these LSEs an improper competitive advantage over the IOUs.

26. The Proposed Settlement recognizes that the POUs are not subject to Commission jurisdiction and it does not impose any GHG Emissions Reduction Targets on them.

27. D.08-09-012 exempted MDL from stranded cost responsibility for new generation resources because the load forecast to determine new resource needs takes into account the departure of customers for municipal service.

28. The GHG Emissions Reduction Targets are based on actual retail sales data that includes all current bundled service customers, not load forecasts that exclude MDL.

29. Approval of the pro forma PPAs and amendments is distinguishable from mandating that a contract’s rate be set at a specific price.
30. The Proposed Settlement resolves disputes that are outstanding at the Commission and establishes a California QF/CHP Program.

31. The cost allocation method set forth in Section 13.1.2.2. of the Term Sheet addresses concerns about the ability of ESPs and CCAs to procure CHP resources and reduces the administrative burden on the Commission.

32. The Proposed Settlement has numerous public interest benefits that include resolution of disputes, a QF/CHP Program that is aligned with Commission-approved procurement processes, continued operation of existing CHP facilities and the development of new CHP facilities, a framework for achieving CARB's current CHP goals for the reduction of GHG emissions, encouraging the retirement or repowering of inefficient CHP facilities, competitively determined CHP PPA energy prices, a transparent procurement process, and equitable allocation of costs associated with the QF/CHP program to all Commission-jurisdictional LSEs.

33. Pending action by the FERC and CARB and a determination that the Conditions Precedent to the Settlement Date have been met, it is premature to close the proceedings.

Conclusions of Law

1. In reviewing the Proposed Settlement, it would be inappropriate to apply the review standards for all-party settlements.

2. There is no connection between the evidentiary hearings held in R.06-02-013 in 2007 and the pending petition for modification that would warrant the strict application of Rule 12.1(a) to this proceeding.

3. Parties who did not join in the Proposed Settlement had adequate time to review and comment on it, and were not unreasonably burdened or prejudiced by the expedited comment schedule.
4. Because parties were given notice of the settlement and had the opportunity to be heard, the process followed in this proceeding for review of the Proposed Settlement meets due process requirements.

5. The Proposed Settlement is within the noticed scope of these consolidated proceedings.

6. Evidentiary hearings and/or workshops on the Proposed Settlement are not necessary for fair resolution of the issues.

7. With respect to implementation of state policy objectives for CHP and GHG emissions reductions, the Proposed Settlement is consistent with state and Commission policy and law.

8. Under Pub. Util. Code Section 365.1(c)(1), enacted as part of SB 695, ESPs should be subject to the same GHG emissions reduction requirements as the IOUs.

9. By approving the Proposed Settlement and directing the IOUs to meet the CHP procurement targets included on behalf of all retail customers in their service territories, the Commission would trigger Pub. Util. Code Section 365.1(c)(2), enacted as part of SB 695, which requires the Commission to allocate the net capacity costs and resource adequacy benefits to all customers, including ESP and CCA customers.

10. Since Pub. Util. Code Section 366.2(f)(2) requires the Commission to ensure that CCA customers reimburse the IOUs for their share of procurement costs attributable to the customer, CCA customers should be responsible for their share of the costs of the QF/CHP Program.

11. Both California statutory law and Commission precedent fully support the Commission’s jurisdiction to adopt the portions of the Proposed Settlement that are applicable to the ESPs and CCAs.
12. Because CHP resources count toward resource adequacy requirements and provide system and local reliability benefits commensurate with their Net Qualifying Capacity, a requirement for procurement of CHP by the IOUs is consistent with SB 695.

13. It is appropriate to provide an exception to the D.08-09-012 conditions to ensure recovery of the QF/CHP program costs that will be incurred over the entire term of the PPAs.

14. The cost allocation provisions of the Proposed Settlement, including provisions that allocate the costs of the QF/CHP Program among all LSEs, are fair, reasonable, and consistent with California law.

15. The Proposed Settlement’s methodology for allocating the GHG Emissions Reduction Targets reflects a fair allocation of these targets among all customers.

16. Requiring MDL customers to bear a share of the IOU costs incurred on their behalf is appropriate, and it is therefore appropriate to approve an exception to D.08-09-012 related to MDL.

17. The Proposed Settlement resolves Commission-jurisdictional issues and is subject to review by the Commission.

18. Taken as a whole, the Proposed Settlement balances the interests at stake and constitutes a reasonable and appropriate resolution of the many QF issues presently under consideration before the Commission and in other forums.

19. The Proposed Settlement promotes state policy for CHP and GHG and does not contravene any provision of law.

20. The Term Sheet attached to the Proposed Settlement is precedential.

21. The Proposed Settlement is reasonable in light of the whole record, consistent with the law, and in the public interest.
22. The Proposed Settlement and attached *pro forma* PPAs and amendments should be approved without modification.

23. The cost allocation method set forth in Section 13.1.2.2. of the Term Sheet should be adopted.

24. Upon the effective date of the QF/CHP Program, exceptions to D.06-07-029, D.08-09-012, and D.07-12-052 should be allowed to the extent set forth in the order.

25. Upon the effective date of the QF/CHP Program, Commission-jurisdictional LSEs should be subject to and be governed by the provisions of the program.

26. These proceedings should remain open pending action on a motion for closure to be filed by Joint Parties if and when the conditions precedent to the settlement effective date set forth in the Settlement Agreement have been met.

**ORDER**

**IT IS ORDERED** that:

1. The “Qualifying Facility and Combined Heat and Power Program Settlement Agreement,” filed on October 8, 2010, is approved and adopted without modification.

2. The *Pro Forma* Purchase Power Agreements set forth in Attachment A, Exhibits 1 through 7 of the October 8, 2010 “Qualifying Facility and Combined Heat and Power Program Settlement Agreement” are approved and adopted without modification.

3. If and when the conditions precedent to the Settlement Effective Date set forth in the October 8, 2010 “Qualifying Facility and Combined Heat and Power Program Settlement Agreement” (Settlement Agreement) are met and the
Qualifying Facility/Combined Heat and Power Program (QF/CHP Program) becomes effective, then exceptions to previous decisions are approved as follows:

(a) Exceptions to conditions in Decision (D.) 06-07-029 and D.08-09-012 will be permitted as set forth below:

(i) the relevant costs (either “above market costs” or “net capacity costs” as appropriate) of this QF/CHP Program can be recovered through Non-Bypassable Charges consistent with Section 13 of the Term Sheet attached to the Settlement Agreement; and

(ii) the same relevant costs of new Purchase Power Agreements entered into pursuant to the QF/CHP Program can be recovered through Non-Bypassable Charges for up to twelve (12) years consistent with Section 13 of the Term Sheet attached to the Settlement Agreement.

(b) The Procurement obligations in the Settlement Agreement and under the Renewables Portfolio Standard Program are permitted as exceptions to the Qualifying Facility Megawatts requirements set forth in D.07-12-052.

4. If and when the conditions precedent to the Settlement Effective Date set forth in the October 8, 2010 “Qualifying Facility and Combined Heat and Power Program Settlement Agreement” (Settlement Agreement) are met and the Qualifying Facility/Combined Heat and Power Program (QF/CHP Program) becomes effective, Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, electric service providers, and community choice aggregators are subject to and shall be governed by the provisions of the QF/CHP Program set forth in the Settlement Agreement.

5. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall procure combined heat and power resources on behalf of electric service providers (ESPs) and community choice aggregators (CCAs) and shall allocate the resource adequacy benefits and net
capacity costs associated with this procurement to the ESPs and CCAs as described in Section 13.1.2.2 of the Term Sheet attached to the October 8, 2010 “Qualifying Facility and Combined Heat and Power Settlement Agreement.”

6. Application 08-11-001, Rulemaking (R.) 06-02-013, R.04-04-003, R.04-04-025, and R.99-11-022 shall remain open pending action on a motion for closure to be filed by proponents, with the supporting documentation, of the October 8, 2010 “Qualifying Facility and Combined Heat and Power Program Settlement Agreement” (Settlement Agreement) if and when the conditions precedent to the settlement effective date set forth in the Settlement Agreement have been met. Subject to the discretion of the assigned Commissioner or Administrative Law Judge, the proceedings may be held in abeyance pending such motion and Commission action on such motion. The Settlement Agreement proponents shall file and serve, with copies also served on the Energy Division Director and the Chief Administrative Law Judge quarterly status reports, beginning three months from today’s order, and continuing until the motion for closure is filed, stating what actions have been completed and what actions remain to be completed before the conditions precedent have been met. The Commission decision that addresses the motion for closure will set the effective date of the Qualifying Facility/Combined Heat and Power Program set forth in the Settlement Agreement.
This order becomes effective today.


MICHAEL R. PEEVEY  
President  
DIAN M. GRUENEICH  
JOHN A. BOHN  
TIMOTHY ALAN SIMON  
NANCY E. RYAN  
Commissioners
APPENDIX A

LINKS TO JOINT MOTION AND ATTACHMENTS, INCLUDING SETTLEMENT AGREEMENT, TERM SHEET, AND EXHIBITS

Joint Motion For Approval Of Qualifying Facility And Combined Heat And Power Program Settlement Agreement:
http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/124871.PDF

Attachment A: Settlement Agreement:
http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/124873.pdf

Attachment A: Settlement Agreement Term Sheet:
http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/124875.PDF

Attachment A, Exhibit 1: Amendment to Legacy QF PPA for PG&E:
http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/124877.PDF

Attachment A, Exhibit 2: Amendment to Legacy QF PPA for SCE:
http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/124880.PDF

Attachment A, Exhibit 3: Amendment to Legacy QF PPA for SDG&E:
http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/124884.PDF

Attachment A, Exhibit 4: Transition PPA for existing Qualifying Cogeneration Facilities:
http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/124885.PDF

Attachment A, Exhibit 5: CHP Request For Offers Pro-Forma PPA for CHP Facilities Participating in Solicitation:
http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/124886.PDF

Attachment A, Exhibit 6: Qualifying Facility PPA for facilities 20 MW or less:
http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/124888.PDF
Attachment A, Exhibit 7: Optional CHP PPA for eligible As-Available Facilities:
http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/124889.PDF

Attachment A, Exhibit 8: Non-Disclosure Agreement for CHP Auditor:
http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/124890.PDF

Attachment A, Exhibit 9: List of Members of Cogeneration Association of California:
http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/124891.PDF

Attachment A, Exhibit 10: List of Members of California Cogeneration Council:
http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/124892.PDF

Attachment A, Exhibit 11: List of Members of Energy Producers and Users Coalition:
http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/124893.PDF

Attachment B: Letter Agreement Between the CAISO and IOUs:
http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/124894.PDF

(End of Appendix A)
1. Summary

We open this rulemaking to continue our efforts to reduce the number of residential gas and electric utility service disconnections due to nonpayment by improving customer notification and education. The economic crisis currently existing in California and a recent increase in utility service disconnections has led us to reexamine utility disconnection rules and practices. We want to identify more effective ways for the utilities to work with their customers and develop solutions that avoid unnecessary disconnections without placing an undue cost burden on other customers.

In this rulemaking, we require Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E), and Southern California Gas Company (SoCalGas) to implement the following interim practices no later than five business days from the mailing of this order:
1) All customer service representatives (CSRs) must inform any customer that owes an arrearage on a utility bill that puts the customer at risk for disconnection that the customer has right to arrange for a bill payment plan extending a minimum of three months in which to repay the arrearage. CSRs may exercise discretion as to extending the three months up to twelve months\(^1\) depending on the particulars of a customer’s situation and ability to repay the arrearage. CSRs may work with customers to develop a shorter repayment plan, as long as the customer is informed of the three-month option. Customers must keep current on their utility bills while repaying the arrearage balance.

2) Once a customer has established credit as a customer of that utility, the utility must not require that customer to pay additional reestablishment of credit deposits with the utility for either slow-payment/no-payment of bills or following a disconnection.

3) Each utility is authorized to file a Tier 1 advice letter to establish a memorandum account to track any significant additional costs associated with complying with the new practices initiated with this rulemaking, including the operations and maintenance charges associated with implementing the practices as well as any uncollectables that are in excess of those projected in the utility’s last general rate case. As part of this proceeding, the Commission will consider the process for determining the categories and amounts of costs in the memorandum account that should be considered reasonable for recovery, as well as the appropriate methods for recovery.

The utilities and parties will have an opportunity to comment on these interim practices and their efficacies, as well as sunset provisions if appropriate, while the parties continue to explore and dialogue about other solutions to assist customers to pay their utility bills and avoid disconnection of service. The

\(^1\) Each utility may implement a repayment plan schedule that exceeds twelve months, but we are not currently requiring any utility to extend the schedule beyond three months.
Commission recognizes that each utility has been implementing its own respective program on outreach and education to reduce the number of unnecessary disconnections; however, there has been no consistency or uniformity across all utilities. The Commission is initiating this Rulemaking to incorporate the productive and effective practices that each utility can share so that all gas and electric utilities have the benefit of implementing best practices in this area.

2. Background

On June 19, 2009, The Utility Reform Network (TURN) filed a Petition to initiate a rulemaking (Petition) to address arrearage management and shutoff prevention for residential customers. (Petition (P.) 09-06-022.) In response to TURN’s Petition, a proposed decision issued on September 25, 2009, which examined the existing low-income programs that are available to low-income customers, evaluated whether the utilities are performing outreach and education on the availability of the low-income programs, and considered whether any additional programs are necessary at this time. Upon initial examination, the proposed decision determined that existing programs and outreach were sufficient and that a rulemaking was not needed at this time.


Commissioners Peevey, Grueneich, Bohn and Simon participated in the en banc and listened to presentations from DRA, TURN, Greenling Institute and
the four major utilities. From the en banc discussion, the Commission learned that the disconnection rate was rapidly rising for low-income households. In addition, the utilities reported that a very high percentage of customers who are disconnected are reconnected within 48 hours.

Following the en banc, all four utilities agreed to a moratorium on service disconnections beginning December 21 and extending through January 5. The reasoning behind the moratorium was to enable customers and the utilities to have time to contact one another about arrearage repayment without fear of a disconnection during the holiday/winter period.

The Commission then held a workshop on January 5, 2010 to afford the utilities and other stakeholders an opportunity to discuss “best-practices” for customer outreach and education so that customers can address repayment of arrearages before they are disconnected. The emphasis by the Commission was on having the utilities work within their communities to get the word out that customers having difficulty paying their utility bill should immediately contact their electric or gas company to discuss how to best repay the arrearage, prevent disconnection, and see whether there are ways to decrease the monthly bill through assistance programs or energy efficiency efforts.

\[2\] SCE voluntarily extended their moratorium through January 21, 2010.
The Commission had envisioned that through the en banc and workshop efforts that the utilities could individually, or jointly, develop innovations to their current bill collection practices that would assure the Commission that bill arrearages and disconnections were being thoroughly addressed by the utilities resulting in fewer residential disconnections. However, the Commission now believes it is appropriate to open a rulemaking to gather input from the utilities and consumer groups on ways to decrease the number of household disconnections while at the same time not shifting the burden of non-paying customers to other ratepayers.

3. Implementation of New Practices

Following the en banc and workshop, the Commission has carefully considered the exchange of information between the utilities and the consumer advocates and has determined that there are some interim practices the Commission can implement immediately that are aimed at addressing the Commission’s primary focus: having the utilities work with their customers to address bill arrearages before disconnection. While we recognize that disconnections for non-payment of utility bills will never be completely obliterated, we find that the following procedures are intended to offer immediate help for customers to address bill arrearages and avoid disconnections. Therefore, we direct PG&E, SCE, SDG&E and SoCalGas to immediately implement the following practices no later than five business days after the mailing of this order:

1) All CSRs must inform any customer that owes an arrearage on a utility bill that puts them at risk for disconnection that the customer has a right to arrange a bill payment plan extending a minimum of
three months in which to repay the arrearage. CSRs may exercise discretion as to extending the three months up to twelve months\(^3\) depending on the particulars of a customer’s situation and ability to repay the arrearage. CSRs may work with customers to develop a shorter re-payment plan, as long as the customer is informed of the three-month option. Customers must keep current on their utility bills while repaying the arrearage balance.

2) Once a customer has established credit as a customer of that utility, the utility must not require that customer to pay additional reestablishment of credit deposits with the utility for either slow-payment/no-payment of bills or following a disconnection.

3) Each utility is authorized to file a Tier 1 advice letter to open a memorandum account to track any significant additional costs associated with complying with the new practices initiated with this rulemaking, including the operations and maintenance charges associated with implementing the practices as well as any uncollectables that are in excess of those projected in the utility’s last general rate case. As part of this proceeding, the Commission will consider the process for determining the categories and amounts of costs in the memorandum account that should be considered reasonable for recovery, as well as the appropriate methods for recovery.

We recognize two important principles: (1) utility service is a matter of health and safety and we do not have the luxury of time to flush out fully best practices in a long proceeding before we take any action to address the current disconnection rate; and (2) we do not have a complete record to fully and finally determine if the above practices are sufficient to help the Commission meet its goal of reducing disconnections whenever some other method of bill payment

\(^3\) Each utility may implement a repayment plan schedule that exceeds twelve months, but we are not currently requiring any utility to extend the schedule beyond three months.
can be arranged. Therefore, we direct the utilities and the consumer groups to continue their dialogue and efforts to determine what are the best practices, and to assess whether the interim practices we are establishing today are ones that will ultimately further our goals.

To ensure that the Commission and parties can fully evaluate the efficacy of these interim practices, and to assist the Commission in determining whether to maintain, expand, or modify these practices, and whether or if to sunset them, we will require the utilities to submit monthly reports of specific disconnection-related data including the number of disconnections experienced by each utility. Appendix A contains the additional data to be submitted on a monthly basis by each respondent investor-owned utility.

In addition, it has come to our attention through reports on utility-sponsored focus groups that an anomaly occurs in the billing/accounting departments of the utilities when a customer owes both for an arrearage and a current bill. For illustration purposes, assume a customer owes an arrearage of $150, is on a 3-month re-payment plan whereby the customer pays $50 towards the arrearage, and the customer has a current monthly bill of $100. If the customer makes a payment of $150, representing the $50 arrearage payment and the $100 current bill payment, how does the utility ensure that the proper monies are credited to the appropriate accounts? If all $150 is applied to the arrearage, the customer is delinquent on the current bill, whereas if all $150 is applied to the current bill the customer has a credit, but is in default on the arrearage re-payment arrangement. We request that the utilities propose a uniform billing/accounting methodology that ensures that the customer receives proper credit for monies paid.
4. Preliminary Scoping Memo

As required by Rule 7.1(d) of our Rules of Practice and Procedure (Rules), this order includes a preliminary scoping memo as set forth below. Unless a further Scoping Memo is deemed appropriate by the assigned Administrative Law Judge (ALJ) or the assigned Commissioner, the Preliminary Scope will be addressed in the first decision in this proceeding. As previously stated, the focus of this proceeding is to reduce the number of gas and electric utility service disconnections due to nonpayment by improving customer notification and education, including ways to help customers avoid disconnections while working with the utilities to pay arrearages and keep current on bills.

In addition to the practices we are implementing with the issuance of this Rulemaking, we also ask parties to consider the following issues as part of the scope of the proceeding and inform the Commission of your comments on whether to adopt any of the following practices:

- Best practices for contacting customers who are delinquent in their bill payments, including methods such as bill inserts, special colored-bills, individualized messages on a bill, separate mailings, dropped-off notices, telephone calls [including whether live-voice or recorded messages], e-mails, text-messaging, third-party notification, etc.;
- Language options and how a utility would know what language would be appropriate for a particular household;
- Outreach and education about customer assistance programs, energy efficiency programs, bill management options, balanced payment plans, etc.;
- How customers are “targeted” for outreach and education information, and whether the customer should be required to initiate the first contact;
• Whether CSRs should have “scripts” or be left to their own discretion in how they communicate with each individual customer;
• How should the utilities tailor their automated call and written notices concerning disconnection so that customers who use telephone relay services and sight-impaired customers are receiving the notices;
• Should a utility charge a customer for a remote connection or disconnection;
• Whether the reporting requirements included in this rulemaking are sufficient or should they be eliminated or expanded;
• Whether the Commission should set a benchmark for the number of disconnections experienced and what such a benchmark should be;
• If the utilities are not to collect post-service initiation deposits, are there other ways for the utilities to reduce future revenue losses from uncollectibles, such as financial institution guarantees;
• How does a utility distinguish between a payment extension and a payment installment plan and how is the difference communicated to the customer;
• If a customer requests a monthly billing date that is different from the date assigned by the utility, does the utility accommodate this request, and if so, how is the customer notified;
• How can the utilities strive to maintain the direct communication and personal contact that customers associate with in-person disconnection visits, when the utilities return to remote disconnections;
• How can all utilities incorporate best practices, such as those employed by SDG&E and SoCalGas, to work with community-based-organizations (CBO) and faith-based organizations to educated customers on the California Alternate Rates for Energy (CARE) and other assistance programs; and
• Should the utilities utilize more data-sharing programs along the lines used by SDG&E to partner with school districts and use the program data as a screen to enroll additional families in the CARE program, while protecting privacy issues.

5. Emergency Fund

Our regulated energy utilities have a unique opportunity to leverage available funds under the federal government’s American Recovery and Reinvestment Act (ARRA) to provide critical payment assistance to eligible low-income customers. Under ARRA, funds were appropriated for the Temporary Assistance to Needy Families (TANF) Emergency Contingency Fund (Emergency Fund) over fiscal years 2009 and 2010. This Emergency Fund is in addition to the regular TANF Contingency Fund that needy families in California can access through established agencies during the economic downturn. Through this provision of ARRA, every one dollar of local contributions will be matched with four dollars from the Emergency Fund. Through this one time program that will expire on September 30, 2010, eligible low-income customers who have experienced an uncontrollable or unforeseen hardship may receive an energy credit on their utility bill.

To take advantage of this unique and fleeting opportunity, we direct respondent investor-owned utilities (IOUs) to file Tier 3 advice letters within 30 days of the effective date of this order outlining their proposed program to take advantage of the Emergency Fund. We envision that respondent IOUs will continue to use their shareholder and employee funded charitable contribution for this purpose, but may also present a proposal to transfer some funds collected in the CARE balancing account for this effort to leverage as much available ARRA funds as possible. We also expect that IOUs will keep administrative costs to a minimum in order to provide the greatest benefit to
needy utility customers. And any unspent ratepayer amounts would be returned to the CARE balancing account.

This is not to be read as preapproval of the concept to transfer CARE dollars for this effort, but the Commission would like to consider this idea on an expedited basis in the advice letter process, so as to take full advantage of the limited time to access federal funding and to leverage as much money as possible to help needy families in California.

This advice letter filing should be utilized by all natural gas and electric utilities under the jurisdiction of this Commission, and not just by the respondents to this Rulemaking. The Commission’s Executive Director will serve this OIR on all jurisdictional gas and electric utilities.

6. Schedule

We ask parties to comment on the three new practices we are adopting today, to suggest other practices that we should adopt, and to address the issues in Section 4. Opening comments are due March 12, 2010, and reply comments are due April 2, 2010. It is the Commission’s intent to have a proposed decision on the Commission’s agenda by June 2010. If parties suggest additional workshops, parties should so state in their comments, specifying what topics should be covered in the workshop. Parties are also encouraged to meet on their own and present additional proposals within the scope of this proceeding, including a joint proposal agreed to by all utilities and consumer groups.

Consistent with Pub. Util. Code § 1701.5, we expect this proceeding to be concluded within 18 months of the issuance of the Scoping Memo, or if a Scoping Memo is incorporated into the final decision, within 18 months of the issuance of this rulemaking.
7. Category of Proceeding and Need for Hearing

Rule 7.1(d) provides that an order instituting rulemaking shall preliminarily determine the category of the proceeding and the need for hearing. Our preliminary determination is that this proceeding is quasi-legislative, as that term is defined in Rule 1.3(d). It is anticipated that the record for this proceeding will be developed through comments and reply comments, and no prehearing conference or evidentiary hearings will be necessary. However, the assigned ALJ or Commissioner may amend this determination.

Any person who objects to the preliminary categorization of this rulemaking as “quasi-legislative” or to the preliminary hearing determination shall state their objections in their opening comments described above. After considering the opening comments, the assigned Commissioner will issue a scoping ruling or decision making the final category determination.

8. Respondents

The respondents to this rulemaking are PG&E, SCE, SDG&E, and SoCalGas.

9. Becoming a Party; Joining and Using the Service List

We will provide for service of this order on the service list for P.09-06-022. Such service does not confer party status in this proceeding upon any person or entity, and does not result in that person or entity being placed on the service list for this proceeding. If you want to participate in the rulemaking or simply to monitor it, follow the procedures set forth below. To ensure you receive all documents, send your request within 30 days after the OIR is published. The Commission’s Process Office will publish the official service list at the Commission’s website (www.cpuc.ca.gov), and will update the list as necessary.
9.1. **During the First 30 days**

Within 30 days of the publication of this rulemaking, any person may ask to be added to the official service list. Send your request to the Process Office. You may use e-mail (Process_Office@cpuc.ca.gov) or letter (Process Office, California Public Utilities Commission, 505 Van Ness Avenue, San Francisco, CA 94102). Include the following information:

- Docket Number of this Rulemaking;
- Name (and party represented, if applicable);
- Postal Address;
- Telephone Number;
- E-mail Address; and
- Desired Status (Party, State Service, or Information Only).

If the Rulemaking names you as respondent, you are already a party, but you or your representative must still ask to be added to the official service list.

9.2. **After the First 30 Days**

If you want to become a party after the first 30 days, you may do so by filing and serving timely comments in the Rulemaking (Rule 1.4(a)(2)), or by making an oral motion (Rule 1.4(a)(3)), or by filing a motion (Rule 1.4(a)(4)). If you make an oral motion or file a motion, you must also comply with Rule 1.4(b). These rules are in the Commission’s Rules of Practice and Procedure, which you can read at the Commission’s website. If you want to be added to the official

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4 If you want to file comments or otherwise actively participate, choose “Party” status. If you do not want to actively participate but want to follow events and filings as they occur, choose “State Service” status if you are an employee of the State of California; otherwise, choose “Information Only” status.
service list as a non-party (that is, as State Service or Information Only), follow the instructions in Section 9.1 above.

9.3. **Updating Information**

Once you are on the official service list, you must ensure that the information you have provided is up-to-date. To change your postal address, telephone number, e-mail address, or the name of your representative, send the change to the Process Office by letter or e-mail, and send a copy to everyone on the official service list.

9.4. **Serving and Filing Documents**

When you serve a document, use the official service list published at the Commission’s website as of the date of service. You must comply with Rules 1.9 and 1.10 when you serve a document to be filed with the Commission’s Docket Office. If you use e-mail service, you must serve by e-mail any person (whether Party, State Service, or Information Only) on the official service list who has provided an e-mail address.

The Commission encourages electronic filing and e-mail service in this Rulemaking. You may find information about electronic filing at [http://www.cpuc.ca.gov/PUC/efiling](http://www.cpuc.ca.gov/PUC/efiling). E-mail service is governed by Rule 1.10. If you use e-mail service, you must also provide a paper copy to the assigned Commissioner and ALJ. The electronic copy should be in Microsoft Word or Excel formats to the extent possible. The paper copy should be double-sided. E-mail service of documents must occur no later than 5 p.m. on the date that service is scheduled to occur.

If you have questions about the Commission’s filing and service procedures, contact the Docket Office.
10. **Public Advisor**

   Any person or entity interested in participating in this Rulemaking who is unfamiliar with the Commission’s procedures should contact the Commission’s Public Advisor in San Francisco at (415) 703-2074 or (866) 849-8390 or e-mail public.advisor@cpuc.ca.gov; or in Los Angeles at (213) 576-7055 or (866) 849-8391, or e-mail public.advisor.la@cpuc.ca.gov. The TTY number is (866) 836-7825.

11. **Intervenor Compensation**

   Any party that expects to claim intervenor compensation for its participation in this rulemaking shall file its notice of intent to claim intervenor compensation no later than 30 days after the date of the issuance of this Rulemaking.

12. **Ex Parte Communications**

   Communications with decisionmakers and advisors in this rulemaking are governed by Article 8 of the Rules of Practice and Procedure. Specifically, Rule 8 (a) allows ex parte communications without restriction or reporting requirement in “quasi-legislative” proceedings.

   **IT IS ORDERED** that:

   1. In accordance with Rule 6.1 of the Commission’s Rules of Practice and Procedure (Rules), the Commission institutes this Order Instituting Rulemaking on its own motion to continue our efforts to reduce the number of gas and electric utility service disconnections due to nonpayment by improving customer notification and education.

Respondents to this proceeding and are parties to this proceeding pursuant to Rule 1.4(d) of the Commission’s Rules of Practice and Procedure.

3. No later than five business days after the mailing of this order, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, and Southern California Gas Company must implement the following interim practices:

(a) All customer service representatives (CSRs) must inform any customer that owes an arrearage on a utility bill that puts them at risk for disconnection that the customer has a right to arrange for a bill payment plan extending a minimum of three months in which to repay the arrearage. CSRs may exercise discretion as to extending the three months up to twelve months depending on the particulars of a customer’s situation and ability to repay the arrearage. CSRs may work with customers to develop a shorter repayment plan, as long as the customer is informed of the three-month option. Customers must keep current on their utility bills while repaying the arrearage balance.

(b) Once a customer has established credit as a customer of that utility, the utility must not require that customer to pay additional reestablishment of credit deposits with the utility for either slow-payment/no-payment of bills or following a disconnection.

(c) Each utility is authorized to file a Tier 1 advice letter to establish a memorandum account to track any significant costs associated with complying with the new practices initiated with this proceeding, including any operations and maintenance charges associated with implementation of the practices as well as any uncollectables that are in excess of those projected in the

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5 Each utility may implement a repayment plan schedule that exceeds twelve months, but we are not currently requiring any utility to extend the schedule beyond twelve months.
utility’s last general rate case. As part of this proceeding, the Commission will consider the process for determining the categories and amounts of costs in the memorandum account that should be considered reasonable for recovery, as well as the appropriate methods for recovery.

4. The Executive Director will cause this Order Instituting Rulemaking to be served on Respondents Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, and Southern California Gas Company, and the service list of Petition 09-06-022. The Executive Director will also cause this Order Instituting Rulemaking to be served on all jurisdictional gas and electric utilities to notify them of the advice letter filing for emergency funds.

5. This Rulemaking is preliminarily determined to be a quasi-legislative proceeding as that term is defined in Rule 1.3 of the Commission’s Rules of Practice and Procedure.

6. This proceeding is preliminarily determined not to need a hearing.

7. The expected timetable for this proceeding is as set forth in the body of this order. Opening comments are due March 12, 2010, and reply comments are due April 2, 2010.

8. Pursuant to Rule 6.2 of the Commission’s Rules of Practice and Procedure, parties shall include in their Opening Comments any objections they may have regarding the category, need for hearing, issues to be considered, or schedule.

9. Interested persons must follow the directions in this Order Instituting Rulemaking to become a party or to be placed on the official service list as a non-party.
10. The Commission’s Process Office will publish the official service list on the Commission’s website (www.cpuc.ca.gov) as soon as practicable. Parties may also obtain the service list by contacting the Process Office at (415) 703-2021.

11. Any party that expects to claim intervenor compensation for its participation in this Order Instituting Rulemaking shall file its notice of intent to claim intervenor compensation no later than 30 days from the date of the issuance of this Rulemaking.

12. Respondents Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, and Southern California Gas Company are directed to file monthly reports in this proceeding of specific disconnection data including the number of disconnections experienced by each of respondents. Appendix A contains the additional data to be submitted in each monthly report by each respondent. The first monthly report shall be filed on the same day that the Opening Comments are due, and further reports filed each month thereafter.

13. Respondents Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, and Southern California Gas Company are directed to file Tier 3 advice letters within 30 days of the effective date of this order outlining their proposed program to take advantage of the Emergency Fund.

14. The assigned Commissioner or assigned Administrative Law Judge has the authority to change the due dates in this order.

This order is effective today.

Dated February 4, 2010, at San Francisco, California.
MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
TIMOTHY ALAN SIMON
NANCY E. RYAN
Commissioners
Appendix A

Data to be reported by each Investor Owned Utility on a monthly basis. Each monthly report should include prior months data.

### BILLING ASSISTANCE / PAYMENT ARRANGEMENTS

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<tr>
<th>Month</th>
<th>Number of CARE customers requesting bill payment assistance</th>
<th>Number of FERA customers requesting bill payment assistance</th>
<th>Number of non-CARE/FERA customers requesting bill payment assistance</th>
<th>Total number of customers requesting bill payment assistance</th>
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<th>Month</th>
<th>Number of CARE customers receiving payment extension of 30 days or less</th>
<th>Number of FERA customers receiving payment extension of 30 days or less</th>
<th>Number of non-CARE/FERA customers receiving payment extension of 30 days or less</th>
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### LATE OR BROKEN PAYMENT ARRANGEMENTS

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<th>Month</th>
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<th>Number of non-CARE/FERA customers with late or broken 12-month payment arrangement</th>
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## ARREARAGES

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<th>Number of CARE customers 30 days in arrears</th>
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## TERMINATION

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<th>Month</th>
<th>Number of CARE customers experiencing service disconnection</th>
<th>Number of FERA customers experiencing service disconnection</th>
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(END OF APPENDIX A)
Emerging Issues in Energy Regulation
Energy Bar Association
Tenth Annual Western Chapter Meeting
San Francisco, 2011
Ted Boyer, Chair, Utah Public Service Commission

General Observations
Aging infrastructure/work force
New build cycle
Transition to cleaner energy
Upward pressure on rates
Uncertainty about federal regulation
Lack of a national energy policy
Differing state ideologies
Financing new technologies
Consumer education

Generation
Coal tradition in the west
Carbon concerns
Expiring contracts
Long-term alternatives
Bridging alternatives

Energy Efficiency and Demand-side Management
Cost benefit analysis
Load control
Reliability
Energy independence
Price volatility

Transmission
Inter-jurisdictional issues
State vs. federal jurisdiction
NIMBY issues
Who pays?
Load forecasting
System balancing
Natural Gas
Supply
Extraction techniques
Transportation
Increased use for electrical generation
Storage
Contract terms
Use as transportation fuel
Energy independence
Relative cleanliness
Safety

Renewables
State of technology
Economics
Backing up intermittent resources
Integration
Transmission

Storage
State of technology
Cost

Grid Management
Management
Security
Cyber security
Smart grid
Cost/benefit

Plug-in Electric Vehicles
Grid issues
Cost
Infrastructure
Role of Regulators

Policy makers vs. administrators
Decisions with long-term consequences
Cost recovery on new technologies
Rating agencies
Traditional rate of return regulation
BIOGRAPHIES
Susan K. Ackerman
Bio

Susan Ackerman was appointed to the Oregon Public Utility Commission as Oregon’s third commissioner by Gov. Ted Kulongoski in March 2010. She is currently serving on the Electricity Committee of the National Association of Regulatory Commissioners and was appointed by former NARUC Chair David Coen to represent NARUC on the Smart Grid Working Group, a group of seven state commissioners that coordinates state commission discussions with the federal government regarding smart grid.

Prior to joining the OPUC, Ms. Ackerman had a 25 year career as a practicing energy lawyer and manager representing various clients on electricity and natural gas state, federal and Canadian regulatory matters. She has a JD from Lewis & Clark Law School in Portland, Oregon and a BA from Augustana College in Sioux Falls, South Dakota. She has been admitted to the Oregon, Washington and California State Bar Associations, although she is happily non-active in all three.
Ted Boyer was appointed to his first term as a commissioner of the Public Service Commission on June 20, 2003. He was re-appointed as Commission Chairman on March 27, 2009. His term expires March 1, 2015.

Commissioner Boyer is a member of the National Association of Regulatory Utility Commissioners (NARUC) and serves on the Energy, Resources and Environment Committee and the International Committee, as well as a past president of the Western Conference of Public Service Commissioners (WCPSC), a member of the Regional Oversight Committee (ROC), a member of Telecommunications Advisory Council and serves on the Steering Committee of the Western Renewable Energy Zones Project of the Western Governor's Association. He also serves on the Advisory Council for the Center For Public Utilities at New Mexico State University and on the Public Interest Advisory Committee of the Gas Technology Institute.

Prior to his appointment, Commissioner Boyer served on the Cabinet of Governor Leavitt as Executive Director of the Utah Department of Commerce and before that as Director of the Utah Real Estate Division. After receiving his BS and MS degrees from Brigham Young University and teaching at Murray State University, he earned his Juris Doctorate from the University of Utah and practiced law in Salt Lake City for over 20 years.
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Practice Areas/Industries
- Environment, Land Use & Natural Resources
  - Environmental Litigation
  - Occupational Health & Safety
- Aviation, Aerospace & Transportation
- Energy
- Litigation
  - Litigation - Corporate Investigations & White Collar Defense
- Whistleblower Prevention & Defense Team
- Disaster Planning & Liability Management

Multidisciplinary Teams
- Crisis Management

Mr. Farley is a partner in Houston, where he heads the office's Environment, Land Use & Natural Resources section. He advises clients on a wide range of environmental, health, and safety (EHS) issues, but focuses on internal investigations and crisis response. Mr. Farley routinely advises companies in connection with major industrial accidents, whistleblowers, process safety incidents and workplace fatalities. His representations have included lead attorney roles in the most significant refinery accidents in the United States in the last 20 years.

Mr. Farley has helped clients respond to investigations by the Federal Bureau of Investigation, the U.S. Environmental Protection Agency, the National Transportation Safety Board, the Chemical Safety Board, the Occupational Safety and Health Administration, and state regulatory agencies. Mr. Farley was one of the lead partners supporting the work of the BP U.S. Refineries Independent Safety Review Panel, which investigated corporate safety culture and oversight at BP's North American refineries on behalf of an independent panel of experts chaired by former U.S. Secretary of State James A. Baker III.

Mr. Farley works extensively in advising companies on EHS culture and the management of process safety. In the aftermath of the Deepwater Horizon incident, he has advised energy companies with upstream operations on emerging regulatory requirements and systems for overseeing EHS performance.

Mr. Farley also coordinates Pillsbury's Health and Safety Working Group for in-house attorneys and safety professionals who work on health and safety, process safety, and risk management matters. Over 20 companies from the energy, chemical and other process industries presently participate. The Working Group's quarterly meetings are a forum for
organizations to stay abreast of safety issues and best practices. Pillsbury attorneys make presentations on emerging issues and discuss how companies may want to address issues of concern. Pillsbury also tracks important regulatory developments and provides members with regular e-mail updates. This real-time dissemination of information regarding health and safety regulatory and enforcement matters assists members in anticipating emerging issues.

Mr. Farley has also worked as in-house environmental counsel for a chemical manufacturer and for a major transportation company serving as its legal representative on crisis response teams.

Recent Matters

- Energy company - representation in investigation by the Chemical Safety Board and Washington State Department of Labor and Industries into refinery accident that resulted in seven fatalities

- BP U.S. Refineries Independent Safety Review Panel—representation as one of the lead lawyers conducting a special investigation into corporate safety culture and corporate safety oversight at BP’s five North American refineries on behalf of an independent panel of experts chaired by former U.S. Secretary of State James A. Baker III.

- Chemical manufacturer—representation in an investigation by the Chemical Safety Board into a release of toxic chemicals that necessitated a community evacuation in Pennsylvania.

- Chemical manufacturer—representation to evaluate the effectiveness of company’s systems for ESH corporate oversight

- Energy company—special investigation into safety performance and culture at refinery in response to whistle blower complaint to CEO after a fatality

- Energy company—representation in connection with inspections and subsequent enforcement by the Occupational Safety and Health Administration under the Petroleum Refinery Process Safety National Emphasis Program.

- Energy company—defense in a Clean Water Act and Clean Air Act federal criminal enforcement case in Oklahoma.

- Environmental manager—defense of an individual in a federal grand jury investigation into the use of ozone-depleting substances.

- Barge fleeting and shifting company—defense in a Clean Water Act federal criminal enforcement case initiated by the Texas Environmental Enforcement Task Force.
Pipeline company—defense in a federal criminal enforcement case involving the unpermitted disposal of hazardous waste in Pennsylvania.

Energy company—defense in a state criminal prosecution under the Texas Water Code.

Oil field services company—representation in an investigation by a federal grand jury and the Bureau of Alcohol, Tobacco and Firearms regarding the management of nonconforming munitions.

Sports arena operator—representation in an investigation by OSHA into a workplace fatality.

Chemical manufacturer—defense in an administrative action filed by the U.S. Environmental Protection Agency alleging violations of the requirements for burning hazardous waste in boilers.

Marine transportation company—defense in multiple environmental whistleblower complaints filed with the U.S. Department of Labor, Office of Administrative Law Judges.

Major passenger air carrier—hazardous waste compliance advice for airport maintenance facilities throughout the United States.

Oil field services company—representation in connection with DOJ and SEC investigation into alleged violations of the FCPA

Energy company—representation in a criminal investigation into alleged violations of SEC regulations regarding oil and gas reserves accounting

Education

J.D., University of Pittsburgh School of Law, 1992, cum laude

M.P.H., University of Pittsburgh, 1992, cum laude

B.A., English, Washington and Lee University, 1988, cum laude

B.S., Biology, Washington and Lee University, 1988, cum laude

Admissions

State of Texas

Commonwealth of Pennsylvania
Courts

United States District Courts for the Southern District of Texas and the Western District of Pennsylvania

Speeches and Presentations


"OSHA's Chemical NEP—Safeguarding the Company's Legal Rights," 2010 AIChE Spring Meeting, March 2010


"It's Coming Right for Us! What to Expect and How to Prepare for the Chemical NEP," 6th Global Congress on Process Safety, March 2010

"OSHA's Chemical NEP - The Legal Perspective," Texas Chemical Council's 2009 NEP Seminar

"U.S. Chemical Safety Board—Responding to CSB Preliminary Assessments," Texas Chemical Council's 2009 Environmental, Health and Safety Seminar

"Crisis Management—What Companies and Their Counsel Must Know to Effectively Manage Major Accidents," Federal Bar Association, April 2009

"Emerging Issues in Investments Abroad, Foreign Joint Ventures and M&A," 2009 State Bar of Texas International Law Section 21st Annual Institute, March 2009


"The Importance of Evaluating EHS Culture," Texas Chemical Council's 2008 Environmental, Health and Safety Seminar


"Investigating Safety Culture," ORC Western Occupational Safety and Health Group, Scottsdale, June 2007

Panelist, "Managing the Legal Fallout From a Major Accident," International Association of Defense Counsel, Houston, May 2007


"Legal Privileges in Environmental Matters," Texas Wetlands Conference, Austin, February 2007

External Publications


Bylined Article—Avoiding Incidents, Exploration + Processing, 7/1/2009

Firm Publications

Client Alert—Record-breaking BP Safety Settlement Alters Regulatory Landscape, 8/13/2010

Client Alert—MMS Revamps Regulation of Off-Shore Operations, 5/11/2010

Client Alert—CSB Cautions on Hazards Associated with Commissioning of Natural Gas Power Plants, 2/25/2010

BART Board Approves Contracts for $492M Oakland Airport Connector Project, 12/14/2009
MICHEL PETER (“MIKE”) FLORIO

Michel Peter “Mike” Florio was appointed to the California Public Utilities Commission on January 27, 2011 by Governor Jerry Brown. Prior to this appointment, he served for over 30 years as the Senior Attorney for The Utility Reform Network (TURN), the leading utility consumer advocate group in California. In this position he was responsible for coordinating the development of TURN's policy positions on energy-related issues and advocating those positions before various governmental agencies. He has testified as an expert witness on a wide variety of issues including ratemaking policy, utility revenue requirements, natural gas procurement policy, cost allocation and rate design.

Commissioner Florio also served on the stakeholder governing boards of both the California Independent System Operator (CAISO) and the California Power Exchange as a residential end-user representative from their creation in May of 1997 until January of 2001. In January of 2001 he was appointed by Governor Gray Davis to serve on the CAISO's new five-member independent governing board, and was reappointed in January of 2002 and confirmed by the State Senate for a full three-year term, which expired in early 2005.

Commissioner Florio received a B.A. in political science and sociology from Bowling Green State University (Ohio) in 1974. From 1974 through 1978 he participated in a joint degree program sponsored by New York University School of Law and the Woodrow Wilson School of Public and International Affairs at Princeton University. In 1978 he received a J.D. from New York University and a Masters of Public Affairs (M.P.A.) from Princeton. He was admitted to the California State Bar that same year.

Commissioner Florio is a known workaholic, whose foibles have been cheerfully tolerated by his immediate family, which includes:
Spouse of over 20 years, Ellen M. Barry – former winner of the MacArthur “genius” award and founder and executive director (for over twenty years) of Legal Services for Prisoners with Children, a San Francisco non-profit organization. Ms. Barry is currently an independent consultant working on women and justice issues. She is also a 1978 graduate of New York University School of Law.

Daughter, age 18, Angela Barry-Florio, a 2010 graduate of Skyline High School in Oakland and currently a freshman at Ithaca College in Ithaca, New York, majoring in creative writing and minoring in psychology.

Son, age 16, Antonio “Tony” Barry-Florio, currently a sophomore at Bishop O’Dowd High School in Oakland. Tony, who has been able to beat his father at Monopoly since before he learned to read, was the starting defensive tackle on the undefeated O’Dowd junior varsity football team last fall and also competes on the rugby squad.
Gary L. Halbert assumed his responsibilities as General Counsel to the National Transportation Safety Board in February 2006. As General Counsel, Mr. Halbert serves as the senior legal advisor to the Chairman of the Safety Board and oversees the provision of legal services to the agency. The Office of General Counsel provides legal support for accident investigations, procurement and leasing activity, ethics and standards of conduct, fiscal law matters, and the agency's human resources function, and oversees the Board’s review on appeal of enforcement proceedings undertaken by aviation and marine regulatory agencies.

Mr. Halbert joined the Safety Board after retiring in the grade of colonel from the United States Air Force, where his diverse assignments included service as a military instructor pilot in jet aircraft and as a judge advocate. His legal assignments embraced both civil and criminal law, including installation claims officer, hospital attorney, and criminal prosecution roles. He was the senior legal officer at two installations, and supervised 14 legal offices with 180 attorneys and staff for an overseas command responsible for 21 installations in 7 European countries. At Air Force Headquarters in the Pentagon, he oversaw the Air Force judge advocate human resources division for an attorney workforce of over 1,300, and served as the executive officer to the Judge Advocate General. He also led the Air Force’s strategic and crisis communications office.

Mr. Halbert has accumulated approximately 1,500 flight hours in sailplanes, general aviation aircraft, and military jet aircraft. He is admitted to practice law before the U.S. Supreme Court, the U.S. Court of Appeals for the Armed Forces, and the courts of the State of Texas and the District of Columbia.

Mr. Halbert earned his bachelor's degree in economics as a Distinguished Graduate from the United States Air Force Academy, his masters of science degree in national security strategy as a Distinguished Graduate from the National Defense University in Washington, D.C., and graduated With Honors and Order of the Coif recognition from the University of Texas School of Law.
David Leo Huard
Partner
Chair: Energy, Environment & Natural Resources
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Los Angeles: 310.312.4247
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PROFESSIONAL EXPERIENCE

Mr. Huard is 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.


Past 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.

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.
Elliot Mainzer is the Executive Vice President for Corporate Strategy at the Bonneville Power Administration. In this capacity, Elliot has responsibility for crafting agency strategy on critical regional and national issues including climate change, renewable resource integration, regional transmission planning and market design. Elliot has held a variety of positions within BPA. Most recently, he served as the Manager of Transmission Policy and Strategy where he led the development of BPA’s Network Open Season and FERC Order 890 tariff filing. In 2006-2007 he led the development of the Northwest Wind Integration Action Plan in cooperation with utilities, developers and policymakers throughout the Pacific Northwest. He also served as Trading Floor Manager and Manager of Pricing and Transaction Analysis in the Agency’s Power business line. Prior to joining BPA, Elliot established and managed Enron’s Renewable Power Desk out of its Portland, Oregon office. He has an MBA and Master of Environmental Studies degrees from Yale University. Elliot is an active speaker on renewables integration and market design issues at conferences across the country, member of the Western Electric Industry Leaders Group, and a former member of the Board of the Utility Wind Integration Group.
Chairman Jon Wellinghoff

Jon Wellinghoff was named Chairman of the Federal Energy Regulatory Commission (FERC), the agency that oversees wholesale electric transactions and interstate electric transmission and gas transportation in the United States, by President Barack Obama on March 19, 2009. A member of the Commission since 2006, the U.S. Senate reconfirmed him to a full, five-year FERC term in December 2007.

Chairman Wellinghoff is an energy law specialist with more than 34 years experience in the field. Before joining FERC, he was in private practice focusing exclusively on client matters related to renewable energy, energy efficiency and distributed generation. While in the private sector, Chairman Wellinghoff represented an array of clients from federal agencies, renewable developers, and large consumers of power to energy efficient product manufacturers and clean energy advocacy organizations.

Chairman Wellinghoff was the primary author of the Nevada Renewable Portfolio Standard (RPS) Act. The Nevada RPS is one of the two states to receive an “A” rating by the Union of Concerned Scientists. In addition, he worked with clients to develop renewable portfolio standards in six other states. The Chairman is considered an expert on the state renewable portfolio process and has lectured extensively on the subject in numerous forums including the Vermont Law School.

His experience also includes two terms as the State of Nevada’s first Consumer Advocate for Customers of Public Utilities. While serving in that role, Chairman Wellinghoff represented Nevada’s utility consumers before the Public Utilities Commission of Nevada, the FERC, and in appeals before the Nevada Supreme Court. While Consumer Advocate, he authored the first comprehensive state utility integrated planning statute. That statute has become a model for utility integrated planning processes across the country.

Chairman Wellinghoff’s priorities at FERC include opening wholesale electric markets to renewable resources, providing a platform for participation of demand response and other distributed resources in wholesale electric markets including energy efficiency and local

Current Term:
Sworn In: May 19, 2008
Term Expires: June 30, 2013

First Term:
Sworn In: July 31, 2006
Term Expires: June 30, 2008

Staff:
James Pederson, Chief of Staff
Mae Davis, Confidential Assistant
Mary Beth Tighe, Senior Technical and Policy Advisor
Michael Henry, Legal and Policy Advisor
Christina Hayes, Legal and Policy Advisor
Janeen Said, Communication Specialist
Tina Jernigan, Secretary

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Chairman Jon Wellinghoff BIO

storage systems such as those in plug-in hybrid and all electric vehicles (PHEVs and EVs), and promoting greater efficiency in our nation’s energy infrastructure through the institution of advanced technologies and system integration. As Chairman he created FERC’s Office of Energy Policy and Innovation (OEPI), which is responsible for investigating and promoting new efficient technologies and practices in the energy sectors under FERC’s jurisdiction. Chairman Wellinghoff is co-chair of the Smart Response Collaborative launched jointly by FERC and the National Association of Regulatory Utility Commissioners (NARUC) and is a member of NARUC’s Committee on Energy Resources and the Environment. He is a member of the Advisory Committee of the Institute for Electric Efficiency and served as an advisor to the Defense Science Board’s Energy Policy Task Force. He is also the Co-Chair of the Executive Leadership Team of the Electric Power Research Institute’s (EPRI) Green Transmission Efficiency Initiative. Chairman Wellinghoff also advises the Energy Foundation and the NRDC on China-U.S. energy policy matters. He was designated by the Obama Administration to be a Principal in the Joint U.S./China Strategic and Economic Dialog and recently returned from China where he participated in diplomatic discussions with China’s energy leaders including China’s Energy Minister, Zhang Guobao.

Education: