Everything You Wanted to Know About Rates

Eric Blake

Larry Feltner

The Prime Group, LLC

Key Questions in Developing Rates

- How much revenue should the utility be allowed to collect?
  - Revenue requirements calculation
- How much of the total revenue requirement should be collected from each customer class?
  - Rate design
  - Many different ways to collect revenue requirement
  - To accurately compare rate designs, they should all collect the same revenue requirement

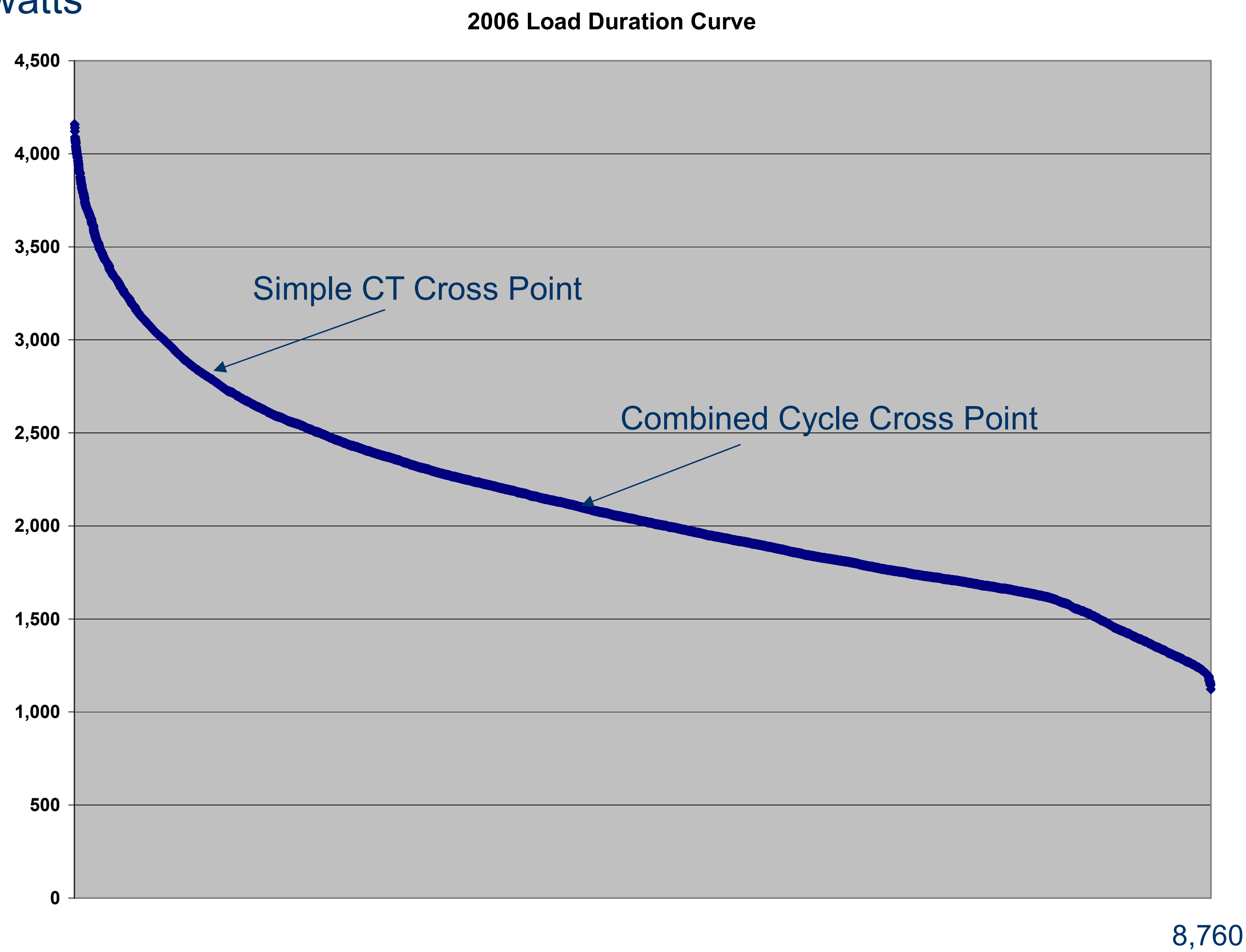
Functions of Utility Rates

- Recover the cost of providing service to customers
- Provide price signals and incentives to customers
- Although any rate accomplishes both functions, some rates put more focus on one function than the other

Rate Design and System Planning

- In the system planning process, customer needs are forecast and generation, transmission and distribution resources are arranged to meet these needs
- A load duration curve provides a picture of customer needs that the utility is trying to meet
- Rates can be used to “shape” the load duration curve for a utility, thus modifying resource needs

Megawatts



Hours

Meeting Customer Needs

- Address load variability on the supply side
  - Build capacity to meet the peaks
- Address load variability on the demand side by reducing peak demands
  - Demand side management programs (direct control)
  - Demand response to price signals (indirect control)

Rate Design and Marketing

- Rates can be used to create a value environment for products and services
  - Capacitors have value to customers if the utility assesses a power factor adjustment charge
  - Equipment to shift usage off-peak has value to customers with time of use rates or a rate with demand charges

Rate Design and Financial Planning

- The path of rates over time is one of the key variables used in financial planning
- The revenue forecast, a key component of financial planning, is driven by the sales forecast and by rate changes
- Need to account for sales changes due to price changes (price elasticity of demand)

Rate Design and Strategic Planning

- Rates need to support and be consistent with the strategic direction of the utility
- This begs the question "What is the utility trying to achieve?"
  - Promoting energy efficiency and conservation?
  - Promoting renewables?
  - Avoiding or delaying generation and transmission construction?
  - Promoting sales of products and services?
  - Other?

Rate Design Principles

- Rates should reflect the cost of serving customers when the rates will be in effect, i.e. the future
  - Based on historical costs during a 12 month test year
  - Pro forma adjustments to reflect known and measurable changes

Rate Design Principles

- Cost causation is the basis for fairly allocating costs to customers
  - If a customer causes a cost to be incurred by the utility, the customer should pay that cost
  - Customers should pay their "fair" share of the utility's margins
  - Begs the question "What customer actions cause costs to be incurred by the utility?"

Test Year

- Any 12 month period used for evaluating the revenues, operating expenses, depreciation, taxes, and rate base for purposes of setting rates
  - **Historic Test Year** - A recent 12 month period which reflects the actual results of operations as adjusted for known and measurable changes
  - **Future or Forecasted Test Year** - A future 12 month period which reflects utility budgets and the anticipated results of operations

Choosing a Test Year

- Ideally, a test year would be a “normal” year for the utility
- A historic year needs to be adjusted for known and measurable changes to reflect the cost of serving customers in the future
- A forecasted test year is based on a utility’s budgeted costs

Revenue Requirements

$$\boxed{RR = E + R + D + T}$$

RR = Revenue Requirements

E = O&M expenses

R = Return on invested capital

D = Depreciation expenses

T = Taxes

Operation and Maintenance Expenses

- Operations
- Maintenance
- Customer accounts expense
- Customer service expense
- Administrative and General

Adjustments to O&M

- Pro-Forma Adjustments – known and measurable changes
- Non-recurring expenses
  - One-time basis, irregular intervals
  - Amortized over the time period between rate cases

Return on Invested Capital

- The following can be used to determine the proper return <u>on</u> the utility's investment to be included in the revenue requirement:
  - Return on rate base
  - Times interest earned ratio (TIER)
  - Debt service coverage(DSC)
  - Cash flow targets

Major Utility Rate Base Items

- Plant in Service
- Construction Work in Progress (CWIP)
- Materials and Supplies
- Cash Working Capital
- Fuel Storage
- Prepayments
- Typical Deductions:
  - Accumulated Depreciation
  - Deferred Taxes
  - Contributions in Aid of Construction

Depreciation

- *Depreciation* charges are made against income and the value (or basis) of the asset to account for the fact that utility plant wears out over time
- Through depreciation charges a utility's owners receive a return <u>of</u> their investment
- Depreciation is usually designed to recover original cost, not replacement cost
- Usually this is reinvested in utility plant

Depreciation Example

- Cost - $100,000
- Salvage - 20,000
- Life - 20 years

$$D = \frac{\$100{,}000 - \$20{,}000}{20 \text{ years}} = \$4{,}000 \text{ / year}$$

Depreciation Example

Year	Depreciation per Year	Accrued Depreciation
1	4,000	4,000
2	4,000	8,000
…		
20	4,000	80,000
+ Salvage		20,000
Recovered		100,000

Property and Other Taxes

- Property Taxes
- Gross Receipts Taxes
- Sales Taxes
- Franchise Fees
- Business Taxes
- Payroll Taxes

Revenue Requirement

O&M Expenses	$	72,888,623
Return on Investment	$	13,446,984
Depreciation (return of investment)	$	12,197,036
Property and Other Taxes	$	219,206
Revenue Requirement	$	98,751,849

Revenue Deficiency

The revenue deficiency is equal to the difference between the revenue requirement and the actual pro forma revenue during the test year:

Revenue Requirement
- Pro Forma Test Year Revenue

Revenue Deficiency

Fixed Cost

- Fixed cost - a cost that does not vary with sales levels
  - Volumetric fixed costs are costs related to the demand that the customer places on the system
  - Non-volumetric fixed costs are costs that occur regardless of demand or usage level
  - Once these costs have been incurred, the level of these costs cannot be changed and the focus shifts to cost recovery

Variable Cost

- A cost that varies with volume, production or sales levels
  - Fuel
  - Scrubber reactant
  - Variable O&M

Controlling Costs

- Fixed Cost
  - To reduce the impact of fixed costs on customers, we need to spread them over a larger number of customers or usage
  - Improve load factor
  - Eliminate unnecessary costs
- Variable Cost
  - Reduce fuel costs
  - Improve heat rates
  - Reduce usage

Embedded Cost Pricing

- Embedded cost pricing refers to the use of actual average historical cost in determining the price of utility service
- Rates are averages
- Rates support expenditures associated with the "average" customer in each class
  - Plant investment
  - Operating expenses
  - Margins

Marginal Cost Pricing

- Marginal cost pricing refers to the use of long-run or short-run marginal costs in determining the price of utility service
  - Short-run marginal cost is the change in total cost due to a change in demand assuming that capacity is fixed
  - Long-run marginal is the change in total cost due to a change in demand assuming that capacity is not fixed (i.e., capacity can be added to meet increased demand)

Utility Rates

- Utility rates are generally determined on the basis of average costs
- However, some elements of marginal cost pricing are often reflected in utility rate designs
  - Time-of-day rates
  - Declining block rates
  - Off-peak rates

Revenue Reconciliation

- First step in the cost of service process
- Check for synchronicity among usage, cost and revenue in the cost of service study
- Rate design tool for assessing the impact of rate design changes
- Shows how revenue is collected by rate component

Revenue Reconciliation

- Calculate revenues for each rate class
  - Multiply each rate component from the tariff that was in effect during the test year by the billing units for that rate component from the cost of service study
  - Sum across rate components
- Subtract per book revenues from calculated revenues to obtain a difference

Revenue Reconciliation

- Divide the difference by per book revenues to obtain a percentage difference
- The percentage difference between calculated revenues and per book revenues should be less than 1% to ensure synchronicity
- Helps to identify data problems

Revenue Reconciliation

Facility Charge

	Customer Months	Per Customer		
All Cust. Months	261,860	$ 10.00	$	2,618,600

Energy Charge

	kWh	Per kWh		
All kWh	120,299,391	$0.10519	$	12,654,293

Fuel Adjustment

Total Fuel Adjustment	$	177,765
Total Rate 1	$	14,992,683
Revenue Per Books	$	15,143,415
Difference	$	(150,732)
Percent Difference		-1.00%

Key Terms

- Kwh vs Kw
  - Kw is the measure of the instantaneous load a member requires
  - Kwh is the measure of the load over time
  - A 1,000 watt light bulb would pull 1 Kw of demand
  - If the bulb is turned on for 1 hour, it uses 1,000 watt hours or 1 Kwh of electricity

Key Terms

- Load Factor – A measure of how much of a member's maximum demand the member uses over the course of time.
  - Load Factor = Average demand / Maximum demand
- Coincidence Factor – A measure of how much of a class's maximum monthly demand is coincident with the wholesale suppliers billing demand
  - CF = Coincident Peak Demand / Class Maximum Demand

Cost of Service Study

- Embedded (average historical) cost
  - Methodology used in cost of service study
  - Public policy tool to achieve fairness and equity
  - Uses historical sunk cost (accounting cost) as the basis for determining profitability and setting rates
- Marginal cost
  - Ignores sunk costs and bases profitability on marginal revenues and marginal costs

Cost of Service Methodology

- Allocate pro forma costs to rate classes based on cost causation principles
- Identify the appropriate cost driver for each account
- Use cost drivers to allocate costs as accurately and as fairly as possible to the various rate classes

Cost of Service Methodology

- Three step allocation process is used in developing a cost of service study
  - Functional assignment
  - Classification
  - Allocation

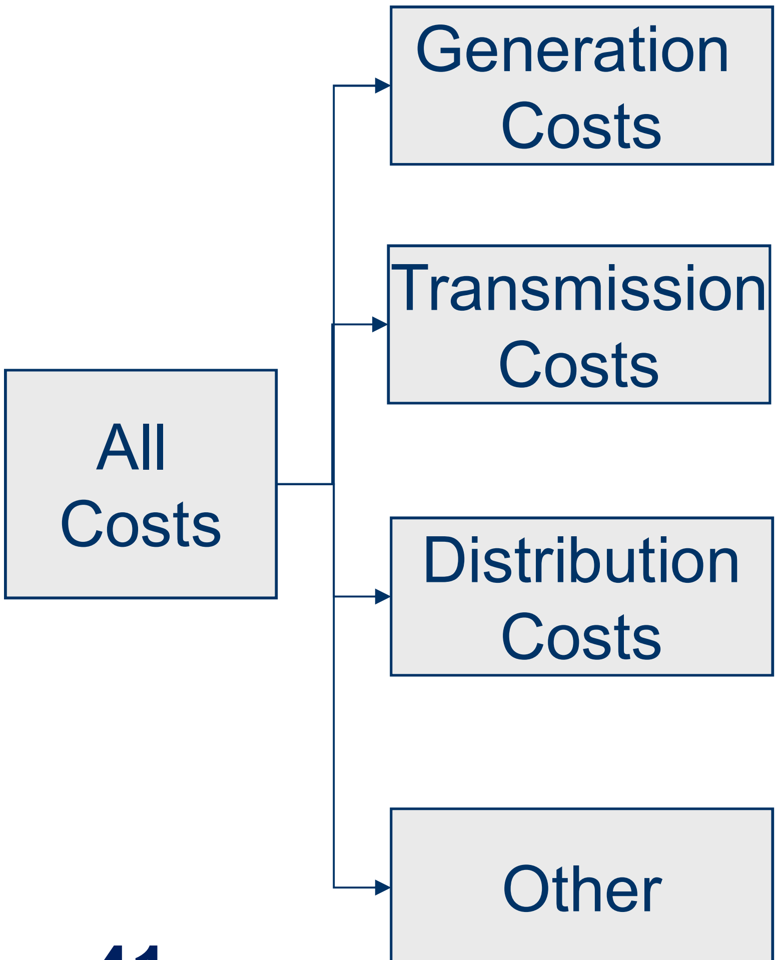
Functional Assignment

- Assign all of the utility’s costs into major functional groups

- Maximizes the effectiveness of the study for detailed pricing, such as rate unbundling

Cost of Service Study

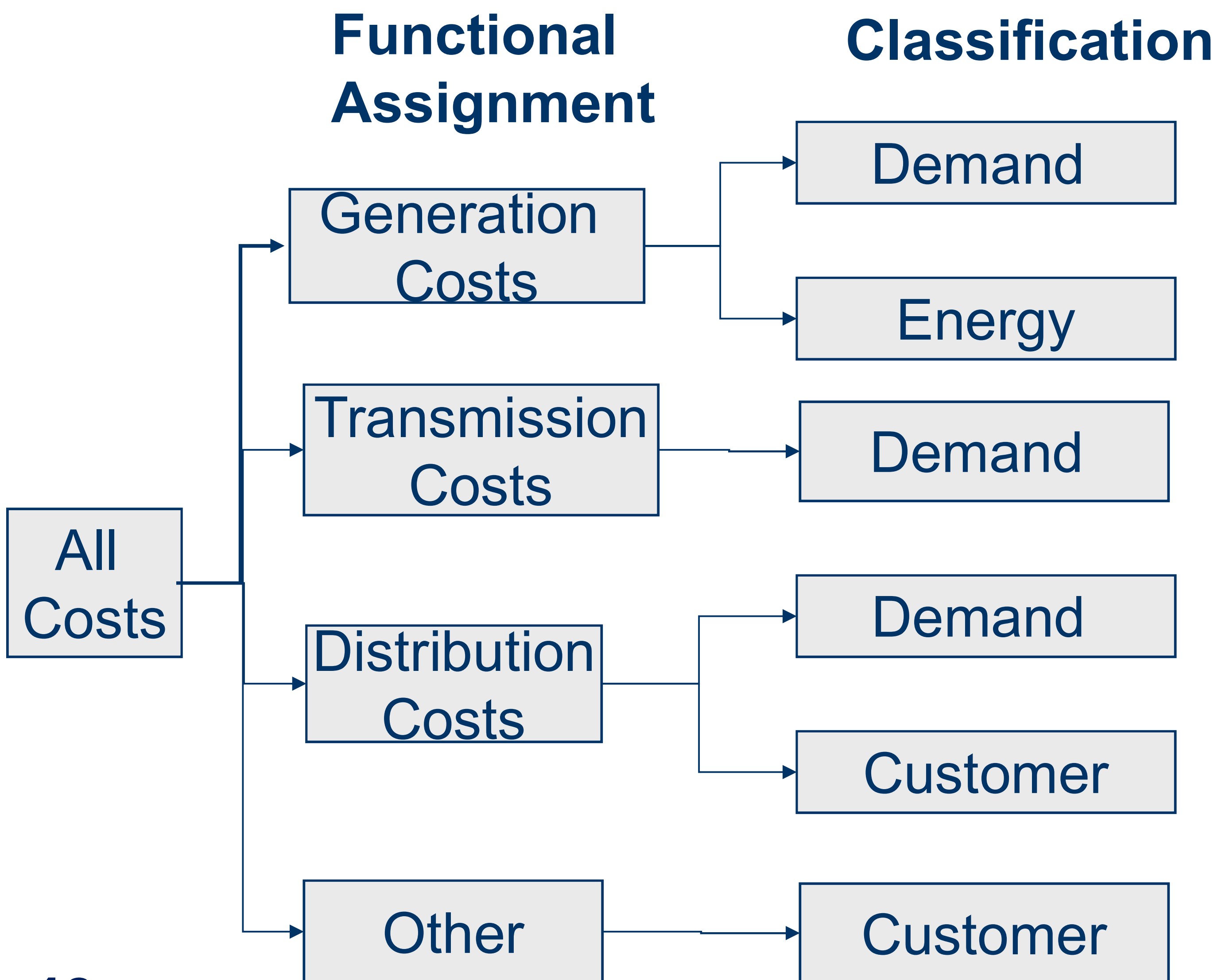
Functional Assignment



Classification of Costs

- Corresponding to the major cost drivers to help in identifying cost causation
  - Energy related costs vary with the consumption of energy
  - Demand related costs vary with the capacity requirements of customers
    - Non-coincident peak demand for distribution capacity
    - Coincident peak demand for generation and transmission capacity
  - Customer related costs vary with the number of customers served

Cost of Service Study



Example of Energy Costs

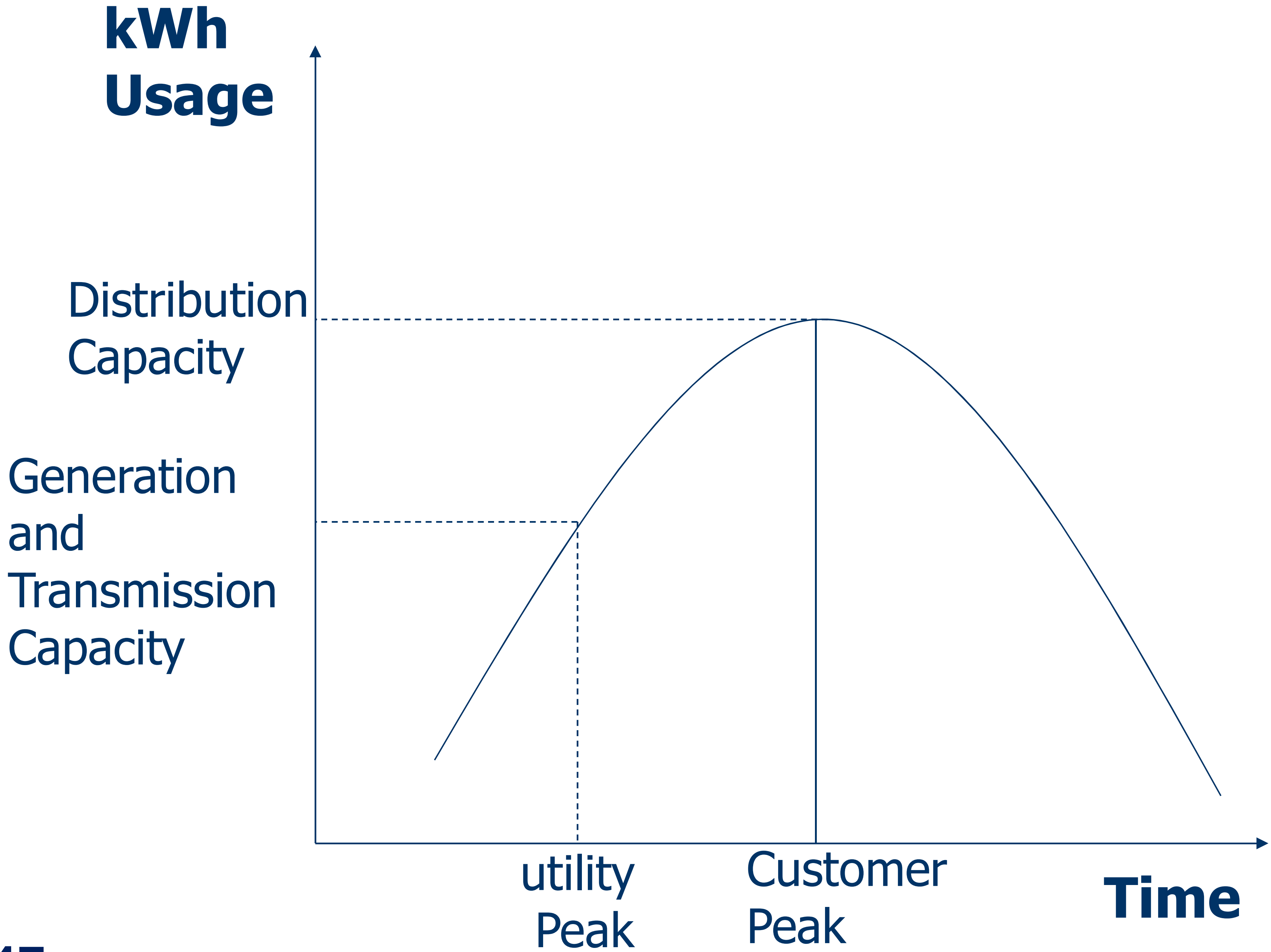
- Fuel
- Scrubber reactant costs
- Variable operation and maintenance expenses
- kWh portion of purchased power

Demand Related Costs

- Coincident peak demand
  - Customer's use of capacity that is coincident with cooperative's peak demand
  - Purchased power demand
- Class Non-coincident peak demand
  - Substation and primary conductor
  - Facilities are designed to meet a diversified demand

Demand Related Cost

- Sum of Individual Customer Non-coincident Peak Demand
  - Secondary conductor and line transformers
  - Facilities are designed to meet a localized non-diversified demand


kWh
Usage
Distribution
Capacity
Generation
and
Transmission
Capacity
utility
Peak
Customer
Peak
Time

Customer-Related Costs

- Distribution costs that are invariant to the size or usage of the customer
- Things that each customer needs one of regardless of the customer's size or usage (minimum system that each customer needs to have access to the grid)
- The portion of distribution costs that vary with size are allocated to distribution demand costs

Customer-Related Costs

- Meters and meter installation costs
- Service drop
- Meter reading expenses
- Billing expenses
- Minimum system - the portion of distribution poles, transformers, conductor that all customers must have to provide access to the electric grid

Allocation of Costs

- Allocate the functionally assigned and classified costs to all of the utility's classes of customers
- Based on each classes' pro rata share of the relevant cost driver

Allocation

- Energy related costs are allocated based on the kWh energy usage for each customer class during the test year
- Customer related costs are allocated based on the number of customers in each class

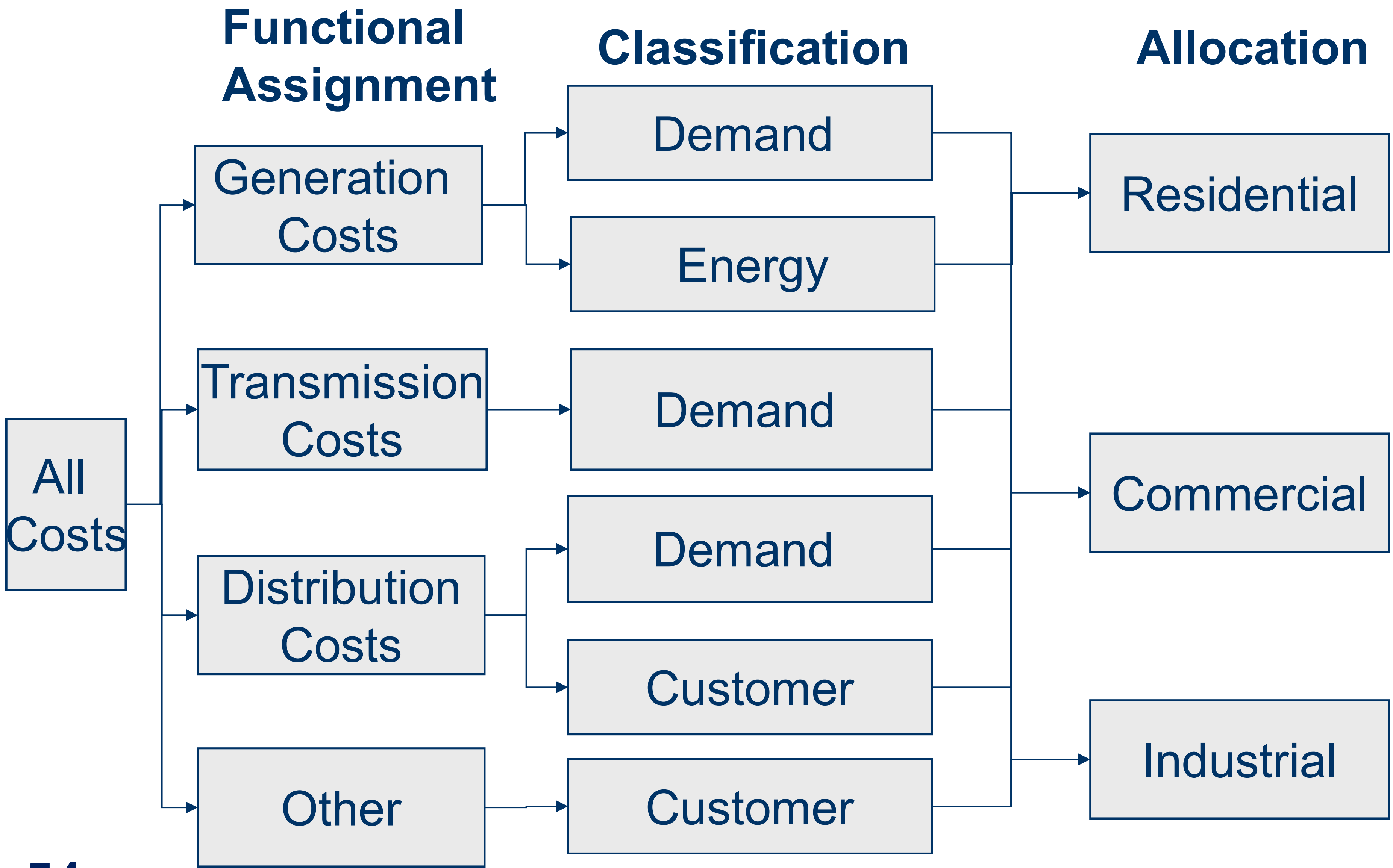
Allocation

- Demand Related Production and Transmission costs
  - Annual CP
  - 12 CP
  - Average and excess
  - There is no single, correct method

Allocation

- Demand Related Distribution Costs
  - Transformers and secondary voltage distribution lines are allocated based on the sum of individual peak demands for all members of a customer class
  - Substations and primary voltage distribution lines are allocated based on non-coincident peak demands for each customer class

Cost of Service Study



Cost of Service Summary

	Revenue	Operating Expenses	Operating Margin	Rate Base	Return on Rate Base	Return on Revenues
Residential	$ 27,687,524	$ 26,495,986	$ 1,191,538	$ 91,057,248	1.31%	4.30%
Residential Pre-Paid	$ 361,192	$ 333,997	27,194	1,239,759	2.19%	7.53%
Residential TOU	$ 6,179,170	$ 6,740,301	(561,131)	20,797,961	-2.70%	-9.08%
Single Phase Small Commercial	$ 7,266,152	$ 6,252,083	1,014,069	16,006,935	6.34%	13.96%
Single Phase Small Commercial Pre-Paid	$ 9,604	$ 8,575	1,029	21,621	4.76%	10.71%
Three Phase Small Commercial	$ 4,447,265	$ 3,669,229	778,037	7,226,186	10.77%	17.49%
Single Phase Small Commercial TOU	$ 218,201	$ 223,754	(5,553)	534,886	-1.04%	-2.54%
Single Phase Small Comm. TOU Pre-Paid	$ 1,136	$ 1,384	(248)	4,052	-6.12%	-21.82%
Large Commercial TOU	$ 28,635	$ 35,386	(6,751)	93,841	-7.19%	-23.58%
Small Commercial 3 Phase TOU	$ 112,921	$ 141,223	(28,302)	301,156	-9.40%	-25.06%
Large Commercial	$ 16,700,989	$ 14,181,094	2,519,895	20,745,030	12.15%	15.09%
Large Commercial Primary	$ 12,856,500	$ 12,559,674	296,826	14,555,043	2.04%	2.31%
Large Commercial Coincident Peak	$ 386,985	$ 322,080	64,905	1,458,368	4.45%	16.77%
Industrial, Transmission Coincident Peak	$ 20,457,893	$ 18,887,650	1,570,243	7,365,502	21.32%	7.68%
Irrigation	$ 402,057	$ 536,602	(134,545)	3,201,909	-4.20%	-33.46%
Sales For Resale	$ 21,553	$ 26,662	(5,108)	46,096	-11.08%	-23.70%
Lighting	$ 513,205	$ 220,871	292,334	1,618,791	18.06%	56.96%
	$ 97,650,981	$ 90,636,550	$ 7,014,431	$ 186,274,385	3.77%	7.18%

Rate or Return on Investment (Rate Base)

- Return on investment equates to a company's weighted average cost of financing
- Example:
  - Cost of Debt = 5%
  - Cost of Members Equity = 7%
  - Cooperative is financed with 50% debt and 50% equity
  - Weighted average cost is (5% x 50%) + (7% x 50%) = 6%

Comparing Return on Rate Base and Return on Revenue

- Return on Rate Base is a return on investment calculation
- Rate Base is the cooperative's investment to serve customers
- Return on Rate Base = Operating Margin/Rate Base
- Return on Revenue is how retailers often look at margins
- Return on Revenue = Operating Margin/Revenue

Comparing Return on Rate Base and Return on Revenue

- Return on Rate Base is a superior measure of fairness and equity because it takes into consideration the amount of money a cooperative has to invest in order to get the margins

Evaluating Fair Share of Margins

- Rates should recover actual cost of serving the class
- All rate classes should pay a "fair share" of margins
- Standards for evaluating whether customer classes are paying their fair share
  - Equalized rates of return on rate base among all customer classes
  - Equalized return on revenues
  - Should risk of incurring stranded costs be considered in justifying differences in rates of return among classes?

Rate of Return and Cross Subsidies

- Compare rate of return for rate classes to rate of return for utility as a whole
  - Classes with a rate of return below the rate of return for utility as a whole are receiving a subsidy
  - Classes with a rate of return above the rate of return for utility as a whole are paying a subsidy
  - Are the differences substantial enough to remedy?

Adjusting Class Rates of Return

- Usually accomplished by assigning more or less margin to a customer class
- Expenses are treated as a given

Basis for Establishing Rate Classes

- Establish rate classes based on similarity of usage characteristics of customers within the class
- Want rate classes that are relatively homogeneous
- Rates are averages
- An average does a good job of describing a relatively homogeneous group

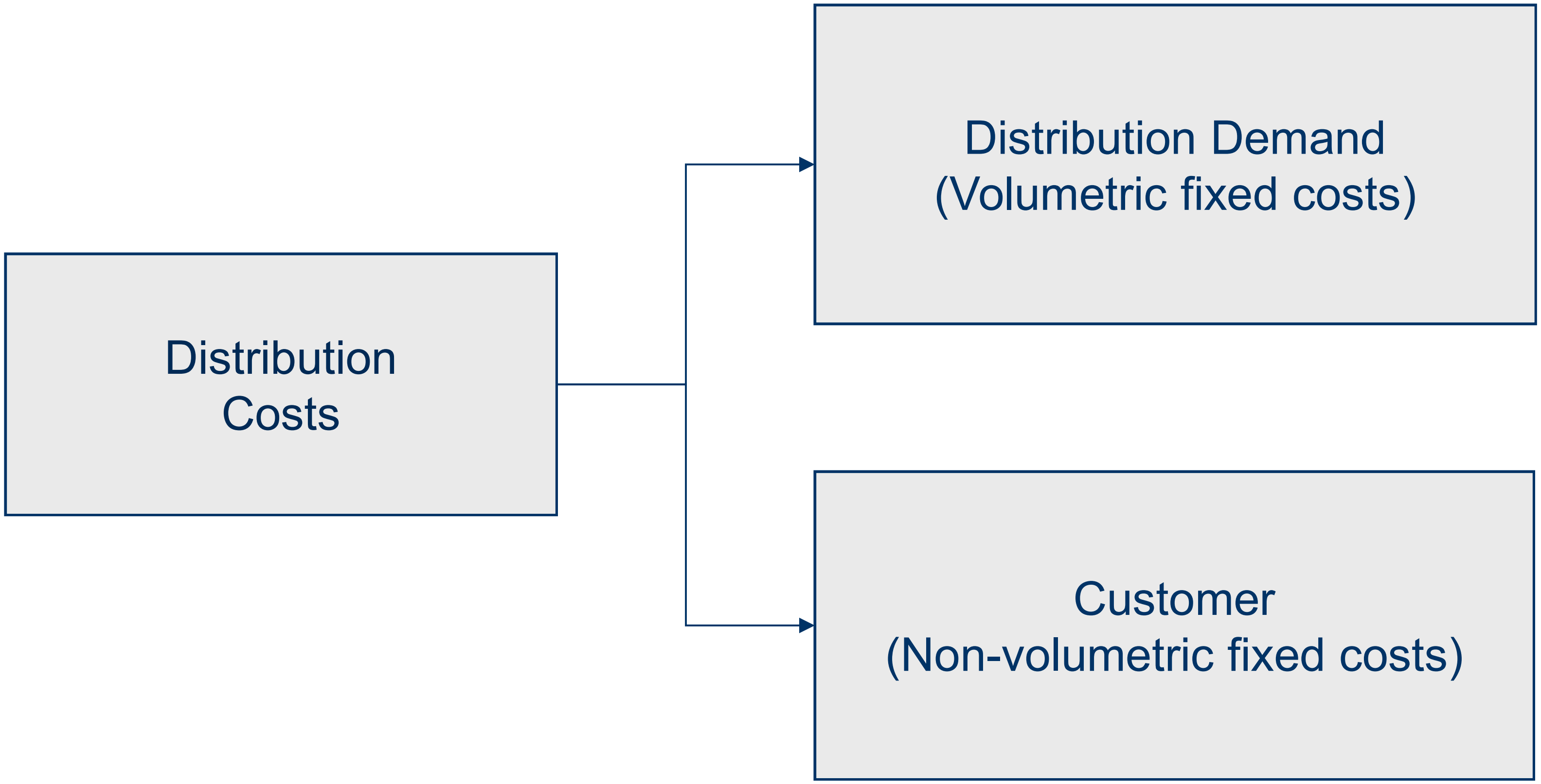
Establishing Rate Classes

- What is the right number of rate classes?
- Combining rate classes with similar cost characteristics
- Combining rate classes with similar usage characteristics
- Splitting an existing rate class into multiple rate classes when it includes customers with different cost or usage characteristics

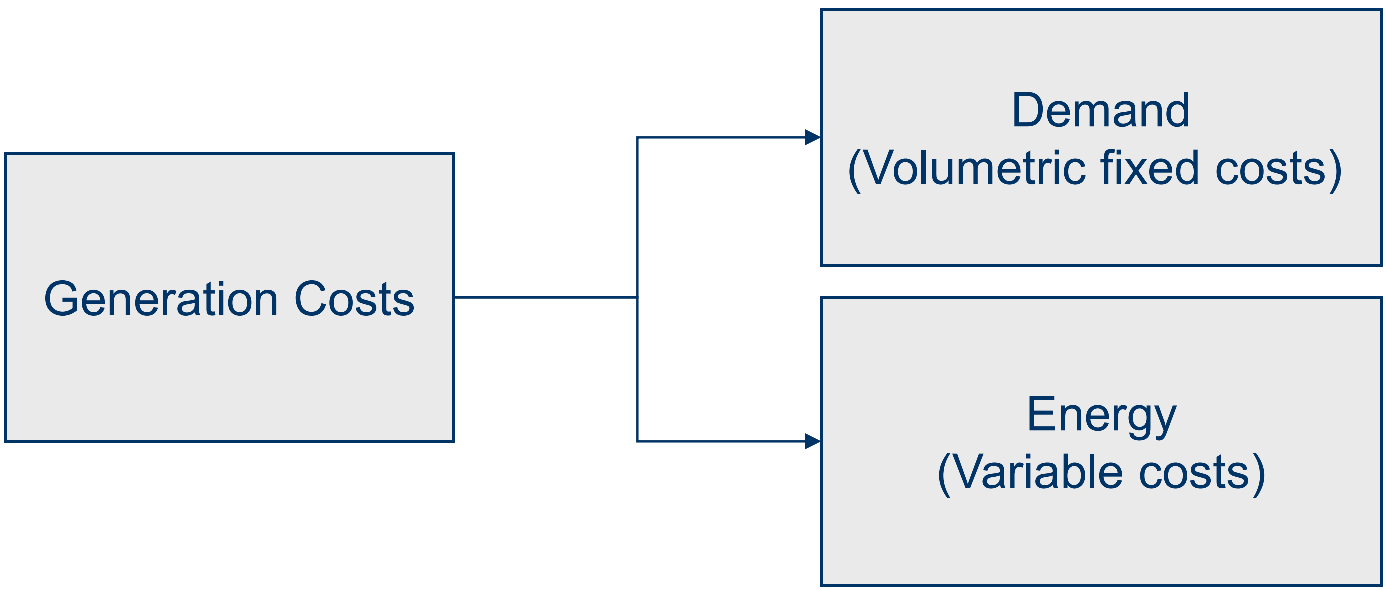
Cost Recovery

- The goal is to recover fixed and variable costs as fairly as possible from both large and smaller usage customers
  - Non-volumetric fixed costs should be recovered through a fixed charge that does not vary with usage (customer charge)
  - Volumetric fixed costs recovered through a demand charge which varies with usage (CP or NCP demand charge)

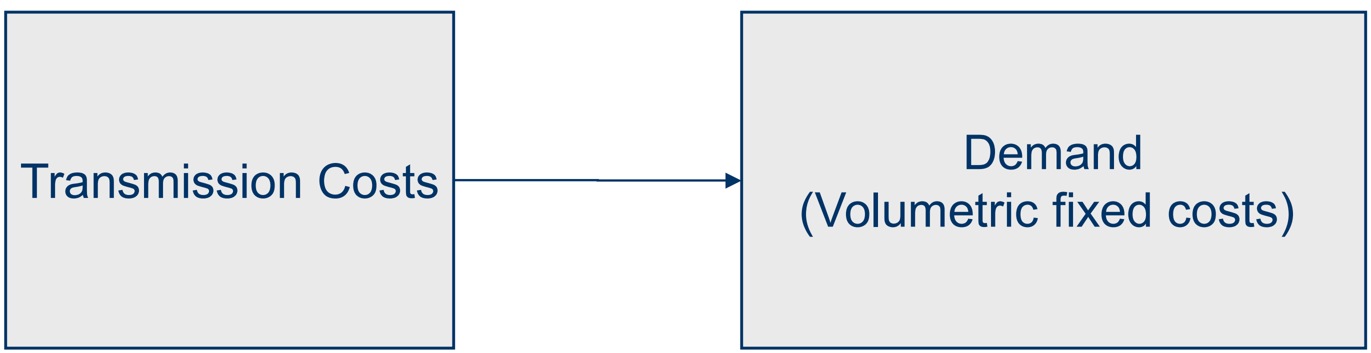
Distribution Cost Recovery



Generation Cost Recovery



Transmission Cost Recovery



Rate Design Principles

- Recover fixed costs through fixed charges
  - If fixed costs are "variablized", there is a risk of not recovering fixed costs if kWh usage is reduced
- Recover variable costs through variable charges
  - If variable costs are "fixed", customers will not benefit from their efforts to reduce or shift energy usage
- Intra-class subsidies are avoided if these principles are followed

“Variabilizing” Fixed Costs

- Fixed costs recovered through kWh charge
  - Distribution demand costs recovered through kWh charge (both volumetric and non-volumetric fixed costs)
  - Generation demand charges in base rates recovered on a kWh basis
  - Power cost adjustment assessed on a kWh basis
- Causes “drift” in class rates of return over time

“Variabilizing” Fixed Costs

- Results in intra-class subsidies
  - Customers with above average usage and high load factors are paying a subsidy
  - Customers with below average usage and low load factors are receiving a subsidy
- This is particularly a problem when sales are reduced relative to test year levels

Example of "Variablizing" Fixed Costs

- Cost of service results:
  - Customer related costs are $24.85/meter/mo.
  - Margins on customer related <u>$6.81/meter/mo</u>.

$31.66/meter/mo.

Impact of Retail Rate Design

- Usage
  - 142,931 customer months
  - 96,232,730 kWh
- Rate design
  - $17.50 customer charge for single phase
  - 10.734¢ per kWh

Impact of Retail Rate Design

\$31.66 - \$17.50 = \$14.16/cust/month

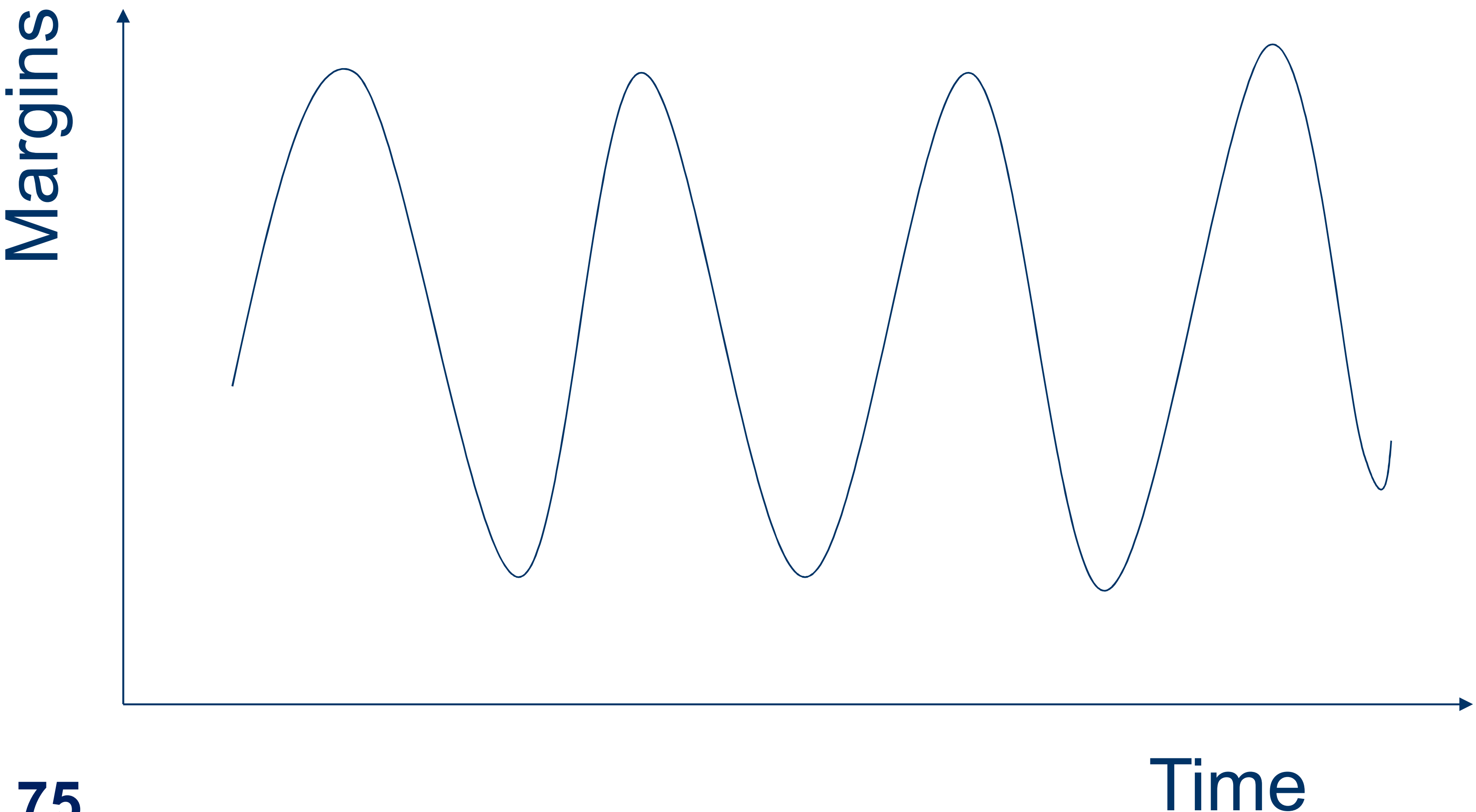
\$14.16 x 142,931 = \$2,023,903 in fixed costs and margins

\$2,023,903 / 96,232,730 kWh = \$0.021/kWh in fixed cost and margins recovered through energy

Impact of Retail Rate Design

- Customer charge is $14.16 too low
- Energy charge is $0.021/kWh too high
  - Customers buying large amount of kWh are paying more than their fair share of fixed costs and margins (high profitability)
  - Customers buying small amount of kWh are paying less than their fair share (low or negative profitability)

Margin Variability



“Fixing” Variable Costs

- Volumetric portion of distribution demand recovered through a fixed monthly customer charge (straight fixed variable rate design)
- Low usage customers are force fed variable costs
- The results in intra-class subsidies
  - Customers with below average usage are paying a subsidy
  - Customers with above average usage are receiving a subsidy

Benefits of Cost Based Rates

- Cost based rates reflect the functional assignment, classification and allocation from the cost of service study
- Cost based rates minimize cross subsidies among customers within a class
- Deviating from cost based rates results in cross subsidies within classes

Cost Based Rates

- Reduce revenue and margin volatility for the utility by recovering fixed costs through fixed charges
- Reduce customer bill volatility
- Frequently benefits low income customers

Benefits of Cost Based Rates

- Creates the right environment for energy conservation, energy efficiency and demand side management
- If fixed costs are being recovered through the energy charge, the utility has no incentive to pursue energy efficiency and conservation efforts

Benefits of Cost Based Rates

- Make utility competitive at the margin against other fuels
- Provides protection in a net metering environment
- Eliminate declining block rate structures
- Reduce the number of rate classes

Rate Components for Recovering Fixed Costs

- Customer charge
- Purchased power demand charge
- Generation demand charge
- Transmission demand charge
- Distribution demand charge
- Power factor adjustment charge
- Facilities charge

Rate Components for Recovering Variable Costs

- Energy charge
- Fuel adjustment clause
- Tracker mechanisms for environmental costs, demand side management costs and other specifically identified costs

Customer Charge

- Charge per bill per month
  - $29.00 per bill per month
- Covers the cost of the equipment (minimum system) necessary to provide a customer with grid access
- Based on costs that are classified as customer-related in a cost of service study

Rate Components

- **Energy Charge** - Charge per kWh per month
  - Flat rate – same rate for all kWh used e.g. 9¢/kWh
  - Declining block rate – different charge for each kWh usage block
    - 12¢/kWh for the first 200 kWh
    - 9¢/kWh for the next 800 kWh
    - 6¢/kWh for all kWh above 1,000

Rate Components

- **Energy Charge (cont.)**
  - On-peak/Off-peak rate
    - 4.5¢/kWh for off-peak kWh usage
    - 16¢/kWh for on-peak kWh usage
  - Multiple tiers with a critical peak
    - 4¢/kWh for low price period
    - 8¢/kWh for intermediate price period
    - 15¢/kWh for high price period
    - 35¢/kWh for critical peak period

Rate Components

- **Energy Charge (cont.)**
  - Inclining block rate
    - 6¢/kWh for the first 200 kWh
    - 9¢/kWh for the next 800 kWh
    - 12¢/kWh for all kWh above 1,000
  - Real time energy price
    - Hourly prices per kWh that reflect market prices or hourly marginal production costs
    - May be provided day ahead or on the same day

Rate Components

- **Demand Charge** - Charge per billed kW per month
  – Coincident Peak (CP demand) – The customer's KW usage during the time period when the utility experiences its monthly peak usage, for example $18/KW of CP demand
  – Non-Coincident Peak (NCP demand) - The customer's maximum KW usage during the month regardless of when it occurs, for example $4/KW of NCP demand

Rate Components

- **Demand Charge (cont.)**
  - Average demand
    - kWh usage during a period divided by the hours in the period
    - This is really an energy charge masquerading as a demand charge
  - Ratcheted demand charge
    - Demand charge based on some percentage of the highest demand in some previously specified period

Rate Components

- Fuel and Purchased Power Adjustment Clauses – charge or credit per kWh for the difference between the actual cost of fuel and purchased power during the month and the fuel and purchased power included in base rates
  - For example, a charge or credit per kWh equal to the amount by which the utility's actual fuel and purchased power costs exceed 4.5¢/kWh

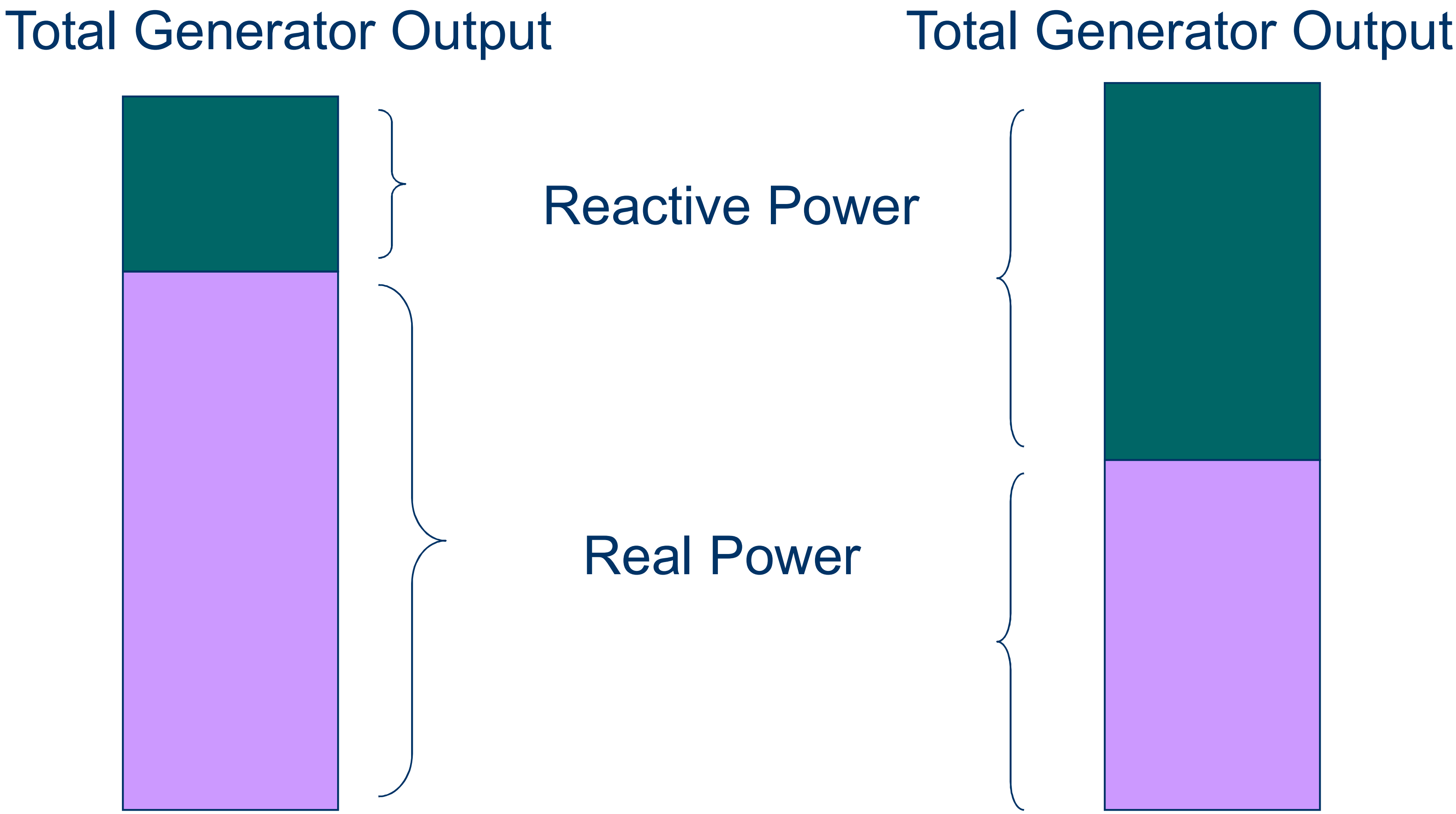
Need For a FAC or PPAC

- Fuel cost variability
  - Natural gas
  - Coal
- Purchased power cost variability
  - Monthly differences in utility Load Factors
  - Purchases to cover forced outages
  - Purchases that are indexed to market
  - Prices in organized energy markets (LMP)

Types of Adjustment Mechanisms

- Calculated annually
- Calculated monthly
- Calculated using a rolling average

Apparent Power



Real Power

- The energy or work producing part of apparent power
- Measured in kW
- The product of real power and length of time is <u>energy</u> which is measured by watt-hour meters and expressed in kWh
- Ex. 5 kW x 10 hours = 50 kWh

Reactive Power

- The portion of apparent power that does no work
- Measured in kilovars (kVar)
- Reactive power must be supplied to most types of magnetic equipment, such as motors
- Supplied by generators or electrostatic equipment, such as capacitors

Rate Components

- Power Factor Adjustment – a charge for differences between a customer's monthly power factor and a specified power factor
  - For example, a charge of 1.5% of the demand charge for each percentage point that a customer's power factor is below 90%
  - Power factor is calculated by dividing kW usage by kVa usage during the month and is usually expressed as a percentage

Rate Components

- Power Factor Adjustment plays an important role in incenting customers to fix power factor problems at the source
- Frees up generation and transmission capacity which would otherwise be used to generate and transmit reactive power and which is expensive to construct

Rate Components

- Facilities charge – charge for non-standard services that the customer requests
  - Key is defining what constitutes standard service
- Minimum bill – minimum charge assessed to a customer regardless of the customer's usage
  - Usually the customer charge
  - An amount higher than the customer charge forces customer to pay for a certain amount of kWh regardless of usage

Translating Costs to Rates

A cost of service study allocates costs to customer or rate classes but does not allocate costs to usage levels within classes.

Cost of Service	**Rate Design**
Energy Costs ($ per kWh)	
Demand Costs ($ per kW)	?
Customer Costs ($ per Customer)	

Two-Part Rate Design

Cost of Service

Energy Costs
($ per kWh)

Demand Costs
($ per kWh)

Customer Costs
($ per Customer)

Rate Design

Energy Charge

Customer Charge

Three-Part Rate Design

Cost of Service		**Rate Design**
Energy Costs ($ per kWh)	→	Energy Charge
Demand Costs ($ per kW)	→	Demand Charge
Customer Costs ($ per Customer)	→	Customer Charge

Four-Part Rate Design

Cost of Service		**Rate Design**
Energy Costs ($ per kWh)	→	Energy Charge
Purchased Power Demand Costs ($ per kW)	→	CP Demand Charge
Distribution Demand Costs ($ per kW)	→	NCP Demand Charge
Customer Costs ($ per Customer)	→	Customer Charge

Designing Rates Using Revenue Reconciliation Spreadsheet

- Develop and evaluate rate alternatives using billing determinants from the revenue reconciliation
- Using the same billing determinants assures that differences are due to rate design

Designing Rates Using Revenue Reconciliation

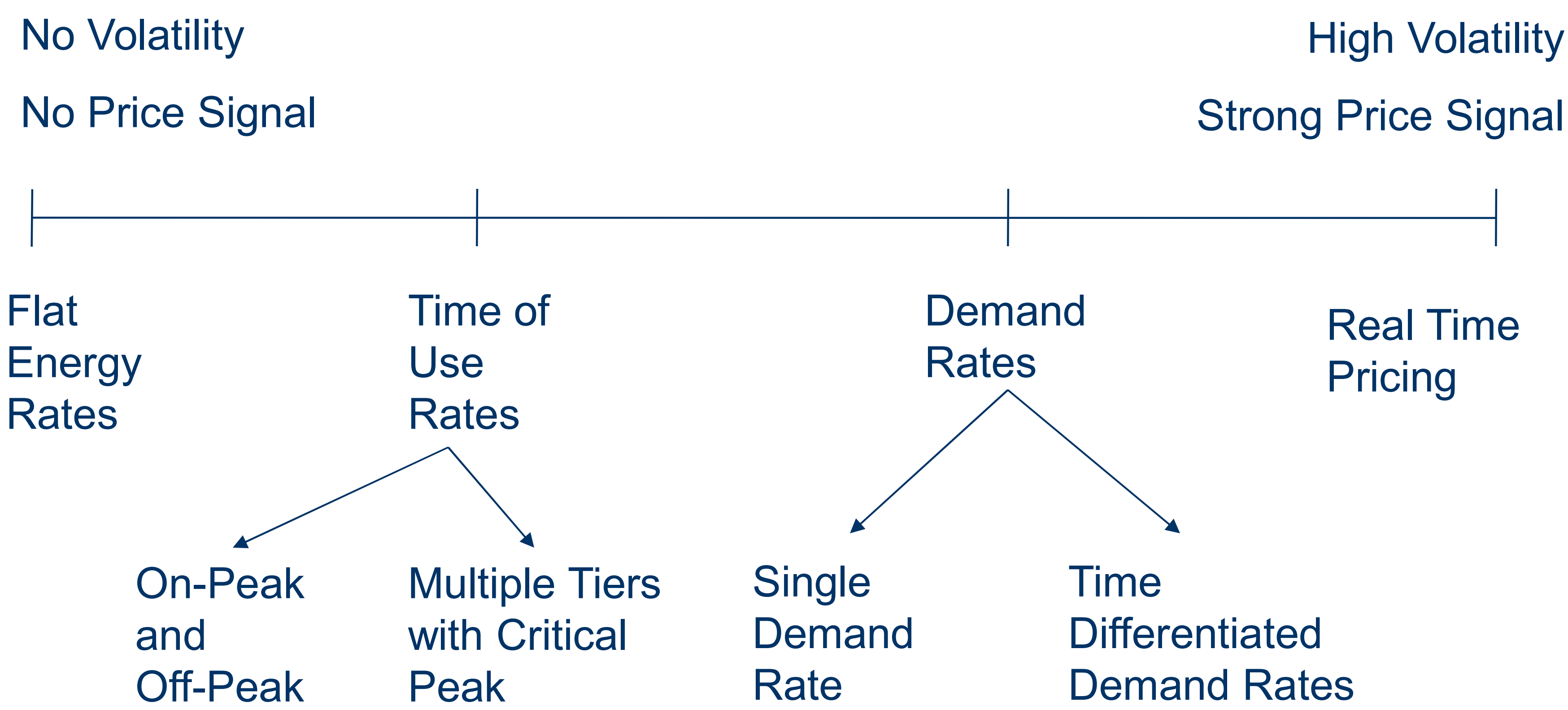
	Test Year Rate		
	Billing Units	**Rate**	**Calculated Billings**
Facility Charge			
	Customer Months	*Per Customer*	
All Cust. Months	261,860	$ 10.00	$ 2,618,600
Energy Charge			
	kWh	*Per kWh*	
All kWh	120,299,391	$0.10519	$ 12,654,293
Fuel Adjustment			
Total Fuel Adjustment			$ 177,765
Total Rate 1			$ 14,992,683
Revenue Per Books			$ 15,143,415
Difference			$ (150,732)
Percent Difference			-1.00%

	Cost Based Rates		
	Billing Units	**Rate**	**Calculated Billings**
Customer Charge			
	Customer Months	*Per Customer*	
Customer Months	261,860	$ 23.76	$ 6,221,794
Energy Charge			
	kWh	*Per kWh*	
Purchased Power Energy	120,299,391	$ 0.02980	$ 3,584,922
Purchased Power Demand	120,299,391	$ 0.03864	$ 4,648,368
Distribution Demand	120,299,391	$ 0.02632	$ 3,166,280
		$ 0.09476	$ 11,399,570
Fuel Adjustment			
Total Fuel Adjustment			$ -
Total Rate 1			$ 17,621,364
Difference			$ 2,628,681
Percent Change			17.5%

Sending the Right Price Signals

- All prices send signals
- What signals are your prices for electric service sending?
- Your rate design should provide financial incentives for customers to take actions that will help your utility to achieve its strategic goals
  - Begs the question, what are you trying to accomplish with your customers

The Rate Continuum



Unbundled Cost Based Residential Rates

- Cost of service results:
  - Customer related costs are $20.84/cust/mo.
  - Margins on customer related $4.83/cust/mo.

  - Distribution demand costs are $0.012/kWh
  - Margins on dist demand are $0.008/kWh

  - Purchased power demand is $0.027/kWh
  - Purchased power energy is $0.024/kWh

Flat Energy Rate Example

- Customer charge = $25.67/customer/mo.
- Energy charge = 7.1¢/kWh
  - Distribution demand charge = 2¢/kWh
  - Purchased power demand = 2.7¢/kWh
  - Purchased power energy = 2.4¢/kWh
- With flat rates, the only way to reduce energy bill is to cut kWh consumption

Basis for Time Differentiated Rates

- The cost of serving load differs substantially over time
- Fixed cost per kWh varies over time as different generating units and technologies are required to meet customer needs
- Variable cost per kWh varies over time as different fuel sources are used to meet customer needs (coal, nuclear, gas)

Reasons for Offering Time Differentiated Rates

- Provides utilities with an opportunity to reduce costs by providing a financial incentive for customers to shift usage to time periods that are less costly to serve
- Provides customers with opportunity to manage their energy bill in a time of rising prices
- Provides customers with choice

Mechanics of Time Differentiation

- Opportunities for time differentiating utility's retail rates
  - Turn CP demand charges into on-peak retail rate differentials
  - Energy charges can be time differentiated based on the utility's system lambda (marginal production cost) or if supplier's energy charges are time differentiated

Developing an On-Peak Adder

- Determination of peak periods
  - Likely to vary by season
  - May or may not include weekends
  - Needs to capture utility's peak
  - Shorter periods provide more opportunity for customers to shift loads
- Recovery of enhanced metering costs

Data Requirements

- Purchased power demand costs from recent cost of service study
- Time of day and day of the week when the utility's monthly system peaks have occurred
- Load data or aggregated meter data by hour by class that can be used to determine energy and demands during the peak periods
- Cost of enhanced metering equipment from vendors
  - Utility chooses whether to include this in customer charge or roll it into base rates

Key Steps in Designing TOU Rates

- Step 1 – Develop on-peak periods
  - Examine 5 to 10 years of utility system peak demands
  - Determine whether weekend/holiday peaks are likely
  - Determine whether different time periods are appropriate by season
    - Summer peaks often occur in the evening
    - Winter and shoulder peaks can occur in the morning or evening

Peak Period Analysis Example

Weekday	Frequency
Monday	35
Tuesday	32
Wednesday	30
Thursday	24
Friday	20
Saturday	7
Sunday	3
	151

Hour Ending	Frequency
8:00	45
9:00	3
15:00	1
17:00	23
18:00	33
19:00	8
20:00	28
21:00	10
Total	151

Winter peaks		
Hour Ending	Frequency	
8:00	23	
9:00	3	
19:00	5	
20:00	5	
21:00	2	
Total	38	
Winter peak window		
7 AM to 9 AM and 6 PM to 9 PM		

Summer Peaks			
Hour Ending	Frequency		
15:00	1	June	
17:00	13		
18:00	24		
Total	38		
Summer peak window of 4 PM to 6 PM			
or 2 PM to 6 PM if you want to avoid all risk			

Peak Period Analysis Example

Fall Peaks	
Hour Ending	Frequency
8:00	9
17:00	7
18:00	4
19:00	3
20:00	13
Total	36

Spring Peaks	
Hour Ending	Frequency
8:00	13
17:00	3
18:00	5
19:00	0
20:00	10
21:00	8
Total	39

Time of Use Rates

- Choosing the on-peak period as narrowly as possible is the key
- Broad peak period (e.g. 7 AM to 11 PM)
  - Not very useful to customers
  - Results is small differential between on-peak and off-peak because the denominator in the calculation of the on-peak adder is large
- Flat rate results if everything is on-peak

Key Steps in Designing TOU Rates

- Step 2 – Determine billing units for the on-peak period
  - Determine kWh in the on-peak period for customer classes
  - Determine peak period demands (kW) for rates with a demand charge

Hourly kWh for On-Peak and Off-Peak

Hour	kWh		
100	528,279		
200	468,095		
300	434,660		
400	407,912		
500	414,599		
600	454,721		
700	528,279		
800	548,340		
900	628,585		
1000	735,578		
1100	829,197		
1200	929,504		
1300	1,029,810		
1400	1,083,306		
1500	1,123,429	13,420,962	Off-peak kWh
1600	1,150,177		
1700	1,196,987		
1800	1,196,987		
1900	1,136,803		
2000	1,089,993	5,770,947	On-peak kWh
2100	1,036,497		
2200	916,129		
2300	722,204		
2400	601,837		
Total	19,191,909	19,191,909	

Key Steps in Designing TOU Rates

- Step 3 – Calculate On-Peak Charge
  - On-peak charge includes:
    - On-peak differential - CP demand charges from utility during the peak period divided by peak period kWh or kW billing demands
    - Utility on-peak energy charge
    - Distribution delivery charge
  - Off-peak charge includes:
    - Utility off-peak energy charge
    - Distribution delivery charge

Cost of Service Data

	Total System	Residential Service
Operating Expenses		
Purchased Power Demand	$ 1,091,302	$ 772,791
Purchased Power Energy	$ 1,146,538	$ 706,756
Distribution Demand	$ 540,261	$ 347,267
Distribution Customer	$ 621,891	$ 544,646
Total	$ 3,399,993	$2,371,461
Rate Base		
Distribution Demand	$ 3,935,580	$2,521,710
Distribution Customer	$ 1,714,646	$1,413,847
Total	$ 5,650,225	$3,935,557

Time of Use Rate Example

Purchased power demand/peak period kWh = \$772,791 / 5,770,947 hrs. = \$0.134

On-peak rate = 2.4¢ + 13.4¢ + 2¢ = 17.8¢ / kWh

Off-peak rate = 2.4 ¢ + 2¢ = 4.4¢ / kWh

Customer charge = \$25.67

Time Differentiated Energy Charges

- Based on the average of system lambda data for on-peak and off-peak periods
- System lambda is the marginal cost of production in $/MWh
- Marginal cost is the cost in $/MWh of the most expensive unit that is dispatched in a least cost dispatch

Example with Time Differentiated Energy Charges

- 3.0¢/kWh energy charge for on-peak period
- 2.0¢/kWh energy charge for off-peak period

Time of Use Rate Example with Time Differentiated Energy

Purchased power demand/peak period kWh =
\$772,791 / 5,770,947 hrs. = 13.4¢/kWh

On-peak rate = 3.0¢ + 13.4¢ + 2¢ = 18.4¢ / kWh
Off-peak rate = 2.0¢ + 2¢ = 4.0¢ / kWh

Customer charge = \$25.67

Obstacles to Time Differentiated Rates

- Opportunities for time differentiating retail rates can be limited by the rate structure of the power provider:
  - NCP billing
  - “Tilted” demand charges (fixed costs shifted to energy charge for recovery)
  - Demand ratchets
  - Average demand components (kWh/hours)

Missing Opportunities

- Focus on cost shifting and reducing the differences in delivered cost among member systems may result in missing opportunities to drive costs out of the business
- Direct benefit in avoiding new construction and power purchases
- Indirect benefit by selling power that is freed up on-peak in energy markets

Even Better Than TOU Rates

- Once the on-peak period is selected and the rate is calculated, any usage during the on-peak period is billed at the on-peak rate, even if there is little or no chance of hitting a peak on that day
- Sends better price signals than flat rates
- A demand rate would send an even better price signal

Cost of Service Data

	Total System	Residential Service
Operating Expenses		
Purchased Power Demand	$ 1,091,302	$ 772,791
Purchased Power Energy	$ 1,146,538	$ 706,756
Distribution Demand	$ 540,261	$ 347,267
Distribution Customer	$ 621,891	$ 544,646
Total	$ 3,399,993	$2,371,461
Rate Base		
Distribution Demand	$ 3,935,580	$2,521,710
Distribution Customer	$ 1,714,646	$1,413,847
Total	$ 5,650,225	$3,935,557

Billing Determinants from Cost of Service Study

	Non-Cooincident Peak Demand	Cooincident Peak Demand
Jan	6,166	4,317
Feb	5,901	3,954
Mar	4,535	3,492
Apr	3,911	3,285
May	4,841	4,696
Jun	5,451	5,069
Jul	7,348	6,907
Aug	7,495	7,121
Sep	6,359	6,359
Oct	5,185	4,459
Nov	4,834	4,351
Dec	6,200	5,518
Total	68,227	59,527

Four Part Rate Example

Customer charge = $25.67

Energy charge = $0.024/kWh

Distribution Demand charge =
$347,267 / 68,227 KW-mos. = $5.09/ NCP KW

Purchased power demand charge =
$772,791 / 59,527 KW-mos. = $12.98/ CP KW

Hours Use of The Demand

- Bills customers based on how many hours they use the maximum demand.
- Encourages customers to improve load factor
- Does not necessarily correspond to cost
- Complicated for customers to understand (They don't get it!)

Hours Use of The Demand

- Example:
  - First 360 hours at $0.10 per kWh
  - Everything over 360 hours $0.07 per kWh
- 100 kw of demand
- 40,000 kWh of energy
- 40,000 kWh/100 Kw = 400 hours use
- First block 360 hours X 100 Kw = 36,000 kWh
- Second block 40,000 – 36,000 = 4,000 kWh

Horse Power Rate

- Bills demand costs based on the HP rating of the motor load instead of metered maximum demand
- Can be good alternative where demand metering does not exist.
- Typically seen with irrigation or grain drying rates

Interruptible Rates

- Under an interruptible rate schedule the utility can require the customer to interrupt taking electric service
- In exchange for the utility’s right to interrupt the load, the customer receives a lower rate
- A lower rate is justified because the utility does not have to install generation capacity to serve the customers

Declining Block Rates

- Declining block rates are used to recover fixed costs more quickly when fixed costs are recovered through the energy charge
- Declining block rates are a discrete representation of an average fixed cost curve

Inclining Block Rates

- Price per kWh increases as kWh increases
  - 7¢/kWh for the first 250 kWh
  - 9¢/kWh for 251 to 750 kWh
  - 11¢/kWh over 750 kWh
- May be difficult to cost justify
- Based on policy of encouraging energy efficiency and conservation
- May reflect increased cost of new generation or transmission resources

Seasonal Rate Structures

- Seasonal rate structures are used to recognize differences in costs relative to the time of year (i.e., seasons)
- Either demand or energy costs can be seasonally differentiated
- In developing seasonal rates it is important to consider marginal costs (which generation units are needed to meet last kWh sales)

Prepaid Residential Service

- Reduce uncollectibles
- Provide a good alternative for low income customers by avoiding late payment fees, disconnect fees, reconnect fees and higher deposits
- Better fit for customers who are paid weekly

Geographically Differentiated Rates

- Used when the cost of serving one geographic area is significantly different than serving another geographic are
  - Rural vs. urban rate differences due to customer density per mile of line
  - Serving an island
- Drawing the line between geographic areas is frequently a problem

Renewable Energy Rates

- Usually a rate rider that charges a differential between the cost of renewable energy and utility’s standard generation portfolio
  - Purchased renewable power
  - Utility-owned renewable generation
  - Renewable energy certificates (RECs) for 1 MWh of renewable energy
- Usually offered in blocks (e.g. 100 kWh blocks)
- Example, 1¢/kWh premium

Economic Development Rates

- Economic Development: Attraction *and* Retention
- Economic Development Rates ("EDRs") are a vehicle for the utility to provide an incentive to large commercial or industrial customers to locate a facility in the utility service territory.
- Incentive is in the form of a discount from the utility's standard tariff rates, terms or conditions.
  - Demand / Energy / Customer charges
  - Charges for Infrastructure / CIAC

Economic Development Rates

- Essentially a political *Site Selection Contest*
  - Contest between countries, states, or cities
  - Contest between utilities
- Numerous parties have an interest in Economic Development – the utility is but one of many stakeholders at the table
  - No stakeholder operates in a vacuum
  - Stakeholder objectives do not necessarily align

Feed-In Tariff

- A policy mechanism designed to accelerate investment in renewable energy technologies
- Renewable energy producers are offered long-term contracts based on the cost of generation of each technology
- Lower cost technologies are awarded a lower per-kWh price while higher cost technologies are offered a higher price

Standby Rate

- A rate for supplying emergency power to customers who own their own generation when the customer-owned generator is not able to produce
- May consist of a demand charge to cover the cost of capacity needed to provide standby service as well as an energy charge to cover the cost of fuel and variable O&M for providing standby service

Special Contract

- A contractual rate that applies to a single customer
- Usually special contracts are only provided for very large customers
- Some regulatory agencies are not willing to approve special contracts

Real Time Pricing

- Reflect actual market price for electric energy to customer
- Requires the infrastructure to transmit prices to customers and to measure customer consumption during appropriate time periods
- Likely to eliminate many problems resulting from existing utility pricing structures

Real Time Pricing

- Customers likely to need risk management tools to handle increased price volatility
- By having a strategy to deal with the high priced side of the market, the customer gets access to the low priced side of the market
- Opportunity to access the low priced side of the market is not available with average embedded cost pricing

Using Price Rather Than “No”

- A philosophy of being willing to provide any service that a customer requests and then pricing the service appropriately using data from the cost of service study
- Avoids customer anger at being told “no” by the utility

Unbundled Cost Based Rates

- Derived from cost of service study
- Margins are usually loaded in demand and customer charges (wires side of the business)
- Variable costs such as fuel and purchased power are passed through with no margin added
- Comparing cost based rates to current rate structure provides indication of how much current rates deviate from cost based

Rate Unbundling

- Rates unbundled into at least 4 components
  - Purchased power demand
  - Purchased power energy
  - Distribution demand charge
  - Customer charge
- Corresponds to principal cost drivers

Rate Unbundling

- A key benefit of rate unbundling is customer communication
- Also useful in determining the amount paid to customers when customers provide services for the utility, such as net metering
- Can rebundle rate components with other products and services

Net Metering Definition

- Allows customers to use their own generation to offset their consumption over a billing period
- Allows for the flow of electricity to and from the customer through a single watt-hour meter
- Meter turns backwards when customer generates electricity in excess of the customer's demand
- Customers receive retail prices for the excess electricity they generate

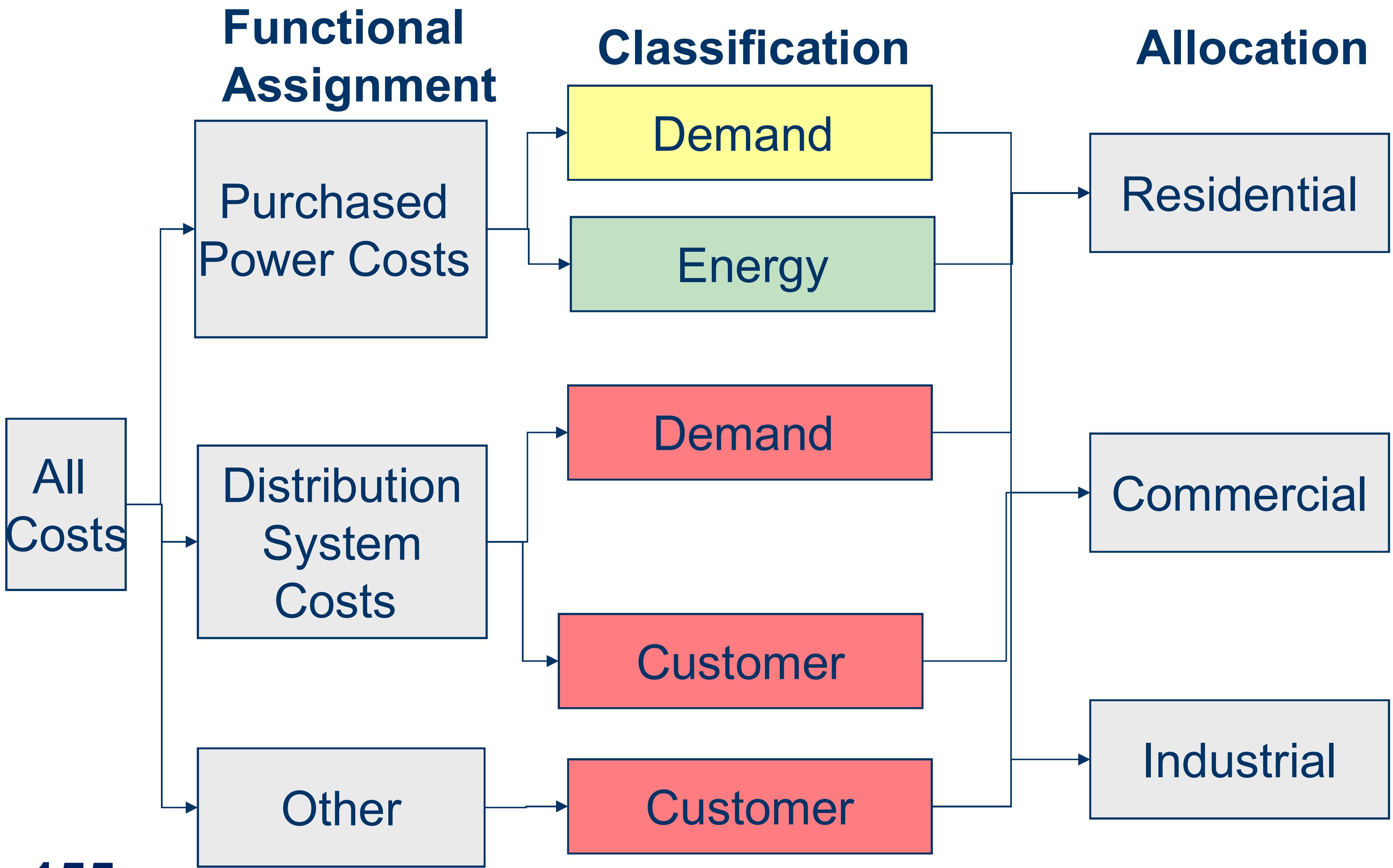
Reasons Cited for Allowing Net Metering

- Easy to administer – the standard watt-hour meter accurately registers the flow of electricity in both directions
- Allows customers to "bank" their energy and use it a different time than it is produced giving customers more flexibility
- Encourages customer investment in renewable energy technologies by providing a subsidy

Sharing Cost Savings with Customers

- It is fair to share with customers any cost savings that the utility realizes as a result of customer actions
- When a customer reduces kWh usage, what is really saved?
- Savings resulting from customer actions need to be considered when developing C&I rates

Cost of Service Study



Net Metering Subsidy

- When a utility sells electric energy to the customer, the utility is selling 3 services
  - Generation
  - Transmission
  - Distribution

Net Metering Subsidy

- When a customer sells to the utility, the customer is only selling generation services
- Customer does not own transmission or distribution, and thus cannot properly sell and charge for these services
- Compensation calculated using the retail rate is too high for power produced by the customer and represents a subsidy

Net Metering Subsidy

- If a single meter is used and the meter runs both forward and backward, the subsidy to net metering consists of:
  - Distribution demand charge
  - Likely a portion of the purchased power demand charge
  - Any customer related costs included in the energy charge assessed on a kWh basis

Dealing With the Subsidy

- Minimize the potential economic damage caused by the subsidy

- Eliminate the subsidy by unbundling rates and developing a cost based net metering program

Minimize the Damage

- Limited to residential and small general service customers
- Cap generator size at 10 kW nameplate rating
- Capacity available for net metering is capped at 0.1% of peak demand
- Minimum of $100,000 liability insurance
- Utility not required to pay consumer for excess
- Credits against future charges but utility retains unused credits if customer discontinues net metering
- Must meet interconnection standards

Eliminate the Subsidy

- Customer buys from the utility at full retail rate
- Customer is paid by the utility at avoided cost for power that the customer produces
  - Energy component of the unbundled retail rate
  - May be some payment for demand component

Conjunctive Billing

- Service for a customer with multiple locations are combined with respect to billing units
- National accounts (e.g., Walmart, Kroger, etc.) sometimes push this to lower their bills
- There is no problem with it if it is done right., but some businesses aren't really interested in doing it right.

Conjunctive Billing

- The right way
  - CP costs (e.g. generation and transmission) billed on a CP basis applied to sum of loads at multiple location
  - NCP costs (e.g. distribution) billed on a NCP basis applied to max demand at each individual location
- The wrong way
  - All costs for multiple locations combined and billed on basis of the maximum demand from sum of loads for multiple locations

Load Factor and Reducing Delivered Price to the Customer

- Delivered price to the Customer vs. the rate stated in the utility's tariff
  - Rate reduction reduces delivered price to the customer but also reduces utility margins
- Improved load factor
  - Improving load factor reduces delivered price to the customer without reducing margins
  - Utilizes capacity more efficiently

Load Factor

Load factor (LF) is the ratio of the average Load that occurs over a period of time to the maximum load that occurs during that same time.

$$LF = kW_{avg} \div kW_{max}$$

$$\boxed{LF = [kWh \div hrs] \div kW_{max}}$$

Impact of Load Factor on Delivered Cost to Customers

Demand Charge per kW		$20.00	
Energy Charge per kWh		$0.050	
	Customer A	Customer B	Customer C
kW	100	100	100
kWh	7,300	36,500	73,000
Demand Cost	$2,000.00	$2,000.00	$2,000.00
Energy Cost	$365.00	$1,825.00	$3,650.00
Total Bill	$2,365.00	$3,825.00	$5,650.00
Load factor	10%	50%	100%
Cost per kWh	$0.324	$0.105	$0.077

Impact of Load Factor on Delivered Cost to Customers

Demand Charge per kW		$0.00	
Energy Charge per kWh		$0.1014	
	Customer A	Customer B	Customer C
kW	100	100	100
kWh	7,300	36,500	73,000
Demand Cost	$0.00	$0.00	$0.00
Energy Cost	$740.22	$3,701.10	$7,402.20
Total Bill	$740.22	$3,701.10	$7,402.20
Load factor	10%	50%	100%
Cost per kWh	$0.1014	$0.1014	$0.1014

Tools for Improving Load Factor

- Need rate options that provide economic incentive for customers to move peak usage to other times
- Need equipment that takes advantage of rate options and makes it convenient for customers to move peak usage to other times
- Avoid CP demand charges by moving load to off-peak periods

Sending the Right Price Signals

- All prices send signals
- What signals are your prices for electric service sending?
- Your rate design should provide financial incentives for customers to take actions that will help your utility to achieve its strategic goals