Cost of Service and Pricing for Gas Utilities

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IPU Advanced Course: Cost Allocation and Rate Design
Delivered Remotely
Overview of Topics

**Introduction**
- Concepts in Pricing
- Efficiency and Pricing

**Cost of Service**
- Purpose and Philosophy
- Gas Supply Chain
- Embedded Cost Study
- Marginal Cost Study

**Pricing**
- Traditional Rate Design
- Modern Rate Design
Introduction
Costs and Prices

What does it mean when we ask how much something costs?

Generally, we mean the price

Cost is not the price but something else

Current Costs
Past Costs
Future Costs
Opportunity Costs

It is this difference between “price” and “cost” that drives the difference in views about pricing public utility services
Incentives v. Cost Recovery

**Economists:** View world through lens of incentives.

- Decentralized decisions
- Price is a signaling device
- Result: People make good decisions, and the result is best for everyone

**Engineers:** View world through lens of problem solving.

- Concerned about making the best decision about deploying resources to meet the objectives of the investment
- Price is a cost recovery mechanism
- Result: Planners make good decisions, and the result is best for everyone
Costs and Prices

What does it mean when we ask how much something costs?

Generally, we mean the price

Cost is not the price but something else

Current Costs
Past Costs
Future Costs
Opportunity Costs

It is this difference between "price" and "cost" that drives the difference in views about pricing public utility services
Principles

Scarcity

Choice has a Cost (Opportunity Cost)

Not all Costs Matter (Sunk Cost)

Comparing the Margins

Equilibrium: People Respond to Incentives
What is the Role of the Public Utility Price?

**Capital Attraction**
Utilities should be willing to provide the level of service necessary to serve all comers.
Applies to rate structure and the rate levels.

**Efficiency-Incentive**
Prices in a competitive market provide incentives for firms to produce more efficiently to maximize profits.
If regulation is a substitute for competition, regulated prices should provide incentives for effective production.

**Demand Rationing**
Consumers also need price signals to make decisions about consumption.

**Income Distribution**
Prices also serve as both a method of transferring cash from consumers to producers and as a method of transferring cash between consumers.
Factors Affecting Rate Design Choices

**Economic**
- Cost of service
- Value of service
- Competitor prices
- Price differences and discrimination
- Availability of gas supply and capacity
- Return and revenue stability

**Regulatory Factors**
- Precedent
- Intervenor interests

**Historical Factors**
- Rate perspective
- Rate continuity

**Social and Political Factors**
- Customer reaction and acceptance
- Public relations aspects
- Economic conditions of service territory
- Social obligations to particular customer groups
- Political attention and involvement
Volumetric rates make up most rate structures at retail level (unlike at wholesale level)

Pricing strategies have largely focused on recovery of reasonable costs. This has led to:

- Trackers and riders
- Decoupling
- Formula ratemaking

Recognition of price as a signal is relatively new:

- MC-based pricing in 1970s
- Interruptible capacity pricing
- Economic Development and bypass rates
- Pricing for DER – Value of resources
- Demand charges and SFV
- Energy Efficiency
- Renewable standards
- Low-emissions credits
- Non-wires and non-pipe solutions
Current State of the Industry

1. Production or Import Facility
2. Processing and Cleaning
3. Underground Storage
4. Pipeline Compression
5. Transmission Pipeline
6. City Gate Meter
7. High-Pressure Distribution
8. Low-Pressure Distribution
9. Customer Meter
Revenue Requirement

Cost of Service

Rate Design

Objectives

Other Factors

Final Prices

Revenue Recovery

Price Signals

Efficiency

Equity

Capital Expenses

OPEX + Interest + Taxes

Return of and on Capital

Operational Data

Economic Analysis

Judgment

Rate Shock

Social Concerns

Policy Concerns

Other Factors

Final Prices
Creating Rates

Revenue Requirement

Cost of Service

Unbundled Costs
What is the Output?
Class Cost Responsibly

Class Profitability

Class Cost Study

By Function
By Cost Driver
By Customer Class

Revenue Requirement

Capital Expenses
OPEX + Interest + Taxes
Return of and on Capital
Operational Data
Economic Analysis
Judgment

Rates
Residential
Commercial
Industrial
Basics of Cost of Service
Brief History of US Gas Industry

How Much?

- Revenue Requirement
- O&M Expenses
- A&G Expenses
- Depreciation
- Taxes
- Rate Base Investment

Who Pays?

- Rate By Customer Class
- Customer Charge
- Demand Charge
- Energy Charge
Time Frame

**Short-run:** One input, normally capital, is fixed
- Fixed Cost: Cost of that fixed input
- Variable Cost: Cost of all other inputs as output changes

**Long-run:** All inputs are variable, there are no fixed costs in the long-run

**Revenue Requirement:** Total cost allowed in rates

**Joint/Common:**
- Common costs result from usage of a common asset
  - Industrial and Residential customers using capacity simultaneously
  - In principle could be allocated based on opportunity cost

**Joint costs result in joint production:**
- Peak and off-peak capacity
- In principle cannot be allocated
Costs Part 2 of 2

**Average Cost**: Total economic cost divided by output

**Marginal Cost**: Measure of change in total economic cost as output changes
  - Economic costs supporting optimal pricing
  - Time frame: Short-run v. Long-run

**Residual Costs**: Difference between LRMC and Revenue Requirement
Cost of service studies (COSS) are used to:

- Attribute costs to different customer classes
- Determine how costs will be recovered from customers within classes
- Calculate costs of different services
- Separate costs between jurisdictions
- Determine revenue requirement between competitive and monopoly services

General types of cost studies

- Embedded (ECOSS)
- Marginal (MCOSS)
  
  What are the basic differences?
Philosophy of Cost Studies

Cost causation is the attempt to apportion the cost to those who caused the cost to be incurred

- Generally will look for a link between the customer activity/characteristics and the cost incurred
- An understanding of the operational and economic attributes of the system are used in determining this link
- Cost causation is not necessarily an economic concept

Joint and common costs

- Costs that are not directly attributable to a customer or customer class
- Distribution mains (gas) or lines/substations (electric)
- Requires some “allocation”
- Sometimes the question of “who benefits” from the cost is mixed into the equation
Natural Gas Supply Chain

Commodity | Transmission | Distribution | Customer
---|---|---|---
Production | Storage | Storage | Competitive Supply Charge
 Commodity Price | Competitive or Tariff Rate | or
 Marketer | Pipeline | Commodity | Purchase Gas Adjustment
 Commodity Price | Contract Demand + Variable Charge | Local Production Contracts
 = WACG | Marketer | Delivery Costs | Base Rates
 Upstream | | | Downstream
Steps in COSS

Obtain test year utility revenue requirement
- Other revenues (e.g., off-system sales, Hub sales, etc.)
- Jurisdictional revenues/costs

Obtain load and market characteristics of customer base

Determine customer classes

Billing determinants: Weather normalization

Apply Cost of Service Approach
- Functionalize
- Classify
- Allocate

Post COSS steps:
- Interclass revenue allocation
- Market characteristics (e.g., bypass opportunities)
Customer Class Determination

End use
- Space heat, non-space heat, etc.
- Type of customer and meter (residential, commercial, industrial, electricity generation)

Size and usage
- Volume and capacity
- Load factor (average usage relative to peak usage)

Type of load
- Firm, interruptible
- Competitive alternatives (dual-fuel, bypass)
What information is needed for COSS?

Revenue requirement

Uniform system of accounts
- Plant investment
- O&M expenses
- Overhead

Capital spending plans (MC OSS but can be useful for ECOSS as well)

Billing Determinants
- Projected and actual revenues by customer class
- Sales (weather adjusted) by customer class
- Number of customers
- Demand

Load research
- Peak demand by customer class
- Special studies (transport customers, storage, etc.)

Other revenues (off-system sales, hub revenues, etc)

Competitive/Market characteristics
Pros and Cons of COSS

By nature, COSS are not particularly accurate, many regulators use COSS as guides.

ECOSS
Equates to revenue requirement
Require significant judgement on the part of the analyst
Different choices can lead to dramatically different outcomes
Generally based on the past not the future (only if past looks like future will this make sense)
Extremely data intensive
More transparent

MCOSS
Does not equate to revenue requirement (how to adjust?)
Less judgment on part of analysts
Many observers claim MCOSS is less transparent
Tends to allocate more cost to residential customers
Better pricing signals
Question of long-run v. short-run (or intermediate run?)
Tends to more closely follow utility investment
Embedded Cost of Service
Embedded Cost Studies

Step 1: Functionalize (production, distribution, transmission etc.)

For gas and electric utilities, functionalization is generally an accounting exercise (i.e., use USOA)
Exception: Electric transmission may need additional analysis (e.g., FERC seven factor test).

Step 2: Classification (demand-related, volume-related, customer-related, etc.)

Step 3: Allocation

Direct assignment
Allocator (demand, energy, customers, etc.)
Overview of Cost Allocation Process

Operations and Customer Data
- Customer Mix
- Load Characteristics
- Metering, Billing, Payments

Revenue Requirement
- Capital Expenditures
- Operating Expenses
- Depreciation and Taxes
- Interest Expense
- Shareholder Return

Functionalize
Classify
Allocate

- Distribution
- Transmission
- Production
- Customer
- Energy
- Demand

- Residential
- Commercial
- Industrial

Rates
COSS for Gas Utility

(1) Cost Functionalization

- Production & Gathering
- Storage
- Other Gas Supply
- Transmission
- Distribution

(2) Cost Classification

- Fixed
  - Customer
  - Demand (Capacity)
  - Commodity
- Variable
  - Commodity

(3) Cost Allocation

Total Cost of Service

Source: R. Feingold "Traditional and Unbundled LDC Rate Design" AGA Rates School, June 2009, Center for Business and Regulation, Chicago, IL
Step 1: Functionalization

What is the purpose of the cost?

Gas utilities
- Gas production
- Distribution (low pressure mains)
- Transmission (high pressure mains)
- Storage
- Customer Service (costs associated with hooking up customers, meters, service drops, etc.)
- General plant and administrative and general expenses (management costs, costs of buildings and offices, etc.)

Determines what part of the operations of the utility will be allocated the costs

Best approach is direct assignment (by accounting division)

Other examples, fuel, O&M, depreciation
General plant and overhead (A&G) is more difficult

General plant often allocated based on the plant (e.g., if 50% of plant is distribution, then 50% of general plant is allocated to distribution)

A&G often allocated based on direct labor e.g., if 30% O&M is distribution then 30% A&G is allocated to distribution

- Direct labor is labor functionalizes directly to the functions (“the field crews”)
- Indirect labor is the labor associated with A&G (“office workers”)

### Functionalized Revenue Requirement

<table>
<thead>
<tr>
<th>Line No.</th>
<th>(A) Production</th>
<th>(B) Transmission</th>
<th>(C) Distribution</th>
<th>(E) General</th>
<th>(F) Total</th>
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</thead>
<tbody>
<tr>
<td>1</td>
<td>Total Operating Expenses</td>
<td>188,377,894</td>
<td></td>
<td></td>
<td>188,377,894</td>
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<tr>
<td>2</td>
<td>Production</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>3</td>
<td>Transmission</td>
<td>4,611,093</td>
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<td></td>
<td>4,611,093</td>
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<td>4</td>
<td>Distribution</td>
<td>10,644,700</td>
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<td>10,644,700</td>
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<tr>
<td>5</td>
<td>Customer Accounts</td>
<td>8,231,423</td>
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<td></td>
<td>8,231,423</td>
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<tr>
<td>6</td>
<td>A&amp;G</td>
<td>21,077,467</td>
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<td></td>
<td>21,077,467</td>
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<tr>
<td>7</td>
<td>Total Depreciation Expense</td>
<td>11,104,730</td>
<td>17,203,809</td>
<td>16,447,534</td>
<td>185,516</td>
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<tr>
<td>8</td>
<td>TOTAL O&amp;M</td>
<td>199,482,624</td>
<td>22,514,902</td>
<td>35,323,057</td>
<td>21,262,983</td>
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<tr>
<td>9</td>
<td>Net Plant in Service</td>
<td>305,700,627</td>
<td>207,856,491</td>
<td>258,576,688</td>
<td>44,397,224</td>
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<tr>
<td>10</td>
<td>Rate Base Additions</td>
<td>39,584,564</td>
<td>26,914,922</td>
<td>33,482,806</td>
<td>5,748,908</td>
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<td>11</td>
<td>Rate Based Subtractions</td>
<td>25,870,307</td>
<td>17,590,121</td>
<td>21,882,400</td>
<td>3,757,172</td>
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<td>12</td>
<td>TOTAL RATE BASE</td>
<td>319,414,885</td>
<td>217,181,252</td>
<td>270,177,093</td>
<td>46,388,960</td>
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<tr>
<td>13</td>
<td>Proposed Return</td>
<td>9.50%</td>
<td>9.50%</td>
<td>9.50%</td>
<td>9.50%</td>
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<tr>
<td>14</td>
<td>Total Return</td>
<td>30,344,414</td>
<td>20,632,223</td>
<td>25,666,824</td>
<td>4,406,951</td>
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<tr>
<td>15</td>
<td>Total Revenue Requirement Ex A&amp;G, Gen, Taxe</td>
<td>223,827,038</td>
<td>43,147,125</td>
<td>60,990,481</td>
<td>-</td>
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<tr>
<td>16</td>
<td>Allocation of General Revenue Req. and Taxes</td>
<td>$35%</td>
<td>$5%</td>
<td>$60%</td>
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<td>17</td>
<td>Taxes Other Than Income</td>
<td>$6,289,426</td>
<td>$898,489</td>
<td>$10,781,872</td>
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<td>18</td>
<td>Income Taxes-State</td>
<td>$330,400</td>
<td>$47,200</td>
<td>$566,400</td>
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<td>19</td>
<td>Income Taxes-Federal</td>
<td>$4,386,550</td>
<td>$626,650</td>
<td>$7,519,800</td>
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<td>20</td>
<td>Gen Plant, A&amp;G, and Taxes</td>
<td>$19,990,862</td>
<td>$2,865,836</td>
<td>$34,270,033</td>
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<tr>
<td>21</td>
<td>Total Functional Rev Req.</td>
<td>249,817,890</td>
<td>46,002,961</td>
<td>95,260,514</td>
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</tr>
</tbody>
</table>
Step 2: Classification of Costs

What service is provided?
- Providing Access
- Standing Ready
- Providing Commodity

What are the costs of the service provided?
- Providing Access Varies with Number of Customers
- Standing Ready Varies with Capacity Needs
- Providing Commodity Varies with Volume
## Classification of Costs

<table>
<thead>
<tr>
<th>Function</th>
<th>Demand</th>
<th>Commodity</th>
<th>Customer</th>
<th>Revenue</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Production &amp; Gas Supply</strong></td>
<td></td>
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<tr>
<td>Gas Supply</td>
<td>Capacity</td>
<td>Volume</td>
<td></td>
<td></td>
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<tr>
<td>Storage</td>
<td>Capacity</td>
<td>Volume</td>
<td></td>
<td></td>
</tr>
<tr>
<td>LNG</td>
<td>Capacity</td>
<td>Volume</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Propane</td>
<td>Capacity</td>
<td>Volume</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Transmission</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Compressor Stations</td>
<td>Capacity</td>
<td>Volume</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mains</td>
<td>Capacity</td>
<td>Volume</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Regulatory Stations</td>
<td>Capacity</td>
<td>Volume</td>
<td></td>
<td></td>
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<tr>
<td><strong>Distribution</strong></td>
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<tr>
<td>Compressor Stations</td>
<td>Capacity</td>
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<td>Mains</td>
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<td>M&amp;R Stations</td>
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<tr>
<td>Services</td>
<td>Capacity</td>
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<tr>
<td>Meters</td>
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<td>No. Customers</td>
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<tr>
<td>House Reg</td>
<td></td>
<td></td>
<td>No. Customers</td>
<td></td>
</tr>
<tr>
<td>Imd M&amp;R Stations</td>
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<td></td>
<td>No. Customers</td>
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<tr>
<td>Customer Installations</td>
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<td>Specific Assignment</td>
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<td><strong>Other</strong></td>
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<td>Customer Accounts</td>
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<td>No. Customers</td>
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<td>Sales Expense</td>
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<td>No. Customers</td>
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<td><strong>Revenue</strong></td>
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<td>Revenue</td>
<td>Revenue</td>
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<tr>
<td>Revenue from Sales</td>
<td>Revenue</td>
<td>Revenue</td>
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<td>Revenue</td>
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<tr>
<td>Revenue Taxes</td>
<td>Revenue</td>
<td>Revenue</td>
<td>Revenue</td>
<td>Revenue</td>
</tr>
</tbody>
</table>

Source: Adapted from American Gas Association, Gas Rate Fundamentals, (Arlington, VA, 1987)
What are gas distribution mains used for?

Meeting peak demand?
- Historic and future planning parameters
- Mains are sized to meet the highest peak demand on the peak day

Meeting average demand?
- What evidence exists concerning the reason for investment (e.g., maintenance and replacement of existing mains)

Hooking up customers?
- How does investment cost change with number of customers?
Some level of main costs are required to serve new customers. This level can be deduced from regressing unit costs of various size of mains on the sizes of mains. This suggests a level of main costs that is necessary just to expand system (i.e., just to hook up customers some level of main investment is needed).

\[ Y = mx + b \]
Zero-intercept method

![Steel Mains graph]

<table>
<thead>
<tr>
<th>Regression Statistics</th>
<th>Coefficients</th>
<th>Standard Error</th>
<th>t Stat</th>
<th>P-value</th>
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<tr>
<td>Multiple R</td>
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<td>Intercept</td>
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<td>2.863498645</td>
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<tr>
<td>R Square</td>
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<td>X Variable</td>
<td>3.32414392</td>
<td>0.488238595</td>
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<td>Adjusted R Square</td>
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<tr>
<td>Standard Error</td>
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<td>Observations</td>
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<tr>
<td>Regression</td>
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<tr>
<td>Residual</td>
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<tr>
<td>Total</td>
</tr>
</tbody>
</table>
The difference between the 2” main costs and the above 2” main costs is the demand related costs (i.e. the costs in excess of a minimum distribution system)

77% (9m/11m) are customer-related, the remaining costs (23%) are demand related
Discussion of Customer-Related Costs

Classifies Larger Share to Customer
Methods are Ad Hoc
Correlation with Number of Customers
Bonbright: These costs are unattributable
What are we left with?
Step 3: Allocation to Customer Classes

Process of assigning revenue requirement to customer classes

- Customer classes attempt to group customers with similar cost characteristics

Allocation requires an understanding of the cost drivers like classification and requires analysis of system and class demand characteristics

Demand-related
Volume-related
Customer-related
Allocation: Joint Production

\[ \text{MC}_{\text{JP}}: \text{Cost of Joint Production} \]
\[ \text{MC}_{\text{WR}}: \text{Cost of Hooking up Water Meter to Gas AMI mesh network} \]
\[ \text{D1}: \text{Demand for gas meter reading} \]
\[ \text{D2}: \text{Demand for water meter reading} \]
## Allocation Data

<table>
<thead>
<tr>
<th>Data Type</th>
<th>Measuring Location</th>
<th>Time Frame</th>
<th>Source</th>
<th>Used For</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Volume</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas (therms)</td>
<td>Customer Meter</td>
<td>Annually</td>
<td>Utility Billing and Control Systems</td>
<td>Allocation of Volume-related Costs</td>
</tr>
<tr>
<td>Electricity (kWh)</td>
<td>Locations on System</td>
<td>Monthly</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Water (Gallons)</td>
<td></td>
<td>Hourly</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Maximum Usage (Demand)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas (therms)</td>
<td>Customer Meter</td>
<td>At System Peak</td>
<td>Utility Billing and Control Systems</td>
<td>Allocation of Demand-related Costs</td>
</tr>
<tr>
<td>Electricity (kW)</td>
<td>Locations on System</td>
<td>Customer's Peak</td>
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<tr>
<td>Water (Gallons)</td>
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<td>Equipment Peak</td>
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<tr>
<td><strong>Customers</strong></td>
<td>System</td>
<td>Annual</td>
<td>Utility Records</td>
<td>Customer-related Costs</td>
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<td>Service Lines</td>
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<td>Line Transformers</td>
<td>System</td>
<td>Annual</td>
<td></td>
<td>Transformers</td>
</tr>
</tbody>
</table>
Load Data

Pattern of demand over a cycle (day, month, year)

Average load

Peak load is maximum demand on system
- Coincident peak is a customer or customer’s classes’ maximum load at the time of the system peak demand
- Non-coincident peak is the maximum load of the customer or customer class at any time
Load Factor

\[ LF = \frac{\text{average load}}{\text{peak load}} \]

LF is between 0 and 1: Higher (lower) load factor the less (more) variable the load is relative to the average load

Higher load factors translate into lower average costs
Load factors vary between customer classes (industrial tend to have high load factors, residential tend to have low load factors)
Demand Allocators

Coincident Peak (CP): Measure of class contribution to system peak
- Logic: System planned to meet peak, costs should be allocated based on customer class contribution to peak demand

Non-coincident Peak (NCP): measure of maximum demand of each class regardless of time of demand
- Logic: Utility must meet customer peak demand
  - Unaffected by timing of system peak

Average and Excess (AE): \( LF \times \text{AVG DEM} + (1-LF) \times (\text{Class NCP} - \text{AVG DEM}) \)
- Logic: Low load factor customers do contribute to load diversity reducing demand costs
  - System peak demand not generally important for this allocator

Average and Peak (A&P): weight \( \times \text{AVG DEM} + (1-\text{weight}) \times (\text{CP}) \)
- Logic: utility assets are uses year-round, not just at peak
  - Not all assets deployed to meet peak (e.g., transmission assets may be used to find new supply which is used year-round)
  - Weighting could be LF or some other number e.g., 50/50 (called the Seaboard Method)
What is the difference?

Source: R. Feingold "Traditional and Unbundled LDC Rate Design" AGA Rates School, August 2010, Center for Business and Regulation, Chicago, IL
### Total volume usage by class

#### Customer-related

**Number of customers**

**Weighted number of customers**

**Meter costs**

**Billing costs**

**Services**

**Meter-reading**

<table>
<thead>
<tr>
<th>Meter</th>
<th>Cost</th>
<th>GS-1</th>
<th>GS-2</th>
<th>GS-3</th>
<th>GS-4</th>
<th>GS-5</th>
<th>GS-6</th>
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<td>2,096</td>
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<tr>
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<td>4</td>
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</table>

**Total Meters**

| 130,430 | 5,557 | 3,062 | 1,463 | 4     | 10    |

**Total Cost**

| 37,563,840 | 2,467,308 | 5,572,118 | 6,550,068 | 300,000 | 2,800,000 | 5,251 |

**Average Cost**

| 288 | 1.54 | 260.42 | 972.22 | 18.23 |

**Weight**

| 1.00 | 1.54 | 6.32 | 15.55 | 260.42 | 972.22 | 18.23 |

**Weighted Customers**

| 130,430 | 8,567 | 19,348 | 22,743 | 1,042 | 9,722 | 18 |
Special Studies

Customer specific usage:
Large distribution mains or substations (376); services (380); meters (381), AMI (382.1)

Uncollectible expenses (904)

Unbundled administrative costs

Special charges
Service activation
Reconnection
Miscellaneous fees
How are allocators chosen?

Reflective of system planning and operation
Cost drivers should be identifiable
Directly assigned costs should not be allocated
Stable results over time
Benefits of system are often taken into account
<table>
<thead>
<tr>
<th>Allocation Principles</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Herz (1956)</strong></td>
</tr>
<tr>
<td>All utility customers should contribute to capacity costs</td>
</tr>
<tr>
<td>The longer the period of time that a particular service preempts the use of capacity the greater should be the amount of capacity costs allocated to that service.</td>
</tr>
<tr>
<td>The allocation of capacity cost should change gradually with changes in the pattern of sales.</td>
</tr>
<tr>
<td>Any service which makes exclusive use of a portion of capacity should bear all the demand costs assignable to that portion of capacity. A 100 percent load factor service should be allocated the entire demand costs but no more.</td>
</tr>
<tr>
<td>Service that can be restricted by the utility should be allocated less in demand costs</td>
</tr>
<tr>
<td>The capacity costs allocated to one class of service should not be affect by the way in which the remaining capacity costs are allocated to other classes.</td>
</tr>
<tr>
<td>More demand costs should be allocated to a unit of capacity preempted during a peak period than to one preempted in off-peak</td>
</tr>
<tr>
<td><strong>NARUC (1955)</strong></td>
</tr>
<tr>
<td>The method should establish a minimum demand-cost allocation to off-peak customers.</td>
</tr>
<tr>
<td>The method should be judged on its recognition of (a) demand (b) usage and (c) time of use</td>
</tr>
<tr>
<td>The method should result in relatively stable cost assignment which would not change radically with a shift in loads.</td>
</tr>
<tr>
<td>The method should recognize the characteristic of the various loads</td>
</tr>
<tr>
<td>The method should permit allocation to a load which is completely under utility control, such as off peak water heating</td>
</tr>
<tr>
<td>The method should be based on some basic philosophy</td>
</tr>
<tr>
<td>The method should require a minimum of measurements before and after allocation</td>
</tr>
<tr>
<td>The method should not be dependent upon judgment introduced in the allocation process</td>
</tr>
<tr>
<td>The method should permit an estimate of the capacity cost that could be assigned to prospective loads</td>
</tr>
<tr>
<td><strong>Brattle (2019)</strong></td>
</tr>
<tr>
<td>Customers who benefit from the use of the system should also bear some responsibility for the costs of utilizing the system</td>
</tr>
<tr>
<td>Reflect cost causation as much as possible; i.e., based upon the actual activity that drives a particular cost and on rate classes’ share of that activity;</td>
</tr>
<tr>
<td>Produce fairly stable results on a year-to-year basis</td>
</tr>
<tr>
<td>Reflect the actual planning and operating characteristics of the utility’s system;</td>
</tr>
<tr>
<td>Recognize customer class characteristics such as demands, peak period consumption, number of customers and directly assignable costs</td>
</tr>
</tbody>
</table>
### The Gas Company

**Schedule 1.00**
**Summary of Embedded Cost of Service Study**

<table>
<thead>
<tr>
<th>Line No.</th>
<th>SC 1 Residential</th>
<th>SC 2 Commercial</th>
<th>SC 3 Large General Service</th>
<th>SC 4 Contract Service</th>
<th>SYSTEM TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
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<td>29</td>
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</tr>
</tbody>
</table>

**Ratemaking Example: ECOSS**

**Current Operating Revenues**
- $47,523,277
- $13,814,922
- $19,508,070
- $533,063
- $82,209,132

**Current Other Revenue**
- $(1,079,831)
- $(309,516)
- $(469,391)
- $(9,953)
- $(2,057,249)

**Current TOTAL Revenue**
- $46,842,996
- $13,260,308
- $19,038,679
- $523,100
- $80,222,883

**Operating Expenses**
- Operation and Maintenance $6,407,763
- Depreciation Expense $16,840,711
- Administrative and General and Cust Exp $21,279,781
- Taxes Other Than Income $2,171,848
- Income Taxes $6,748,191

**Operating Total**
- $47,455,215
- $15,022,834
- $11,301,679
- $302,678
- $14,672,406

**Current Net Operating Income**
- $(592,248)
- $(2,316,506)
- $(7,838,030)
- $(621,221)
- $(5,558,477)

**Rate Base**
- Net Plant in Service $140,664,465
- Rate Base Additions
  - Cash Working Capital $618,943
  - Materials and Supplies $4,205,299
  - Prepayments $1,232,445
  - Deferred Charges $592,462
  - Gas Stored Underground $26,672,865
  - Unamortized Software $6,394,863

**Rate Base Subtractions**
- Customer Deposits
- Construction Advances $28,684,419
- Net Asset Retirement Obligation $465,037
- Deferred Investment Tax Credit $(1,030)
- Deferred Income Taxes $(3,759,965)

**Net Rate Base**
- $135,390,809
- $71,554,469
- $76,317,306
- $2,082,071
- $265,344,655

**Current Return**
- 0.44%
- 3.24%
- 10.27%
- 29.84%
- 1.95%

**Proposed Revenues @ Equal Returns**
- $60,307,342
- $22,420,508
- $18,551,023
- $500,475
- $101,780,148
## Interclass Revenue Allocation

### The Gas Company

#### Schedule 1.91
Interclass Revenue Allocation

<table>
<thead>
<tr>
<th>Line No.</th>
<th>SC-1 Residential</th>
<th>SC-2 Commercial</th>
<th>SC-3 Large General Service</th>
<th>SC-4 Contract Service</th>
<th>SYSTEM TOTAL</th>
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<tbody>
<tr>
<td>1</td>
<td>46,852,966</td>
<td>13,306,398</td>
<td>19,139,709</td>
<td>921,300</td>
<td>80,222,883</td>
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<td>2</td>
<td>-9.44%</td>
<td>-3.24%</td>
<td>16.27%</td>
<td>29.84%</td>
<td>1.95%</td>
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<tr>
<td>3</td>
<td>(0.22)</td>
<td>(1.66)</td>
<td>5.28</td>
<td>15.34</td>
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<td>PROPOSAL AT EQUALIZED RETURNS</td>
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<tr>
<td>5</td>
<td>PROPOSED REVENUES</td>
<td>60,307,342</td>
<td>22,429,538</td>
<td>18,551,823</td>
<td>500,475</td>
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<tr>
<td>6</td>
<td>PROPOSED INCREASE (DECREASE)</td>
<td>13,454,375</td>
<td>9,114,290</td>
<td>(687,886)</td>
<td>(423,425)</td>
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<td>7</td>
<td>PERCENT INCREASE (DECREASE)</td>
<td>23.72%</td>
<td>68.50%</td>
<td>-3.07%</td>
<td>-45.63%</td>
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<td>8</td>
<td>PROPOSED NET OPERATING INCOME</td>
<td>12,882,127</td>
<td>6,797,675</td>
<td>7,529,144</td>
<td>197,797</td>
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<td>9.50%</td>
<td>9.50%</td>
<td>9.50%</td>
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<td>12</td>
<td>CONSTRANDED PROPOSAL (BASED ON ECQSS)</td>
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<tr>
<td>13</td>
<td>CONSTRANDED REVENUES</td>
<td>56,223,560</td>
<td>22,429,538</td>
<td>18,551,823</td>
<td>921,300</td>
</tr>
<tr>
<td>14</td>
<td>PROPOSED INCREASE (CONSTRANDED CLASSES)</td>
<td>9,370,593</td>
<td>-</td>
<td>-</td>
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<tr>
<td>15</td>
<td>PERCENT INCREASE (CONSTRAINTS)</td>
<td>20.00%</td>
<td>NONE</td>
<td>NONE</td>
<td>0.00%</td>
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<td>16</td>
<td>REVENUE SHORTFALL FROM CONSTRAINTS</td>
<td>3,880,357</td>
<td>1,665,376</td>
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<td>17</td>
<td>REALLOCATION OF SHORTFALL</td>
<td>-</td>
<td>2,602,988</td>
<td>1,665,376</td>
<td>-</td>
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<td>18</td>
<td>PROPOSED REVENUES (CONSTRANDED)</td>
<td>56,223,560</td>
<td>24,423,496</td>
<td>20,209,193</td>
<td>921,300</td>
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<td>PROPOSED INCREASE (ALL CLASSES)</td>
<td>20.00%</td>
<td>83.55%</td>
<td>5.59%</td>
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<td>20</td>
<td>PROPOSED NET OPERATING INCOME</td>
<td>8,778,345</td>
<td>8,800,662</td>
<td>8,907,514</td>
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<td>6.48%</td>
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<td>0.68</td>
<td>1.29</td>
<td>1.23</td>
<td>3.14</td>
</tr>
</tbody>
</table>
Interclass Revenue Allocation Issues

Can customer class withstand increase to cost of service?

What do we do with revenues for special contract customers?

What types of subsidies exist?
Marginal Cost of Service
**Why Marginal Cost?**

*Equilibrium occurs where quantity supplied equals quantity demanded. At this point the marginal cost of the last unit produced (measured by the supply curve) is just equal to the marginal benefit (measured by the demand curve).*

Society can do no better reallocating the resources to produce this last unit. This is called **allocative efficiency**.

\[
Marginal\ Cost = \frac{\text{\(\Delta\)Total\ Cost}}{\text{\(\Delta\)Output}}
\]

**Marginal Cost**

\[
P = MC = \text{MinATC};\ the\ product\ cannot\ be\ produced\ at\ a\ lower\ cost.\ This\ is\ called\ \text{productive\ efficiency}.\ If\ more\ of\ the\ good\ were\ produced\ the\ economy\ would\ need\ to\ sacrifice\ some\ other\ good\ to\ do\ so.
\]

\[
Q_f = \frac{Q_e}{n}
\]

**Quantity of Good X**
What Marginal Costs?

Time Element

Short-run: No Changes in Capacity
Long-run: Capacity changes

Relationship of Costs to Time

Marginal and average short-run cost are production time cost
Average long-run cost is the minimum of average short-run cost

What is the relationship of costs?

In simple version of model: LRMC = SRMC = SRAC = LRAC
Set price equal to SRMC or LRMC, does not matter, right?
What Marginal Costs?

Bridge is built with a set of fixed assets

Charging a price greater than zero underuses the assets

What if charging price of zero causes congestion?

Set price equal to congestion costs (short-run marginal cost)
Toll Bridge Pricing

The bridge is built to accommodate expected 20,000 crossings when the toll is zero.

Number of Crossings

Toll

Bridge Capacity

New Bridge Capacity

Demand for Crossings (Actual)

Demand for Crossings (Expected)

T = Congestion

T = 0

The bridge is built to accommodate expected 20,000 crossings when the toll is zero.
What is wrong with SRMC?

**SRMC changes with usage or congestion (i.e. demand)**
- Volatile prices might cause customers to over or under invest
- The administrative cost of calculating and disseminating prices is too high
- What if SRMC does not cover cost of construction?

**Set priced based on LRMC**
- Isn’t this the same as SRMC? Only under restrictive conditions
  - Capacity is continuous both increasing and decreasing
  - Investment is optimal or adjusts quickly to changing demands
  - Not likely for a gas utility
- LRMC Sends Constant Long-term Price Signals
- LRMC takes into Account Capital Costs
- LRMC is most Common Approach
## Marginal Costs

### Marginal Cost by Function

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<thead>
<tr>
<th>Production</th>
<th>Electric</th>
<th>Gas</th>
<th>Water</th>
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</thead>
<tbody>
<tr>
<td>Energy/Volume</td>
<td>Fuel Cost &amp; O&amp;M Purchased Power</td>
<td>Gas Cost Some delivery costs</td>
<td>Power, Chemicals, Maintenance</td>
</tr>
<tr>
<td>Capacity</td>
<td>Generation Asset</td>
<td>Storage</td>
<td>Source of Supply (Surface, ground)</td>
</tr>
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</table>

<table>
<thead>
<tr>
<th>Transmission</th>
<th>Electric</th>
<th>Gas</th>
<th>Water</th>
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<tbody>
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<td>Capacity</td>
<td>High Voltage Lines Transformers</td>
<td>High Pressure Mains Regulator Stations</td>
<td>High Pressure Mains</td>
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</table>

<table>
<thead>
<tr>
<th>Delivery</th>
<th>Electric</th>
<th>Gas</th>
<th>Water</th>
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<tbody>
<tr>
<td>Capacity</td>
<td>Low Voltage Lines Transformers</td>
<td>Low Pressure Mains Regulator Stations</td>
<td>Low Pressure Mains</td>
</tr>
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</table>

<table>
<thead>
<tr>
<th>Customer</th>
<th>Electric</th>
<th>Gas</th>
<th>Water</th>
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</thead>
<tbody>
<tr>
<td>Customer</td>
<td>Meters Services</td>
<td>Meters House Regulators Relief Valves Services</td>
<td>Meters Services</td>
</tr>
</tbody>
</table>

Short-run Marginal Cost in Red
Converting Fixed Cost to MC
Using Economic Carrying Charge

<table>
<thead>
<tr>
<th>Inputs</th>
<th>Derivation and Symbol</th>
<th>Economic Carrying Charge</th>
</tr>
</thead>
<tbody>
<tr>
<td>Investment Book Basis ($)</td>
<td>IBB $1.00</td>
<td>Year T=1 0.1457 First Year Rental Rate per Dollar of Investment = Economic Carrying Charge (ECC)</td>
</tr>
<tr>
<td>Investment Tax Basis ($)</td>
<td>ITB $1.00</td>
<td></td>
</tr>
<tr>
<td>Book Life (years)</td>
<td>N 10 $</td>
<td></td>
</tr>
</tbody>
</table>

MACRS Class (years) (Tax Depreciation)

<table>
<thead>
<tr>
<th>Incremental Income Tax Rate</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Federal</td>
<td>FT 21.00%</td>
</tr>
<tr>
<td>State</td>
<td>ST 7.00%</td>
</tr>
<tr>
<td>Combined</td>
<td>CT =FT*(1-ST) + ST 26.53%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Incremental Capital Structure</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Equity</td>
<td>%E 46.25%</td>
</tr>
<tr>
<td>Debt</td>
<td>%D 53.75%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Incremental Cost of Capital</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Equity</td>
<td>ROE 9.14%</td>
</tr>
<tr>
<td>Debt</td>
<td>ROD 5.24%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Weighted Average Cost of Capital</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>%E<em>ROE + %D</em>ROD</td>
<td>7.04%</td>
</tr>
</tbody>
</table>

| Inflation less Productivity                | RPIX 0.77%             |

Discount Factor = \( \frac{1}{1 - \left( \frac{1 + \text{RPIX}}{1 + \text{WACC-AT}} \right)^N} \)

Levelized Carrying Charge

$0.1503 Annual Payment to recover PVRR at WACC-AT over life of asset
## Converting Fixed Cost to MC

### Find Marginal Cost Gas Transmission Main

<table>
<thead>
<tr>
<th>Line No</th>
<th>Cost Category</th>
<th>Amount</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Total Cost of New Gas Transmission (In next few years)</td>
<td>$6,930,000</td>
<td>Includes only those projects intended to meet new design day forecasts</td>
</tr>
<tr>
<td>2</td>
<td>Incremental System Load (MMCF Design Day)</td>
<td>150</td>
<td>Estimate from Engineering Costs and includes any financing required</td>
</tr>
<tr>
<td>3</td>
<td>Marginal Investment Cost per MCF</td>
<td>$46.20</td>
<td>Line 1 divided by Line 2</td>
</tr>
<tr>
<td>4</td>
<td>Marginal Investment Cost per MCF with General Plant</td>
<td>$49.06</td>
<td>General Plant Estimated at 6.2% per dollar of new plant</td>
</tr>
<tr>
<td>5</td>
<td>Annual Carrying Costs</td>
<td>12.77%</td>
<td>Economic Carrying Charge</td>
</tr>
<tr>
<td>6</td>
<td>Overhead (A&amp;G) Related to New Plant</td>
<td>0.06%</td>
<td>Estimated Marginal Overhead Expenses</td>
</tr>
<tr>
<td>7</td>
<td>Total Carrying Charge</td>
<td>12.83%</td>
<td>Line 5 + Line 6</td>
</tr>
<tr>
<td>8</td>
<td>Annualized Costs</td>
<td>$6.29</td>
<td>Line 7 * Line 4</td>
</tr>
<tr>
<td>9</td>
<td>O&amp;M Expenses</td>
<td>$0.68</td>
<td>Estimated Marginal O&amp;M Expenses associated with Plant Investment</td>
</tr>
<tr>
<td>10</td>
<td>A&amp;G Expenses for O&amp;M Expenses</td>
<td>$0.95</td>
<td>Estimated A&amp;G For O&amp;M Expenses (1.4 * Line 9)</td>
</tr>
<tr>
<td>11</td>
<td>Annual Cost</td>
<td>$7.25</td>
<td>Line 8 + Line 10</td>
</tr>
<tr>
<td>12</td>
<td>Working Capital</td>
<td>$0.01</td>
<td>Estimated as Marginal Working Capital in Revenue Requirement</td>
</tr>
<tr>
<td>13</td>
<td>Annual Marginal Cost For Transmission Mains</td>
<td>$7.26</td>
<td>Line 11 + Line 12</td>
</tr>
</tbody>
</table>

* Based on: Dir. Testimony of H. Parmesano, ICC Docket No. 04-0779, Ex. 13.1
Example: MC of Gas Storage

<table>
<thead>
<tr>
<th>Derivation of Marginal Storage Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Line No.</td>
</tr>
<tr>
<td>1 Total Storage Revenues</td>
</tr>
<tr>
<td>2 Baseload Volume (MMCF)</td>
</tr>
<tr>
<td>3 Storage Cost per MCF</td>
</tr>
<tr>
<td>4 Marginal Cost of Storage</td>
</tr>
<tr>
<td>5 Ratio of Sales Customer Capacity to Total Send out in Peak Season</td>
</tr>
<tr>
<td>6 Marginal Cost in Peak Season Per MCF</td>
</tr>
</tbody>
</table>
Connection between Marginal and Embedded

If marginal costs are below average cost then average cost must be falling. What does this say about embedded cost?

Maybe nothing! Why?

What causes the divergence?

Degree of optimal historical investment
Philosophy of regulator
Size and type of recent additions
Practical Issues in Marginal Cost Analysis

Sunk Costs
MC are Hypothetical
MC will not normally equal revenue requirement
Embedded costs are perceived to be easier to understand.
What Next?

**Marginal Cost Revenue (MCR) Study**

Find MC by Function and Determine Total MC

\[
MCR = \text{Units} \times \text{Unit Annual Marginal Cost}
\]

**Compare to Revenue Requirement**

Will need adjustment

Equal Percent of Marginal Cost

Lump Sum

Ramsey Solution: \((P - MC)/P = c/\text{Elasticity of Demand})^*

Use Embedded Cost Study

\*c is a constant required to assure that the allocation equals the total revenue requirement.
<table>
<thead>
<tr>
<th>SUMMARY</th>
<th>TOTAL MARGINAL PRODUCTION</th>
<th>TOTAL MARGINAL ENERGY</th>
<th>TOTAL MARGINAL DISTRIBUTION</th>
<th>TOTAL MARGINAL TRANSMISSION</th>
<th>TOTAL MARGINAL COSTS</th>
<th>Current Revenues</th>
<th>Current Revenues as Percent of MC</th>
</tr>
</thead>
<tbody>
<tr>
<td>SC-1 Residential</td>
<td>$ 37,717,330</td>
<td>$ 42,460,437</td>
<td>$ 10,610,950</td>
<td>$ 4,469,820</td>
<td>$ 108,715,457</td>
<td>$ 103,442,461</td>
<td>95%</td>
</tr>
<tr>
<td>SC-2 Commercial</td>
<td>$ 22,109,287</td>
<td>$ 34,738,950</td>
<td>$ 6,501,167</td>
<td>$ 5,632,700</td>
<td>$ 72,854,984</td>
<td>$ 111,829,584</td>
<td>153%</td>
</tr>
<tr>
<td>SC-3 Large General Service</td>
<td>$ 23,647,324</td>
<td>$ 62,940,859</td>
<td>$ 6,733,840</td>
<td>$ 1,889,680</td>
<td>$ 95,479,618</td>
<td>$ 144,352,375</td>
<td>151%</td>
</tr>
<tr>
<td>SC-4 Contract Service</td>
<td>$ 709,420</td>
<td>$ 826,623</td>
<td>$ -</td>
<td>$ 1,590</td>
<td>$ 1,550,897</td>
<td>$ 1,771,328</td>
<td>114%</td>
</tr>
<tr>
<td>TOTAL</td>
<td>$ 84,183,360</td>
<td>$ 140,966,869</td>
<td>$ 23,845,957</td>
<td>$ 12,005,464</td>
<td>$ 278,600,955</td>
<td>$ 361,395,748</td>
<td>130%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Customer Class</th>
<th>Current Revenues</th>
<th>Full MC</th>
<th>Current Rates as % of MC</th>
<th>Revenue Requirement/MC</th>
<th>RR @ EPMC</th>
</tr>
</thead>
<tbody>
<tr>
<td>SC-1 Residential</td>
<td>103,442,461</td>
<td>$ 108,715,457</td>
<td>95%</td>
<td>140%</td>
<td>152,607,478</td>
</tr>
<tr>
<td>SC-2 Commercial</td>
<td>111,829,584</td>
<td>$ 72,854,984</td>
<td>153%</td>
<td>140%</td>
<td>102,268,947</td>
</tr>
<tr>
<td>SC-3 Large General Service</td>
<td>144,352,375</td>
<td>$ 95,479,618</td>
<td>151%</td>
<td>140%</td>
<td>134,027,894</td>
</tr>
<tr>
<td>SC-4 Contract Service</td>
<td>1,771,328</td>
<td>$ 1,550,897</td>
<td>114%</td>
<td>140%</td>
<td>2,177,045</td>
</tr>
<tr>
<td>TOTAL</td>
<td>361,395,748</td>
<td>$ 278,600,955</td>
<td>140%</td>
<td>140%</td>
<td>391,081,365</td>
</tr>
</tbody>
</table>

**Marginal Cost Revenue Study**
## Interclass Revenue Allocation

### The Gas Company

**Schedule 1.01**

**Interclass Revenue Allocation**

<table>
<thead>
<tr>
<th>Line No.</th>
<th>SC-1 Residential</th>
<th>SC-2 Commercial</th>
<th>SC-3 Large General Service</th>
<th>SC-4 Contract Service</th>
<th>SYSTEM TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>103,442,461</td>
<td>111,829,584</td>
<td>144,352,375</td>
<td>1,771,328</td>
<td>361,395,748</td>
</tr>
<tr>
<td>2</td>
<td>-1.69%</td>
<td>19.52%</td>
<td>9.05%</td>
<td>-5.16%</td>
<td>6.02%</td>
</tr>
<tr>
<td>3</td>
<td>(0.28)</td>
<td>3.24</td>
<td>1.50</td>
<td>(0.86)</td>
<td>1.00</td>
</tr>
<tr>
<td>4</td>
<td><strong>PROPOSAL AT EQUALIZED RETURNS</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>150,124,062</td>
<td>92,348,631</td>
<td>145,382,901</td>
<td>3,225,771</td>
<td>391,081,365</td>
</tr>
<tr>
<td>6</td>
<td>46,681,601</td>
<td>(19,480,953)</td>
<td>1,030,526</td>
<td>1,454,442</td>
<td>29,685,617</td>
</tr>
<tr>
<td>7</td>
<td>45.13%</td>
<td>-17.42%</td>
<td>0.71%</td>
<td>82.11%</td>
<td>8.21%</td>
</tr>
<tr>
<td>8</td>
<td>39,635,740</td>
<td>18,477,784</td>
<td>21,994,663</td>
<td>942,224</td>
<td>81,050,412</td>
</tr>
<tr>
<td>9</td>
<td>9.50%</td>
<td>9.50%</td>
<td>9.50%</td>
<td>9.50%</td>
<td>9.50%</td>
</tr>
<tr>
<td>10</td>
<td>1.00</td>
<td>1.00</td>
<td>1.00</td>
<td>1.00</td>
<td>1.00</td>
</tr>
<tr>
<td>11</td>
<td><strong>PROPOSAL AT EQUAL PERCENT MARGINAL COST (EPMC)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>152,607,478</td>
<td>102,268,947</td>
<td>134,027,894</td>
<td>2,177,045</td>
<td>391,081,365</td>
</tr>
<tr>
<td>13</td>
<td>49,165,017</td>
<td>(9,560,636)</td>
<td>(10,324,481)</td>
<td>405,717</td>
<td>29,685,617</td>
</tr>
<tr>
<td>14</td>
<td>47.53%</td>
<td>-8.55%</td>
<td>-7.15%</td>
<td>22.90%</td>
<td>8.21%</td>
</tr>
<tr>
<td>15</td>
<td>42,119,156</td>
<td>28,398,101</td>
<td>10,639,656</td>
<td>(106,502)</td>
<td>81,050,412</td>
</tr>
<tr>
<td>16</td>
<td>10.10%</td>
<td>14.60%</td>
<td>4.60%</td>
<td>-1.07%</td>
<td>9.50%</td>
</tr>
<tr>
<td>17</td>
<td>1.06</td>
<td>1.54</td>
<td>0.48</td>
<td>(0.11)</td>
<td>1.00</td>
</tr>
</tbody>
</table>
Rate Design
Why Does Pricing Matter?
Introduction to Rate Design

Rate design covers both the structure of rates

Traditionally rates were used (almost) solely to recover revenue, but today rates are also used to send signals, but what signals?

- What does it cost to serve the customer?
- How do we encourage “good” behavior?
- Should we consider externalities?
Terms Used in Rate Design

**Billing determinants**
Factors used to compute a customer’s bill (e.g., number of customers, usages, demand, power factor, etc.)

**Base Rates**
rates that are set in the tariff until allowed to increase by a decision of the regulatory body

**Riders**
Mechanisms used to track certain costs (e.g., gas costs)
Economist Approach to Pricing

Define the value of a transaction
consumer surplus and producer surplus (i.e., profit).

Competitive markets maximize consumer surplus

Optimal pricing asks the question
Price such that, subject to the break-even constraint, surplus is maximized

Two things to remember
Total surplus = consumer surplus plus producer surplus. The economics does not differentiate between the two.

Surplus (always) increases if the quantity sold increases
Does not matter who gets the surplus if it is as large as possible

Most regulators charged with balancing the interests of consumers and utilities

Surplus increases if quantity increases

Many regulators charged with promoting lower sales due to climate change concerns

Pricing in practice does not seem to fit pricing in theory
The Bonbright Criteria for Sound Rate Structure

**Revenue-related attributes**
- Effective at yielding total revenue requirement
- Revenue stability and predictably
- Stable rate structures

**Cost-related attributes**
- Static efficiency (efficient control of demand and supply)
- Reflection of total costs and benefits (including externalities)
- Fairness as to the allocation of costs

**Practical attributes**
- Simplicity, convenience of payment, feasibility, understandability, public acceptance
- Rates should be free from interpretation controversy
Methods of Charging Customers

Customer or base charge: $/customer
  Should this only recover customer-related costs?
  Is this the same as an access charge?

Demand: $/therm
  How should demand be measured and charged?
  Is this the same as an access charge?

Vol: $/usage
  Flat Rates
  Blocked Rates

Demand and Energy Rates
  Customer, Demand, and Energy rates (Hopkinson)
  Hours-of-Use rates (Wright)

Time-Differentiated Rates
  Seasonal Rates
  Time-of-Use Rates (more on the electric side)

Non-firm Rates
Carl’s Gas Bill

<table>
<thead>
<tr>
<th>Gas Service</th>
<th>Rate 1 - Small Residential Heating</th>
</tr>
</thead>
<tbody>
<tr>
<td>Meter P2306492</td>
<td>Actual Reading 10/31/2022 860</td>
</tr>
<tr>
<td></td>
<td>Actual Reading 09/30/2022 -846</td>
</tr>
<tr>
<td></td>
<td>Total Gas Use 14 CCF</td>
</tr>
</tbody>
</table>

14 CCF x 1,049 BTU = 14.7 Therms

<table>
<thead>
<tr>
<th>Delivery Charges</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Customer Charge</td>
<td>$34.01</td>
</tr>
<tr>
<td>Distribution Charge</td>
<td>$2.86</td>
</tr>
<tr>
<td>Storage Service Charge</td>
<td>$0.54</td>
</tr>
<tr>
<td>Gas Charge</td>
<td>$15.77</td>
</tr>
<tr>
<td>Energy Efficiency Program</td>
<td>$0.22</td>
</tr>
<tr>
<td>Environmental Charge</td>
<td>$0.35</td>
</tr>
<tr>
<td>UEA - Gas Cost Adjustment</td>
<td>$0.45</td>
</tr>
<tr>
<td>Volume Balancing Adjustment</td>
<td>$0.04</td>
</tr>
<tr>
<td>Tax Cost Adjustment</td>
<td>$-0.16</td>
</tr>
<tr>
<td>Qualified Infrastructure Plant Charge</td>
<td>$13.17</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$73.21</strong></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Taxes</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chicago Municipal Tax</td>
<td>$5.54</td>
</tr>
<tr>
<td>State Tax</td>
<td>$0.07</td>
</tr>
<tr>
<td>State Gas Revenue Tax</td>
<td>$0.35</td>
</tr>
<tr>
<td><strong>Subtotal</strong></td>
<td><strong>$73.21</strong></td>
</tr>
</tbody>
</table>

Gas Service Total: $73.21
### Pricing Illustration

#### Residential Class - Full Cost Rate

<table>
<thead>
<tr>
<th>Item</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Customer Costs</td>
<td>$33,212,000</td>
</tr>
<tr>
<td>Demand Costs</td>
<td>$18,233,000</td>
</tr>
<tr>
<td>Energy Costs</td>
<td>$-</td>
</tr>
<tr>
<td>Sales</td>
<td>$206,858,022</td>
</tr>
<tr>
<td>Customers</td>
<td>179,951</td>
</tr>
<tr>
<td>Customer Charge</td>
<td>$15.38</td>
</tr>
<tr>
<td>Volume Charge</td>
<td>$0.0881</td>
</tr>
<tr>
<td>Total Cost</td>
<td>$51,445,000</td>
</tr>
</tbody>
</table>

#### Residential Class - Customer Charge Capped at $10

<table>
<thead>
<tr>
<th>Item</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Customer Costs</td>
<td>$33,212,000</td>
</tr>
<tr>
<td>Demand Costs</td>
<td>$18,233,000</td>
</tr>
<tr>
<td>Energy Costs</td>
<td>$-</td>
</tr>
<tr>
<td>Sales</td>
<td>$206,858,022</td>
</tr>
<tr>
<td>Customers</td>
<td>179,951</td>
</tr>
<tr>
<td>Customer Charge</td>
<td>$10.00</td>
</tr>
<tr>
<td>Volume Charge</td>
<td>$0.1444</td>
</tr>
<tr>
<td>Total Cost</td>
<td>$51,445,000</td>
</tr>
</tbody>
</table>

#### Residential Class - Multi Block (Customer Charge Capped at $10)

<table>
<thead>
<tr>
<th>Item</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Customer Costs</td>
<td>$33,212,000</td>
</tr>
<tr>
<td>Demand Costs</td>
<td>$18,233,000</td>
</tr>
<tr>
<td>Energy Costs</td>
<td>$-</td>
</tr>
<tr>
<td>Sales</td>
<td>$206,858,022</td>
</tr>
<tr>
<td>0-50 Therms</td>
<td>$41,371,604</td>
</tr>
<tr>
<td>Over 50 Therms</td>
<td>$165,486,418</td>
</tr>
<tr>
<td>Customers</td>
<td>179,951</td>
</tr>
<tr>
<td>Customer Charge</td>
<td>$10.00</td>
</tr>
<tr>
<td>Volume Charge</td>
<td>$0.1444</td>
</tr>
<tr>
<td>0-50 Therms</td>
<td>$0.3690</td>
</tr>
<tr>
<td>Over 50 Therms</td>
<td>$0.0881</td>
</tr>
<tr>
<td>Total Cost</td>
<td>$51,445,000</td>
</tr>
</tbody>
</table>

#### Total Revenue

<table>
<thead>
<tr>
<th>Item</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Customer Charge</td>
<td>$21,594,120</td>
</tr>
<tr>
<td>Per Therm</td>
<td>$29,850,580</td>
</tr>
<tr>
<td>Total Revenue</td>
<td>$51,445,000</td>
</tr>
</tbody>
</table>
Types of Utility Tariffs

- Flat rates
- Declining Tariffs
- Inverted Black Tariffs
- Hopkinson (Two-part) Tariffs
- Time of Use (Seasonal)
- Modern pricing (more unbundling, more granular costing)
Advantages and Disadvantages of Flat Tariffs

Advantages
- Easy to bill.
- Easy for customers to understand.
- Requires simple metering technology.

Disadvantages
- Fails to capture differences in demand.
- Fails to capture difference in time-of-use.
- Requires that customers must be homogeneous.
Declining Tariffs

The declining tariff has two (or more) blocks with a reduced charge for the subsequent blocks. These tariffs are employed when the marginal cost to serve a customer is less than the average revenue requirement of the tariff.
Using Marginal Cost to set Tail Block

Cents per Therm

Typical consumption = 43 therms

First Block up to 30 therms

Number of therms consumed in first block \times price
of first block = Allocated Revenue requirement minus marginal cost revenue

Second Block Over 30 Therms

Marginal Cost Revenue = MC \times number of therms consumed over 30

Therms
Advantages and Disadvantages of Declining Block Rates

**Advantages**

- Simple for the utility to bill.
- Simple for the utility to meter.
- Fairly simple for customers to understand.
- Appropriate when the average revenue requirement exceeds the marginal cost to supply customers.

**Disadvantages**

- Fails to capture differences in demand.
- Fails to capture difference in time-of-use.
- Requires that customer classes be homogeneous.
- Not appropriate unless average revenue requirement is less than marginal costs.
- Can shift costs to smaller users.
Increasing Block Tariffs

The Increasing Block Tariff is the opposite of the Declining Block Tariff – the last block of usage is billed at a higher charge.

This type of rate design is appropriate when the average revenue requirement is less than the marginal cost to serve customers.
Increasing Block Tariffs – Advantages and Disadvantages

**Advantages**

Simple for the utility to bill.
Simple for the utility to meter.
Fairly simple for customers to understand.
Appropriate when the average revenue requirement is less than the marginal cost to supply customers.

**Disadvantages**

Fails to capture differences in demand.
Fails to capture difference in time-of-use.
Requires that customers must be homogeneous.
Not appropriate unless average revenue requirement is greater than marginal costs.
Can shift costs to larger users.
P = a + b Q
What is “a” and what is “b”?  

**Advantages**
Captures the differences in load factor form customer to customer.
Is generally understood by larger customers.
Provides explicit price signal to customers for both energy and capacity.

**Disadvantages**
Requires more costly meters. The metering investment must be balanced with the benefits of implementing the tariff.
Requires more effort to bill.
Demand Charge Ratchet Mechanisms

Demand Charge Ratchets are implemented on for cost components which are established by the customer’s highest demand in a series of billing periods (e.g., each year).

Distribution charges often are good candidates for a demand ratchet.

The cost of the distribution system is established by the highest demand for an annual period even if the customer does not use that demand each month.

Think of this as a rental charge for capacity e.g., renting office space.
Advantages and Disadvantages of Demand Ratchets

**Advantages**

- Provides the customers with a better price signal regarding component costs
- Provides an additional mechanism for the unbundling of tariffs

**Disadvantages**

- More difficult for the customer to understand
- More difficult to bill
- Removes incentive to reduce demand in off peak months (at least in the short run, may increase incentive to reduce demand in long run)
Modern Rate Design
Modern Pricing

Electric and gas markets have been evolving over the last 20-30 years.

New pricing issues have led to new types of pricing:

- Competitive Rates
- Consolidation of rates
- Unbundling
- Peaking rates
- Line extension
How do Current Rates Match Up with Costs?

**Cost Categories**

- **Variable**
  - Supply
  - O&M
- **Fixed**
  - Customer (Metering, billing, services)
  - A&G
- **Demand**
  - Transmission Capacity
  - Distribution Capacity

**Cost Structure**

- **Variable**
- **Fixed**

**Rate Structure**

- **Variable**
- **Fixed**
What is the solution?

**Industry:** Higher fixed charges
- SFV (for residential this normally means much higher customer charge)
- Demand rates
- Fixed fees should recover fixed costs
- Many examples of fixed fees (Amazon, Costco, parking garages, etc.)
- Outside utilities, no other industry is required by law to pay consumers to use less of the product

**Counter argument:** Higher variable charges
- Fixed costs are a short-run concept, all cost are variable in long run
- No economics behind “fixed fees recover fixed costs”
- High fixed charges prevent price responsive demand
- Low-income consumers hurt by high fixed charges
- No competitive firms charge fixed fees (indicative of market power)
Questions to Consider

Suppose a gas company is selling delivery service at an average cost, but its competitor (e.g., an interstate pipeline) is selling at marginal cost.

How does this affect the decision to price delivery service? (Hint: suppose a customer can switch service between the two competitors.)

How would you evaluate a proposal from a company with multiple subdivisions to consolidate its rates into one system-wide rate?

Why would a utility unbundle rates?
Questions to Consider

What is a line extension rate?
Regulator will typically include a set number of feet of line extension in rates (e.g., 100 feet)

What is the problem?
Suppose a customer is 125 feet from the nearest main at $15 a foot that would entail a loss of margin to extend beyond the 100 feet
Run a simple financial calculation (is it worth extending the line?)
Include future gas sales growth
What about competition (electric, oil, etc.)?
Pricing Issues with AMI

Can new services be provided?
Who should provide the communications network?
How can that network be priced?
Does this fit into smart grid, smart cities?
We want to promote efficiency and good resource management but at the same time maintain and promote affordability.

**Fracking:** Promotes lower cost gas but may run afoul of environmental goals.

**Electricity generation:** competitive markets promote better pricing but gas is often marginal fuel ---how does it get to markets where it is needed? (gas v. electric transmission)

**Exporting:** creates opportunities for US citizens but may have cost and environmental issues (LNG facilities)

**DER:** How do Genrac’s fit in?
Current and Future Issues

**Climate change**: Gas can be part of solution v. coal but is it really a transition fuel?

Lower usage makes gas utilities less attractive to investors and more costly to consumers (at least for delivery)

**Need to maintain and expand current facilities**
- Transport and storage constraints (NE, CA, etc.)
- While average prices are generally low very high prices can occur behind bottlenecks

**Does this suggest another restructuring (Utility 3.0?)**
- Biogas potential, competitive storage, more information to consumers
- Electrification (space heating, water heating)
  - …residential…[electric space heating applications]…are approaching cost parity with incumbent natural gas technologies in moderate to warm climates, but in cold climates, incumbent gas technologies…exhibit…[cost advantage]” NREL “Electrification Futures Study,” 2017 (with caveats re: high regional gas prices)

**Gas demand management**
- Better pricing with AMI metering
- Can DR save the day in transport tight regions?
Innovation Lagging: Natural gas pricing largely lags the electric industry.

- Time of use not as important
- Uses of gas less diverse
- AMI and other technologies have lower penetration rates
- Gas demand side response is longer term than electric

Some movement:

- Demand-based charging and seasonal or peak rates (e.g., AGL, SoCalGas)
- Expansion rates (Gas AC, NGV, co-generation or other DER)
- Fixed charges
- Non-pipes solutions (e.g., ConEd targeting electrification of buildings)
Summary of pricing discussion

Pricing is not always about the economics: social, political, and other factors influence decisions.

History matters: the best tax is an old tax (is this still true?)

Economic conditions in service territory – rate impact studies important

New technologies may make some/most of this discussion less relevant in the future (e.g., AMI)

Economists believe that incentives change behavior

The problem is how do we implement that insight?

- We want people to conserve so set a high price (Yes?)
- We want people to hook up to the network so set a low access fee (Yes?)
Thank You

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