South Asian Energy Officials

California's Electricity Restructuring
August 1, 2006

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Energy Commission Role

- Permitting new thermal generation of 50+ MW, expansions
- Developing building, appliance standards
- Energy efficiency program evaluation, technical assistance
- Fund energy-related research
- Evaluation of market conditions, long-run forecasting

Energy Action Plan

- Multi-agency Plan (Energy Commission, Public Utilities Commission, Power Authority, etc)
- Enacted in 2003 and established the state's preferred Resource "Loading Order"
- Has been integrated into the major decisions governing energy policy and procurement.
- Resources prioritized as follows:

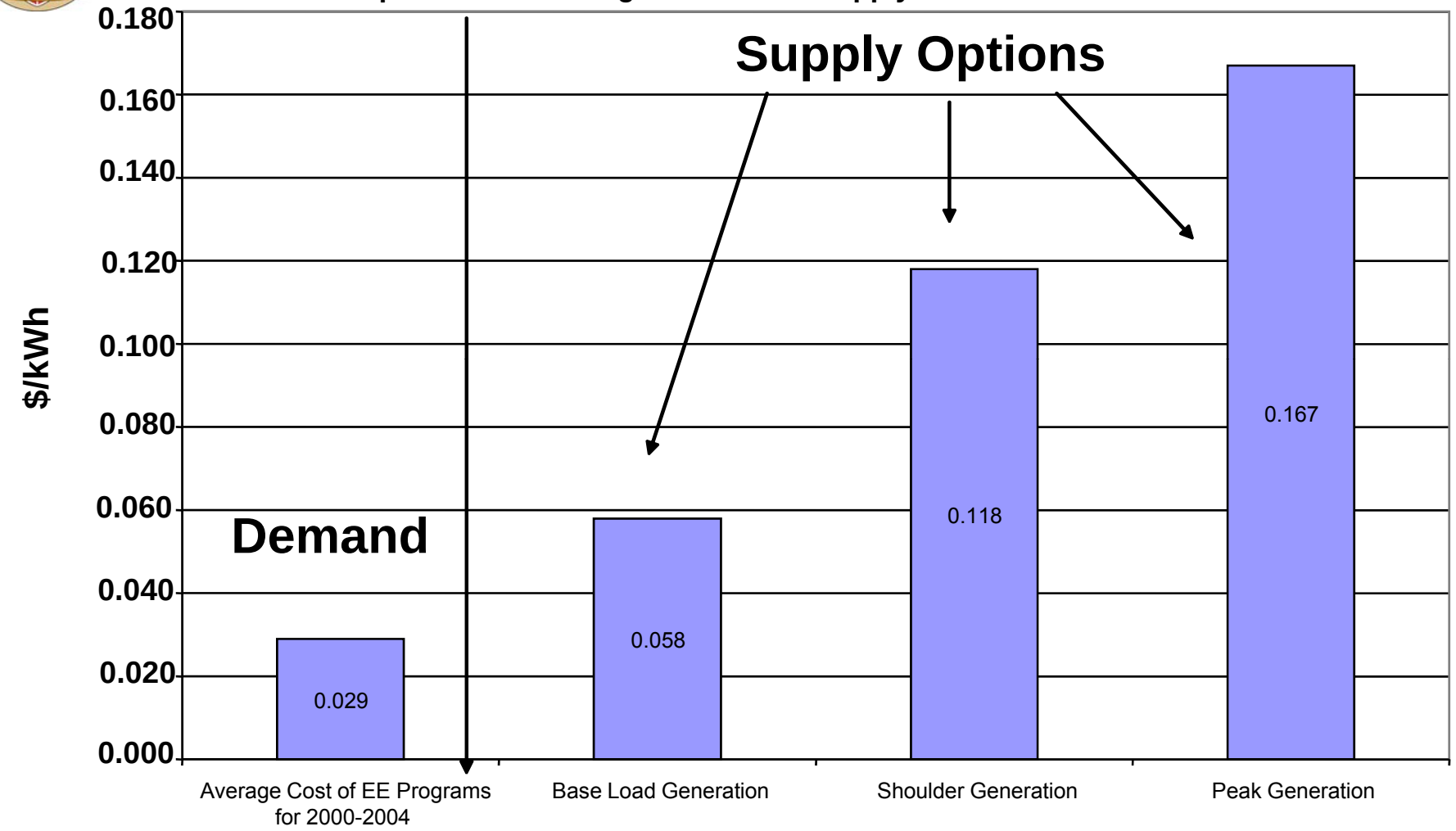
  1. Energy Efficiency/Demand Response

  2. Renewable Generation, including renewable DG

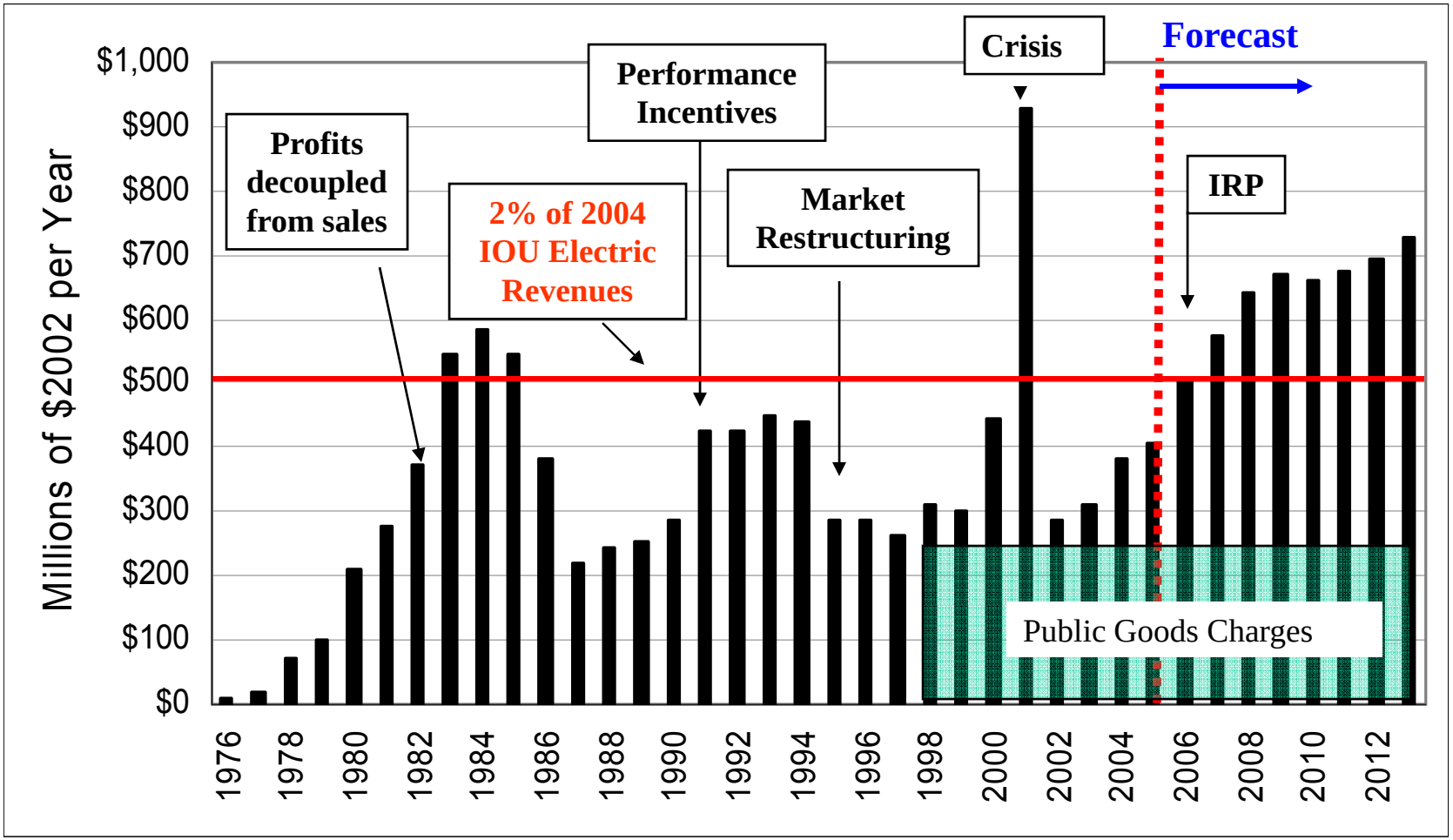
  3. Increased development of affordable & reliable conventional generation

  4. Transmission expansion to support all of California's energy goals.

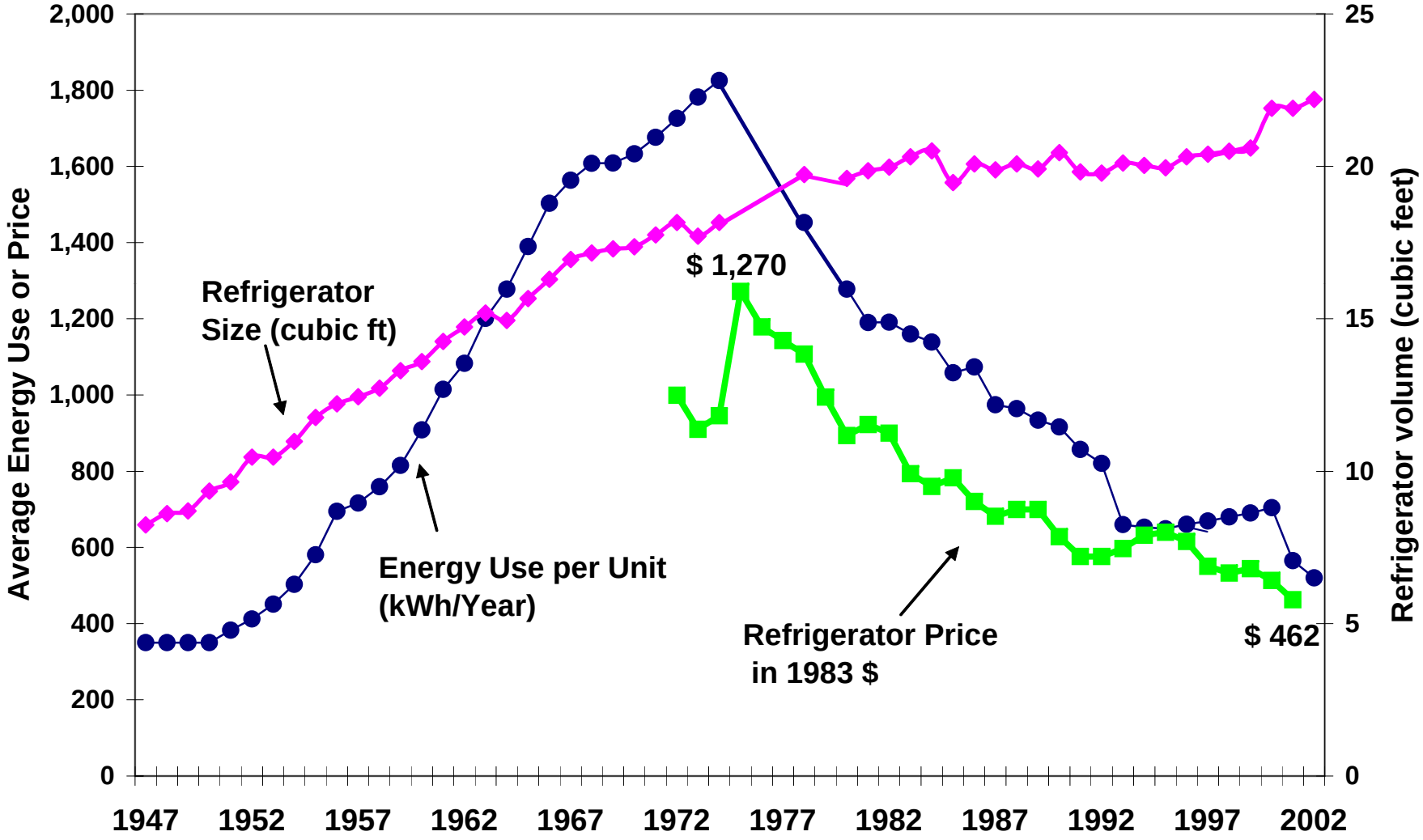
Figure 8
Comparison of EE Program Costs to Supply Generation Costs



California IOU's Investment in Energy Efficiency

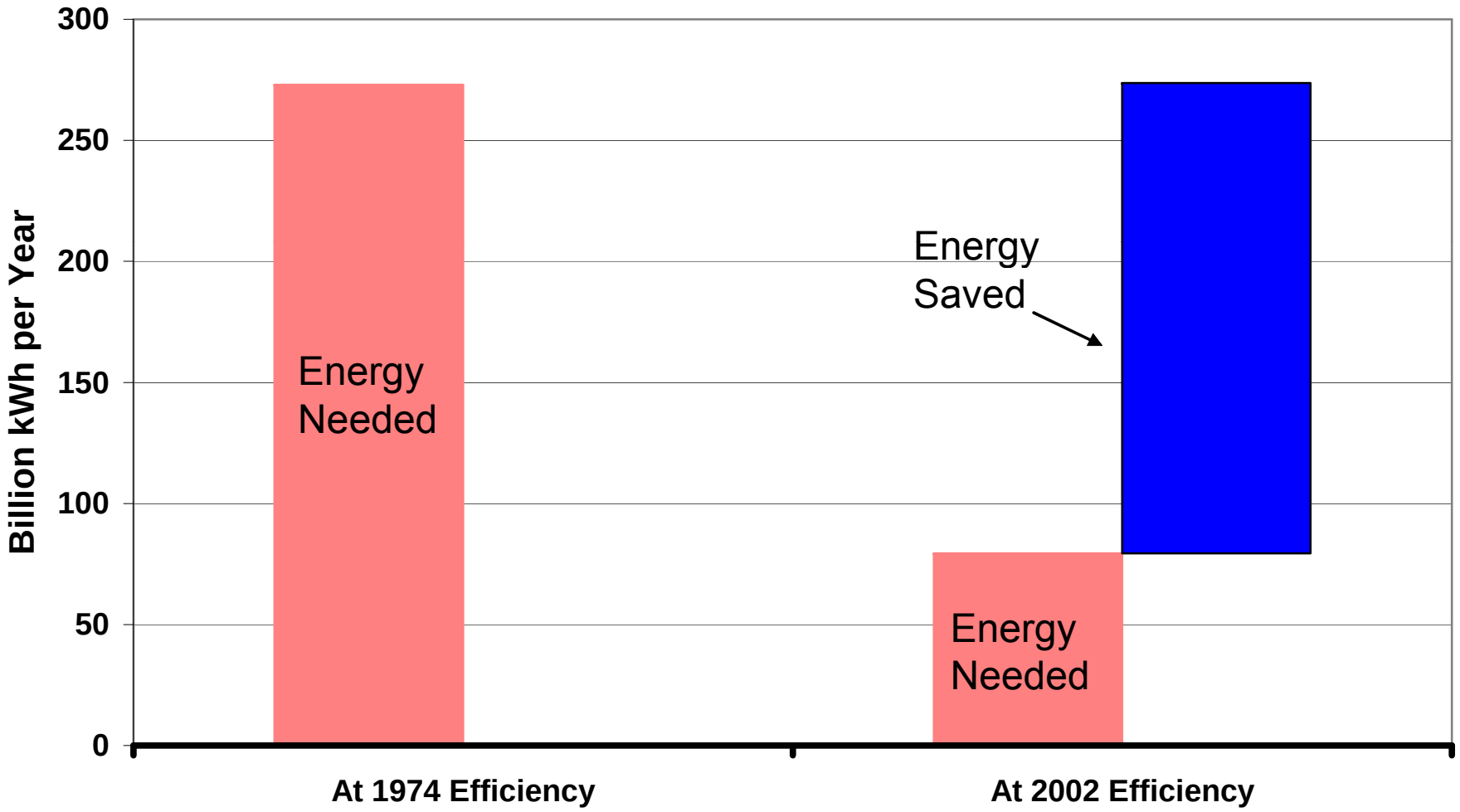


New United States Refrigerator Use v. Time and Retail Prices

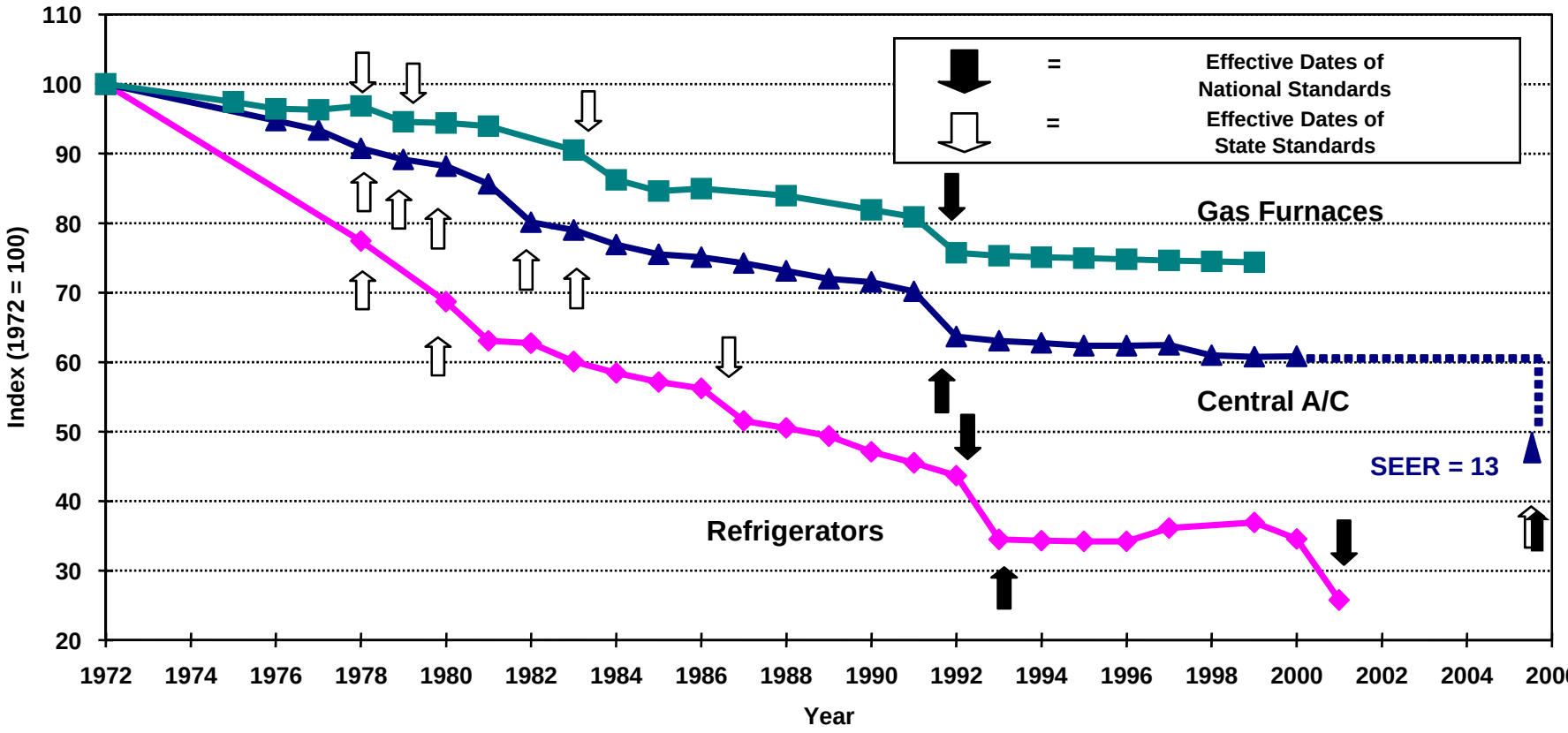


Source: David Goldstein

New Refrigerator Energy Use: 71% will be saved when stock completely turns over to 2001 Standards



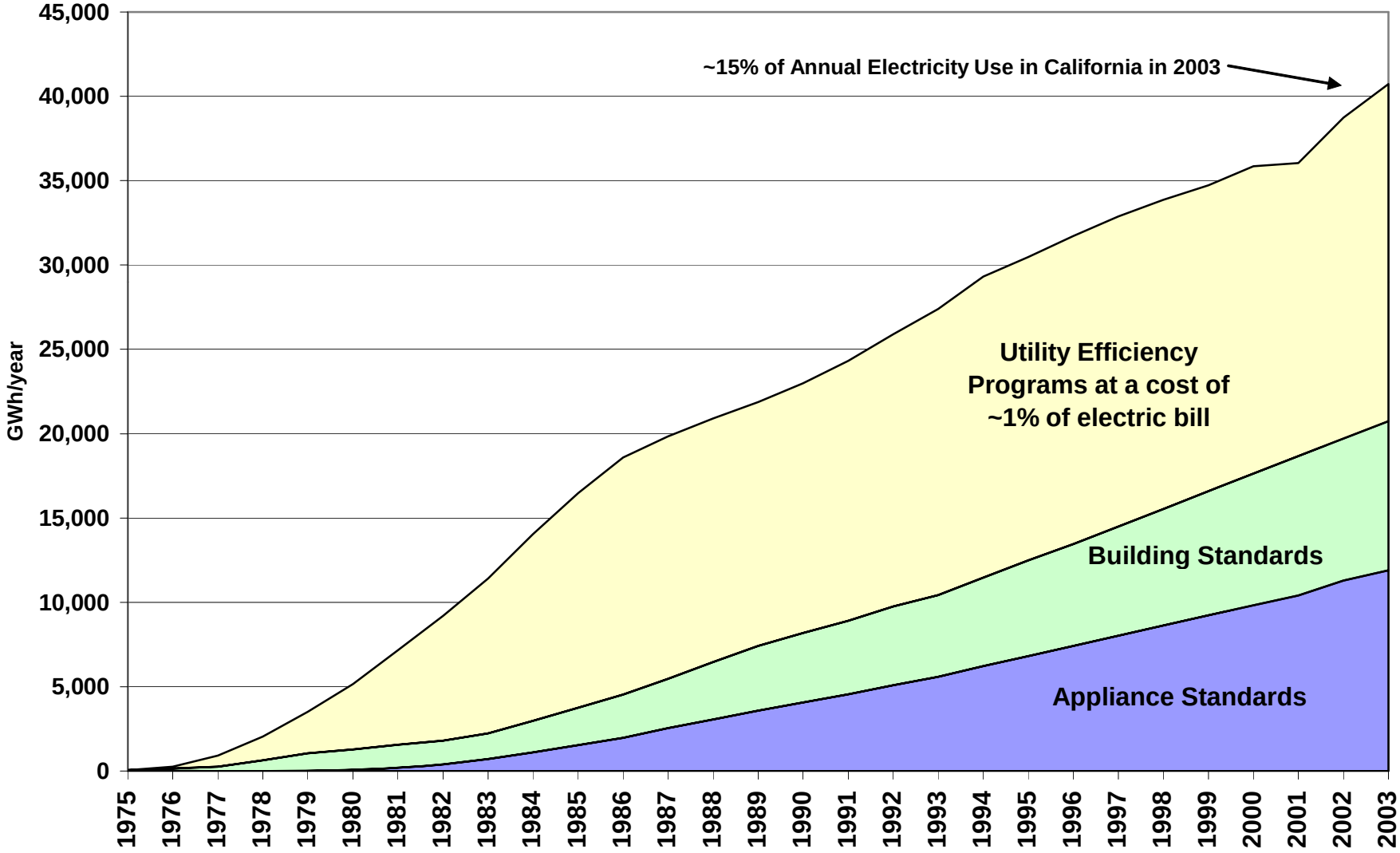
Impact of Standards on Efficiency of 3 Appliances



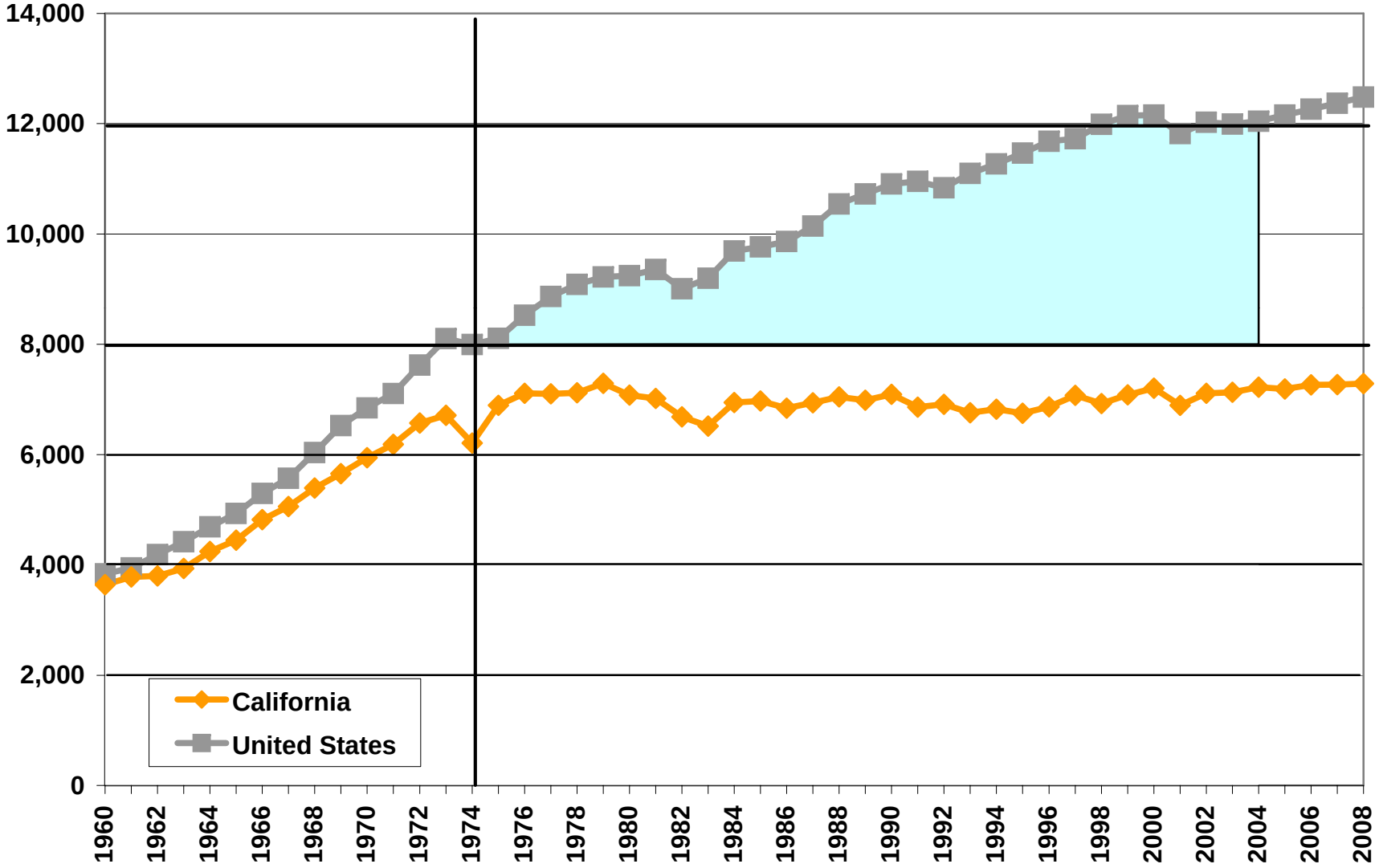
Source: S. Nadel, ACEEE,

in ECEEE 2003 Summer Study, www.eceee.org

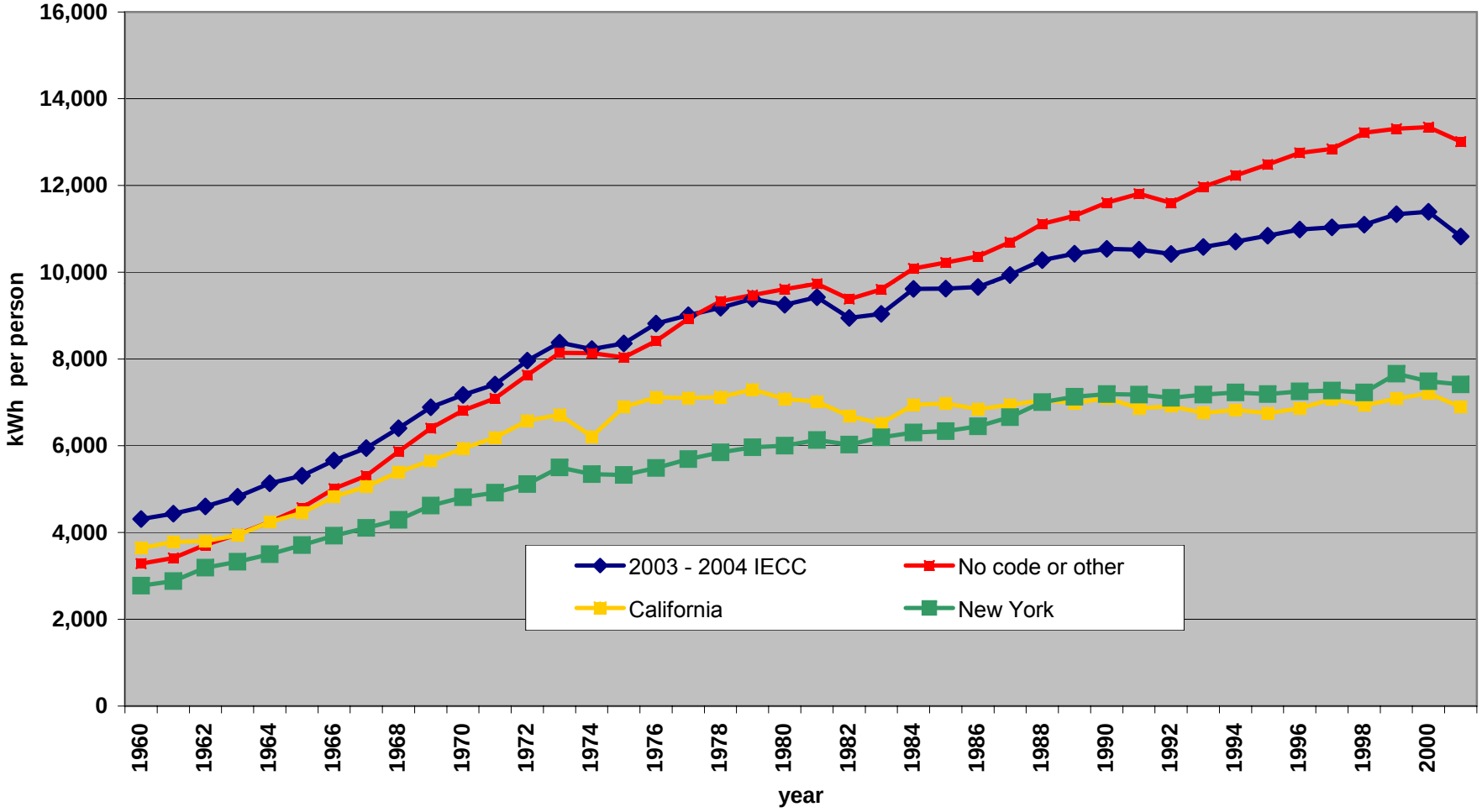
Annual Energy Savings from Efficiency Programs and Standards



Per Capita Electricity Sales (not including self-generation) (kWh/person) (2005 to 2008 are forecast data)

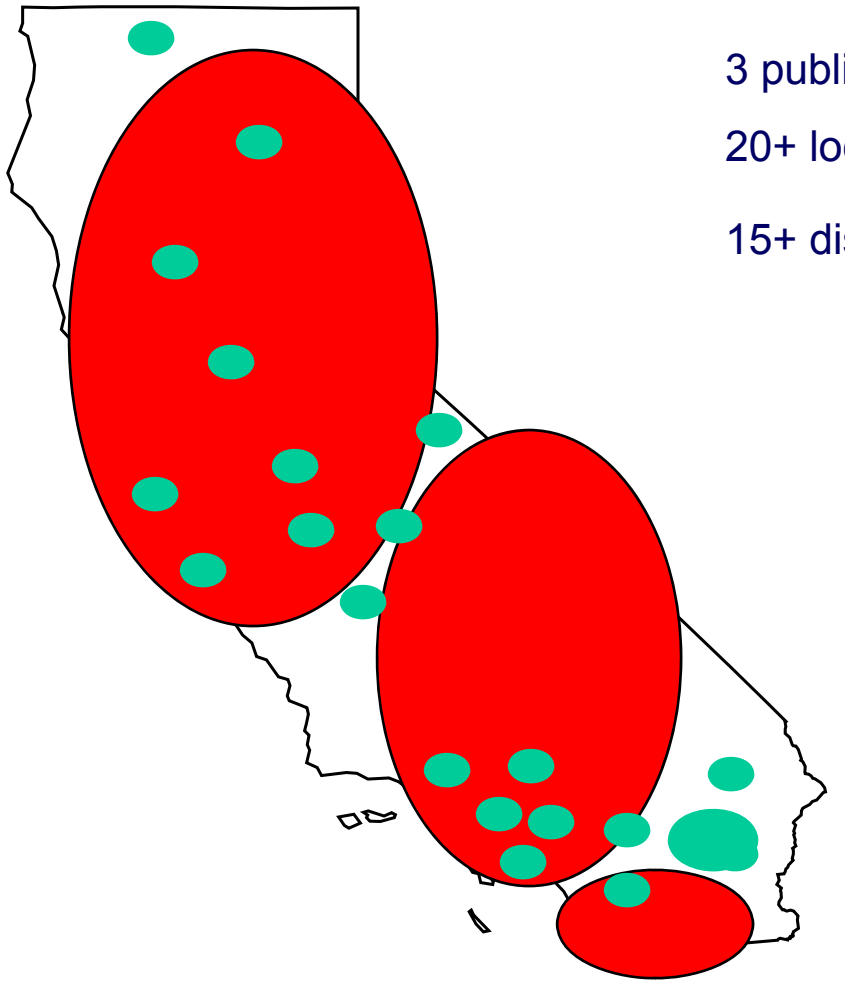


Per Capita Elec Sales Grouped
by Residential State Building Code Status 1960 - 2001



Overview of California System

Distributors

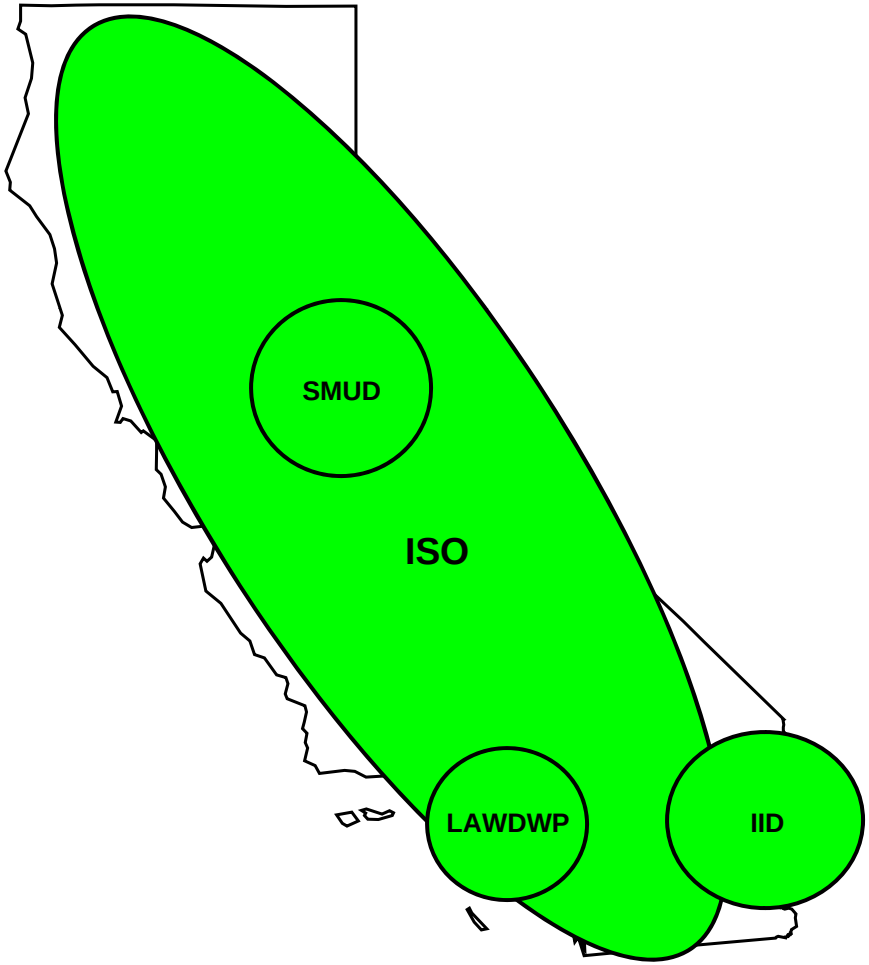


3 publicly traded utilities (IOU): 70%

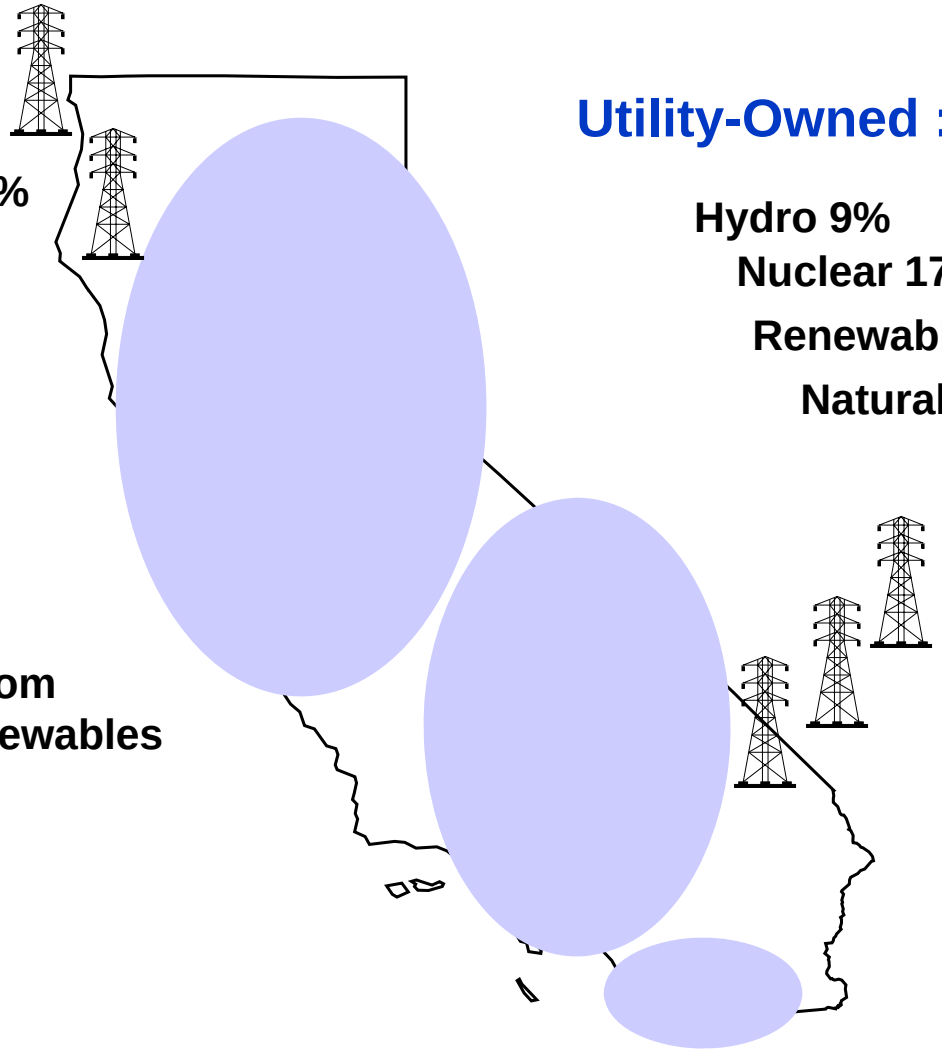
20+ local government utilities: 22-23%

15+ distribution only companies: 7-8%

Control Areas



Sources of Energy - 1996



Hydro Imports 8%

Purchases from Cogenerators/Renewables 25%

Utility-Owned :

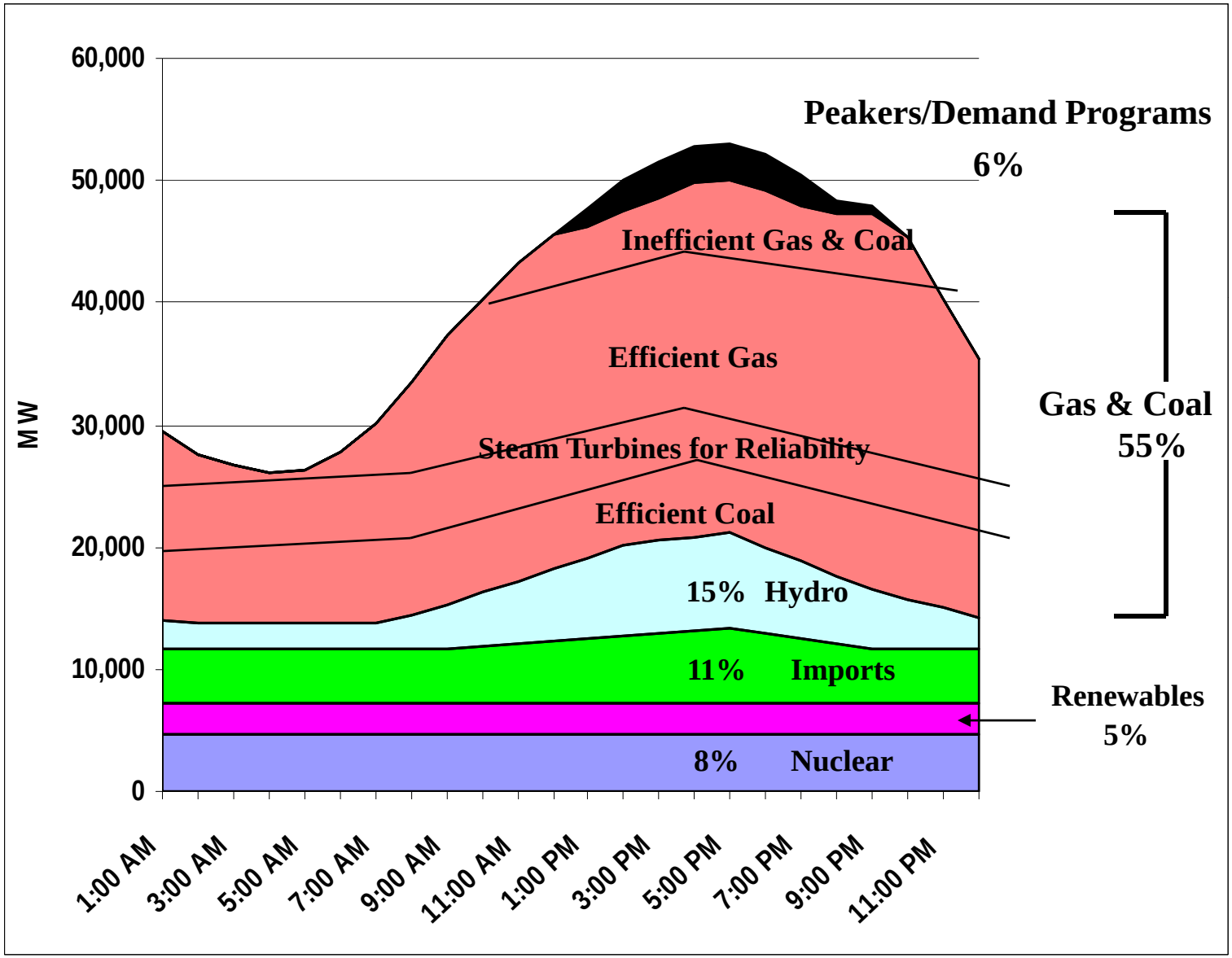
Hydro 9%

Nuclear 17%

Renewables 2%

Natural Gas 32%

Coal Imports 7%


60,000
50,000
40,000
30,000
20,000
10,000
0
MW
1:00 AM
3:00 AM
5:00 AM
7:00 AM
9:00 AM
11:00 AM
1:00 PM
3:00 PM
5:00 PM
7:00 PM
9:00 PM
11:00 PM
Peakers/Demand Programs
6%
Inefficient Gas & Coal
Efficient Gas
Steam Turbines for Reliability
Efficient Coal
15% Hydro
11% Imports
8% Nuclear
Gas & Coal
55%
Renewables
5%

Review of Deregulation and 2000-2001 Crisis

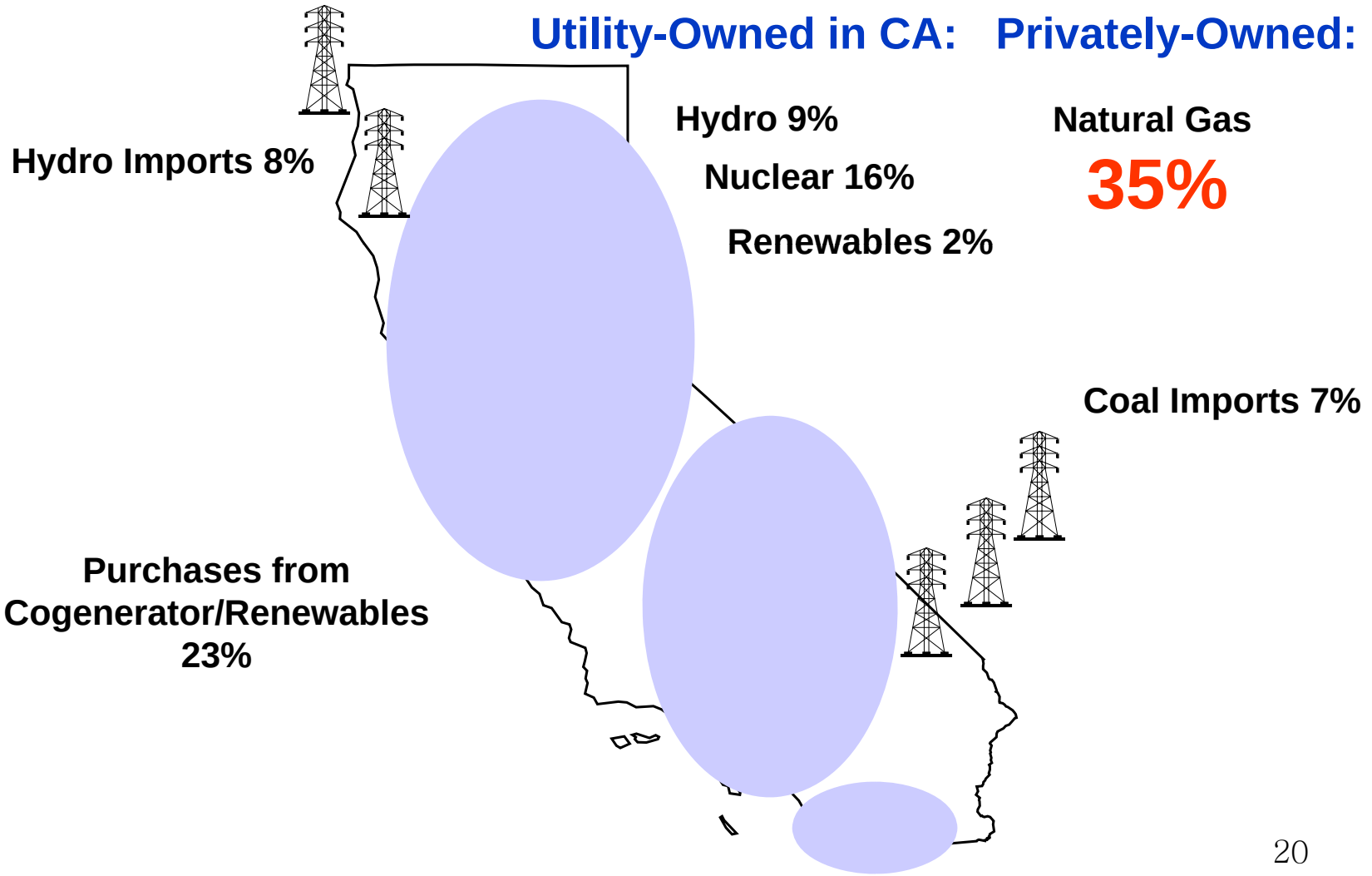
Forces for Deregulation

- 1990-92 economic recession in California
- Pressure from large consumers for rate reduction, desire to attract business to state
- Ascendancy of free-market ideology among state government officials (deregulation → economic efficiency → lower prices)

Key Components of Deregulation

- Fear of (investor-owned) utility market power
  - divestiture of gas-fired assets
    - 50% divestiture required
    - financial incentive to divest remainder (up to 0.5% increase in ROC)
  - control of transmission to independent operator, utilities retain ownership and revenues
  - sale and purchase of all energy in day- and hour ahead spot markets; no forward contracting
- Cost recovery for non-economic assets
- (Large) customers allowed to choose retail suppliers
- Freeze of retail rates charged by utilities

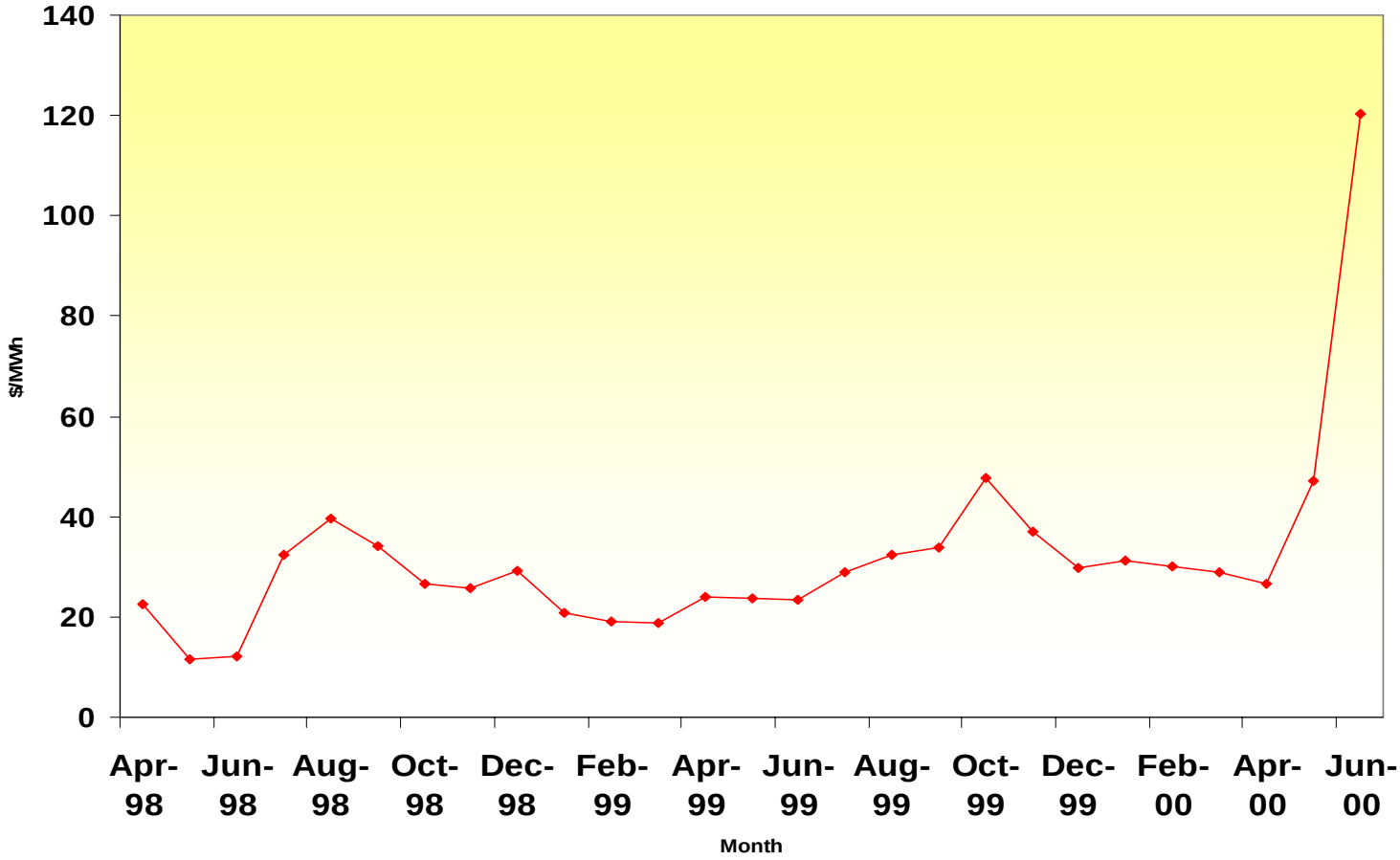
Sources of Energy - 2001



Underlying Assumptions

- Enough supply to meet demand through 2002-3
- Market would provide new capacity in a timely manner
- Wholesale prices would be well below retail rate caps

The Lull Before the Storm

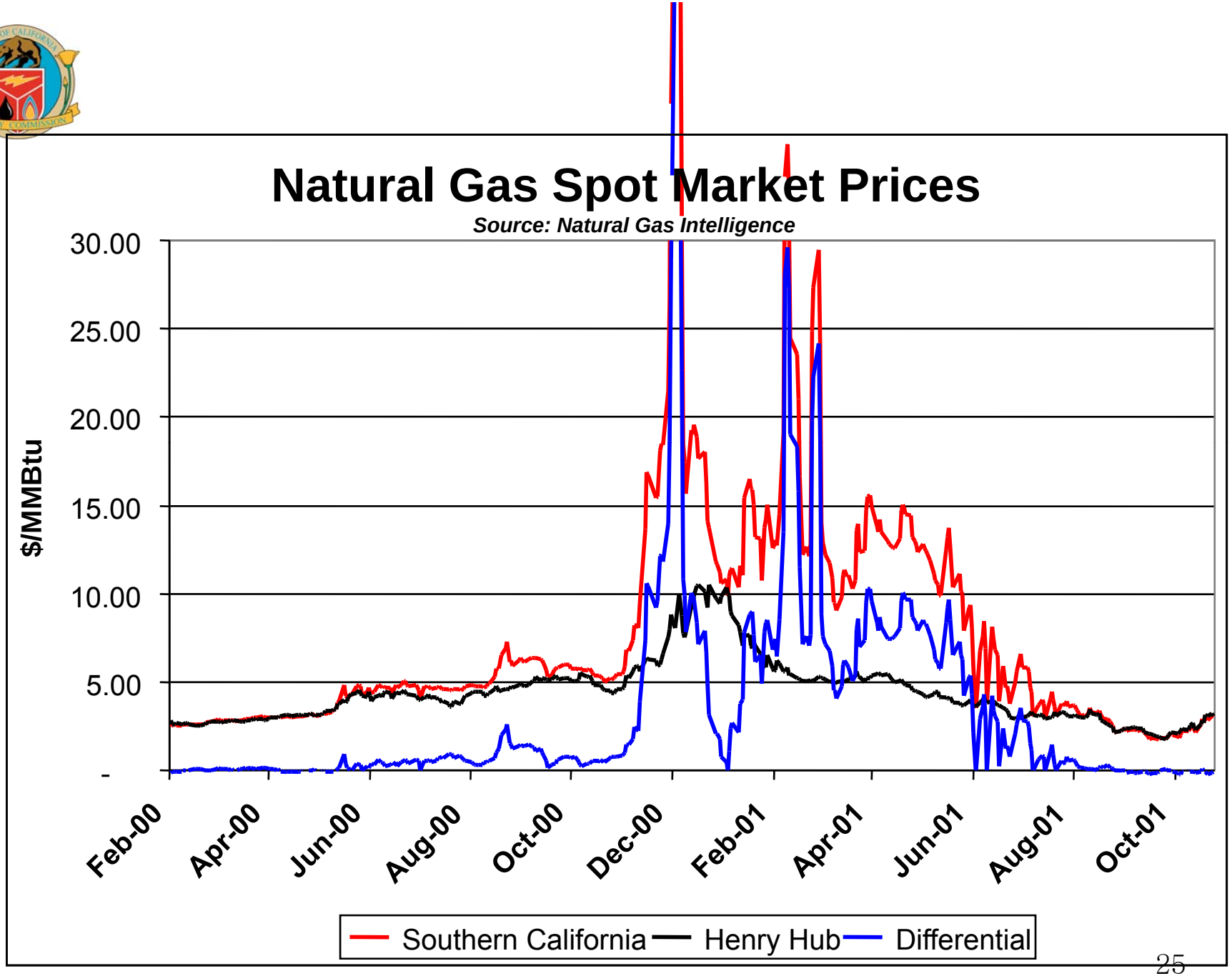


1995 - 1999

- Uncertainty regarding deregulation discouraged the development of new power plants
  - Investor-owned utilities discouraged from construction, no guarantee of cost recovery
  - Merchant developers expected low market prices
- Rapidly growing economy in the late 1990's
- Rapid growth in electricity demand in neighboring states
- Above average hydro conditions in 1995-1999

Crisis

- Summer 2000
  - early summer heat, sudden price jump ($50/MWh → $180+)
  - tight supply-demand balance, economic withholding of capacity in forward markets
- Winter 2000-2001
  - Prices to $290/MWh, electricity and gas prices in “death spiral”
  - Financial crisis
    - largest utility declares bankruptcy, others cannot meet payment obligations
    - generators refuse to sell to utilities
  - Rotating outages


Natural Gas Spot Market Prices
Source: Natural Gas Intelligence
$/MMBtu
30.00
25.00
20.00
15.00
10.00
5.00
-
Feb-00
Apr-00
Jun-00
Aug-00
Oct-00
Dec-00
Feb-01
Apr-01
Jun-01
Aug-01
Oct-01
Southern California
Henry Hub
Differential

Response

- (Small) rate increases in January 2001
- Long term contracts for large share of IOU needs
  - negotiated, backed by state government
  - Well above market prices (at “normal” gas prices)
- Conservation (8% - 14%)
- Federal intervention
  - Non-hydro plants must offer power into market at prices reflecting cost of generation
- Retail competition “frozen”
- Prices return to normal in June 2001

2001 - 2004

- 10,500 MW of new capacity constructed, mostly gas-fired baseload
  - Excess construction affects overly leveraged developers
- Energy contracts, must-offer order, price ceilings depress spot market prices, leading to threats of retirements of aging plants
- No new plants built on speculation by private developers after 2003, long-term contracts required due to risk

2001 - 2004

- Biennial procurement process for investor-owned utilities established in 2002 by regulators
  - demand forecast, existing resources, future energy and capacity needs estimated (procurement plan)
  - approval of plan provides permission, *but not obligation* to procure under long-term contracts
  - approval does not distinguish between existing and new generation resources
- Actual procurement is through annual competitive solicitations

Problems with Procurement thru 2004

- Investor-owned utilities reluctant to sign long-term contracts
  - Uncertain load obligations due to potential competition in distribution, no guarantee of cost recovery
  - Capacity payments in long-term contracts treated as debt by market, raise cost of capital
  - Must offer requirement lowers cost of relying on spot market
  - Utility need is primarily for capacity, not energy; existing plants are a cheaper source of capacity

Local Reliability

- 8,000 MW of aging plants are on line due to local reliability contracts, needed in transmission constrained areas
  - one year contracts administered by transmission operator
  - pay a share (sometimes all) of going forward capital costs and fuel costs in exchange for availability
- Additional costs of meeting demand due to transmission constraints are paid by utility, providing an incentive to upgrade the transmission grid

Resource Adequacy Requirements

- In 2006, regulators require distributors to contract with capacity equal to
  - 103.5% of forecasted summer peak demand by September 30th of prior year
  - 115% of forecasted monthly peak 30 days prior to start of month
- Capacity must be located so as to ensure reliable service given transmission constraints

Requirements for New Capacity

- In 2006, regulators require two largest investor-owned utilities to procure 3700 MW of new resources under ownership or long-term contract
  - half by 2009, remainder by 2010
  - costs socialized, include distribution-only entities
  - energy from resources will be auctioned off, details uncertain

Long Term Issues

Planning Under Traditional Regulation

- Regulators, utilities agreed upon
  - Long-term peak demand forecast (capacity need), consumption (energy need)
  - Operating costs of existing power plants, fuel costs
  - Construction, operating, and environmental costs of new plants
  - Availability of cost-effective energy efficiency
  - Availability of power from QFs, neighboring utilities
- As a result, agreement was reached upon power plant additions and retirements needed to meet peak demand (capacity requirements) at least cost.

Planning Today

- Looks suspiciously similar to traditional planning, but
  - Merchant component of generation a random variable; given high resource adequacy requirements, spot market prices will never be high enough to provide incentives for new generation
  - Rules regarding retail competition need to be set in order to facilitate least (low?) cost planning
  - Deintegration of generation and transmission makes it difficult to optimize resource development; not certain that locational marginal pricing will provide effective signals
  - Transmission operator a conservative actor that undervalues factors other than reliability

Current Market Structure

Who is involved?

In the California ISO controlled area

- Electricity provided by: generators, marketers, utility retained generation, importers from out of ISO area
- California ISO that controls transmission grid, central clearing house for schedules, area control operator
- Utilities that control distribution grid
- Entities that sell electricity to customers
  - Electric utilities, “direct-access” providers (~12% of ISO load and almost all large industrial and commercial accounts)

In Municipal Utility Areas (e.g SMUD)

- Traditional, vertically integrated utility that control generation, transmission and sales
  - Considerable transactions at the wholesale level (imports, etc.)

Role of the California ISO

- Does many things!!
- A not-for-profit California corporation with a board of directors
  - Initially selected by participants, later by the Governor of California (in response to electricity crisis)
- With about 600 employees and a budget of $250 million per year
- Responsible for day-to-day operation of most of the California high voltage electricity grid (>230 kV) – later we'll try to follow a day of ISO operation
- Along with transmission owners, plans for transmission line expansion (either for economic or reliability needs)
- Determines and contracts with generating units needed for local area reliability in areas that are not considered "competitive"
- Monitors the markets to try to ensure "just and reasonable" rates although this also involves Federal Energy Regulatory Commission
- Coordinates when maintenance may occur on generating units and transmission lines (to some extent)

Role of the California ISO (cont'd)

- Runs markets for
  - Transmission congestion contracts (hedges against transmission congestion charges)
  - Ancillary services (operating reserves, etc.)
  - Energy in "real-time" to balance system supply and demand
  - Adheres to national and regional standards to
    - ensure adequate operating reserves
    - voltages are within acceptable limits on all lines and substations
    - Frequency is maintained
    - Etc.,Etc., Etc.
  - And attempts to do most of this in an open and transparent market structure using bids submitted by market participants (mostly generators, some larger loads)

Role of the Distributors

- Generally, these are the investor-owned utilities who have given up control (but not ownership) of their bulk transmission system
  - Still maintain their own grid
  - Still receive revenues (cost of service based) from end-use customers through charges in retail tariffs and some wholesale transactions (e.g. wheeling through CA.)
- Retained control of their distribution grid (<230 kv)
  - Still manage all aspects of this grid: planning, construction, maintenance, voltage regulation, scheduling, etc.
  - And again, they receive revenues based on cost of service
- Buy and sell electricity and ancillary services
- Now with a forward market capacity obligation through what is know as the Public Utilities Commission Resource Adequacy Requirements (115% to 117% of monthly peak)

Role of Generators

- Various types of generators provide power
  - Generation that utilities still own (nuclear, hydro, coal)
  - Generation that utilities sold off – mostly natural gas fired
  - New merchant generation – mostly natural gas fired
  - Existing contracts with qualifying facilities (cogeneration, wind, geothermal, solar, small hydro, biomass)
  - Imports from other regions either from utilities or merchants or marketers or other arrangements
- Numerous and varied contracts and other types of agreements

Contracts between the various parties

- All arrangements involving the CAISO are governed by the CAISO's filed tariffs.
  - These tariffs are filed with the Federal Energy Regulatory Commission
  - Those firms buying and selling into the CAISO markets pay and are paid according to these tariffs
    - Tariffs included credit worthiness standards (bonds, etc.)
  - Market-based transactions are at times reviewed to ensure that these are "just and reasonable"
    - This can be a nebulous concept, at best
  - Also, price caps have been a standard feature of these markets
    - Have varied, if I recall, from $100/MWH to $1,000/MWH with out of market purchasing going even higher

Contracts (cont'd)

- Bilateral contracts – between buyers and sellers can take many different forms and include many different types of risk management features
- Another class of contracts were between the State of California and sellers
  - Entered into during the electricity crisis to ensure adequate supply to California
- Contracts for "normal" retail service is governed by tariff sheets filed by the investor owned or municipal utilities
  - Investor owned tariffs are reviewed and approved by the California Public Utilities Commission
    - These vary by type of customer
    - Most are not "dynamically priced" – they don't change as a function of wholesale market prices or system conditions

Contracts (cont'd)

- Direct-access contracts
  - Essentially contracts between customers and independent providers of electricity
  - Can be viewed in two parts:
    - Electricity portion is a private contract and the terms and conditions are between the two parties in question
    - Transmission and distribution portion is under the tariff of the distribution utility (and this includes the transmission price, as well)

Some Issues regarding this market structure

- No day-ahead energy market until next year
  - The story of the California Power Exchange
- Day-ahead market is all bi-lateral and “self-scheduled”
- No transparent day-ahead electricity price on a hourly basis
  - Only “over-the-counter” trading of peak and off-peak electricity

Daily Operations

A timeline of CAISO operations leading up to and through an operating day and beyond

- D – 1 month – Forecast of transmission line and other equipment outages
- D – 1 week – Peak load forecast looking a week in advance; estimated available transmission
- D – 2 days – Hourly load forecast for the day after tomorrow; forecast of ancillary service requirements (including regulation up and down; spinning reserve; and non spinning reserve); forecast of transmission line capacities (these change based on various conditions)
- D – 1 day – Markets begin operation early in the morning and close in late morning. Details follow on next slide
- Reference http://oasis.caiso.com for posted information

Day of Operation

- These times are approximate
- 6:00 a.m. – additional up to date forecasts on loads, ancillary services, transmission line conditions, etc.
- 8:00 a.m. – Schedules and bids submitted by scheduling coordinators (scheduling coordinators, SC, register with CAISO and can be utilities, marketers, etc.)
  - Important current features
  1. Each SCs scheduled must be “balanced” (supply = demand). SCs don’t “trade” energy in this market
  2. There is no central, forward energy market
  3. All energy is arranged bi-laterally
  4. Bids are only for ancillary services and congestion management
  5. Lots of self-scheduling by SCs of ancillary services

Day of Operation (cont'd)

- 8:00 a.m. to 10:00 a.m. – CAISO assesses congestion and if "inter-zonal" transmission lines would be congested based on schedules, issues "interim" re-dispatch and ancillary services awards (prices and quantities)
  - Based on SCs "adjustment" bids
  - Congestion "solved"
  - Maintains market separation of SCs – no trades
- If no congestion – market closes
- 10:00 a.m. – SCs can submit revised schedules and bids to try to avoid congestion
- 12:00 a.m. – Second run by CAISO of congestion management and ancillary services markets
- By 3:00 p.m. – Notification of day-ahead final schedules

Day of Operations (cont'd)

- By 3:00 p.m. CAISO notifies SCs of their binding day-ahead schedules for energy and ancillary services
  - Prices are now available for congested transmission lines and ancillary services but not for energy (MWH)
- How markets clear
- Congestion on "inter-zonal" transmission lines
  1. Inter-zonal is between the CAISO three zones and lines outside of CAISO's control area (map)
  2. Adjustments bid submitted by SCs used to alleviate congestion.
  3. Bids clear in increasing order of price
  4. Again market separation is maintained

Transmission congestion example

Initial schedules = 1,100 MW

SC #1 bids to increase generation by 50 MW in the east and decrease by 50 MW in the west at a price of $10/MWH
SC #2 same bid but at $20/MWH
CAISO takes both bids, solves congestion and the price of flows on this line = $20/MWH

Ancillary Services Example

- CAISO must obtain services to support the transmission system and to ensure system reliability
  - To comply with the Western Electricity Coordinating Council's and North American Electricity Reliability Council's reliability requirements (www.wecc.biz and www.nerc.com)
- SCs either bid in or self-schedule to provide the following:
  - Regulation up and Regulation Down
  - Spinning Reserve
  - Non-spinning reserve
- The CAISO clears these markets using a algorithm called "Rational Buyer" (optimization of all products jointly)
- Also buys reactive power and black start capability but not in a market – rather directly from particular power stations

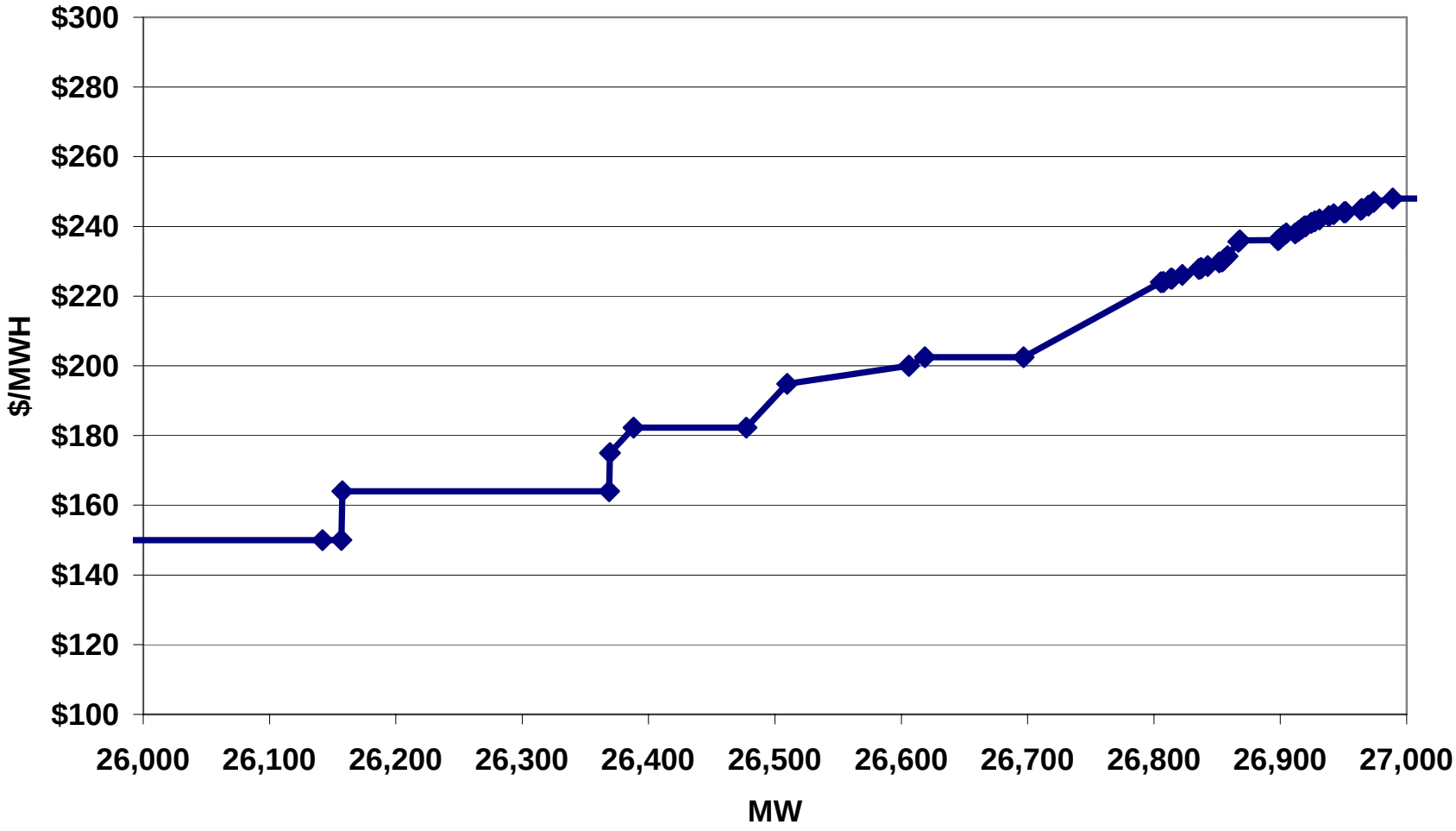
Moving Closer and into Real Time Operation

- Hour ahead market – like the day-ahead
  - Runs 2 – 3 hours before real time
  - Used to adjust day-ahead schedules based on more current forecasts
- Real Time Operation
  - Final Schedules are financially binding and are expected to be met
  - Still, the CAISO must balance its system in real time
  - To do so, it accepts incremental and decremental bids from generation and some load (large water pumps)
  - Places these in merit order and dispatches to meet system needs (example to follow)
- Managing intra-zonal congestion – only done in real time not in forward market

The real time energy market

- Each hour is a separate market
- Within the hour, the CAISO runs a real-time balancing market
  - Bids are submitted and evaluated to ensure
    - Supply = Demand
    - Reserves are adequate
    - Voltages are within limits
    - And many other operating requirements are met
  - Energy prices by zone are posted every 5 minutes and stream along the CAISO web page in real time
  - The next figure provides an illustration of how this work in a conceptual manner

An Example of bids into the real time market



Financial Settlements

- Day-ahead schedules, adjusted by hour-ahead schedules are financially binding
- CAISO settles for energy deviations at the real-time price
- There are penalties associated with deviations beyond an acceptable tolerance (a few percent)
- For more details, please refer to
- http://www.caiso.com/pubinfo/tariffs/index.html

Future Changes Expected in CAISO Markets

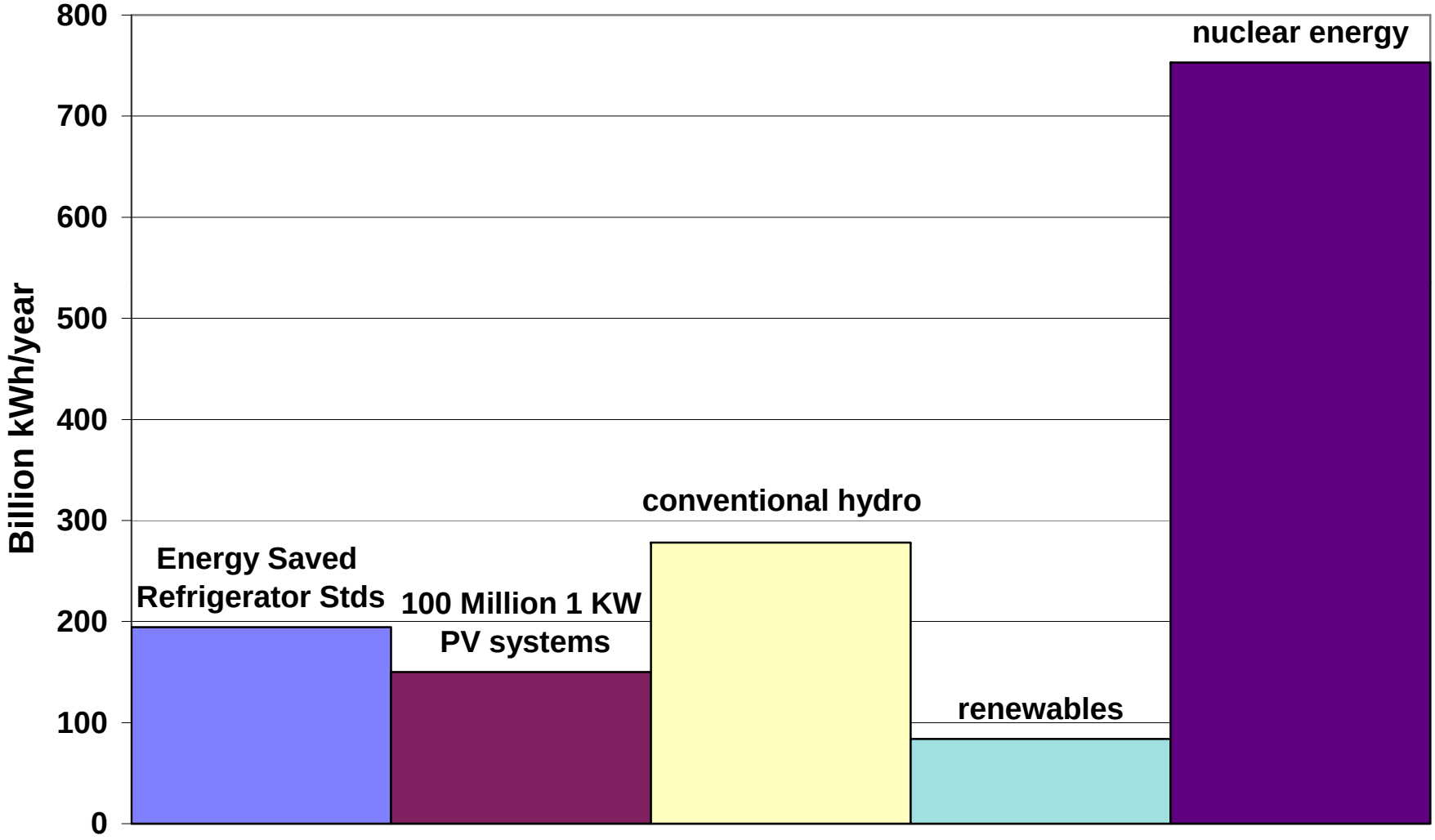
- Next year the CAISO is expected to alter it market structure
- Will then have the following features
- Full Network Model
  - Depicts available capacity and constraints on the CAISO Controlled Grid across all market time frames
  - Including solving intra-zonal congestion in forward markets
- Locational Marginal Pricing (LMP)
  - determines marginal Energy prices that accurately reflect the cost of serving the next MWh of Demand at each location on the Grid
- Integrated Forward Market
  - Day-Ahead Market with energy prices
  - Hour-Ahead Scheduling Process
  - Real-Time Market
- No market separation
  - Trades can be arranged between different SC in a market

If considering deregulation: Our list of lesson learned, some the hard way

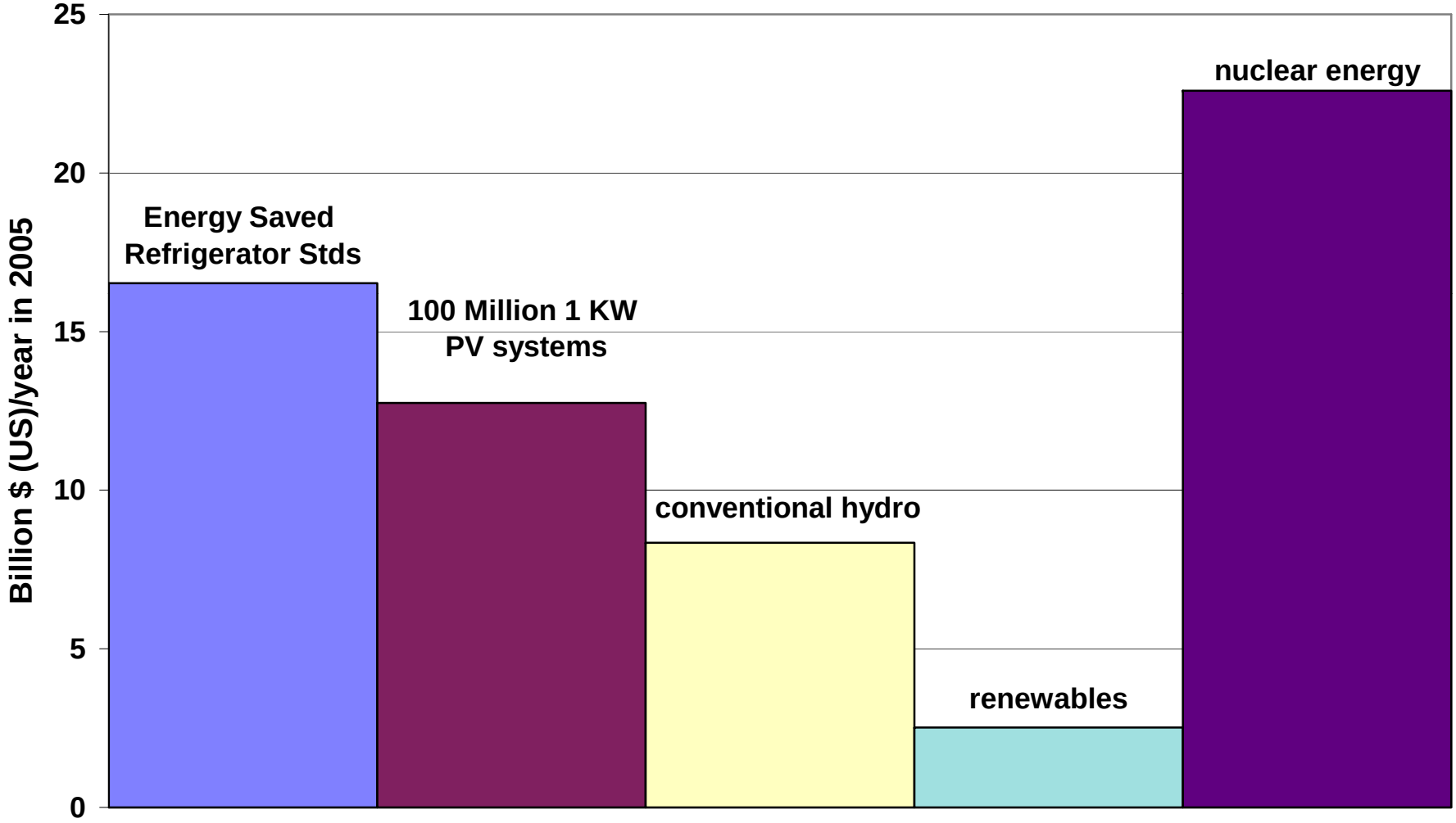
- Mandate risk management
  - Forward contracts or something like these
    - As buyers run out of money, even the best market structure won't work
- Try to have supply be competitive
    - This is difficult when loads peak
- Market rules take a long time to develop and seem to get more and more complicated
- Clear and consistent regulatory policies are very important
- If possible, get it right the first time as it is very hard to change
  - For example, CAISO market redesign has taken 5 years and will likely take longer to get a day-ahead hourly energy market in place

Additional Items of Interest
(if time allows)

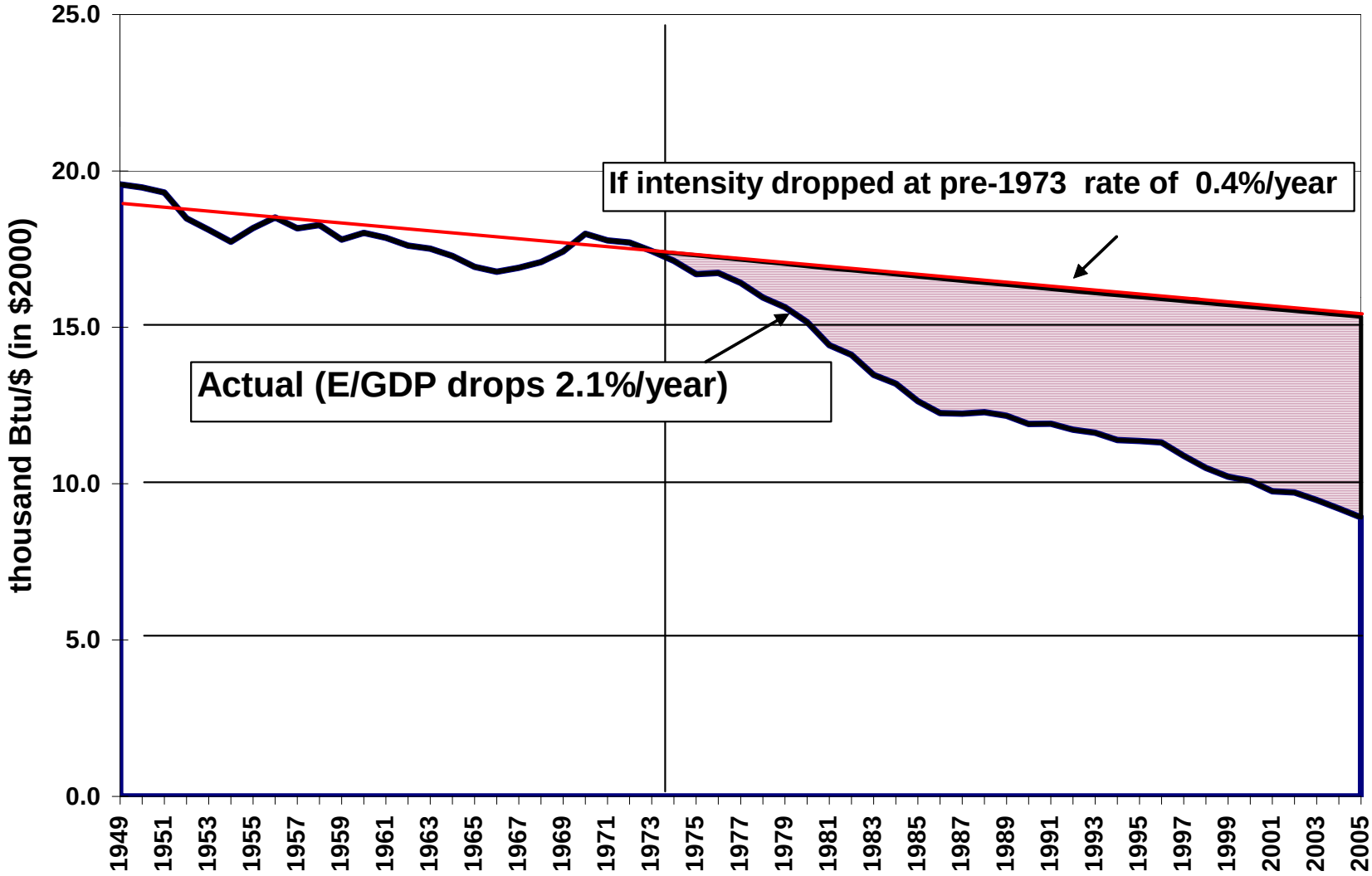
Annual Energy Saved vs. Several Sources of Supply

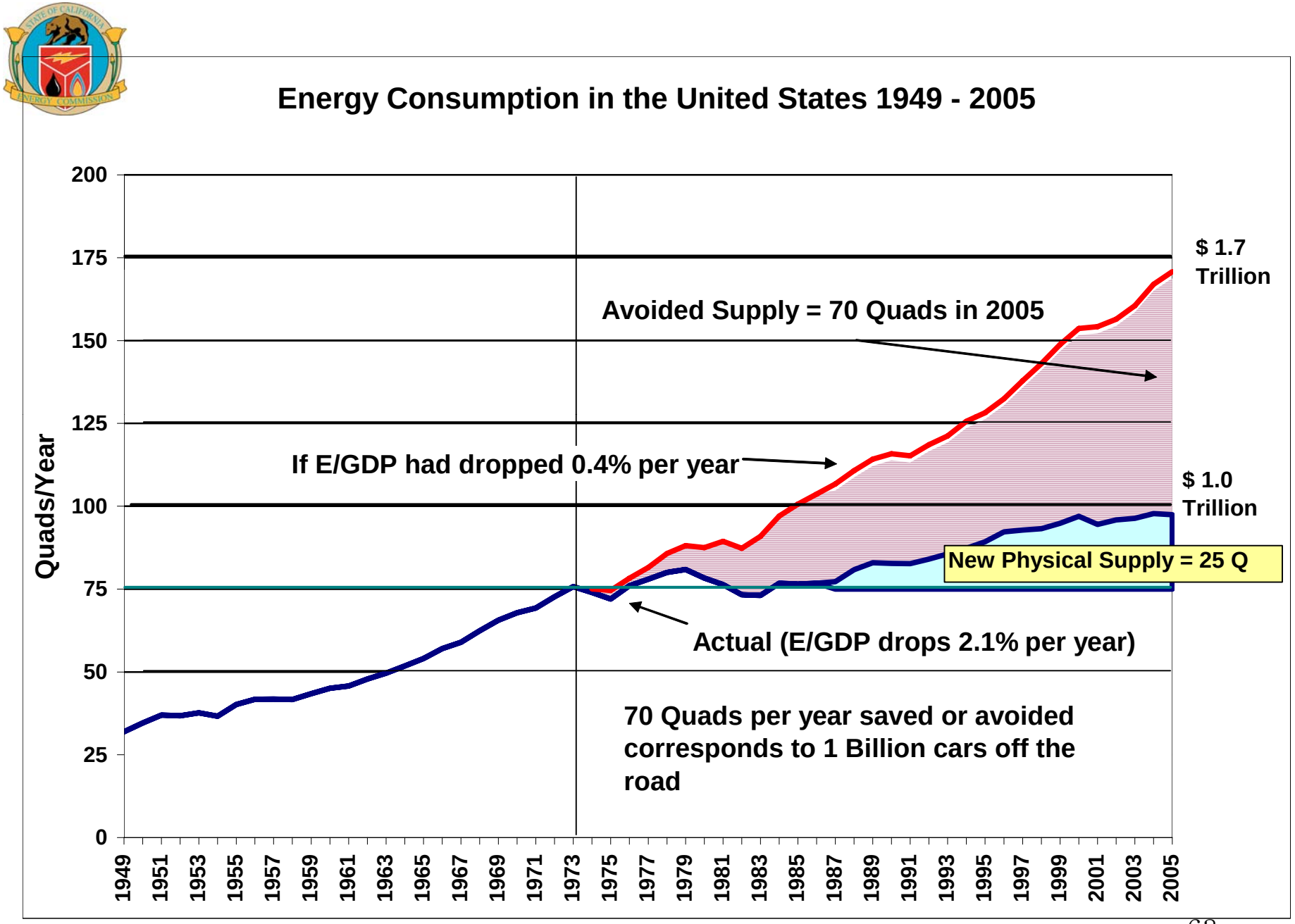


Value of Energy to be Saved (at 8.5 cents/kWh, retail price) vs. Several Sources of Supply in 2005 (at 3 cents/kWh, wholesale price)



Energy Intensity in the United States 1949 - 2005




Energy Consumption in the United States 1949 - 2005
Quads/Year
200
175
150
125
100
75
50
25
0
1949
1951
1953
1955
1957
1959
1961
1963
1965
1967
1969
1971
1973
1975
1977
1979
1981
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
$ 1.7 Trillion
Avoided Supply = 70 Quads in 2005
If E/GDP had dropped 0.4% per year
$ 1.0 Trillion
New Physical Supply = 25 Q
Actual (E/GDP drops 2.1% per year)
70 Quads per year saved or avoided corresponds to 1 Billion cars off the road

How Much of The Savings Come from Efficiency?

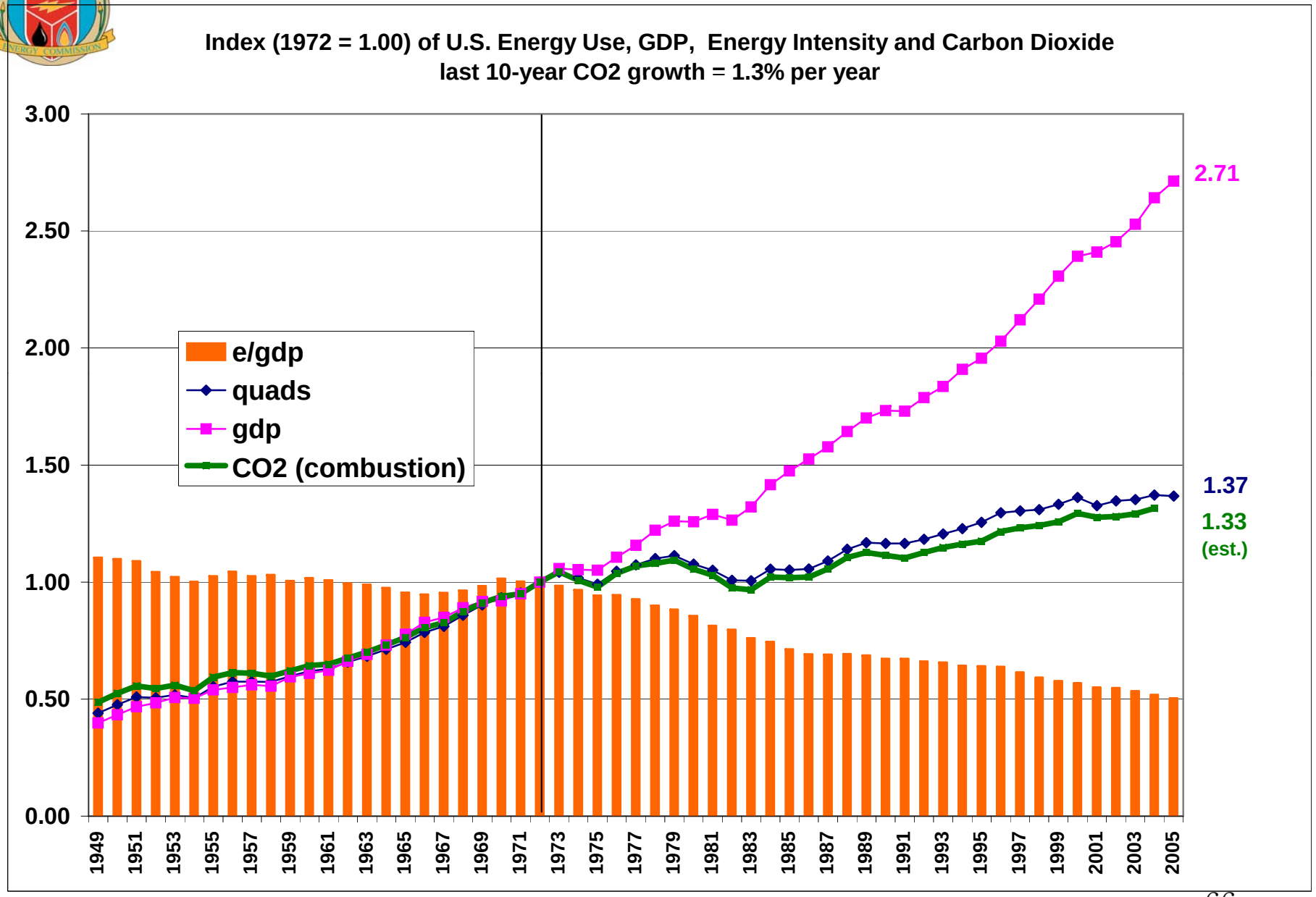
- Easiest to tease out is cars
  - In the early 1970s, only 14 miles per gallons
  - Now about 21 miles per gallon
  - If still at 14 mpg, we'd consume **75 billion gallons more** and pay **$225 Billion more** at 2006 prices
  - But we still pay **$450 Billion per year**
  - If California wins the "Schwarzenegger-Pavley" suit, and it is implemented nationwide, we'll save **another $150 Billion per year**
- Commercial Aviation improvements save another **$50 Billion per year**
- Appliances and Buildings are more complex
  - We must sort out true efficiency gains vs. structural changes (from smokestack to service economy).

How Much of The Savings Come from Efficiency (cont'd)?

- Some examples of estimated savings in 2006 based on 1974 efficiencies minus 2006 efficiencies

	Billion $
Space Heating	**40**
Air Conditioning	**30**
Refrigerators	**15**
Fluorescent Tube Lamps	**5**
Compact Floursecent Lamps	**5**
Total	**95**

- Beginning in 2007 in California, reduction of "vampire" or stand-by losses
  - This will save $10 Billion when finally implemented, nation-wide
- Out of a total **$700 Billion**, a crude summary is that 1/3 is structural, 1/3 is transportation, and 1/3 is buildings and industry.


Index (1972 = 1.00) of U.S. Energy Use, GDP, Energy Intensity and Carbon Dioxide
last 10-year CO2 growth = 1.3% per year
3.00
2.50
2.00
1.50
1.00
0.50
0.00
e/gdp
quads
gdp
CO2 (combustion)
2.71
1.37
1.33
(est.)
1949
1951
1953
1955
1957
1959
1961
1963
1965
1967
1969
1971
1973
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