Regulatory Tactics for Electric Peak Management

A Workshop for Arizona State Government

Presented by Richard Sedano

August 4, 2016
Introducing RAP and Rich

• RAP is a non-profit organization providing technical and educational assistance to government officials on energy and environmental issues. RAP staff have extensive utility regulatory experience. RAP technical assistance to states is supported by US DOE, US EPA and foundations.

  – Richard Sedano directs RAP’s US Program. He was commissioner of the Vermont Department of Public Service from 1991-2001 and is an engineer.
Objectives Policy-Makers May Have

- Encourage wise use of energy
- Encourage wise investment in energy capital
- Reduce cost-intensive peak use
- Properly allocate costs
- Strategically deploy grid resources

- Provide customers with choices
- Address climate change
- Ensure fairness, social justice
- Reasonably ensure utility revenue adequacy
- Enable new grid resources
- Project an aura of progress in AZ
Peak Management in Policy Context

• Cost and Resource Management

• Success with Other Social Objectives
Peak is Expensive

• Capital replacement in kind is expensive
  – Larger sizes only more so

• Settlement patterns can make siting harder
A lot of resources to serve a small amount of time
Approaches to Reduce Peak

• Rate design
• Programs
• Programs and rate design with technology
  – Addressing vulnerable customer groups
• Performance regulation
• IRP and Enhanced Planning
• Address Opex / Capex bias
• Recognize shifting peak hours
Customer Solutions

Utility Solutions

Policy, Regulation
Revenue Requirement
How much money does utility need to deliver good service?

Rate Base
X Rate of Return
+ Operating Expenses
= Revenue Requirement
÷ Sales
= Rate per kWh
Traditional Rate of Return Regulation

• Rate Base
  – Total Plant in Service at Original Cost
  – Less Accumulated Provision for Depreciation
  – Adjustments
    • Working Capital
    • Allowance for Funds Used During Construction
    • “Regulatory Assets” such as abandoned plant
    • Deferred Taxes
Plant In Service at Original Cost

- Generation • $400,000,000
- Transmission • $100,000,000
- Distribution • $600,000,000
- General Plant • $200,000,000
- Total Plant in Service • $1,300,000,000
Rate Base Calculation

• Plant in Service
• - Accumulated Depreciation
• = Net Plant in Service
• + Working Capital
• + Regulatory Assets
• - Deferred Taxes
• = Rate Base

• $1,300,000,000
• ($300,000,000)
• $1,000,000,000
• $ 50,000,000
• $ 10,000,000
• ($60,000,000)
• $1,000,000,000
<table>
<thead>
<tr>
<th>Rate Base</th>
<th>$1,000,000,000</th>
</tr>
</thead>
<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>
Traditional Rate of Return Regulation
Cost of Capital

• Rate of Return
  – Cost of Common Equity
  – Equity Capitalization Ratio
  – Cost of Debt
  – Debt Ratio
  – Preferred Stock and Short Term Debt as appropriate

• Commission sets this to assure an adequate flow of capital over time at a reasonable cost
Rate of Return Calculation

- Equity Ratio
  - x Allowed Return on Equity
  - = Weighted Equity Cost
    - 50% • 12%
    - 6%

- Debt Ratio
  - x Cost of Debt
  - = Weighted Debt Cost
    - 50% • 8%
    - 4%

- Sum = Rate of Return
  - 10%
Operating Expenses

- Production: $50,000,000
- Transmission: $5,000,000
- Distribution: $25,000,000
- Administrative and General: $10,000,000
- Taxes: $10,000,000

- Total Expenses: $100,000,000
Traditional Rate of Return Revenue Requirement

- Rate Base: $1,000,000,000
- x Rate of Return: X 10%
- = Return Requirement: $100,000,000
- + Operating Expenses: $100,000,000
- = Revenue Requirement: $200,000,000
What Does the Commission “Regulate” in a Simple Rate Case?

- **Rate Base:** Providing service or not? Prudently incurred?
- **Rate of Return:** What is the appropriate capital structure? The appropriate return on equity?
- **Operating Expenses:** Which expenses are allowable for ratemaking? Imprudent? Not related to providing service? Political?
- **Cost Allocation:** How much of the revenue requirement is paid by each customer class? Operating Expenses: Which expenses are allowable for ratemaking? Imprudent? Not related to providing service? Political?
- **Rate Design:** How shall costs be divided between customer charges, energy charges, and other types of charges.
What Else Does the Commission Regulate?

• Accounting Policies
• Securities Issuance
• Service Standards
• Service Policies
• Resource Planning
• Energy Efficiency
• Low-Income Programs
• Any Issue Assigned by Legislature
• Any issue brought by complaint
Peak Drives Rates

• Costs up with growing peak
• while sales are flat

Rates = costs
       sales

• Helping customers control peak controls costs and rates
Rate Design Can Drive Peak

• Opportunity to influence customers and peak demand

• Options
  – Time of use prices
  – TOU with critical peak
  – Real time prices
  – Demand rates in a three part tariff
Embedded Cost of Service

• Functionalization

• Classification

• Allocation
Rate Design Addresses the Past and the Future

Identifying and classifying embedded, sunk costs, allocating them fairly among customers

Signalining forward looking actions affecting peak on consumption and investment by utility and by customers
A Fixed TOU Rate in Use

• **On-Peak**
  
  Summer: weekdays 10 a.m. - 8 p.m.
  Winter: weekdays 7 a.m. - 11 a.m. and 5 p.m. - 9 p.m.

• **Intermediate-Peak**
  
  Summer: weekdays 7 a.m. - 10 a.m. and 8 p.m. - 11 p.m.
  Winter: weekdays 11 a.m. - 5 p.m.

• **Off-Peak**
  
  Summer: weekdays 11 p.m. - 7 a.m., Sat., Sun., holidays
  Winter: weekdays 9 p.m. - 7 a.m., Saturday, Sunday, holidays
What is a Time-based Rate Trying to Do?

• Signal value to customers
  – Customers can act in their own self-interest in ways that can save money for the grid
    • Operating their stuff
    • Investing in new stuff
  – For customers to exercise control of their equipment, peak periods can’t be too long
  – For customers to be motivated to act, peak period needs to cost significantly more
In the Long Run, All Costs are Variable

• Some costs today appear fixed
  – But 10-20 years ago or more, a decision to invest was made, and that decision could have been different
  – Similarly, the utility under ACC direction is making decisions today and will every year that lock in costs
  – Customer resources can be alternatives for many of these investments – how are customers signaled as to the value of their choice? Rates!
Peak Load Benefits of Different Residential Rate Designs

Conceptual Representation of the Risk-Reward Tradeoff in Time-Varying Rates

- **Flat Rate**
- **Inclining Block Rate**
- **Seasonal Rate**
- **TOU**
- **Super Peak TOU**
- **CPP**
- **VPP**
- **RTP**

Potential Reward (Discount from Flat Rate) vs. Increasing Risk (Variance in Price)
Sample Time of Use with Critical Peak:

<table>
<thead>
<tr>
<th>Rate Element</th>
<th>Based On the Cost Of</th>
<th>Illustrative Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Customer Charge</td>
<td>Customer-Specific Costs Only</td>
<td>$7.00/month</td>
</tr>
<tr>
<td>Off-Peak Energy</td>
<td>Baseload Resources + transmission and distribution</td>
<td>$.08/kWh</td>
</tr>
<tr>
<td>Mid-Peak Energy</td>
<td>Baseload + Intermediate Resources + T&amp;D</td>
<td>$.11/kWh</td>
</tr>
<tr>
<td>On-Peak Energy</td>
<td>Baseload, Intermediate, and Peaking Resources + T&amp;D</td>
<td>$.15/kWh</td>
</tr>
<tr>
<td>Critical Peak Energy (or PTR)</td>
<td>Demand Response Resources</td>
<td>$.75/kWh</td>
</tr>
</tbody>
</table>
This section focuses on the types of capabilities and rates that are achievable with smart meters. Smart meters are expected to reach 91% of the US by 2022. It is important to note, however, that merely installing smart meters does not alone facilitate advanced pricing; meter data management systems (MDMS) investments, billing engine modifications, and sophisticated rate studies are needed to develop advanced pricing.

While smart meters can enable advanced pricing mechanisms, the relative price-variability risks and rewards of different types of pricing shows that the greater possible rewards, in the form of lower bills for consumers that modify their consumptions, that smart meters enable are applicable only to a subset of pricing options. Figure 2 shows this risk-reward tradeoff, and where smart meters become relevant and useful.

Examples of rates of each of these types can be found in Appendix E. Note that in some restructured states with retail competition and smart meters, this metering and billing service can (or must) be provided by a competitive provider.

Smart meters, and the support systems necessary for them to realize their full potential, are a costly investment. These costs have been justified by the full spectrum of benefits described above, many of which are related to energy savings, peak load management, and distribution cost controls, not just the billing of consumers. Therefore, these costs should not be recovered in fixed monthly charges.

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**Figure 2:** Risk-Reward Tradeoff of Rate Design and Smart Meter Utilization

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*Energy solutions for a changing world*
Grouping results by tariff design helps explain some of the variation in impacts.
Significant Peak/Off-peak Price Ratio

Pilot Impact versus Price Ratio (with and without Enabling Technology)

Price-Only

Technology

Energy solutions
for a changing world
Basic Customer Method

ONLY customer-specific facilities classified as customer-related
Minimum System Method:

~50% of Distribution System Classified as Customer-related
Georgia Power offers a Residential Demand Rate. Under the Demand Rate, the energy prices are significantly less for both On-Peak and Off-Peak time periods, and, there is a demand charge of $6.53 per kW of peak demand. Peak demand is defined as the highest 30-minute interval load during the current month.

The table below compares the rates of these two plans. On-Peak hours are from 2 to 7 PM, Monday – Friday, June through September.

<table>
<thead>
<tr>
<th>Georgia Power Comparison Demand and Nights and Weekends</th>
</tr>
</thead>
<tbody>
<tr>
<td>Type of Charge</td>
</tr>
<tr>
<td>Basic service charge</td>
</tr>
<tr>
<td>Energy</td>
</tr>
<tr>
<td>On-Peak</td>
</tr>
<tr>
<td>Off-Peak</td>
</tr>
<tr>
<td>Demand</td>
</tr>
</tbody>
</table>
Problems with Demand Charges

1) Normally measure non-coincident peak, which is irrelevant to anything but the final line transformer.

2) Rewards customers that contribute to the system peak, modest aggregate effect on peak.

3) Lack of customer understanding, responsiveness.

4) Multi-Family pays too much.
Demand Charge Addressing Peak

• Addresses system peak costs if it is a coincident peak charge over a short duration (especially nice to let customer choose peak hours within a range)

• To motivate consumer response, use a short ratchet period (daily is best, monthly is better than annual)

• A daily demand charge and a well designed TOU rate with a critical peak converges in effect, latter may seem easier for consumers to understand, manage
Principles for Modern Rate Design

Universal Service: A customer should be able to connect to the grid for no more than the cost of connecting to the grid.

Time-Varying: Customers should pay for grid services and power supply in proportion to how much they use and when they use it.

Fair Compensation: Customers supplying power to the grid should be compensated fairly for the value of the power they supply.
## A Simple Cost-Based Rate Design

<table>
<thead>
<tr>
<th>Customer-Specific Charges</th>
<th>Energy Charges</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Customer Charge</strong></td>
<td><strong>$/Month</strong></td>
</tr>
<tr>
<td>Transformer:</td>
<td><strong>$/kVA/Mo</strong></td>
</tr>
<tr>
<td><strong>$/Month</strong></td>
<td>$ 3.00</td>
</tr>
<tr>
<td><strong>$/kVA/Mo</strong></td>
<td>$ 1.00</td>
</tr>
<tr>
<td><strong>$/kWh</strong></td>
<td>$ 0.08</td>
</tr>
<tr>
<td><strong>$/kWh</strong></td>
<td>$ 0.12</td>
</tr>
<tr>
<td><strong>$/kWh</strong></td>
<td>$ 0.18</td>
</tr>
<tr>
<td><strong>$/kWh</strong></td>
<td>$ 0.75</td>
</tr>
</tbody>
</table>
Location in Rates

• System value differs throughout the utility system
  – In some places, capital may be needed to address demand growth, or to address system congestion that causes expensive resources to run instead of lower cost ones

• Prices can motivate customers to be a lower cost, lower risk solution
Location Options

• Distribution credits to customers for taking beneficial actions
  – Based on commission determination
  – Shares the savings
  – May be time limited

• Programs only available in target circuits

• Future may have more “real time” approaches enabled by smart grid
Programs

- Energy Efficiency
- Demand Response
- Customer Generation
- Storage

- If peak is driving costs, programs can motivate customers to take actions to reduce peak
Programs

• Energy Efficiency to reduce end uses active during peak
• Demand Response that shifts away from peak
• Customer Generation to encourage production during peak
• Storage that shifts away from peak while filling troughs in the daily load shape
Demand Response

• Progress
• Much more to do
  – Markets for flexibility (ramping, cycling)
    • Ancillary Services
  – Better planning to identify valuable times and locations
  – Pricing to motivate customers
  – Programs to connect services with customers and monetize benefits
  – Technology to operationalize DR benefits
New Evolutions

• Microgrids with ready tariffs that motivate peak reduction
• EV charging that motivates peak reduction using on board tech and smart grid
• ...

Energy solutions for a changing world
Utility Regulation and Vulnerable Customers

• Serving long term system at least cost
  – With attention to risk management
  – Controlling peak demand cost
• Build in process to keep people on line
• Decide on rate subsidies
• Consider education, especially what the bill communicates
Gross/net demand comparison

After taking all wind and solar, this is the operator’s task

Little demand for baseload, big demand for mid-merit, demand for peaking pretty much unchanged
Principal Sources of Flexibility

• Customers
  – Demand response
  – Storage

• The Grid
  – Load following capacity in thermal plants
  – Storage
Flexible generation is just one piece of the puzzle

Source: IEA Energy Technology Perspectives 2014
Flexible generation is just one piece of the puzzle

Source: IEA Energy Technology Perspectives 2014
### Suite of actual balancing options

<table>
<thead>
<tr>
<th>Emergency Level</th>
<th>Marginal Resource</th>
<th>Trigger</th>
<th>Price</th>
<th>Marginal System Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>n/a</td>
<td>Generation</td>
<td>Price</td>
<td>Approximately $20-$250</td>
<td>Same</td>
</tr>
<tr>
<td>n/a</td>
<td>Imports</td>
<td>Price</td>
<td>Approximately $20-$250 Up to $1,000 during load shed</td>
<td>Same</td>
</tr>
<tr>
<td>n/a</td>
<td>Non-Spin Shortage</td>
<td>Price</td>
<td>Marginal Energy + Non-Spin ORDC w/ $X = 2,000</td>
<td>Marginal Energy + Non-Spin ORDC w/ $X = 1,150</td>
</tr>
<tr>
<td>n/a</td>
<td>Emergency Generation</td>
<td>Price</td>
<td>$500</td>
<td>Same</td>
</tr>
<tr>
<td>n/a</td>
<td>Price-Responsive Demand</td>
<td>Price</td>
<td>$250-$9000</td>
<td>Same</td>
</tr>
<tr>
<td>n/a</td>
<td>Spin Shortage</td>
<td>Price</td>
<td>Marginal Energy + Non-Spin + Spin ORDC w/ $X = 2,000</td>
<td>Marginal Energy + Non-Spin + Spin ORDC w/ $X = 1,150</td>
</tr>
<tr>
<td>n/a</td>
<td>Regulation Shortage</td>
<td>Price</td>
<td>Power Balance Penalty Curve</td>
<td>Same</td>
</tr>
<tr>
<td>EEA 1</td>
<td>30-Minute ERS</td>
<td>Spin ORDC x-axis = 2,300 MW</td>
<td>$3,239 at Summer Peak (from ORDC)</td>
<td>$1,405</td>
</tr>
<tr>
<td>EEA 1</td>
<td>TDSP Load Curtailments</td>
<td>Spin ORDC x-axis = 1,750 MW</td>
<td>$9,000 (from ORDC)</td>
<td>$2,450</td>
</tr>
<tr>
<td>EEA 2</td>
<td>Load Resources in RRS</td>
<td>Spin ORDC x-axis = 1,700 MW</td>
<td>$9,000 (from ORDC)</td>
<td>$2,569</td>
</tr>
<tr>
<td>EEA 2</td>
<td>10-Minute ERS</td>
<td>Spin ORDC x-axis = 1,300 MW</td>
<td>$9,000 (from ORDC)</td>
<td>$3,681</td>
</tr>
<tr>
<td>EEA 3</td>
<td>Load Shed</td>
<td>Spin ORDC x-axis = 1,150 MW</td>
<td>VOLL = $9,000</td>
<td>Same</td>
</tr>
</tbody>
</table>

Source: Brattle Group report to Texas Public Utilities Commission
We have talked about a focus on Customers, Now we begin to discuss Utility Solutions
Performance Regulation

• Metrics can motivate peak reduction
  – Rewards can motivate more
Designing Performance Indicators

• Reflect public policy
  – Big picture important
  – Anecdotally important (an indicator)
• Understanding of BAU performance
• Does exceptional performance matter to customers?
• Measurement of performance is clear
• Not too many
• Multi-year may be better
For example, successful implementation of cost-effective energy efficiency can reduce emissions associated with fossil generation (an environmental benefit) and defer or avoid new generation, capacity, transmission, and distribution resources, resulting in cost savings (a traditional focus of utility performance regulation).

Planning has a critical role in informing regulatory outcomes across all three areas, and thus it takes a central location in the Venn diagram below.

Figure 2. Dimensions of Utility Performance That May Warrant Tracking or Incentives

- **Traditional Goals**
  - Reliability
  - Power plant performance
  - Employee safety
  - Customer service
  - Lower costs

- **Resiliency**
  - Innovation
  - Customer engagement
  - Customer-targeted services
  - Flexible Resources
  - Smart grid

- **Environmental Goals**
  - Renewable energy
  - Improved load factor
  - DG
  - Reduced emissions
  - Reduced losses

- **New Business Models**
  - Customer-targeted services
  - Energy efficiency
  - Flexibility
  - Resiliency

Load Factor Has Been Declining

• As peak has grown with stagnant sales

Load Factor = \[
\frac{\text{kWh sales}}{\text{Peak kW} \times 8760}
\]

• Increasing Load Factor an indicator, but a poor metric for improvement
Associating Performance to Reward

• The Goldilocks Rule
  – Enough, Not too much

• Promote more improvement if valuable

• Communicate value to customers
  – If this is overlooked, customers will just see the cost and not recognize the benefits

• Change the metrics periodically to match the times
Performance: Why Not in Wide Use?

• Regulator takes responsibility for performance that matters
  – Staffing limits ability of PUC to have confidence
• Utility has all the information, regulator has some of the information
• Measurement failures create disagreement on anticipated rewards
An Illustration of Metrics Influencing Peak

• A peak intensity applied to mass market customers (kW/customer)

• Program targets for EE and DR effects on peak for C&I end uses
Planning

• Intended to identify most valuable utility investments
  – Evaluate cost and risk
  – Fit into long term capital plan
• Transparent planning engages outsiders, assures societal concerns are considered and planner biases are scrubbed
Integrated Resource Planning

• Intended to identify most valuable utility resource investments
  – Tends to address how energy efficiency/demand response can replace utility resources
  – May also address Transmission resources

• Transparent planning engages outsiders, assures societal concerns are considered and planner biases are scrubbed
Enhanced Planning

• Intended to identify most valuable utility investments throughout the system
  – Includes distribution and transmission
  – Intended to value and monetize consumer resources
  – Drive long term capital plan

• Transparent planning engages outsiders, assures societal concerns are considered and planner biases are scrubbed
Summary

Early IRP
- Utility-centric
- Focused on major generation investments
- Energy Efficiency Focus
- Little DG or DR
- No consideration of distribution system

Evolved IRP
- Customer-focused
- Multi-resource
- Time-Varying
- Multi-nodal
  - Geographic targeting of EE, DR, and DG
- Multi-Utility
- Multi-Fuel
Much is the Same, with Many Changes

- Physics
- Commitment to
  - Reliability
  - Affordability
  - Customers
  - Safety
  - Environment
  - Universal service
- How the grid operates w/demand
- Role of utility as integrator
- Relationships
- Better alignment of public and private interests
Evolution in Planning Helps Manage Peak

• Lots of new grid side technology
• Smart meters enabling more smart services
• Forecasting customer resources
  – Today, many forecasts represent what policy says will happen
  – Utility programs and prices can dramatically influence pace, nature (@peak) of deployment
• Fundamental question:
  – Do you trust customer resources to deliver?
Requirements of Distribution Planning

• Questions to consider include:
  o What is end-goal/purpose of distribution planning
  o What information needs to be compiled by the utility
  o What are the Commission’s resources to process the (voluminous) information
  o What new policies or changes will be needed to optimize the use of the information received?
Opex / Capex Bias

• How does a utility make money?
Opex / Capex Bias

• How does a utility earn net income?

From the rate case:

Revenue Requirement = Expenses
+ Rate Base * rate of return

From operations post-rate case:

Net income = Revenue - Costs
Opex / Capex Bias

• The utility has the opportunity to earn a return on **capital** expenses
• The utility typically does not have the same opportunity with **operating** expenses
• Traditional regulation motivates the utility to solve system challenges with capital
  – Even if the better solution involves customer programs supported by expenses
Use Regulatory Assets to Address Capital Bias

• Regulatory Asset: An Accounting Device
  – Decide the a certain expense will be recovered in rates as an asset would be
  – Expense is added to rate base
  – Amount is amortized over a specific number of years
  – Unamortized balance earns return
Use Regulatory Assets to Address Capital Bias: Example

- A $200 million substation can be avoided
- With $100 million in customer programs
  - Cost of staff and equipment installed on customers premises and customer incentives
- Regulator issues an accounting order
- $100 million will become a regulatory asset, regulator decides to amortize over 10 years
- Rate case: $10 million allowed in rates as part of depreciation
- Remaining $90 million is in rate base
  - If weighted average cost of capital is 7%, $6.3 million is added to allowed revenue
  - Roughly half must go to debt payments, the rest is available for net income
  - Asset account diminishes over ten years to zero
Solution:
Regulatory Asset for Selected OpEx

- Regulatory asset results from an accounting order from the commission
  - Expenses can be placed in a capital account
- Which expenses?
  - Expenses associated with addressing issues identified in the planning process
  - Other out-sourced services
Utility Income for Assets Under Management Mechanism

- The long-term cost commitment for contracts that the utility enters into with third parties for grid services is determined and is eligible for a rate of return.
- The utility’s compensation would be based on the assets that are controlled by the utility as a result of establishing long-term contracts with third parties.
- The incentive to invest in infrastructure would be the same as the incentive to contract for services.
- This approach would address an ongoing financial problem faced by utilities resulting from the imputed “debt equivalence” of these long-term contractual obligations by rating agencies.
Build Stuff ➞ Earnings
Build Big Stuff
More Earnings
Build Really Big Stuff
Really Big Earnings
Cheaper = Less Profitable
Customer Builds Stuff: No Earnings
Efficient Investment (Peak drives value):

What if the best source of investment is customers?

- Rates that signal value to customers
- Programs motivate customers
- Eliminate the throughput incentive
- Eliminate the capital bias with a new system of earning net income and a focus on total expenses
- Planning to identify best investments
- Performance incentives that guide utility to societally important outcomes
The Duck: The California ISO’s Flexibility Curve

- **Head**: growing evening peak demand
- **Neck**: the combined effect of decreasing midday and increasing evening net load results in a longer, steeper neck, requiring generators to respond much faster to keep up with electricity needs
- **Belly**: significant midday decrease in net load may result in having too much electricity on the grid which could result in low or negative prices
- **Belly**: additional demand or storage may help absorb excess generation in overgeneration conditions

*(the ISO’s Building A Sustainable Energy Future; 2014-2016 Strategic Plan)*
10 Ready Solutions to Accommodating Growing PV

• Teaching the Duck to Fly
  – 2nd Edition emphasis on water
    • Pumping
    • Heating
    • Ice
    • Storage
  – Ideas adaptable
Teaching the “Duck” to Fly:
10 strategies to control generation, manage demand, & flatten the Duck Curve

1. **Targeted Efficiency**
   - Focus energy efficiency measures to provide savings in key hours of system stress.

2. **Peak-Oriented Renewables**
   - Add renewables with favorable hourly production. Modify the dispatch protocol for existing hydro with multi-hour “pondage.”

3. **Manage Water Pumping**
   - Run pumps during periods of low load or high solar output, curtailing during ramping hours.

4. **Control Electric Water Heaters**
   - Increase usage during night & mid-day hours, & decrease during peak demand periods.

5. **Ice Storage for Commercial AC**
   - Convert commercial AC to ice or chilled-water storage operated during non-ramping hours.

6. **Rate Design**
   - Focus pricing on crucial hours. Replace flat rates & demand charge rate forms with time-of-use rates. Avoid high fixed charges.

7. **Targeted Electric Storage**
   - Deploy storage to reduce need for transmission & distribution, & to enable intermittent renewables.

8. **Demand Response**
   - Deploy demand response programs that shave load during critical hours on severe stress days.

9. **Inter-Regional Power Exchange**
   - Import power from & export power to other regions with different peaking periods.

10. **Retire Inflexible Generating Plants**
    - Replace older fossil & nuclear plants with a mix of renewables, flexible resources, & storage.
Depictions of future load like those in Figure 1 have entered the industry vernacular as "the Duck Curve" for obvious reasons. In actuality, however, ducks vary their shape depending on different circumstances, and as explained here, utility load shapes can do the same.

A duck in water tends to center its weight in the water, floating easily. Figure 3 shows the duck shape commonly associated with the graph in Figure 1.

A duck in flight, however, stretches out its profile to create lower wind resistance in flight. This is illustrated in Figure 4.

Metaphorically, our goal is to teach the "duck" in Figure 2 to fly, by implementing strategies to both flatten the load and to introduce supply resources that can deliver.

![Change in Load Shape From Implementation of the Ten Strategies](image)

<table>
<thead>
<tr>
<th>Hours</th>
<th>Pre Strategies Load</th>
<th>Post Strategies Load</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Total Load</td>
<td>Post Strategies Total Load</td>
</tr>
<tr>
<td>2</td>
<td>Load Net of Wind and Solar</td>
<td>Post Strategies Net Load</td>
</tr>
<tr>
<td>3</td>
<td></td>
<td>Original Net Load</td>
</tr>
</tbody>
</table>

For a small portion of daily energy requirements, this paper discusses strategies that enable high levels of energy needs to be served, provided that pricing and technology to increase the flexibility of loads are employed.

This paper identifies a number of low-carbon strategies that can be applied to meet this challenge. These strategies are generally limited to existing commercially available technologies, but perhaps deployed in ways that have not been done on a commercial scale to date. These strategies not only enable greater renewable integration, they enhance system reliability and reduce generation and transmission capital and fuel costs by modifying the load profiles and better utilizing existing transmission assets. Not every strategy will be applicable to every region or utility around the country, and every region will have additional strategies that are not among these ten.

Specific implementation plans, which are beyond the...
What Other States Are Doing

- Most states are evaluating costs in rate cases
- Some are taking actions with peak reductions in mind
- Many with DG policy are recognizing that personal customer investment is replacing utility investment, removing these avoided costs from the rate process
New York REV

• Reforming the Energy Vision (in progress)
  – Arrest long term cost trends driven by peak demand growth, especially capital cost trends
  – Use rate design to signal value to customers
  – Use performance metrics that improve load factor (sell the same or more energy with less peak demand)
  – Address bias between Operating and Capital Expenses ... and more
Brooklyn-Queens Project

• A trial of the vision
• Change course from traditional response to reliability challenge
  – Build $1.2B sub or
  – Reduce sustained load for years
  – Innovation needed
    • Utility side response: find 52 MW locally, cheaper
    • Regulatory response: 10 year amortization of expenses
      – Remove bias between opex and capex
MD Peak Time Rebate Reducing Peak

- Delaware Delmarva Power and Light (DPL) has a critical peak rebate program for residential customers.
- Customers receive a $1.25 credit for every kWh they reduce their usage below a baseline during an event.
- Customers get this credit automatically; they do not have to enroll in the program.

Sacramento Municipal Utility District

- Rate design shifts with technology reduce demand from customers with central AC by 30%
  - Other customers reducing demand by 11%
Massachusetts Grid Modernization

• The commission is supervising implementation of orders including one to bring time varying rates to all customers
Total Expenditure Accounting (TOTEX) in Britain

- Utilities are eligible to earn a return on both invested capital (CapEx) as well as selected operational expenditures (OpEx). This would include long-term contracts with third-parties for grid services.
- Typical operating expenses, such as employee salaries, would continue to be passed through to ratepayers as they currently are in rate cases as an operating expenses.
- Under a TOTEX approach, the incentive to invest in infrastructure would be no different than the incentive to contract for services. Regulated returns would be determined based on a combination of utility capital expenditures and some operational expenditures – like third-party contracts. This differs from traditional regulation where only capital expenditures earn a return.
- All T&D companies in UK are covered by this approach
Vermont: Geographic Targeting for T&D

- Identify key nodes where T&D capacity is limited
- Estimate avoidable costs
- Establish nodal premium for energy efficiency acquisition
Rhode Island Examines System Value of DER

• RI PUC Docket 4600 is developing a new method for the utility to assess and reveal the value of Distributed Energy Resources in its system.
  – This will be used for other reforms in 2017.
California and Time Varying Rates

- The PUC decided in 2015 that time varying rates will be the default for IOU customers in 2019, with customers having the opportunity to opt out.
California Focuses on Planning and Procurement

• Distribution Resource Planning docket
  – Value on the system, reveals hosting capacity and locational net benefits
    • If peak is expensive, it would be revealed here

• Docket on utility procurement of DER
  – DER a key resource procured based on value

• Docket on redefined IRP
  – Capital spending with system value and local resources integrated
About RAP

The Regulatory Assistance Project (RAP) is a global, non-profit team of experts that focuses on the long-term economic and environmental sustainability of the power sector. RAP has deep expertise in regulatory and market policies that:

- Promote economic efficiency
- Protect the environment
- Ensure system reliability
- Allocate system benefits fairly among all consumers

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