Technology Background of PCE Regulatory Issues

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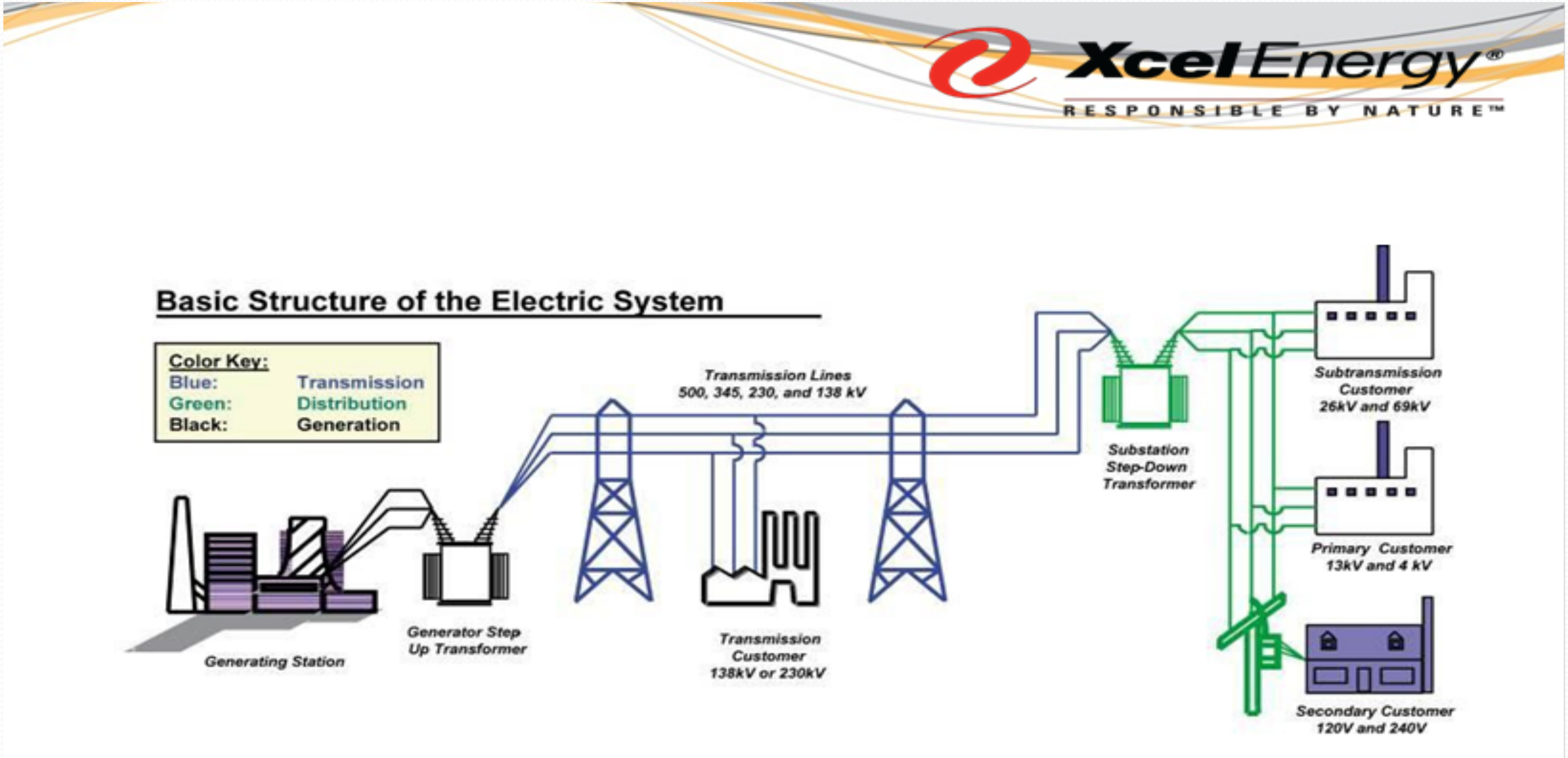
Overview

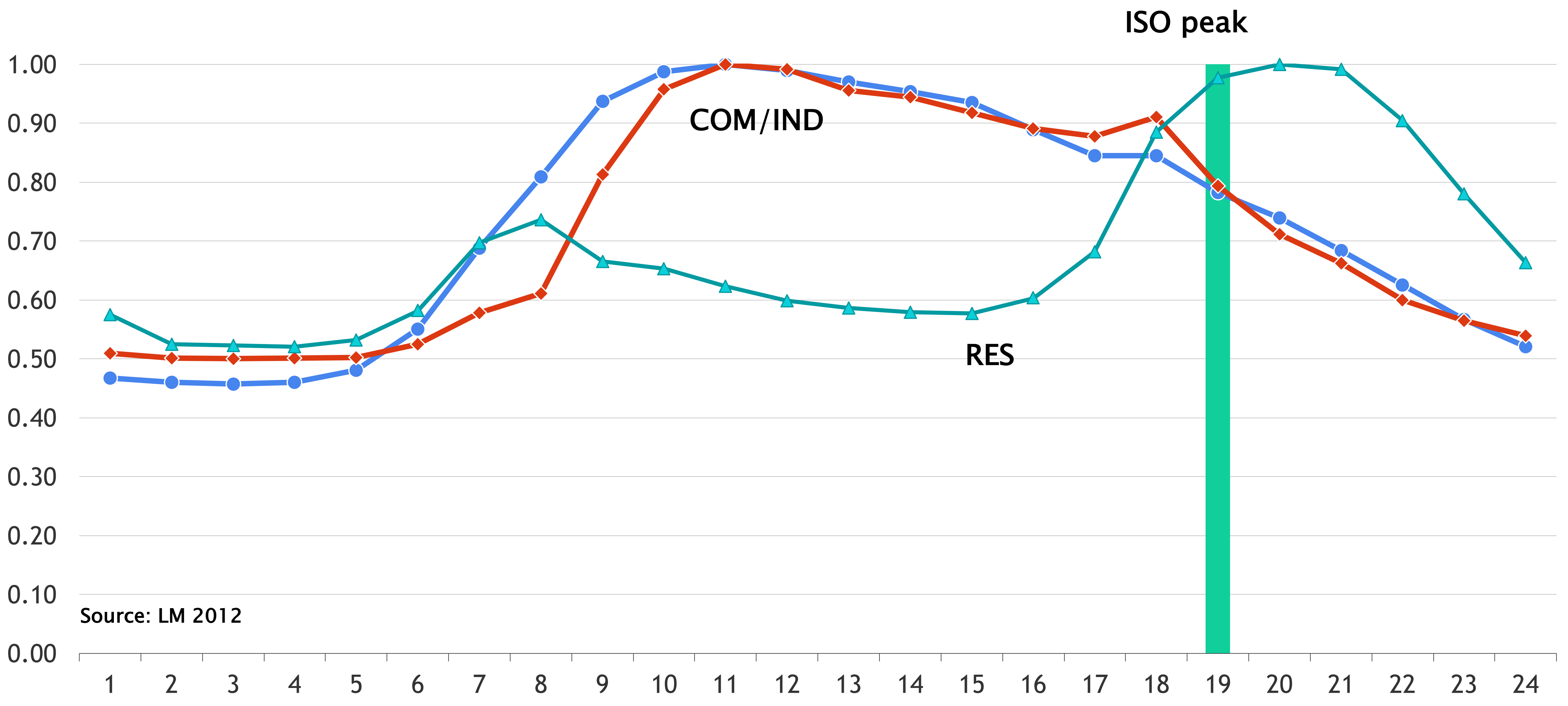
- Electric utility systems foundations
  - System configuration
  - Regulation
  - Transmission management
- Business Environment
- PCIA- Review
- IRP Concerns
- Resource Adequacy

UTILITY SYSTEMS


Xcel Energy®
RESPONSIBLE BY NATURE™
Basic Structure of the Electric System
Color Key:
Blue: Transmission
Green: Distribution
Black: Generation
Transmission Lines
500, 345, 230, and 138 kV
Generating Station
Generator Step Up Transformer
Transmission Customer
138kV or 230kV
Substation Step-Down Transformer
Subtransmission Customer
26kV and 69kV
Primary Customer
13kV and 4 kV
Secondary Customer
120V and 240V

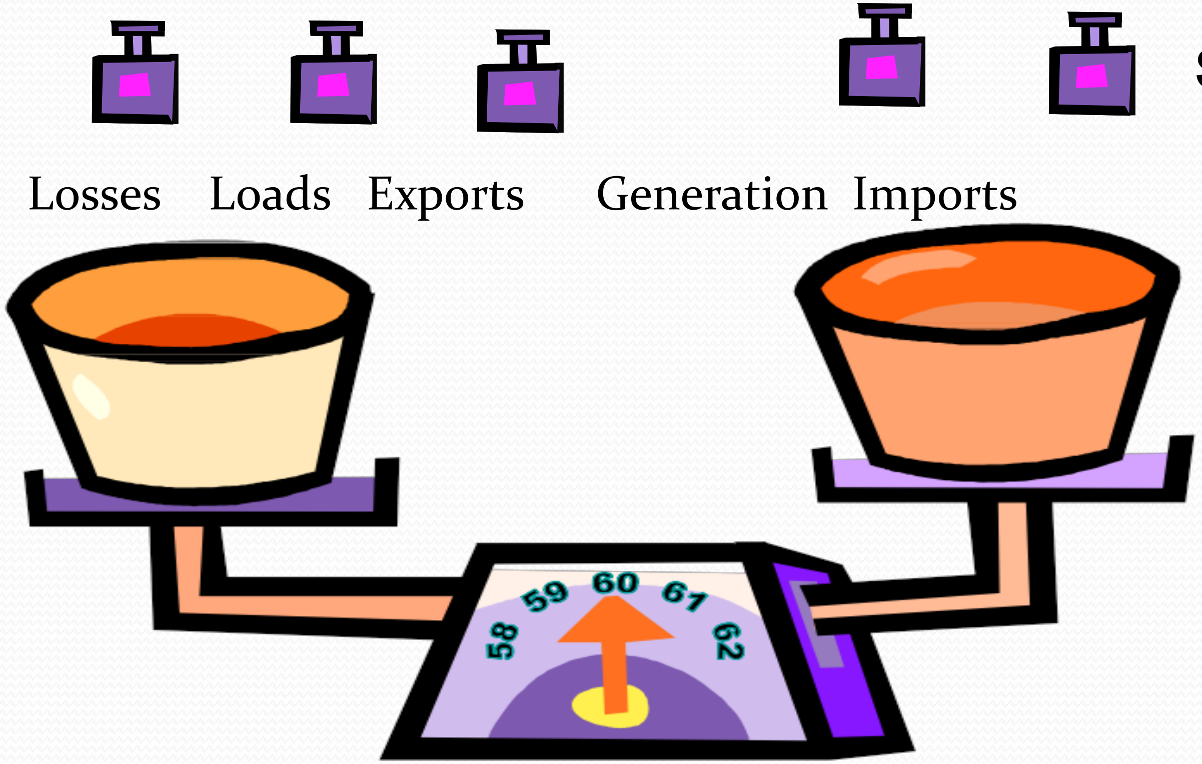
Unlike highways, pipelines, and telecom, the flow of electricity on the AC grid can not be easily routed or controlled. Power flows via the path of least resistance. This is a critical difference in how the grid differs from other transportation mechanisms

Load profile – January



Supply – Demand Balance: The Goal of the System

Electricity by nature is difficult to store



Supply must equal demand at any given instant

System frequency measures the extent to which supply and demand are in balance

<u>BIG CONCERN- LOW FREQUENCY FOLLOWING CAPABILITY</u>

Regulation

U.S. Electricity Regulation: Who is Responsible for What?

Federal Regulation (FERC

- Wholesale sales of electricity for resale.
- Transmission of electricity in interstate commerce
- (Very) Limited transmission siting authority
- Permitting of hydro plants
- Reliability of transmission grid

State Regulation (PUCs)

- Retail sales to end users
- Low-voltage distribution
- Siting of power plants and transmission lines
- Resource planning; i.e. the generation types used by a utility to serve customers

Transmission Ownership

- **Ownership of the transmission grid is fragmented - hundreds of discrete owners**
- Roughly two-thirds of U.S. transmission is owned by investor-owned utilities; roughly one-third is owned by public entities
- Ownership affects regulatory jurisdiction

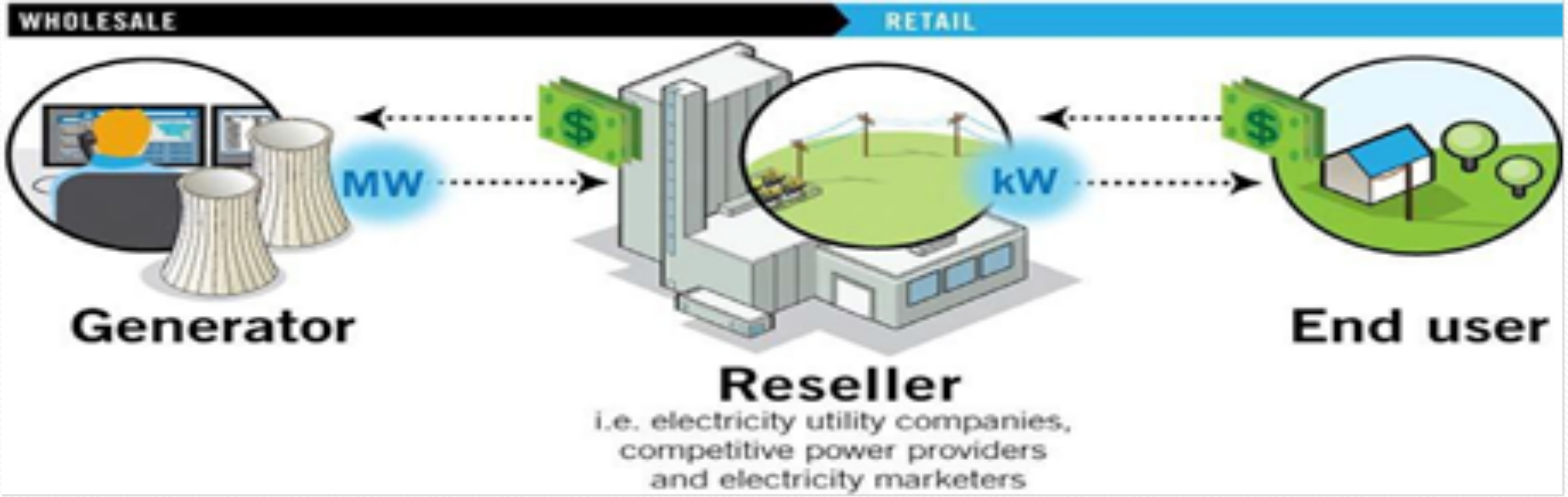
- **Many owners have turned operational control over to regional transmission operators – RTOs or ISOs**
- Independent regional operators serve roughly two- thirds of electricity consumers in the United States
- Operational control also affects regulatory jurisdiction

Independent System Operator (ISO)

- Facilitate competition among wholesale electricity suppliers
- Provide non-discriminatory access to transmission by scheduling and monitoring the use of transmission
- Perform planning and operations of the grid to ensure reliability
- Manage the interconnection of new generation
- Oversee competitive energy markets to guard against market power and manipulation
- Provide greater transparency of transactions on the system

ISO-organized Electricity Markets

- A megawatt of electricity, like any other commodity, is frequently bought and re-sold many times before finally being consumed. These transactions make up the wholesale and retail electricity markets



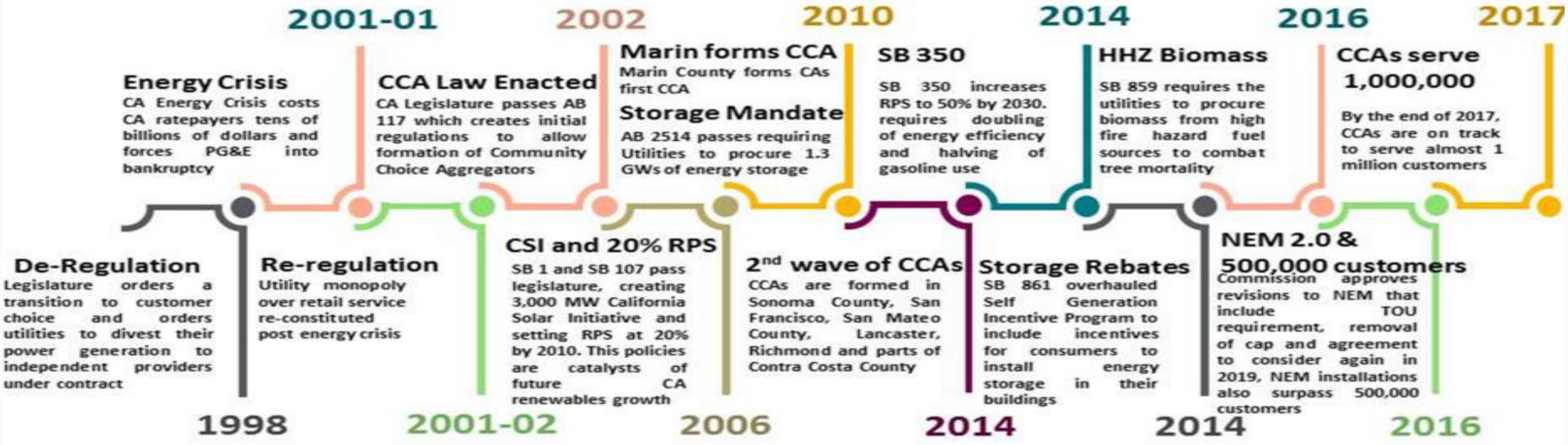
ISO Market Characteristics

- Manage and provide a central clearing house for transactions (transmission and generation) versus bilateral markets with parties working directly to establish terms and conditions
- Sets hourly prices for next-day's (Day-Ahead) operations
- Sets five-minute prices, or spot market prices, in Real-Time during the operating day

Transmission Project Development

- Rate Based Projects
  - Submit project and justification to ISO
  - ISO studies the project
  - If approved, project is funded by all rate payers in the footprint and receives FERC-approved rate of return
- Participant-Funded Projects
  - Transmission developer has a participant(s) willing to pay to use transmission line
  - Execute contract with stated terms, payment amounts, etc.
  - Transmission developer uses contract to attract third-party financing
  - All other Rate payers are not affected

Business Environment


2001-01
2002
2010
2014
2016
2017
Energy Crisis
CA Energy Crisis costs CA ratepayers tens of billions of dollars and forces PG&E into bankruptcy
CCA Law Enacted
CA Legislature passes AB 117 which creates initial regulations to allow formation of Community Choice Aggregators
Marin forms CCA
Marin County forms CAs first CCA
Storage Mandate
AB 2514 passes requiring Utilities to procure 1.3 GWs of energy storage
SB 350
SB 350 increases RPS to 50% by 2030. requires doubling of energy efficiency and halving of gasoline use
HHZ Biomass
SB 859 requires the utilities to procure biomass from high fire hazard fuel sources to combat tree mortality
CCAs serve 1,000,000
By the end of 2017, CCAs are on track to serve almost 1 million customers
De-Regulation
Legislature orders a transition to customer choice and orders utilities to divest their power generation to independent providers under contract
Re-regulation
Utility monopoly over retail service re-constituted post energy crisis
CSI and 20% RPS
SB 1 and SB 107 pass legislature, creating 3,000 MW California Solar Initiative and setting RPS at 20% by 2010. This policies are catalysts of future CA renewables growth
2nd wave of CCAs
CCAs are formed in Sonoma County, San Francisco, San Mateo County, Lancaster, Richmond and parts of Contra Costa County
Storage Rebates
SB 861 overhauled Self Generation Incentive Program to include incentives for consumers to install energy storage in their buildings
NEM 2.0 & 500,000 customers
Commission approves revisions to NEM that include TOU requirement, removal of cap and agreement to consider again in 2019, NEM installations also surpass 500,000 customers
1998
2001-02
2006
2014
2014
2016

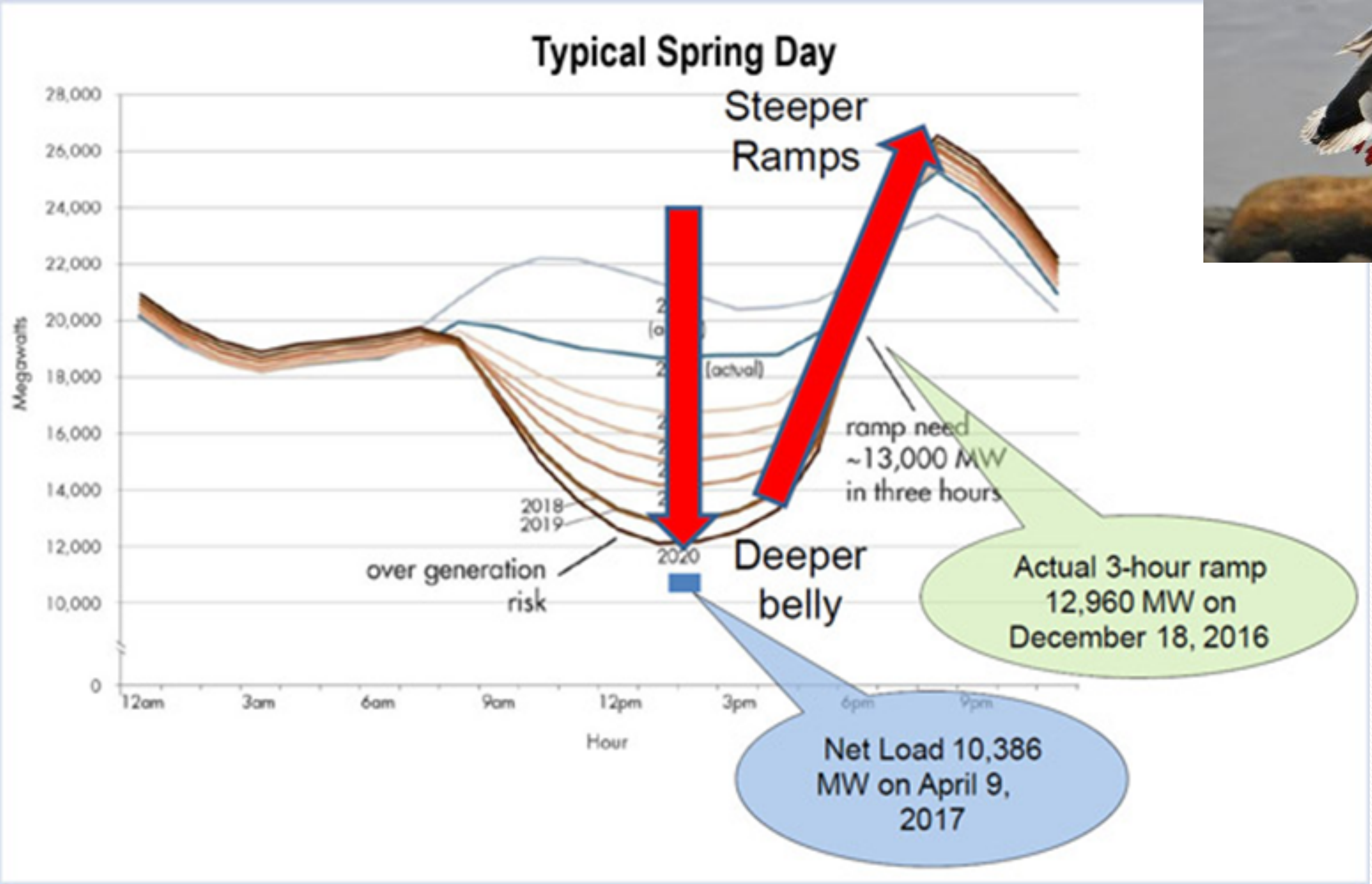
Energy Environment Goals

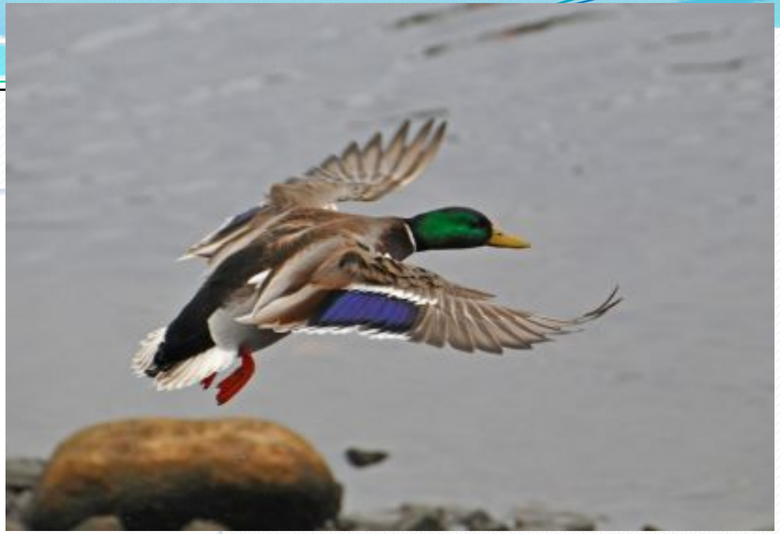
- 50 percent of retail electricity from renewable power by 2030;
- Greenhouse gas emissions reduction goal to 1990 levels;
- Regulations in the next 4-9 years requiring power plants that use coastal water for cooling to either repower, retrofit or retire;
- Policies to increase distributed generation; and
- An executive order for 1.5 million zero emission vehicles by 2025.

Changing Suppliers

- By 2017- 25% of IOU retail load served by non IOU providers.
- Some estimates- by mid 2020s- 85%.
- NEM- Since 2007, Solar PV increased by 4,500 MW.
- GHG Reductions 40% by 2030 using RPS and 1.5 millions EVs.

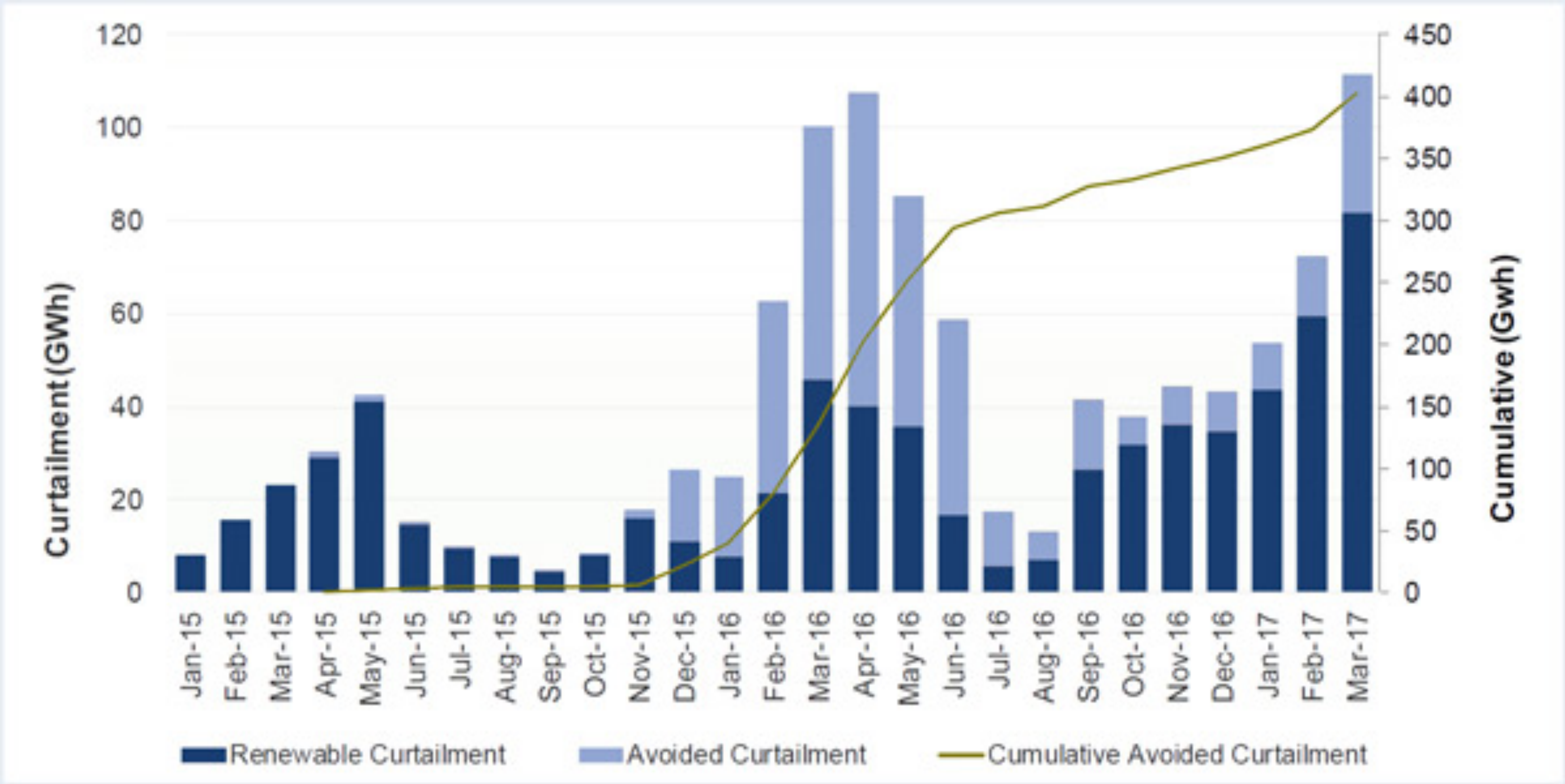
DUCK CURVE


Typical Spring Day
Steeper Ramps
Deeper belly
over generation risk
ramp need ~13,000 MW in three hours
Actual 3-hour ramp 12,960 MW on December 18, 2016
Net Load 10,386 MW on April 9, 2017
2018
2019
2020
(actual)
Megawatts
Hour
28,000
26,000
24,000
22,000
20,000
18,000
16,000
14,000
12,000
10,000
0
12am
3am
6am
9am
12pm
3pm
6pm
9pm



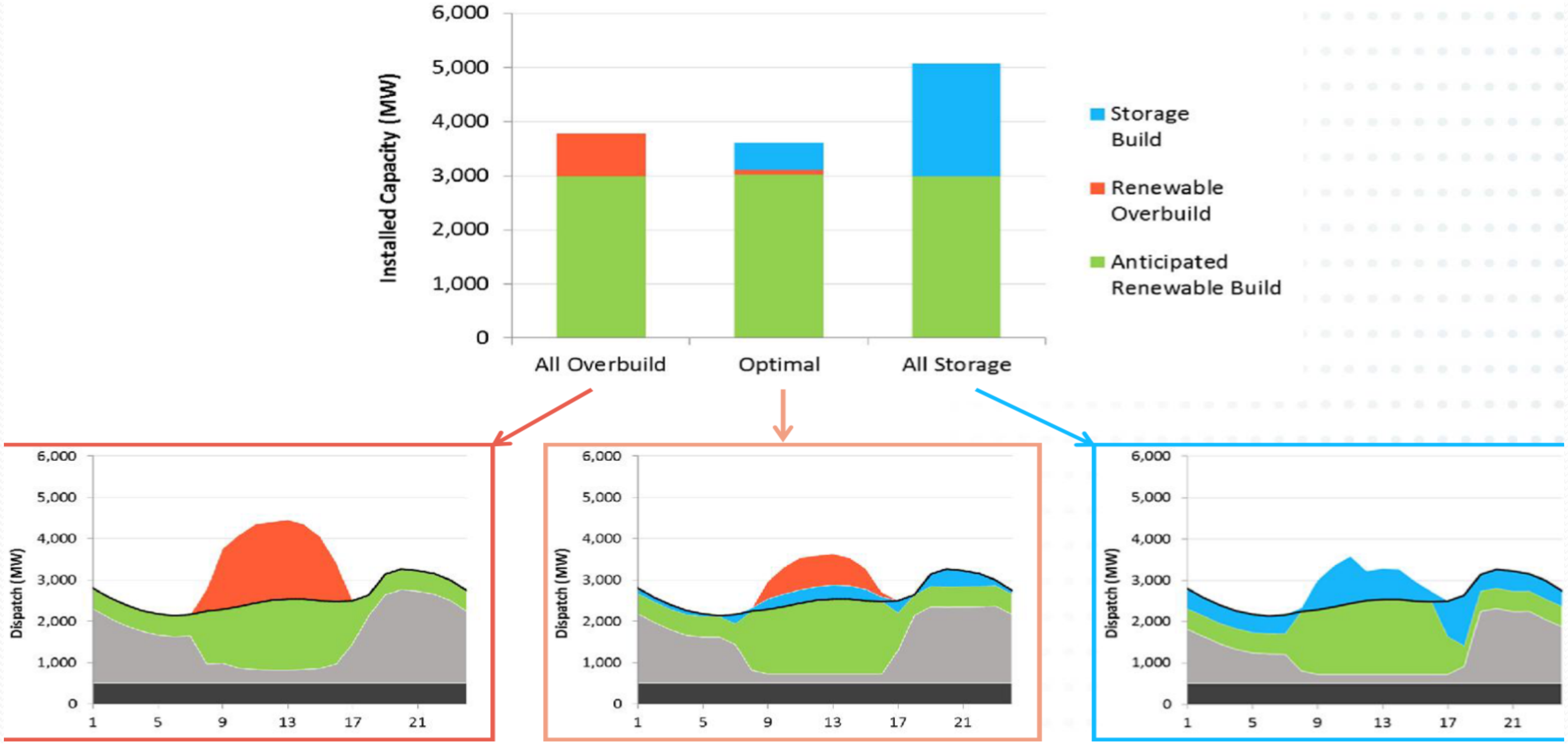
Requires New Operating Conditions

1) Expand the ISO control area beyond California
2) Increase participation in the western Energy Imbalance Market in which real-time energy is made available in western states
3) Transition cars and trucks to electricity
4) Time-of-use rates that promote using electricity during the day when there is plentiful solar energy
5) Increase energy storage
6) Increase the flexibility of power plants to more quickly follow ISO instructions to change its generation output levels.



120
100
80
60
40
20
0
Curtailment (GWh)
450
400
350
300
250
200
150
100
50
0
Cumulative (Gwh)
Jan-15
Feb-15
Mar-15
Apr-15
May-15
Jun-15
Jul-15
Aug-15
Sep-15
Oct-15
Nov-15
Dec-15
Jan-16
Feb-16
Mar-16
Apr-16
May-16
Jun-16
Jul-16
Aug-16
Sep-16
Oct-16
Nov-16
Dec-16
Jan-17
Feb-17
Mar-17
Renewable Curtailment
Avoided Curtailment
Cumulative Avoided Curtailment

Optimal Solution Balances Non-Renewable Solutions with Overbuild



Inventory of Current Candidate Resources

Integration Solution	Examples of Available Options	Functionality
Energy Storage	• Batteries: 1-, 2-, 4-, or 8-hour • Pumped Storage: 12-hr, 24-hr	• Stores excess energy for dispatch in later hours • Contributes to meeting minimum generation and ramping constraints
Flexible Loads & Advanced Demand Response	• Flexible electric vehicle charging • Flexible water heaters • Flexible building thermal loads (eg. pre-cooling or pre-heating) • Flexible fuel production (electrolysis) • Other flexible loads	• Delays and dispatches electric loads based on balancing needs subject to service demand constraints • Can be scheduled based on seasonal/diurnal trends or dispatched dynamically
Conventional Demand Response	• LTPP modeled programs ($600/MWh and $1,000/MWh priced resources) • New demand response programs	• Provides capacity to avoid unserved energy
New Flexible Gas Plants	• Simple cycle gas turbines • Reciprocating engines • Flexible combined cycle gas turbines	• Dispatches economically based on heat rate, subject to ramping limitations • Contributes to meeting minimum generation and ramping constraints
Renewables	• Biofuels • Geothermal • Solar PV • Wind	• Dynamic downward dispatch (with cost penalty) of renewable resources to help balance load

PCIA Review

Charges Paid by CCAs

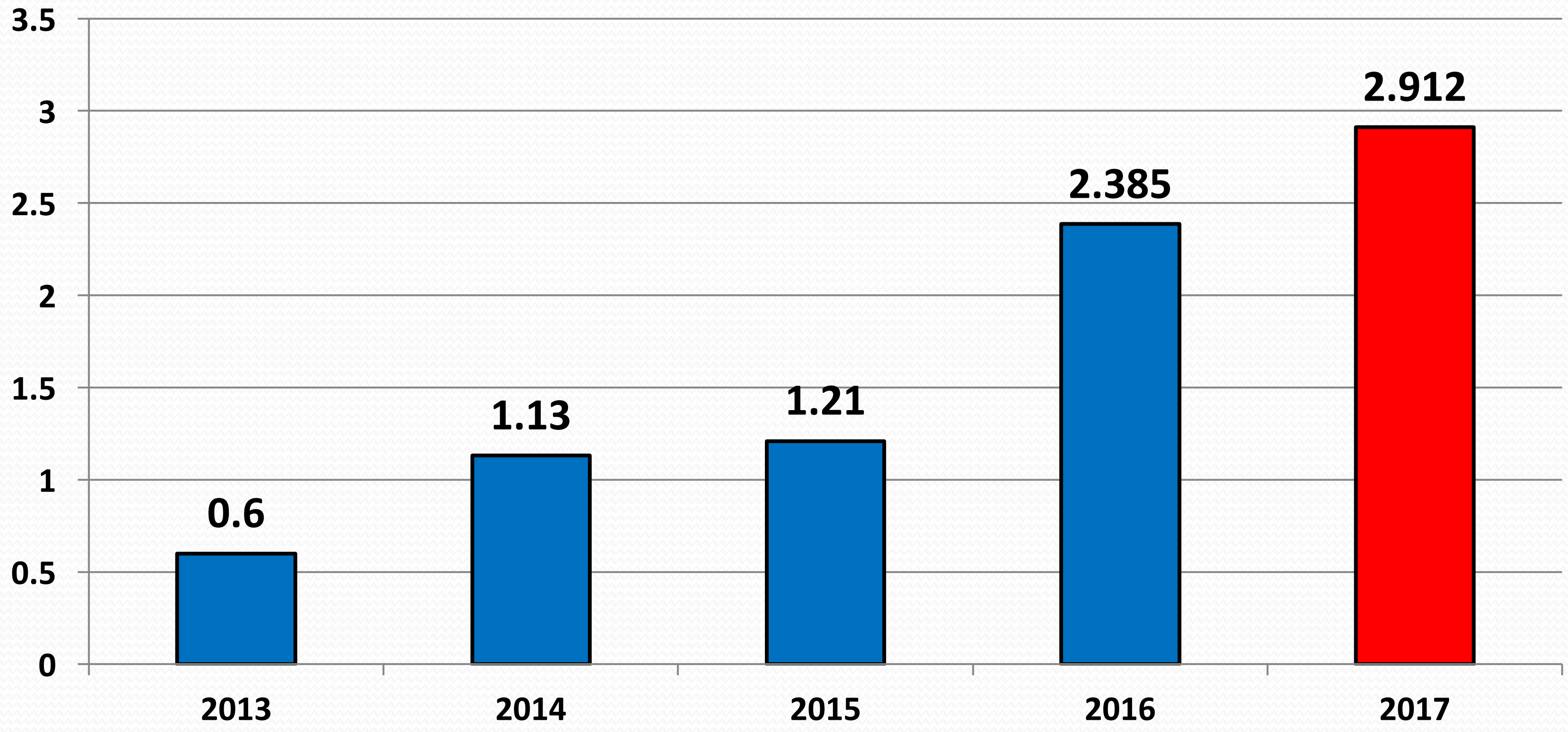
- Energy Cost Recovery Amount (ECRA)
  - Pays principal and interest on bond costs set by PG&E bankruptcy decision.
- Dept of Water Resources (DWR) Bond Charges
  - Recovers under collection of procurements costs during 2001 crisis paid by DWR
- Competition Transition Charge (CTC)
  - Charge for legacy contracts prior to 1998, that exceed CPUC market price limit
- Power Charge Indifference Adjustment (PCIA)
- Cost Allocation Mechanism (CAM) Charge
  - To pay for new resources added for system reliability
- Nuclear Decommissioning (ND) Charge
  - Restore closed nuclear plant sites to original conditions.
- Public Purpose Program (PPP) Charge
  - Low income ratepayer assistance and energy efficiency

PG&E 2016 CCA Charges ($)

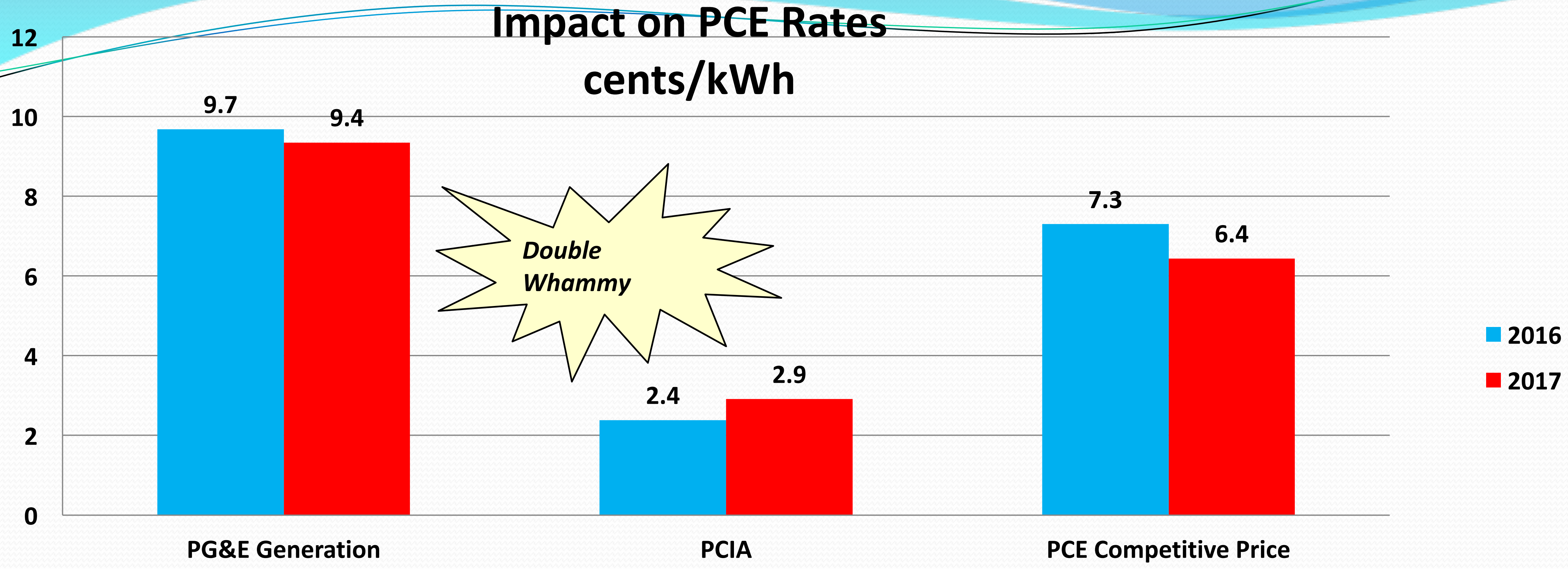
Charge	Residential (KWh)	Large Industrial (kWh)
Energy Cost Recovery (ECRA)	0.00002	0-00002
DWR Bond	0.00539	0.00539
CTC	0.00338	0.00187
PCIA (2015 Vintage)	0.02323	0.01284
CAM	0.00255	0.00160
ND	0.00022	0.00022
PPP	0.01405	0.00982
TOTAL	0.04880	0.03172

Charge	PG&E	SCE	SDG&E
PCIA	0.02323	0.00098	0.01278
TOTAL	0.04880	0.03217	0.03247

PCIA (cents/kwh)



PG&E is asking $245.9M in 2017 from PCIA accounts.
PCIA will rise to about 3 cents/ kwh, 0.65 cents higher than 2016.



For every $1 PG&E will spend on electricity generation, CCA will only be able to spend $0.68 to remain competitive.

Power Charge Indifference Adjustment

- PCIA is a utility exit fee aimed at recovering stranded utility costs resulting from departing customer load. It pays for power that has been contracted by the utility but is no longer needed by departing customers.

- The idea is to keep the bundled ratepayer from being adversely impacted by departing load brought about by CCA and other competitive market options.

- The PCIA methodology is in dire need of reform, greater transparency, fair application, and greater accountability.

PCIA Methodology

- The PCIA represents the difference between the utilities' contracted rate and the market price benchmark set annually by the CPUC.
- The market price benchmark (MPB) represents what the utility would get in the current market to sell-off unused power contracts
- RPS adder, a component of MPB, uses average of DOE Survey of Western energy premiums and PG&E' RPS compliant resources.
- In essence, we pay the difference between power prices of several years ago and wholesale prices today.

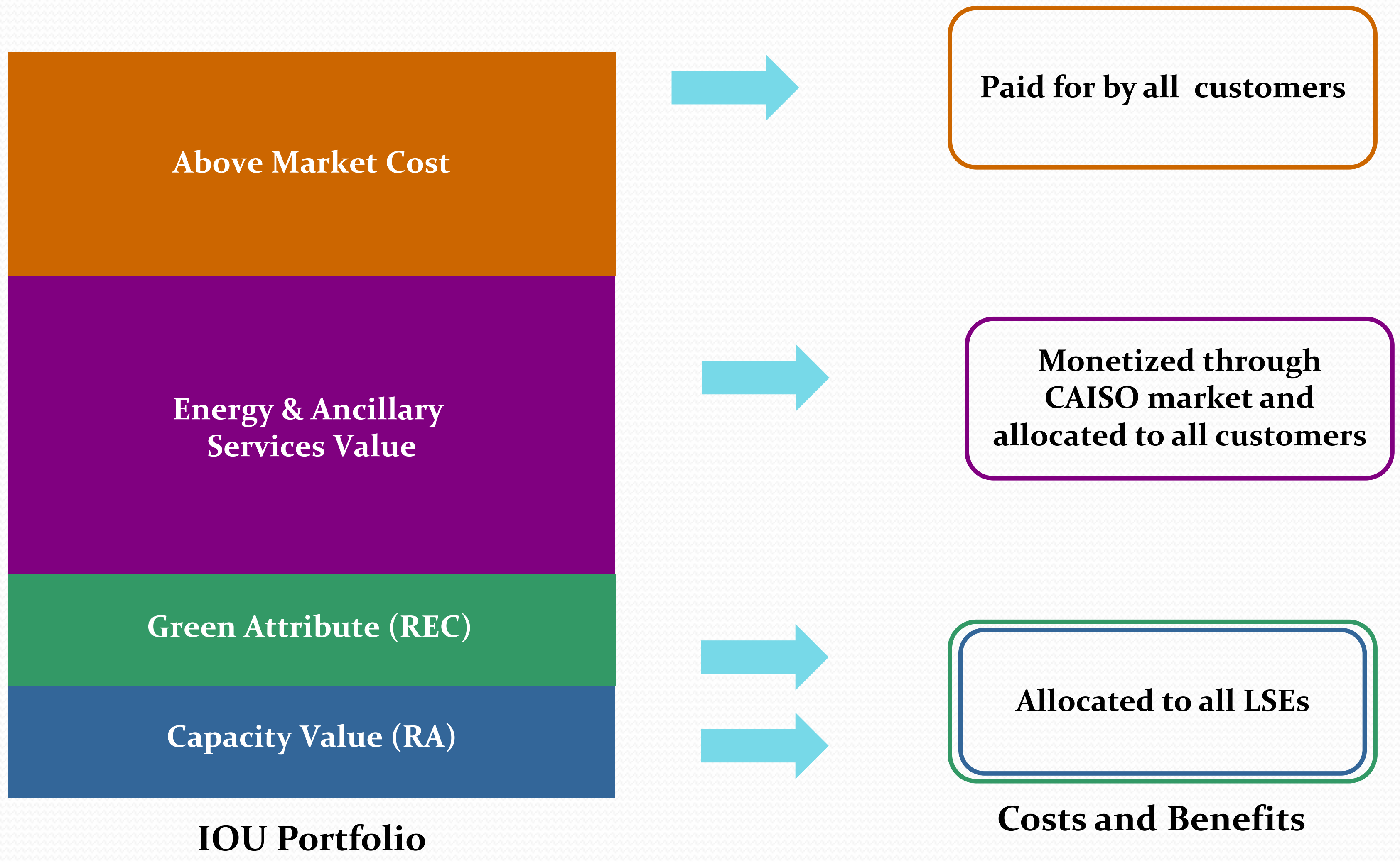
PCIA ISSUES

- SB 350- protection of departing customers from costs not incurred on their behalf.
- Information sharing- load forecasting, IOU contracts, non disclosure.
- Data access
- Modify PCIA Methodology
  - Cost inputs
  - Market price benchmarks
  - IOU portfolio to minimize stranded costs
  - PCIA forecasting and cap
  - Sunset of PCIA
  - Accuracy of indifference assumption
- Alternatives
  - PAM
  - Portfolio buy out
  - IOU contracts assigned to CCAs

IOU Proposed Portfolio allocation methodology (PAM)

MARKET-BASED DETERMINATION OF ACTUAL COSTS	Pro-rated net costs allocated to customers would be determined on a vintaged portfolio basis, based on forecast portfolio costs and market revenues, and would be trued up to reflect actual costs and revenues.
EQUITABLE ALLOCATION OF ACTUAL BENEFITS	Load Serving Entities (LSEs) would receive a pro-rated allocation of resource attributes, including Resource Adequacy (RA), Renewable Energy Credits (RECs), and any future attributes.

PAM OVERVIEW



CalCCA- Issues with PAM

1. Utility costs higher than sum of RECs, RA, energy.
2. Data unavailable- SFPUC request denied.
3. Regulatory gaps- process to transfer RECs, RA, RPS contracts.
4. Monetization of benefits to LSE-
5. LSEs have contracted for their needs
6. Avoided costs due to departing loads not included.

PUC Order

- Improve transparency
- Methodology to improve stability and certainty
- Address issues related to inputs and calculations
- Alternatives to PCIA
- Consider SB 350
- Bundled customers indifference
- Should be transparent
- Predictable outcomes
- Flexible and stable even though departing customers numbers change
- Should not create unreasonable obstacles to CCAs
- Consistent with California State policies.

New IRP
CCA Concerns

Existing Resource Planning

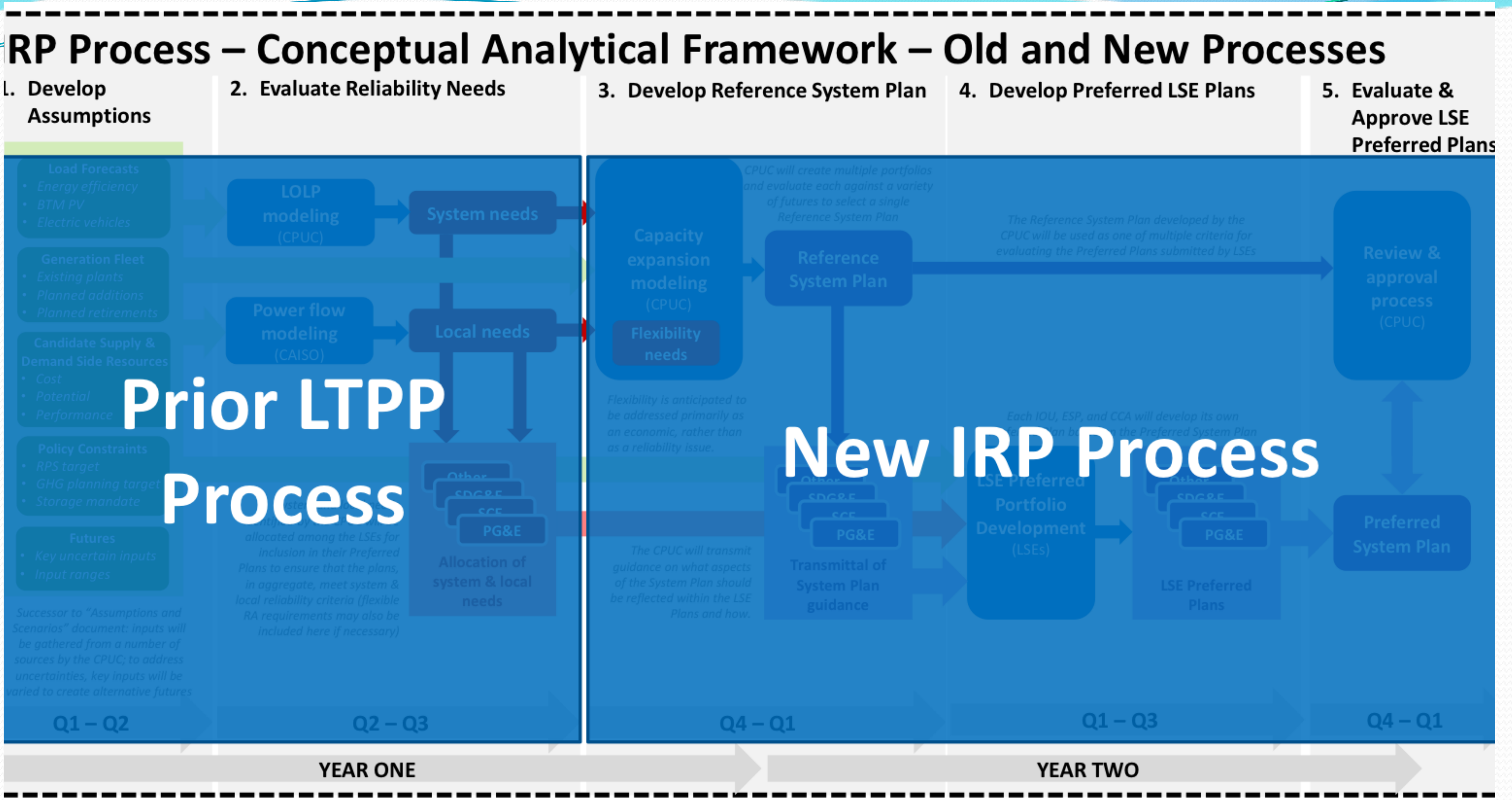
- CEC- Integrated Energy Planning Report for 10 years. (IEPR)
- CPUC- Using IEPR, develops Long Term Procurement Process (LTTP) and sets long term resource goals to meet state goals such as RPS or storage.
- CAISO uses IEPR to transmission planning.

CPUC IRP (SB 350)

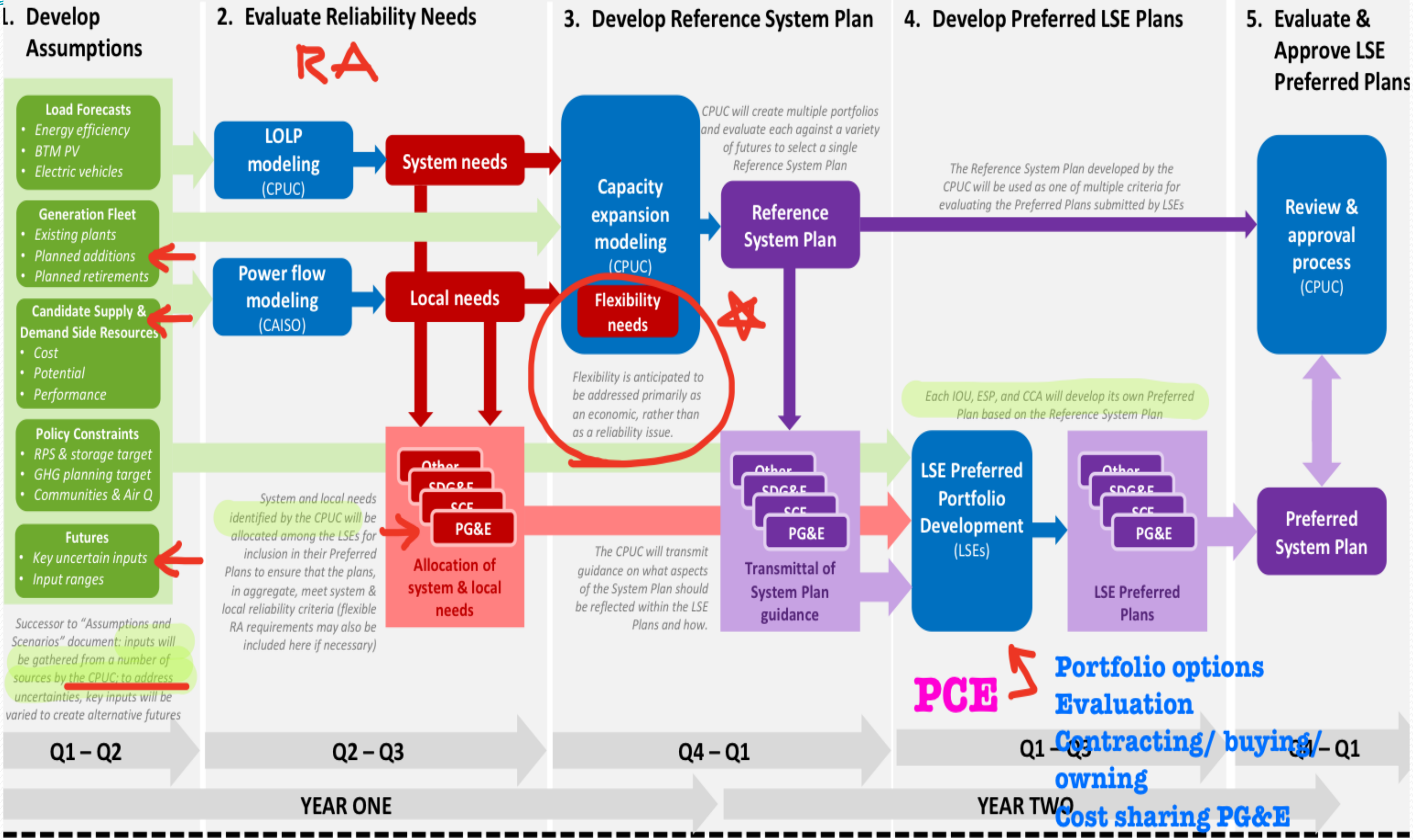
- Achieve the state's GHG reduction goals
- Maintain Reliability
- Minimize cost
- Prioritize Air Quality in Disadvantaged Communities
- Best mix of supply- and demand-side resources
- *Guide resource investment decisions across all types of load-serving entities (LSEs) and resource programs*

PUC Proposed Approach

- CARB establishes GHG targets
- PUC identifies optimum portfolio and action plan called Reference System Plan (RSP)
- LSEs (CCAs also) use RSP to develop their plans for PUC review. (E2)
- PUC aggregates LSE plans to develop Preferred System Plan which replaces RSP.


RP Process – Conceptual Analytical Framework – Old and New Processes
1. Develop Assumptions
2. Evaluate Reliability Needs
3. Develop Reference System Plan
4. Develop Preferred LSE Plans
5. Evaluate & Approve LSE Preferred Plans
Load Forecasts
Energy efficiency
BTM PV
Electric vehicles
Generation Fleet
Existing plants
Planned additions
Planned retirements
LOLP modeling (CPUC)
System needs
Power flow modeling (CAISO)
Local needs
Capacity expansion modeling (CPUC)
Flexibility needs
Reference System Plan
Review & approval process (CPUC)
Preferred System Plan
PG&E
Allocation of system & local needs
Transmittal of System Plan guidance
LSE Preferred Portfolio Development (LSEs)
LSE Preferred Plans
Prior LTPP Process
New IRP Process
Q1 – Q2
Q2 – Q3
Q4 – Q1
Q1 – Q3
Q4 – Q1
YEAR ONE
YEAR TWO

RP Process – Conceptual Analytical Framework



PCE

Portfolio options

Evaluation

Contracting/ buying/ owning

Cost sharing PG&E

POLR vs RA

CPUC Staff Guiding Principles

- *The IRP process should recognize that filing entities have different governing bodies, procurement processes, and statutory obligations*, while also ensuring that the basic content and format of their IRPs are consistent and usable despite those differences
- Any resulting costs from procurement directed by the IRP process should be allocated in a fair and equitable manner to LSE customers, and there should be *no cost shifting between customers of LSEs*.(PG&E, SCE, SDG&E)

CCA Concerns

- CCA PROGRAM PROCUREMENT AUTONOMY AND JURISDICTIONAL AUTHORITY MUST BE PRESERVED AS A MATTER OF LAW .

  - CCA programs have broad and exclusive authority to control procurement for their customers.
  - Legislature has granted the Commission limited jurisdiction over CCA programs, such as the renewables portfolio standard, resource adequacy requirements and energy storage mandates

- SB 350'S REQUIREMENTS FOR CCA PROGRAMS SHOULD NOT BE CONFUSED WITH REQUIREMENTS FOR ELECTRICAL CORPORATIONS

  - LSEs are required to file an integrated resource plan, but an electrical corporation must file a plan that includes an "assessment of the price risk associated with the electrical corporation's portfolio". A CCA program, meanwhile, must meet less onerous requirements, and file a plan with "[e]conomic, reliability, environmental, security, and other benefits and performance characteristics" and a "diversified procurement portfolio consisting of both short-term and long- term electricity and electricity-related and demand reduction products."

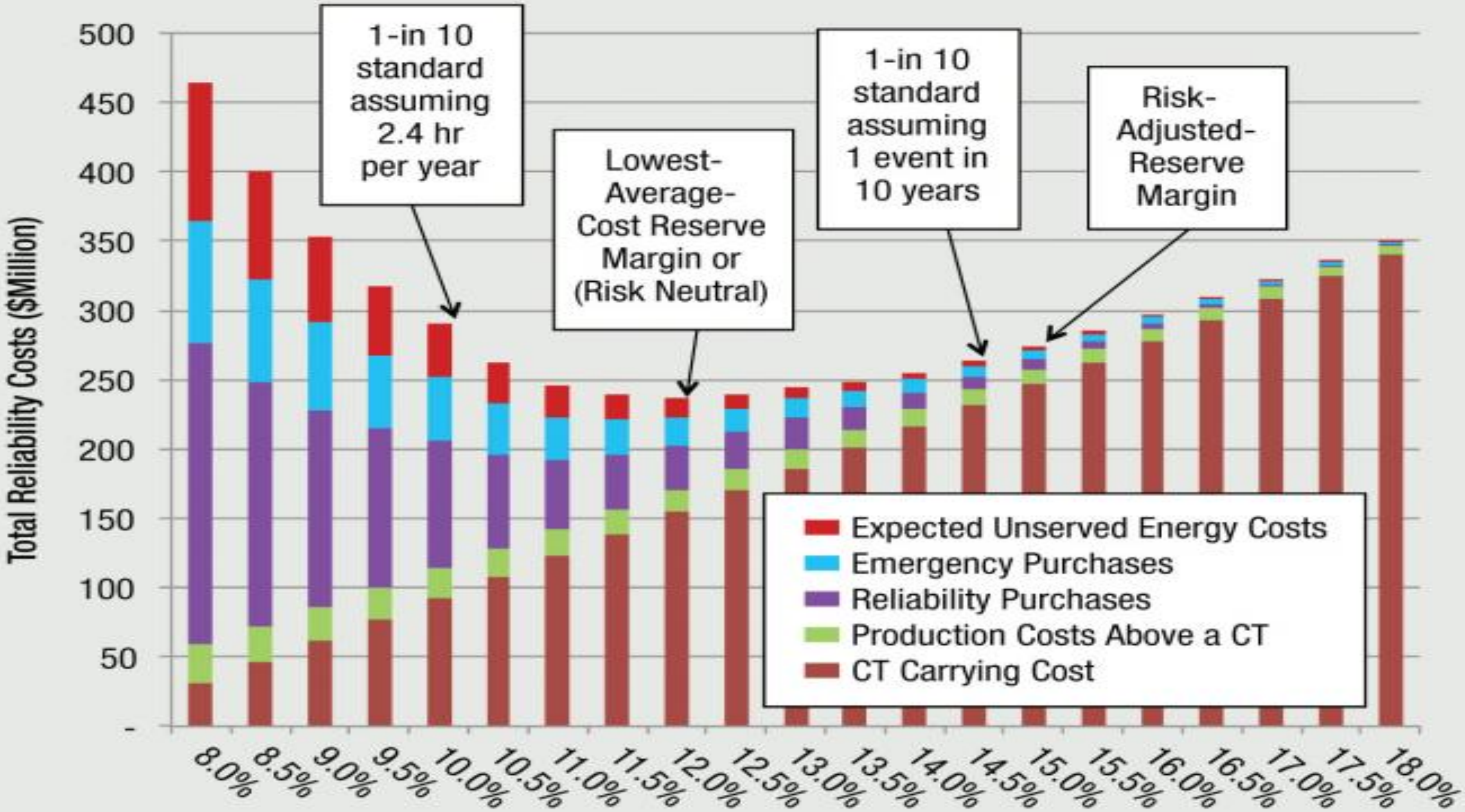
Resource Adequacy

Ability to Meet Peak Load and Generation Outage

- Loss of Load Probability- LOLP- one event (3 hours) of firm load shed in 10 years.
- With more solar- ramping has become important
- Traditional- CAISO Reliability Must Run Contracts for reliability
- RA as replacement for CAISO RMR – LSE contracts for capacity required in bilateral manner-
- East coast- Centralized Capacity Markets

Reliability Issues

- CPUC Resource Adequacy covers IOUs, CCAs, ESPs.
- LSEs submit load forecasts- CPUC determines RA requirements.
- Whenever new procurement needed- CPUC orders IOUs to procure capacity.
- Cost is shared by all LSEs through Cost Allocation Mechanism (CAM).
- With growing non IOU load, the RA program of objectives of reliability and policy goals may face issues.



The cost of reliability events increases quickly as reserve margins decline. And different interpretations of the 1-in-10 standard—i.e., either 2.4 hours of lost load per year or one event in 10-

Conclusions

- Electric utility systems foundations
  - System configuration- more focus on DER critical
  - Regulation- collaboration needed
  - Transmission management- wider interconnections and storage
- Business Environment- changes occurring faster
- PCIA- CCA push for new methodology
- IRP Concerns- jurisdiction issues
- Resource Adequacy- double counting