Developing Optional Time of Use and Demand Rates

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Factors Affecting Electric Rates

- Generation plant cost increases
- Carbon and environmental regulations
- Cost of renewable portfolio standards
  - Cost of renewable generation
  - Intermittent nature of renewables
  - Location of renewables - new transmission to move power from renewable generators
- Fuel price changes

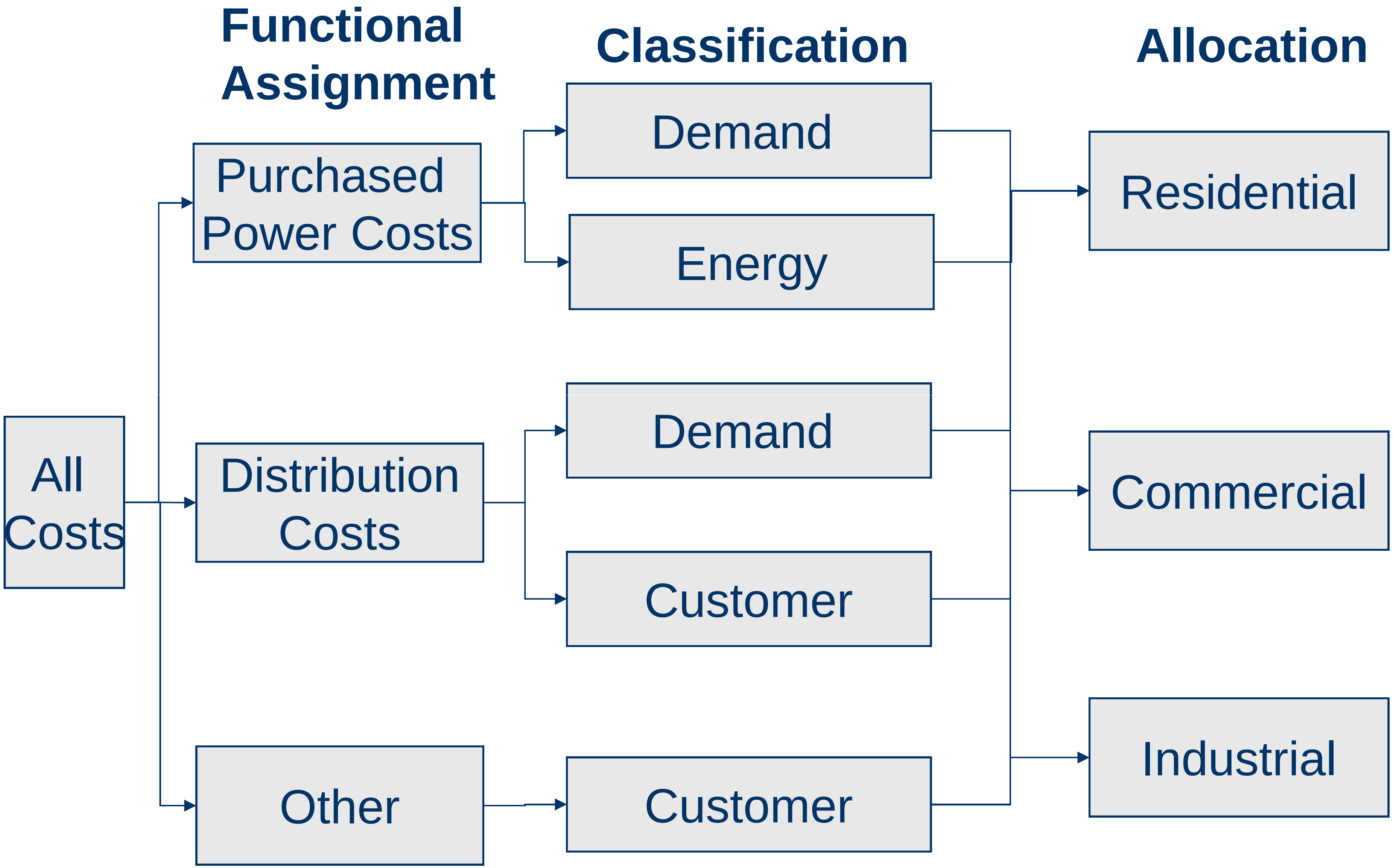
Customer Response to Higher Prices Is Predictable

- Desire to mitigate energy bill increases
- Reduced customer usage and sales due to:
  - Energy efficiency
  - Conservation
  - On-site generation and net metering
- Complaints and griping

Sending the Right Price Signals

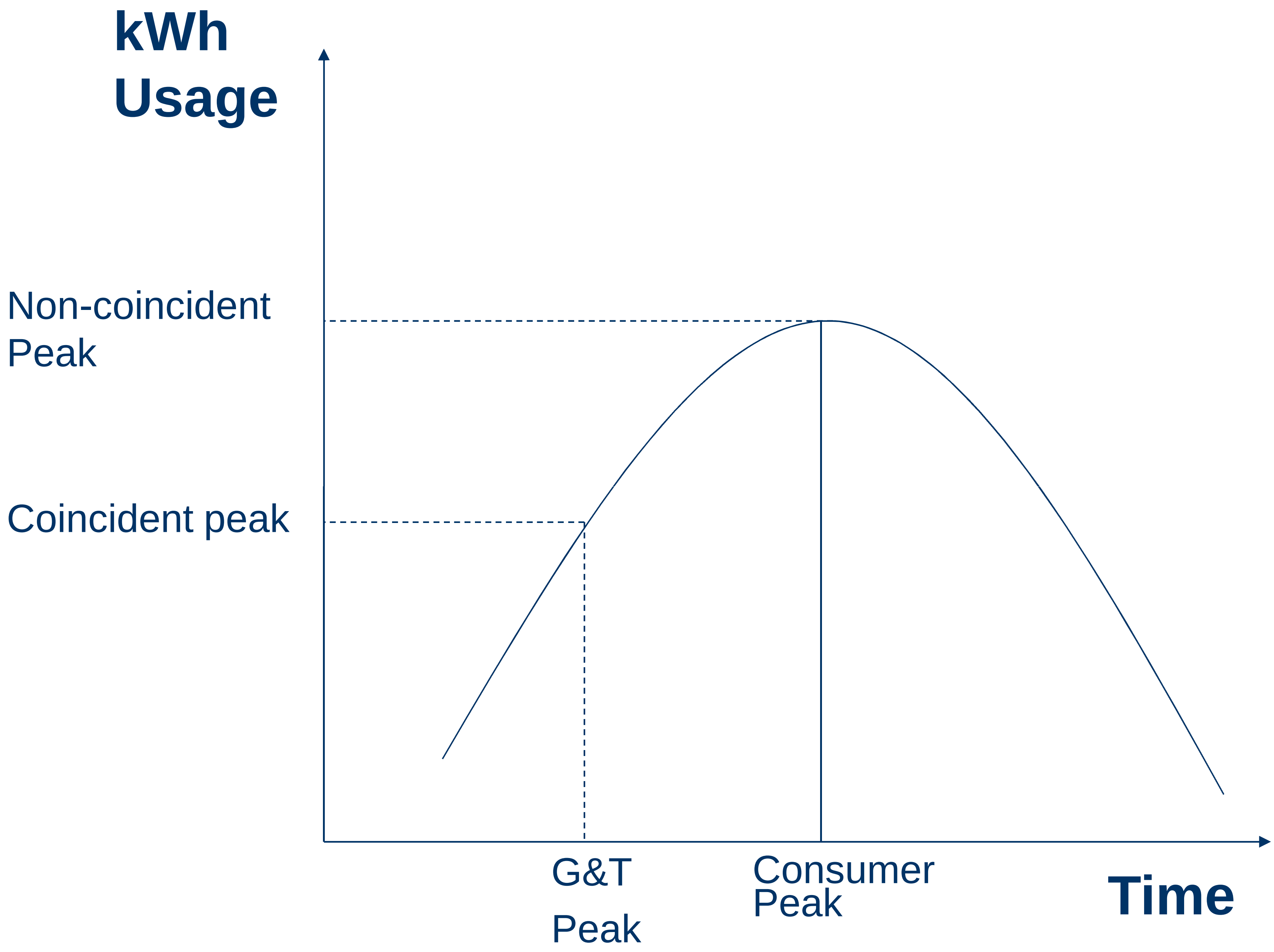
- All prices send signals
- What signals are your prices for electric service sending?
- Your rate design should provide financial incentives for customers to take actions that will help your cooperative to achieve its strategic goals
  - Begs the question, what are you trying to do with your customers

Cost of Service Study



Demand Related Costs

- Coincident peak demand
  - Customer’s use of capacity that is coincident with Utility’s peak demand
  - Purchased power demand
- Non-coincident peak demand
  - Capacity needed to meet the customer’s maximum use regardless of when it occurs
  - Distribution demand


kWh
Usage
Non-coincident
Peak
Coincident peak
G&T
Peak
Consumer
Peak
Time

Cost Drivers for Cooperative Costs

- Purchased power costs
  - Demand charge
    - Coincident peak demand makes this a variable cost for distribution cooperatives
    - Ratchets, average demand, NCP demand and shifting fixed costs to the energy charge can reduce the ability to offer price signals at retail level and make demand charge less of a variable cost for distribution cooperatives
  - Energy charge
    - kWh charge is a variable cost
    - Price signal can be enhanced by time differentiation

Cost Drivers for Cooperative Costs

- Distribution Costs
  - Meters, service drops, transformers, poles, conductor and distribution substations are all fixed costs for distribution cooperatives
  - Most of the other costs incurred in maintaining and operating a distribution system are also fixed costs
  - Using less kWh does not reduce these costs

What Is Really Saved?

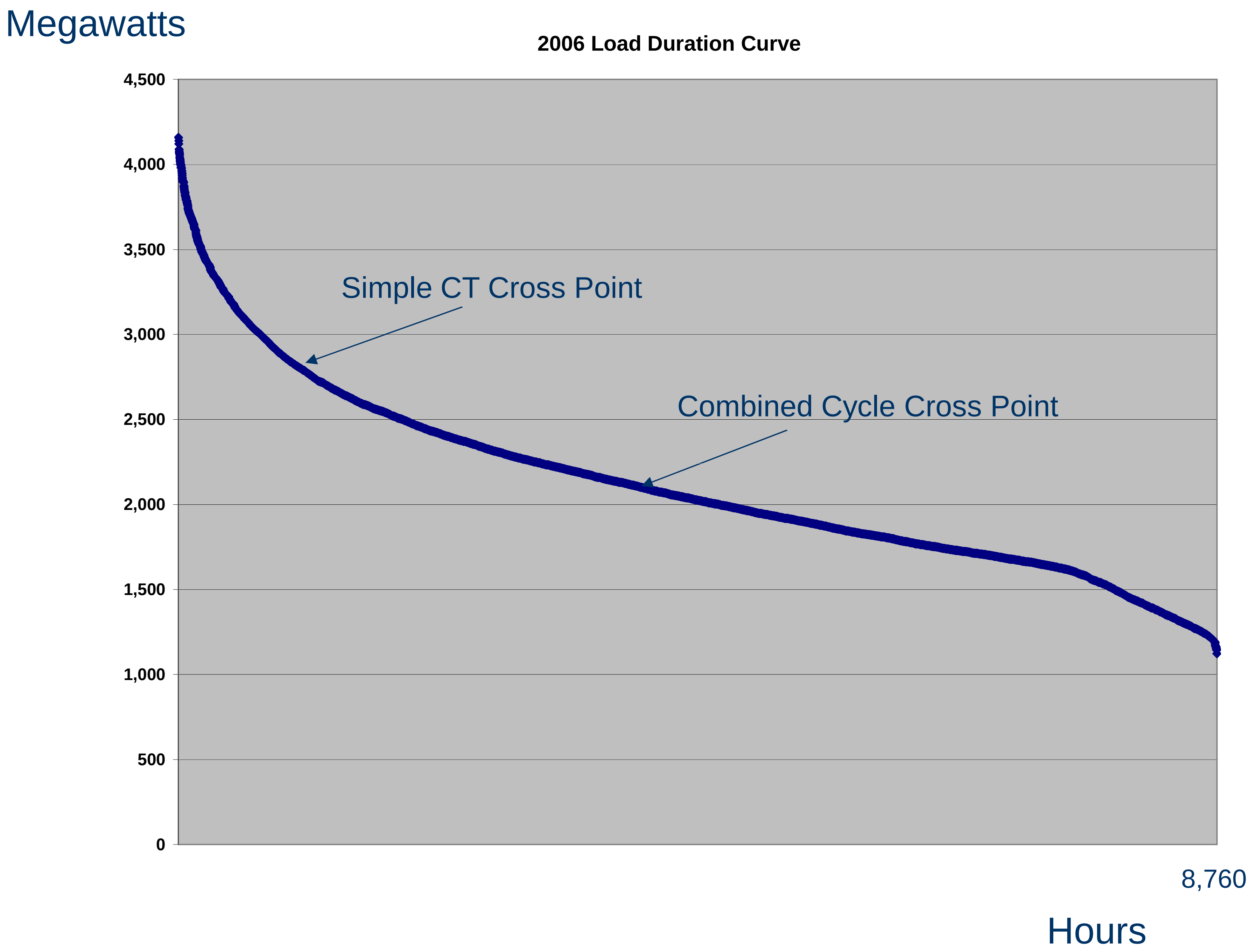
- When a customer reduces kWh use, the cooperative actually saves
  - Energy charge assessed by G&T
  - CP Demand charge if reduced usage is on-peak
- When a customer reduces kWh use, the cooperative does not save distribution costs and including these costs in the kWh charge compensates the customer for costs that the cooperative is not actually saving

What Is Really Saved?

- We need to do a better job of reflecting actual savings in a cooperative’s rate design
  - Cost-based customer charge
  - Optional time of use and demand rates
  - NCP distribution demand charge
  - Unbundle charges on the bill

Meeting Customer Needs

- A load duration curve provides a picture of the customer needs that the utility is trying to meet
- 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)
  - Price signals (indirect control)

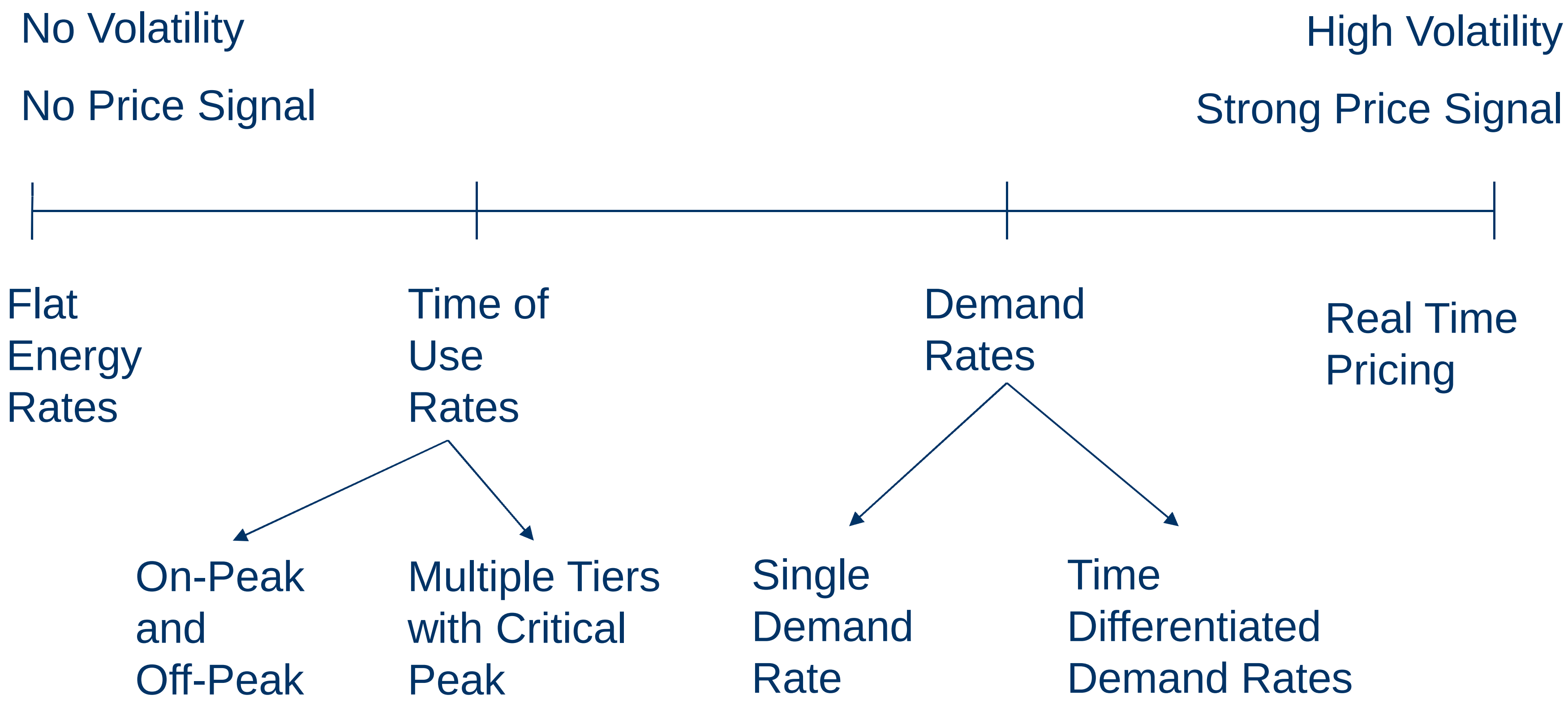


Megawatts
2006 Load Duration Curve
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Simple CT Cross Point
Combined Cycle Cross Point
8,760
Hours

Reasons for Offering Time Differentiated Rates

- Provides cooperatives 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

The Rate Continuum



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)

Current Costs

	Natural Gas Fired Simple CT	Combined Cycle	Conventional Coal Plant	Nuclear
Capacity (KW)	75,000	500,000	1,000,000	1,000,000
Cost per KW	$665	$1,003	$2,844	$5,339
Total Fixed Cost	$49,875,000	$501,500,000	$2,844,000,000	$5,339,000,000
Carrying charge	12.0%	12.0%	10.0%	10.0%
Fixed Cost/year	$5,985,000	$60,180,000	$284,400,000	$533,900,000
Hours of Operation	200	2,500	7,446	8,059
Fixed Cost /kWh	$0.399	$0.048	$0.038	$0.066
Fuel cost per kWh	$0.055	$0.040	$0.023	$0.007
Total Cost /kWh	$0.454	$0.088	$0.061	$0.073

Current Costs – Meeting All Load With New Generation

Fixed Cost / kWh	$0.0539
Fuel Cost / kWh	$0.0250
Undelivered Cost / kWh	$0.0789

Candidates for Time Differentiation

Likely	**Not Likely**
Production Demand	Customer Costs
Transmission Demand	Distribution Demand
Production Energy	

Time Differentiated Rates

- Opportunities for time differentiating G&T wholesale rates
  - Demand charges applicable during peak periods
    - Production demand costs
    - Transmission demand costs (generally calculated using a load share ratio)
  - Energy charges
    - On-peak (representing units with high running cost)
    - Off-peak (running cost of base load units)

Mechanics of Time Differentiation

- Opportunities for time differentiating distribution cooperatives retail rates
  - Turn CP demand charges into on-peak retail rate differentials
  - Time differentiated energy charges at the G&T level enhance distribution cooperative’s ability to offer on-peak and off-peak differentials
  - The cost of distribution substation equipment can also be time differentiated (these facilities are generally sized to meet peak demands)

Developing an On-Peak Adder

- Determination of peak periods
  - Likely to vary by season
  - May or may not include weekends
  - Needs to capture G&T’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 G&T'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
  - Board choice 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 G&T 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

Key Steps in Designing TOU Rates

- Step 1 (cont.) – Develop TOU periods
  - Determine whether the peak period should be split up into two non-contiguous periods
  - If G&T has TOU or window rates, then those periods may be used unless they are overly broad
  - Address the concept of risk with the cooperative Board

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

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 from
  - Determine peak period demands (kW) for rates with a demand charge

Key Steps in Designing TOU Rates

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

Residential Per Unit Costs from Cost of Service Study

- 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 a flat energy rate the only way to reduce the energy bill is to reduce consumption

Data for Calculating Hourly kWh Usage for TOU Rate

- You need hourly kWh to calculate on-peak kWh to use as the denominator for calculating the on-peak adder
  - Aggregate hourly kWh usage for all customers in a class from AMI system
  - Usage per customer per hour multiplied by the number of customers in the class

Usage Per Customer Per Hour

- Load research data that provides kWh usage per customer for each hour for a class of customers
- Borrowed profiles
- Data from a distribution sub that that records hourly kWh usage that serves solely residential load (need kWh by hour and number of customers served by the sub)

Borrowed Profiles

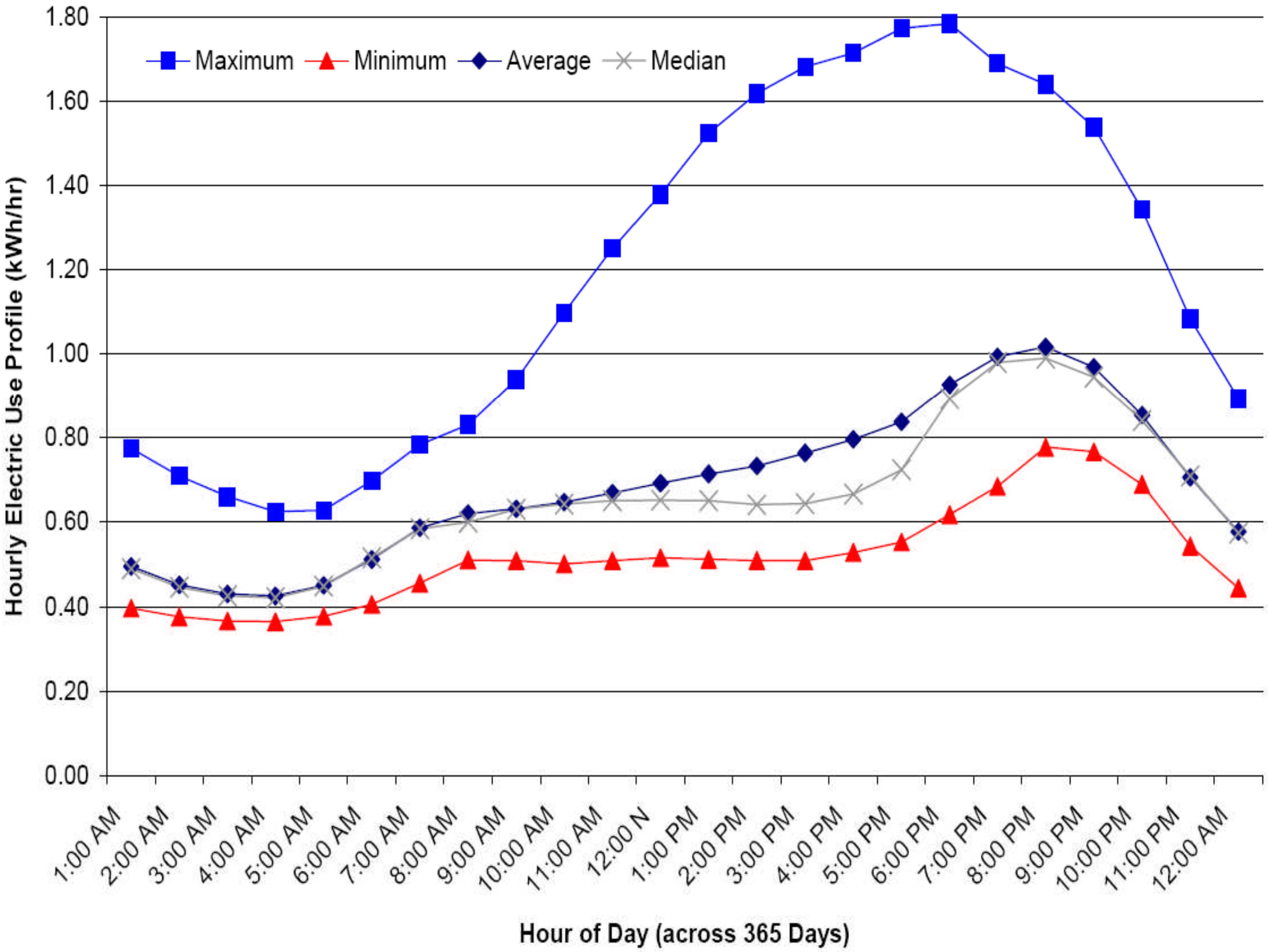


Figure 20 - Hourly Average Residential Load Profile (Southern California Edison Territory)

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	

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

G&T 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 G&T 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 G&T 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

Dispelling Myths

- Myth - Distribution cooperatives cannot provide meaningful TOU rates to customers until G&Ts time differentiate their energy rates
- Fact – the big difference between on-peak and off-peak rates comes from converting the CP demand charge into an on-peak adder

Obstacles to Time Differentiated Rates

- Opportunities for time differentiating retail rates can be limited by the rate structure of the G&T provider:
  - NCP billing
  - “Tilted” demand charges (fixed costs shifted to energy charge for recovery) – MLF rate
  - 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

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

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
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Billing Determinants from Cost of Service Study

	Non-Coincident Peak Demand	Coincident 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

Single Demand 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

Communication With Customers Is Critical

- In a flat rate environment, there was no financial benefit for customers to move usage to other time periods
- Need to convince customers that the game is worth playing
- Need to help customers develop the skills to win the game

Convincing Customers

- Need to communicate the benefits in terms that are meaningful to customers
  - Avoid technical data when possible
  - Communicate the dollar savings

Appliance Energy Usage

- Clothes dryer – 5 kW
- Water heater – 4.5 kW
- Electric Oven – 3.5 kW
- Electric Range (large element) – 2.3 kW
- Dishwasher – 1.8 kW
- Portable heater – 1.5 kW
- Vacuum cleaner - 1.6 kW
- Washing machine – 0.5 kW

Convincing Customers

- With an on-peak rate of 17.8¢/kWh and an off-peak rate of 4.4¢/kWh, a customer can save:
  - 67¢ by shifting one hour of clothes drying from on-peak to off-peak (17.8¢ - 4.4¢) x 5 kWh
  - 24¢ by shifting one hour of dish washing from on-peak to off-peak
  - 7¢ by shifting one hour of clothes washing from on-peak to off-peak

Developing Skills

- Help to identify equipment that will helps customers take advantage of TOU rates
- Educate customers how to use equipment to take advantage of rates
- Educate community opinion leaders
- Establish blog for customers to share ideas about how to take advantage of TOU rates
- Others?

A Program Targeted at Every Appliance

- Direct load control
- Indirect load control
- Energy efficiency
- Energy conservation

Preparing for a Higher Cost Future

- We don’t have control over the cards that we are dealt
- What we do have is responsibility for how we play the hand
- We need to build customer skill set for reducing energy bills before higher prices arrive

Questions?

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