

Retail Costing and Pricing for Electricity

PRESENTED TO

IPU's Annual Regulatory Studies Program:
The Fundamentals Course

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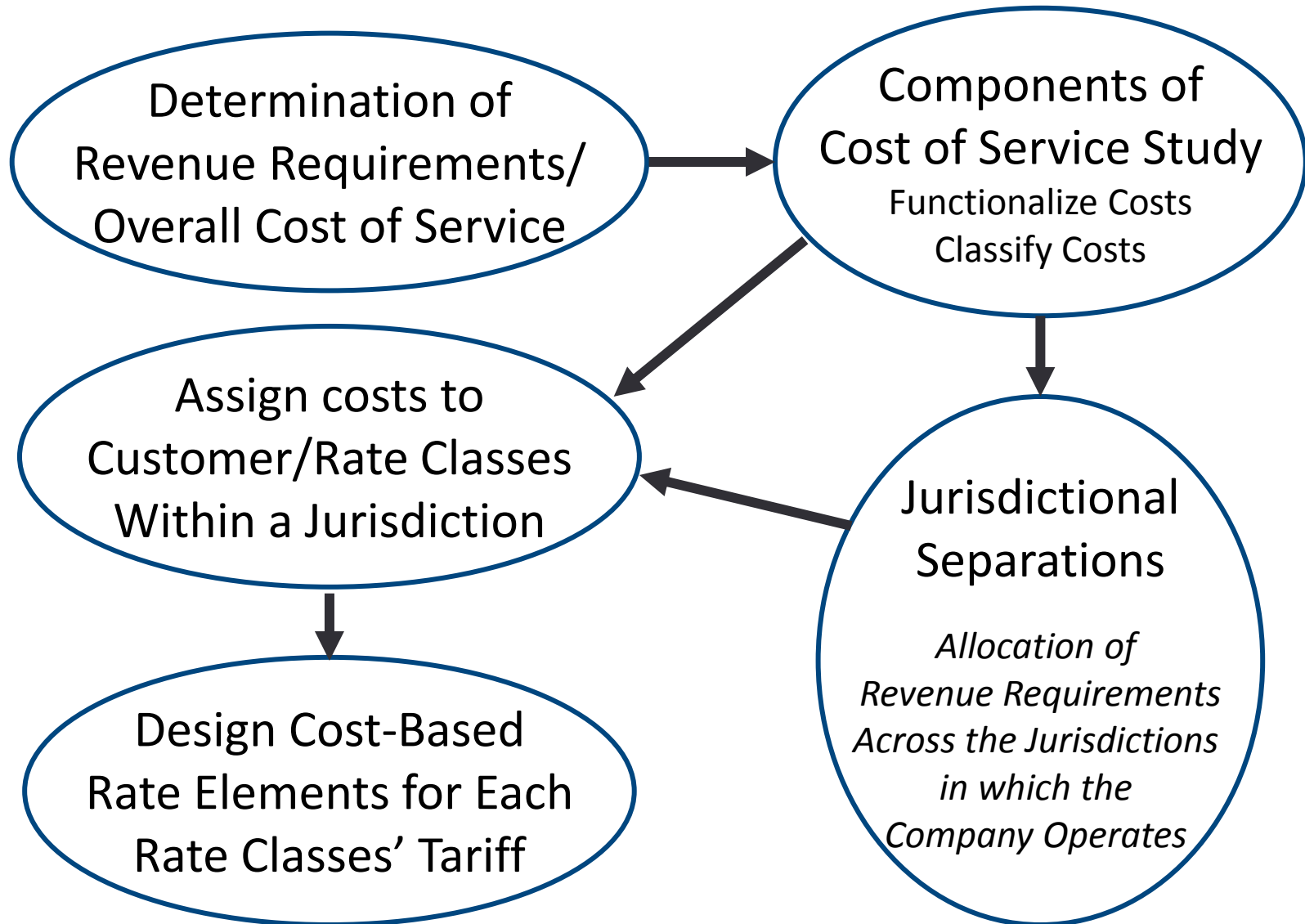
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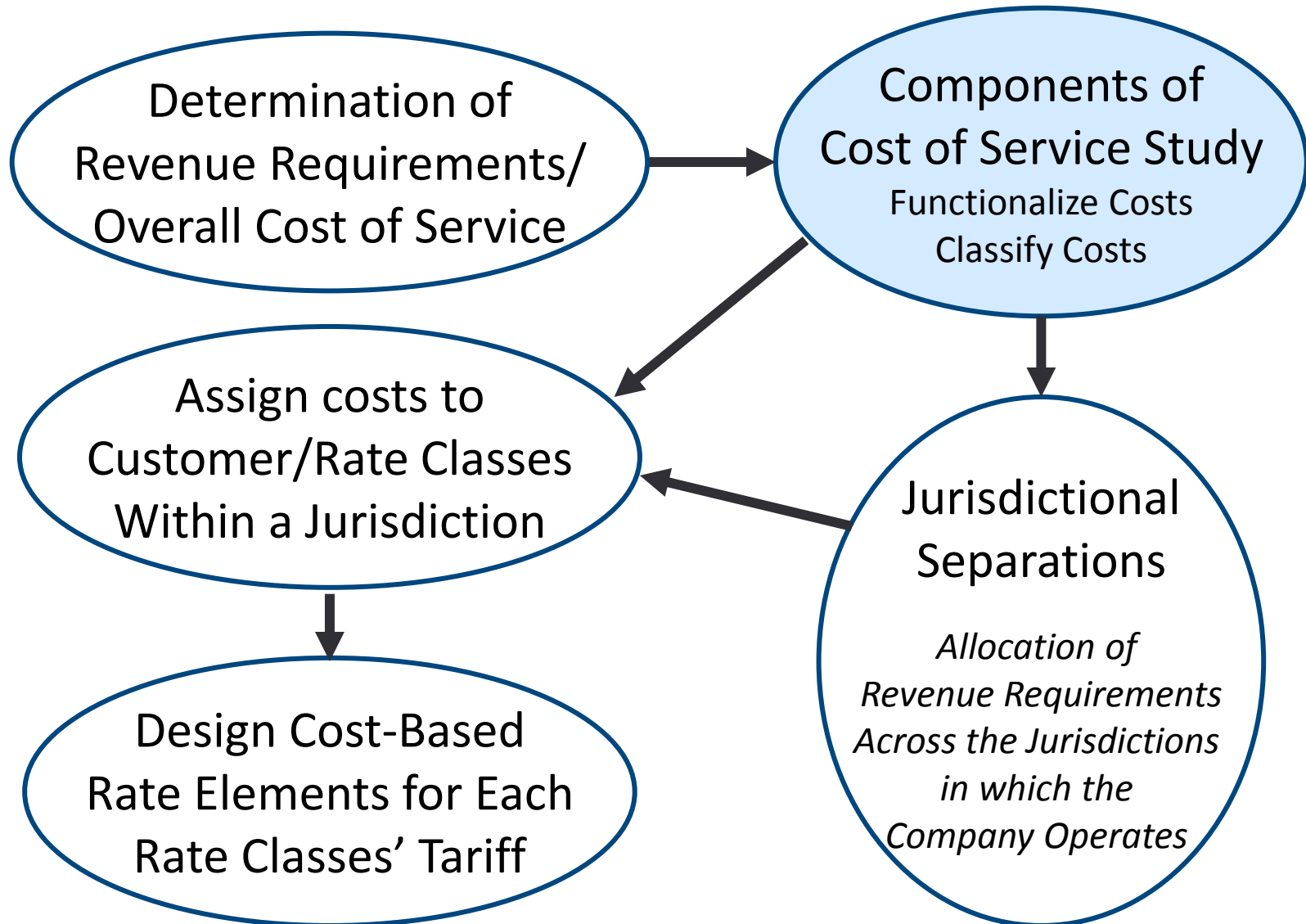


THE **Brattle** GROUP

Basic Steps in Rate Setting Process



Basic Steps in Rate Making Process



Steps in an Embedded Cost of Service Study

Step 1: Functionalization

Step 2: Classification

Step 3: Allocation

Key question to be asked at every step in the process:

- What caused the costs to be incurred?
(cost causation)

Step 4: Rate Design

Functionalize and Classify

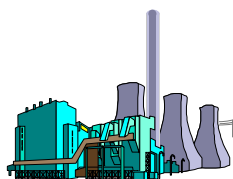
Classify

Demand

Demand-Customer

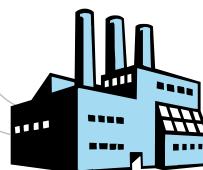
Customer

Demand-Energy



Generation (6-14 kV)

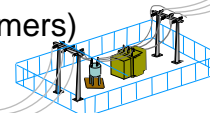
Network
switchyard
step-up transformers



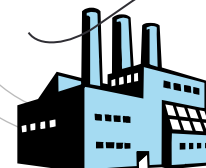
Common Facilities (used by all customers);
sized based on system peak demand

transmission subs
(step-down transformers)

Sub-Transmission 69-115 kV lines



3-phase primary distribution feeder lines (21 – 36 kV)
distribution substations (step-down transformers)



Drop lines to homes
120-240 volts



Facilities not
used by
all customers;
Sized based
on subset of
system demands
-- class NCP

Functionalize

STEP 1: FUNCTIONALIZATION

Step 1: Functionalization

- Functionalization is the process of dividing the total revenue requirement into functional components as related to the operations of the utility (operating functions)
 - Generation (aka Production)
 - Transmission
 - Distribution
 - Meters and Services
 - General Plant (eventually must be apportioned to the other non-general functions)
- Usually, the rate-base (capital expenditure) component of revenue requirements is functionalized first; then the expense components are functionalized

Step 1: Functionalization—General Categories

Production

- Generation and/or Purchased Power

Transmission

- High-Voltage Transmission Lines
- Substations and Lower-Voltage Transmission Lines

Distribution

- Distribution Substations
- Primary Distribution lines
- Line Transformers
- Secondary Distribution Lines
- Meters, Service Drops and Metering Services
- Customer Services
- Direct Assignment *e.g.*, Street Light

General

- General Plant and Administrative and General

STEP 2: CLASSIFICATION

Step 2: Classification

Classification is the process of further separating the functionalized costs by the primary driver for that cost

- In other words, this is the process of separating the functionalized costs into classifications based on what the costs are sensitive to

Primary Cost Classification Categories

- Demand-Related Costs: (aka Capacity-Related Costs) Those costs that vary with the kW of instantaneous demand (and therefore peak capacity needs)
- Energy-Related Costs: Those costs that vary with kWh of energy generated
- Customer-Related Costs: Those costs that vary with the number of customers on the system

Step 2: Classification

Examples of Demand-Related Costs

- Costs of Generation Capacity
- Costs of Transmission Lines
- Costs of Distribution Lines and Transformers
 - These costs show up in Rate Base
 - The resulting costs that show up in Revenue Requirements
 - Return dollars on rate base
 - Annual depreciation expense
 - Operations and Maintenance

Step 2: Classification

Examples of Customer-Related Costs

- Costs of Metering
 - Return dollars and depreciation expense on meters themselves
 - Labor costs involved in reading the meters
- Costs of billing and account processing
 - Return dollars and depreciation expense on needed information equipment and software as well as customer service buildings
 - Labor costs associated with billing, account processing and fielding customer complaints
- Costs of attaching customers to the system
 - Costs associated service drops and poles as well as some low-voltage distribution facilities

Step 2: Classification

Examples of Energy-Related Costs

- Fuel
- Costs of energy purchases
- Generation variable O&M (*e.g.*, lubricants)

NOTE: With respect to the production of energy (kWh), both Demand-Related and Customer-Related costs are viewed as “Fixed Costs” while Energy-Related costs are viewed as “variable costs.”

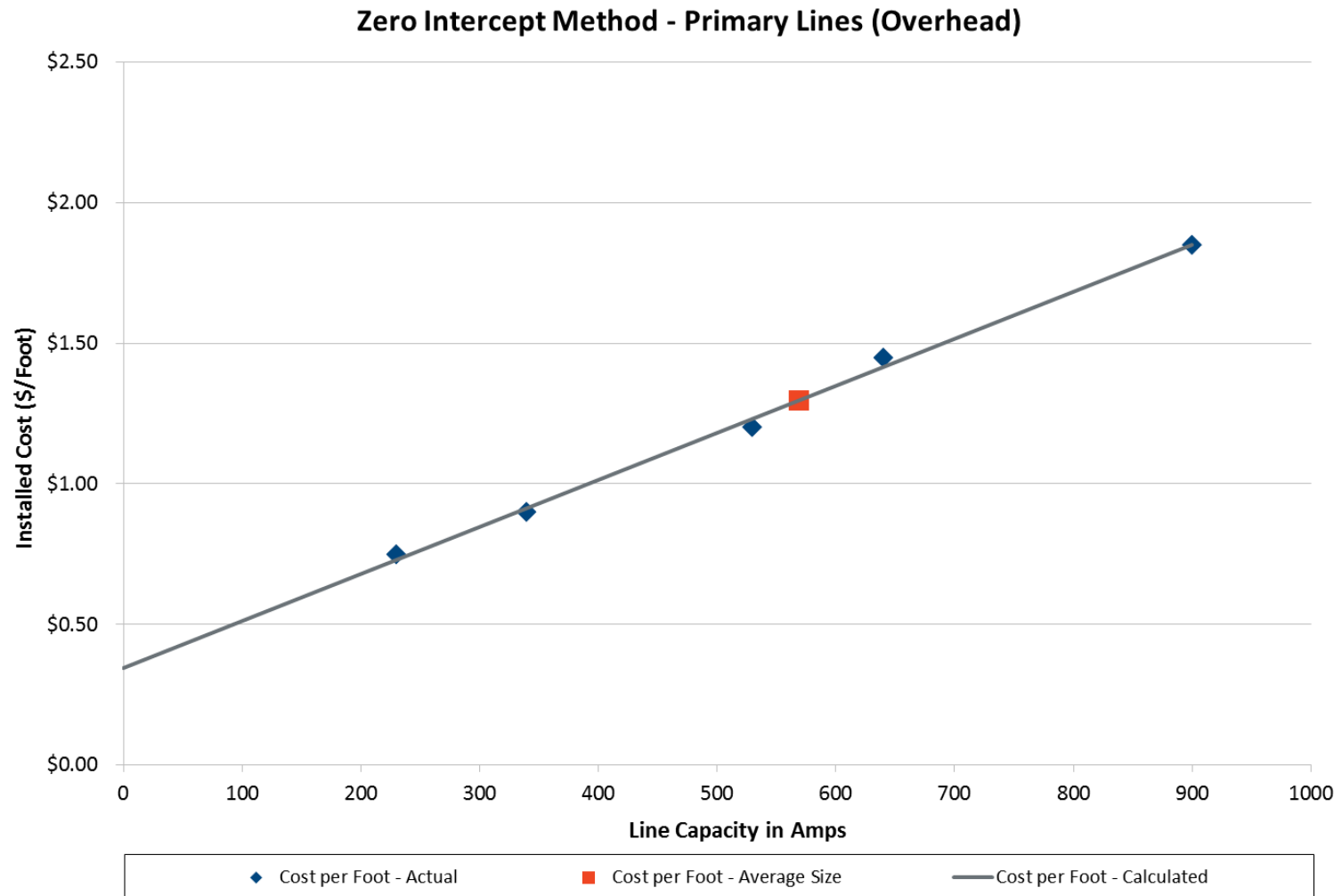
NOTE: During the functionalization step, the reason general plant in rate base is re-functionalized into the non-general plant components is because general plant does not directly lend itself to being classified as either a demand-, energy- or customer-related cost

Step 2: Classification

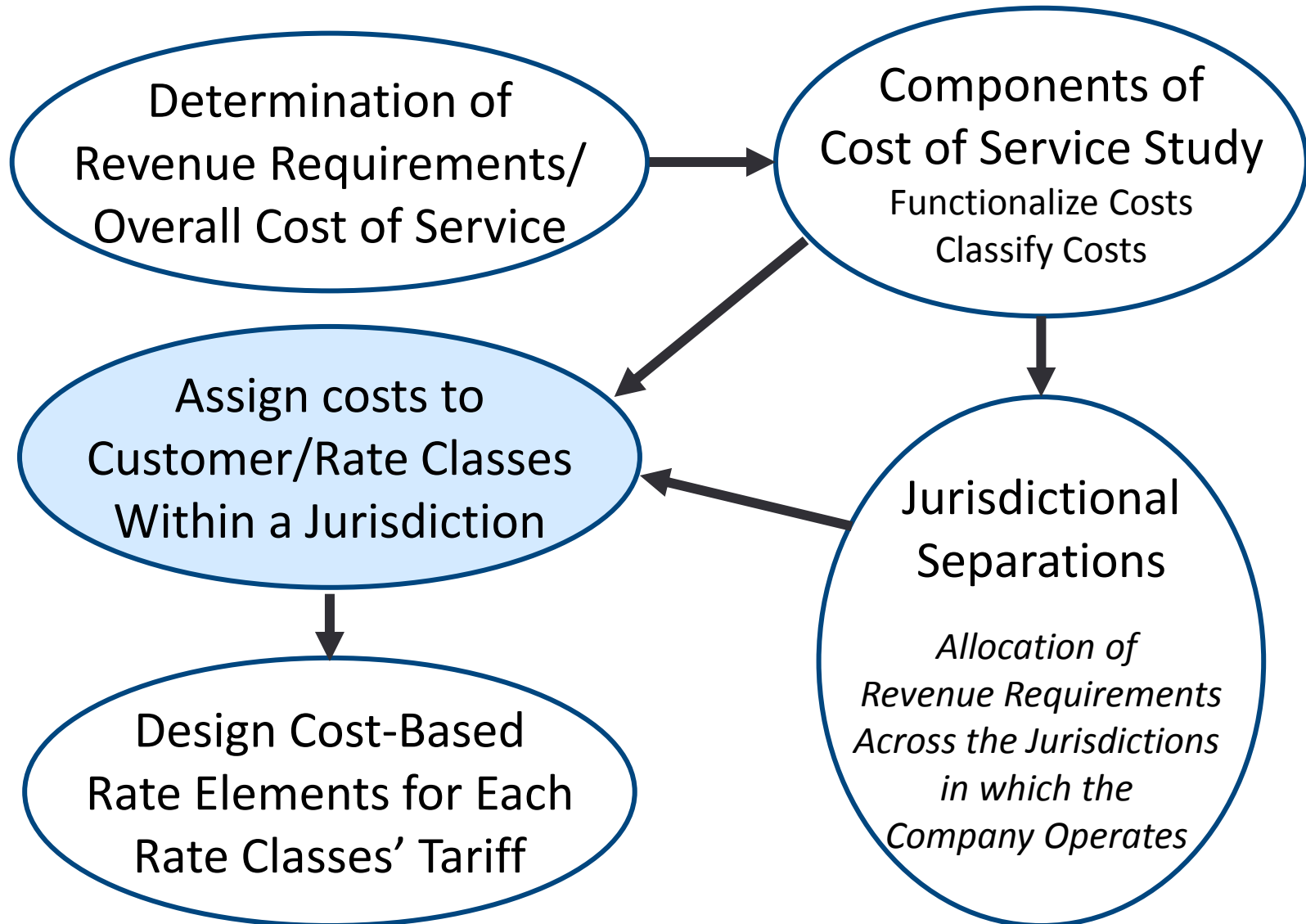
Demand/Customer Split Methods

- Minimum-Plant Method for Distribution Lines and Transformers
 - Customer costs for all sizes based on the costs of the smallest (actual) size wire or transformer
- Zero-Intercept Method for Distribution Lines and Transformers
 - Customer costs for all sizes based on the imputed fixed costs of the (hypothetical) “zero-size” wire or transformer
- Note: Minimum-Plant Method vs. Zero Intercept
 - Generates higher customer portion and lower demand portion (as compared to zero-intercept method)—why—it is argued that a small portion of the minimum plant represents capacity related investment

Step 2: Classification



Basic Steps in Rate Making Process



STEP 3: ALLOCATION

Allocation: Class Cost of Service Study

Allocation is the process of assigning the functionalized and classified revenue requirements (cost of service) to the different jurisdictions and the different customer rate classes within a jurisdiction.

- A rate class is a relatively homogeneous group of customers that possess similar characteristics and who face the same set of prices (*e.g.*, residential, small power, irrigation, industrial power)
- Characteristics include: energy consumed; load characteristics and end use; delivery voltage; metering characteristics; other conditions of service

In order to conduct a class cost-of-service study, the demand characteristics of the total system, as well as individual rate classes, must be analyzed.

- Such analysis is referred to as “load research”

Allocation

After the Functionalization step is completed, some costs can be identified as logically incurred to serve only a particular customer (costs of “Dedicated Facilities”)

- Cost-causation would dictate that these costs are only allocated to that particular customer

After the Functionalization step is completed, some costs can be identified as not being incurred by particular customers

- For example, distribution lines are not used to serve customers that take power at higher voltages (*e.g.*, off the distribution substations)
- For example, distribution lines and sub-stations are not used to serve customers that take power at even higher voltages (*e.g.*, off the sub-transmission)
- Cost-causation dictates not to allocate the costs of these facilities to the particular customers who do not use these facilities

Allocation

How should the rent of a two-bedroom house shared by a married couple and a single person be allocated?

- What drives rent costs? (*i.e.*, what are the cost drivers?)
 - Married couple argues it's the number of bedrooms
 - Single person argues it's the total size of the house and yard required to accommodate three household members
- Cost drivers help in choice of appropriate allocation methods
 - Married couple says use “relative number of bedrooms” method (50% of rent goes to married couple and 50% of rent goes to single person)
 - Single person says use “relative number of people” method (67% of rent goes to married couple and 33% of rent goes to single person)

Allocation

- Once the various customer class categories have been designated, particular functionalized and classified costs are allocated among the rate classes based on an allocation method which is deemed the most consistent with cost causation
 - Different cost components require different allocation methods
- A particular allocation method (*i.e.*, allocation factor) is a set of percentages that sum to 100%
 - Demand-Related Allocation Methods
 - Energy-Related Allocation Methods
 - Customer-Related Allocation Methods

Allocation

Demand-Related Cost Allocation Methods

- System Peak Responsibility (1CP, 4CP, 12CP)
- Non-Coincident Demand (NCP)
- Average-Excess Demand

Energy-Related Cost Allocation Methods

- kWh of Energy Sold (both at customer meter and at generation)

Customer-Related Cost Allocation Methods

- Number of Customer
- Weighted Number of Customers—where weights can be based on:
 - class-average meter costs
 - class-average billing costs
 - class-average service line costs
 - class-average meter-reading costs

Allocation

Generally, the following criteria should be utilized to determine the appropriateness of an allocation method:

- The method should reflect the actual planning and operating characteristics of the utility's system.
- The method should reflect cost causation, *i.e.*, should be based on the actual activity that drives a particular cost and on rate classes' share of that activity
- The method should recognize customer class characteristics such as electric load demands, peak period consumption, number of customers, and directly assignable costs.
- The method should produce stable results on a year-to-year basis.
- Customers who benefit from the use of the system should also bear some responsibility for the costs of utilizing the system.

Allocation of Revenue Requirement

A particular group of demand-related costs are allocated through the use of one of the demand allocators

- The choice of which demand allocator should be used with which group of demand-related costs, should be based on cost causation

A particular group of energy-related costs are allocated through the use of one of the energy allocators

- The choice of which energy allocator should be used with which group of energy-related costs, should be based on cost causation

A particular group of customer-related costs are allocated through the use of one of the customer allocators

- The choice of which customer allocator should be used with which group of customer-related costs, should be based on cost causation
- What to do about net energy metering?

Use load information to allocate demand and energy costs

Load Curve

Load Curve describes the pattern of instantaneous demand through a particular period of time (*i.e.*, through a cycle)

- A daily cycle (for a daily load curve) is 24 hours
- An average monthly cycle (for a monthly load curve) is 730 hours
- An annual cycle (for an annual load curve) is 8,760 hours (or 8784)

Information From Load Curves

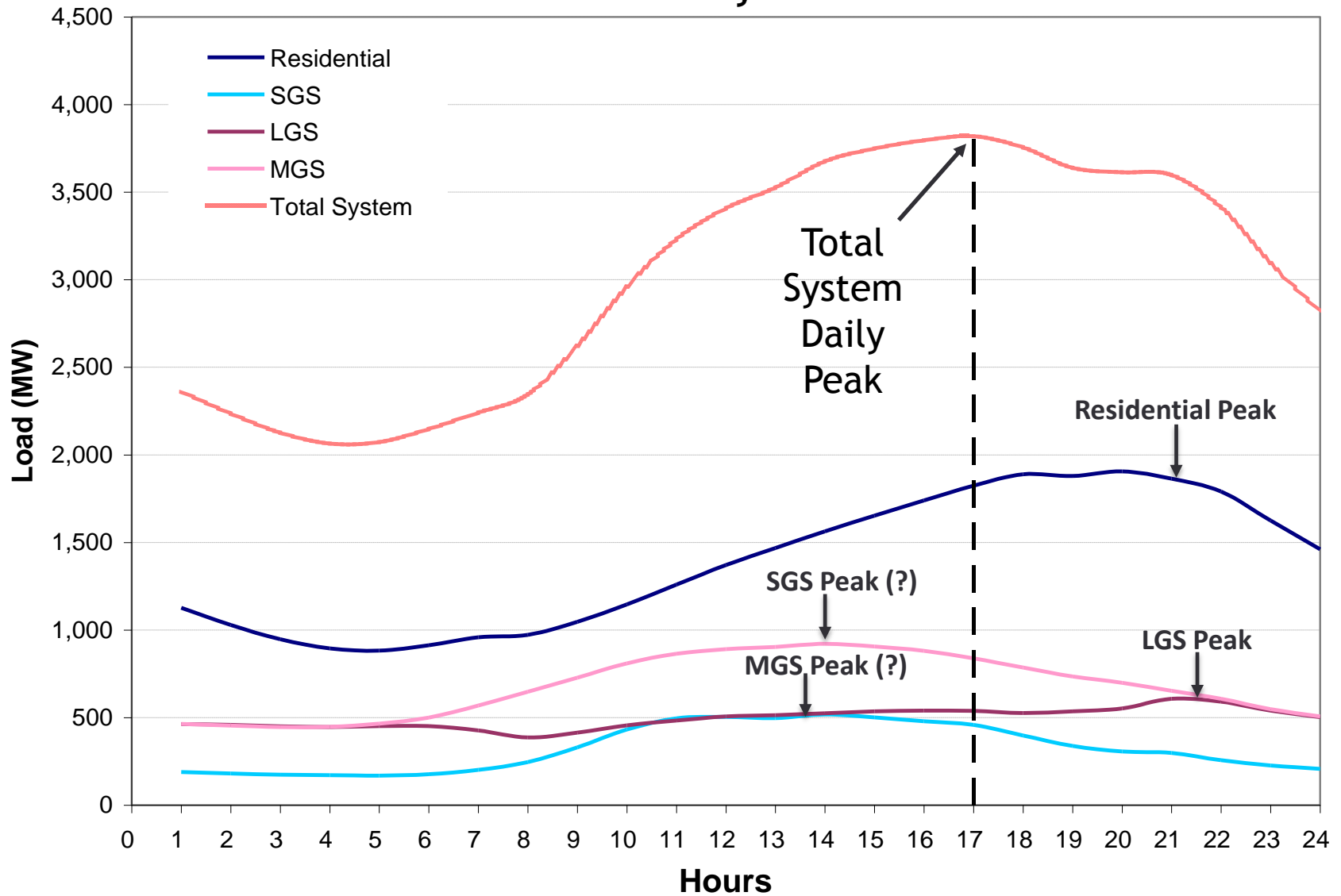
Average Load is derived by taking the total kWh of energy used through the cycle and dividing by the total number of hours through the cycle.

- For example, if a customer consumes 7,300 kWh during a month, then that customer's average load (instantaneous demand) is 10 kW
- Average load is analogous to average speed on a trip

Peak Load is the maximum instantaneous demand (load) during the cycle (measured in kW or MW)

- Non-Coincident Peak Load (NCP) is a customer's (or customer classes') maximum demand irrespective of when it happens
- Coincident Peak Load (CP) is a customer's (or customer classes) demand at the moment in time that the total system is experiencing its peak load

Peak Day



Information From Load Curves

Load Factor (LF) is a measure that captures the degree of variation in a particular pattern of demand

- LF is a number between zero and one (*i.e.*, a percentage)
 - The closer load factor is to 1, the less the variation in the pattern of demand
 - The closer load factor is to 0, the more the variation in the pattern of demand
- $LF = (\text{average load}) / (\text{peak load})$
 - For example, suppose that a customer uses 7,300 kWh during a month (average load = 10 kW) and that the customer's NCP during the month is 25 kW.
 - $LF = (\text{average load}) / (\text{peak load}) = 10/25 = 0.4$ (40%)

System Load Factor

- High system load factor translates into high utilization of the capacity built into the system.
- High system load factor translates into lower average cost per kWh.
- High system load factor is a result of:
 - High load factor individual customers or customer class
 - Customer or Rate Class Diversity

Alternative Coincident Peak Measures

1-CP

- Uses the “system peak” as being the highest single hour’s system demand during the entire year. Each class’s CP is that class’s demand during that hour the system peak occurred

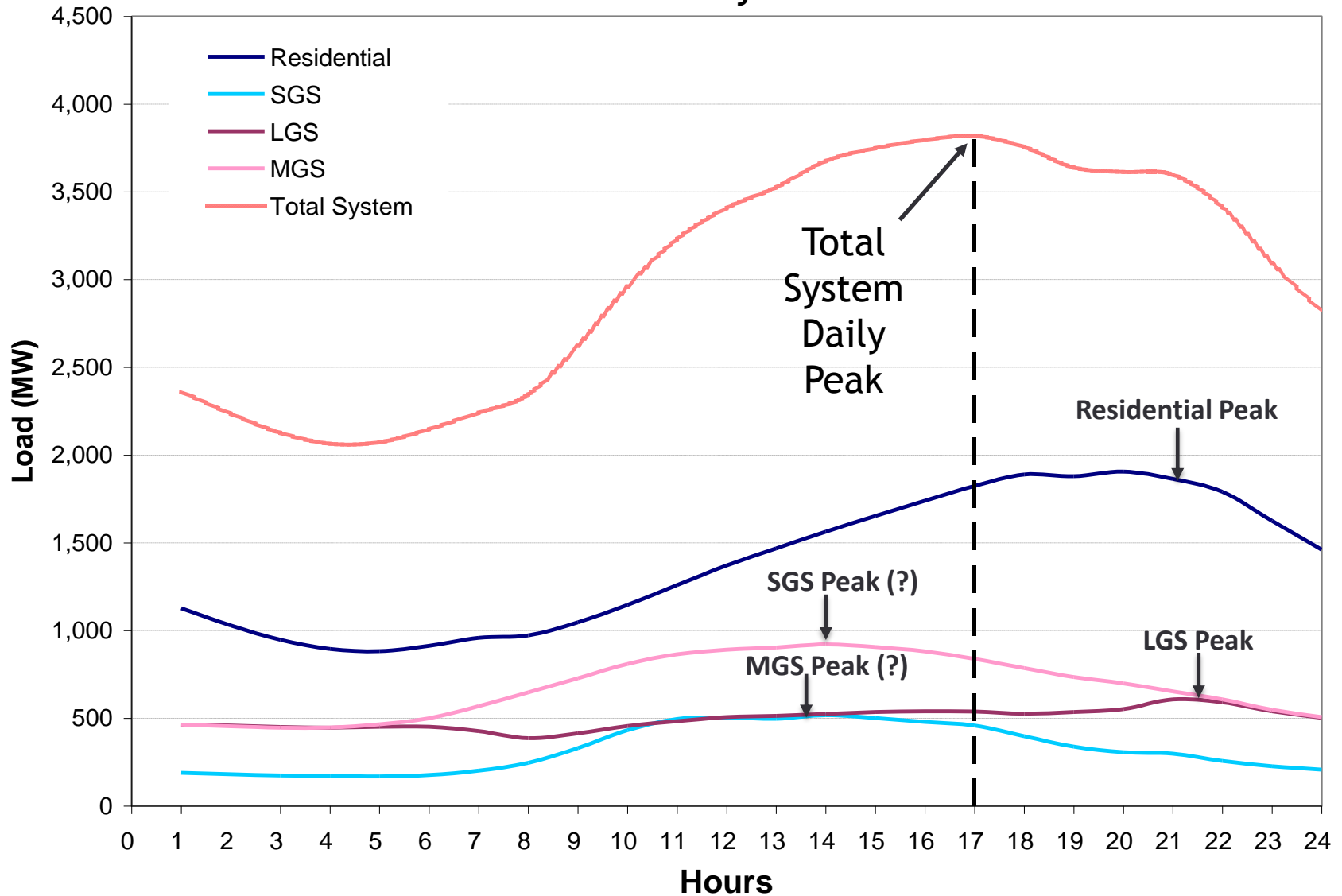
4-CP

- Determines the highest single hour’s system demand during each of the individual 12 months and then uses the “system peak” as being an average of the four highest of these 12 system demands (the four demands are from four different months’ hours). Each class’s CP is that class’s average demand over those four particular hours

12-CP

- Determines the highest single hour’s system demands for each of the individual 12 months and then takes the “system peak” as being an average of all these 12 system demands (the 12 demands are from 12 different months’ hours). Each class’s CP is that class’s average demand over those 12 particular hours

Peak Day

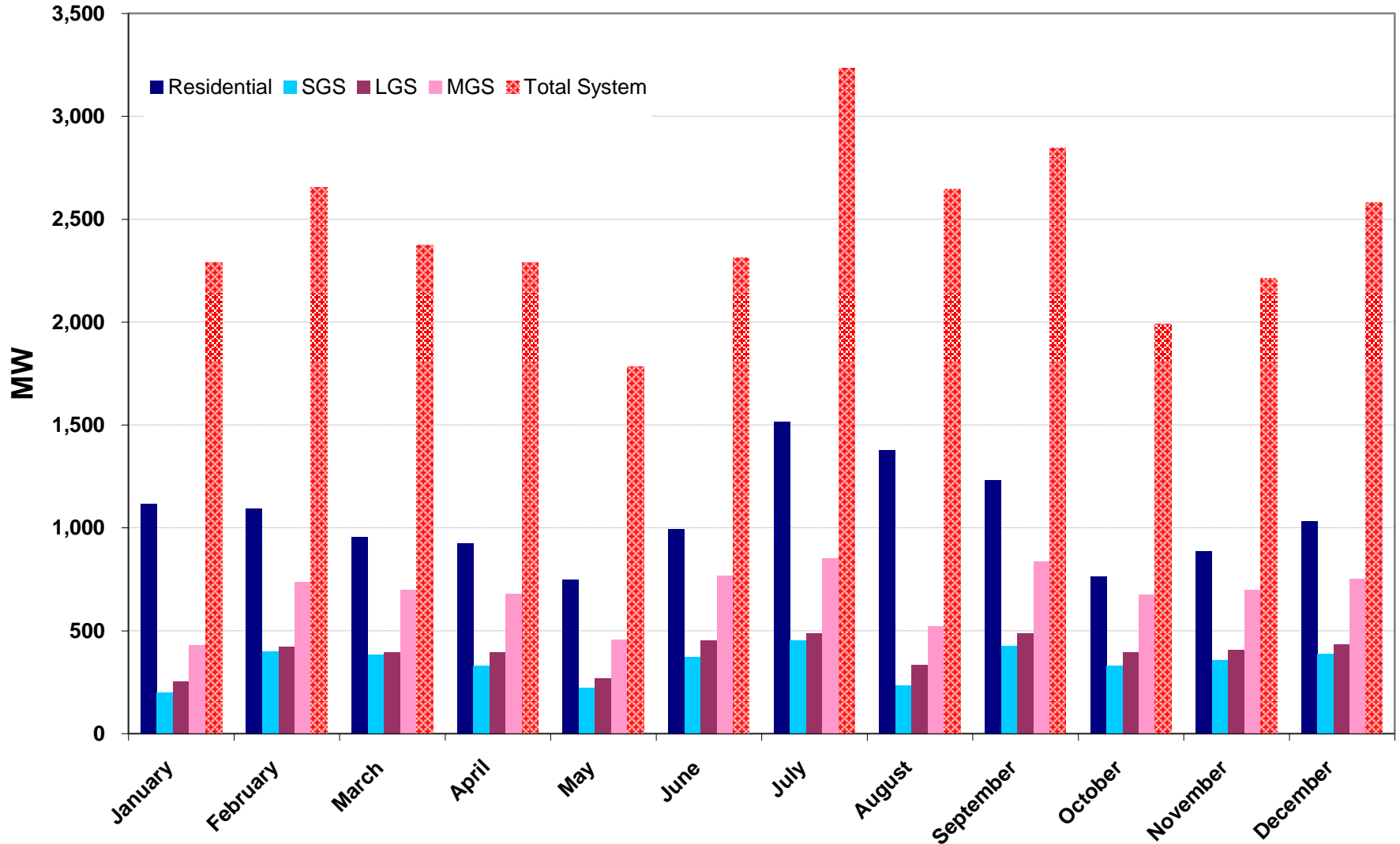


Allocation

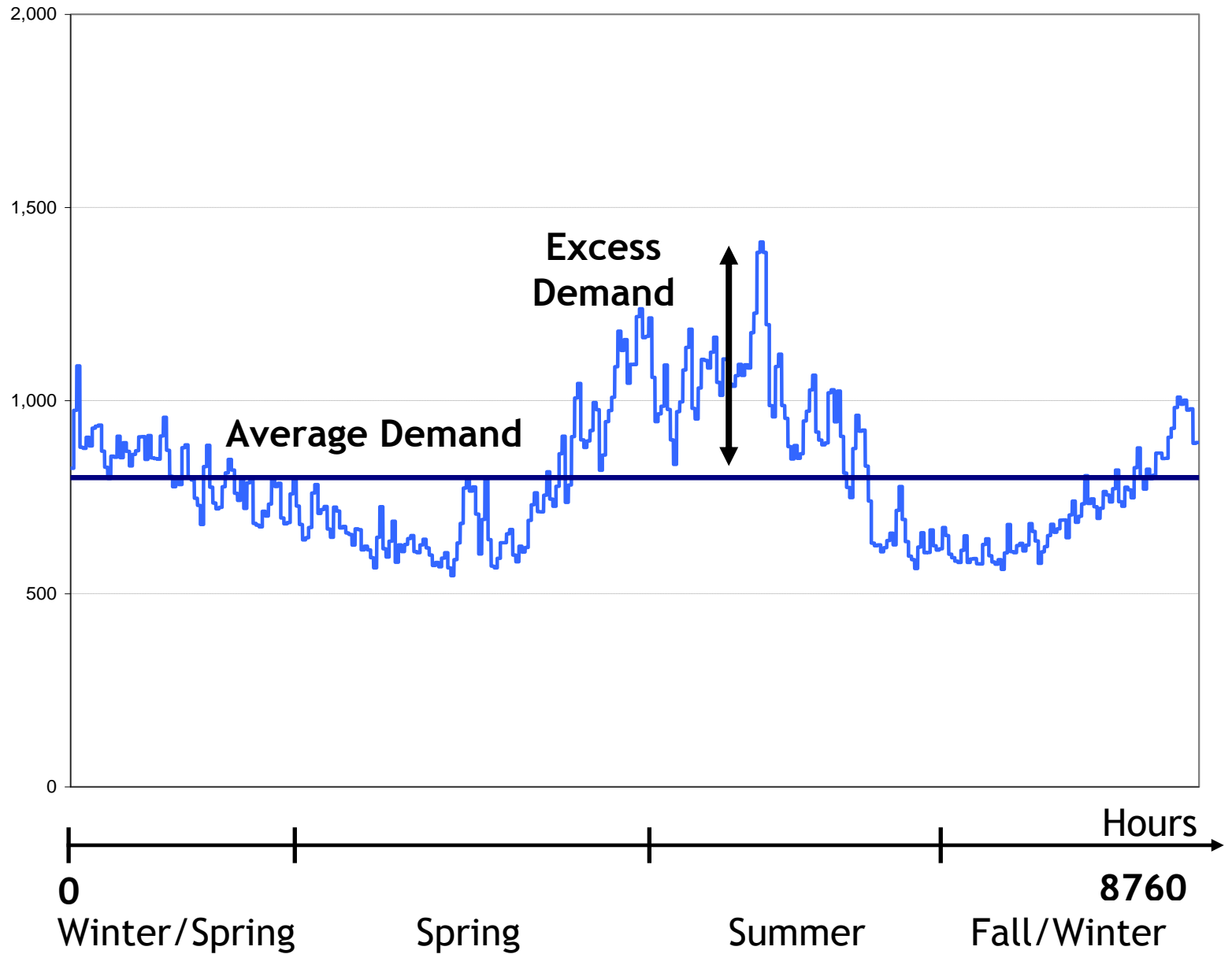
Demand-Related Cost Allocation Methods

- System Peak Responsibility (1CP, 4CP, 12CP) – 12CP often used for the allocation of transmission demand-related costs
- Non-Coincident Demand (NCP) – typically used for the allocation of distribution demand-related costs
- Average-Excess Demand (AED) – typically used for the allocation of generation demand-related costs
 - This Method uses a weighted average of the Average-Demand Allocators (weight = system load factor) and the Excess-Demand Allocators (weight = one minus the system load factor)
 - A Class's "Excess Demand" is the difference between that class's NCP and that class's Average Demand

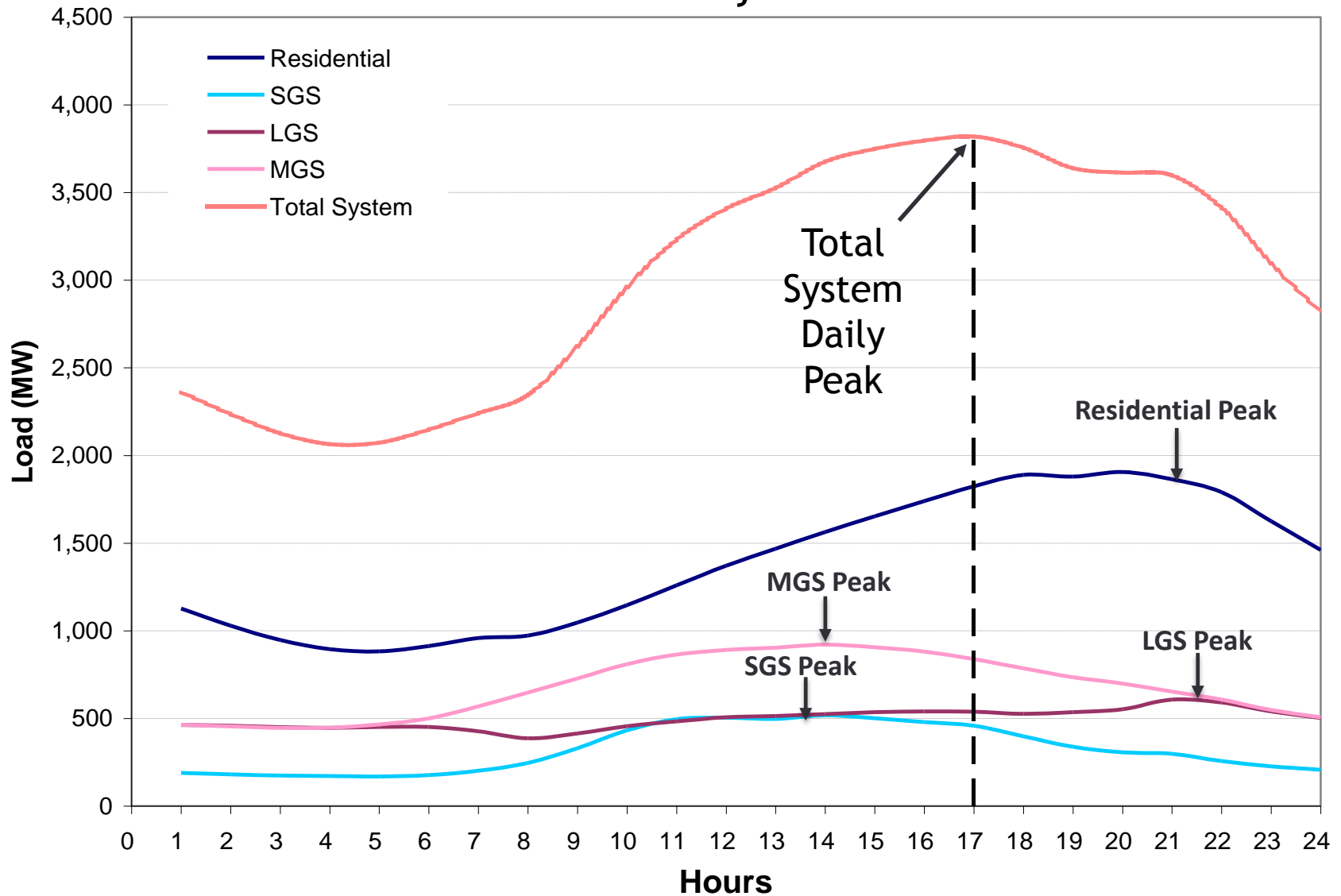
Monthly Peak Loads by Class



MWh



Peak Day



Allocation

Energy-Related Cost Allocation Methods

- kWh of Energy at the customers' meters—after line and transformer losses
- kWh of Energy at the generation plants—before line and transformer losses
- Losses are:
 - Due to the transformation of kWh to heat
 - Inversely related to voltage (*i.e.*, higher voltage means lower loss)
 - Directly related to the number of voltage transformations (*i.e.*, more voltage transformations from the generator to the customer means more loss)
 - Directly related to distance (*i.e.*, the greater the length of a given circuit, the greater the losses)
 - “Loss factors” will vary by rate class (low-voltage distribution customers—like residential customers—have the highest loss factors)

Allocation of Energy-Related Generation

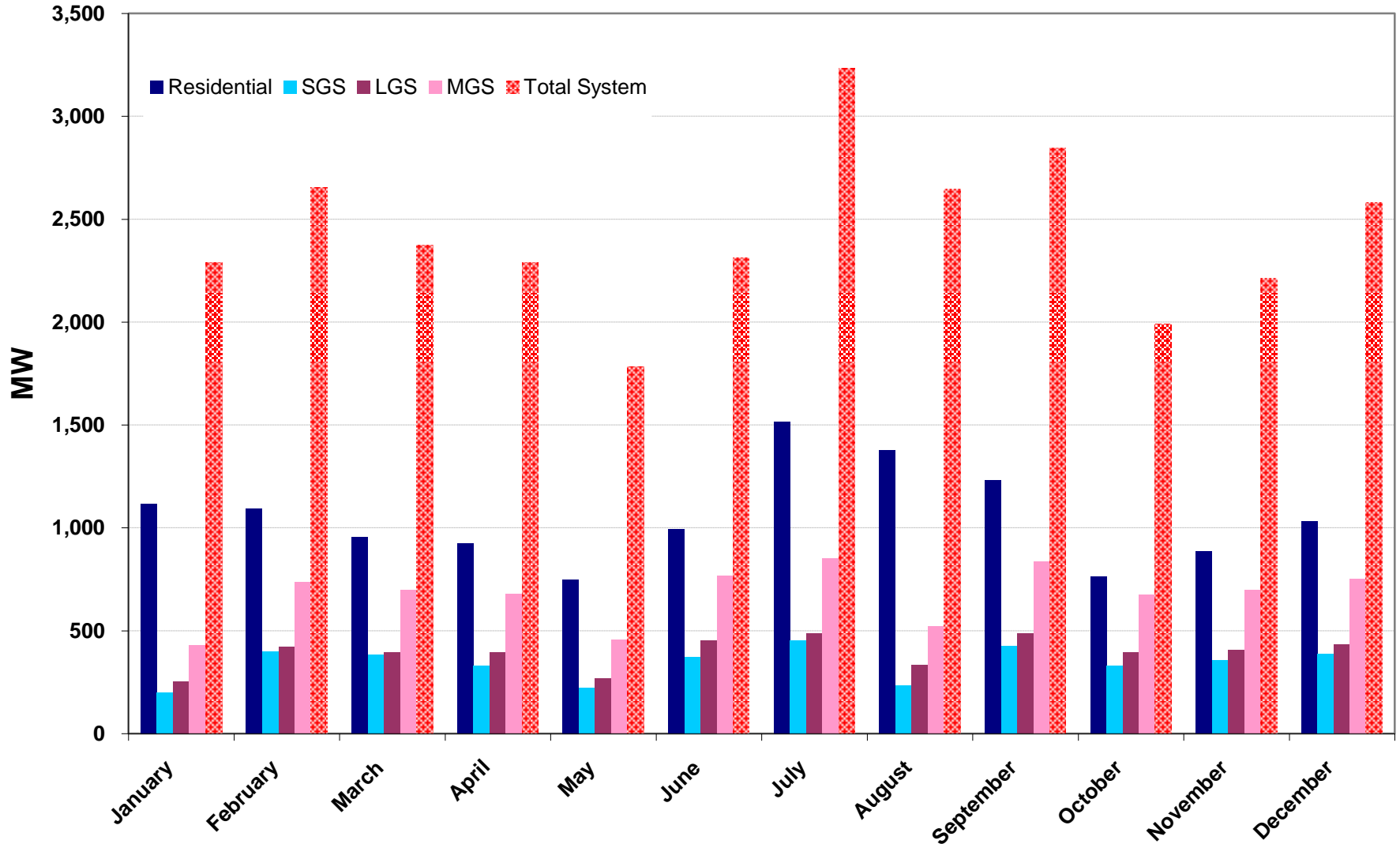
- Energy-Related generation cost allocation methods should take into account the fact that different rate classes have different contributions to line losses.
 - Residential and small commercial customers contribute significantly more to losses than do large high-voltage customers
- Energy-Related generation cost allocation methods could also take into account the fact that different rate classes have different load factors and, therefore, may have different contributions to (expensive) peak-load generation energy costs.
 - Residential and small commercial customers consume a greater share of their kWh during peak times and, therefore, consume proportionately more energy from peaker units

Allocation of Transmission Demand-Related Costs

Transmission costs are entirely demand-driven, thus allocation factors for generation are similarly applied to transmission.

- 1-CP, 3-CP are used by regional transmission organizations
- 12-CP was a common allocation method the FERC used for transmission and, therefore for consistency, it was also used by states where this was applied
- Sometimes transmission-system loads are often significantly high (relative to transmission capacity) even during low total-system load months because remote base-load generation facilities are still being relied upon (as they are during high total system load months)

Monthly Peak Loads by Class



Allocation of Distribution Costs

NCP is the allocation method typically used for distribution demand-related costs

- Investment in distribution facilities is generally made to serve class maximum demands that are not coincident with the system peak, and therefore the NCP allocation methodology provides reasonable results.
- This method is consistent with a generally accepted approach to distribution demand allocation.

Methods that allocate customer-related costs associated with metering and customer service should take into account that average meter or service costs (per customer) varies across rate classes

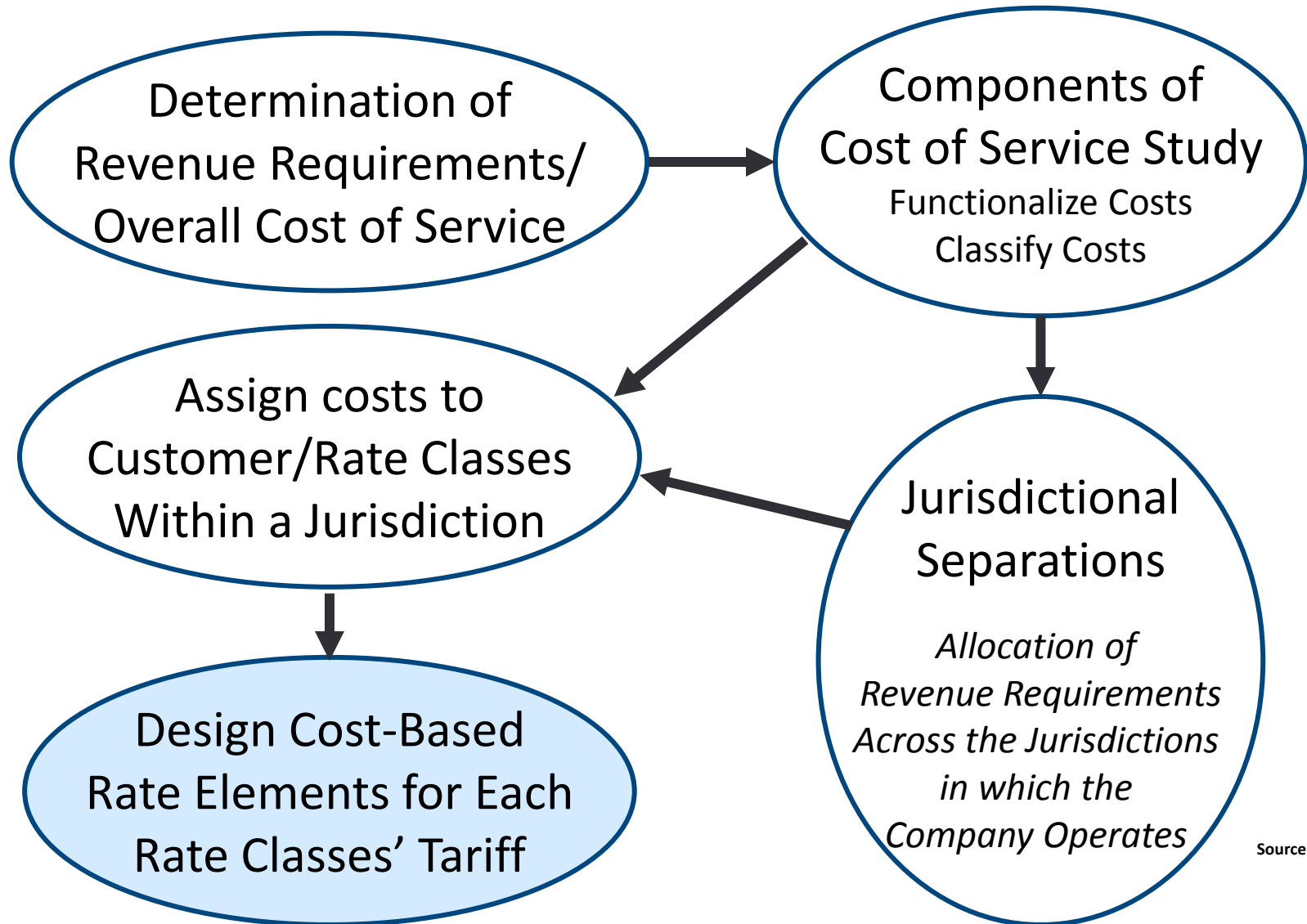
- Use a weighted customer method, or directly assign these costs to rate classes wherever and whenever possible

Allocation

Customer-Related Cost Allocation Methods

- Relative Number of Customers
- Relative Weighted Number of Customers—where weights can be based on:
 - class-average meter costs
 - class-average billing costs
 - class-average service line costs
 - class-average meter-reading costs

Basic Steps in Rate Making Process



Source: Blank & Gegax

STEP 4: COSTS INTO RATES

Rate Design

A tariff is a document, approved by the responsible regulatory agency, listing the terms and conditions under which utility services will be provided to customers within a particular class. Tariff sheets typically include:

- a schedule of all the rate elements (individual prices) plus the provisions necessary for billing
- the service characteristics (*e.g.*, voltage, single or three phase) and metering methods
- rules and regulations, *i.e.*, a statement of the general practices the utility follows in carrying out its business with its customers

Rate Design

Billing Determinants

- Any element of the customer's account that will be used in the computation of a customer's bill. These include the applicable rates and riders and the components of consumption, such as energy, peak demand, power factor, etc.

Base Rates

- Base Rates are rates that are fixed in the tariffs (until the next rate case comes along)

Rate Design

Riders

- A rider is a mechanism that follows or "tracks" some unpredictable costs that a utility incurs in providing service to consumers and allows the prices customers pay in order to recover these unpredictable costs to vary (without the need for a new rate case)
- The rider is an additional charge for each kilowatt-hour and is increased or decreased based on variable costs such as fuel and market power. The rider is adjusted monthly or quarterly.
- A Fuel and Purchased Power Adjustment Clause is an example of a rider
- Other costs may be tracked

Rate Design

Role of Rates

- Rates serve as the means by which the utility collects revenues and covers its allowed cost of service (including that which is required under the “fair-return standard”)
- Rates induce particular behaviors on the part of customers
 - Principles of Public Utility Rates by James C. Bonbright
 - Rate attributes: simplicity, understandability, public acceptability, and feasibility of application and interpretation
 - Effectiveness of yielding total revenue requirements
 - Revenue (and cash flow) stability from year to year
 - Stability of rates themselves, minimal unexpected changes that are seriously adverse to existing customers
 - Fairness in apportioning cost of service among different consumers
 - Avoidance of “undue discrimination”
 - Efficiency, promoting efficient use of energy and competing products and services

Fundamental Rate Elements

Demand Charge

- Measured in dollars per kW of monthly metered customer billing demand

Energy Charge

- Measured in dollars per kWh of monthly customer energy use

Customer Charge

- Measured in dollars per customer per month

Fundamental Rate Elements: Energy and Customer Charges

- Energy charges are derived by taking the class energy-related costs and dividing these costs by class energy use
- Customer Charges are derived by taking the class customer-related costs and dividing by the class “customer months”
 - A class’s customer-months is calculated by multiplying the total number of customers in the class by 12

Fundamental Rate Elements: Demand Charges

Demand Charge

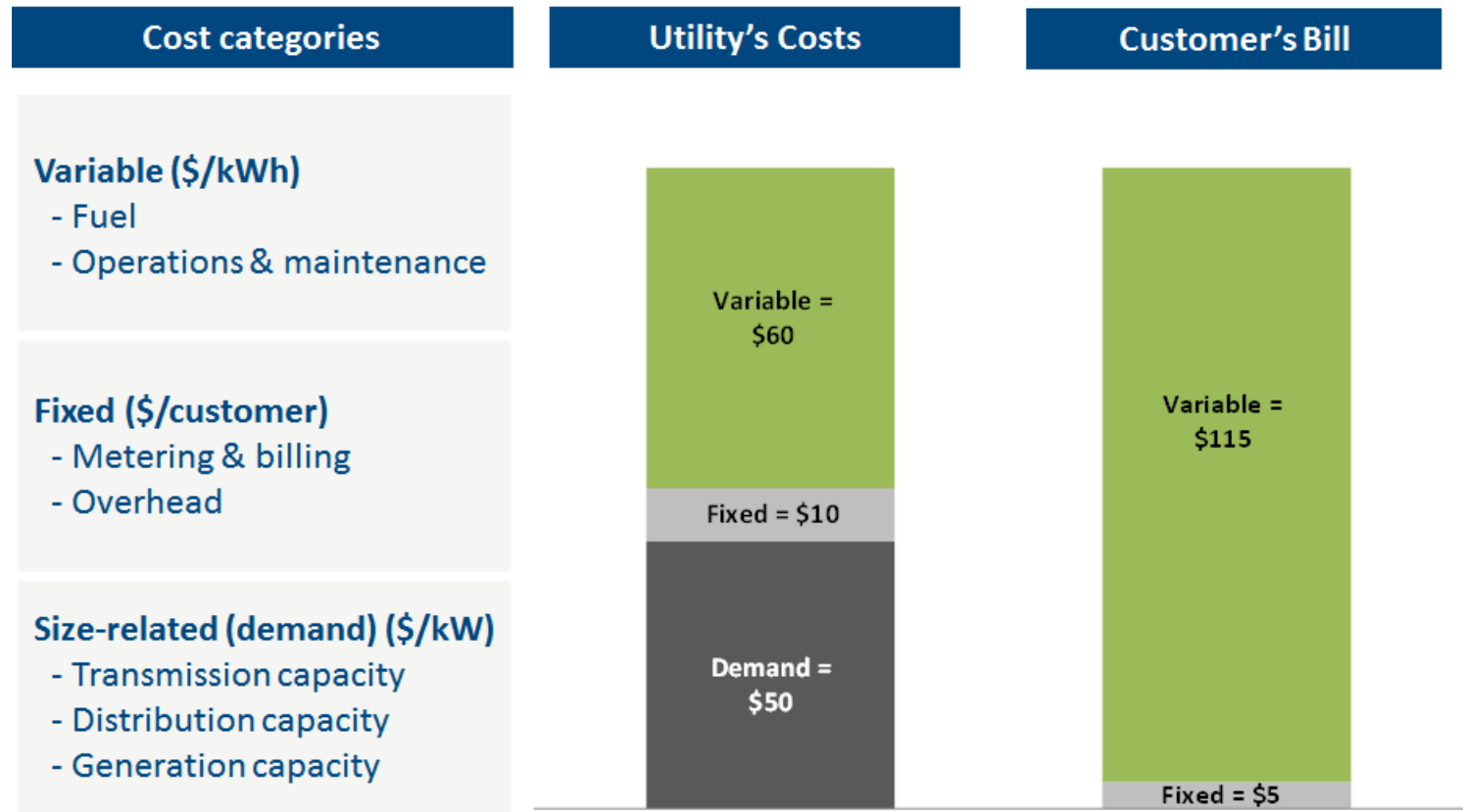
- Derived by taking the demand-related costs and dividing these costs by class “billing demand”
- The manner in which the demand charge is calculated must be consistent with the manner in which individual customers are metered; otherwise, the utility will over- or under-collect.
- For a class in which individual customers do not have demand meters, demand-related costs must be recovered either through the energy charge or the customer charge
 - Note: Use of the energy charge to recovery of fixed demand- and customer-related costs can increase risk of fixed-cost recovery

Residential rate design is ripe for rethinking

Flat rate pricing is ubiquitous today and it has persisted over the past century because of two reasons

- Lack of advanced metering
- A perception that residential customers are not ready for a change, which has become a self-fulfilling prophecy
- A long time ago, Professor Bonbright warned us of guarding against the “tyranny of the status quo”

For Many Utilities, Their Residential Rates and Costs Are Grossly Misaligned



This is not just a problem for the utility's shareholders

- The oversized volumetric rate can be avoided through investment in high-efficiency appliances and distributed generation
- Customers who don't (or can't) make these investments, particularly low income customers, subsidize those who do
- The cross-subsidy has significant implications with regard to equity and fairness—two important ratemaking criteria (more later)

Residential Technology Is Changing and Demand Flexibility Will Soon Be the Norm

Digital technology is becoming ubiquitous (the Internet of Things)

- Smart thermostats, smart appliances, smart light bulbs and smart plug loads
- Home energy management systems
- These allow households to manage their loads dynamically in real time

If prices fall in the middle of the day, *e.g.*, as renewable energy resources kick in, customer loads will rise automatically; as prices rise later in the evening, loads will fall automatically

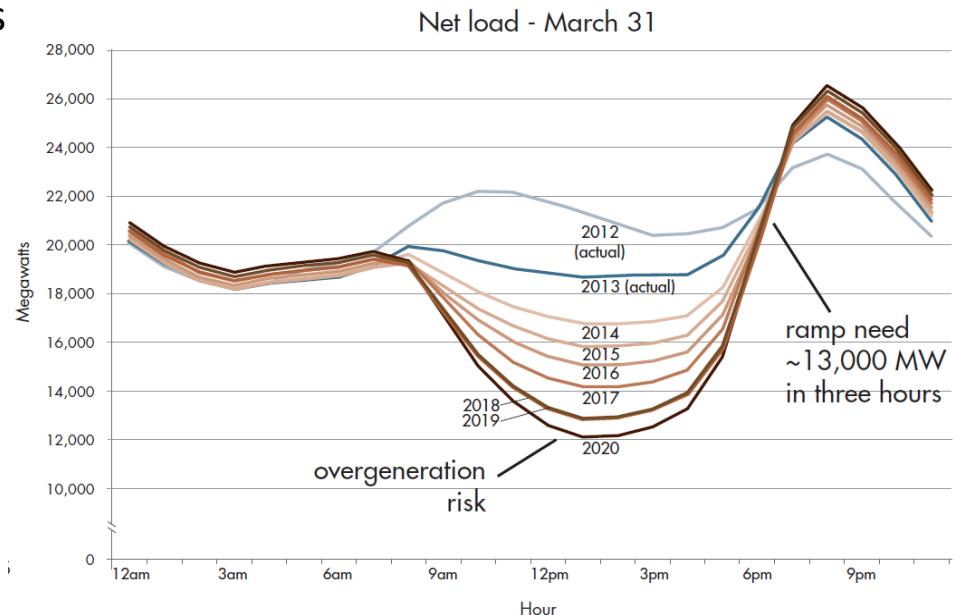
MIT's Fred Schweppe called this “homeostatic control” in 1981

However, if customers adopt uneconomic levels of DG, this will raise energy costs for all customers

Increases in customer generation may have two effects:

- Reduce capacity costs
 - Depends on the degree generation is coincident with system peak
 - Depends on the degree of customer generation reliability
- Increase other costs
 - Intermittency may result in
 - Increased generation ramping requirements [the duck! (now a goose)]
 - Increased level of operating reserves (idling generation)
 - Reduced efficiency of unit commitment
 - There may also be additional costs associated with maintaining power quality
 - And distribution-level capacity upgrades may be needed

The California ISO “Duck Curve”



Several New Flavors Are Being Considered

- Demand Charges
- Buy-Sell Arrangement (FIT/VOS)
- Fixed Monthly Charge
- Time-Varying Rates
- Capacity Charge
- Installed Capacity Fee (Grid Access Charge)
- DG Output Fee
- Interconnection Fee
- Minimum Bill
- Standby Rates

Time-Varying Prices Should Be the Foundation for All *Energy* Rates

Economic efficiency

- The costs of supplying and delivering electricity vary by day, and some economists have argued that the electricity used in each hour is a separate commodity
- Unless consumers see this time variation in prices, they will have no incentive to modify their pattern of energy usage
- Excess capacity will have to be built and kept on reserve to meet peak loads during a few hundred hours of the year

Equity

- Under flat energy rates, customers who consume relatively less power during peak periods subsidize those who consumer relatively more power during peak periods

TVP Will Lower Energy Costs and Reduce Cross-Subsidies

There are almost 60 million households with smart meters today but less than 2 million of them are on TVP

That prevents us from harnessing the benefits of universal dynamic pricing

- \$7 billion per year in lower energy costs
- \$3 billion per year in reduced cross-subsidies between customers

But the Story Does Not End with TVP, It Just Begins with It

A few utilities have begun moving to a three part rate, *i.e.*, a monthly service charge, a demand charge and time-variant pricing (TVP), and many others are expected to follow

- Such rates have a long history for commercial and industrial (C&I) customers, backed up by a long series of papers dating back to Hopkinson and Wright (see Appendix A and C)
- TVP of energy does not eliminate the need for demand charges; Georgia Power has 2,200 C&I customers on real time pricing but these customers still face a demand charge for their use of the grid.
[https://www.georgiapower.com/docs/rates-schedules/marginally-priced/6.20 RTP-DA.pdf](https://www.georgiapower.com/docs/rates-schedules/marginally-priced/6.20_RTP-DA.pdf)
- Facility-based demand charges will persist in California even when CPP is rolled out for C&I customers

Three Part Rates Convey a Cost-Based Price Signal

Utilities that supply energy would use a five-part rate

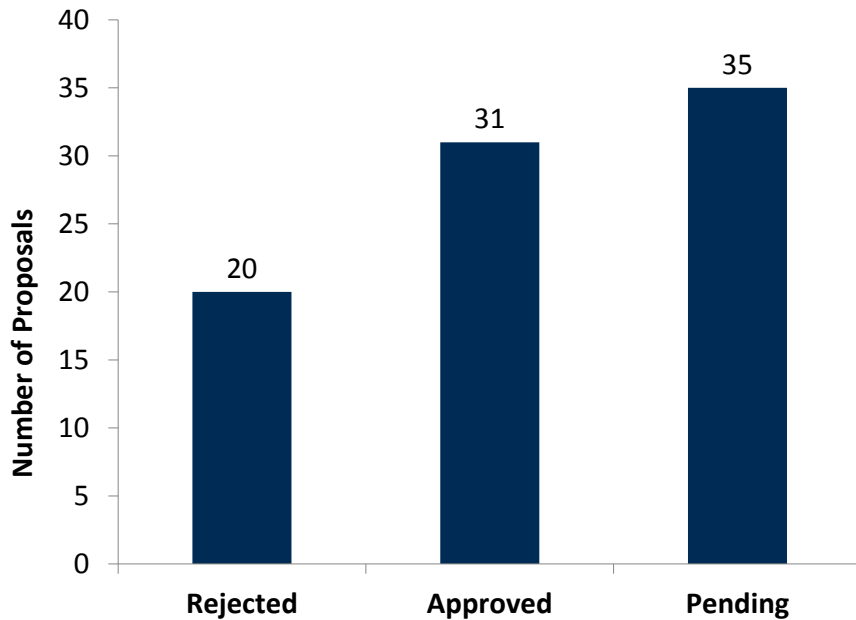
- Monthly service charge
- Charge for connected load (or maximum customer demand)
- Maximum demand charge (coincident with the distribution peak)
- Charge for generation capacity
- Time-varying energy charge

Distribution-only utilities would use a three-part rate

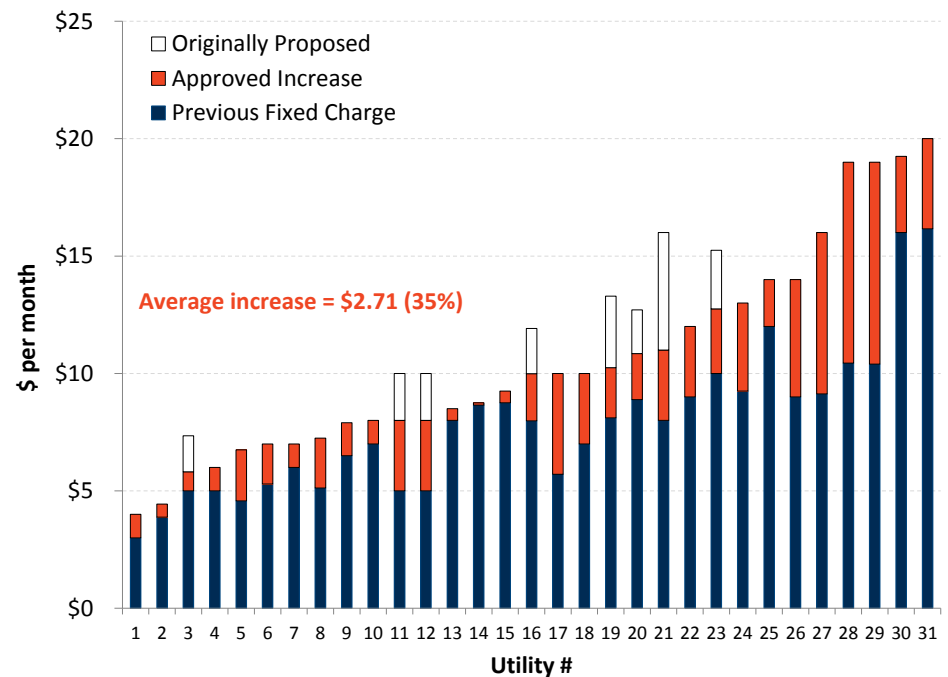
- Monthly service charge
- Charge for connected load (or maximum customer demand)
- Maximum demand charge (coincident with the distribution peak)

Many Utilities Have Proposed to Increase the Fixed Charge and Stick with a Two-Part Rate

Recent Proposals to Increase Fixed Charge



Amount of Approved Increase



Data sources: NC Clean Energy, "The 50 States of Solar," Q2 2015. Supplemented with review of additional utility rate filings.

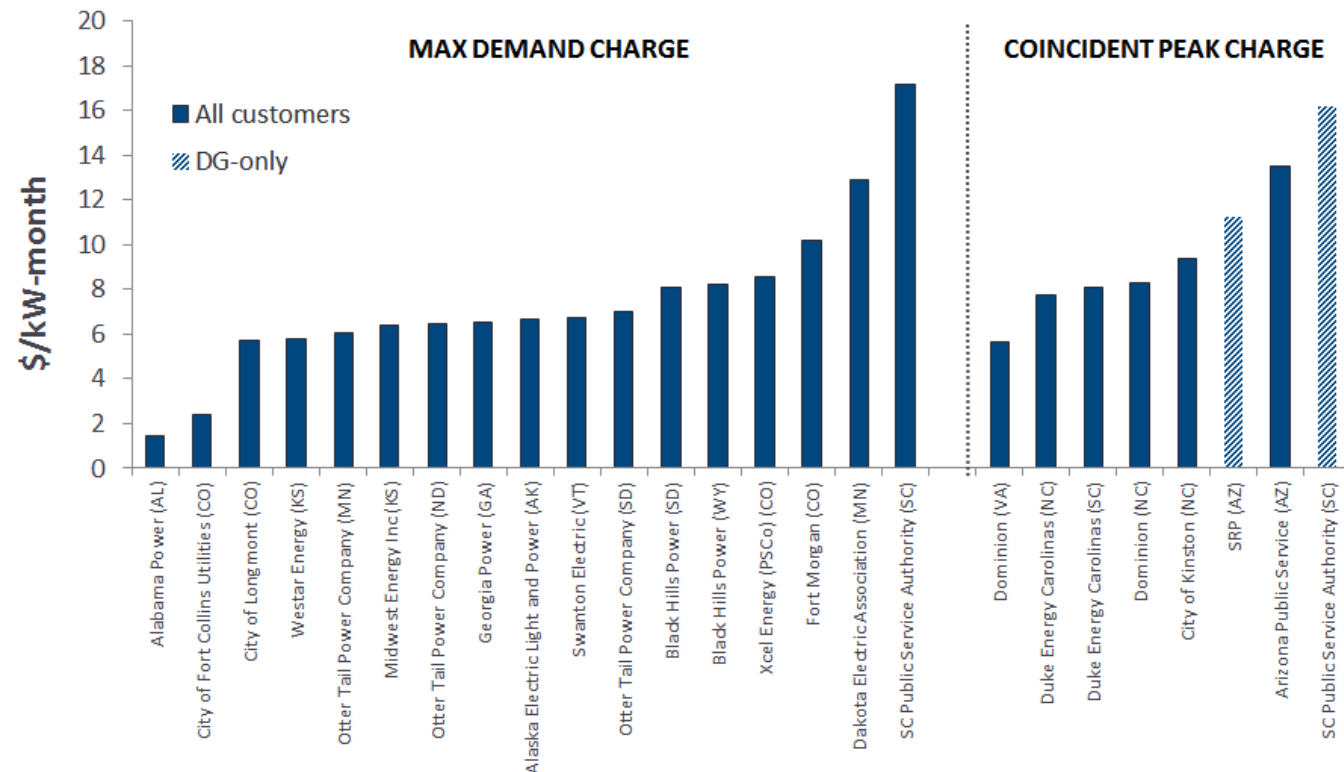
Fixed Charges Can Help to Address the “Cost Shift” Problem

- In the absence of advanced metering infrastructure (AMI), rate design options for addressing the cost-shift issues associated with DG adoption and volumetric rates are somewhat limited
- Fixed charges are one option for addressing the cost-shift issue and do not require metering upgrades
- Some costs, such as metering, billing, and general overhead are clearly fixed and vary with the number of customers, not with the amount of electricity consumed

Many Utilities Are Considering Demand Charges, Which Are Being Offered By Some Others

Summer Demand Charges in Existing Rates

Comments



- 19 utilities offer residential demand charges, 10 of which are IOUs
- They have been proposed in Arizona, Kansas, Illinois, Nevada, and Oklahoma

Notes:

- 1) All rates are drawn from their respective utility tariff sheets, valid as of July 2015.
- 2) The SRP rate is tiered and varies by season and amount of demand; we show the average summer demand charge for a 10 kW customer for illustrative purposes.
- 3) The SC Public Service Authority DG rate includes a peak rate of \$11.34/kW-mo and an off-peak rate of \$4.85/kW-mo. We present the sum for simplicity.

Can residential customers understand demand charges?

- Anyone who has purchased a light bulb has encountered watts; ditto for anyone who has purchased a hair dryer or an electric iron
- Customers often introduced to kWh's by way of kW's; *e.g.*, if you leave on a 100 watt bulb for 10 hours, it will use 1,000 watt-hours, or one kWh
- Similarly, if you run your hair dryer at the same time that someone else is ironing their clothes and lights are on in both bathrooms, the circuit breaker may trip on you since you have exceeded its capacity, expressed in kVA's or kW's

Customers Don't Need to Be Electricity Experts to Understand a Demand Charge

- Responding to a demand charge does not require that the customers know exactly when their maximum demand will occur
- If customers know to avoid the simultaneous use of electricity-intensive appliances, they could easily reduce their maximum demand without ever knowing when it occurs
- This simple message should be stressed in customer marketing and outreach initiatives associated with the demand rate
- Examples from utility websites
 - APS: “Limit the number of appliances you use at once during on-peak hours”
 - Georgia Power: “Avoid simultaneous use of major appliances. If you can avoid running appliances at the same time, then your peak demand would be lower. This translates to less demand on Georgia Power Company, and savings for you!”

Staggering the Use of a Few Key Appliances Could Lead to Significant Demand Reductions

Avg. Demand Over 15 min

Appliance	Avg. Demand (kW)	
Clothes Dryer	4.0	Flexible Load (18.5 kW)
Oven	2.0	
Stove	1.0	
Hand iron	0.5	
Central air conditioner	5.0	Inflexible Load (1 kW)
Spa heater and filter	6.0	
Misc. plug loads	0.2	
Lighting	0.3	
Refrigerator	0.5	
Total	19.5	

Comments

- Use of some of the appliances is inflexible (1 kW)
- Use of other appliances could be easily staggered to reduce demand
- Simply delaying use of the clothes dryer, oven, stove, and hand iron would reduce the customer's maximum demand by 7.5 kW
- This would bring the customer's maximum demand down to 12 kW, a **roughly 38% reduction in demand**

Bonbright Reloaded for the 21st Century

The ideal rate design should promote economic efficiency, enhance customer equity, ensure the financial health of the utility, be transparent to customers, and empower customer choice.

Stakeholder Concerns Can Be Addressed Through Some New Initiatives—I

- Codify and learn from the experience of utilities that have deployed new rates in the US and in Europe
- Quantify bill impacts, particularly for low- and moderate income customers
- Assess customer understanding of the new rates through market research (interviews, focus groups and surveys) and identify the best way to communicate the concept and to design the rates

Stakeholder Concerns Can Be Addressed Through Some New Initiatives—ii

- Assess customer response to new rates through a new generation of experiments whose design builds on insights gleaned from prior work on time-of-use pricing experiments
- Study ways in which to mitigate financial impact on vulnerable customers, maybe by excluding them initially from the new rates, or by phasing in the rates, or by providing them financial assistance for installing energy efficiency measures

Conclusions

- We are standing at the cusp of a revolution in rate design, driven by the arrival of the Internet of Things, the deployment of smart meters and the greening of consumers
- Over the next three to five years, residential rates will begin evolving into three-part rates, featuring fixed charges, demand charges and time-varying energy charges
- When energy-smart customers face cost-based prices, a win-win outcome that emphasizes economic efficiency and restores equity among customers will become increasingly likely

Presenter Information



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The views expressed in this presentation are strictly those of the presenter(s) and do not necessarily state or reflect the views of The Brattle Group.

Appendix A: References

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