CITY OF RIVERSIDE

Arts & Innovation

2014 Power Supply Integrated Resource Plan

Utility Services/Land Use/Energy Development Committee

July 7, 2015

Glossary

AB32 – Assembly Bill 32 – Global Warming Solutions Act

CAISO – CA Independent System Operator

CARB – CA Air Resources Board

CEC – California Energy Commission

CC – Combined Cycle

COS_{LN} - Cost of Service

CPUC – CA Public Utilities Commission

EIM – Energy Imbalance Market

ES – Energy Storage

EPA – Environmental Protection Agency

FERC – Federal Energy Regulatory Comm.

FRAC/MOO – Flexible Resource Adequacy Criteria/Must Offer Obligation

GHG – Green House Gas

IPP – Intermountain Power Project

JRF – Joint Reliability Framework

MIC – Maximum Import Capability

NG – Natural Gas

PV – Photovoltaic

PCC – Portfolio Content Category

PPA – Power Purchase Agreement

RA – Resource Adequacy

RPS – Renewable Portfolio Standard

SC – Simple Cycle

SCAQMD – South Coast Air Quality Management District

IRP Process: Background Information

Process / Activity	Time Period
IRP Pre-planning activities	Aug-Sept 2013
Initial IRP studies / simulations	Oct-Dec 2013
Drafting of initial document (13 chapters, 6 Appendices)	Jan-May 2014
External review of initial draft IRP	Jun-Jul 2014
Revised IRP studies / additional analyses	Aug-Oct 2014
Document revisions / additions & updates	Sep-Dec 2014
Final internal RPU review of revised draft IRP	Dec-2014 – Jan-2015
Presentation to PUB	Feb 2015

2014 IRP Purpose

<u>What is an Integrated Resource Plan (IRP)?</u>

The IRP is used to guide decision making as RPU plans to meet its forecasted annual peak and energy demand (along with an appropriate reserve margin), using a combination of supply-side and demand-side resources over a period into the future.

2014 IRP Purpose & Goals

1. Provide background material/overview (Ch 2-4)
    - 20-year forward energy & peak demand forecasts
    - Current generation and transmission resources, & distribution electric system
2. Discuss critical legislative/regulatory mandates & CAISO stakeholder initiatives (Ch 5)
    - CEC, CARB, EPA, SCAQMD
    - CAISO initiatives (FRAC/MOO, EIM, ISO/CPUC JRF, FERC Order 764, etc.)
3. Summarize and assess current EE/DSM programs (Ch 6)
4. Quantify 5 year intermediate-term power resource forecasts (Ch 8)
    - Projected capacity and RA needs
    - Renewable energy and RPS mandates
    - GHG goals and mandates
    - Cash-flow risk metrics (hedging assessment)
    - Power resource budget forecasts

2014 IRP Purpose & Goals: continued

5. Quantify 20 year long-term forecast (issues, decisions & impacts: Ch 9-13)

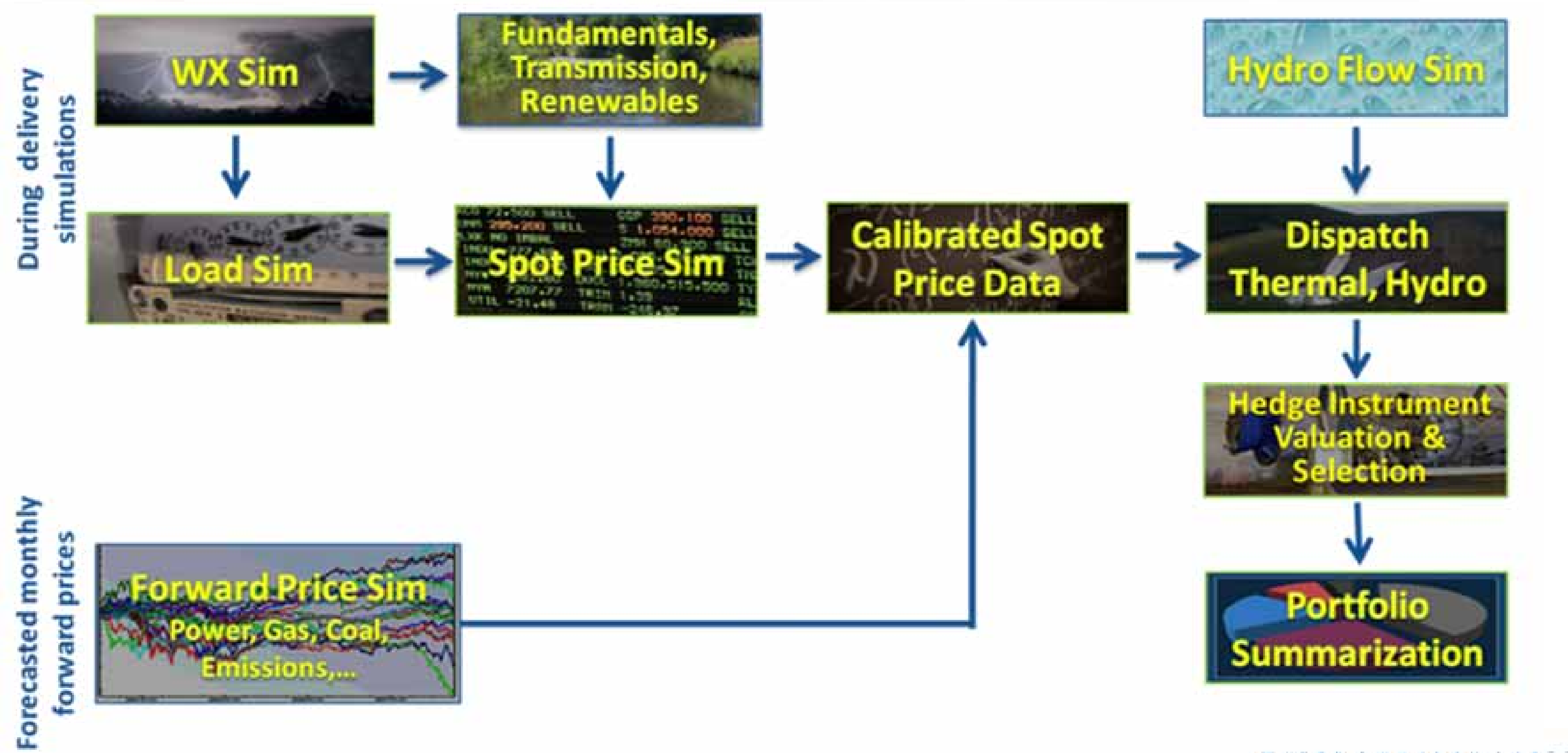
- Projected, load-normalized Cost-of-Service (COS_{LN}) scenario impacts
- Projected load growth impacts
- Critical intermediate - and long-term budgetary issues
- Sensitivity analysis - market price shock impacts
- Timing impacts of uncertain IPP contract termination date
- Potential IPP replacement options
- Impacts of changes to RPS mandates (40% and 50% by 2030 mandates)
- Impacts of increasing customer solar PV installations
- Assessment of key future market paradigms; e.g., Energy Storage, Electric Vehicles, etc.

Guiding Principles
(Selecting New Assets or Contracts)

- Will the new generation asset or contract:
  - Help RPU ensure wholesale and/or retail price stability?
  - Maintain or improve technology diversification within RPU's resource portfolio?
  - Support/improve our local or system reliability needs?
  - Meet cost effectiveness criteria?
  - Properly align with RPU's daily and/or seasonal load serving needs?
  - Reduce RPU's Carbon footprint and/or increase RPU's renewable energy supply?
  - Support RPU's commitment to environmental stewardship?

RPU is actively increasing the percentage of renewable energy assets in its resource portfolio. In the last 3-4 years, PUB/CC has approved 7 PPA's for renewable energy projects.

Analytical Workhorse: Ascend Software Suite

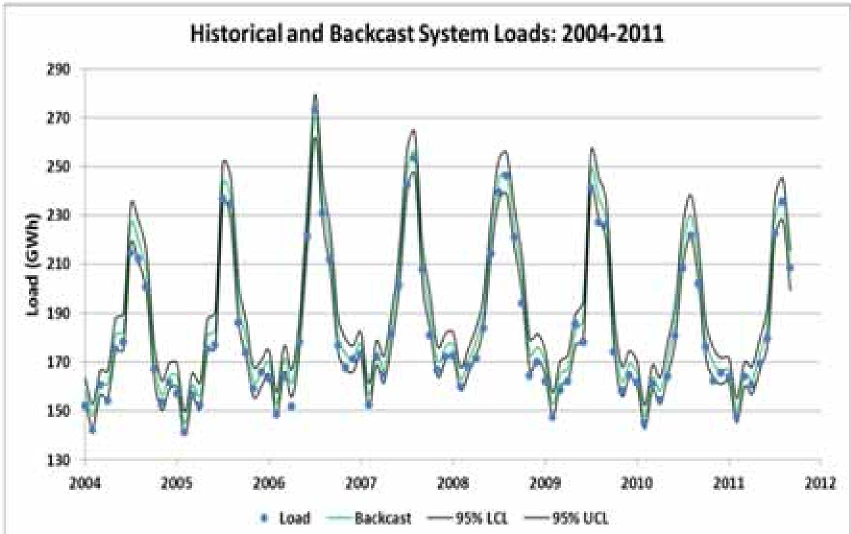


WATER | ENERGY | LIFE

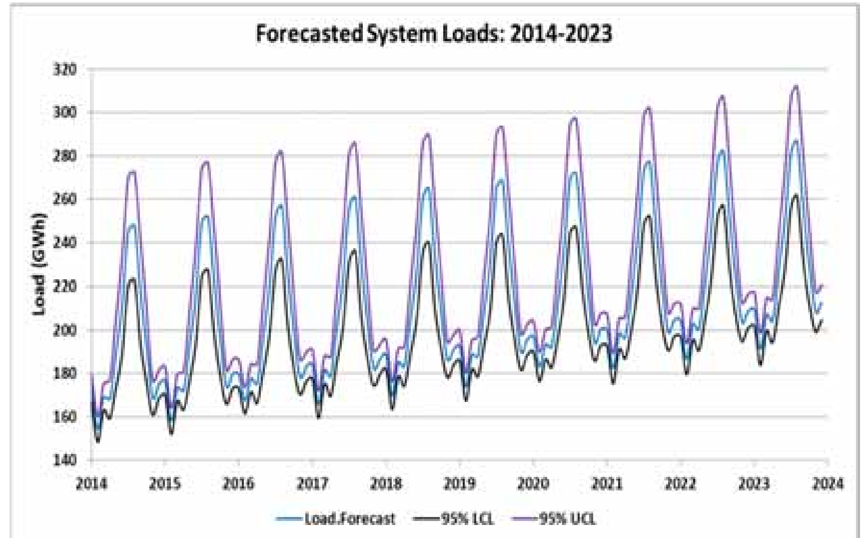
A fully integrated, PCM simulation used to value LSE portfolios (e.g., generation assets, load obligations, structured transactions, and market hedges), and to model transmission, ancillary services and DSM programs.

Chapter 2: Energy Demand Models

Historical



Forecast



Primary drivers are increasing employment & continued economic expansion

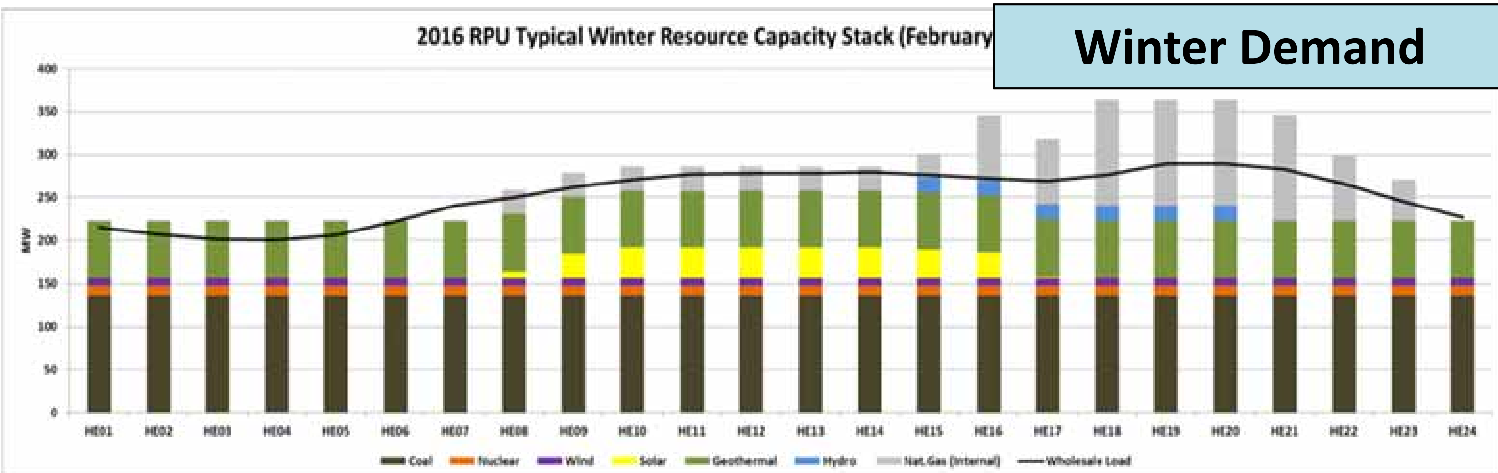
- **Strong Case:** Energy: 2.4% annual growth, Peak: 1.1% annual growth in system peak
- **Weak case:** 0.5% annual growth in energy and peak demand.

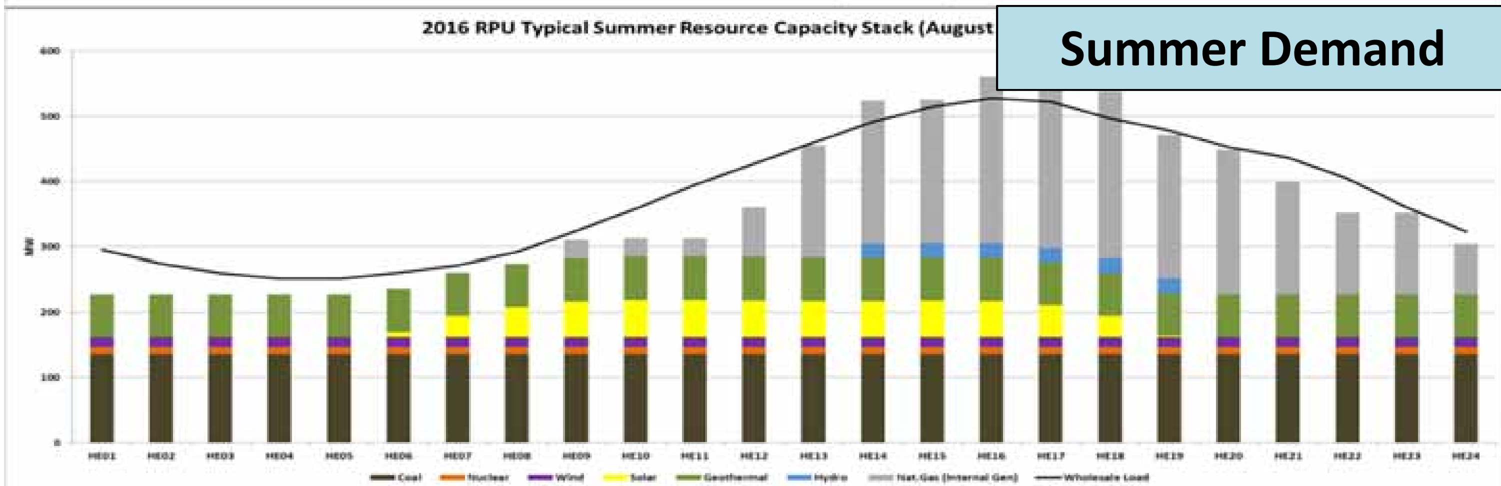
Chapter 3: RPU Resources

Existing Resources	Technology	Capacity (MW)	Contract End Date	Asset Type
Intermountain (IPP)	Coal, base-load	136	May-2027	Entitlement/PPA
Palo Verde	Nuclear, base-load	12	Dec-2030	PPA (SCPPA)
Hoover	Hydro, daily peaking	20-30	Sep-2067	PPA (SCPPA)
BPA-2	Exchange, daily peaking	15/60	May-2016	EEA
RERC 1-4	Nat.gas, dailypeaking	194	n/a	Owned Asset
Springs	Nat.gas, daily peaking	36	n/a	Owned Asset
Clearwater	Nat.gas, base-load	28.5	n/a	Owned Asset
Salton Sea 5	Geothermal, renewable (base-load)	46	May-2020	PPA
Wintec	Wind, renewable	1.3	Dec-2018	PPA
WKN	Wind, renewable	6	Dec-2032	PPA
Future Resources (under contract)	**Technology**	**Nameplate Capacity (MW)**	**Contract Start & End Dates**	**Asset Type**
North Lake	Solar PV, renewable	20	Jul-2016 Jun-2040	PPA
SIlverado	Solar PV, renewable	20	Jan-2015 Dec-2039	PPA
First Solar	Solar PV, renewable	14	Jan-2016 Dec-2035	PPA
Recurrent	Solar PV, renewable	26	Jan-2015 Dec-2034	PPA
Tequesquite	Solar PV, renewable	7	Jan-2016 Dec-2040	PPA w/PO
CalEnergy Expansion	Geothermal, renewable (base-load)	20/40/86	(Feb-2016, Jan-2019, Jun-2020) Dec-2039	PPA
Cabazon	Wind, renewable	39	Jan-2015 Dec 2024	PPA
Recently Expired Contracts	**Technology**	**Nameplate Capacity (MW)**	**Termination (or Force Majeure) Date**	**Asset Type**
BPA 1	Exchange, daily peaking	16/23	Mar-2011	EEA
SONGS	Nuclear (base-load)	39	Feb-2012 Force Majeure	Ownership interest
Covanta	Waste-to-energy, renewable (base-load)	18	Dec-2013	WSPP contract

- Includes existing, future, and recently expired power contracts
- Includes existing transmission contracts

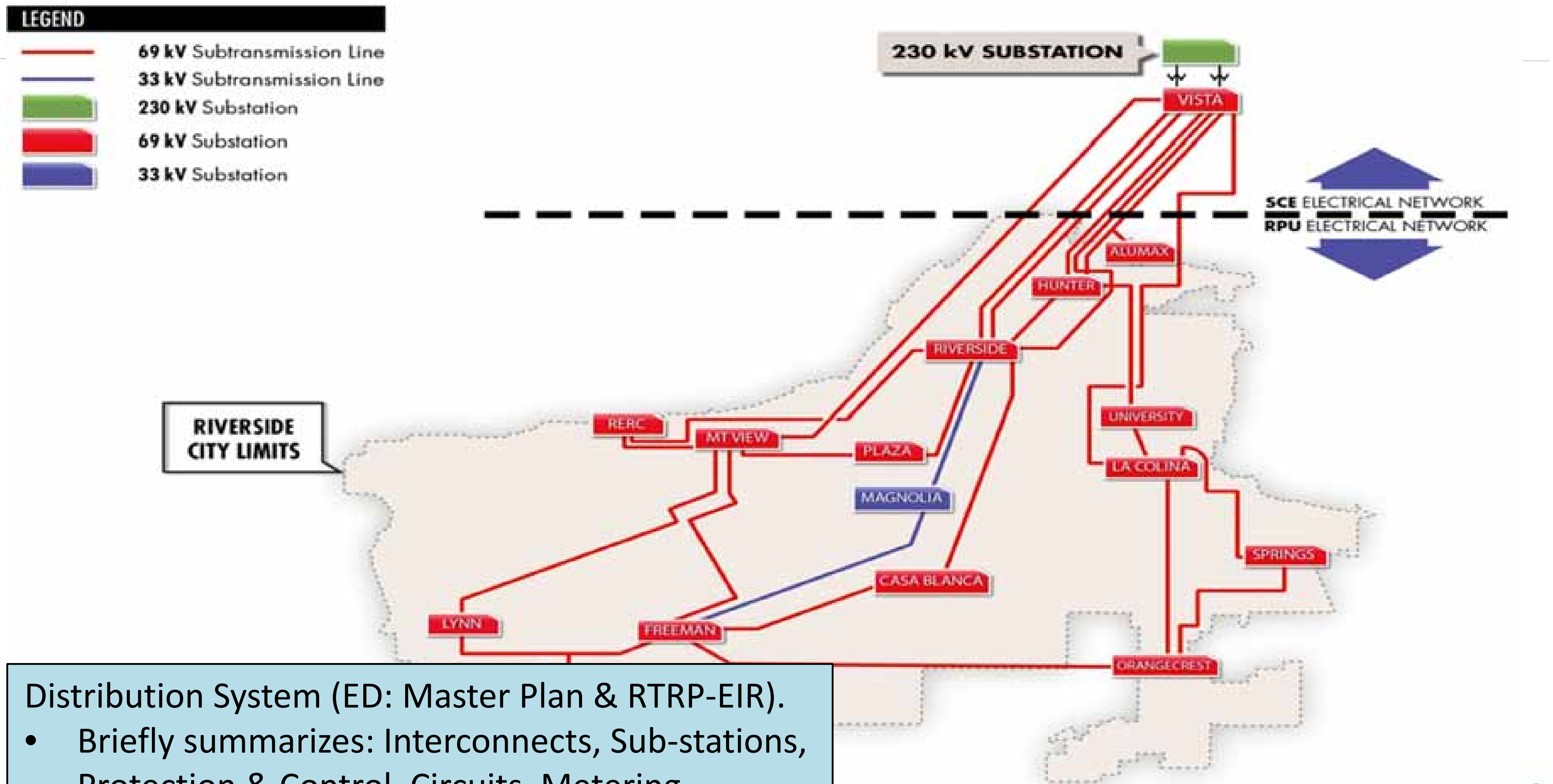
Typical RPU Winter & Summer Resource Stack and Hourly System Load Profiles





- Feb & Aug 2016 projection
- Economics: Market power v. internal gas generation

Chapter 4: RPU Electric System



Distribution System (ED: Master Plan & RTRP-EIR).

- Briefly summarizes: Interconnects, Sub-stations, Protection & Control, Circuits, Metering Systems, RTRP

Chapter 5: Critical Legislative / Regulatory Mandates & CAISO Initiatives Considered

Issues impacting RPU's planning process for future portfolio

- SB X1-2: Renewable Portfolio Standard (RPS)
- AB 32: California GHG Reduction Mandate
- SB 1368: Emission Performance Standard
- AB 2514: Energy Storage (Chapter 12)
- AB 2021: EE/DSM (Chapter 6)
- Distributed Generation (DG): Governor's executive directive
- Energy Imbalance Market (EIM) Initiative
- FERC Order 764: 15 Minute Market Initiative
- Flexible Resource Adequacy Criteria & Enhanced Must Offer Obligation (FRAC/MOO & MIC)
- CAISO/CPUC Joint Reliability Framework

Chapter 6: Review of RPU EE/DSM Programs

Riverside	Resource Savings Summary		
FY12/13 Program Sector (Used in CEC Report)	**Units Installed**	**Net Peak kW Savings**	**Net Annual kWh Savings**
Residential			
Appliances	1,162	157	61,237
HVAC	16,175	775	2,406,984
Appliances	614	52	15,080
Consumer Electronics	552	6	52,081
Lighting	25,532	241	1,509,075
Pool Pump	147	8	32,559
Refrigeration	3,369	198	933,811
HVAC	539	75	103,628
Water Heating	-	-	-
Comprehensive	627		492,330
Non-Residential			
Cooking	-	-	-
HVAC - Cooling	1,472	182	316,218
HVAC - Heating	-	-	-
Lighting	1,323	263	7,370,370
Motors	64	29	694,965
Pumps	-	-	-
Refrigeration	89	50	964,568
Comprehensive	1,348	2	3,903,174
Other	175,258		265,152
Total	228,271	2,037	19,121,234

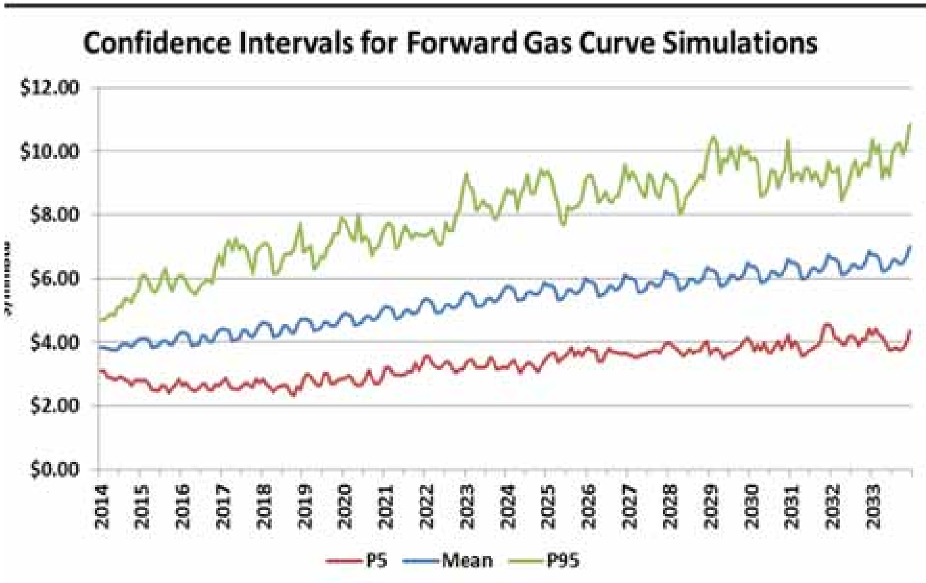
- Discusses cost/benefit principles (and provides examples)
- Discusses integration issues and offers recommendations.

Chapter 7: Market Outlook

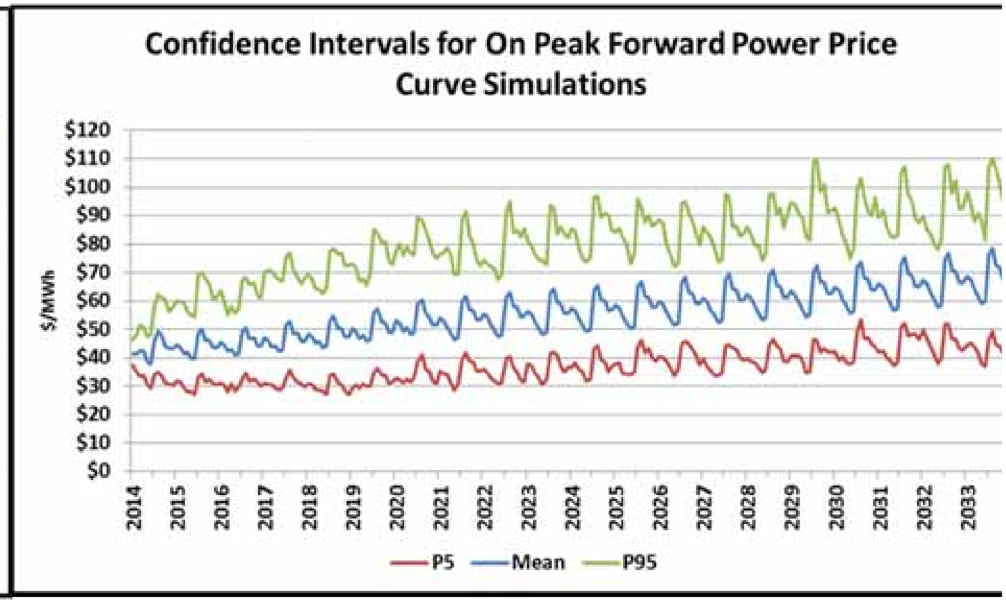
- Forward nat.gas and power curves used in all forward simulations
- So.Cal Citygate (gas) & SP15 (power) pricing for next 5-7 years from ICE.
- L/T pricing escalated at ~ 2% (consistent with cost expectations for CCNG unit)
- Price curves simulated w/avg. price levels constrained to match forward curves
- Nat.gas curve drives forward power curves (highly correlated & preserves realistic Market Heat Rates simulations)
- Nat.gas curve consistent with current industry standard forecasts (EIA & CEC).

Natural Gas/Electricity Market Price Simulations

Nat.Gas



Power



Nat.gas simulated pricing:

- 2020: $3/MMBtu to $8/MMBtu
- 2030: $4/MMBtu to $10/MMBtu

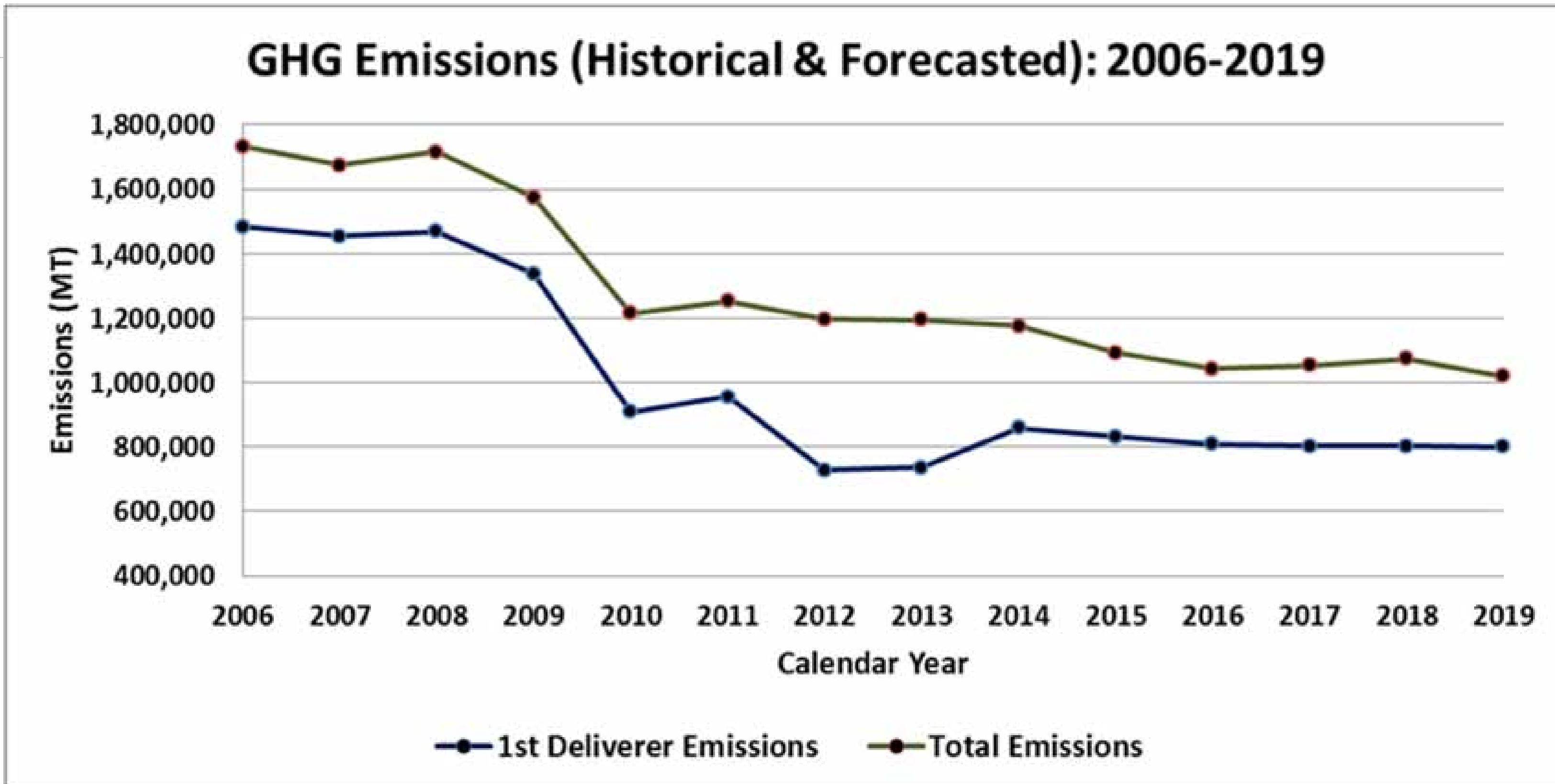
HL Power simulated pricing:

- 2020: $30/MWh to $80/MWh
- 2030: $40/MWh to $100/MWh

Chapter 8: 5-Year Forward Resource & Position Assessments (2014-2018)

- 8.1: Forecasted capacity, system peaks and Resource Adequacy needs
- 8.2: Projected RPS%'s and renewable energy resources
- 8.3: Primary resource portfolio metrics
- 8.4: Internal generation forecasts
- 8.5: Forecasted Hedging %'s and Open Energy positions
- 8.6: Unhedged Energy costs and Cost-at-Risk metrics
- 8.7: Forecasted GHG emission profiles and net carbon allocation positions
- 8.8: Five-year forward power resource budget forecasts

RPU GHG Emission Profiles



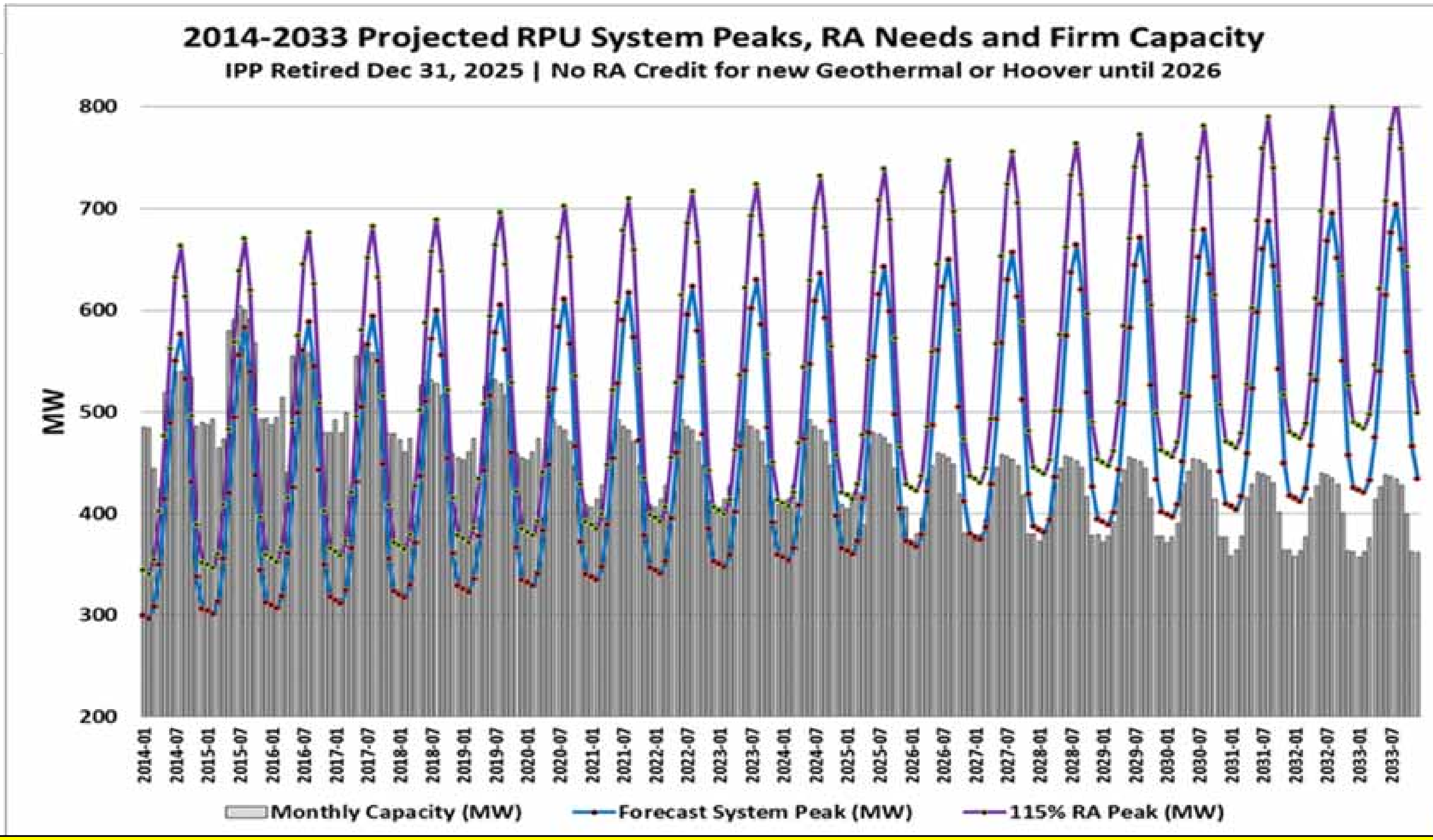
- RPU actively reducing GHG emissions profile since 2008.
- Continue reducing GHG footprint, at least through 2020.

Chapter 8 Summary

- On target for 37% RPS by 2019
- 40% RPS by 2020 is possible
- Capacity & RA needs are manageable (provided no significant changes)
- ~85% of load is naturally hedged via long-term contracts
- Open energy positions are effectively hedged and managed
- Cost-at-Risk (CAR) is ~ 2% to 4% of budget
- Sufficient carbon allowances through 2020 to cover expected GHG emissions
- Power Resource project budgets are stable through FY17/18

Most significant intermediate term risk(s): New & future CAISO initiatives (FRAC/MOO & MIC), resulting in rapidly increasing RA and ISO-uplift costs from renewable integration issues and grid stability concerns.

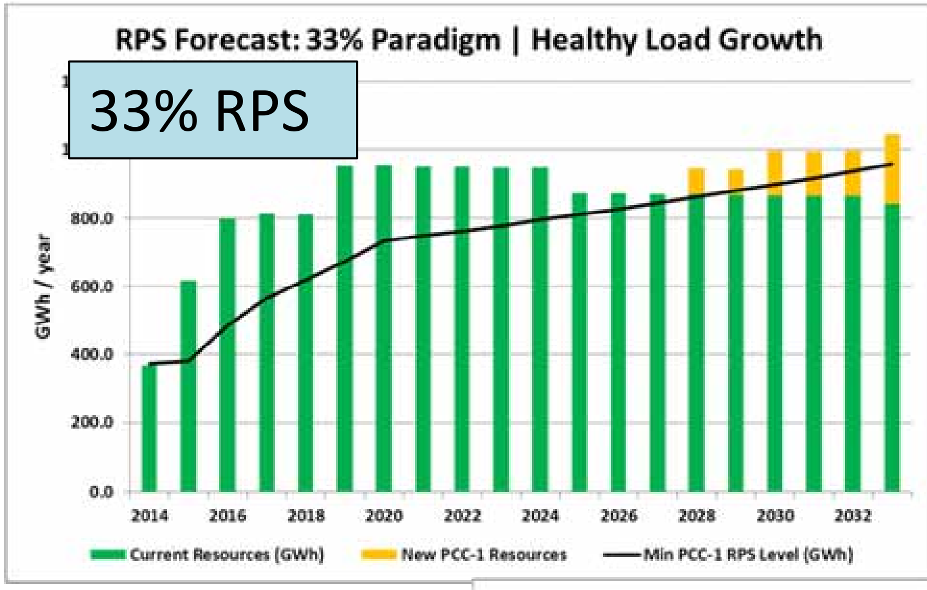
Chapter 9: Longer term RA and RPS Issues

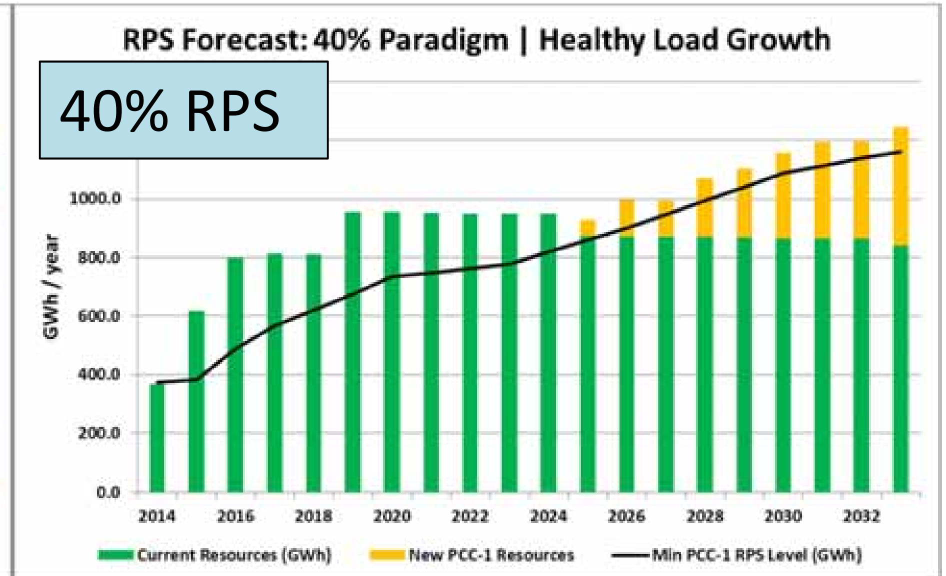


Process to receive l/t RA allocation (MIC) for Salton Sea and Hoover contracts creates significant RA/capacity needs on/after 2020.

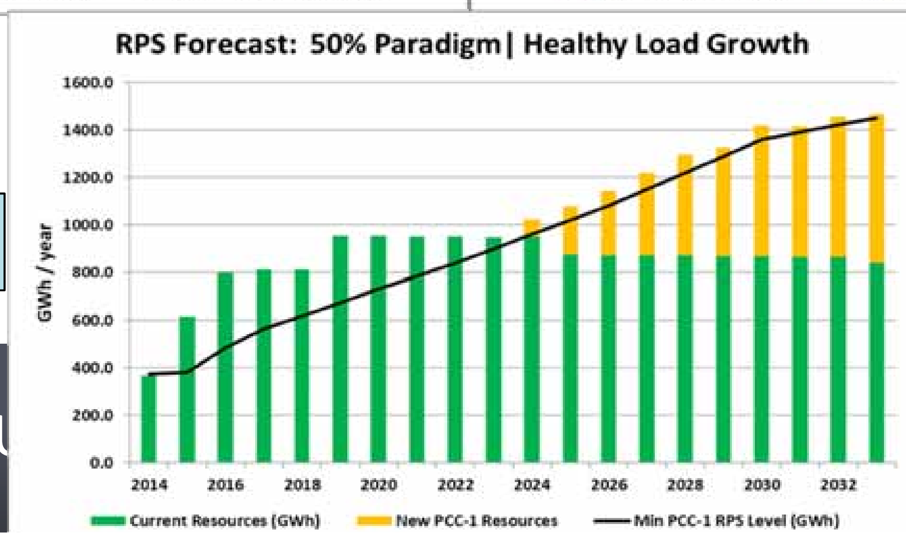
Future Renewable Energy Needs

Impacted by future load growth and RPS mandate; (Strong (healthy) load growth assumption shown)





50% RPS



Chapter 10: 12 Primary IRP Scenarios

(L/T Portfolio Analysis: Part I – Market Purchases Replace IPP)

Scenario #	Load Growth	RPS Mandate	IPP End-date (Dec 31, 20XX)	IPP Replacement Option
1	Strong	33%	2020	Market Purchases
2	Strong	33%	2020	Hedged Market Purchases
3	Strong	33%	2025	Market Purchases
4	Strong	40%	2020	Market Purchases
5	Strong	40%	2020	Hedged Market Purchases
6	Strong	40%	2025	Market Purchases
7	Weak	33%	2020	Market Purchases
8	Weak	33%	2020	Hedged Market Purchases
9	Weak	33%	2025	Market Purchases
10	Weak	40%	2020	Market Purchases
11	Weak	40%	2020	Hedged Market Purchases
12	Weak	40%	2025	Market Purchases

- 2x2x2 (2 load growth, 2 RPS mandates & 2 IPP End dates using hedged/unhedged replacements
- Quantify projected COS_{LN} and associated Risk under each scenario
- Quantify cost impacts due to each input variable
- Perform portfolio stress tests

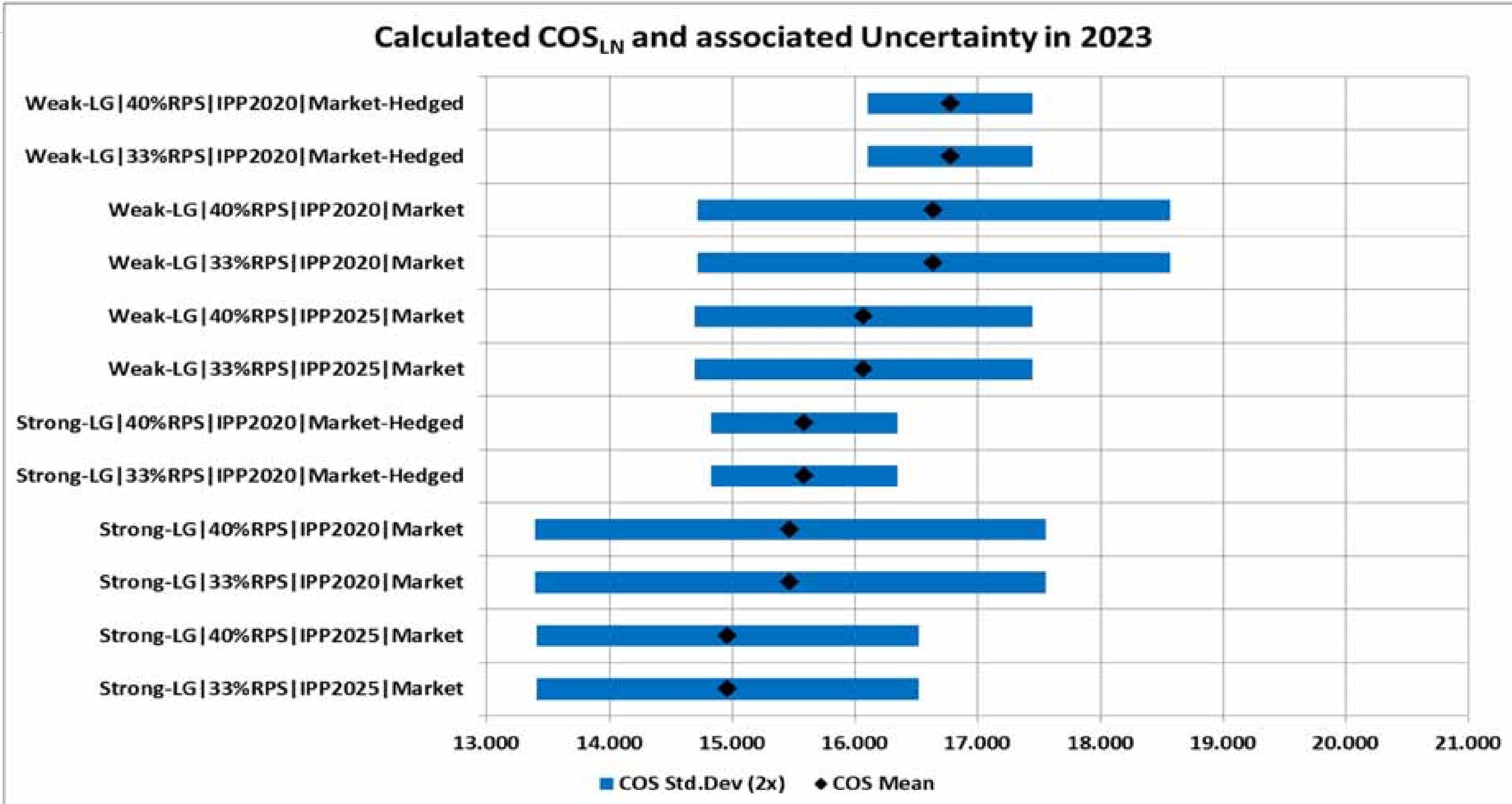
Load-normalized, Cost-of-Service (COS_{LN}) Forecasts

- Cost-of-Service comparisons on all IRP portfolios, using both the COS_{LN} forecast and the associated uncertainty surrounding this estimate (Std(COS_{LN}))

- Lower cost estimates ***AND*** lower uncertainty (risk) components should be preferred portfolio (using least-cost, least-risk selection criteria).

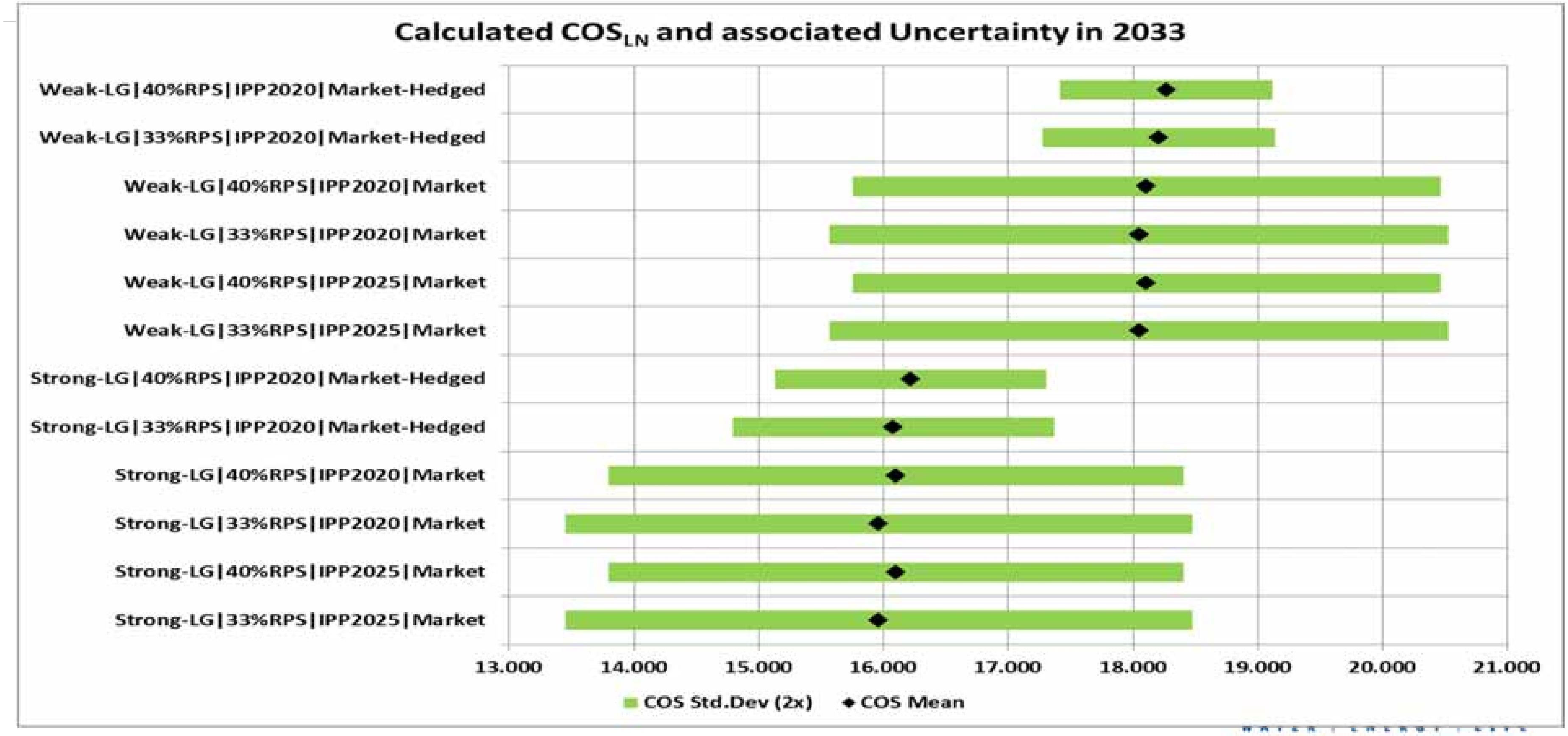
- COS_{LN} forecasts include:
  - Total generation costs (for all assets)
  - Total load costs
  - Total gross generation revenues (for all assets)
  - Mark-to-market value of all forward hedging
  - **SONGS remaining cost obligations**
  - **CAISO Transmission costs & TAC rates**
  - GHG costs & Carbon Allocation revenues
  - Resource Adequacy (RA) costs
  - **CAISO Uplift fees**
  - **RPU personnel and O&M costs**
  - **Long-term debt service costs**
  - **Expected General Fund transfer (GFT)**
  - **Misc. expenses and fees**

Factor Impacts on COS_{LN} (2023)



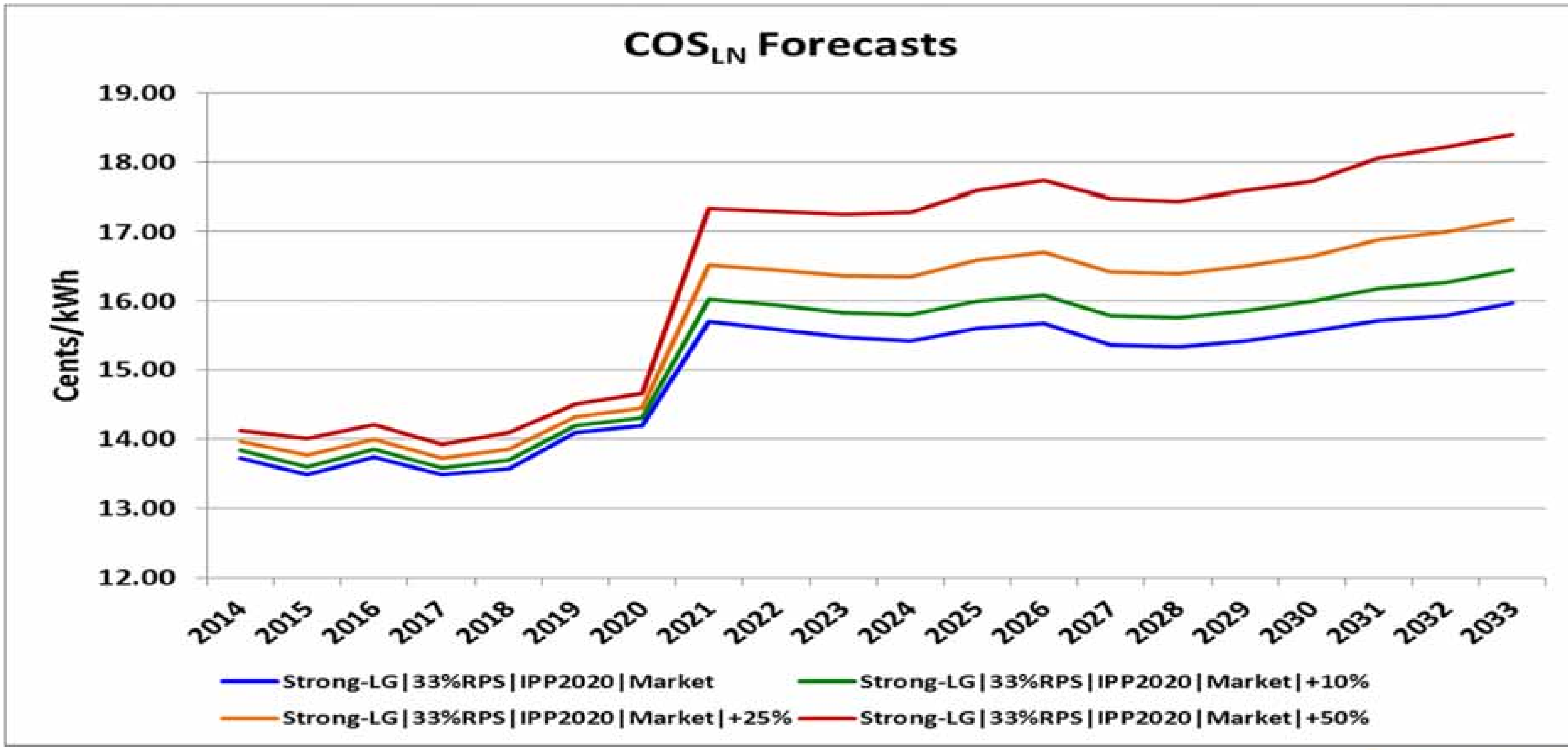
- Weak load growth raises COS_{LN} by ~8%
- Early IPP retirement raises COS_{LN} by ~4%
- 40% RPS impacts COS_{LN} beginning 2025
- Forward hedging IPP energy raises COS_{LN} by < 1%, but reduces our price risk by > 50%.

Factor Impacts on COS_{LN} (2033)



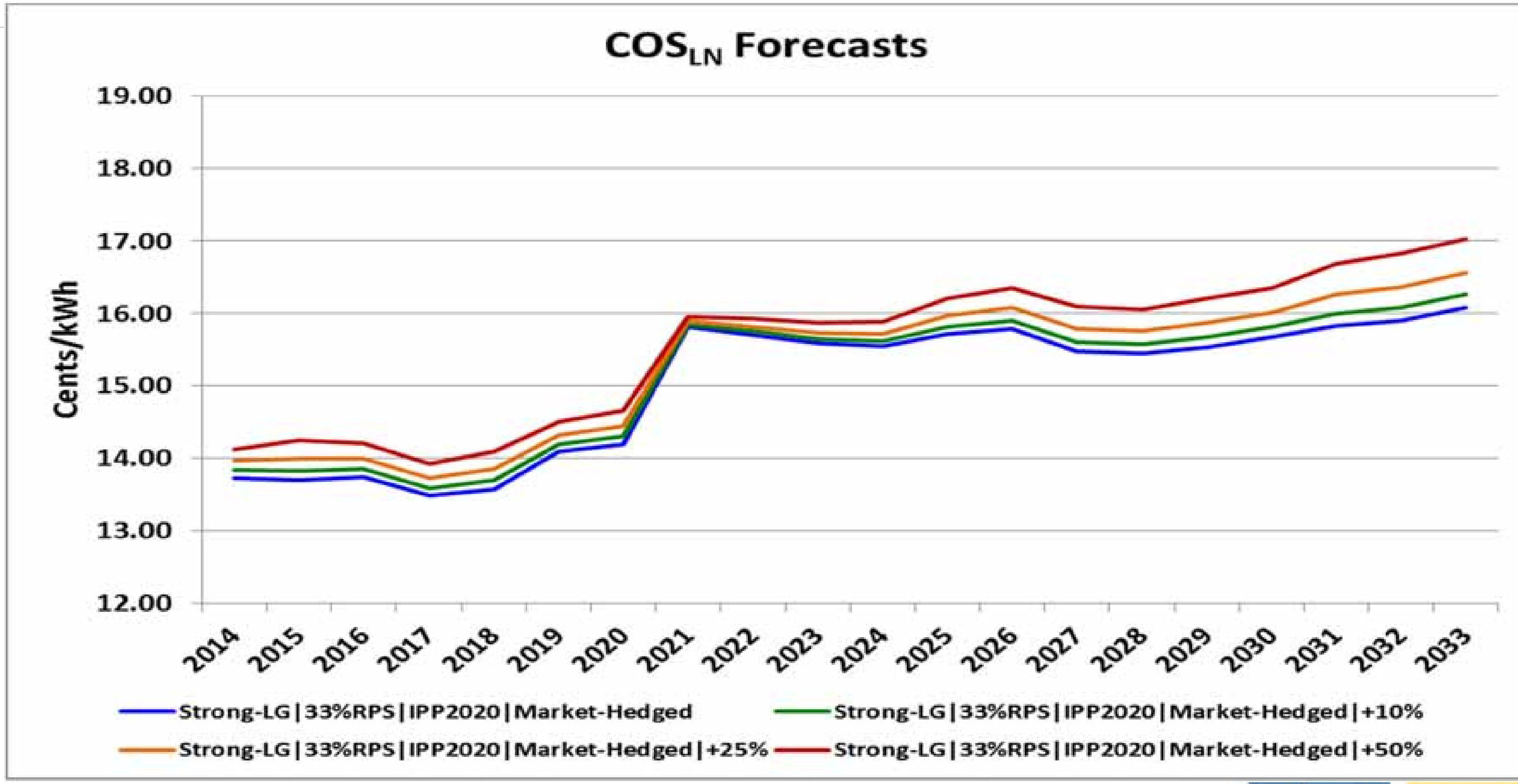
- Weak load growth raises COS_{LN} by ~13%
- Early IPP retirement has no impact after 2027
- 40% RPS raises COS_{LN} by ~1% (assumes renewable resources pricing is competitive
- Forward hedging IPP energy raises COS_{LN} by < 1%, but reduces price risk by > 50%.

Portfolio Stress Testing: IPP Replaced with Unhedged Market Energy



- 10%, 25% & 50% Market price shocks beginning in 2014.
- Unhedged market energy replaces IPP.
- COS_{LN} robust thru 2020 (before early IPP termination), w/significant impacts thereafter
- 2018: 10% → 0.9%, 50% → 3.8%
- 2028: 10% → 2.8%, 50% → 13.7%

Portfolio Stress Testing: IPP Replaced with Long-term, Forward Hedging Market Power



- 10%, 25% & 50% market price shocks beginning in 2014
- Forward market energy replaces IPP: COS$_{LN}$ remains very robust after 2020.
- 2018: 10% → 0.9%, 50% → 3.8%
- 2028: 10% → 0.8%, 50% → 3.9% (hedging significantly reduces uncertainty)

Summary Points: Long Term Analyses – Part I

- Load growth significantly impacts (10%-13%) future COS_{LN} (~ 2.0¢/kWh)
- 40% RPS has minimal impact on future COS_{LN} (~ 1%/yr., v. 33% RPS scenario)
- 50% RPS impact on future COS_{LN} (~2-7%/yr., v. 33% RPS scenario)
- Early IPP termination could result in ~ 4% COS_{LN} impact (~ 0.6¢/kWh to 0.7¢/kWh), if fixed costs extend beyond retirement date
- Loss of Carbon allowances (2020 and beyond) results in ~ 7% COS_{LN} impact (~ 1.0¢/kWh to 1.1¢/kWh).
- Risk levels decrease moderately under weak load growth and higher RPS scenarios
- Risk levels increase substantially when unhedged market purchases replace IPP energy
- Current portfolio is highly robust to adverse market price shocks, and future portfolio remains robust if RPU effectively hedges IPP replacement energy

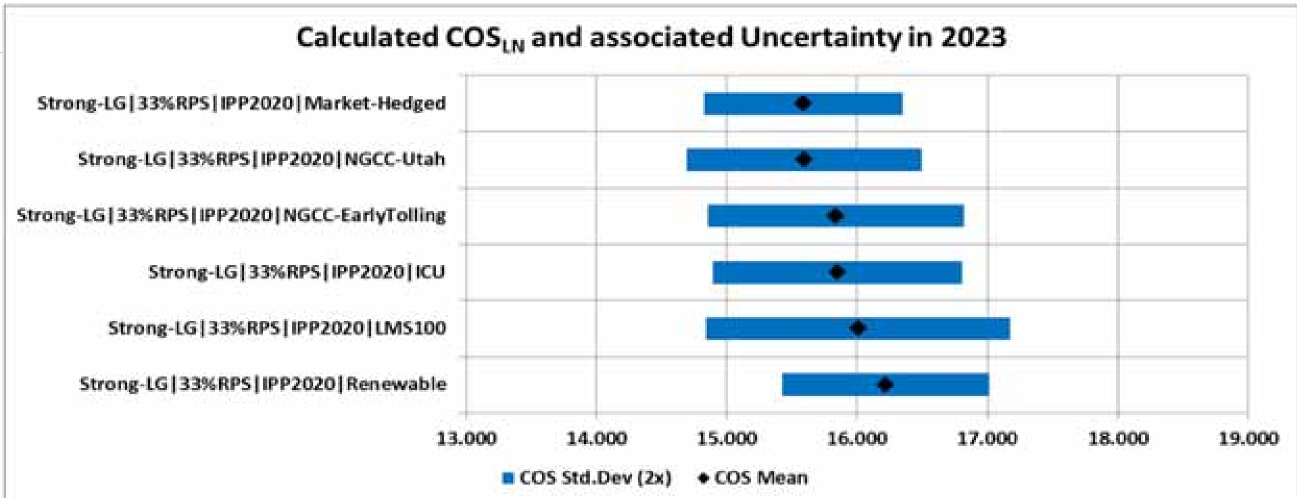
Chapter 11: Five Additional IPP Replacement Options

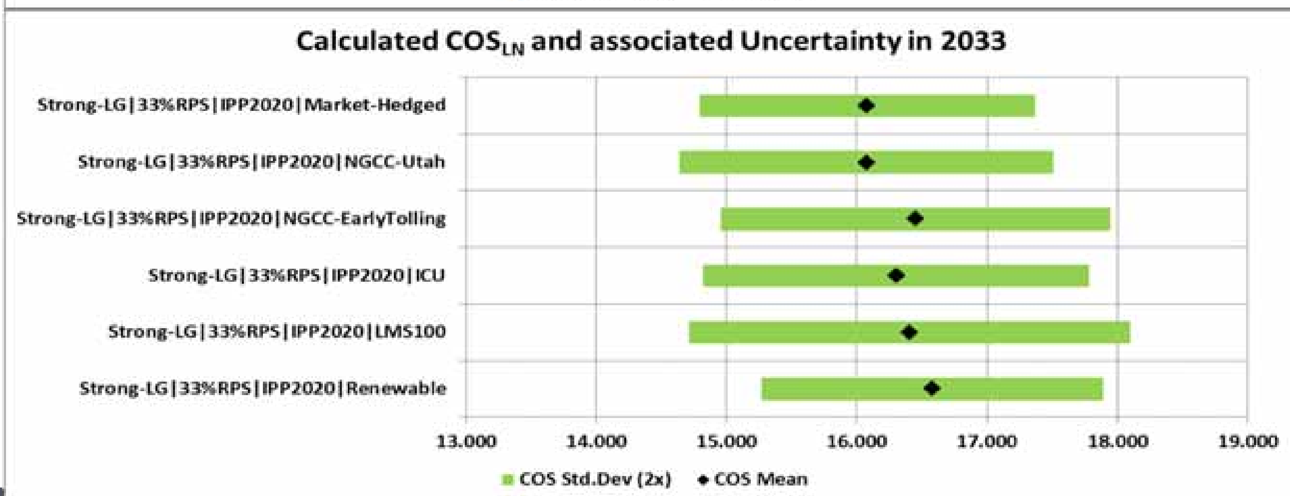
Scenario	Capacity (MW)	Location	Description	Dispatch Flexibility	Permitting challenge
Baseline	150	n/a market	Forward hedged market power contracts	None	n/a (None)
Alternative A1	100*	Riverside, CA	GE LMS-100 NG SC	High	High
Alternative A2	46.5*	Riverside, CA	ICE Wartsila SC	High	High
Alternative B	50*	Delta, UT	IPP Repower NG CC	Moderate	Moderate
Alternative C	75*	CA	Baseload renewable PPA	Low	Low
Alternative D	150*	CA (CAISO)	1/1/16 Tolling contract	Moderate	Low

* L/T power hedges added (total 150MW) for scenario comparison purposes
- Chapter 11 - Extensive information concerning each Alternative

Replacement Option COS_{LN} Impacts (2023 and 2033)

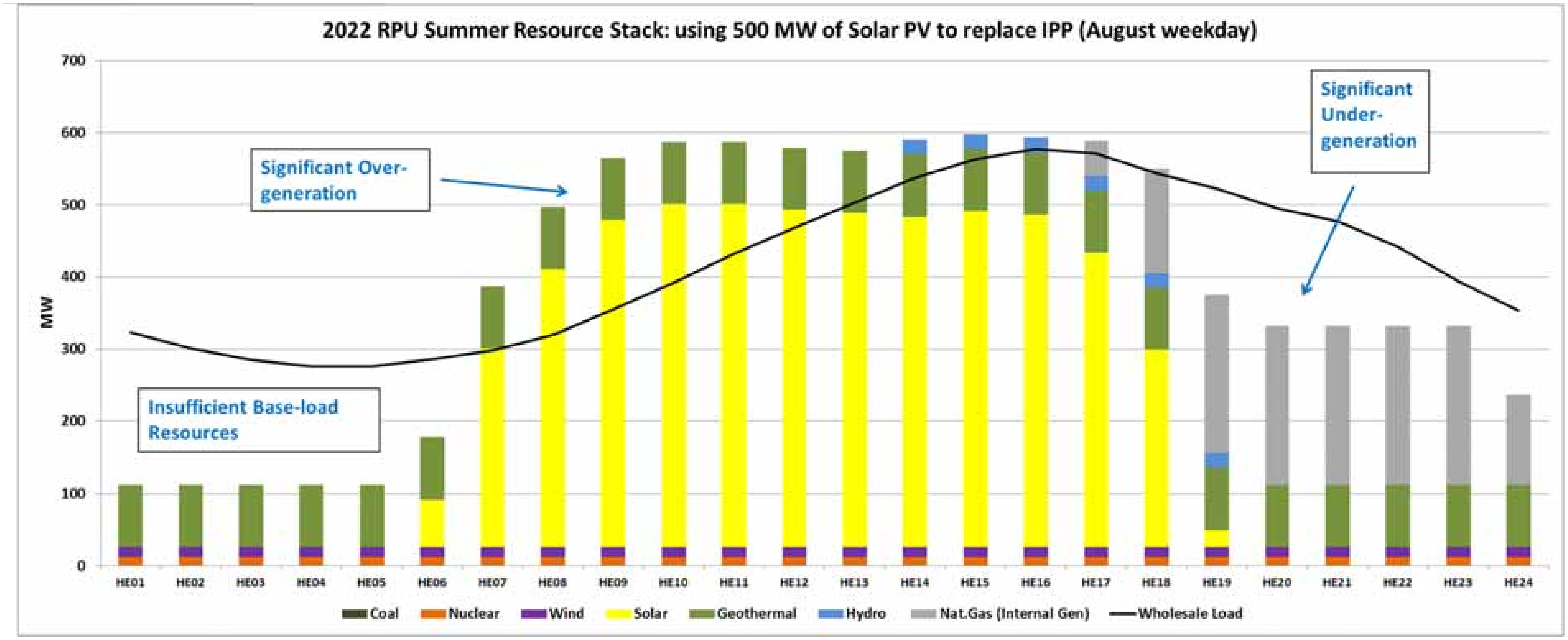
Scenario A – D Low to High Cost





- Market hedging is lowest cost option
- Base-load renewable & early tolling options are most expensive alternatives
- Doesn't assess ancillary services and/or load-following value of the various gas-fired generation options
- Could be material—but market rules still under development

Why Not Replace IPP w/Utility-scale Solar PV?



- Significant diurnal miss-match between solar PV output and RPU's post-IPP load serving needs
- Current cost of Solar + Energy Storage greatly exceeds all alternatives studied in IRP.

Summary Points: IPP Replacement Options

- Forward market hedges is least cost option today
- IPP Repower project next most cost effective solution-but not wide margin
  - RPU should preserve this replacement option
- New local generation offers additional unquantified value
  - Additional studies needed to understand/quantify
- 75 MW Renewable scenario (60% RPS) – difficult to implement (maintain diversity—technology, & geographic location, and a slight further reduction in base-load renewable pricing)
- Early tolling option - not a viable alternative, given the current (considerable) uncertainty of IPP contract end-date and associated cost uncertainty for post-2020 Carbon allowances

Chapter 12: Expanded Analysis of 40% and 50% by 2030 RPS

Analysis using strong load growth scenario two future renewable energy pricing assumptions:

(1) Normal escalation of current renewable prices, and

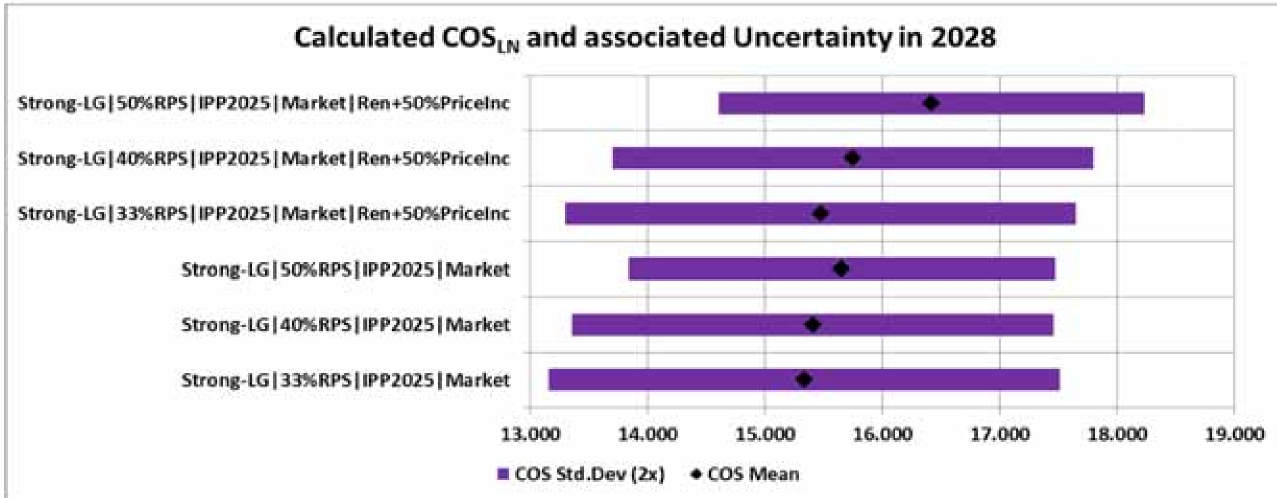
(2) High renewable price scenario (50% above current prices)

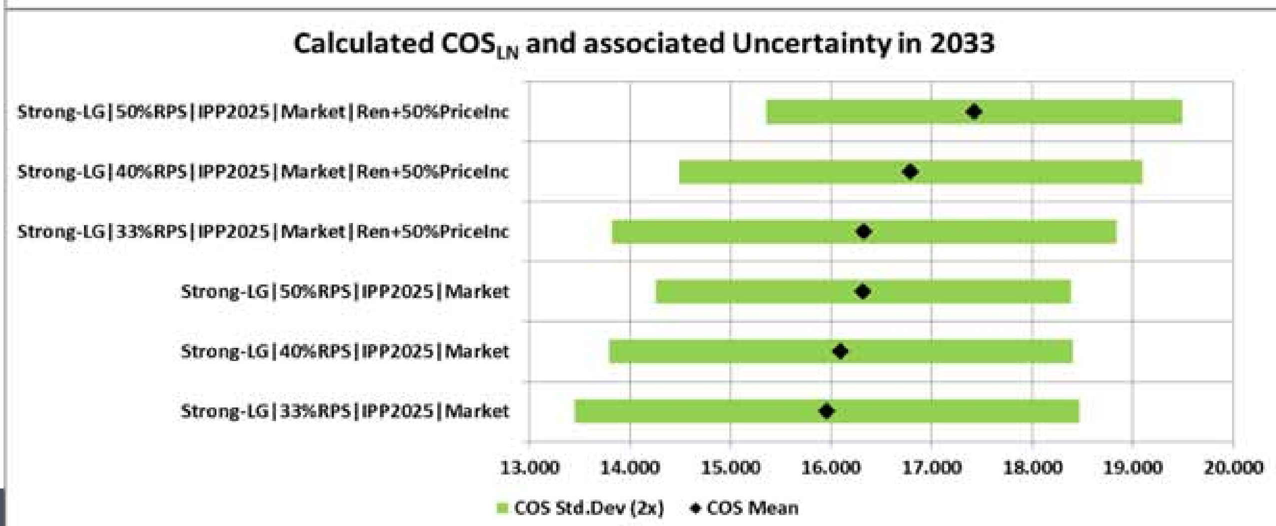
Current RPS mandate is 33% by 2020.

Alternative post-2020 RPS scenarios:

Mandate	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031+
40% RPS	33%	33%	33%	33%	34%	35%	36%	37%	38%	39%	40%	40%
50% RPS	33%	34.7%	36.4%	38.1%	39.8%	41.5%	43.2%	44.9%	46.6%	48.3%	50%	50%

RPS Mandate Impacts on COS_{LN}
(2028 and 2033)



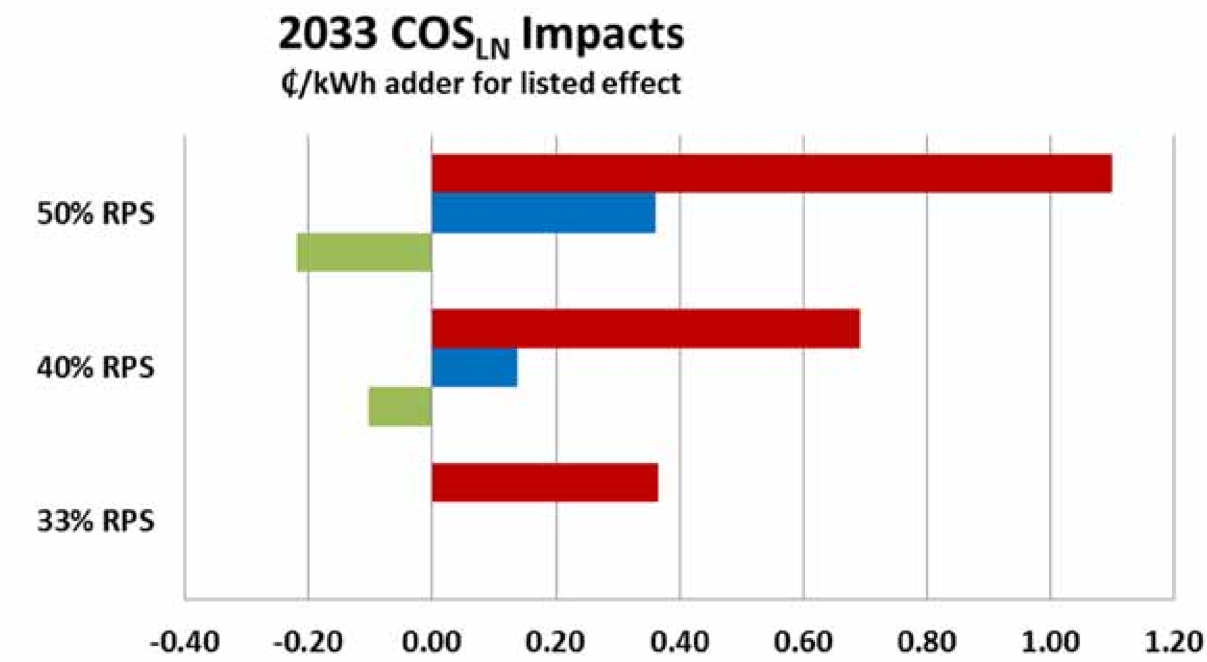


- 40% RPS by 2030 - (COS_{LN} impact:
- Normal pricing < 1% /yr
- Elevated pricing < 3%/yr
  - 50% price increase

- 50% RPS by 2030
- More difficult w/elevated pricing (COS_{LN} impact ~ 9%)/yr
  - 50% price increase

2033 RPS Cost Components (over 33% Baseline)

(33% RPS Baseline COS_{LN} = 15.96 ¢/kWh)



	33% RPS	40% RPS	50% RPS
50% Price Increase (¢/kWh)	0.37	0.69	1.10
RPS Mandate (¢/kWh)	0.00	0.14	0.36
Risk Reduction (¢/kWh)	0.00	-0.10	-0.22

Future RPU Renewable Energy Strategy

- Continue adding renewable energy assets in a very careful and strategic manner
- Minimize renewable integration costs; e.g.,
  - competitively priced, cost-effective energy storage options
  - Contracts with “firmed-up” delivery schedules
- L/T contracts (10+ years) - CEC eligibility for RPS excess procurement rules
- Maximize use of cost effective PCC-2 contracts and PCC-3 TRECs
- Maximize use of (expected) Historic Carryover credits

Chapter 13: Important Secondary Issues and Summaries

ISSUES:

- Value of generic energy storage (ES)
  - Examine hypothetical, generic 10 MW ES system
  - $/kW values for passive (energy only) and dynamic systems (energy + ancillary services)
- Value of "ideal" DSM/DR program
  - $/kW values for program to reduce summer peaking needs by 5%, but without reducing our volumetric energy sales

HIGH LEVEL SUMMARY:

- Value of generic energy storage (ES) systems.
  - 20-year dynamic: $1,100/kW to $2,200/kW
  - 20-year passive: $450/kW to $1,150/kW.
  - Installed cost still exceed these values
- Current value of "ideal" DSM/DR program.
  - Maximum savings potential is ~ $8/kW in 2016, increasing to $13/kW by 2033

Chapter 13: Important Secondary Issues and summaries

ISSUES:

- Customer Solar PV - Current cost/benefit impacts
  - Quantified partial unmet revenue effect
  - Estimated “solar subsidy” of non-solar RPU customers.
- Electric Vehicles (EV) benefits/impacts
  - Examined effect of significant EV penetration in RPU service territory

HIGH LEVEL SUMMARY:

- Customer installed solar PV systems
  - Currently - 14 MW of solar PV (including UCR facility), forecast is 33 MW by 2023.
  - Today, a typical non-solar customer (1,000 kWh/mo.) pays an extra $10.70/yr. (lost solar revenues), forecast is $36/yr. by 2023
- Electric Vehicles (EVs)
  - Potential benefits are large, but EV penetration to date is negligible

Chapter 14: Summary of IRP Major Findings

Significant Challenges

1. How should RPU effectively deal with all of the major new CAISO market initiatives?
2. What is the best way for RPU to tackle new EE/DSM/ES mandates?
3. How can RPU best position itself to meet a new, post-2020 RPS mandate (> 33%)?

Major Findings

1. Maintain flexibility in the CAISO Markets
   - Resolve multiple stakeholder processes (FRAC/MOO, Import Capacity, etc.)
   - Position RPU to quickly and cost-effectively adjust its CAISO participation strategy
2. Search for Energy Storage / Demand Side Management synergies
   - Some DSM technologies could be cost effective for all RPU customers.
   - DSM + Energy Storage could be particularly effective (example: ICE-Bear)
3. Work towards a 40% by 2020 RPS goal

   Maximize cost-effective build up "excess procurement" credits (33% mandate will almost certainly be increased after 2020).

Chapter 14: Summary of IRP Major Findings

Significant Challenges

4. What sort of resources or contracts should be used to replace our expiring IPP contract?

5. How significant are the customer solar PV penetration levels in the RPU service territory?

Major Findings

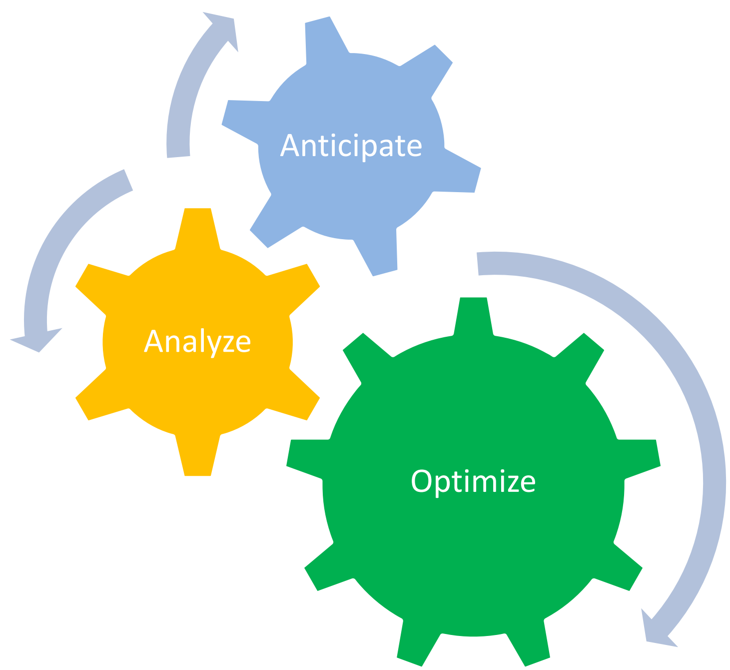
4. Continue to examine all viable IPP Alternatives
   - RPU may pursue multiple alternatives, to maximize future flexibility
   - When rules stability, quantify value of ancillary services (to better assess natural gas generation alternatives)

5. Monitor Customer Solar PV penetration levels
   - Current rates structure results in cost increases to non-solar customers
   - Monitor escalation rates with expiration of RPU's PV rebates, and federal tax credit

Next Steps

- ✓ 2/20/15 - PUB presentation and posting to City website
- ✓ Feb-Jun – PUB/public review, questions & comments
- ✓ 6/4/15 – PUB recommendation to adopt/approve IRP
- 7/7/15 – LUC Presentation and consideration to adopt/approve IRP
- 7/28/15 – City Council consideration to adopt/approve IRP

Questions?



Appendix: Power Resource Total Net Portfolio Cost (TNPC)

(Under Economic Dispatch)

$$TNPC = TGC + TLC - TGGR - HP(MtM)$$

where the variables on the right hand side of this equation are defined as shown below.

- TGC: The total generation costs associated with all of the generation assets in the portfolio.
- TLC: The total cost for purchasing our system load (from the CAISO SP15 day-ahead market).
- TGGR: The total gross revenue received from selling all of the energy generated by our RPU portfolio back into the SP15 market.
- HP(MtM): The total payoff amount associated with all of our forward hedging instruments, computed on a mark-to-market basis.

Appendix: Other Budgetary Costs
(that flow into a Cost of Service calculation)

- SONGS: The cost obligations associated with winding down our SONGS contract and initializing the decommissioning process.
- CAISO Transmission costs: Our transmission costs, as determined by future CAISO Transmission Access Charge (TAC) rates.
- GHG/Carbon revenues: The revenues associated with the sale of allocated carbon emission credits, and the assumptions concerning the number of free allowances (if any) beyond 2020.
- Resource Adequacy (RA) costs: The cost assumptions surrounding our future RA purchases needed to satisfy the 115% CAISO RA paradigm.
- CAISO Uplift fees and other Power Resource costs: The ongoing costs associated with our CAISO energy and transmission uplift fees, CRR auction expenses, and internal generation facilities.
- Utility Personnel and O&M costs: RPU's "all-other" operational costs, not related to power supply activities.
- Long-term Debt Service costs: RPU's long-term Debt Service costs.
- General Fund Transfer (GFT) Fee: RPU's obligation to transfer 11.5% of its gross annual revenues to the City of Riverside.

Appendix: Net, Gross, and Load-normalized Cost of Service Calculations

Our total net cost of service (NCOS) before the GFT is calculated as the TNPC plus the sum of all of our additional portfolio costs, minus any revenue from the sale of carbon allowances. Mathematically, this formula can be expressed as

$$NCOS = TNPC + SONGS + TAC + RA + UFOC + AO - GHG$$

where the remaining variables represent our additional costs associated with SONGS, our CAISO Transmission Access charge (TAC), system RA needs (RA), CAISO uplift fees and other Power Resource costs (UFOC), our all-other (AO) utility costs, including our long-term debt service requirements, and our GHG allowance revenues (GHG), if any. Once the net COS has been determined, we then divide this by the additional GFT ratio to produce a gross cost of service (GCOS) estimate; i.e.,

$$GCOS = NCOS / 0.885$$

where the 0.885 division factor is used to calculate the additional revenue that must be obtained in order for our total revenues to be in balance with our total gross COS. Finally, the load normalized metric (COS_{LN}) is defined as

$$COS_{LN} = GCOS / Retail.Load$$

where by definition our retail load is set equal to 95% of our total (strong or weak) system load forecasts, respectively.

IRP: Document Overview & Organization

- 14 Chapters, 6 Appendices, ~ 300 pages
- Planning & Analytics – all in-house expertise & analysis
- IRP written & produced internally (except Appendix A regarding software)
- Initial draft IRP (May 2014) reviewed by industry expert, subsequently revised in Fall 2014

- IRP Organization:
  - ES & Ch.14: high-level summaries
  - Ch.2 - Ch.4, Appendix A: background info
  - Ch.5 : Legislative & Regulatory
  - Ch.6: EE/DSM Programs
  - Ch.7: Market Outlook
  - Ch.8: 5-Year forward Forecasts
  - Ch.9 & 10: 20-Year forward Forecasts:
  - Ch.11: IPP Replacement Options
  - Ch.12: RPS Mandates
  - Ch.13: New Paradigms
  - Appendices B-F: Additional Technical Info