# Review of State of the Market for 2002

Report to the Federal Energy Regulatory Commission

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# Overview of Control Area

- 10 million customers served
- 25,000 circuit miles of network transmission
- 42,441 MW peak load
- 232,000 GWh annual energy
- 45,000 MW of installed generation capacity before derates for hydro and outages
- 5,000 MW net imports

*All statistics are for 2002

# 2002 Market Rule Changes

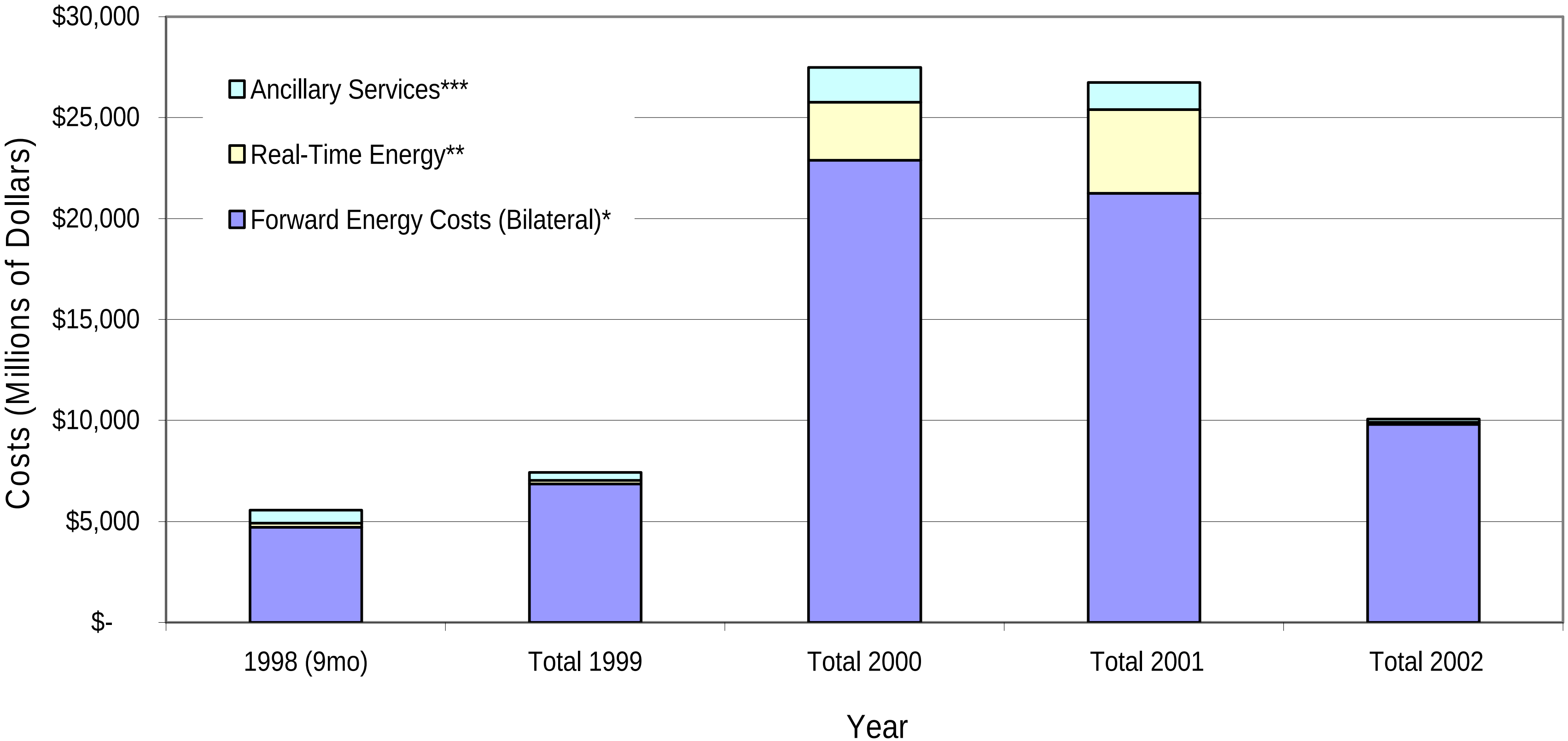
- Current ISO markets
  - Real Time Imbalance Energy Market (Zonal)
  - Day Ahead and Hour Ahead congestion management
  - Ancillary service mrkts: regulation,spin,non-spin,replacement
  - No Day Ahead energy market, State purchased energy to make up the deficiency in utility generation
- Feb: Zero-bid requirement on import bids in real-time
- April: Imports to be paid instructed energy price
- May: New Automated Dispatch System (ADS)
- October: MD02 Phase IA
  - Soft price cap changed to $250/MWh from $91.87/MWh
  - Automated Mitigation Procedures (AMP)

# 2002 Market Highlights: Market Health and Costs

- Market health vastly improved since 2000-01 crisis due primarily to supply/demand fundamentals
  - Long-term contracts, new generation, significant imported energy all helped to stabilize ISO markets
  - Moderate loads; few demand response programs but being encouraged by new State and ISO initiatives
  - Real-time volumes small, improved accurate forward scheduling
- Most load met by long-term contracts and utility-retained generation. Total market costs just over $10 billion in 2002 ($43/MWh), compared to $27 billion in 2000 and 2001, $7.4 billion in 1999

# *Total wholesale electricity costs decreased 62% between 2001 and 2002, Including 95% decrease in real-time and ancillary services costs*

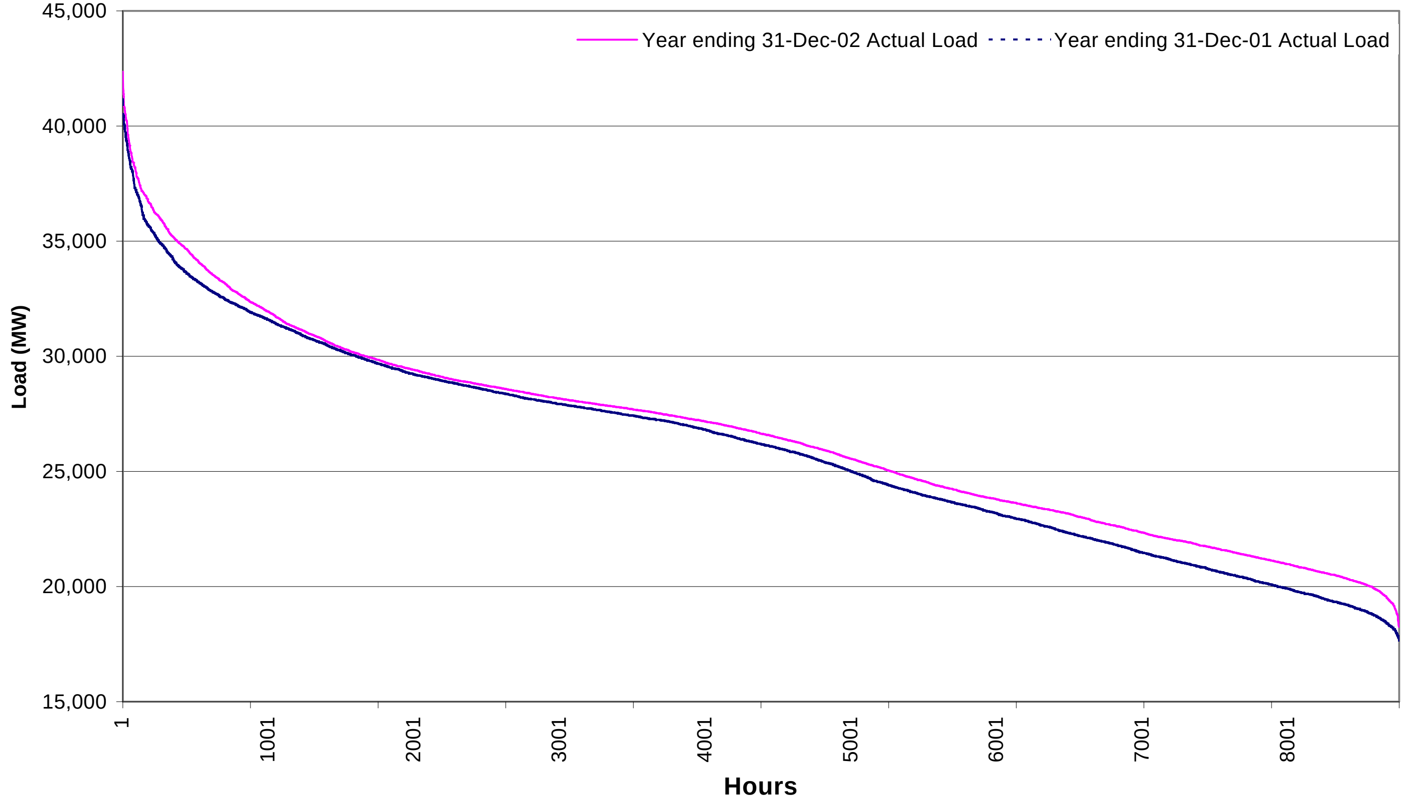
## *Total Wholesale Electricity Costs in ISO Control Area, 1998-2002*



# Load Growth in 2002

## Total Energy Consumption was up 2% in 2002 due to warmer weather and reduced conservation. Little change in Peak Load.

### Load Duration Curve for 2001 and 2002




Note: values are instantaneous top-of-hour actual loads. Intra-hour peaks are not included.

# I. Nearly 4,000 MW of generation added since 2001

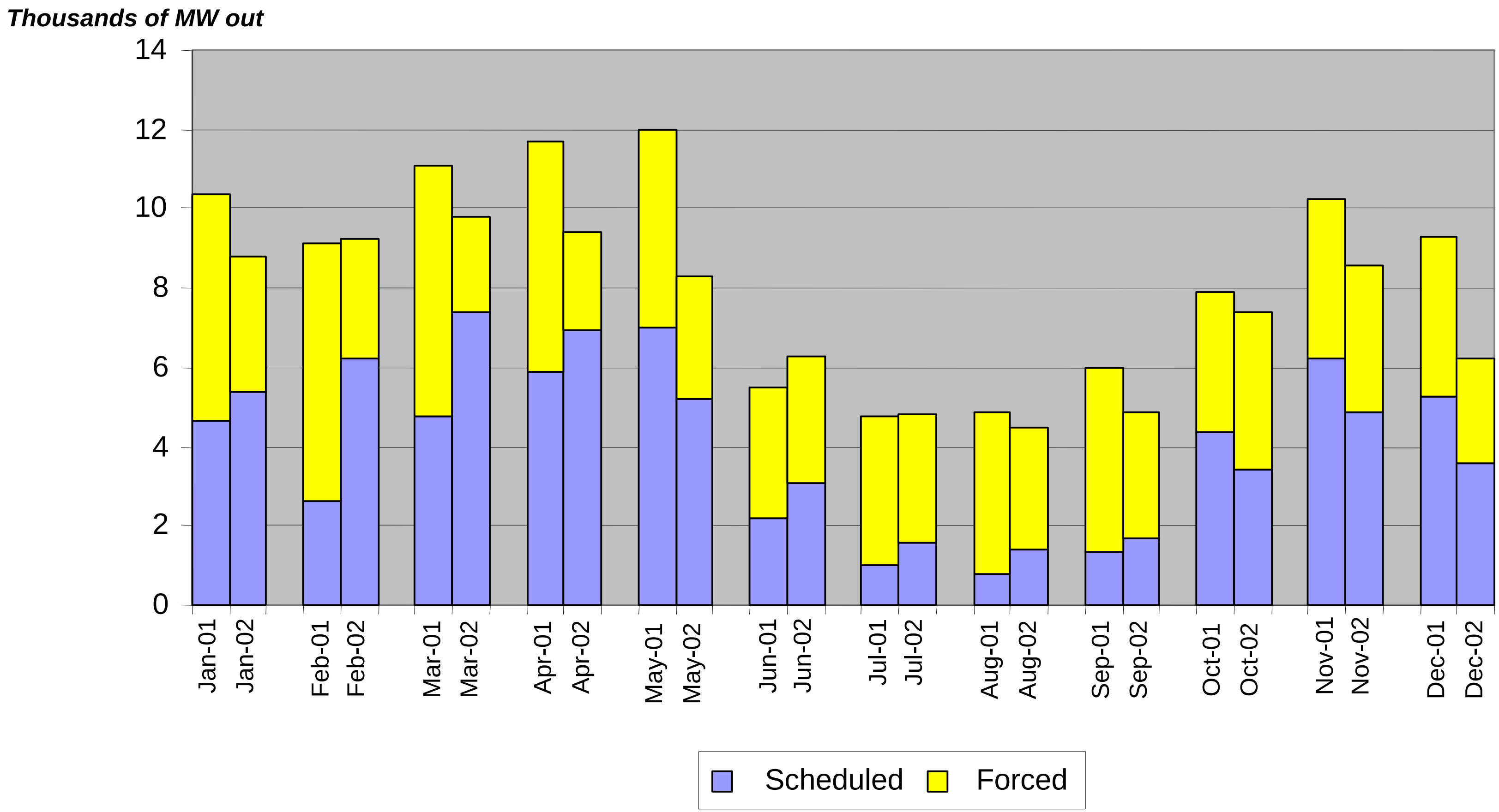
## 2001-2002 New Generation Additions and Retirements

| *Congestion Zone* | *2001 Generation Additions (MW)* | *2002 Generation Additions (MW)* | *2002 Generation Reductions (MW)* | *Net Generation Change (MW)* |
|---|---|---|---|---|
| NP15 | 1,550 | 2,263 | -8 | 3,805 |
| ZP26 | 338 | 71 | 0 | 409 |
| SP15 | 685 | 430 | -1,401 | -286 |
| ISO Control Area | **2,573** | **2,764** | **-1,409** | **3,928** |

# II. Reviewed and approved 22 transmission upgrades worth $700 million

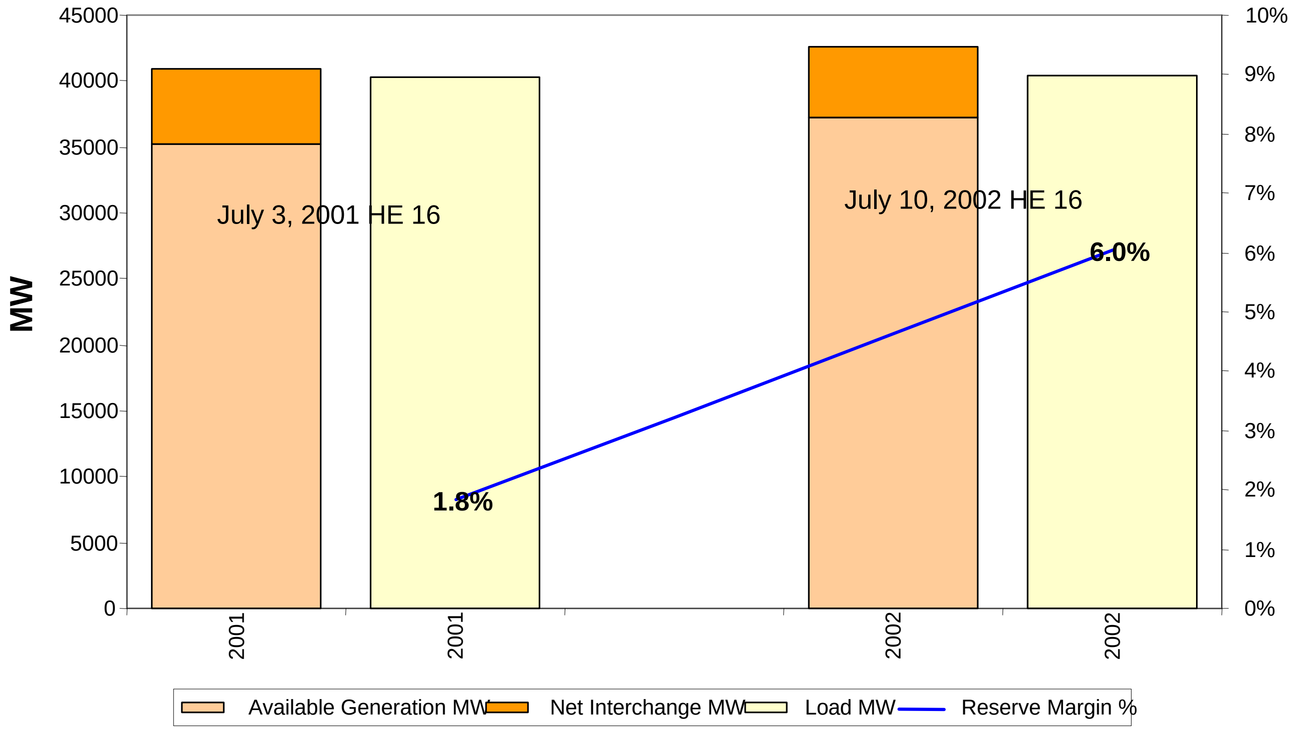
# Improved generation outage co-ordination in 2002 has kept outages below levels in 2001

## Average Hourly Outages by Type



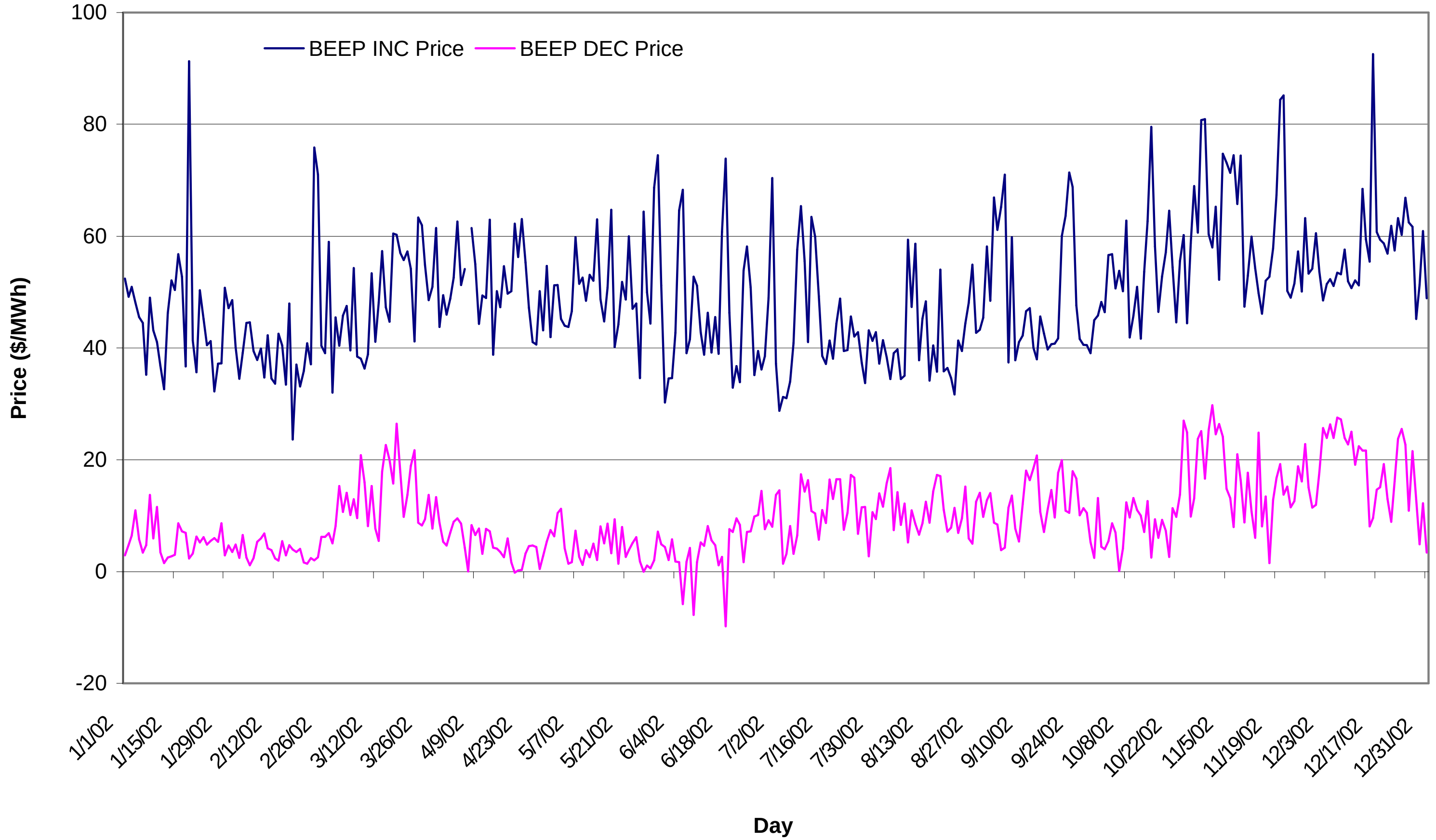
# Reserve Margin increased to 6% in peak hour of 2002 from 1.6% in peak hour of 2001

## Annual Peak Hour Reserve Margins in 2001 and 2002



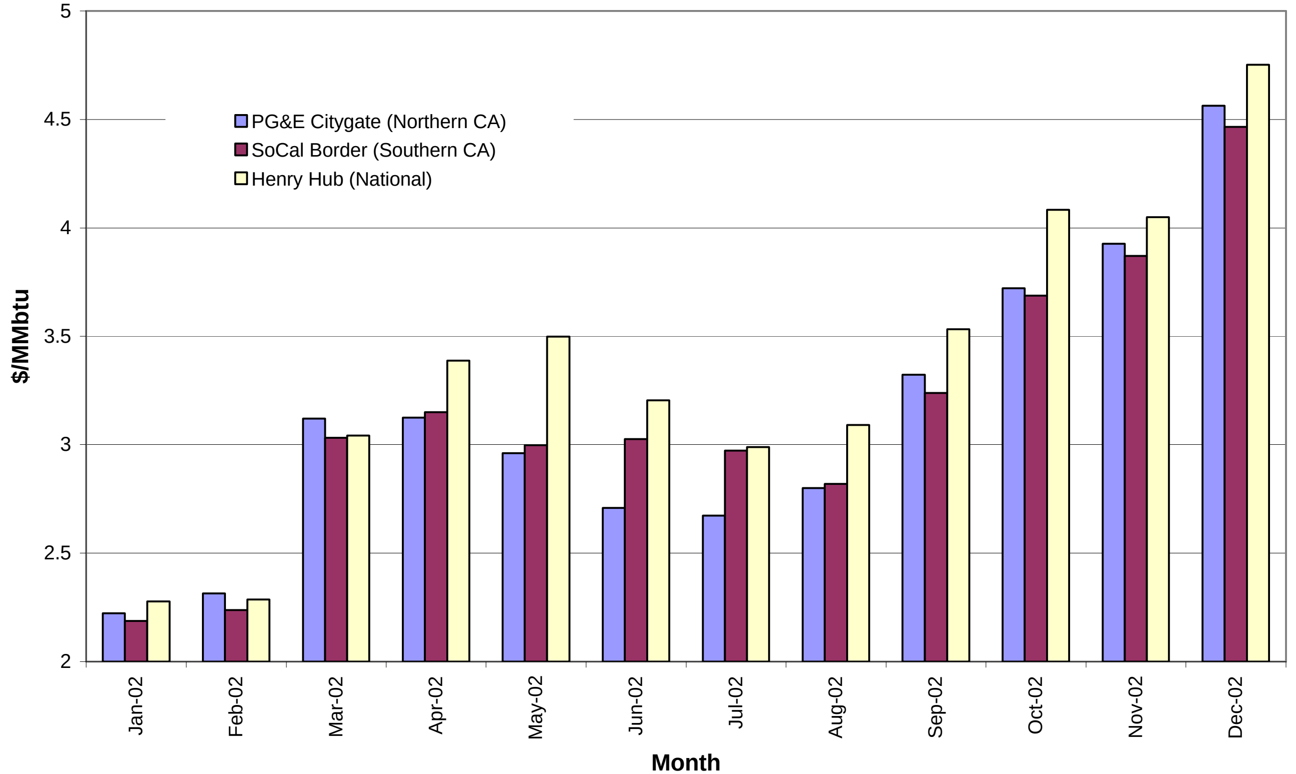
# Average real-time Incremental dispatch price varied between $40 and $60/MWh for most days in 2002

## Daily Average Real-Time INC and DEC Prices in 2002



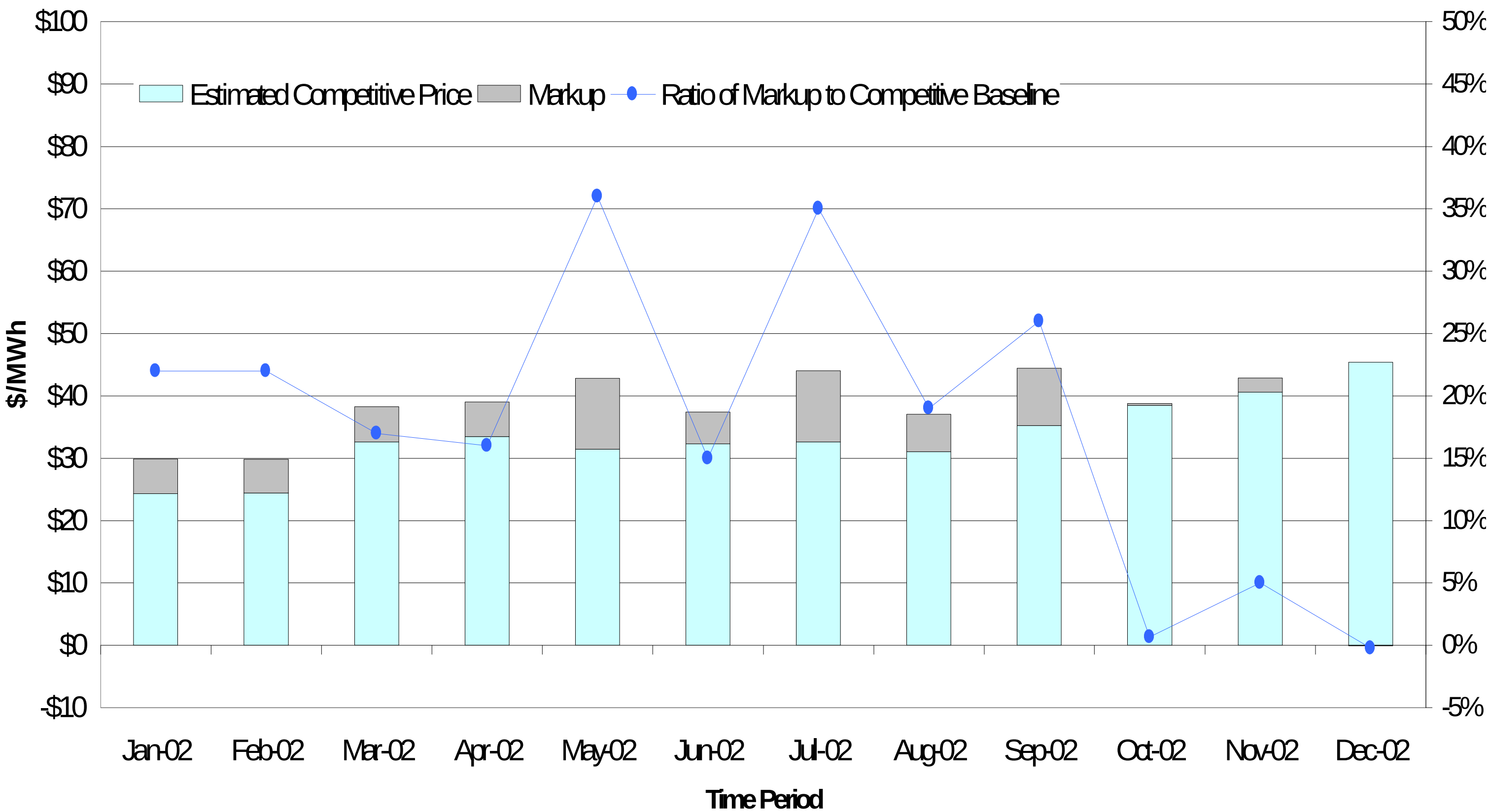
# Gas prices increased steadily in 2002, Causing electricity prices to rise in step

## Monthly Average Prices for Natural Gas



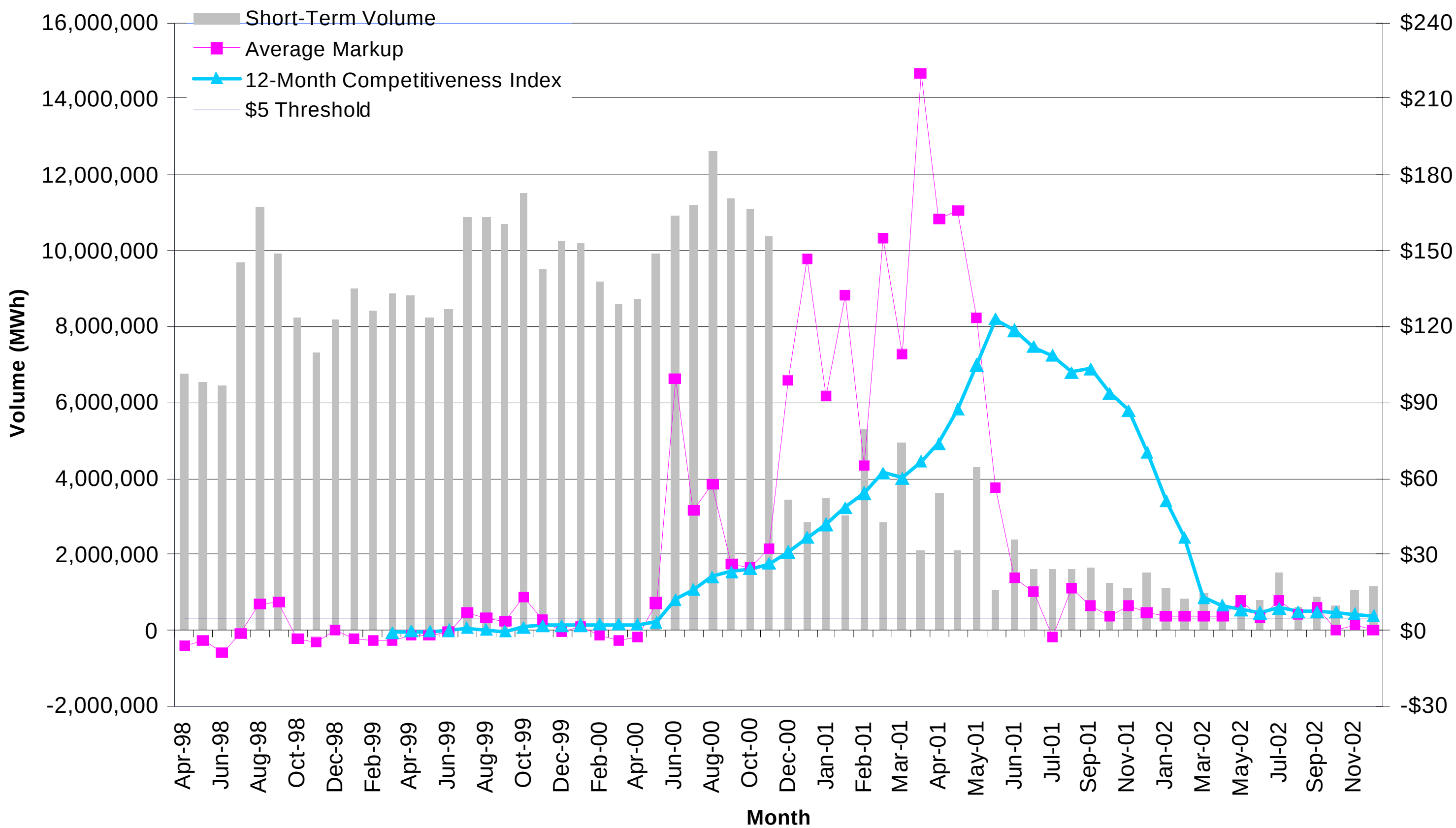
# Favorable market conditions in 2002 checked suppliers' ability to exercise market power, when compared to previous years

## Estimated Monthly Mark –up of Prices above Competitive levels
## (Price-to-Cost Markup in Short-Term Energy)



# Long-term market outcomes returned to workably competitive levels in 2002

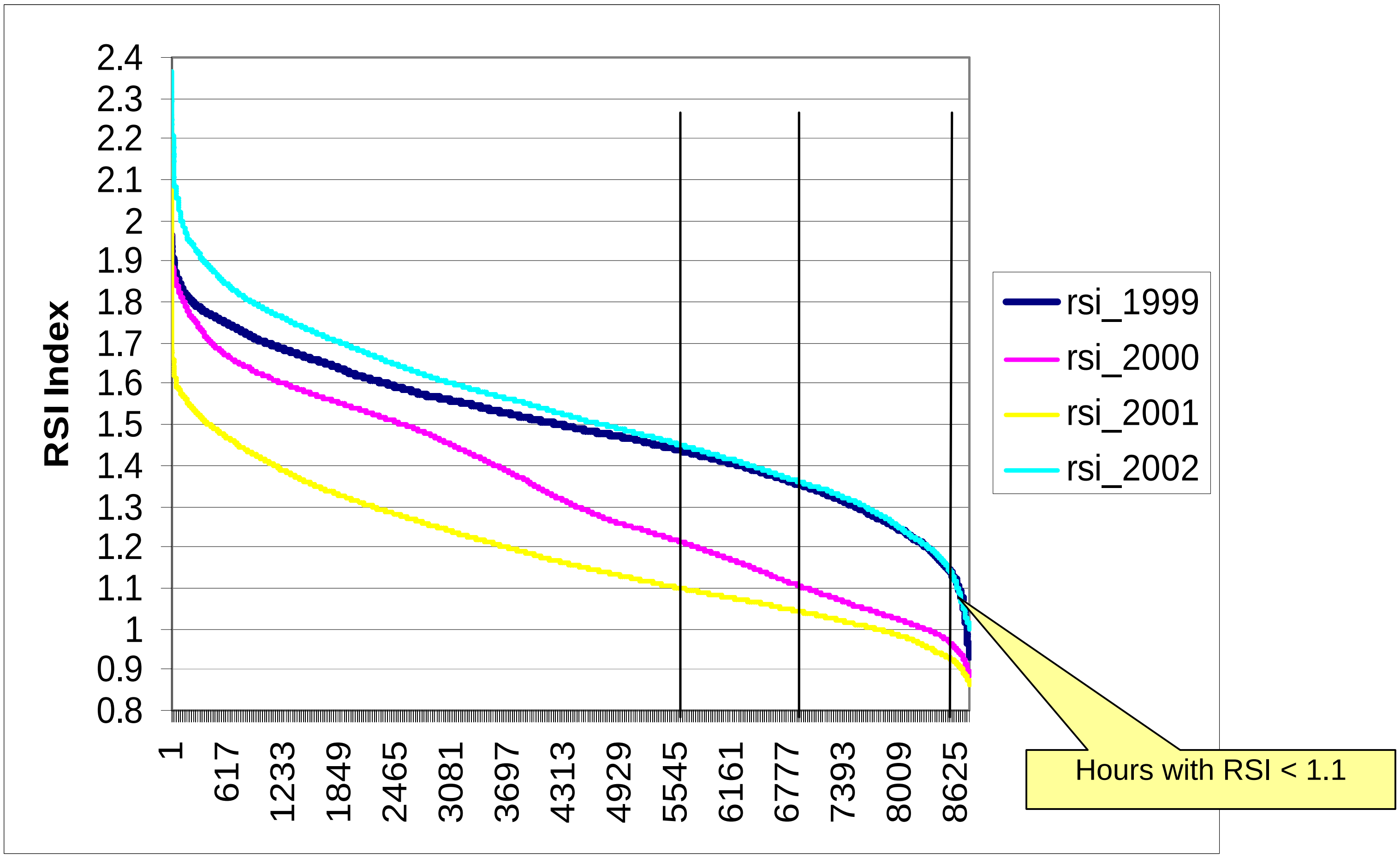
## Twelve-Month Competitiveness Index through Dec-02



# Return to Market Health with suppliers pivotal in fewer than 1% of hours in 2002

## Residual Supply Index Duration Curves: 1999-2002

(RSI less than 1.1 indicates suppliers able to set market prices )



# Market Revenues in 2002 Supported Recovery Fixed Cost of New Generation at $72 - 77/kW-yr

### Estimated Operating Revenue in ISO Energy and Ancillary Service Markets

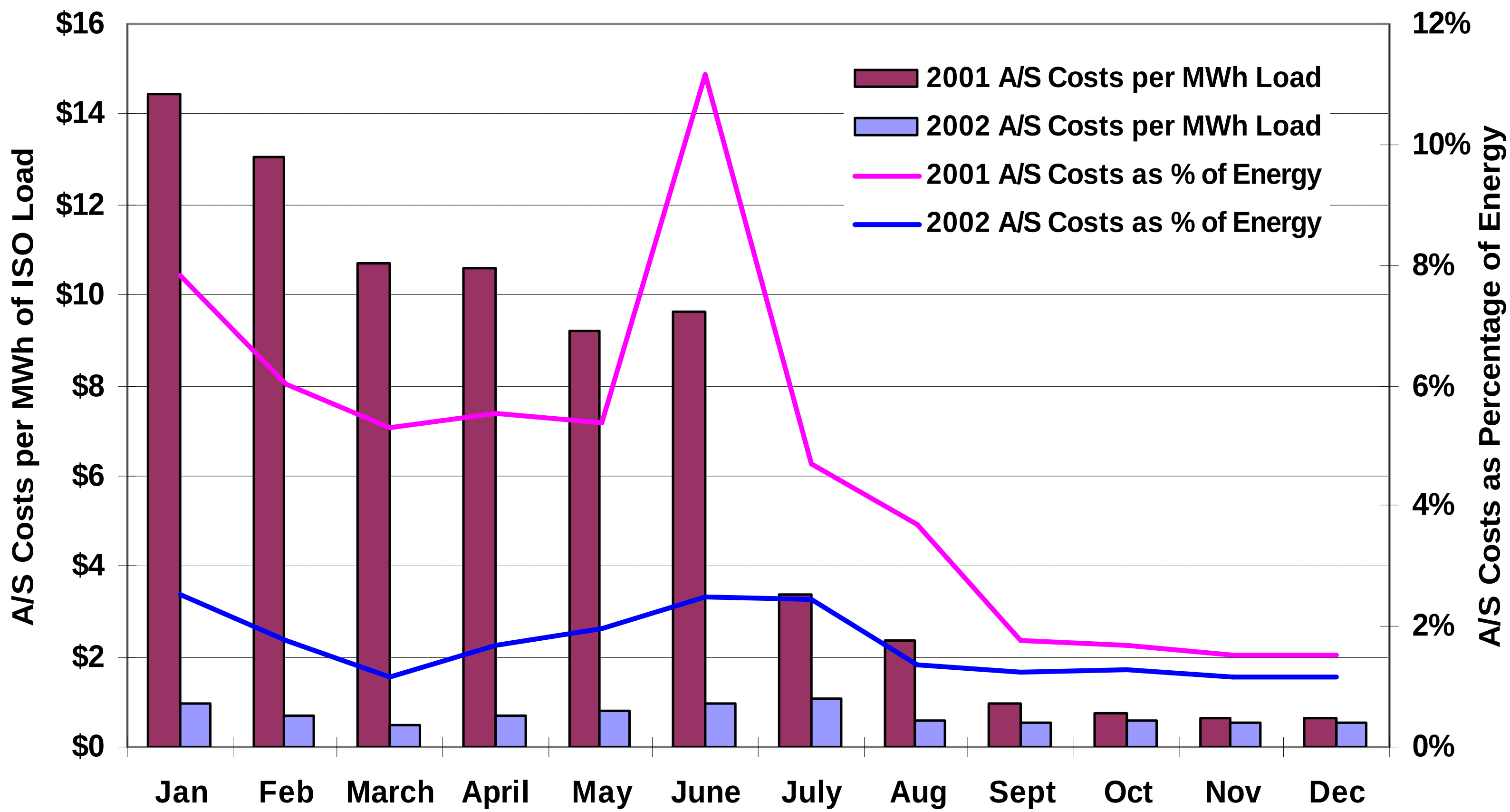
| | NP15 | SP15 |
|---|---|---|
| Load Factor | 61% | 62% |
| Average Energy Revenue ($/MWh) | $ 40 | $ 41 |
| Average Operating Cost ($/MWh) | $ 26 | $ 26 |
| Net Energy Revenue ($ /kW/yr) | $ 66 | $ 71 |
| A/S Capacity Revenue ($/kW/yr) | $ 6 | $ 6 |
| Total Net Revenue ($/kW/yr) | $ 72 | $ 77 |

- **Net revenue can cover the lower end of annual fixed cost estimated at $70 to 90/kW/year**

- **Long-term contract with load is the more desirable means to ensure revenue adequacy and stability**

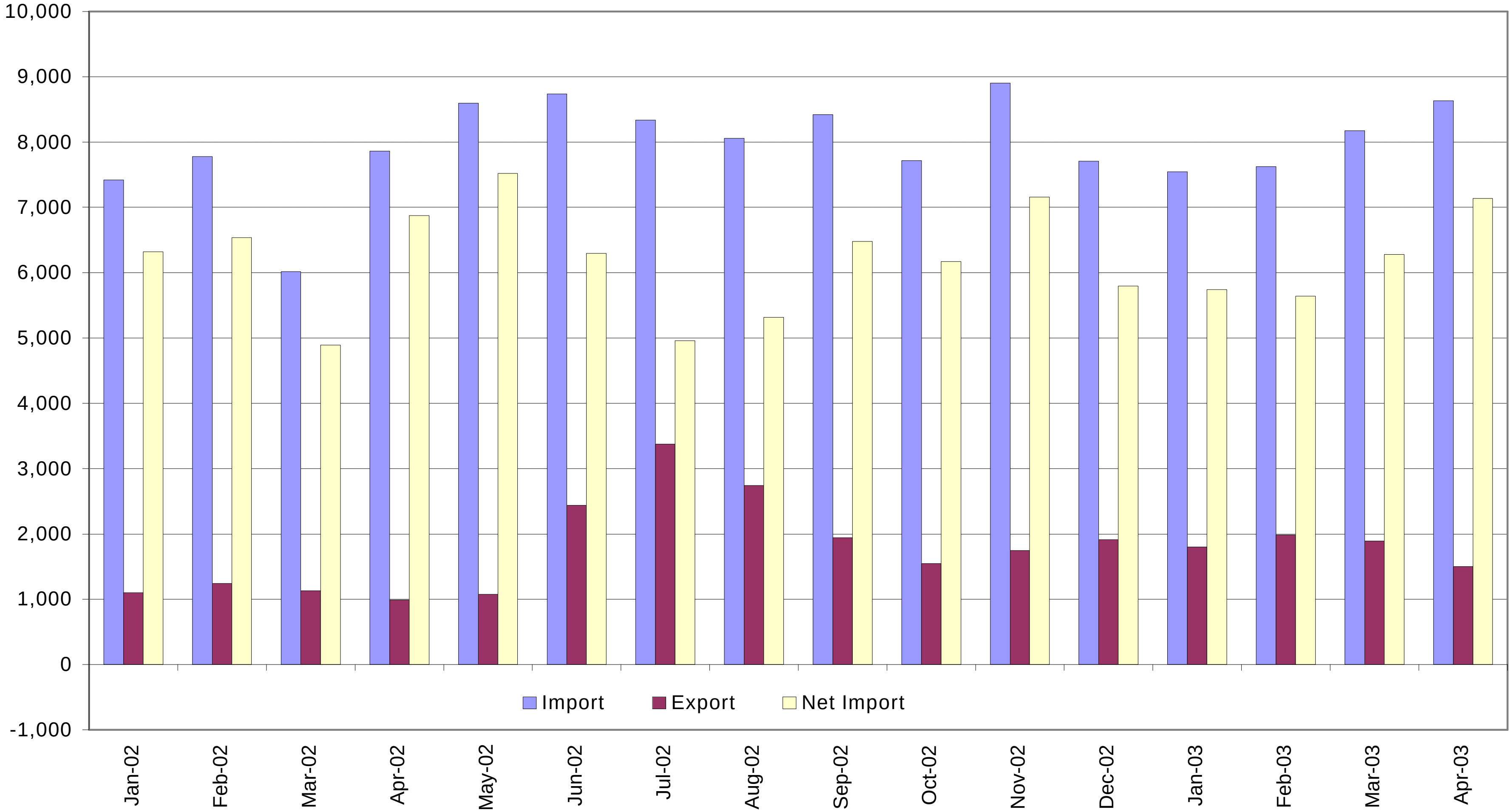
# Ancillary Services Costs Down 88% in 2002 from 2001 levels

## AS requirements reduced from 13 % of system load to 9.3%, largely due to less purchases of regulation service; lower prices for all A/S services



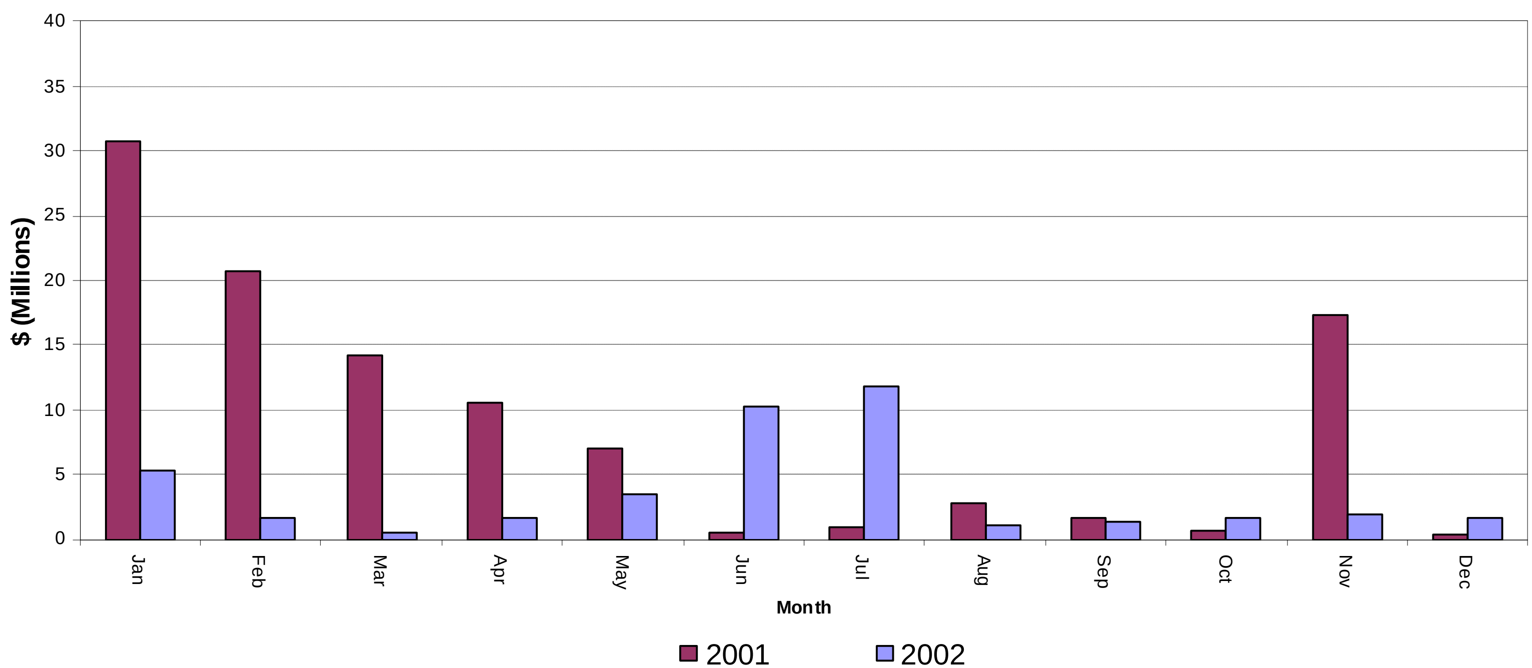
## Strong import volumes into California overall

## Scheduled Imports and Exports - Monthly Averages



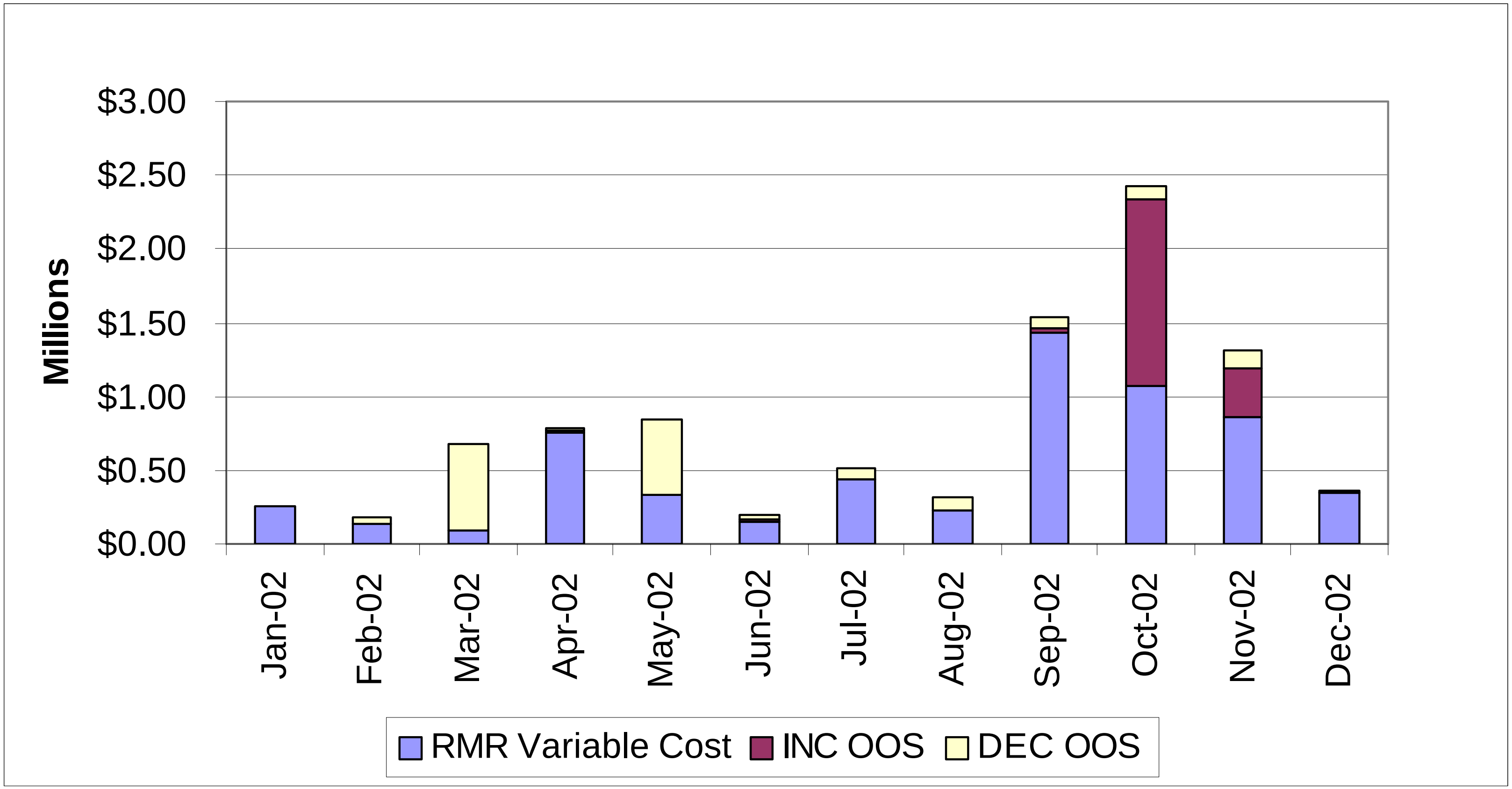
# Congestion costs down 61% in 2002 from 2001 levels; 2002 monthly costs significantly higher only in June and July, due to derates of key transmission lines

## Monthly Total Interzonal Congestion Costs: 2002 v. 2001



# Increased (within zone) intrazonal congestion due to new generation additions and inadequate local market power mitigation

## Monthly Total Intrazonal Congestion Costs in 2002 + $263 mil RMR Fixed Cost



# Critical Market Issues Going Forward

- Lack of an effective local market power mitigation mechanism
  - Expect increased local market power with new generation
  - Current local AMP  threshold of $50 for INC and -$30 for DEC makes mitigation ineffective
- Decline in import bids in real-time due to zero bid requirement may impact reliability
- Generators frequently decline dispatch instructions
  - Declined incremental dispatch was more than 50% in December

# Going Forward: MD02 Market Redesign

- Lack of forward market mechanism to resolve intrazonal congestion
  - Intrazonal congestion managed in real time since ISO startup; susceptible to exercise of market power (DEC game, etc.)
  - MD02 Phase 2 Integrated Forward Market to simultaneously manage intrazonal and interzonal congestion in day ahead
- No formal day ahead unit-commitment process
  - Must-Offer Waiver Process is a workaround used to maintain availability of generation.
  - Integrated Forward Market set for 2004
- Slow development of price responsive demand
  - ISO markets can accommodate load-side bidding, but state has been slow in developing necessary rate design and metering systems
  - March 2003: CPUC begins 2600-customer pilot price-responsive demand study
- Other MD02 Development
  - AMP in effect since 10/30/02, but has not yet triggered mitigation
  - Real-time fully-automated economic dispatch software to be tested Summer 2003, deployed Fall 2003
  - Locational Marginal Pricing still subject to discussion but targeting fall 2004

# *New Demand Response Programs in California*

- ISO began Participating Load Program (PLP) in 1999; mostly pump load participating; about 1 MW of non-pump load participating as ancillary services
- Mar-03: ISO formed working group to update PLP technical standards
- Mar-03:  California PUC approved three pilot programs to test demand response in 2600 end-users:
  - Peak/off-peak pricing
  - Day-ahead notification of peak pricing
  - Same-day notification of peak pricing