About RAP – U.S.

• RAP provides technical and policy support at the federal, state and regional levels, advising utility and air regulators and their staffs, legislators, governors, other officials, and national organizations.

• We help states achieve ambitious energy efficiency and renewable energy targets and we provide tailored analysis and recommendations on topics such as ratemaking, smart grid, decoupling and clean energy resources. RAP publishes papers on emerging regulatory issues and we conduct state-by-state research that tracks policy implementation.
Key Takeaways

- PBR has the potential to better align utility, ratepayer, and public interests than traditional cost of service regulation.
- PBR succeeds where it is clear, transparent at each step, and aligns rewards and incentives for utilities and customers.
- SB 5295 prescribes some details for the implementation of PBR to keep in mind while developing the overall framework to achieve your goals.
- Start with a clear articulation of goals/considerations against which the resulting PBR framework can be tested and adjusted.
Agenda

• Context – SB 5295
• Review of Traditional COS Regulation
• Basics of Performance Based Regulation
  • Multi-Year Rate Plans
  • Performance Metrics and Mechanisms
  • PBR Frameworks
• Examples
SB 5295 – Transforming the regulation of gas and electrical companies toward multiyear rate plans and performance-based rate making

• Requires multi-year rate plans (MYRPs) as of 1/1/22 for gas and electric utilities

• Requires determination of performance measures to be used to assess a utility operating under a MYRP

• Initial year fair value determination of property that is used and useful as of the rate effective date

• All revenues in excess of 0.5% higher than the authorized rate of return to be deferred for customer refunds or another determination by the commission.
## SB 5295 – Factors for Consideration

“Factors” to be considered in development of policy statement and performance measures, incentives, and penalty mechanisms

<table>
<thead>
<tr>
<th>Factor</th>
<th>Measure</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lowest reasonable cost planning</td>
<td>Affordability</td>
</tr>
<tr>
<td>Increases in energy burden</td>
<td>Cost of service</td>
</tr>
<tr>
<td>Customer satisfaction and engagement</td>
<td>Service reliability</td>
</tr>
<tr>
<td>Clean energy or Renewable procurement</td>
<td>Conservation acquisition</td>
</tr>
<tr>
<td>Demand side management expansion</td>
<td>Rate stability</td>
</tr>
<tr>
<td>Timely execution of competitive procurement</td>
<td>Attainment of state energy and emissions reduction policies</td>
</tr>
<tr>
<td>Rapid integration of renewable energy resources</td>
<td>Fair compensation of utility employees</td>
</tr>
</tbody>
</table>
1 Brief Review of Traditional Cost-of-Service Regulation
Major Steps in a Rate Case

1. Determine revenue requirement based on historic cost basis with modifications
2. Allocate costs among defined customer classes
3. Design retail rates for each customer class to recover their allocated portion of the revenue requirement

- Focused on inputs vs. outputs or outcomes
- Sets prices, not revenues
Simplified rate-making process

1. **Determine revenue requirement**
   - Net rate base
     - (Plant in service – depreciation reserve)
   - Rate of return
   - Depreciation expense
     - (Plant in service x depreciation rate)
   - Operating expense
     - (Fuel + purchased power + labor + labor overheads + supplies + services + income taxes)
   - Other taxes
2. **Allocate costs among customer classes**
   - Residential
     - Dollars per month
     - Cents per kWh peak
     - Cents per kWh off-peak
   - Commercial
     - Dollars per month
     - Cents per kWh peak
     - Cents per kWh off-peak
   - Industrial
     - Dollars per month
     - Cents per kWh peak
     - Cents per kWh off-peak
     - Dollars per kW monthly
   - Street lighting
     - Dollars per light per month
3. **Design retail rates**
   - Dollars per month
   - Cents per kWh peak
   - Cents per kWh off-peak
   - Dollars per month
   - Cents per kWh peak
   - Cents per kWh off-peak
   - Dollars per kW monthly
   - Dollars per light per month
Utilities File Rate Cases When They Aren’t Recovering their Costs of Service through Current Rates

- Actual costs of service > assumed
  - Higher than expected operating costs
  - Need for large capital expenditures
- Billing determinants < assumed
  - i.e., # customers, kW, kWh
2 Drivers for Change
Power Sector Transformation

“All regulation is incentive regulation”
– Peter Bradford

“Incentives” of traditional regulation

- Build and own assets to grow rate base
- Increase volume of sales and electricity usage to enhance profits
- Focus on inputs, not outputs
- Avoid disallowances/excessive conservatism
- Institutional inertia
3 Performance-Based Regulation
Performance-Based Regulation (PBR) is...

- A regulatory framework that connects achievement of specified objectives to utility financial performance

- A PBR framework can include a collection of revenue adjustment mechanisms (i.e. decoupling) and performance incentive mechanisms (PIMs), namely, metrics and formulas that can range from being simply reported, to scored against baseline, to financial rewards or penalties (i.e., adjustments to allowed revenues)
PBR May Help Overcome Bad Outcomes

- Good things that are not profitable for the utility that don’t get done (non-wires solutions, public interest social goals, aggregated DERs)
- Bad things that are profitable to the utility that should be prevented (gold-plating physical assets)
- Bad incentives not easily seen (deferring expenses like tree trimming, customer care, underserved communities)
What are the typical components of PBR?

- Multi-year determination/formula for allowed revenue — *for cost containment and rate stability*
- Decoupling - *to address the throughput incentive*
- Earnings sharing mechanisms — *sharing risks/rewards*
- Financial incentives and performance metrics linked to outcomes — *motivate good things, discourage bad activities*

*Not all of these will be present in every PBR established*
Q&A
4 Multi-year Rate Plans
Multi-year rate plans can:

- Reduce frequency of rate cases, freeing up commission and utility staff for other needs
- Improve culture of utility management
- Improve utility performance and lower utility costs
What is a Multi-Year Rate Plan?

Typical Components:

- Rate case moratorium (usually a 3-5 year rate case cycle)
- Attrition Relief Mechanism (ARM) allows for automatic relief from cost pressures, but is not linked to actual costs
- Earnings Sharing Mechanisms can mitigate risk
- Performance incentive mechanisms can be linked to MYRPs to ensure service quality
- Incentivizes cost containment: allow utility to keep some/all savings if efficient
- Other components can work simultaneously with a MYRP (e.g., decoupling, cost trackers, additional PIMs)

Graphics credit: RAP & Rocky Mountain Institute (RMI)
Carte blanche for cost cutting is not the way to improve performance

Pacific Northwest Bell

- Cut customer service
- Charged for customer service phone access
- Incentive to keep customers on hold

Lesson:
- Need customer service and reliability metrics

Photo credit: Quino Al on Unsplash
Productivity Growth of CMP with MYRP(s) vs. U.S. Utilities, 1992-2014

5 Designing Performance-Based Metrics
Set Guiding Goals/Considerations

Examples:
• Make/keep energy affordable for customers
• Improve distribution system reliability
• Reduce GHG emissions
Understand Current Incentives

• How does the status quo create incentives or disincentives for achieving your guiding goals?
• Avoid rewarding twice for same activity, where are gaps?
• How do new SB 5295 requirements fit existing mechanisms?
Develop Measurable Performance Criteria

Examples:
• Declining customer bills
• Reduced customer outages
Create Metrics

Examples:

• Average monthly bills for residential customers
• Frequency & duration of customer outages (SAIDI/SAIFI/CAIDI/MAIFI)
Establish Performance Targets

Example:
- 2% reduction in average monthly residential bills
- 5% improvement in SAIFI from baseline value
Performance Tracking Options

- **Public Metrics Only**
  - Metrics are publicized on a publicly available "dashboard."

- **Public Metrics with Ranking**
  - Metrics are publicized and ranked
  - Examples: Denmark DSO efficiency ranking, RIIO

- **Public Metrics with Financial Incentives**
  - Metrics are publically available, and utilities receive financial awards or penalties depending on achievement of the metrics.
  - Examples: NY REV
Metric Design Considerations

- Tracks outputs or outcomes, not inputs
- Clear, measurable and meaningful metrics
- Evaluated regularly
- Focus on outcomes within utility control
- Data is accessible, transparent

Graphic: MN PBR docket
https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BF0E8E68-0000-CF1F-93DB-4CE874187020%7D&documentTitle=20191-148970-01
Q&A
Designing Performance Incentive Mechanisms
Performance Incentive Mechanism (PIM) Options

- Incentives or penalties calculated with reference to the allowed ROE
- Lower overall rate of return (to cost of debt, for example) with percentageadders based on performance
- Specified dollar rewards for achievement of milestones (no change to allowed rate of return)
- Shared savings mechanism
Design Principles to Consider:

• For every PIM, ensure that the benefits exceed the costs
• Try to find the balance between the amount of reward that will incentivize the utility without over-compensation
• Assign greater rewards/penalties to most important policy goals and cost containment goals
• For non-monetizable benefits, consider reporting metrics only or a smaller incentive/penalty, until you have more information
• Tracking/reporting metrics help gather information, so you can set financial incentives later
No Deadband, Symmetric Compensation

- Based on a compliant result at the origin
- Utility wins or loses revenue based on performance
- Dollar for unit, no limits

Note pressure on measurement and verification of savings
Symmetric Deadband & Compensation

- Based on a compliant result around a deadband at the origin
- Utility wins or loses revenue based on performance
- Dollar for unit
- No limits

Note pressure on measurement and verification of savings
One-sided Penalty (Bad Utility, Bad Utility)

- No upside
- Deadband from adequate performance
- Severe penalty for poor performance
Asymmetric Compensation
(Maybe you have a little potential)

- Upside
- Capped, for superior performance
- Deadband from adequate performance
- Severe penalty for poor performance
One-sided Reward
(We like you, we really like you, ... but there’s a limit)

- Upside
- Capped for superior performance above present level
- No penalty
Hit the Target, get the toy

- Upside bonus
- Capped for significant specific superior performance
- No penalty
Practices That Lead to Difficulty

- Basing performance incentives on inputs (\$\$ spent)
- Basing rewards or penalties on factors beyond the control of the utility
  - Weather, economic growth, etc.
- Unclear or uncertain metrics or goals
- Lack of clarity around measurement methodology
Q&A
7 PBR Framework Review
Bringing all the pieces together

- PBR Framework consists of multiple components
- Taking a holistic view helps to avoid unintended outcomes, motivate positive outcomes
  - Fuel Adjustment Clause
  - Cost trackers
  - Earnings sharing mechanism
  - Decoupling
  - MYRP components
  - PIMs and Shared Savings Mechanisms
Examples of Frameworks and PIMs from Other States
Hawaii Phase 1 Outcomes

D&O 36326 establishes the regulatory guiding principles, goals, and outcomes to guide Phase 2

The following guiding principles will inform the development of the PBR framework:

1. **Customer-centric approach**, including immediate “day 1” savings for customers when the new regulations take effect;

2. **Administrative efficiency** to reduce regulatory burdens to the utility and stakeholders;

3. **Utility financial integrity** to maintain the utility’s financial health, including access to low-cost capital

<table>
<thead>
<tr>
<th>Regulatory Goal</th>
<th>Regulatory Outcome</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enhance Customer Experience</td>
<td>Affordability</td>
</tr>
<tr>
<td></td>
<td>Reliability</td>
</tr>
<tr>
<td>Emergent</td>
<td>Interconnection Experience</td>
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<tr>
<td></td>
<td>Customer Engagement</td>
</tr>
<tr>
<td>Improve Utility Performance</td>
<td>Traditional</td>
</tr>
<tr>
<td></td>
<td>Cost Control</td>
</tr>
<tr>
<td>Emergent</td>
<td>DER Asset Effectiveness</td>
</tr>
<tr>
<td></td>
<td>Grid Investment Efficiency</td>
</tr>
<tr>
<td>Advance Societal Outcomes</td>
<td>Traditional</td>
</tr>
<tr>
<td></td>
<td>Capital Formation</td>
</tr>
<tr>
<td></td>
<td>Customer Equity</td>
</tr>
<tr>
<td>Emergent</td>
<td>GHG Reduction</td>
</tr>
<tr>
<td></td>
<td>Electrification of Transportation</td>
</tr>
<tr>
<td></td>
<td>Resilience</td>
</tr>
</tbody>
</table>

Hawaii Public Utilities Commission
# Tools of PBR – Hawai‘i’s process

Phase 2 will focus on the development of 8 key PBR mechanisms

<table>
<thead>
<tr>
<th>Revenue Adjustment Mechanisms</th>
<th>Performance Mechanisms</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Multi-Year Rate Plan (MRP) with Indexed Revenue Adjustment</td>
<td>6. Performance Incentive Mechanisms (PIMs)</td>
</tr>
<tr>
<td>2. Earnings Sharing Mechanism</td>
<td>7. Shared Savings Mechanisms</td>
</tr>
<tr>
<td>3. Major Project Interim Recovery (MPIR)</td>
<td>8. Scorecards and Reported Metrics</td>
</tr>
<tr>
<td>4. Revenue Decoupling and Existing Cost Trackers</td>
<td></td>
</tr>
<tr>
<td>5. Off-Ramps</td>
<td></td>
</tr>
</tbody>
</table>

Illinois: Tracking Metrics

More than 60 metrics developed as part of a settlement agreement with ComEd, including:

- Reduced GHG emissions (as measured through load shifting, peak reduction, reduced truck rolls)
- Load served by distributed resources
- Time to connect DERs to grid
- Peak load reductions (from DR)
- Customers enrolled in time-varying rates
- Customer awareness of ComEd’s portal for viewing usage data
Illinois Performance Metrics for Reliability

• Guiding principle to achieve grid reliability and operational efficiency through formula rates and annual performance metrics over 10 yr.
  • 20% improvement over baseline in SAIFI
  • 15% improvement over baseline in system CAIDI
  • 20% improvement in the CAIFI over a baseline
  • 75% improvement in number of customers who exceed service reliability targets (5 basis point reduction realized for failure to meet this metric)
  • Financial penalties calculated as basis points
• Require annual reliability reports with worst performing circuits
Utility revenue within NY REV

Minnesota PBR Process

- Extensive look at innovative metrics
- Stakeholder process serves as a model for many states
- Outcomes: Affordability, Reliability, Customer service quality, Environmental performance, Cost effective alignment of generation and load
- Started with a review of existing landscape of incentives
- 28 metrics adopted for Xcel in 2019 for 2020 reporting

https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BF0E82E68-0000-CF1F-93DB-4CE874187020%7D&documentTitle=20191-148970-01
Minnesota Reliability and Resilience Metrics

- System Average Interruption Duration Index (SAIDI)
- System Average Interruption Frequency Index (SAIFI)
- Customer Average Interruption Duration Index (CAIDI)
- Customers Experiencing Long Interruption Duration (CELID)
- Customers Experiencing Multiple Interruptions (CEMI)
- Average Service Availability Index (ASAI)
- Equity – Reliability by geography, income, or other relevant benchmarks
- Momentary Average Interruption Frequency Index (MAIFI)
- Power Quality

Key Takeaways

• PBR has the potential to better align utility, ratepayer, and public interests than traditional cost of service regulation.

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• Start with a clear articulation of goals against which the resulting PBR framework can be tested and adjusted.
RAP Resources

- Next-Generation Performance-Based Regulation: Volume 1 (Introduction—Global Lessons for Success)
- Next-Generation Performance-Based Regulation: Volume 2 (Primer—Essential Elements of Design and Implementation)
- Next-Generation Performance-Based Regulation: Volume 3 (Innovative Examples from Around the World)
- Performance Incentives for Cost-Effective Distribution System Investments
- Protecting Customers from Utility Information System and Technology Failures
- Metrics to Measure the Effectiveness of Electric Vehicle Grid Integration
Q&A
Supplemental Slides
Traditional regulation: The problem of the “throughput incentive”

- Traditional regulation sets *prices*, not *revenues*
  - Revenue requirement is only an estimate of total cost to provide service; used only as basis for determining rates

- Consumption-based rates ($/kWh and $/kW) are most economically efficient (consumers pay only for what they use) and, arguably, most fair, but...

- ... they link revenues (and thus net income) to sales
  - More kilowatt-hours sold = more $ utility makes
  - Because in most hours, price of electricity is greater than cost to produce and deliver it

- Incentive to increase sales is extremely powerful
  - This is the “throughput incentive”
  - It encourages sales even when such sales are not economically efficient or desirable
<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></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><strong>-1.00%</strong></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>-5.00%</td>
<td>-$9,047,538</td>
<td>-$5,880,900</td>
</tr>
</tbody>
</table>
Traditional regulation: Capital bias

• Traditional regulation determines utility profits based on capital investments in rate base
  • Leads to preference for utility-owned capital solutions over more efficient alternatives, known as the Averch-Johnson effect

• Capital investments are scrutinized by regulators under “used and useful” and “prudence” standards

• Asymmetry of info makes regulatory scrutiny difficult, even under best conditions
  • Utilities often know their system and relevant options better than regulators or other stakeholders
Objectives of decoupling

• To improve economic efficiency
  • Preserves the utility’s incentive to improve its operational efficiency
    • Net income remains a function of utility operations & management
  • Removes the utility’s incentive to increase net income by increasing sales
  • Shifts focus to customer service

• To reduce risk for both the utility and the customer
  • Eliminates impacts (up or down) on revenue from weather, changes in the economy, and other exogenous factors
  • Likewise, eliminates impacts associated with least-cost actions
Credit implications of decoupling

- Standard & Poor views decoupling as generally positive from a credit perspective:
  - Provides opportunity for a utility to earn a pre-determined level of distribution revenue regardless of actual KWH sold
  - Enables utilities to project cash flow more accurately and avoid most earnings volatility from changes due to policy goals (and other influences – weather/economy) that occur under traditional regulations
  - Reduces need for rate case filings, resulting in lower overall costs for utilities
## Multi-Year Rate Plans Feature Different Types of ARM

### Four Well-Established Methods

<table>
<thead>
<tr>
<th>Forecasts</th>
<th>Indexing</th>
<th>Hybrids</th>
<th>Rate Freeze</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Rate adjustments during the MYRP period are based on cost forecasts</td>
<td>• An indexed ARM uses industry cost trend research to develop a base productivity trend that is then combined with other factors to arrive at a revenue cap index</td>
<td>• Uses a combination of methods</td>
<td>• ARM provides no rate escalation; growth depends on billing determinants or tracked costs</td>
</tr>
<tr>
<td>• Adjustments typically increase revenue on predetermined percentage in a stairstep fashion each year</td>
<td>• In the U.S., has been used so OpEx is indexed while revenue related to CapEx has a stairstep approach</td>
<td>• Can exacerbate the throughput incentive unless combined with revenue regulation</td>
<td></td>
</tr>
</tbody>
</table>

Indexed attrition relief mechanisms (ARMs) tie utility revenues to external market factors instead of utility costs

Attrition Relief Mechanism

- **Inflation**
  - Often represented by a macro-economic price index such as the GDP Price Index ("GDPPI")
  - Custom indexes of utility input price inflation also are sometimes used in ARM design

- **Productivity Factor ("X")**
  - Reflects the average historical multifactor productivity trend of a peer group of utilities
  - Can be based on broad regional or national peer groups
  - Peer group can in principle be customized to mirror special circumstances of the subject utility

- **Exogenous Events ("Z Factor")**
  - Accounts for uncontrolled exogenous events that affect a utility's costs (e.g., the "2017 Tax Cut and Jobs Act")

- **Stretch Factor (Consumer Dividend)**
  - A stretch factor can be included to share with customers the benefit of stronger cost containment incentives expected under the MYRP

Graphics credit: RAP & Rocky Mountain Institute (RMI)
Cost Trackers in MYRPs

Cost trackers used for expedited recovery of costs - recovered in riders

Cost trackers can challenge PBR because they weaken incentives to improve performance

However, sometimes still used in conjunction with MYRPs to allow for recovery of costs that are difficult to control, and that are hard for the ARM to address

For example, CapEx trackers may be used to compensate to address for annual costs that capex can create, and which are hard to address with an ARM
Earnings Sharing Mechanisms share surplus/deficit earnings between utilities and their customers to mitigate upside and downside risk

- An Earnings Sharing Mechanism (ESM) can provide both “upside” and “downside” sharing of earnings between the utility and customers.
- This results when the rate of return on equity (ROE) deviates significantly from a public utility commission-approved target.
- ESMs often have “deadbands” (neutral zones around the target) in which earnings variances are not shared with customers.
- Some argue that ESMs may mitigate utility cost containment incentives.

- Of these 11 states, 10 include asymmetrical provisions for sharing earnings in excess of the authorized ROE level (i.e., above the deadband), but not below the authorized ROE.

Efficiency Carryover Mechanisms (ECMs) allow utilities to benefit from efficiency gains throughout and across MYRP periods.

- ECMs maintain the utility’s incentive to control costs and optimize spending throughout the MYRP period by allowing the utility to carry forward a portion of savings from one MYRP period into the next.

  - Without an ECM, a utility has a greater incentive to implement cost-saving measures in the beginning of an MYRP period.

  - Utilities also may be incentivized to defer certain expenditures in the early years of an MYRP period to increase the revenue levels reflected in an MYRP’s test year.

  - ECMs also can have a sharing component that allows customers to benefit from savings achieved or bear a portion of cost overruns.

- Efficiency gains are calculated using benchmarks. Can compare a proposed revenue requirement for a new MYRP to the revenue requirement established by an expiring MYRP.

  - Alternatively, a benchmark can be based on statistical cost research.
Maryland’s behavioral demand response program

PBR to promote peak demand reduction

- Opt-out peak rebate program - $1.25/kWh rebate for energy reduction on Energy Savings Days with 24-hour notice.
- BGE may capitalize the operating expenses associated with Smart Energy Rebate (SER) program
- BGE could not recover any of the AMI costs, or earn the 9.75% return on equity on its smart grid program until the utility proved that the deployment had a positive benefit-cost.
- The SER program was instrumental in maximizing the AMI business case and ultimately recovering the costs ($687 million capex)
Treating Cloud Computing Services as Capital Expenditures in Illinois

• Changes to treatment of “CAPEX” and “OPEX”
• Allows utilities to treat service contracts for cloud computing services like utility-owned IT
• Removes penalties for investments in services inherent in traditional cost-of-service model
• Levels investment playing field between CAPEX and OPEX
## SER Program Summary to Date

<table>
<thead>
<tr>
<th>Year</th>
<th># of Energy Savings Days</th>
<th>Eligible Customers</th>
<th>Average Bill Credit</th>
<th>Peak Demand Reduction (MW)</th>
<th>Total Bill Credits to Customers</th>
<th>% Participation</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>4</td>
<td>315,000</td>
<td>$9.03</td>
<td>96</td>
<td>$7 M</td>
<td>82%</td>
</tr>
<tr>
<td>2014</td>
<td>2</td>
<td>860,000</td>
<td>$6.55</td>
<td>209</td>
<td>$5.6 M</td>
<td>76%</td>
</tr>
<tr>
<td>2015</td>
<td>4</td>
<td>1,020,000</td>
<td>$6.67</td>
<td>309</td>
<td>$15.5 M</td>
<td>81%</td>
</tr>
<tr>
<td>2016</td>
<td>3</td>
<td>1,074,000</td>
<td>$6.73</td>
<td>336</td>
<td>$11 M</td>
<td>71%</td>
</tr>
<tr>
<td>2017</td>
<td>2</td>
<td>1,095,000</td>
<td>$6.13</td>
<td>330</td>
<td>$6.1 M</td>
<td>74%</td>
</tr>
</tbody>
</table>

### SER Wholesale Market Benefits to Customers, 2013 to 2015

<table>
<thead>
<tr>
<th>Benefits from Peak Demand Reductions</th>
<th>Benefits from Energy Reductions</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wholesale Capacity Revenue $46 M</td>
<td>Wholesale Energy Revenue $25 M</td>
<td>$406 M</td>
</tr>
<tr>
<td>Avoided Capacity Cost $87 M</td>
<td>Avoided Energy Cost $9 M</td>
<td></td>
</tr>
<tr>
<td>Capacity Price Mitigation $234 M</td>
<td>Wholesale Energy Price Suppression $5 M</td>
<td></td>
</tr>
<tr>
<td>Share of Total 11%</td>
<td>21%</td>
<td>6%</td>
</tr>
</tbody>
</table>

[https://info.aee.net/hubfs/MD%20DR%20Final.pdf](https://info.aee.net/hubfs/MD%20DR%20Final.pdf)
Interactions of Decoupling, MYRPs, PIMs

HOW ALLOWED REVENUES AND RATES COULD ADJUST WITH DECOUPLING, MYRPS, AND PIMS

The term Allowed Revenues here more precisely describes certain components of the revenue requirement established in a rate case, as adjusted for various factors. Allowed Revenues usually excludes costs that vary with sales, or are collected through other trackers and riders, such as fuel and purchased power expenses.

More recent MYRPs generally cap and adjust allowed revenues, which make them complementary to decoupling mechanisms. Together, they can reduce the utility’s throughput incentive and encourage utility cost reductions.

Adjustments to Allowed Revenues can account for customer growth, external cost pressures, and/or multi-year cost forecasts.

Penalties and rewards from performance incentive mechanisms (PIMs) can make annual adjustments to Allowed Revenues.

Earnings Sharing Mechanisms (ESMs) can make annual adjustments to Allowed Revenues. ESMs provide a safeguard to ensure that revenue adjustments do not result in excessive or deficient utility earnings.