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Cost of Service For Energy Utilities

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Foundations: Economics

Natural Monopoly: competition leads to monopoly

Convert to standard normal:

- Strongest case: MC is declining below AC
- Less stringent case: Cost may be increasing but still cheaper to have one firm provide product

Transactions costs: Sunk cost leads to hold up problem

Why state commission-based regulation? Insull's Regulatory Bargain

> While it is not supposed to be popular to speak of exclusive franchises, it should be recognized that the best service at the lowest possible price can only be obtained…by exclusive control of a given territory being placed in the hands of one undertaking…In order to protect the public, exclusive franchises should be coupled with the condition of public control requiring all charges for services fixed by public bodies to be based on cost, plus a reasonable profit. (S. Insull, President's Address, NELA, 1898)

Cost of Service and Rate Design

Cost of service is an analytical approach to determining who should pay for the total revenue requirement

Judgment plays a major part of cost of service and reasonable people do disagree

Cost of service supports rate design, but rate design is often related to the objectives of designing rates

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

Capital Expenses

OPEX +Interest + Taxes

Return of and on Capital

Revenue Requirement

Operational Data

Economic Analysis

Judgment

Cost of Service

Revenue Recovery

Price Signals

Efficiency

Equity

Rate Design Objectives

Rate Shock

Social Concerns

Policy Concerns

Other Factors

Final Prices

Creating Rates

Capital Expenses

OPEX +Interest + Taxes

Return of and on Capital

Revenue Requirement

Operational Data

Economic Analysis

Judgment

Cost of Service

Unbundled Costs

What is the Output?

Class Cost Responsibly

Class Profitability

By Function

By Cost Driver

By Customer Class

Revenue Requirement

Class Cost Study

Rates

Residential

Commercial

Industrial

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Basics of Cost of Service

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

Introduction to Cost of Service

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 (1 of 2)

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

Philosophy of Cost Studies (2 of 2)

Set prices to encourage efficient consumption and production

Balance the needs of different customer classes

Pricing should be sufficiently detailed such that each service is priced to recovers the cost of that service

Avoid excess or deficient earnings

Ease of collection and understanding of tariffs

Avoid undue discrimination

Costs (1 of 2)

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 (2 of 2)

Average Cost: Total <u>economic</u> 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

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, related to average cost)

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 (MCOSS 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.)

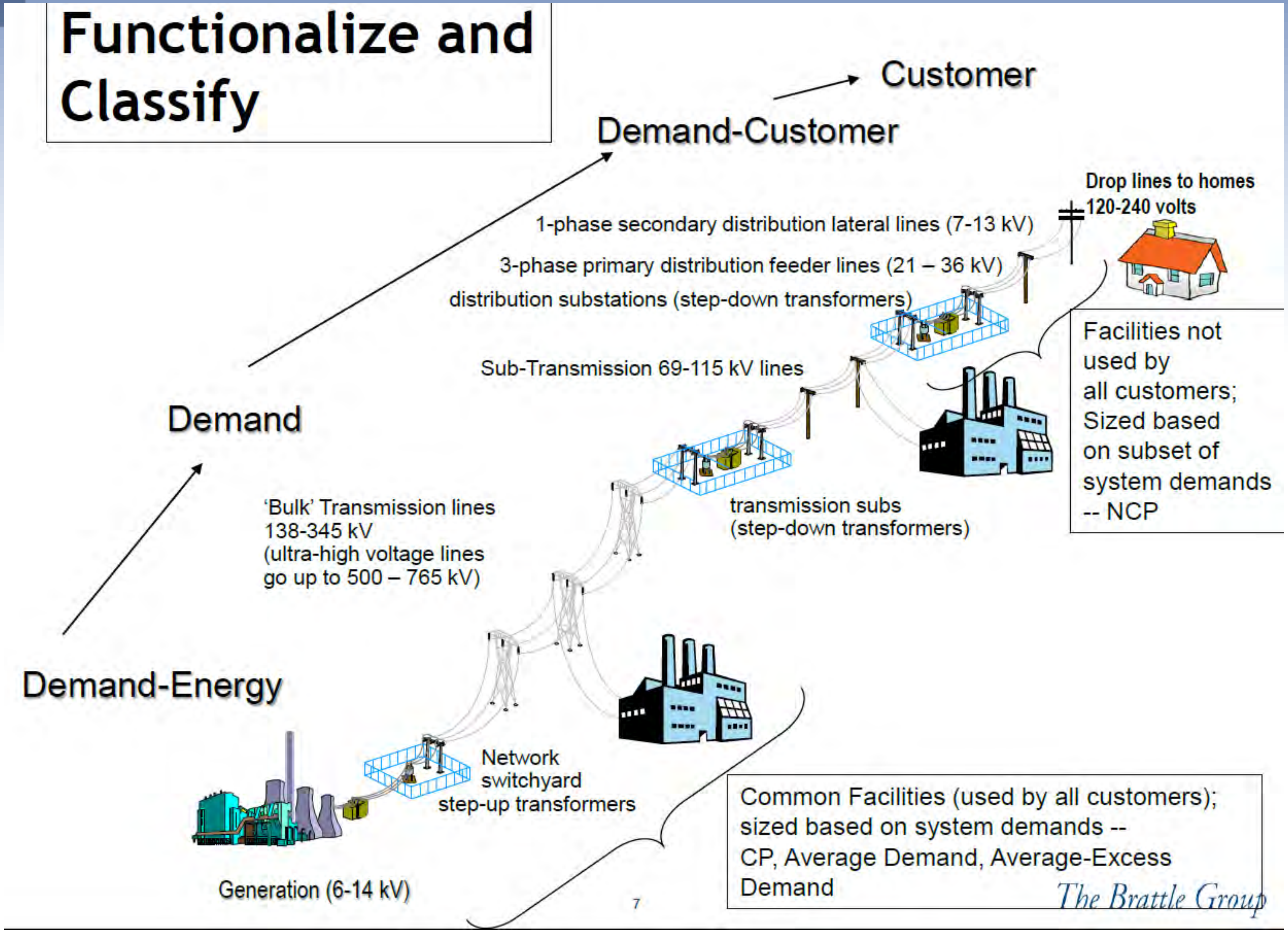
- For gas and electric utilities, functionalization is generally an accounting exercise (i.e., use USOA)
- Exception: Electric transmission may need additional analysis (e.g., FERC seven factor test).

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

Step 3: Allocation

- Direct assignment
- Allocator (demand, energy, customers, etc.)

Stylized Electric System

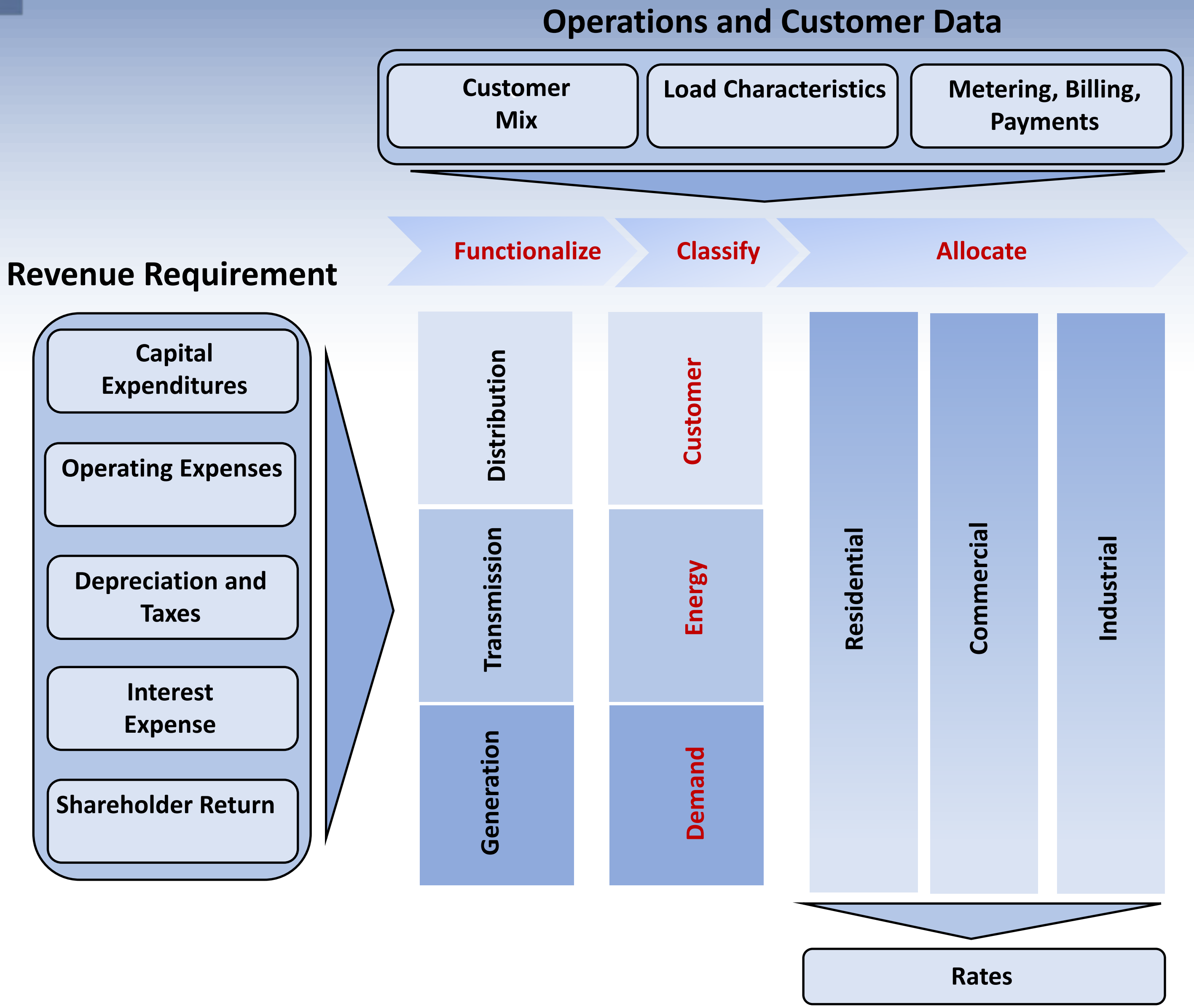


Natural Gas Supply Chain

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

Upstream → Downstream

Overview of Cost Allocation Process



Step 1: Functionalization

- What is the purpose of the cost?
- Electric and Gas utilities
  - Generation or gas production
  - Distribution (low voltage lines, low pressure mains)
  - Transmission (high voltage lines, high pressure mains)
  - 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 cost of the different operations of the utility
- Best approach is direct assignment

Functionalization- General Plant

Overhead (A&G) is more difficult

A&G costs cover items such as: (1) general management salaries and associated costs, (2) pensions and benefits, (3) insurance expenses, (4) shared services.

A&G often allocated based on:

- labor by function
- Net plant (excluding general plant)
- O&M (excluding gas costs)
- Compound factors
- “Efforts” studies (find cost drivers)

Examples: Discuss

- 920 – Administrative and General Salaries
- 923 – Outside Services Employed (corporate shared services)
- 924 – Property Insurance
- 925 – Injuries and Damages

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Functionalized Revenue Requirement

	(A)	(B)	(C)	(D)	(E)	(F)
Line No.		**Production**	**Transmission**	**Distribution**	**General**	**Total**
1	Total Operating Expenses					
2	Production	188,377,894				188,377,894
3	Transmission		4,611,093			4,611,093
4	Distribution			10,644,700		10,644,700
5	Customer Accounts			8,231,423		8,231,423
6	A&G				21,077,467	21,077,467
7	Total Depreciation Expense	11,104,730	17,903,809	16,447,534	185,516	45,641,588
8	TOTAL O&M	199,482,624	22,514,902	35,323,657	21,262,983	278,584,165
9	Net Plant in Service	305,700,627	207,856,491	258,576,888	44,397,224	816,531,230
						-
10	Rate Base Additions	39,584,564	26,914,922	33,482,605	5,748,908	105,731,000
11	Rate Based Subtractions	25,870,307	17,590,121	21,882,400	3,757,172	69,100,000
12	TOTAL RATE BASE	319,414,885	217,181,292	270,177,093	46,388,960	853,162,230
13	Proposed Return	9.50%	9.50%	9.50%	9.50%	9.50%
14	Total Return	30,344,414	20,632,223	25,666,824	4,406,951	81,050,412
15	Total Revenue Requirement Ex A&G, Gen, Taxe	229,827,038	43,147,125	60,990,481	-	333,964,643
16	Allocation of General Revenue Req. and Taxes	35%	5%	60%		
17	Taxes Other Than Income	$ 6,289,426	$ 898,489	$ 10,781,872		
18	Income Taxes-State	$ 330,400	$ 47,200	$ 566,400		
19	Income Taxes-Federal	$ 4,386,550	$ 626,650	$ 7,519,800		
20	Gen Plant, A&G, and Taxes	$ 19,990,852	$ 2,855,836	$ 34,270,033		57,116,721
21	**Total Functional Rev Req.**	**249,817,890**	**46,002,961**	**95,260,514**		**391,081,365**

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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

Provides basis for pricing different elements

(customer charge, energy or volume, demand)

Classification of Costs (Gas)

Function	Demand	Commodity	Customer	Revenue
Classification with Allocation Methods				
Production & Gas Supply				
Gas Supply	Capacity	Volume		
Storage	Capacity	Volume		
LNG	Capacity	Volume		
Propane	Capacity	Volume		
Transmission				
Compressor Stations	Capacity	Volume		
Mains	Capacity	Volume		
Regulatory Stations	Capacity	Volume	Specific Assignment	
Distribution				
Compressor Stations	Capacity			
Mains	Capacity		No. Customers	
M&R Stations	Capacity		No. Customers	
Services	Capacity		No. Customers	
Meters			No. Customers	
House Reg			No. Customers	
Imd M&R Stations			Specific Assignment	
Customer Installations			Specific Assignment	
Other				
Customer Accounts			No. Customers	
Sales Expense			No. Customers	
Revenue				
Revenue from Sales				Revenue
Revenue Taxes				Revenue

Source: Adapted from American Gas Association, Gas Rate Fundamentals, (Arlington, VA, 1987)

Classification of Costs (Electric)

Functions	Demand	Energy	Customer	Revenue
Production				
Thermal	X	X		
Hydro	X	X		
Other	X	X		
Transmission	X	X	X	
Distribution				
OH/UG Lines	X	X	X	
Substations	X	X	X	
Services			X	
Meters			X	
Customer			X	X

Source: NARUC Electric Utility Cost Allocation Manual 1992

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Application: The Logic of Classification--Gas Distribution Mains

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?

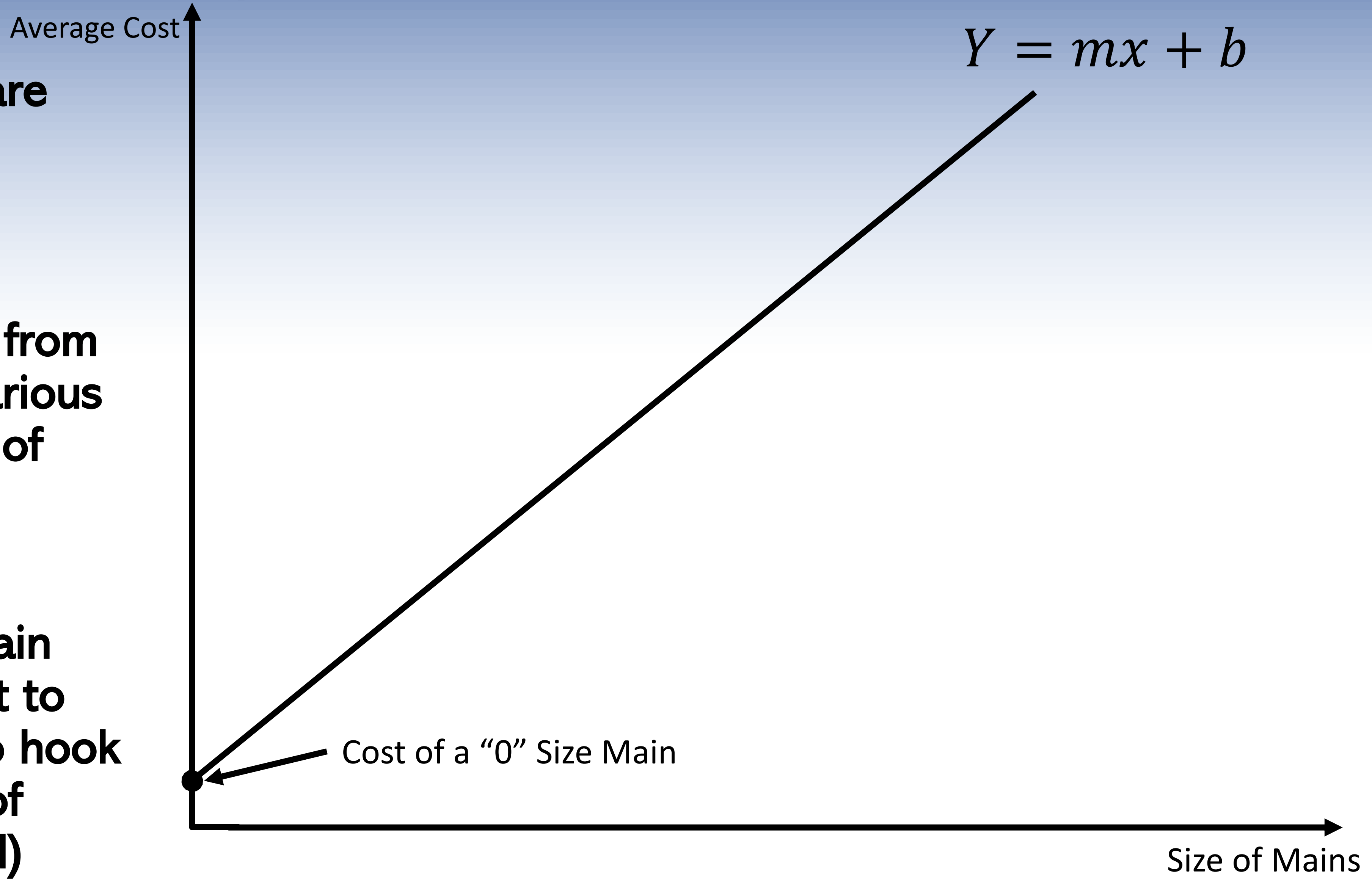
- How does investment cost change with number of customers?

Zero-intercept method

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)



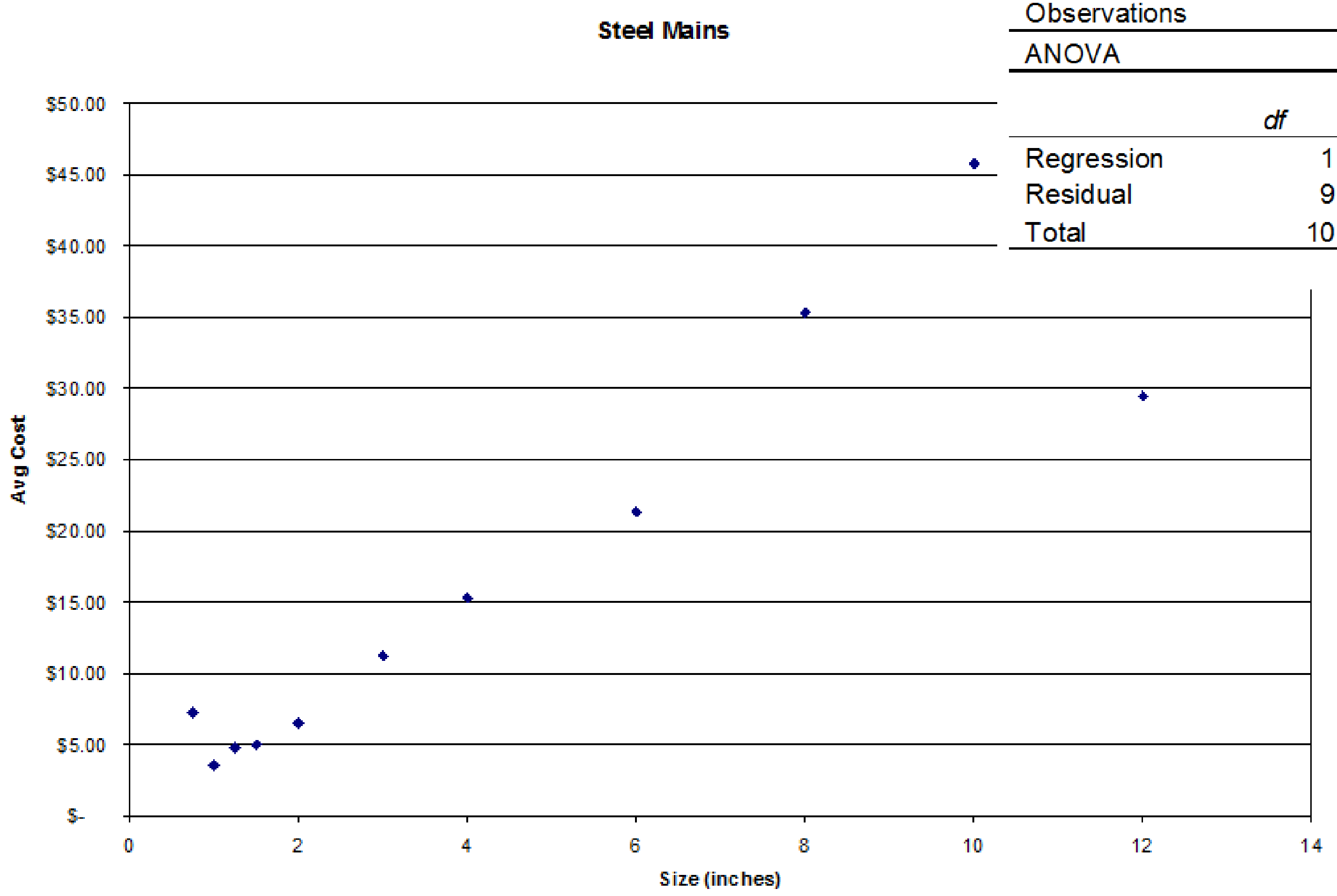
Zero-intercept

Regression Statistics	
Multiple R	0.9151026
R Square	0.8374127
Adjusted R Square	0.8193474
Standard Error	6.0907642
Observations	11

	Coefficients	Standard Error	t Stat	P-value
Intercept	1.90232947	2.863498645	0.66433748	0.5231286
X Variable	3.32414392	0.488238595	6.80844152	7.831E-05

ANOVA

	df	SS	MS	F	Significance F
Regression	1	1719.6458	1719.6458	46.3548759	7.8306E-05
Residual	9	333.87668	37.0974091		
Total	10	2053.5225			



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Minimum Distribution System-Example

Size	Feet		Total Cost		Cost per Foot
2" or less	2,543,218	$	**6,413,228**	$	2.52
3 and 4"	972,435	$	4,755,842	$	4.89
6 and 8"	84,480	$	619,326	$	7.33
Total	3,600,133	$	11,788,396	$	3.27
Total >2"	1,056,915	$	5,375,168	$	5.09
@ 2" Cost	1,056,915	$	**2,665,221**	$	2.52
Difference		$	2,709,947		
Cost of 2" Minimum					
Distribution System		$	**9,078,449**		
Percent Customer-related			77%		
Percent Demand-related			23%		

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?

Classification Example: Electric Generation

Generation Plant

- Is generation plant entirely related to providing capacity?
- Does plant provide energy?

Options

- 100% Demand
- Load Factor (some demand some energy)

Classification Example: Results

	ABC Edison Company										
	Exhibit 2.4 (COSS)										
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Line No.			**Production**			**Distribution**			**Transmission**		**Total**
		Demand	**Energy**	**Customer**	**Demand**	**Energy**	**Customer**	**Demand**	**Energy**	**Customer**	
1	Total Operating Expenses										
2	Production	34,282,654	165,385,485	-							199,668,139
3	Distribution				22,162,739	1,076,066	3,853,430				27,092,234
4	Transmission							18,086,854	-	4,428,048	22,514,902
5	A&G	-	6,555,016	3,703,095	-	936,431	529,014	-	11,237,171	6,348,163	11,723,556
6	TOTAL O&M	34,282,654	171,940,502	3,703,095	22,162,739	2,012,497	4,382,443	18,086,854	11,237,171	10,776,211	278,584,165
7	Net Operating Income	30,330,685	1,405,063	-	23,930,743.27	2,087,967.00	3,164,702.86	17,413,313.68	173,997.25	2,543,939.78	81,050,412
8	Taxes Other Than Income	-	6,289,426	-	-	10,781,872	-	-	898,489	-	17,969,787
9	Income Taxes-State	-	330,400	-	-	566,400	-	-	47,200	-	944,000
10	Income Taxes-Federal	-	4,386,550	-	-	7,519,800	-	-	626,650	-	12,533,000
	Total Classified Rev Req.	**64,613,339**	**184,351,941**	**3,703,095**	**46,093,482**	**22,968,536**	**7,547,146**	**35,500,168**	**12,983,507**	**13,320,150**	**391,081,365**
	Note: Overhead and General plant allocated to function using allocation in Exhibit 6.0 (COSS)										

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

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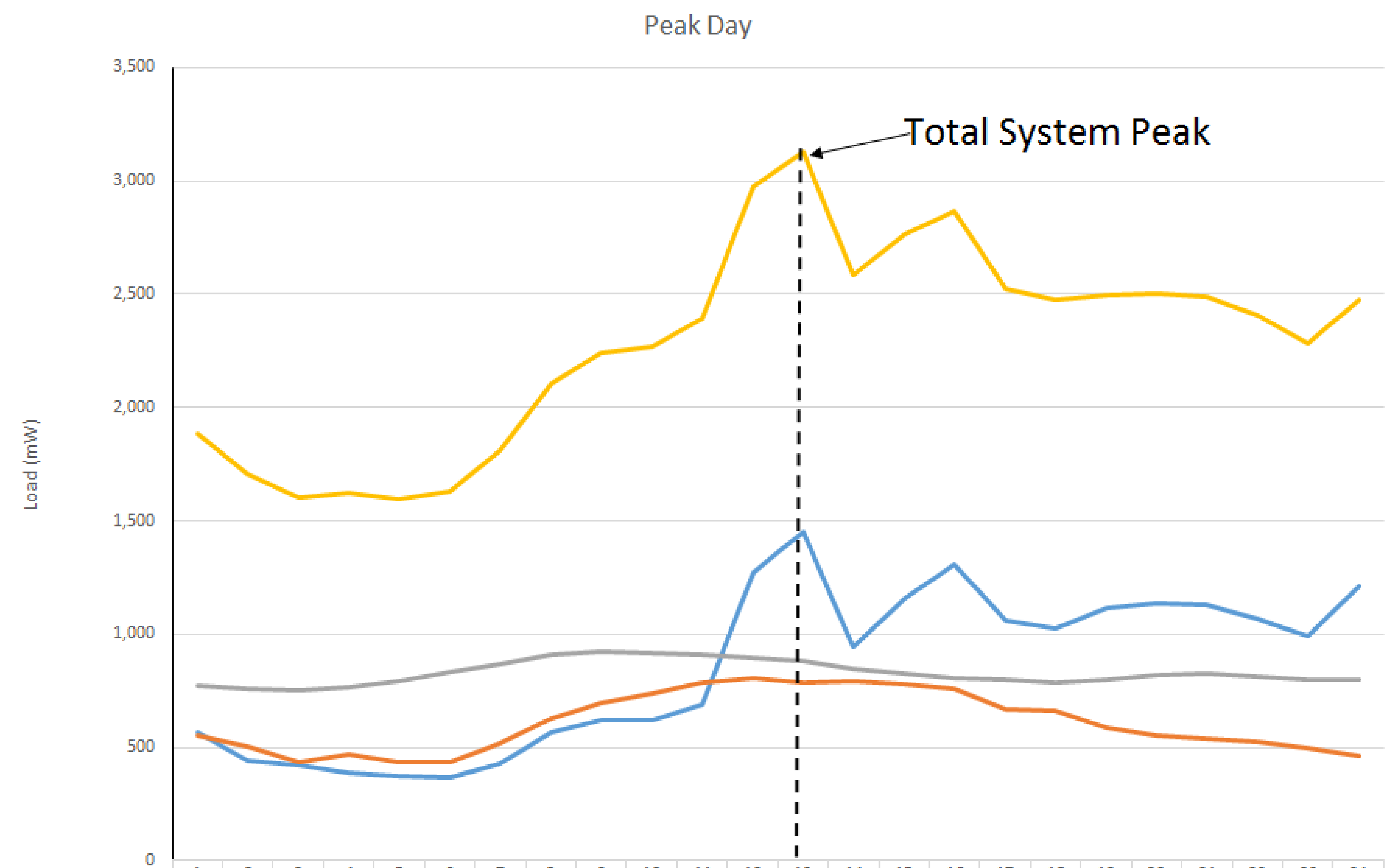
Allocation Data

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

Load Data

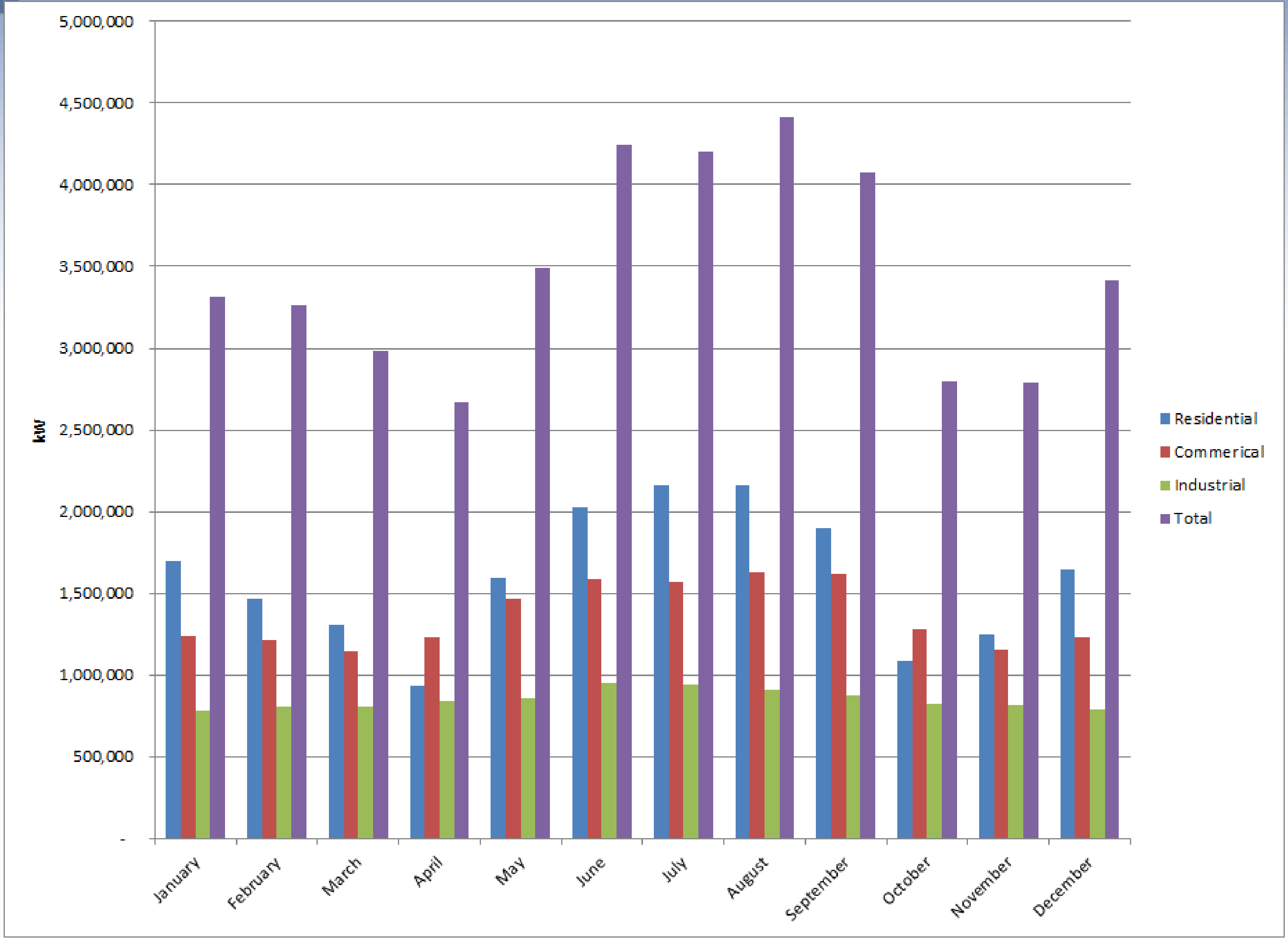
- Pattern of demand over a cycle (day, month, year)
- Average load
- Peak load is maximum demand on system
  - Coincident peak is a customer or customer's classes' maximum load at the time of the system peak demand
  - Non-coincident peak is the maximum load of the customer or customer class at any time

Load Data: Electric Daily



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Residential	563	444	418	387	374	366	428	566	623	617	693	1,275	1,455	943	1,157	1,307	1,058	1,023	1,117	1,133	1,128	1,070	990	1,212
Commerical	554	506	438	471	434	432	514	627	696	736	788	807	788	791	776	755	668	663	583	551	535	523	496	464
Industrial	771	755	748	766	790	836	865	912	925	918	912	895	885	850	829	807	796	788	799	820	829	812	801	800
Total	1,887	1,706	1,604	1,623	1,598	1,634	1,807	2,106	2,244	2,271	2,393	2,977	3,127	2,585	2,762	2,869	2,522	2,475	2,499	2,504	2,492	2,405	2,287	2,477

Load Data: Electric Monthly



Load Factor

LF = average load / 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*AVG DEM + (1-LF)* (Class NCP – 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 *AVG DEM + (1-weight)* (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)

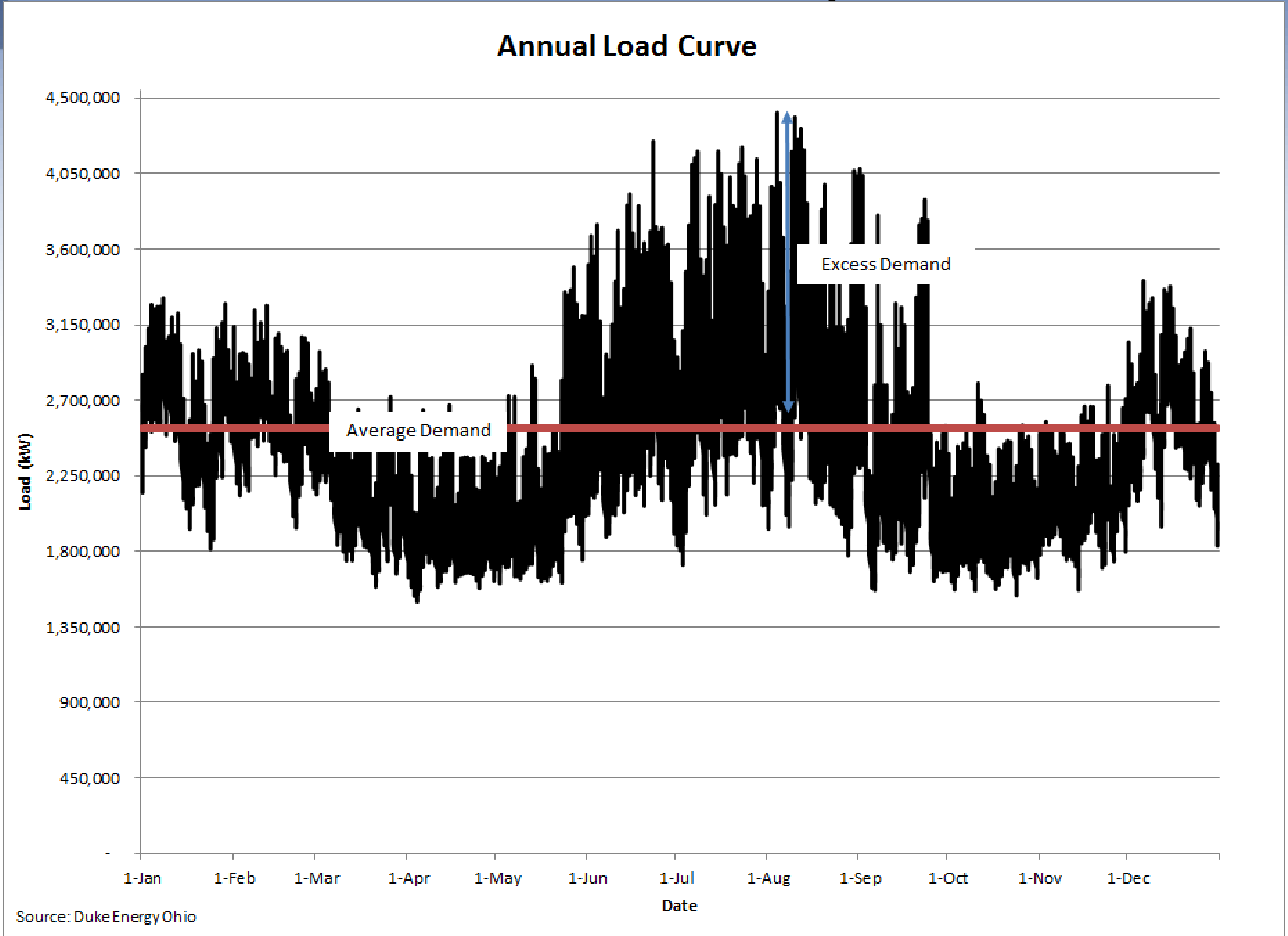
Demand Allocators: Example

Demand Allocators						
	1 CP	Percent	Average of 12 CP	Percent	Non-coincident Peak	Percent
DOM	4,735	34.84%	3,522	32.22%	5,357	36.94%
LSMP	5,062	37.25%	4,173	38.17%	5,062	34.91%
LP	3,347	24.63%	2,932	26.82%	3,385	23.34%
AG&P	447	3.29%	266	2.43%	572	3.94%
ASL	-	0.00%	38	0.35%	126	0.87%
TOTAL	13,591	100%	10,931	100%	14,502	100%

(1) Summer is assumed to be July-September

(2) Winter is assumed to be December-February

Demand Allocators: Average and Excess



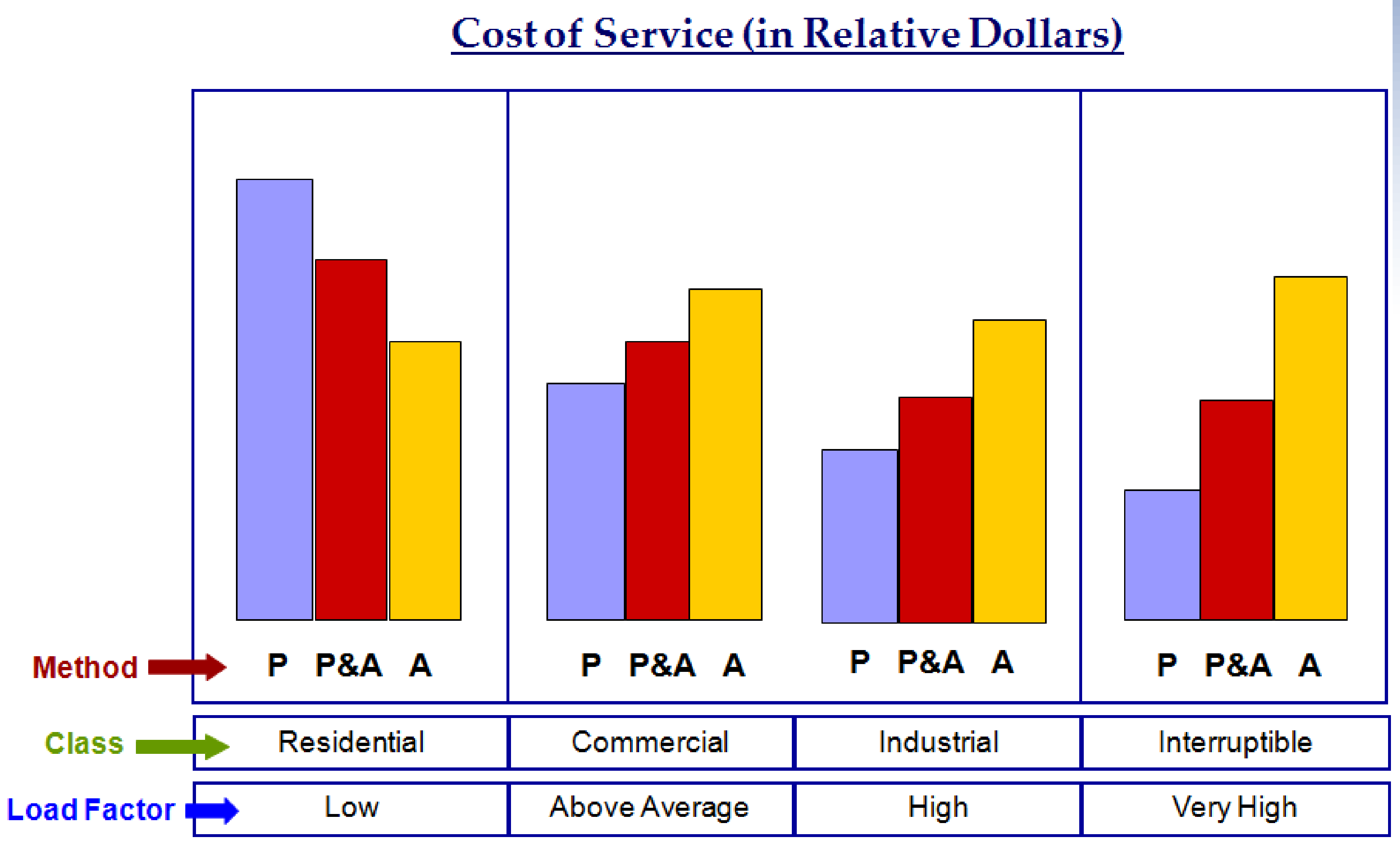
Demand Allocators: Average and Excess

	Average Demand (3)	Percent * LF	Excess Demand (NCP - AVG)	Percent * (1-LF)	Total
DOM	2,447	18.00%	2,910	18.46%	36.46%
LSMP	2,676	19.69%	2,386	15.13%	34.82%
LP	2,466	18.15%	919	5.83%	23.97%
AG&P	254	1.87%	318	2.01%	3.89%
ASL	59	0.43%	67	0.43%	0.86%
TOTAL	7,902	58.14%	6,600	41.86%	100.00%

The higher the load factor the more the allocator reflects the average demand (for generation-related costs this might reflect the fact that base load plants run all year)

The lower the load factor the more this reflects peak demand (notion is that "excess demand" drives need for peaking plants).

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

Energy and Customer Related Allocators

Total volume usage by class

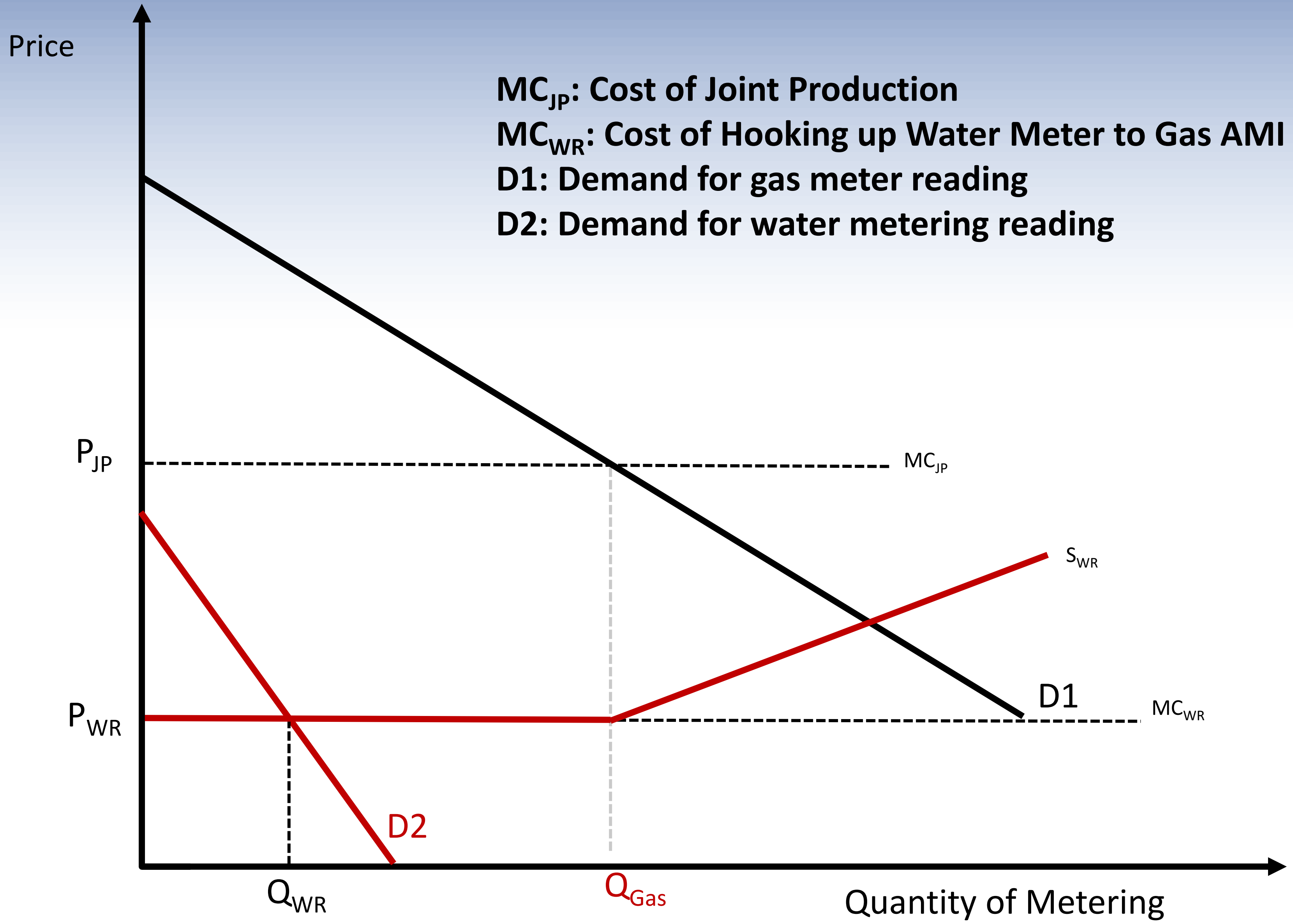
Customer-related

- **Number of customers**
- **Weighted number of customers**
  - Meter costs
  - Billing costs
  - Services
  - Meter-reading

Meter	Cost	GS-1	GS-2	GS-3	GS-4	GS-5	GS-6	GS-7
1	$ 288	130,430						
2	$ 444		5,557					
3	$ 1,177			966				
4	$ 2,116			2,096				
5	$ 3,723				470			
6	$ 4,099				541			
7	$ 5,251				449			1
8	$ 75,000				3	4		
9	$ 280,000						10	
Total Meters		130,430	5,557	3,062	1,463	4	10	1
Total Cost		$ 37,563,840	$ 2,467,308	$ 5,572,118	$ 6,550,068	$ 300,000	$ 2,800,000	$ 5,251
Average Cost		$ 288	$ 444	$ 1,820	$ 4,477	$ 75,000	$ 280,000	$ 5,251
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

Allocation: Joint Production

MC_{JP}: Cost of Joint Production
MC_{WR}: Cost of Hooking up Water Meter to Gas AMI mesh network
D1: Demand for gas meter reading
D2: Demand for water metering reading



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

Allocation Principles

Herz (1956)	NARUC (1955)	Brattle (2019)
All utility customers should contribute to capacity costs	The method should establish a minimum demand-cost allocation to off-peak customers.	Customers who benefit from the use of the system should also bear some responsibility for the costs of utilizing the system
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.	The method should be judged on its recognition of (a) demand (b) usage and (c) time of use	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;
The allocation of capacity cost should change gradually with changes in the pattern of sales.	The method should result in relatively stable cost assignment which would not change radically with a shift in loads.	Produce fairly stable results on a year-to-year basis
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.	The method should recognize the characteristic of the various loads	Reflect the actual planning and operating characteristics of the utility's system;
Service that can be restricted by the utility should be allocated less in demand costs	The method should permit allocation to a load which is completely under utility control, such as off peak water heating	Recognize customer class characteristics such as demands, peak period consumption, number of customers and directly assignable costs
	The method should be based on some basic philosophy	
	The method should require a minimum of measurements before and after allocation	
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.	The method should not be dependent upon judgment introduced in the allocation process	
More demand costs should be allocated to a unit of capacity preempted during a peak period than to one preempted in off-peak	The method should permit an estimate of the capacity cost that could be assigned to prospective loads	

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Ratemaking Example: ECOSS

The Gas Company
Schedule 1.00
Summary of Embedded Cost of Service Study

Line No.		SC-1 Residential	SC-2 Commercial	SC-3 Large General Service	SC-4 Contract Service	SYSTEM TOTAL
1	**Current Operating Revenues**	$ 47,923,277	$ 13,814,922	$ 19,608,070	$ 933,863	$ 82,280,132
2	**Current Other Revenue**	$ (1,070,311)	$ (508,614)	$ (468,361)	$ (9,963)	$ (2,057,249)
3	**CURRENT TOTAL REVENUE**	**$ 46,852,966**	**$ 13,306,308**	**$ 19,139,709**	**$ 923,900**	**$ 80,222,883**
4	OPERATING EXPENSES					
5	Operation and Maintenance	$ 6,407,763	$ 2,680,464	$ 2,431,420	$ 60,034	$ 11,579,682
6	Depreciation Expense	$ 10,840,711	$ 5,129,462	$ 4,734,131	$ 126,629	$ 20,830,933
7	Administrative and General and Cust Exp	$ 21,276,701	$ 3,753,786	$ 192,689	$ 3,003	$ 25,226,179
8	Taxes Other Than Income	$ 2,171,848	$ 966,794	$ 898,587	$ 26,910	$ 4,064,140
9	Income Taxes	$ 6,748,191	$ 3,092,328	$ 3,044,852	$ 86,101	$ 12,971,472
10	TOTAL OPERATING EXPENSES	**$ 47,445,215**	**$ 15,622,834**	**$ 11,301,679**	**$ 302,678**	**$ 74,672,406**
11	CURRENT NET OPERATING INCOME	**$ (592,248)**	**$ (2,316,526)**	**$ 7,838,030**	**$ 621,221**	**$ 5,550,477**
12	RATE BASE					
13	Net Plant in Service	140,664,455	64,705,341	64,528,571	1,729,747	271,628,114
14	***Rate Base Additions***					
15	Cash Working Capital	(618,943)	(146,043)	(68,008)	(1,678)	(834,672)
16	Materials and Supplies	4,206,299	992,499	462,181	11,403	5,672,381
17	Prepayments	1,232,445	290,802	135,419	3,341	1,662,007
18	Deferred Charges:	592,462	139,794	65,099	1,606	798,961
19	Gas Stored Underground	25,872,855	15,166,248	16,221,291	486,639	57,747,033
20	Unamortized Software	6,394,853	1,107,770	16,969	101	7,519,693
21	***Rate Base Subtractions***					
22	Customer Deposits	-	-	-	-	-
23	Construction Advances	(28,684,419)	(4,968,955)	(76,115)	(452)	(33,729,941)
24	Net Asset Retirement Obligation	(465,837)	(198,520)	(179,362)	(5,369)	(849,088)
25	Deferred Investment Tax Credit	(3,375)	(1,438)	(1,300)	(39)	(6,152)
26	Deferred Income Taxes	(13,799,986)	(5,533,029)	(4,787,438)	(143,228)	(24,263,681)
27	NET RATE BASE	**$ 135,390,809**	**$ 71,554,469**	**$ 76,317,306**	**$ 2,082,071**	**$ 285,344,655**
28	CURRENT RETURN	**-0.44%**	**-3.24%**	**10.27%**	**29.84%**	**1.95%**
29	PROPOSED REVENUES @ Equal Returns	**$ 60,307,342**	**$ 22,420,508**	**$ 18,551,823**	**$ 500,475**	**$ 101,780,148**

Interclass Revenue Allocation

The Gas Company
Schedule 1.01
Interclass Revenue Allocation

Line No.		SC-1 Residential	SC-2 Commercial	SC-3 Large General Service	SC-4 Contract Service	SYSTEM TOTAL
1	REVENUES @ CURRENT RATES	46,852,966	13,306,308	19,139,709	923,900	80,222,883
2	RETURN @ CURRENT RATES	-0.44%	-3.24%	10.27%	29.84%	1.95%
3	RETURN INDEX	(0.22)	(1.66)	5.28	15.34	1.00
4	**PROPOSAL AT EQUALIZED RETURNS**					
5	PROPOSED REVENUES	60,307,342	22,420,508	18,551,823	500,475	101,780,148
6	PROPOSED INCREASE (DECREASE)	13,454,375	9,114,200	(587,886)	(423,425)	21,557,265
7	PERCENT INCREASE (DECREASE)	28.72%	68.50%	-3.07%	-45.83%	26.87%
8	PROPOSED NET OPERATING INCOME	12,862,127	6,797,675	7,250,144	197,797	27,107,742
9	RETURN	9.50%	9.50%	9.50%	9.50%	9.50%
10	RETURN INDEX	1.00	1.00	1.00	1.00	1.00
18	**CONSTRAINED PROPOSAL (BASED ON ECOSS)**					
19	CONSTRAINED REVENUES	56,223,560	22,420,508	18,551,823	923,900	98,119,791
20	PROPOSED INCREASE (CONSTRAINED CLASSES)	9,370,593	-	-	-	
21	PERCENT INCREASE (CONSTRAINTS)	20.00%	NONE	NONE	0.00%	
22	REVENUE SHORTFALL FROM CONSTRAINTS	3,660,357				
23	REALLOCATION OF SHORTFALL	-	2,002,988	1,657,370	-	
24	PROPOSED REVENUES (CONSTRAINED)	56,223,560	24,423,496	20,209,193	923,900	101,780,148
25	PERCENT INCREASE (ALL CLASSES)	20.00%	83.55%	5.59%	0.00%	26.87%
26	PROPOSED NET OPERATING INCOME	8,778,345	8,800,662	8,907,514	621,221	27,107,742
27	RETURN	6.48%	12.30%	11.67%	29.84%	9.50%
28	RETURN INDEX	0.68	1.29	1.23	3.14	1.00

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Interclass Revenue Allocation Issues

Can customer class withstand increase to cost of service?

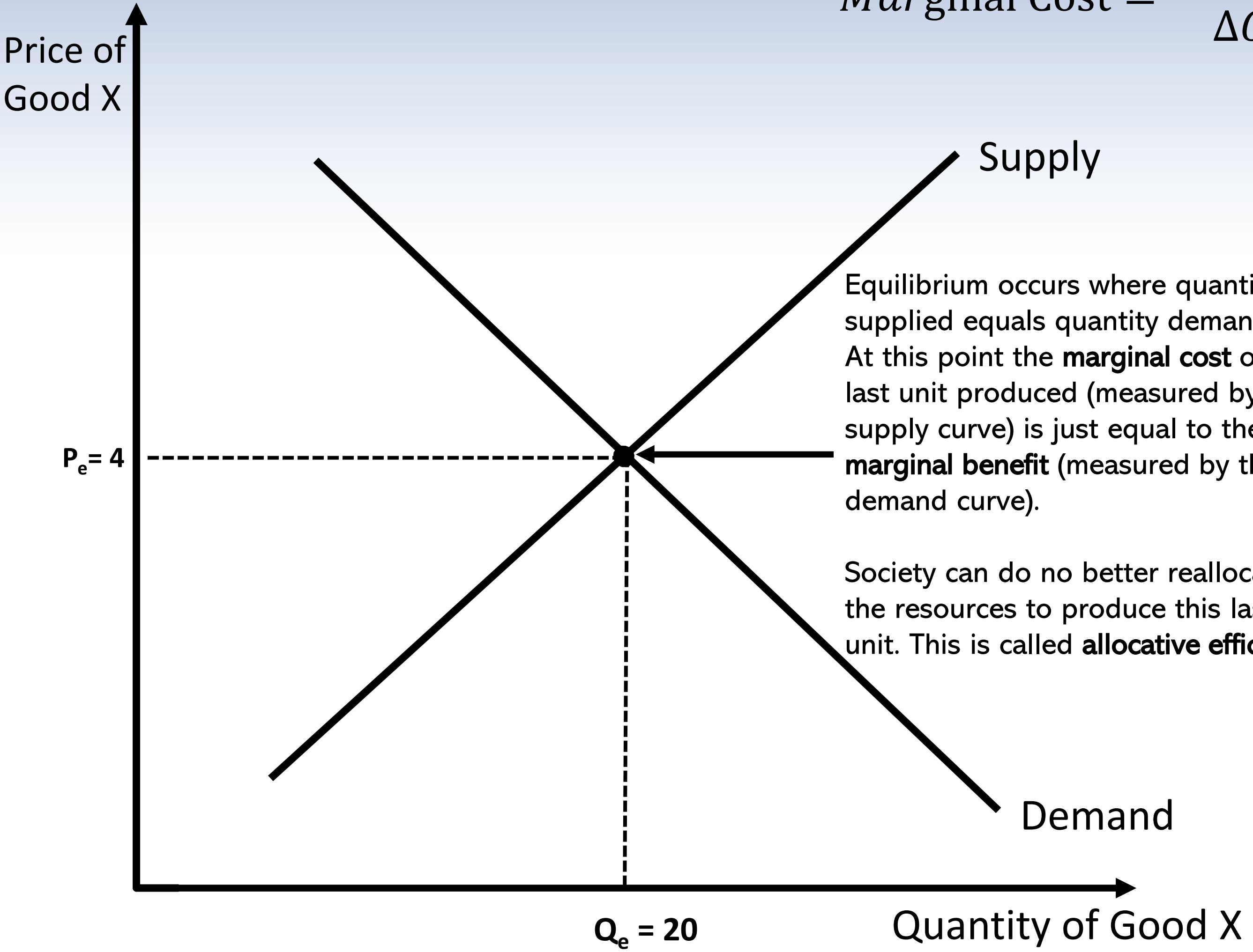
What do we do with revenues for special contract customers?

What types of subsidies exist?

Marginal Cost of Service

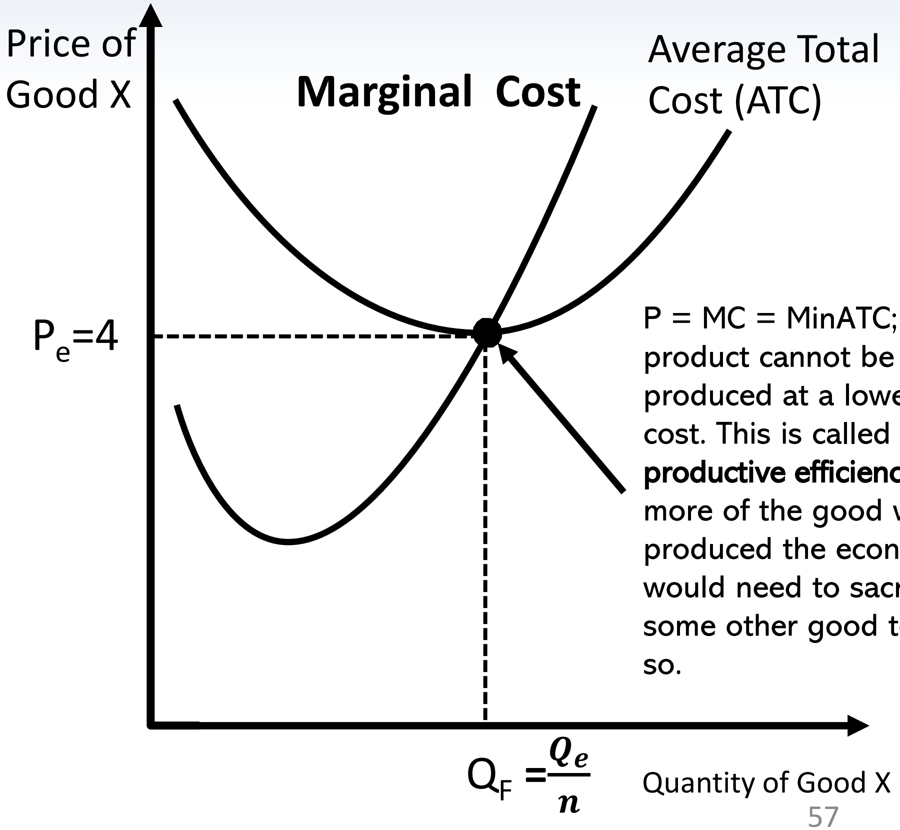
Why Marginal Cost?

$$Marginal\ \text{Cost} = \frac{\Delta Total\ Cost}{\Delta Output}$$



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**



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

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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?

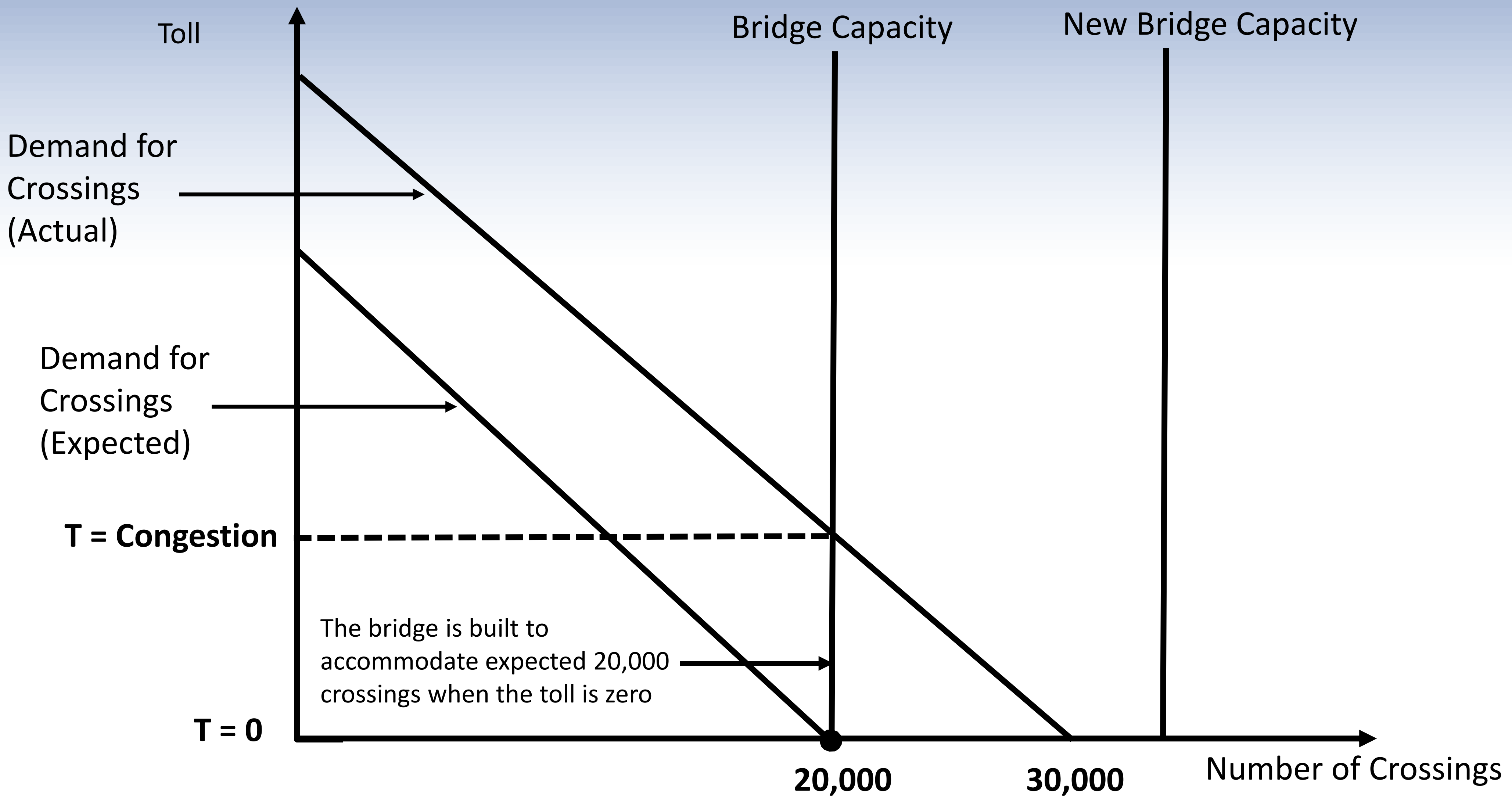
Bridge is built with a set of fixed assets

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



What is wrong with SRMC?

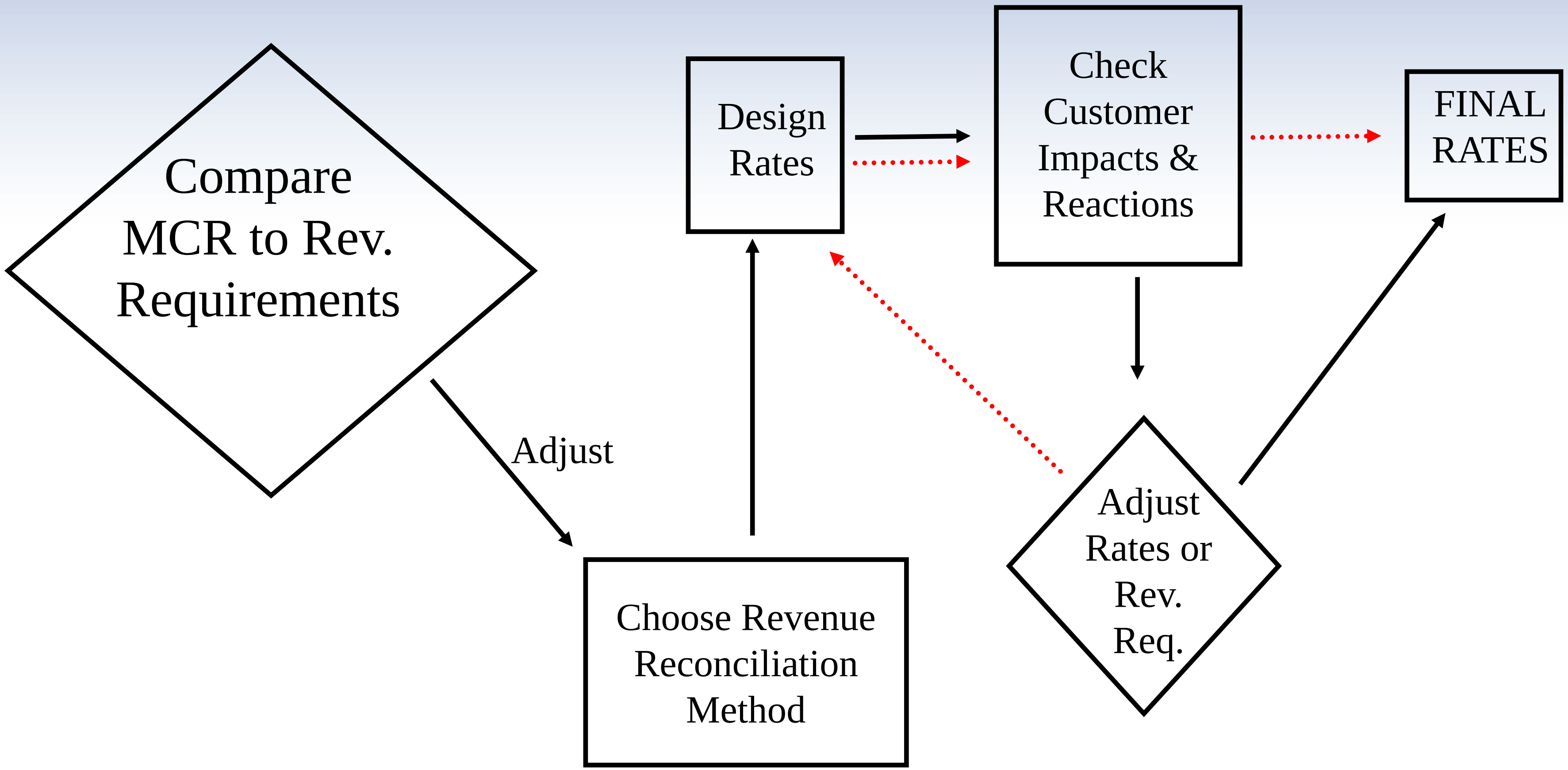
SRMC changes with usage or congestion (i.e., demand)

- 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

Reconciling Marginal Cost with Revenue Requirement and Pricing



Marginal Costs

Marginal Cost by Function	Classification	Electric	Gas	Water
Production	Energy/Volume	**Fuel Cost & O&M** **Purchased Power**	**Gas Cost** **Some delivery costs**	**Power, Chemicals, Maintenance**
	Capacity	Generation Asset	Storage	Source of Supply (Surface, ground) Treatment Plant
Transmission	Capacity	High Voltage Lines Transformers	High Pressure Mains Regulator Stations	High Pressure Mains
Delivery	Capacity	Low Voltage Lines Transformers	Low Pressure Mains Regulator Stations	Low Pressure Mains
Customer	Customer	Meters Services	Meters House Regulators Relief Valves Services	Meters Services

Short-run Marginal Cost in Red

Converting Fixed Cost to MC

Using Economic Carrying Charge

Inputs	Derivation and Symbol		
Investment Book Basis ($)	IBB	$ 1.00	Year T=1
Investment Tax Basis ($)	ITB	$ 1.00	1
Book Life (years)	N	10	$ **0.1457**
MACRS Class (years) (Tax Depreciation)		5	
Incremental Income Tax Rate			
Federal	FT	21.00%	
State	ST	7.00%	
Combined	CT =FT*(1-ST) + ST	26.53%	
Incremental Capital Structure			
Equity	%E	46.25%	$0.1503
Debt	%D	53.75%	
Incremental Cost of Capital			
Equity	ROE	9.14%	
Debt	ROD	5.24%	
Weighted Average Cost of Capital	WACC-AT = %E*ROE + %D*ROD	7.04%	
Inflation less Productivity	RPIX	0.77%	

Economic Carrying Charge

First Year Rental Rate per Dollar of Investment = Economic Carrying Charge (ECC)

ECC = PVRR (WACC-AT - RPIX)*(1 + RPIX)^ (T-1) *Discount Factor

Discount Factor = 1 divided by 1-{ (1 + RPIX) / (1+ WACC-AT)}^N = 2.21

Levelized Carrying Charge

Annual Payment to recover PVRR at WACC-AT over life of asset

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Converting Fixed Cost to MC

Find Marginal Cost Gas Transmission Main

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

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

Example: MC of Gas Storage

Derivation of Marginal Storage Costs							
Line No.			2012			2013	
1	Total Storage Revenues	$	2,018		$	2,147	
2	Baseload Volume (MMCF)		9,000			9,000	
3	Storage Cost per MCF		0.22			0.24	
4	Marginal Cost of Storage						0.23
5	Ratio of Sales Customer Capacity to Total						59%
	Send out in Peak Season						
6	Marginal Cost in Peak Season						$ 0.14
	Per MCF						

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Example: Marginal Energy Costs

ABC Edison Company

Exhibit 7.0 (COSS)

Marginal Cost Summary

	Generation Capacity	Distribution Capacity	Distribution Customer	Transmission Capacity	Marginal Energy Costs (including losses) Summer Non-TOU	Non-Summer Non-TOU	Summer Peak	Summer Off-peak	Non-Summer Peak	Non-Summer Off-peak
SC-1 Residential	$ 75.89	$ 21.35	$ 8.83	$ 22.00	29.56	27.01	34.36	24.77	31.48	22.54
SC-2 Commercial	$ 75.89	$ 20.53	$ 14.67	$ 22.00	28.67	26.20	33.33	24.02	30.54	21.86
SC-3 Large General Service	$ 75.89	$ 20.53	$ 66.25	$ 22.00	27.81	25.41	32.33	23.30	29.62	21.21
SC-4 Contract Service	$ 75.89	$ -	$ 66.25	$ 22.00	27.40	25.03	31.84	22.95	29.18	20.89

Marginal Energy Costs (at Generation, $/MWH)

Peak Hours	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC
10	29.90	29.40	29.99	30.59	31.35	32.92	33.25	33.58	31.90	29.99	29.40	29.90
11	31.10	30.50	31.11	31.73	32.53	34.15	34.49	34.84	33.10	31.11	30.50	31.10
12	29.70	27.60	28.15	28.72	29.43	30.90	31.21	31.53	29.95	28.15	27.60	29.70
13	27.40	26.00	26.52	27.05	27.73	29.11	29.40	29.70	28.21	26.52	26.00	27.40
14	27.60	25.30	25.81	26.32	26.98	28.33	28.61	28.90	27.45	25.81	25.30	27.60
15	26.40	24.70	25.19	25.70	26.34	27.66	27.93	28.21	26.80	25.19	24.70	26.40
16	25.80	24.80	25.30	25.80	26.45	27.77	28.05	28.33	26.91	25.30	24.80	25.80
17	29.20	28.10	28.66	29.24	29.97	31.46	31.78	32.10	30.49	28.66	28.10	29.20
18	37.50	30.30	30.91	31.52	32.31	33.93	34.27	34.61	32.88	30.91	30.30	37.50
19	33.10	36.50	37.23	37.97	38.92	40.87	41.28	41.69	39.61	37.23	36.50	33.10
20	28.70	28.90	29.48	30.07	30.82	32.36	32.68	33.01	31.36	29.48	28.90	28.70
21	25.20	26.50	27.03	27.57	28.26	29.67	29.97	30.27	28.76	27.03	26.50	25.20
22	23.50	25.60	26.11	26.63	27.30	28.67	28.95	29.24	27.78	26.11	25.60	23.50
AVERAGE	**28.85**	**28.02**	**28.58**	**29.15**	**29.88**	**31.37**	**31.68**	**32.00**	**30.40**	**28.58**	**28.02**	**28.85**
Off-Peak Hours												
1	18.70	18.66	19.04	19.42	19.90	20.90	21.11	21.32	20.25	19.04	18.66	18.70
2	18.30	18.26	18.63	19.00	19.48	20.45	20.65	20.86	19.82	18.63	18.26	18.30
3	18.20	18.16	18.53	18.90	19.37	20.34	20.54	20.75	19.71	18.53	18.16	18.20
4	18.10	18.06	18.43	18.79	19.26	20.23	20.43	20.63	19.60	18.43	18.06	18.10
5	18.20	18.16	18.53	18.90	19.37	20.34	20.54	20.75	19.71	18.53	18.16	18.20
6	19.00	18.96	19.34	19.73	20.22	21.23	21.44	21.66	20.58	19.34	18.96	19.00
7	21.70	21.66	22.09	22.53	23.09	24.25	24.49	24.74	23.50	22.09	21.66	21.70
8	23.20	23.15	23.62	24.09	24.69	25.93	26.19	26.45	25.12	23.62	23.15	23.20
9	26.10	26.05	26.57	27.10	27.78	29.17	29.46	29.75	28.27	26.57	26.05	26.10
23	21.50	21.46	21.89	22.32	22.88	24.03	24.27	24.51	23.28	21.89	21.46	21.50
24	19.60	19.56	19.95	20.35	20.86	21.90	22.12	22.34	21.23	19.95	19.56	19.60
AVERAGE	**20.24**	**20.20**	**20.60**	**21.01**	**21.54**	**22.61**	**22.84**	**23.07**	**21.92**	**20.60**	**20.20**	**20.24**

SUMMER (JUNE-SEPT) At Generation	
Peak	31.36
Off-Peak	22.61
NON-SUMMER	
Peak	28.74
Off-Peak	20.58

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Example: Transmission Marginal Capacity Costs

Determine from transmission plan

Some companies use historic data as well

Step 1: Determine which projects or portions of projects are needed to serve incremental load (as opposed to maintenance or interconnection to other markets)

Step 2: Use capital cost transformation method to find first year costs

Issue: What if there are no planned transmission investments to meet incremental load? MC = 0

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 Issus 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.

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What Next?

Marginal Cost Revenue (MCR) Study

- Find MC by Function and Determine Total MC
- MCR = Units * Unit Annual Marginal Cost

Compare to Revenue Requirement

- Will need adjustment
- Equal Percent of Marginal Cost
- Lump Sum
- Ramsey Solution: (P – MC)/P = c/ (Elasticity of Demand)*
- Use Embedded Cost Study

* c is a constant required to assure that the allocation equals the total revenue requirement.

Marginal Cost Revenue Study

SUMMARY	TOTAL MARGINAL PRODCUTION CAPACITY COSTS	TOTAL MARGINAL ENERGY COSTS	TOTAL MARGINAL DISTRIBUTION CAPACITY COSTS	TOTAL MARGINAL DISTRIBUTION CUSTOMER COSTS	TOTAL MARGINAL TRANSMISSION CAPACITY COSTS	TOTAL MARGINAL COSTS	Current Revneues	Current Revenues as Percent of MC
SC-1 Residential	$ 37,717,330	$ 42,460,437	$ 10,610,950	$ 13,456,920	$ 4,469,820	$ 108,715,457	$ 103,442,461	95%
SC-2 Commercial	$ 22,109,287	$ 34,738,950	$ 6,501,167	$ 3,872,880	$ 5,632,700	$ 72,854,984	$ 111,829,584	153%
SC-3 Large General Service	$ 23,647,324	$ 62,940,859	$ 6,733,840	$ 267,915	$ 1,889,680	$ 95,479,618	$ 144,352,375	151%
SC-4 Contract Service	$ 709,420	$ 826,623	$ -	$ 1,590	$ 13,264	$ 1,550,897	$ 1,771,328	114%
TOTAL	$ 84,183,360	$ 140,966,869	$ 23,845,957	$ 17,599,305	$ 12,005,464	$ 278,600,955	$ 361,395,748	130%

Total

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

Interclass Revenue Allocation

The Gas Company
Schedule 1.01
Interclass Revenue Allocation

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

Thank You

Carl Peterson

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