Exceptions, Shortcomings, and Work-Arounds for the Traditional Approach

Electric Utility Ratemaking Education and Engagement Workshop

Regulatory Assistance Project
www.raponline.org
Outline

- 90 minute session
- Exceptions to the Traditional Ratemaking Approach
- Shortcomings of the Traditional Ratemaking Approach
- Performance-Based Regulation
- Other Work-Arounds to Mitigate the Shortcomings
Exceptions to the Traditional Ratemaking Approach
Ratemaking and Regulation Don’t Always Adhere to the “Traditional Approach”

• Municipal utilities and electric cooperatives
• Utilities served by competitive wholesale electricity markets
• “Full/all requirements” customers of generation and transmission (G&T) utilities
• Bilateral rates and special contracts
• Retail choice
Shortcomings of the Traditional Ratemaking Approach
Shortcomings of Traditional Cost of Service/Rate of Return Regulation and Rate Design

• Cost Allocation is Not an Exact Science
• Capital Bias ("Averch-Johnson Effect")
• Performance-Based Regulation
• Throughput Incentive
• Regulatory Lag
• Regulatory Capture
Cost Allocation Is Not An Exact Science
“Allocation of costs is not a matter for the slide rule. It involves judgment of a myriad of facts. It has no claim to an exact science.”

Justice William O. Douglas
U.S. Supreme Court
Embedded Cost Methods

- Peak Responsibility
  - Fixed Costs Classified as Demand or Customer
  - Variation: Average and Excess Demand
    - Takes account of seasonal variations
- Peak and Average Demand
  - Classifies some costs to energy
- Energy-Weighted
  - Classifies most costs to energy
Baseload Generation

Expensive to build
Cheap to operate
Lower fuel costs

**Issue:** Classify part of capital cost as though it is avoided fuel cost.
Transmission

Purpose may be to move power, cheaper than moving fuel.

Issue: Classify a portion of the investment as energy (avoided fuel)?
Distribution

Built to deliver energy. Designed to carry peak demand. Connects to every customer.

**WHY** was the system built in the first place?
Meters

**Historical:** used only for billing

**Smart Meters:** Used for conservation program design, peak load management, reliability services, and billing
# Engineering vs. Economic Approaches

<table>
<thead>
<tr>
<th>Cost Category</th>
<th>Engineering Approach</th>
<th>Economic Approach</th>
</tr>
</thead>
<tbody>
<tr>
<td>Baseload Power Plants</td>
<td>Demand</td>
<td>~75% Energy</td>
</tr>
<tr>
<td>Other Power Plants</td>
<td>Demand</td>
<td>~50% Energy</td>
</tr>
<tr>
<td>Demand Response</td>
<td>Demand</td>
<td>Demand</td>
</tr>
<tr>
<td>Fuel / Purch. Power</td>
<td>Energy</td>
<td>Energy</td>
</tr>
<tr>
<td>Transmission</td>
<td>Demand</td>
<td>Mostly Energy</td>
</tr>
<tr>
<td>Substations</td>
<td>Demand</td>
<td>Demand</td>
</tr>
<tr>
<td>Poles, Wires, Xfmrs</td>
<td>Demand/Customer</td>
<td>Demand/Energy</td>
</tr>
<tr>
<td>Meters</td>
<td>Customer</td>
<td>Demand / Energy /</td>
</tr>
<tr>
<td>Billing and Collection</td>
<td>Customer</td>
<td>Customer</td>
</tr>
</tbody>
</table>
Comparison of Results of Two Studies: Engineering vs. Economic

![Comparison Graph]
Marginal Cost Approaches

- **Long-Run** Marginal Costs
  - All costs are variable
  - Full cost of system reproduction

- **Short-Run** Marginal Costs
  - Existing Capital Facilities
  - Fuel and variable labor costs only

- **Intermediate** Time Frames

- **Mixed** Time Frames
Results of Marginal Cost Studies

- $/kW for demand for peaking resources
- $/kWh for energy, time-varying
- $/customer for customer-specific facilities

- Typically does not match the utility revenue requirement
- Reconciliation required
Controversy in Marginal Cost Analysis

- Mixed time horizons
  - Short-run cost for energy (dispatch)
  - Long-run cost for peaking capacity and distribution investments
- Reconciliation to Revenue Requirement
Bottom Line on Cost Allocation

• Many methods;
• “How” system is built vs. “Why” system is built results in very different conclusions.
• Multiple studies often considered.
• There is no “right” way to compute this.
Capital Bias
Averch-Johnson effect

The tendency to over-invest capital to increase profit

- Results from revenue requirement calculation
- Bias for utility-owned infrastructure
Utility Revenue Requirement: “The Capital Bias”

Revenue Requirement (aka Cost-of-Service) = Capital Investments (Cap-ex) + Operating Expenses (Op-ex)

“Rate Base” x Rate-of-Return (Interest on Shareholders’ “Loan”) = Pass-Through, No Rate-of-Return

$1 x 10% = $1.10

$1 = $1
Utility Revenue Requirement: Discourages Distributed Energy Resources

- Revenue Requirement (aka Cost-of-Service)
- Capital Investments (Cap-ex)
- Operating Expenses (Op-ex)

Both reduce kWh sales => raises rates

Distributed Generation = less need for cap-ex = lower earnings

Energy Efficiency = more op-ex & less need for cap-ex

Regulatory Assistance Project (RAP)®
Throughput incentive

Increased sales lead to increased utility profit

- True when load is served with existing facilities, thus costs are fixed
- Creates incentive to resist measures that reduce sales
How Changes in Sales Affect Earnings: It’s Significant

<table>
<thead>
<tr>
<th>% Change in Sales</th>
<th>Revenue Change</th>
<th>Impact on Earnings</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Pre-tax</td>
<td>After-tax</td>
</tr>
<tr>
<td>5.00%</td>
<td>$9,047,538</td>
<td>$5,880,900</td>
</tr>
<tr>
<td>4.00%</td>
<td>$7,238,031</td>
<td>$4,704,720</td>
</tr>
<tr>
<td>3.00%</td>
<td>$5,428,523</td>
<td>$3,528,540</td>
</tr>
<tr>
<td>2.00%</td>
<td>$3,619,015</td>
<td>$2,352,360</td>
</tr>
<tr>
<td>1.00%</td>
<td>$1,809,508</td>
<td>$1,176,180</td>
</tr>
<tr>
<td>0.00%</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>-1.00%</td>
<td>-$1,809,508</td>
<td>-$1,176,180</td>
</tr>
<tr>
<td>-2.00%</td>
<td>-$3,619,015</td>
<td>-$2,352,360</td>
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<tr>
<td>-3.00%</td>
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</tr>
<tr>
<td>-5.00%</td>
<td>-$9,047,538</td>
<td>-$5,880,900</td>
</tr>
</tbody>
</table>
Is Something Wrong with the Throughput Incentive?

- There are many reasons why utility sales might go up or down, but what should the utility motivation be?
- Public interest appears to be in conflict with throughput incentive
  - Energy Efficiency (EE), Distributed Generation (DG), other policies reduce sales
- Utility rate designs recover embedded investment and labor costs in the kWh charge
3 Performance-Based Regulation
“All regulation is incentive regulation”

Incentives of traditional regulation
• Build rate base in a rate case
• Exaggerate costs for a future test year
• Increase volume of sales between rate cases, i.e., the “throughput” incentive
• Cost reduction between rate cases

1989 Resolution of the National Association of Regulatory Utility Commissioners (NARUC):

“A utility’s least cost plan should be it’s most profitable plan.”
Performance-Based Regulation (PBR) is...

- A regulatory framework to connect achievement of specified policy objectives to utility financial performance and executive compensation.

- A PBR scheme is a collection of performance incentive mechanisms (PIMs), namely, metrics and formulas that determine the levels of financial rewards or penalties (i.e., adjustments to allowed revenues) for achievement of the specified objectives.
Successful PBR components

1. Clear Goals
2. Measurable Metrics
3. Transparency
4. Value to the Public
5. Align Benefits and Rewards
6. Annual Review: Learn from Experience
7. Compared to What?
8. Simple Designs are Good
9. Evaluation and Verification
10. Public Review
11. Award of rewards or penalties
What could possibly go wrong?

- Disproportionate rewards or penalties
- Unintended consequences
- Regulatory burden
- Poorly designed metrics
- Gaming and manipulation
Practices that can lead to difficulty

- Basing performance incentives on inputs ($$ spent)
- Rewards or penalties based on exogenous factors ex: weather, economic growth, etc.
- Unclear or uncertain metrics or goals
- Lack of clarity and measurement methodology
- Not understanding utility motivations
Energy Efficiency Funding
U.S. State of Washington, 1980

• 2% increased return on equity for energy efficiency investments
• incentive to spend as much as possible on measures that save as little as necessary
• maximizing the incentive while minimizing the lost revenue to the utility.
• This is an example of focusing on inputs (amount spent), poor operational incentives and metrics.
Carte Blanche for Cost Cutting
Pacific Northwest Bell, 1986

5-year rate freeze, no restrictions on the cost-cutting methods

Result:

• Cut customer service
• 1-900 number for customer service
• Incentive to keep customers on hold

Photo by Quino Al on Unsplash
Energy Efficiency Incentive Structure, 1990

Puget Sound Power and Light, Washington

- Incentive structure:
  - Part 1: based on how much energy efficiency was achieved,
  - Part 2: how cheaply it was achieved.

- Utility short of the targets in 9 out of 10 topical areas, but received huge incentive
Examples of Successful PBR
California PBR for nuclear plant capacity factor

Diablo Canyon nuclear plant costs were high

- Rate base of cost overruns rejected
- Performance metric based on plant availability
- Diablo Canyon enjoyed a very high availability rate and operated with a very high capacity factor for much of its service life.
ConEd’s Brooklyn-Queens Demand Management Project
Brooklyn-Queens Demand Management Project
Case 14-E-0302

- Change course from traditional response to reliability challenge
  - **Build $1.2B substation**
  - or
  - **Reduce sustained load for years**
- Innovation needed
  - Utility side response: find 52 MW locally
  - Regulatory response: 10 year amortization of expenses
    - Remove bias between opex and capex
- Incentive—shared savings:
  - Utility—cost recovery of DER assets, Return on Equity adder
  - Customers -- avoided costly distribution charges
One Idea:
Get Rid of Rate Base as a Determinant of Earnings
## Investment Earnings

<table>
<thead>
<tr>
<th>Rate Base</th>
<th>$1,000,000,000</th>
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<tbody>
<tr>
<td>X Rate of Return</td>
<td>10%</td>
</tr>
<tr>
<td>= Return</td>
<td>$100,000,000</td>
</tr>
<tr>
<td>+ Operating Expenses</td>
<td>$100,000,000</td>
</tr>
<tr>
<td>= Revenue Requirement</td>
<td>$200,000,000</td>
</tr>
<tr>
<td>/ Expected Sales</td>
<td>2,000,000,000</td>
</tr>
<tr>
<td>= Average Rate</td>
<td>$0.10</td>
</tr>
</tbody>
</table>
Build Big Stuff
More Earnings
Build Really Big Stuff
Really Big Earnings

Vogtle Nuclear Plant
Cheaper = Less Profitable
Customer Builds: No Earnings
We can fix this.
Step 1: Debt Return On Rate Base
Step 2: Make them **EARN** the shareholder return.
Score them on multiple measures

REPORT CARDS

Math  A+
English  A+
Science  B+
History  A-
Attendance  A
Service Reliability and Quality
Customer Service
Keeping customer bills low

Dropping electrical bills
Typical monthly bill for residential customers using 650kWh/month.

(In 2012 dollars)

*Weighted average of NSTAR companies (Boston Edison, Commonwealth Electric and Cambridge Electric and Light Company)

SOURCE: Massachusetts Department of Public Utilities

James Abundis GLOBE STAFF
Emissions Performance
Energy Efficiency Performance
Renewable performance
If they get Straight A’s, they make a lot of money.
If they flunk, they pay their bondholders...and that’s it.
Step 3: Allowed Revenue

<table>
<thead>
<tr>
<th>Metric</th>
<th>Grade</th>
<th>Shareholder Return</th>
</tr>
</thead>
<tbody>
<tr>
<td>Customer Service</td>
<td>C</td>
<td>$8,000,000</td>
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<tr>
<td>Reliability</td>
<td>A</td>
<td>$16,000,000</td>
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<tr>
<td>Emissions</td>
<td>B</td>
<td>$12,000,000</td>
</tr>
<tr>
<td>Energy Efficiency</td>
<td>B</td>
<td>$12,000,000</td>
</tr>
<tr>
<td>Renewable Energy</td>
<td>C</td>
<td>$8,000,000</td>
</tr>
<tr>
<td>Low Bills</td>
<td>D</td>
<td>$4,000,000</td>
</tr>
<tr>
<td>Total Allowed Revenue</td>
<td></td>
<td>$200,000,000</td>
</tr>
</tbody>
</table>

- Debt Return: $40,000,000
- Operating Expenses: $100,000,000
- Estimated kWh Sales: 2,000,000,000
- Rate per kWh: $0.10
### Step 4: True Up For Sales

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Allowed Revenue</td>
<td>$ 200,000,000</td>
</tr>
<tr>
<td>Estimated Sales</td>
<td>2,000,000,000</td>
</tr>
<tr>
<td>Established Rate</td>
<td>$ 0.1000</td>
</tr>
<tr>
<td>Actual Sales</td>
<td>1,950,000,000</td>
</tr>
<tr>
<td>Required Rate</td>
<td>$ 0.1026</td>
</tr>
<tr>
<td>True-Up Adjustment</td>
<td>+ $.0026</td>
</tr>
</tbody>
</table>
### Step 5: Put the Parties on Commission

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Requested Increase:</td>
<td>$100,000,000</td>
</tr>
<tr>
<td>Allowed Increase:</td>
<td>$40,000,000</td>
</tr>
<tr>
<td>Denied Increase:</td>
<td>$60,000,000</td>
</tr>
<tr>
<td>Intervenor's Commission:</td>
<td>7%</td>
</tr>
<tr>
<td>Intervenor's Commission:</td>
<td>$4,200,000</td>
</tr>
</tbody>
</table>
Where the profit comes from...
Regulatory Lag
Regulatory Lag

• Upward
  • Utility concern that higher costs wait until after a rate case. Earned return < allowed return

• Downward
  • Consumer concern that long period between rate cases evades depreciation and productivity impacts
Regulatory Capture
Regulatory Capture

• Elected Commissions
  • Only the utilities have a large vested interest in the outcome.
    • Arizona: Contribution limits

• Appointed Commissions
  • Utilities have undue influence over Governor
    • Consumers need to focus effort
4 Other Work-Arounds to Mitigate the Shortcomings
Other Work-Arounds to Mitigate the Shortcomings: Ratemaking Outside of Rate Cases

- Tariff Riders
  - Fuel Cost Adjustments
  - Energy Efficiency Programs
  - Infrastructure Cost Recovery
- Decoupling
- Net Energy Metering and Other Special Tariffs/Rate Designs for DERs
Tariff Riders
Tariff Riders: Adjustments to Rates Between Rate Cases

- Fuel and purchased power
- Infrastructure
- Energy Efficiency
- Decoupling
- City Fees
- State Tax
Not Everything Moves With Sales

Things Go Up

Labor cost
Infrastructure investment
for non-revenue plant

Things Go Down

Rate Base for Power Plants
Rate Base for Transmission

Some things vary more randomly, or with weather:

Fuel Costs
Purchased Power Cost
Sales for Resale
The Challenge: Balance
Fuel and Purchased Power

- Utility Owned Resources
  - Investment and Labor in Base Rates
  - Fuel in Adjustment Clause
- Purchased Power
  - Investment, labor, and fuel in Adjustment Clause
- Result: Shifting to Power Purchase Agreement (i.e., solar or wind) may result in over-recovery of costs.
Infrastructure Cost Recovery
Infrastructure Issues

- Older transmission & distribution (T&D) assets wear out
- New ones cost more
- No new revenue to go with the new cost

- Issue: US Depreciation Rules only allow recovery of original investment.
- Old Transformer: $1,000  New Transformer: $3000
What’s Wrong With Infrastructure Recovery Mechanisms?

• Things that rise in price flow through to rates immediately.

• Things that decline in price do not.

• “Single Issue Ratemaking”
Energy Efficiency (EE) Programs
Third Party Administration of EE Programs

- Delegating energy efficiency to a non-utility third-party provider puts programs in the hands of an entity without a lost-margin bias.

- Positives
  - Throughput incentive is irrelevant
  - Performance has been very good
  - Higher level of oversight is common

- Negatives
  - Lower level of coordination with T&D planning
  - Utility still faces lost margins and rate case pressure

- Examples: Efficiency Vermont; Energy Trust of Oregon
Decoupling
What Does Decoupling Do?

- Breaks link between sales and revenue collected by the utility
- Adjusts rates (prices) and usually revenues between rate cases
- Relies on found revenue requirement
- When sales deviate from rate case assumption, rate is adjusted to collect calculated revenue
  - Basis can reflect changes owing to trends or forecasted events, an added level of complexity
Comparing Decoupling with Traditional Regulation

- Traditional regulation sets *prices* and lets *revenues* rise and fall with sales volumes.
- Most distribution costs vary little in the short run with respect to sales.
- If *prices* are set to recover distribution costs by volume, then lower/higher sales means lower/higher *revenues* (and profits).
- Decoupling resets *revenues* to recover target non-power costs by adjusting the *price*.
A Well-Designed Decoupling Mechanism Provides Predictable Revenue Independent of Sales

Traditional Regulation: Constant Price = Fluctuating Revenues/Bills

Decoupling: Precise Revenue Recovery = Fluctuating Prices

Revenues = Price * Sales

Price = Target Revenue ÷ Sales
Simple Calculations: Traditional Regulation and Decoupling

Rate Case calculations are the same:

1. Rate Base x Rate of Return = Return
2. Return + Operating Expenses + Taxes = Revenue Requirement

Between rate cases they differ:

Traditional:
• Revenue Requirement / Sales (kWh) = Rates

Decoupling:
• Revenue Requirement = Revenues Allowed
• Rates = Revenues Allowed / Actual Sales (kWh)
Design Goal for Decoupling

- Over time, utility *revenues* track what frequent rate cases would have produced
  - Note emphasis on revenues
  - Because over the term of the decoupling mechanism, non-power costs do not change that much
- Works best if decoupling becomes the norm
Forms of Decoupling

• Revenue Per Customer
  • Commission allows a defined revenue per customer (by class) in rate case
  • As customer count grows, revenues grow

• Attrition
  • Commission allows defined revenue level in rate case
  • Each year, it reviews attrition factors, and adjusts the rate case allowance.
What Form is Best?

Revenue Per Customer or Attrition Decoupling?

What Type of Utility is It?
- Vertically Integrated
- Distribution Only

What Costs are Being Included in the Decoupling Mechanism?
- Distribution and Power Supply Costs
- Distribution Costs Only

What Type of Decoupling Mechanism Should Be Considered?
- Attrition Decoupling
- Attrition or Revenue Per Customer Decoupling
Decoupling Downsides

• **Rates** change more frequently (generally by less than power costs) and outside of a general rate case

• Great success with EE and DG will increase **rates**, even as total costs may ↓↓↓
  • Note that EE participants tend to save far more than **rates** tend to rise

• Public Utility Commission (PUC), others unfamiliar with decoupling

• Delays rate cases, which can be illuminating
Net Metering
Net-Metering: An Infant Industry Subsidy?

- Railroads
- Airlines
- Semiconductors
Concern with Economic Justice

- Most solar customers are single-family homeowners.
- Income is above that of many customers.
- “Subsidy” arguably flows from poor to rich.
- Community solar programs are one response.
- Dedicate excess generation to low-income assistance?
Compare to Other Subsidies

• Single-Family vs. Multi-Family
• Overhead vs. Underground
• Urban vs. Suburban vs. Rural
• New vs. Old
How Big Is The Impact If:  
5% of Customers Install Solar over 5 Years?

• Assume:
  • Distribution is 40% of the bill
  • No Distribution Cost Savings
  • Average Power Supply Cost = Marginal Power Supply Cost

• Then:
  • Impact on other consumers is 2%
Customer Credits for Monthly Net Excess Generation (NEG) Under Net Metering
www.dsireusa.org / July 2016

NOTE: The map shows NEG credits under statewide policies for investor-owned utilities (IOUs); other utilities may offer different NEG credit amounts. IOUs in HI, NV, MS, and GA have other policies for compensating self-generators. Some IOUs in TX and ID offer net metering, but there is no statewide policy. IOUs in WI differ in their treatment of NEG.
System Cost Impacts
Half of System Peak in Maui

Table 3. HECO Companies’ Net Energy Metering Program Capacity and Enrollment

<table>
<thead>
<tr>
<th>Capacity (MW)</th>
<th>HECO</th>
<th>HELCO</th>
<th>MECO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installed or Approved</td>
<td>327.9</td>
<td>73.3</td>
<td>88.8</td>
</tr>
<tr>
<td>In the Queue</td>
<td>17.3</td>
<td>5.1</td>
<td>11.9</td>
</tr>
<tr>
<td>Total</td>
<td>345.2</td>
<td>78.4</td>
<td>100.7</td>
</tr>
</tbody>
</table>

| Total NEM Customers           | 51,680     | 11,549     | 12,893     |
| System Peak Load (MW)         | 1,165      | 188        | 191        |
| NEM % of All Customers        | 17%        | 14%        | 18%        |
| NEM % of System Peak          | 30%        | 42%        | 53%        |
Circuits and Substations “Running Backward”
Peak Load Benefits May Reach A Limit

2006 Peak: 1,200 MW at 1 PM
2014 Peak: 1,050 MW at 7 PM

2006: 500 MW ramp 6 AM to 1 PM
2014: 250 MW ramp 6 AM to 1 PM

Figure 1-7. O'ahu System Load Profiles, 2006–2014

Source: Hawaiian Electric Co
System Cost Impacts

Low levels of saturation: 0% - 5%

Moderate levels of saturation 5% - 10%
• Voltage Regulation

High levels of saturation  Over 10% of Customers
• Generation and Transmission Impacts
Other Approaches to DER Compensation
NEM is Not the Only Method

- Value of Solar Tariff (VOST)
- Power Cost Only
  - Long-run marginal cost
  - Short-run avoided fuel and purchased power
- High Fixed Charges
- Demand Charges
Two Views of Cost Recovery

**Traditional Utility View**
DG customer “uses” the grid and should pay for it;

**Solar Advocate View**
Value of distributed resource is greater than the than retail rate;
2014 Survey Of Multiple VOS Studies: Average: $0.1672/kWh

Source: Rocky Mountain Institute
Value of Solar Studies: Utility Economic Values Only

<table>
<thead>
<tr>
<th>Location</th>
<th>Rate per-kWh</th>
<th>Value of Solar Studies: Utility Economic Values Only</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maine Short-Run</td>
<td>$0.090</td>
<td></td>
</tr>
<tr>
<td>Maine Long-Run</td>
<td>$0.138</td>
<td></td>
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<tr>
<td>Minnesota</td>
<td>$0.135</td>
<td></td>
</tr>
<tr>
<td>Austin</td>
<td>$0.107</td>
<td></td>
</tr>
<tr>
<td>Average per-kWh Rate</td>
<td>$0.115</td>
<td></td>
</tr>
</tbody>
</table>
High-Cost vs. Low-Cost Utilities

- Seattle: $0.05
- Austin: $0.10
- Kansas City: $0.10
- Detroit: $0.15
- San Diego: $0.20

Legend:
- Res Rate
- VOS Low
- VOS High
Mississippi VOS Study
At Least Two Quantifiable Benefits Usually Missing

- Solar Shading Effect
- Price Effects
Solar Shading
Price as a Function of Load
DRIPE: Demand-Response Induced Price Effects
Use of DRIPE

*: Integrated DRIPE
R: renewable only
?: DRIPE under consideration
G: justified generation
% restructured shown for MI, NH
DRIPE as a % of Avoided Energy Costs

![Chart showing DRIPE as a % of Avoided Energy Costs over different years levelized over 5, 10, 15, and 20 years. The chart compares high and low scenarios.](image)
Power Cost Only: Pedernales Electric Cooperative

- Fixed Charge: $22.50/month
- Transmission Charge: $.01256/kWh
- Delivery Charge: $.02712/kWh
- Energy Charge: $.0605/kWh

Customer avoids $.10 for power used on-site, and receives $.06 for power fed to grid.
Straight Fixed/Variable Rate: Franklin Public Utility District

Fixed Charge: $34.00

Energy Charge: $0.0673/kWh
A Hostile Approach to Solar: Salt River Project (Arizona)

<table>
<thead>
<tr>
<th>Fixed Charge</th>
<th>0 - 200 Amp</th>
<th>&gt;200 Amp</th>
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<tbody>
<tr>
<td></td>
<td>$32.44</td>
<td>$45.44</td>
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</table>

<table>
<thead>
<tr>
<th>Demand Charges</th>
<th>First 3 kW</th>
<th>Next 7 kW</th>
<th>Over 10 kW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Summer</td>
<td>$8.03</td>
<td>$14.63</td>
<td>$27.77</td>
</tr>
<tr>
<td>July/August</td>
<td>$9.59</td>
<td>$17.82</td>
<td>$34.19</td>
</tr>
<tr>
<td>Winter</td>
<td>$3.55</td>
<td>$5.68</td>
<td>$9.74</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Energy Charges</th>
<th>On-Peak</th>
<th>Off-Peak</th>
</tr>
</thead>
<tbody>
<tr>
<td>Summer</td>
<td>$0.0475</td>
<td>$0.0360</td>
</tr>
<tr>
<td>July/August</td>
<td>$0.0622</td>
<td>$0.0412</td>
</tr>
<tr>
<td>Winter</td>
<td>$0.0430</td>
<td>$0.0390</td>
</tr>
</tbody>
</table>
Is Solar Power More Valuable?
A Home-Grown Tomato is a “Better” Tomato
Lots of People Grow Their Own Tomatoes
What if you don’t have enough?
What If You Have Too Many?
All Tomatoes Are Not Equal

Local Organic Tomatoes: $3.00/lb.
California Tomatoes: $2.00/lb.

We Buy Local Organic Tomatoes: $2.00/lb.
About RAP

The Regulatory Assistance Project (RAP)® is an independent, non-partisan, non-governmental organization dedicated to accelerating the transition to a clean, reliable, and efficient energy future.

Learn more about our work at raponline.org

Contact us at:
jlazar@raponline.org
jshenot@raponline.org
jshipley@raponline.org
Unique Issues for Consumer-Owned Utilities
Public Power and Cooperatives
Types of COUs

- Municipals
  - Own Some or All Generation
  - Buy from IOUs
  - Buy from TVA
- Cooperatives
Municipals

• Controlled by elected City Council
  • Many issues (police, fire, parks, etc)
  • Limited policy staff and expertise
  • Dependent on Utility Staff
  • Generally have relatively good public process
• Those buying from TVA have an odd rate process
Cooperatives

- Non-Profit private utilities
  - Not subject to public meetings, public records
  - “Lawless entities”
- National Rural Electric Cooperative Association (NRECA) has rate manual
  - Guidance is contrary to advocate interests
- Buy power from G&Ts, also unregulated
- Probably unaware they are subject to PURPA
Points of Leverage

- Elections
- Delivering public to hearings
- Formal intervention under PURPA
- Other?
Generation and Transmission Entities
# Expansive Study: Colorado

<table>
<thead>
<tr>
<th>Benefits to PSCo Ratepayers</th>
<th>Fully Valued</th>
<th>Undervalued</th>
<th>Not Included</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Energy</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Avoided energy (including fuel)</td>
<td>✔</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Avoided T&amp;D line losses</td>
<td>✔</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Capacity</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Avoided generation capacity</td>
<td></td>
<td>✔</td>
<td></td>
</tr>
<tr>
<td>Avoided T&amp;D capacity and fixed O&amp;M</td>
<td></td>
<td>✔</td>
<td></td>
</tr>
<tr>
<td><strong>Grid support services</strong></td>
<td></td>
<td>✔</td>
<td></td>
</tr>
<tr>
<td><strong>Financial</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fuel Hedging</td>
<td>✔</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Avoided RPS or renewables costs</td>
<td>✔</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Grid security and resiliency</strong></td>
<td></td>
<td>✔</td>
<td></td>
</tr>
<tr>
<td><strong>Environmental</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Air pollutants (NO₅, SO₂, PM, &amp; CO₂)</td>
<td></td>
<td>✔</td>
<td></td>
</tr>
<tr>
<td>Reduced water usage in power production</td>
<td></td>
<td>✔</td>
<td></td>
</tr>
<tr>
<td>Avoided land costs for generation or T&amp;D</td>
<td></td>
<td>✔</td>
<td></td>
</tr>
<tr>
<td><strong>Societal benefits (not direct ratepayer benefits)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Job creation benefits</td>
<td></td>
<td>✔</td>
<td></td>
</tr>
<tr>
<td>Economic development, including local taxes</td>
<td></td>
<td>✔</td>
<td></td>
</tr>
<tr>
<td>Avoided health impacts</td>
<td></td>
<td>✔</td>
<td></td>
</tr>
</tbody>
</table>
### Expansive Study: Colorado

<table>
<thead>
<tr>
<th>Benefit / (Cost)</th>
<th>Low Gas</th>
<th>Base Gas</th>
<th>High Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$/MWh</td>
<td>%</td>
<td>$/MWh</td>
</tr>
<tr>
<td>Avoided Energy Costs</td>
<td>35.80</td>
<td>24%</td>
<td>52.10</td>
</tr>
<tr>
<td>Fuel Hedge Value</td>
<td>6.60</td>
<td>4%</td>
<td>6.60</td>
</tr>
<tr>
<td>Avoided Emissions</td>
<td>27.40</td>
<td>18%</td>
<td>27.40</td>
</tr>
<tr>
<td>Avoided Generation Capacity</td>
<td>50.60</td>
<td>34%</td>
<td>50.60</td>
</tr>
<tr>
<td>Avoided Distribution</td>
<td>6.00</td>
<td>4%</td>
<td>6.00</td>
</tr>
<tr>
<td>Avoided Transmission</td>
<td>18.00</td>
<td>12%</td>
<td>18.00</td>
</tr>
<tr>
<td>Avoided Line Losses</td>
<td>4.70</td>
<td>3%</td>
<td>6.20</td>
</tr>
<tr>
<td>(Solar Integration Costs)</td>
<td>(0.50)</td>
<td></td>
<td>(1.80)</td>
</tr>
<tr>
<td>Subtotal</td>
<td>148.60</td>
<td>100%</td>
<td>165.10</td>
</tr>
<tr>
<td>10% Adder for Societal Benefits</td>
<td>14.90</td>
<td></td>
<td>16.50</td>
</tr>
<tr>
<td>Total Net Benefits / (Costs)</td>
<td>163.50</td>
<td></td>
<td>181.60</td>
</tr>
</tbody>
</table>
Minnesota Value of Solar Analysis

- Wide range of costs
- Full consideration of utility system direct benefits.
- No consideration of non-utility system benefits.
Bi-lateral Market Rates for Large Customers
Special Contracts: The Theory

- Very large customers have special needs
- They are capable of supplying their own power
  - Utilities often assert “keeping them on the system” benefits all ratepayers.
- Sometimes there are extensive grid investments needed, so a long-term contract is important.
Special Contracts: Reality

- Often used in locational negotiations
- Often a ruse to avoid sharing system costs
- Long term contracts erased by bankruptcy
- Violates several premises of regulation
  - Discriminatory: Munn vs. Illinois
  - Fair Return: Bluefield and Hope