What Went Wrong with California's Re-structured Electricity Market?
(And How to Fix It)

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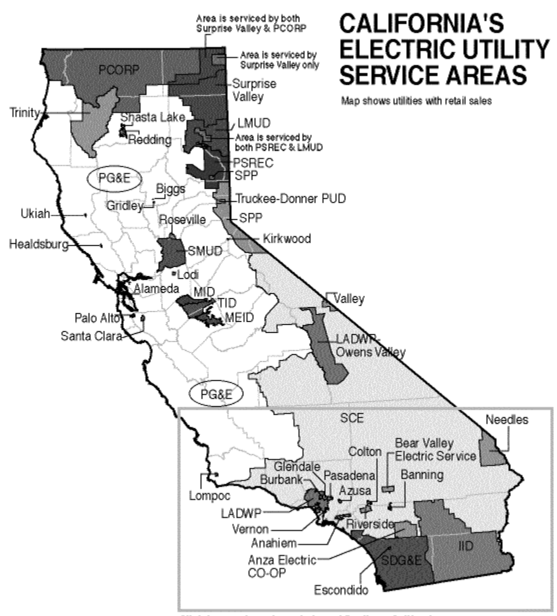
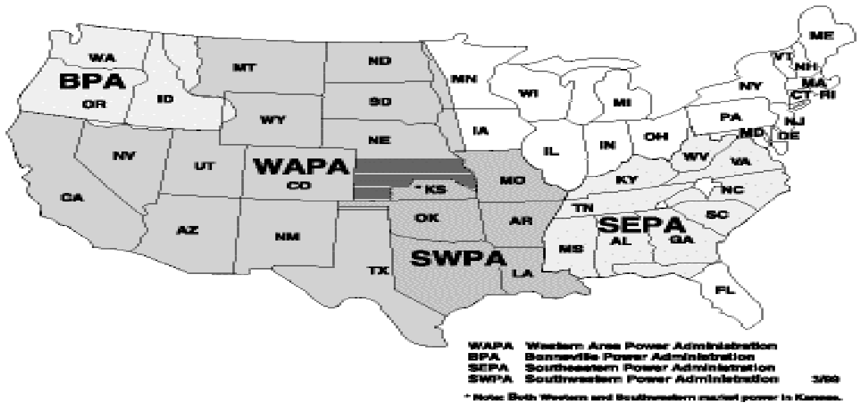
Outline of Talk

- Introduction to California electricity market
- Market Performance
  - April 1998 to April 2000--Competition works
  - May 2000 to Dec 2000--Competition fails
- Market structure reasons for failure
- Regulatory reasons for market failure
- Prospects for summer of 2001
- Proposed solution to current problems

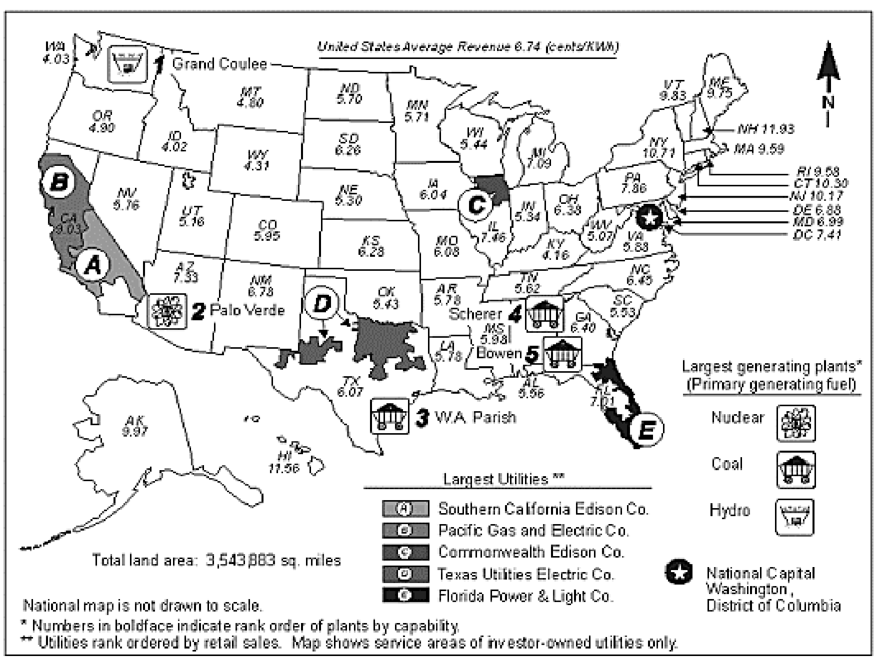
Industry Before March 31, 1998

- Three Large Investor-Owned Utilities (IOUs)
  - Pacific Gas and Electric (PG&E)
  - Southern California Edison (SCE)
  - San Diego Gas and Electric (SDG&E)
- Vertically integrated into generation, transmission, and distribution
- Significant out-of-region energy needed to serve in-state demand (approximately 25%)
- Retail electricity rates regulated by California Public Utilities Commission (CPUC)





Federal Power Producers



Goals of Restructuring

- Lower retail prices through competition in wholesale electricity production
  - Existing Firms--PG&E, SCE, and SDG&E
  - New Firms--Duke, AES/Williams, Dynegy, Reliant, Southern
  - Existing Govt Entities--BPA, WAPA, LADWP, CADWR
- Transmission and distribution remain regulated monopoly services
  - Transmission prices set by Federal Energy Regulatory Commission (FERC)
  - Distribution prices set by CPUC
- Competition in electricity supply (unclear)
  - Procuring wholesale energy and selling to final customers

After March 31, 1998

- Divestiture of 18,000 MW of instate fossil-fuel units by IOUs to new "merchant" producers
- IOUs received 4-year opportunity for full stranded asset recovery
- Consumers received rate freeze for 4 years or until stranded assets recovered
  - Price of electricity to final customers set at 90% of 1996 retail prices
  - IOUs received difference between wholesale price implicit in frozen retail rate and actual wholesale price as Competition Transition Charge (CTC)

After March 31, 1998

- Independent System Operator (ISO) and Power Exchange (PX) established
  - Regulated by Federal Energy Regulatory Commission (FERC)
  - FERC must approve all market rules
  - Industry re-structuring not de-regulation
- PX runs forward energy markets
  - Day ahead and day-of markets
  - Prices set on hourly basis
- ISO prices transmission in forward markets
  - Runs reserve capacity markets
  - Operates real-time energy market
  - Manages transmission grid in real-time

After March 31, 1998

- PG&E, SCE, and SDG&E own and maintain transmission grid in their service area
  - Transmission prices regulated by Federal Energy Regulatory Commission
- ISO operates transmission grid
  - Guarantees that all generation owners have equal access to transmission grid
- Supply business is "open to competition"
  - Utility distribution companies (UDCs) affiliated with IOUs are subject to CPUC regulation

Competition versus Regulation

- Competitive regime
  - All generation unit owners have equal access to wholesale market
  - Lowest bidder sells into market
- Regulated regime
  - Vertically integrated monopoly and regulator jointly determine wholesale market purchases
  - "Used and useful" expensive generation units can displace lower cost units owned by merchant producer

Monthly Indexes of Market Performance for April 1998 to December 2000

$$MP(S) = (TR_{ACT} - TR_{BM})/(Q_{ISO} - Q_{MUST\text{-}TAKE})$$
$$= PAVG_{ACT} - PAVG_{BM}$$

MP(S) = average \$/MWh markup for month S

TR_{ACT} = actual monthly wholesale revenues from the sale of total ISO load less must take energy for all hours during the month

TR_{BM} = monthly revenues from the sale of this same quantity of energy assuming perfectly competitive pricing of energy

$PAVG_{AVG}$ = monthly average actual price
$PAVG_{BM}$ = monthly average price for competitive pricing

Monthly Indexes of Market Performance for April 1998 to December 2000

Competitive benchmark price computed using methodology from “Diagnosing Market Power in California’s Restructured Wholesale Electricity Market,” Borenstein, Bushnell and Wolak (2000), available from Web-site.

Methodology distinguishes high prices due to economic scarcity from those due to the exercise of market power

Assumptions made in methodology bias results against a finding of the exercise of market power

In determining competitive benchmark price for energy, methodology controls for unit outages, import response due to to lower instate prices, and capacity held out of energy market to provide ancillary services.

Energy, A/S Costs and Market Power Markup from 4/98 to 12/00

Month	Energy Cost $/MWh	A/S Costs $/MWh of Load	Total Costs per MWh	MP(S) $/MWh
Apr-98	23.45	2.44	25.89	1.30
May-98	12.98	3.71	16.69	-9.04
Jun-98	13.58	2.95	16.53	-8.05
Jul-98	36.90	5.18	42.08	10.33
Aug-98	44.80	6.18	50.97	17.90
Sep-98	38.29	4.37	42.65	13.40
Oct-98	26.93	2.69	29.63	1.97
Nov-98	26.13	2.24	28.37	0.08
Dec-98	29.95	2.99	32.93	3.50
Jan-99	22.29	1.75	24.05	-0.47
Feb-99	19.91	1.14	21.05	-1.21
Mar-99	20.31	1.51	21.82	-1.27
Apr-99	25.34	2.1	27.44	1.01
May-99	25.48	2.37	27.84	0.18
Jun-99	26.93	2.26	29.19	1.91
Jul-99	35.05	2.6	37.65	6.00
Aug-99	37.55	1.85	39.41	2.62
Sep-99	36.47	1.52	37.99	5.61
Oct-99	50.19	2.28	52.47	16.96
Nov-99	35.54	1.19	36.73	10.37
Dec-99	29.90	0.55	30.45	3.82
Jan-00	31.63	0.62	32.26	5.43
Feb-00	30.43	0.58	31.01	2.34
Mar-00	29.55	0.06	30.15	-0.20
Apr-00	30.78	0.95	31.73	-3.17
May-00	58.06	3.16	61.22	15.56
Jun-00	146.77	20.19	166.96	94.81
Jul-00	112.06	5.71	117.77	64.85
Aug-00	167.89	12.18	180.07	115.62
Sep-00	118.55	7.39	125.94	55.71
Oct-00	97.73	2.95	100.68	39.26
Nov-00	154.86	6.13	160.99	50.01
Dec-00	294.19	22.65	317.84	90.08

Summary of Market Performance for April 1998 to April 2000

1) Market power historically exercised during months of August to September

2) Little market power exercised during months of October to April

3) For one year period October 1998 to September 1999 little market power exercised, P(actual) - P(benchmark) approximately equal to zero

4) Except for start-up problems during summer of 1998, market worked well
   a) IOUs collected almost $40/MWh per of electricity delivered in stranded asset recovery
   b) Almost $5 billion per firm for PG&E and SCE to parent company

Summary of Market Performance for April 2000 to December 2000

1) Extraordinary amount of market power exercised since June 2000

2) Average market power markup for
   Calendar year 1999--$4/MWh
   Calendar year 2000--$45/MWh
   January 2001--More than $130/MWh

3) Current residential retail rate is $110/MWh
   Subtracting transmission and distribution charges yields $70/MWh as the implied wholesale rate

4) Since implementation of FERC “remedies” market performance much worse
   January to April 2001 average wholesale price is >$300/MWh

Market Structure Factors Contributing to Current Problems

1) Small amount of new capacity built in California during 1990's--approximately 1,000 MW

2) Very small amount new capacity built in surrounding northwestern states--approximately 800 MW
   - Large demand growth in other western states besides CA
   - Lower net summer surplus to sell to California
   - Higher winter deficit to purchase from California

3) High water runoff years in 1998 and 1999 in California and Pacific Northwest
   - Normal runoff year in 2000
   - Increased environmental concern further reduced summer 2000 hydroelectricity production

Market Structure Factors Contributing to Current Problems

1) Higher natural gas prices
   a) Average price for 1999 approximately $2.75/MMBTU
   b) Average price for 2000 approximately $6.50/MMBTU
   c) Average energy and ancillary services prices
      1) $33/MWh of load in 1999
      2) $116/MWh of load in 2000
   d) Market power index accounts for gas price changes
   e) FERC regulations potential source of price increase

2) Unprecedented levels of forced outages since Summer of 2000
   a) Verifiable forced outage problem

3) Wholesale demand is extremely price inelastic
   a) Very few consumers face real-time price
   b) Retail rate freeze

Myth and Reality in California Electricity Crisis

1) Myth--Unusually hot weather during summer of 2000
   Reality--Summer of 2000 was milder than 1998 or 1999
   System Peak Summer 2000--43,509 MW-August 16, 43,447 MW-June 14
   System Peak Summer 1999--45,574 MW July 12

2) Myth--Unusually high demand growth
   Reality--Demand Growth from 1998 to 1999, approximately 4%
   Demand Growth from 1999--2000 approximately 4%
   1990 California Energy Commission forecast of 2000 demand is greater than actual demand in 2000

3) Myth--Unexpected Energy Shortage in California
   In-state hydro production in 2000 approximately equal to in-state hydro production in 1999
   In-state fossil-fuel production in 2000 significantly greater than instate fossil-fuel production in 1999

Myth and Reality in California Electricity Crisis

4) Myth--California's demand grew much faster than rest of west
   Reality--Growth in population over decade of 1990's much higher in surrounding states
   NV-50%, AZ-30%, UT-24%, CO-23%, ID-24%,WA-18%
   CA-13%

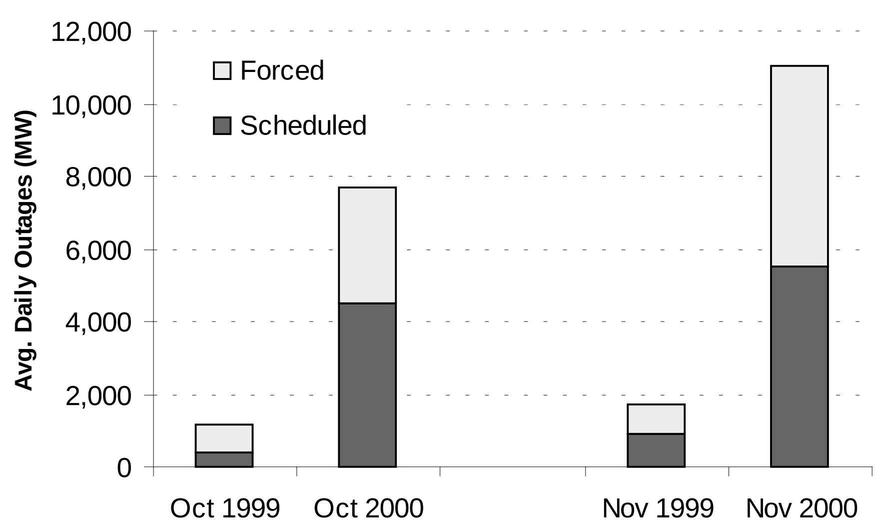
5) Myth--California's didn't re-structure enough
   Reality--Measured by any metric California re-structured more than any market in US
   All other ISOs formed out of tight power pools
   Little forced divestiture of capacity by incumbent IOUs
   Little dependence on imports to meet in-control area demand
   CA consolidated three control areas--PG&E, SCE, and SDG&E
   CA forced divestiture of 17,000 MW of IOU capacity
   CA historically gets approximately 25% of load from imports

Myth and Reality in California Electricity Crisis

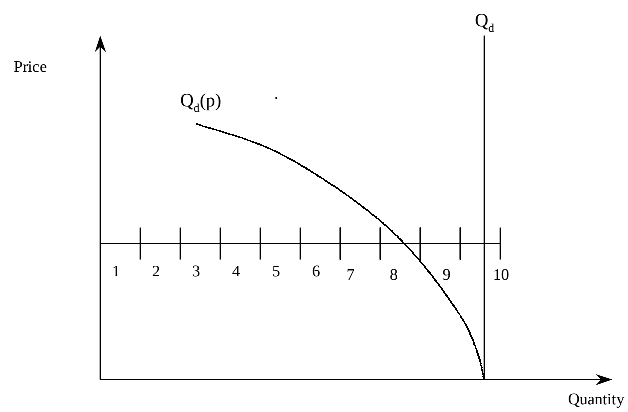
6) Myth--Fossil units were run harder than they have been run
Reality--Unit level load factors for many units during the summer months of 2000 were significantly less than 50%
Relative to 1994, last year of low hydro conditions in west, best available data reveals less output from in-state fossil units in 2000 than in 1994

7) Myth--Rolling blackouts in California in January and March of 2001 caused by capacity shortage in California
Reality--Daily peak demand in January and March is approximately 30,000 and total in-state capacity is 45,000 MW

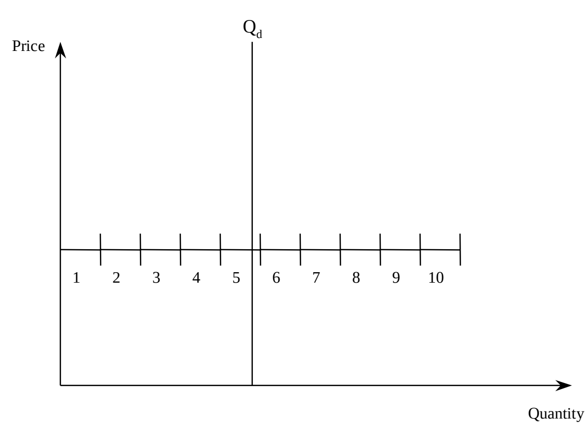
Reported Capacity Outages (1999 vs. 2000)



Market Power Problems without Price-Responsive Demand



Significant Excess Capacity Can Solve These Problems



Regulatory Factors Causing to Current Problems at State Level

1) Lack of forward financial contracting for between loads and generation in California

a) Virtually all energy purchased on spot market
b) IOUs own capacity to provide less than half of their wholesale energy needs
c) Surrounding areas purchase less than 5% of their wholesale energy needs from spot market

2) A 1 percent increase in spot electricity price increases California wholesale energy costs by more than 10 times more than wholesale energy costs in surrounding areas

Forward Contracting Restrictions

- Different from all other re-structuring processing around the world and in US
  - California did not assign vesting contracts to units sold
- Vesting contract is an obligation to sell a significant fraction of a unit's output at regulated price for at least two years
  - For a 500 MW unit, typical vesting contract would require selling 400 MW every hour for two years for a pre-specified price or pattern of price
- Provides wholesale price certainty for load-serving entities
  - Regulator can credibly set a fixed retail price

Forward Contracting Restrictions

- Forward contracting by UDCs outside of PX markets not guaranteed cost-recovery by CPUC
  - Must get CPUC approval of contract terms
- Severely limits ability of UDCs to manage wholesale price risk
- Competitive market requires buyer(s) motivated and able to take all available actions to keep wholesale prices down
  - Monopoly retailer has little incentive to keep wholesale prices down--wholesale price is cost of doing business
  - Competitive retail market--Each retailer wants low wholesale price to attract customers away from other retailers

Regulatory Factors Causing to Current Problems at Federal Level

- FERC regulates wholesale electricity rates
  - Federal Power Act requires FERC to
    - Ensure the wholesale rates are just and reasonable
    - If they are not, take action to make them just and reasonable
  - "Whenever the Commission, after a hearing had up its own motion or upon complaint, shall find that any rate, charge, or classification, demand, observed, charged or collected by any public utility for transmission or sale subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affected such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification rule, rule, regulation, practice or contract to be thereafter observed and in force, and shall fix the same by order." (Federal Power Act)
    - Order refunds for rates in excess of just and reasonable levels
- Just and reasonable rates recover production costs, including a return to capital

Regulatory Factors Causing to Current Problems at Federal Level

- How does FERC introduce wholesale competition?
  - Competitive market yields prices reflective of production costs
  - If market participant can demonstrate that it cannot influence market price (cannot exercise market power)
    - FERC will deem participant eligible to receive market-based rates
    - All firms start out with cost-based rates set by FERC
  - All California market participants had to make market-based rate filing approved by FERC
    - Demonstrate that they have no ability to exercise market power
    - FERC makes determination of validity of this claim
    - Extremely difficult to determine if market is competitive on ex ante basis

Regulatory Factors Causing to Current Problems Federal Level

- Events of past six months demonstrate that FERC's logic for allowing market-based rates is false
  - Under Federal Power Act FERC has power to take corrective action
- FERC's November 1, 2000 preliminary order and December 15, 2000 final order states that
  - Wholesale rates in California are "unjust and unreasonable"
  - Reflect the "exercise of significant market power"
- Since August 1998 FERC's response to problems in market
  - Hard price caps on wholesale prices in CA through December 2000
    - California is net importer buying in entire western states market
    - Willingness of California to pay whatever it takes to importers to keep the lights on caused enormous reliability problems--megawatt laundering
    - Price caps eliminate incentives to engage in forward contracts
    - Price caps eliminate incentives to develop price responsive retail demand

Regulatory Problems at Federal Level

- In early December 2000, FERC imposed soft price-cap
  - How does FERC-imposed soft cap at $150/MWh work?
    - If generator can cost-justify bid above price cap and it is needed to meet demand then market participant is paid as bid
- How soft cap allows generators to increase profits
  - Merchant producers are significant players in gas market
    - Own long-term gas supply for at least half their annual needs
  - Put long-term gas deliveries into storage in California
  - Buy gas on California spot market to burn in generating facility
    - Send bill for spot gas to FERC to cost-justify high bid for electricity
  - Can work a deal with own gas affiliate (or non-affiliate with a rebate) for even higher gas price on invoice
  - Creates artificial scarcity of gas in California
    - Explains unprecedented difference between California and Henry Hub in Louisiana spot natural gas prices
      - Pre-soft cap average daily difference in prices is less than $0.50/MMBTU
      - Post-soft cap average daily difference in prices is greater than $7/MMBTU

Without Federal Regulation Problems May Get Far Worse

- January daily peak demand is 30,000 MW
  - California has experienced rolling blackouts due to available generation inadequacy several times in early January 2001
  - Since late December 2000 until March 2001, California ISO has declared Stage 3 system emergency almost daily
    - Stage 3 emergency--operating reserves less than 1.5 % of system load
- Water levels for hydro facilities in rest of Northwest far below normal for this time of year
  - Many hydro facilities in California and Northwest have operated beyond normal rates to meet current shortfalls throughout west
- Summer daily peak demand can be as high as 45,000 MW
  - Average peak in July 2000 was around 40,000 MW
- Rolling blackouts extremely likely during many hours
  - Unknown how frequent they will be and how long they will last
  - Lost economic output to state and national economy could be enormous

Solutions to current problem at Federal Level

FERC-mandated vesting contracts for all California market participants

- To receive market-based rates, require all California market participants to offer vesting contracts at
  - Price set by FERC to be just and reasonable
  - For 75% of their expected sales to California for next two years
  - December 1, 2000 Market Surveillance Committee (MSC) Report outlines procedure to determine just and reasonable contract price and allocate contract quantities to market participants
  - February 6, 2001 MSC Report provides sample contract prices to demonstrate feasibility of approach

Those that do not offer contracts receive cost-based rates for all sales going forward--lose market-based pricing authority

Puts California in similar long-term contract position to surrounding states

Solutions to current problem at Federal Level

Given its position as large importer and tight supply and demand conditions in western US

- Do not impose price cap or bid caps on spot market in California
- Only way that California can attract imports is through high spot prices

Regional price caps may leave California without sufficient power during the summer of 2001

- Cannot require out-of-state generators to sell into California
- Recall non-verifiable forced outage problem

Impose availability standards on all instate generators in California market that requires them to bear all forced outage risk

- Except for pre-agreed (with ISO) planned outage hours, all generators must make full capacity of all units available to market in all hours
- Generation unit owners must manage forced outage risk with energy bids and energy purchases from other suppliers

State Level Solution to California Crisis

Real-time pricing for all customers as soon as possible

All customers have opportunity to reduce energy bill if they respond to prices
- No need to consume less energy, could consume more
- Example: Two periods, two prices: $10/MWh and $100/MWh
- Consumer purchases 1/2 MWh in each period
- Total bill is $55
- Consumer shifts 1/4 MWh from high price to low price period
- Total bill becomes $32.50

Suppose consumer is currently paying $20/MWh
- Pay this consumer $15/month for taking on real-time price risk
- If price-responsive, then bill is $17.50 = $32.50 - $15.00
- If not price-responsive, then bill is $40.00 = $55 - $15.00

State Level Solution to California Crisis

Real-time pricing creates win-win situation
- California taxpayers pay less for electricity
- California consumers pay less for electricity

Consider example from previous slide

Without real-time pricing
- Consumer pays $20
- California taxpayers pay $35 = $55 - $20 = Wholesale energy purchases - revenues collected from consumer

With real-time pricing
- Consumer pays $17.50
- California taxpayers pays $15 to consumer to take on real-time price risk.

Saving to California taxpayers and ratepayers = $22.50
- Ratepayers Save $2.50
- Taxpayers Save $20.00

Why Real-Time Pricing Is Necessary

Potential for “California problem” exists for any state that sets fixed default provider rate at retail level and has an unexpected wholesale price increase

Safe to assume that retail revenues plus payments by State government must equal wholesale purchase costs

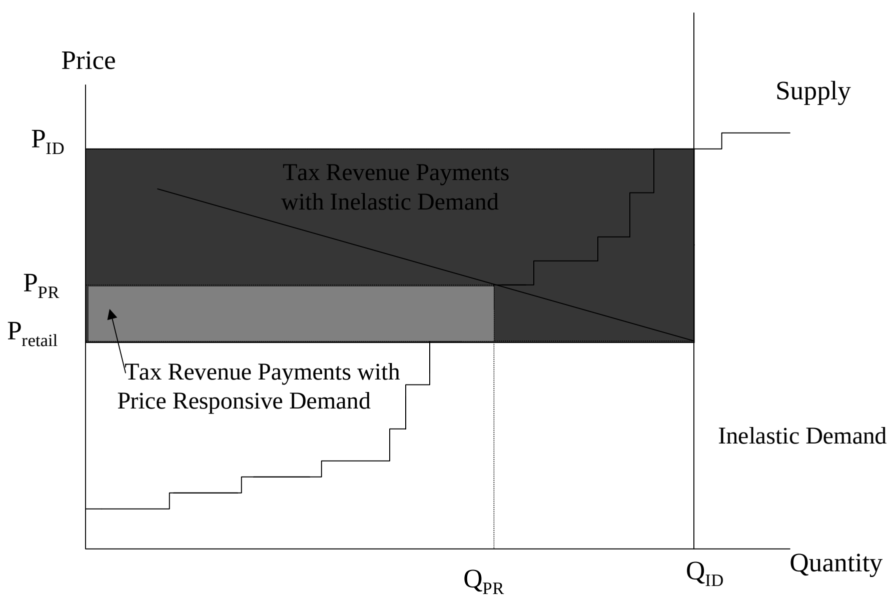
Two groups pay for wholesale purchases

- State taxpayers
- State ratepayers
- Virtually every State resident is member of both groups

Without real-time pricing, even with single State buyer there still no price elasticity in real-time aggregate demand and high spot price remains

- Increased tax revenues must be collected fromcitizens
- No way for taxpayer to avoid paying higher wholesale price for power
- State’s taxpayers pay large blue box on next slide
- Real-pricing allows customers to reduce the amount they pay as taxpayer and rate-payer (green box on next slide)

Real-Time Pricing versus Tax Revenue Financing



State Level Solution to California Crisis

- Real-time pricing
  - Mandatory for all large customers as soon as possible
  - Each customer class paid to take on real time price risk
    - Area of small box
  - Different monthly payments for different customer classes designed to provide each customer with the opportunity to reduce their bill by being price-responsive
  - Offer residential and small business customers the choice of real-time price risk and associated monthly payment or guaranteed retail rate increase at fixed rate

Real-Time Pricing

- With significant amount of load facing real-time prices, retailer can exercise monopsony power
  - Use price responsiveness of customers on real-time pricing contract to limit demand in certain hours
  - Bid demand into wholesale market in anticipation of this price responsiveness to minimize wholesale purchase costs
- This strategy has potential to save California billions of dollars in wholesale energy costs over next two years
  - Necessary condition is real-time pricing for as many megawatts as possible--at least all customers with above 200 kw peak demand

Real-Time Pricing Allows Retailers to Obtain Lower Forward Contract Prices

Generators will recognize that effects shown on previous slides will operate to reduce spot prices and demand, particularly during high load periods

- This implies that spot market prices will be lower in future than they would be in the absence of significant real-time pricing
- The lower future spot prices that will result from a significant commitment to real-time pricing will create a lower opportunity cost to a generator signing a forward contract
- Consequently, generators will be more likely to sign forward contracts at lower prices than they would in the absence of a large commitment to real-time pricing

Immediate benefits to consumers to reducing market power in spot and forward markets from real-time pricing

- Only losers from real-time pricing are generators

Real-Time Pricing not Time-of-Use Pricing

- Consumers must pay hourly wholesale price in hourly retail rate
- Time-of-use pricing creates the same basic incentives as fixed-rate billing scheme--two fixed prices instead of one
- Time-of-use pricing may not yield lower average spot electricity prices or increase incentives for generators to sign low-priced forward contracts
- Time-of-use pricing creates similar incentives to those from load-profile billing

Load-Profile Billing

- Measure total monthly consumption of electricity
- Representative load shape used to compute weighted-average energy price for month
  - p(h,d) = price for hour h of day d,
  - w(h,d) = weigh for hour h of day d, $\sum_{h,d} w(h,d) = 1$
  - Monthly bill = (monthly consumption) x (monthly weighted-average energy price). $\sum_{h,d} w(h,d)\,p(h,d) = p$
- Demand reduction when hourly energy price is $0/MWh leads to same monthly savings as same demand reduction when hourly price is $250/MWh.
- Want consumer to realize maximum benefit from reducing consumption when wholesale price is highest
  - Imagine difficulty in running competitive long-distance telephone company only measuring minutes of phone use per month

Robust Retail Competition Requires Real-Time Metering

- Without real-time metering, competition takes place on one dimension
  - Monthly average price
- Recall that conventional meters only measure total monthly consumption of electricity
- Firms have no idea who in a given customer class is more expensive to serve in terms of wholesale energy costs
- No surprise there is little retail competition
- With real-time meters competition can take place on
  - (hours of the 24)*(Days of the Month), p(h,d) = price for hour h of day d
  - May not need all of these dimensions, but with widespread real-time metering there will be robust retail competition
- Recall dimensions that service measurement in telephony

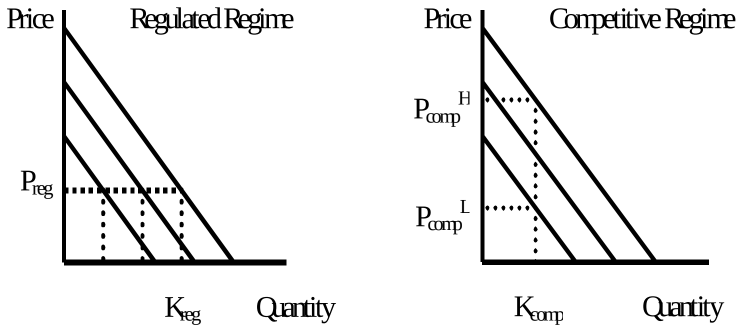
Limited Benefits of Restructuring Without Involving Demand

- US has privately-owned, profit-maximizing firms facing cost-of-service price regulation or incentive regulation plan
  - Detailed prudence review of investment
  - Hard to argue there are large deviations from minimum cost production
  - Vertically integrated ownership and centralized dispatch should be able to improve on bid-based dispatch on true production cost basis

Markets use prices to allocate scarce resources

- Competitive market should be able to get by with lower level of capacity and serve same customers
  - This implies lower capacity costs for market at large
  - If dispatch costs are close to the same, then average price in competitive market should be less than average price in regulated market
- A necessary condition for this to occur is a sufficient number of price-responsive consumers

Optimal Capacity Choice Under Regulation versus Competition



$K_{reg} >> K_{comp}$

Example--US Airline Industry

- Load Factors = (Seats Filled)/(Seats Total),
  - In regulated regime highest load factors approximately 55% in 1976
  - Currently Load Factors are close to 73%
- This increased capacity utilization rate allows real average fare per passenger-mile to be significantly less than under regulated regime
- Regime works because of large number of sophisticated price-responsive consumers.