Agenda

• Background and Key Concepts – 30 minutes
• Cost Allocation 201 – 30 minutes
• Cutting Edge Issues for CT Today – 30 minutes
• Break – 15 minutes
• Peering into the Future – 30 minutes
• Open Discussion – 45 minutes
Electric Cost Allocation for a New Era

A Manual
By Jim Lazar, Paul Chernick and William Marcus
Edited by Mark LeBel

https://www.raponline.org/knowledge-center/electric-cost-allocation-new-era/
Why Does Cost Allocation Matter?

- Cost allocation matters to customers: the allocated costs are used to set rates for each class
- Two key analytical perspectives
  - Cost causation
  - Costs follow benefits
- Data and analysis from cost allocation process informs rate design
Key Concepts

• Tradeoff between operating costs and capital costs means that most capacity costs are driven by shared usage metrics

• Changing nature of the electric system means that regulatory methods should change too

• As long as marginal cost pricing does not yield the exact revenue requirement, there will be inefficiencies in resulting cost allocation and pricing structures

• Equity is in the eye of the beholder
Key Questions for Connecticut

• Is the customer/demand/energy split still helpful or relevant?
• How can embedded-cost jurisdictions incorporate marginal cost concepts?
• How should states with restructured utilities wrestle with ISO pricing?
• How should public policy program costs be treated?
“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

Background and Key Concepts
In the Beginning: Let There Be Light!

- Early competition to provide electricity service started in cities in late 19th century
- State regulation begins in early 20th century and includes state-backed monopoly service territories
  - Natural monopoly and “wasteful competition”
- Federal legislation and regulation fills an important role starting in the 1930s
  - “Interstate commerce” gap
  - Break-up of major interstate utility conglomerates
  - Expansion of rural service
The Start of Nothing New Under the Sun

- Pricing debate in the 1890s
  - British engineer Hopkinson described concept of demand charges
  - Demand meter invented by Arthur Wright
  - TOU meter invented by Gisbert Kapp
- Basic pattern established in early 20th century
  - Demand charges for industrial customers
  - Volumetric kWh charges for small customers
Traditional Electric Utility

[Diagram of a traditional electric utility system, showing generation, transmission, and distribution processes.]

Vertically Integrated Utilities Rule the Earth in the mid-20th Century

- Majority of electric service provided by utilities that own generation, transmission, and distribution assets
  - Most generation is either steam turbines or hydroelectric
  - They are "natural monopolies," generally characterized by increasing economies of scale
- Cost-of-service ratemaking is predominant model
  - "Original cost" basis approved by Hope in 1944
  - FERC Uniform System of Accounts
- States possess primary regulatory jurisdiction; holding companies broken up by federal government
- Wholesale sales regulated by FERC, insofar as they affect interstate commerce
  - Sales to smaller utilities (e.g., munis and coops)
  - Purchased power agreements
  - Informal sales and trading
Why and How Do We Regulate Utilities?

- Public policy goals
  - Protection against abuses of monopoly power, efficient pricing, and promotion of competition where possible
  - Safe, adequate, and reliable service
  - Societal equity (e.g., universal access and affordability)
  - Environmental and public health requirements

- Principles for setting utility prices
  - Effective recovery of revenue requirement
  - Customer understanding, acceptance, and bill stability
  - Equitable allocation of costs
  - Efficient forward-looking price signals
The Regulatory Prerequisite: Data

- FERC Uniform System of Accounts
  - Important industry standard but not specific enough for some purposes
- Overall system load and generation data
- Location-specific T&D data have become more sophisticated
- Customer-specific data
  - Load sampling is no longer necessary with AMI
Simplified rate-making process

1. Determine revenue requirement
2. Net rate base (Plant in service – depreciation reserve)
3. Rate of return
4. Depreciation expense (Plant in service x depreciation rate)
5. Operating expense (Fuel + purchased power + labor + labor overheads + supplies + services + income taxes)
6. Other taxes
7. $ millions

Allocate costs among customer classes

- Residential
- Commercial
- Industrial
- Street lighting

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 month
- Cents per kWh peak
- Cents per kWh off-peak
- Dollars per kW monthly
- Dollars per light per month
Traditional Embedded Cost of Service Study (ECOSS) Process
## The 1992 NARUC Manual on Embedded Cost Methods

Typical cost classifications used in cost allocation studies are summarized below.

<table>
<thead>
<tr>
<th>Typical Cost Function</th>
<th>Typical Cost Classification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production</td>
<td>Demand Related</td>
</tr>
<tr>
<td></td>
<td>Energy Related</td>
</tr>
<tr>
<td>Transmission</td>
<td>Demand Related</td>
</tr>
<tr>
<td></td>
<td>Energy Related</td>
</tr>
<tr>
<td>Distribution</td>
<td>Demand Related</td>
</tr>
<tr>
<td></td>
<td>Energy Related</td>
</tr>
<tr>
<td></td>
<td>Customer Related</td>
</tr>
</tbody>
</table>

Determining Customer Classes

Types:
- Residential
  - Single-Family
  - Multi-Family
  - Solar?
  - Heating?
- Commercial
- Industrial
- Agriculture
- Street Lighting
Signs of Coming Change

- Nuclear power and combustion turbines established as viable technologies in 1950s and 1960s
  - Combined-cycle generation becomes viable in 1980s and 1990s
- Major northeast blackout in 1965
- International oil crises in 1970s have major economic impacts across many different fuel and electricity markets
- Economies of scale in supply begin to erode
- “Deregulatory” movement gains steam in 1960s and 1970s across industries
  - Bipartisan in many key respects
The Academy Invades Regulation: Marginal Cost, Time-Varying Pricing, and Competition

- Marcel Boiteux – French economist and utility executive
  - Academic and practical work on marginal cost-based time-varying rate design
- Alfred Kahn – Cornell economist
  - Led NY Public Service Commission in mid 1970s
  - Led federal deregulation of airlines in late 1970s
- William Vickrey – Columbia professor, won Nobel Prize
  - Emphasized short-run marginal cost basis for pricing and auction theory
- Scheppe, Caramanis, Tabors, and Bohn
  - Published “Spot Pricing of Electricity” in 1988
U.S. Average Electricity Prices Over Time

Traditional MCOSS Process

- Created in the 1970s
  - Adopted in a handful of states
- The basics
  - Functionalize, like ECOSS
  - Estimate marginal unit costs for each function
  - Compute sum of marginal costs by class
  - Reconcile to total revenue requirement
- Theory that efficient pricing should be better linked to marginal costs at all points in the process
  - In principle, this is the societal marginal cost
Cost Causation for Electric System

- System serves joint needs of all customers across all hours of the year
- Each function has distinct cost drivers
  - Energy supply costs are time-differentiated
  - Transmission lines serve multiple purposes
  - Distribution is built only where there is load to support it
  - Basic meters are for billing, but the costs of AMI are incurred for a broad array of purposes
- Administrative and general costs scale with size of the business
- Public policy programs reflect a mix of motivations
  - Electric system benefits
  - Broader societal goals
"Fixed" Costs, Generally

- All enterprises incur costs that are "fixed" in the short run
  - They are not driven by changes in sales in the short run
  - "Bricks and mortar"
  - "The CEO's desk"
- Most fixed costs are spread over the units that are sold
- As businesses grow, they incur additional fixed costs

Source: www.alexslemonade.org
Fixed Costs in the Electric System

- Equipment type and cost depend on expected use
  - Generation mix
  - Transmission lines added to connect remote resources
  - Line and transformer sizing
- Wear and tear drives continuing costs
  - Generator usage
  - T&D equipment ages from repeated high loads
Example: Fixed v. Variable

- Multiple ways to serve an increase in peak demand
  - Peaker – mix of fixed and variable costs
  - Utility-owned battery storage – almost entirely fixed costs
  - Demand response – primarily variable costs
## Presentation of Results

Computing class rate of return in an embedded cost study

<table>
<thead>
<tr>
<th></th>
<th>Total</th>
<th>Residential</th>
<th>Small (up to 20 kWs)</th>
<th>Medium (20 to 250 kWs)</th>
<th>Large (more than 250 kWs)</th>
<th>Large primary</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>Revenues</td>
<td>$117,760,688</td>
<td>$28,116,419</td>
<td>$8,342,138</td>
<td>$26,156,458</td>
<td>$38,730,796</td>
<td>$15,134,759</td>
<td>$1,280,117</td>
</tr>
<tr>
<td>Allocated expenses</td>
<td>$112,438,805</td>
<td>$28,297,246</td>
<td>$8,997,362</td>
<td>$23,807,377</td>
<td>$35,927,265</td>
<td>$14,280,041</td>
<td>$1,129,515</td>
</tr>
<tr>
<td>Operating income</td>
<td>$5,321,883</td>
<td>-$180,827</td>
<td>-$655,223</td>
<td>$2,349,081</td>
<td>$2,803,532</td>
<td>$854,718</td>
<td>$150,603</td>
</tr>
<tr>
<td>Allocated rate base</td>
<td>$87,878,094</td>
<td>$24,935,855</td>
<td>$8,339,503</td>
<td>$18,481,728</td>
<td>$26,069,711</td>
<td>$9,399,629</td>
<td>$651,667</td>
</tr>
<tr>
<td>Allocated return</td>
<td>$5,321,883</td>
<td>$1,510,111</td>
<td>$505,039</td>
<td>$1,119,251</td>
<td>$1,578,778</td>
<td>$569,240</td>
<td>$39,465</td>
</tr>
<tr>
<td>Rate of return</td>
<td>6.06%</td>
<td>-0.73%</td>
<td>-7.86%</td>
<td>12.71%</td>
<td>10.75%</td>
<td>9.09%</td>
<td>23.11%</td>
</tr>
<tr>
<td>Profit margin</td>
<td>4.52%</td>
<td>-0.65%</td>
<td>-7.82%</td>
<td>8.94%</td>
<td>7.21%</td>
<td>5.62%</td>
<td>13.33%</td>
</tr>
<tr>
<td>Revenue-cost ratio</td>
<td>100.00%</td>
<td>94.33%</td>
<td>87.79%</td>
<td>104.93%</td>
<td>103.27%</td>
<td>101.92%</td>
<td>109.51%</td>
</tr>
<tr>
<td>Revenue shortfall (or surplus)</td>
<td>$1,690,938</td>
<td>$1,160,262</td>
<td>($1,229,831)</td>
<td>($1,224,754)</td>
<td>($285,478)</td>
<td>($111,138)</td>
<td></td>
</tr>
<tr>
<td>Percentage increase for equal rate of return</td>
<td>6.01%</td>
<td>13.91%</td>
<td>-4.70%</td>
<td>-3.16%</td>
<td>-1.89%</td>
<td>-8.68%</td>
<td></td>
</tr>
</tbody>
</table>

Note: Independent rounding may affect results of calculations.
Sankey diagram for modern embedded cost of service study

Revenue requirement: 1,500

Generation: 600
Transmission: 200
Distribution: 400
Customer service, billing and A&G: 300

Peak hours: 250
Intermediate hours: 375
All hours: 635

Site infrastructure, billing and collection: 240

Residential: 500
Commercial: 460
Industrial: 400
Street lighting: 140
Using the Results of Studies

- Examine multiple approaches
- Define a range of reasonableness
- Apply judgment
- Change allocation of costs (and rates) gradually
Relationship Between Cost Allocation and Rate Design

• Cost allocation and rate design have different purposes:
  • Cost allocation = group equity
  • Rate design = customer understanding, individual bill impacts, and efficiency

• Bad cost allocation techniques encourage bad rate design
• Good cost allocation techniques can inform modern rate design
Rate design should make the choices customers make to minimize their own bills. . .

. . . consistent with the choices we would make to minimize system costs.
Creating a Modern ECOSS

• More granular functions;
• Need sophisticated understanding of demand and energy classifications
  • Classification and allocation should reflect time-varying costs;
• Clear division between shared distribution plant and the equipment that connects individual customers.
Before Costs Are Allocated…

- Identification of revenue requirement
  - Includes cost allocation across states and different business units within a holding company
- Data collection
- Customer class definitions
Load Research & Data Collection

Then
- Sampling
- 10% error band

Now
- All customers
- Granular data
- Location-specific
Three Steps to Embedded Cost Allocation
**Functionalization is Clear… Except When It’s Not…**

- If a generator is located next to the shared transmission system, it is obvious the short segment connecting the generator to the shared system belongs to the generation function
  - What if the line connecting the generator to the shared system is 30 miles long? 100 miles long?
  - Does it matter if another generator might connect to that segment in the future?
- Billing and customer service should be a separate function
  - Meters are not part of the distribution function strictly speaking
- Administrative and general costs should be a separate function
- Public policy program costs could be divided up among functions or separated as new function
The Black and White Era for Classification

- The customer/demand/energy classification method was established by the 1930s
  - Operating/running costs were all designed as “energy-related”
  - Capacity costs were all “demand-related” and built to satisfy system peaks
  - Customer-related costs were very small and many customers had no customer charge
- By 1964, at least 20 different methods had been proposed to allocated demand-related costs
Customer Diversity and the Peak Responsibility Method

![Diversity at the customer class level](image)

- **Street lighting**
- **Industrial**
- **Commercial**
- **Residential**

- **System peak is at hour 18**
- **Industrial peak is at hour 11**
- **Commercial peak is at hour 14**
- **Residential peak is at hour 20**
Demand-Related Costs at Off-Peak Times

• D.J. Bolton in 1951:
  • “Another reason why the half-hour of absolute annual peak is not the sole criterion of plant cost lies in the necessity of overhaul…. Peak responsibility must then have regard not only to the absolute system capacity but to the capacity temporarily available… As an example, during 1948, load on the grid had to be shed on 38 occasions between April and October, although the load was far below the winter peak. There was therefore a definite indication of demand-related expenses on account of generating plant even in the summer.”
  • Same logic applies to other reliability costs!
The 1960s Changed Everything

• Since the invention of the modern combustion turbine, all utilities have had a relevant choice in the type of capacity to build
• Not all capacity is created equal!
  • Nuclear: high fixed investment cost, low fuel cost
  • Gas combustion turbine: low fixed investment cost, high fuel cost
• A significant portion of capacity costs are energy-related
  • More expensive capacity is justified by lower operating costs (fuel, O&M) with additional hours of generation
Issues with Traditional Demand & Energy Classifications

- What is the proper split between demand and energy for capital assets?
- Demand at what hours?
  - System peak, equipment peak, or class peak?
  - Demand allocators typically only use a subset of the relevant hours
- Energy-classified costs are usually allocated using annual kWh usage
  - Fails to reflect time-varying energy costs
Traditional vs. New Methods
Generation

The Traditional Way
• Fixed costs classified to demand
• Allocated on narrow measures of peak demand (1CP, 12CP)

New Methods
• Fixed and variable costs assigned to relevant hours.
• Costs allocated on class hourly usage
### Equivalent Peaker

Table 14. Equivalent peaker method analysis using replacement cost estimates

<table>
<thead>
<tr>
<th>Resource type</th>
<th>Cost per kW</th>
<th>Capacity-related share of cost</th>
<th>Energy-related share of cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peaking</td>
<td>$770</td>
<td>100%</td>
<td>0%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>$3,689</td>
<td>20.9%</td>
<td>79.1%</td>
</tr>
<tr>
<td>Fossil*</td>
<td>$1,976</td>
<td>39.0%</td>
<td>61.0%</td>
</tr>
<tr>
<td>Combined cycle</td>
<td>$1,020</td>
<td>75.4%</td>
<td>24.6%</td>
</tr>
<tr>
<td>Hydro</td>
<td>$4,519</td>
<td>17.0%</td>
<td>83.0%</td>
</tr>
</tbody>
</table>
Base – Intermediate – Peak
Traditional Ways vs. New Methods

Transmission

The Traditional Way

- All costs classified as demand-related
- Allocated on narrow measures of peak

New Methods

- Each component is allocated based on its use and need.
Traditional Ways vs. New Methods

Distribution

The Traditional Way
- Many shared costs classified as customer-related
- Demand costs allocated on non-coincident load

New Methods
- No shared costs are customer-related
- Demand costs allocated on usage in broad peak periods
Modern embedded cost of service study flowchart

- Revenue requirement
- Functionalization
  - Generation
  - Transmission
  - Distribution
  - Billing, customer service, and A&G costs

- Allocation
  - Site infrastructure, billing and collection
  - Residential
  - Commercial
  - Industrial
  - Street lighting

Time Assignment
- Peak hours
- Intermediate hours
- All hours, including off-peak
What is “Customer-Related”?

• The marginal costs of adding a residential customer are relatively modest
  • Billing, simple metering for billing, service line in many cases, dedicated line transformer in a limited number of cases, and part of customer service
  • Long line extensions are paid for by the customer
Minimum System Fallacy

- Shared distribution system expenses, such as primary conductors, poles and substations, do not meaningfully depend on the number of customers.
  - A building can be one hotel or 100 apartments.
- The cost of a “minimum system” does not vary with the number of customers, but rather area/miles spanned.
## Distribution Cost Methods: Shared System Elements

<table>
<thead>
<tr>
<th>Element</th>
<th>Demand/Energy Method</th>
<th>Hourly Allocation Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>Substations</td>
<td><strong>Functionalization:</strong> Entirely primary</td>
<td>Allocate to all hours, with emphasis on high-load hours</td>
</tr>
<tr>
<td></td>
<td><strong>Classification:</strong> Demand and energy</td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Demand allocator:</strong> Hours at and near peaks</td>
<td>Revenue-driven line extension costs allocated on a revenue basis</td>
</tr>
<tr>
<td>Poles</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Primary conductors</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
### Distribution Cost Methods: Site-Specific Elements

<table>
<thead>
<tr>
<th>Element</th>
<th>Method</th>
<th>Hourly Allocation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Line transformers</td>
<td>Secondary demand and energy</td>
<td>Transformer peaks and high-load hours</td>
</tr>
<tr>
<td>Secondary conductors</td>
<td>Secondary demand and energy</td>
<td>Line peaks and high-load hours</td>
</tr>
</tbody>
</table>
Traditional vs. AMI Metering
Advanced Metering Costs

- “Smart meters” do more than provide billing data
  - Enable more efficient rate designs and demand response programs
  - Enable volt/VAR optimization
  - Data improve system planning
  - Communications system has multiple uses

- **City of Burbank**: using AMI data, transformer right-sizing lowered line losses by 1%, saving $1 million per year
### Advanced Metering Infrastructure

<table>
<thead>
<tr>
<th>Smart Grid Element</th>
<th>Legacy Account</th>
<th>Smart Grid Classification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Smart Meters</td>
<td>370</td>
<td>Demand, Energy and Customer</td>
</tr>
<tr>
<td>Distribution Control Devices</td>
<td>362, 365, 367</td>
<td>Demand and Energy</td>
</tr>
<tr>
<td>Data Collection</td>
<td>902</td>
<td>Demand, Energy and Customer</td>
</tr>
<tr>
<td>Meter Data Management System</td>
<td>391, 903, 905</td>
<td>Demand, Energy and Customer</td>
</tr>
</tbody>
</table>
Administrative and General Costs

- Generally, functionalize as much as possible, then follow cost causation for allocation
- Includes: Overhead for O&M, Labor, Plant, Regulatory, Admin & Exec, and Advertising
- e.g., Regulatory costs cover a broad range of issues in terms of cost causation, can be distributed by class revenues
Other Resources and Public Policy Programs

• Energy efficiency costs produce system wide benefits - fair alignment of costs and benefits
• Demand Response – add back curtailed loads before allocating costs based on metrics of peak usage
Key Takeaways

• More granular functions;
• Need sophisticated understanding of demand and energy classifications
  • Classification and allocation should reflect time-varying costs
• Clear division between shared distribution plant and the equipment that connects individual customers
3 Cutting-Edge Issues for Connecticut Today
Regulatory Changes Since 1992

- Restructuring
  - New jurisdictional lines
  - New wholesale and retail markets
- Public policy costs for efficiency, environment, and equity
Topics

- What to do about ISO-NE?
- Distribution System In Depth
- Public Policy Programs
- Performance-Based Ratemaking
Retail Generation Supply in Restructured Jurisdictions

- Cost allocation is driven by both:
  - Wholesale market structures
  - Retail supply rules and procurement structures
- States have more control over the second than the first
  - Less direct control than traditional regulation of vertically integrated utilities
- Generators recover some or all of their fixed costs through the wholesale energy market
ISO-NE Transmission Pricing

• 12CP pricing for regional network service does not have a good cost-causation basis
• Reducing peaks in most months doesn’t have a strong impact on long-run transmission costs
Distribution System Economics 101

- Marginal customer costs
  - Billing and related customer service
  - Simple meters for billing (but not AMI!)
  - Service lines for small single customer premises
- Short-run marginal energy costs
  - Marginal line losses are higher at peak times
- Marginal peak costs
  - Significant portions of distribution capacity are upsized for broad set of peak hours
Historic Methods for Allocating Shared Distribution System Costs

• Often assumed to be demand-related
• Substations and primary voltage lines tend to be allocated based on class NCP
  • Not particularly accurate assumption in many cases
• Sometimes customers that connect at primary voltage are exempt from secondary voltage costs
  • Variety of practical problems here
Month and hour of Delmarva Power & Light substation peaks in 2014

- **Substation peak**: Size of circle is proportional to peak load.

Source: Delmarva Power & Light. (2016, August 15). Response to the Office of the People’s Counsel data request; 5 11, Attachment D. Maryland Public Service Commission Case No. 9424.
Cost Duration Curve Method in NH

Unique collaboration in NH to define time-of-use distribution rate
Cost Duration Curve Method in NH

- Used load for both residential and small C&I customers on rationale that they often share circuits
- No geographic distinctions
- Left current residential customer charge at $14.54 per month and allocated all other distribution costs among TOU blocks
Liberty NH TOU Rate Structure

Summer = May 1 to October 31
Liberty NH TOU Rate Structure

Winter = November 1 to April 30
Distribution System Economics 201

• Shared service drops and shared line transformers are sized for the combined peak of smaller groups of customers
  • Nearly impossible to allocate (or price) locationally, but class-specific tracking and using weighted averages can help
  • Significantly less load diversity than broadly shared elements of system

• For larger customers, dedicated service lines and dedicated line transformers are sized to the individual customer
  • May have diversity of usage behind the individual meter, but could plausibly be managed by the overarching entity
Typical utility estimates of diversity in residential loads

Nevada Power Residential Customer Classes

- Residential Multi-Family – separately metered in a permanent single-family dwelling in a multi-unit complex (like an apartment)
  - Monthly customer charge of $7.70
- Residential Single-Family – separately metered in a permanent single-family dwelling
  - Monthly customer charge of $12.50
- Large Residential Service – three-phase service to a separately metered, permanent, single-family dwelling
  - Monthly customer charge of $70.70
Energy Efficiency Programs

- Status quo cost recovery methods
  - Sometimes allocated across classes based on program participation
    - One version of “costs follow benefits”
    - Frequently priced on simple kWh basis
- Could classify, allocate, and price based on cost causation instead
2021 AESC Summer Peak Electric Cost Components

- All classes benefit from EE investment!
- Hard questions remain
Storage: Performs Many Functions

Source: Tesla
Storage Functionalization

- Reserves
- Energy Arbitrage
- Transmission
- Distribution
Storage in the FERC Uniform System Of Accounts

• 363 Energy Storage Equipment – Distribution
• 584 Underground Line Expenses (major only)
• 584.1 Operation of Energy Storage Equipment
Customer Storage Programs

Figure 1: Program Net Present Value of Cost/Benefit Categories by Cost Test

- Participant Incremental DER Costs
- Lease Value
- TPO Administration
- Performance Incentive Administration
- Upfront Incentive Administration
- Non-Program Incentives
- Performance Incentives
- Upfront Program Incentives
- Participant Bill Savings
- Net Avoided Outage Benefits
- Non-Embedded Emissions
- Cross-DRPE Impacts
- DRPE Capacity Impacts
- DRPE Energy Impacts
- Reliability
- Avoided T&D Capacity
- Avoided Generation Capacity
- Avoided Energy
Low-Income Discounts and Uncollectibles

- Providing discounts to ratepayers who have difficulties paying their bills does have some financial benefits
  - Otherwise, a zero-sum game and those costs must be put on other ratepayers
- Need to synchronize treatment over classes and time
  - If industrial customers are shielded from residential uncollectibles, then residential customers should be shielded from industrial uncollectibles
Performance-Based Ratemaking

- Tools in the PBR basket
  - Multi-year determination/formula for allowed revenue
  - Decoupling
  - Earnings sharing mechanisms
  - Metrics to improve transparency
  - Financial penalties and rewards linked to outcomes
- Moving away from cost-of-service ratemaking means that a lower percentage of revenue can be linked to cost causation
  - Fall back on “costs follow the benefits”
Peering into the Future
Topics

• Changing nature of electric system
• Smarter pricing and its cost allocation implications
• The never-ending cost shift debate
• Marginal and residual costs
• New allocation and billing determinants
Brief History of U.S. Electric System

- **Pre-1960**
  - Combustion steam units, with significant hydro in some parts of the US
- **1960-1980**
  - Emergence of nuclear power and combustion turbines
  - Oil crises and beginning of federal environmental regulation
- **1980-2000**
  - PURPA implementation and then restructuring in many areas
  - Introduction of energy efficiency programs and demand-side resources
  - Emergence of combined cycle generation
- **2000-2020**
  - Major increase in fossil gas extraction from hydraulic fracturing
  - Emergence of utility-scale wind and solar, distributed generation, advanced meters and smart grid
To Infinity and Beyond...

- Massive increases in computing power and data storage capabilities
- High penetrations of variable renewable resources change operation and economics of electric system
- Energy management technology becomes cheap and widespread
- Electrification of transportation and heating may increase load
- Continued cost declines for clean distributed generation and energy storage
Decarbonized and decentralized!
New Risks and Opportunities: Generation

- Fossil fuels phased out
- Solar, wind, storage increase greatly
- Flexible demand, including customer-side storage
- Green hydrogen? Allam Cycle? Modular Nuclear?
- New transmission lines between regions?
Illustrative Example of Gross vs. Net Load

![Illustrative Example of Gross vs. Net Load Graph]

- Gross load (before wind and solar)
- Net load
Overall resource mix matters!

The Demand Classification is Splintering

- Peak demand related
- Capacity related
- Reliability related

1950

2020
Demand-side strategies span many timescales

New Risks and Opportunities: Local Reliability and Resiliency

- System hardening, undergrounding and tree trimming are “traditional” approaches
- Are multi-customer microgrids a public or private good?
  - Who operates the microgrid and gets paid when the macrogrid is down?
- How many individual residential customers would consider investing in sufficient DG and storage to operate critical loads when macrogrid is down?
  - Would those customers want to remain connected to the grid? Does rate design matter?
Who Pays for All This?

- Private investment at customer sites
- Tax credits and government spending
- Ratepayers in a manner controlled by utility regulators
“It's tough to make predictions, especially about the future.”

-- Lawrence Peter “Yogi” Berra
Ratemaking in the Future

• Increasing importance of SRMC pricing
  • Particularly if you are relying on demand-side for generation resource adequacy
• The problem of residual costs gets harder
  • As grid cleans up, marginal emissions rate likely goes down
  • With high penetrations of DER, traditional billing determinants stagnate, and price elasticity will likely increase across multiple dimensions
Options for SRMC Pricing

• Wholesale market options
  • Directly pass-through wholesale energy market costs
  • Directly pass-through capacity market signals?

• State level options
  • Critical peak pricing
  • Create new granular pricing scheme?
What Does This Mean for Cost Allocation?

• As pricing becomes more granular, the class load profile is less relevant
  • Instead of accounting for cost differences at the cost allocation stage you are doing it automatically in the rate design stage!

• Technology-neutral time-varying rates of increasing complexity
  • Assigning costs to time periods for rate design is similar to the traditional cost allocation challenge
Changing Purpose of Customer Class Distinctions

• In principle, a perfect set of time- and location-varying prices would eliminate the need for customer classes and even cost allocation in the traditional sense

• Customer class distinctions can be used to push the envelope on pricing sophistication
  • Segment residential class into “basic” and “advanced”
What If Critical Times Aren’t Predictable?

• Changing nature of resource adequacy
  • Time windows may not be consistent
  • Critical needs may not arise every year

• Key questions
  • How do we structure critical peak pricing to balance accuracy and customer understanding?
  • Does this pose a revenue stability issue?
Residual or “Unallocable” Costs

- Marginal cost frameworks explicitly wrestle with concept of what to do with residual costs
- Embedded cost frameworks force you to put every single cost into one of three buckets
  - Administrative and general costs?
  - Distribution system backbone or “minimum system” costs?
What is a Cost Shift?

- Embedded cost definitions focus on changes in cost allocation determinants and rate levels from rate case to rate case.
- Marginal cost definitions compare the value of the resource with the compensation levels.
- Residual cost definitions look at additional customer contributions to utility revenue after considering a particular marginal value for a resource or customer action.
Minimum Distribution System Revisited

“But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs for the reason just given, while it is also denied a place among the customer costs for the reason stated previously, to which cost function does it then belong? The only defensible answer, in my opinion is that it belongs to none of them…. But the fully distributed cost analyst dare not avail himself of this solution, since he is the prisoner of his own assumption that ‘the sum of the parts equals the whole.’ He is therefore under impelling pressure to ‘fudge’ his cost apportionments by using the category of customer costs as a dumping ground for costs that he cannot plausibly impute to any of his other categories.”

James C. Bonbright, 1961, p. 348-49
Algorithm for Socially Efficient Price Signals

1. Start with short-run marginal costs where you can
2. Layer in long-run marginal costs
3. Add any unpriced externalities
4. End by allocating and pricing “residual” costs that must be recovered through rates
Minimum System as an Energy-Related Cost

- Representation of short-run marginal costs due to marginal line losses
- Correspondence with long-run marginal costs
- Existence of unpriced externalities
- Competition and adjacent markets
Problems with Ramsey Pricing

Ramsey pricing rule - place residual costs on the least elastic pricing element

- Elasticity estimates are not always obvious and can change
- Ramsey model underplays dynamic efficiency, information asymmetry, and competition across markets
- Distributional impacts can be challenging
Exploring Customer Elasticity in CA

• High traditional customer charges have same distributional problem as per capita taxation
• Academic proposal for tiered income-based customer charges
  • $200 per month or higher for high-income customers
• New “grid participation” installed capacity charge proposal
  • $8/kW installed
TOU Rates With High Solar Penetration

Allocate and Price for Flows

Illustrative modern electric system

Advanced Residential Rate Design for a High-DER Future

<table>
<thead>
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<th>Cost Recovery Only</th>
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<tr>
<td>Customer charge ($/month)</td>
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<tr>
<td>Site infrastructure charge ($/individual NCP kW)</td>
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<td>Bidirectional distribution flow charge (cents/kWh on imports and exports)</td>
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<th>Symmetric Charges and Credits</th>
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<tr>
<td>Off-peak (cents/kWh)</td>
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<td>On-peak (cents/kWh)</td>
<td>30 cents</td>
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<tr>
<td>Critical peak (cents/kWh)</td>
<td>75 cents</td>
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</table>
The Virtues of Gradualism and Thinking Ahead

• “A stitch in time saves nine.”
  • Traditional proverb
• “Don’t panic. There will be plenty of time for that later!”
  • Gregg Easterbrook
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