EDISON INTERNATIONAL®

Business Update

May 2014

Forward-Looking Statements

Statements contained in this presentation about future performance, including, without limitation, operating results, asset and rate base growth, capital expenditures, San Onofre Nuclear Generating Station (SONGS), and other statements that are not purely historical, are forward-looking statements. These forward-looking statements reflect our current expectations; however, such statements involve risks and uncertainties. Actual results could differ materially from current expectations. These forward-looking statements represent our expectations only as of the date of this presentation, and Edison International assumes no duty to update them to reflect new information, events or circumstances. Important factors that could cause different results are discussed under the headings "Risk Factors" and "Management's Discussion and Analysis" in Edison International's Form 10-K, most recent form 10-Q, and other reports filed with the Securities and Exchange Commission, which are available on our website: www.edisoninvestor.com. These filings also provide additional information on historical and other factual data contained in this presentation.

SCE Highlights

- One of the nation's largest electric utilities
  - Nearly 14 million residents in service territory
  - Approximately 5 million customer accounts
  - 50,000 square-mile service area
- Significant infrastructure investments:
  - 1.4 million power poles
  - 700,000 transformers
  - 103,000 miles of distribution and transmission lines
  - 3,700 MW owned generation – 21% of energy to serve customers
- 7 – 9% projected average annual rate base growth 2014 – 2017 driven by:
  - System reliability and infrastructure replacement
  - California Renewables Portfolio Standard
  - Technology improvements

SCE Decoupled Regulatory Model

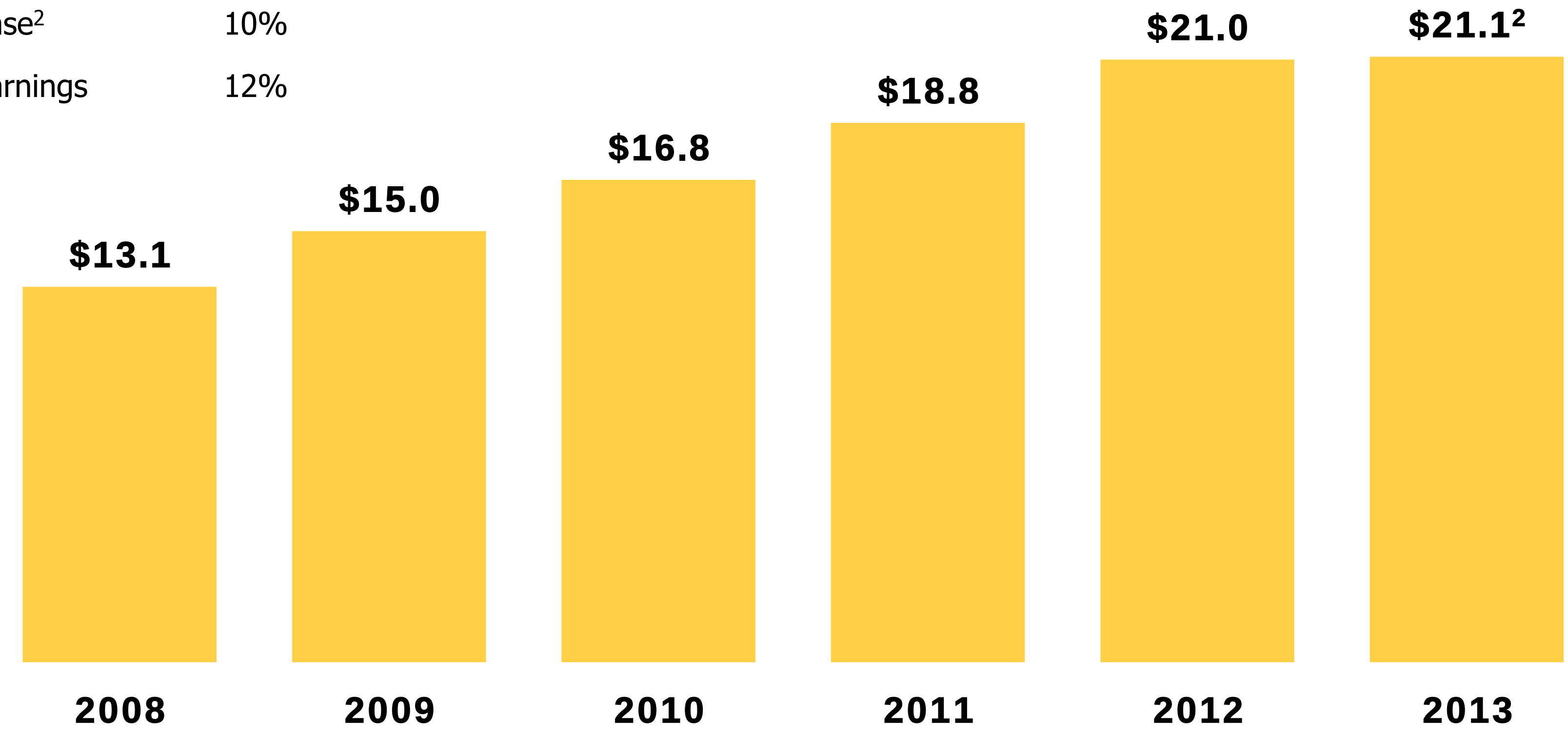
Regulatory Model	Key Benefits
Decoupling of Regulated Revenues from Sales	• SCE earnings are not affected by changes in retail electricity sales • Differences between amounts collected and authorized levels are either billed or refunded to customers • Promotes energy conservation • Stabilizes revenues during economic cycles
Major Balancing Accounts • Fuel • Purchased power • Energy efficiency • Pension-related contributions	• Trigger mechanism for fuel and purchased power adjustments at 5% variance level • Utility cost-recovery via balancing accounts represented over 50% of 2013 costs
Advanced Long-Term Procurement Planning	• Sets prudent upfront standards allowing greater certainty of cost recovery (subject to reasonableness review)
Forward-looking ratemaking	• Three-year rate case and cost of capital cycles

SCE Historical Rate Base and Core Earnings

($ billions)

2008 – 2013 CAGR

Rate Base[2]	10%
Core Earnings	12%

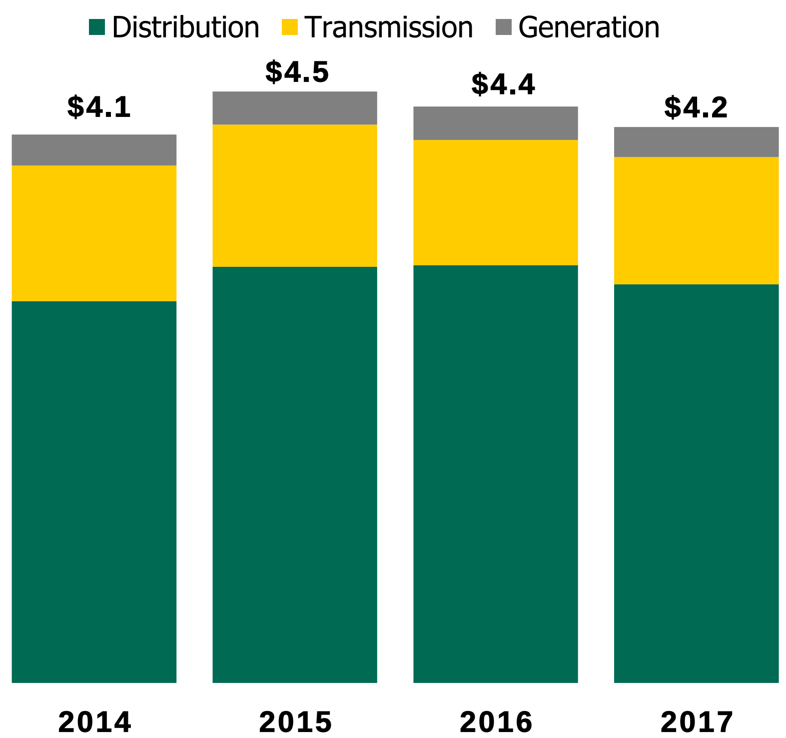


	2008	2009	2010	2011	2012	2013
Core Earnings	$2.25	$2.68	$3.01	$3.33	$4.10	$3.88

1 Recorded rate base, year-end basis. See Non-GAAP Reconciliations and Use of Non-GAAP Financial Measures in Appendix
2 2013 rate base excludes San Onofre Generating Station.

SCE Capital Expenditures Forecast

($ billions)



	2014	2015	2016	2017	2014-17 Total
Requested	$4.1	$4.5	$4.4	$4.2	$17.2
Range	$3.6	$3.9	$3.9	$3.7	$15.1

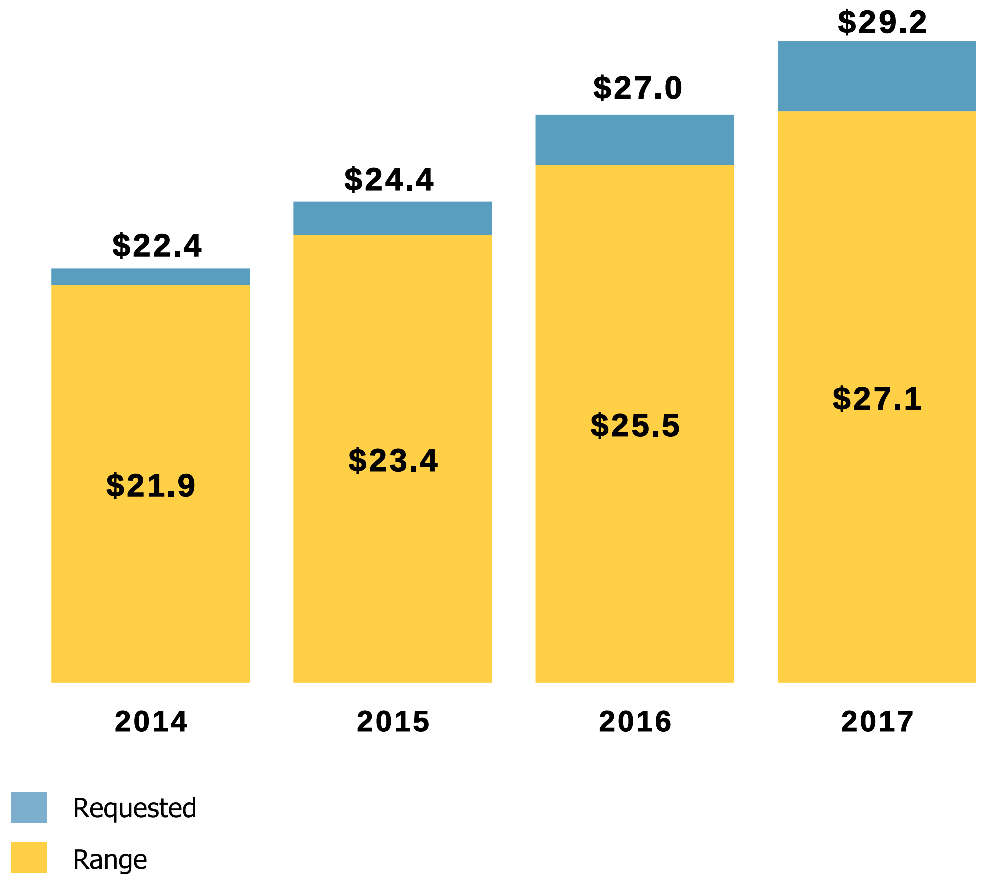
$15.1 – $17.2 billion forecasted capital program 2014 – 2017

- Capital expenditures forecast reaffirmed
- CPUC GRC focused on infrastructure replacement
- Includes Tehachapi scope changes for FAA requirements and $360 million estimate for Chino Hills undergrounding

Note: forecasted capital spending subject to timely receipt of permitting, licensing, and regulatory approvals. Forecast range reflects an average variability of 12%.

SCE Rate Base Forecast

($ billions)



7 – 9% CAGR projected rate base 2014 – 2017

- Growth rate reaffirmed
- Driven by infrastructure replacement, reliability investments, and public policy requirements
- FERC rate base includes CWIP and is approximately 22% of 2014 rate base forecast, increasing to 24% in 2017
- Excludes SONGS rate base

Note: Weighted-average year basis, including forecasted 2014 FERC and 2015-2017 CPUC rate base requests and consolidation of CWIP projects. Rate Base forecast range reflects capital expenditure forecast range.

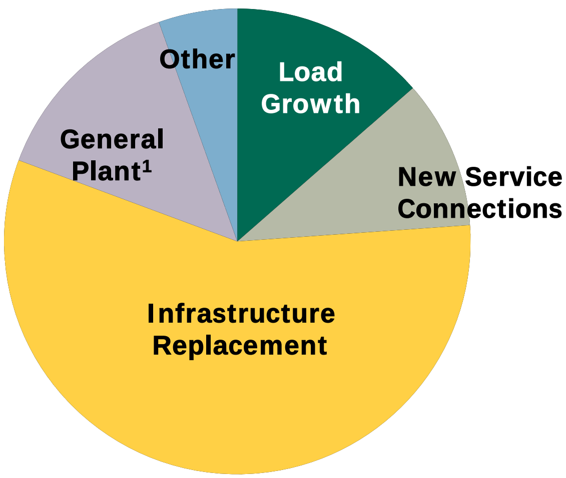
SCE System Investments

($ millions)

Distribution

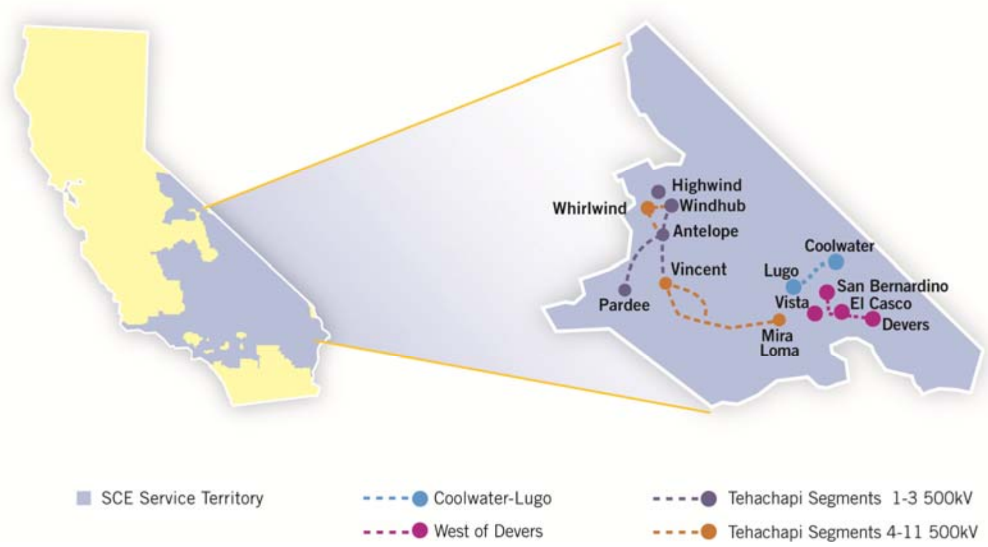
- Aging system reaching equilibrium replacement rate
- 2015 GRC request includes ~120% increase in infrastructure replacement

2015 – 2017 Requested GRC Expenditures for Distribution Assets $9.3 Billion



Transmission

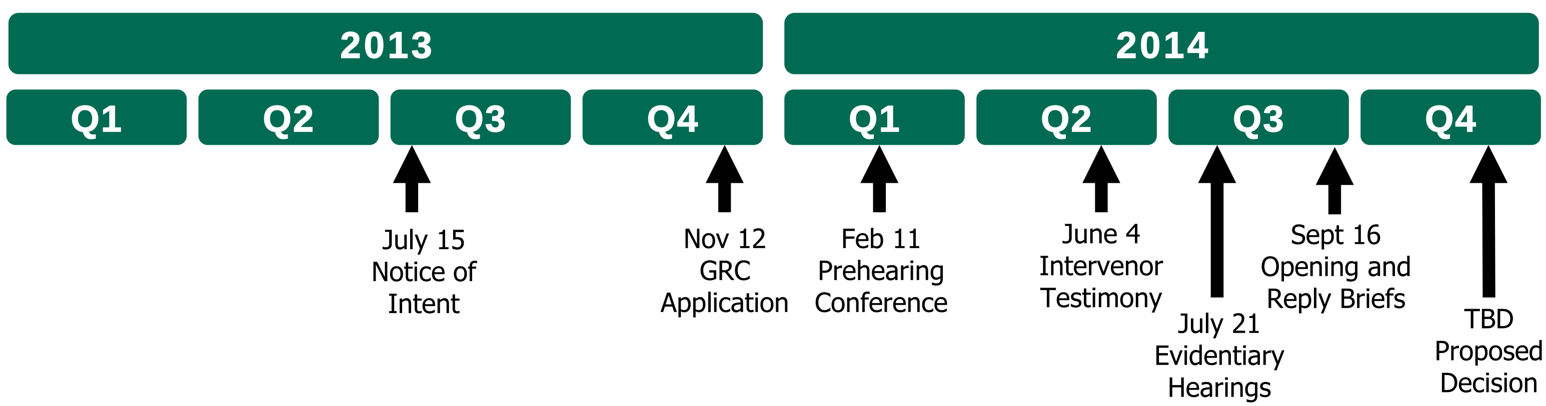
- Large transmission projects:
  - Techachapi – $3,174 million total project cost; 2016-17 in service date
  - Coolwater-Lugo – $813 million total project cost; 2018 in service date
  - West of Devers – $1,034 million total project cost; 2019-20 in service date



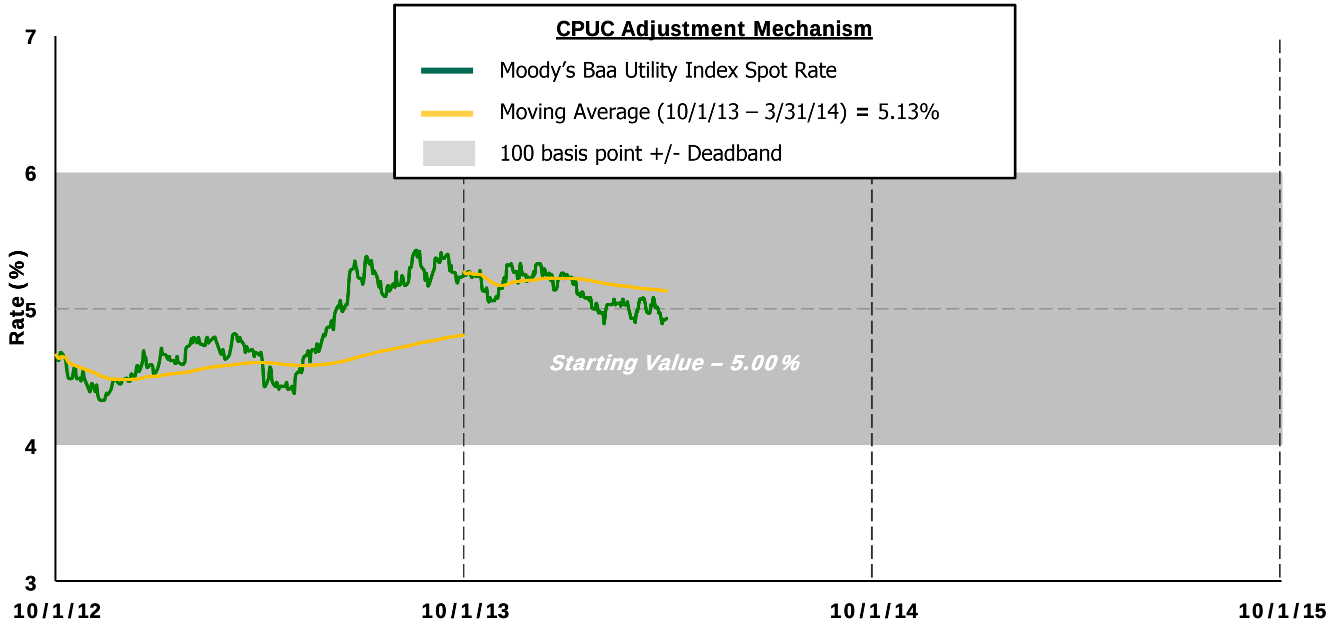
Note: Total Project Costs are nominal direct expenditures, subject to CPUC and FERC cost recovery approval

SCE 2015 CPUC General Rate Case

- November 2013, 2015 GRC Application A.13-11-003 filed
  - March 2014, Scoping Memo issued
  - Updates, ordered by the scoping memo, to remove SONGS and Four Corners testimony and forecast costs from the GRC submitted April 7th
- Request sets base revenue requirement for 2015 – 2017
  - Includes operating costs and CPUC jurisdictional capital
  - Excludes fuel and purchased power (and other utility cost-recovery activities), cost of capital, and FERC jurisdictional transmission
- 2015 revenue requirement request of $5.860 billion, after removing SONGS and Four Corners in April 2014
  - $227 million increase over presently authorized base rates (excluding SONGS)
  - Post test year requested increase of $321 million in 2016 and additional increase of $330 million in 2017
- Request consistent with SCE strategy to ramp up infrastructure investment consistent with capital plan while mitigating customer rate impacts through productivity and lower operating costs



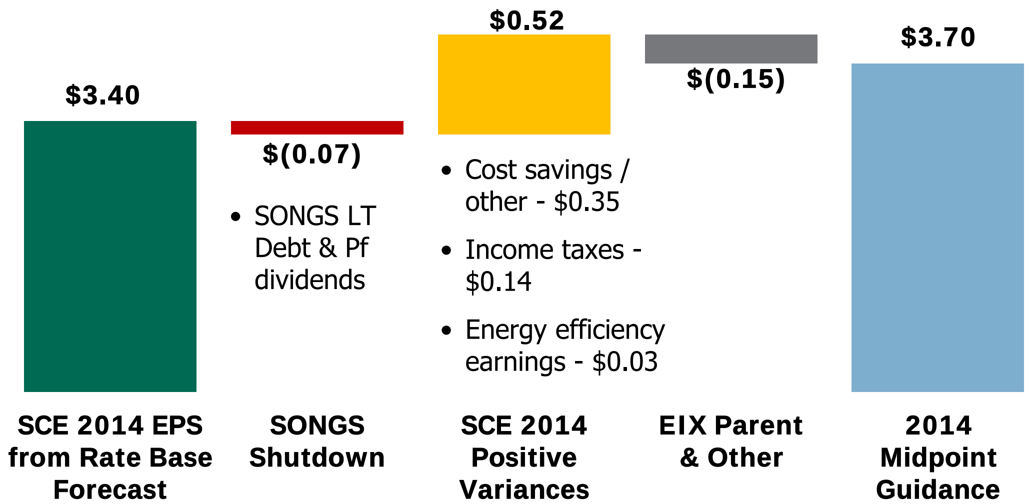
CPUC and FERC Cost of Capital



- CPUC – 10.45% Return on Equity (ROE) and adjustment mechanism approved through 2015
  - ➢ Weighted average authorized return – 7.90%
  - ➢ ROE adjustment based on 12-month average of Moody's Baa utility bond rates, measured from Oct. 1 to Sept. 30
  - ➢ If index exceeds 100 bps deadband from starting index value, authorized ROE changes by half the difference
  - ➢ Starting index value based on trailing 12 months of Moody's Baa index as of September 30, 2012 – 5.00%
  - ➢ SCE will submit new application in April 2015 for Cost of Capital in 2016
- FERC – November 2013 settlement 10.45% ROE comprised of: 9.30% base + 50 bps CAISO participation + 65 bps weighted average for project incentives
  - ➢ Moratorium on ROE changes through June 30, 2015
  - ➢ FERC Formula recovery mechanism in effect through 2017

2014 Core and Basic Earnings Guidance

	2014 Earnings Guidance as of 2/25/14 Low	Mid	High	2014 Earnings Guidance as of 4/29/14 Low	Mid	High
SCE		$3.85			$3.85	
EIX Parent & Other		(0.15)			(0.15)	
EIX Core EPS	**$3.60**	**$3.70**	**$3.80**	**$3.60**	**$3.70**	**$3.80**
Non-core Items [1]		-			(0.36)	
EIX Basic EPS	**$3.60**	**$3.70**	**$3.80**	**$3.24**	**$3.34**	**$3.44**



Key Assumptions:

- Midpoint rate base of $22.1 billion
- Approved capital structure – 48% equity, 10.45% CPUC & FERC ROE
- 325.8 million common shares outstanding (no change)
- No significant transmission project delays

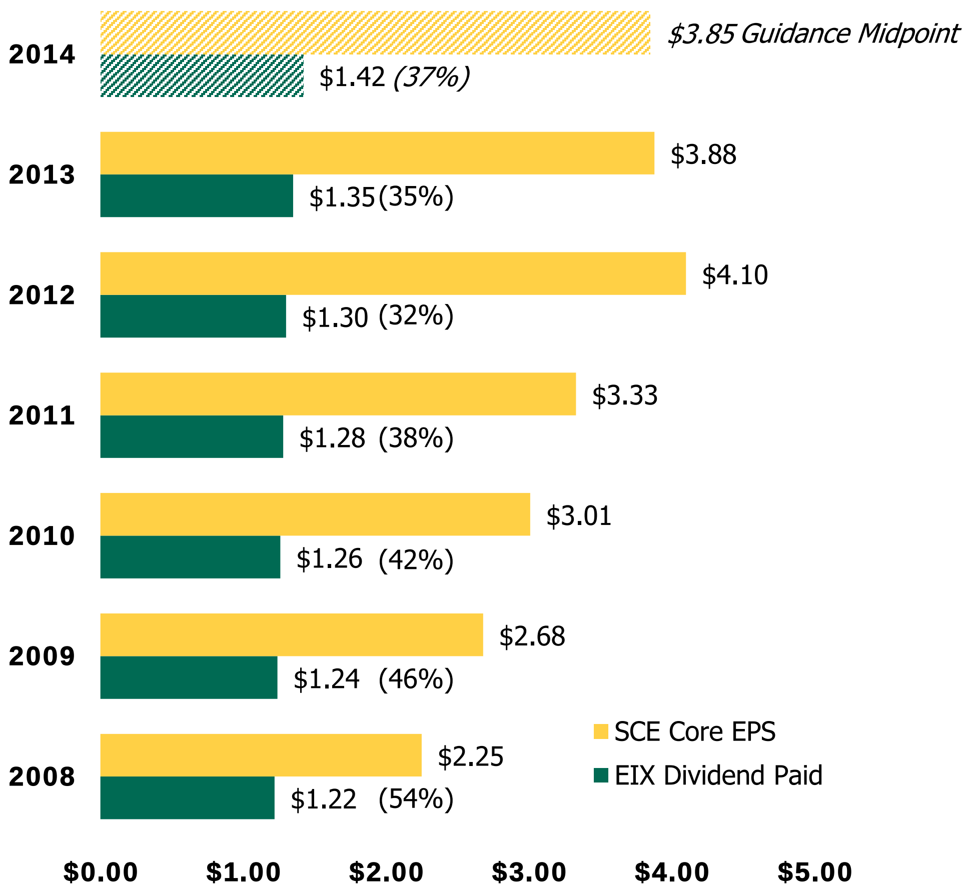
Other Assumptions:

- No change in tax policy
- O&M cost savings flow through to ratepayers in 2015 GRC
- To be updated following approval of SONGS Settlement

1 Represents non-core items recorded during Q1 2014QTR. Impact of EME Settlement expected to be recorded in Q2 2014 – Estimated net benefits of $152 million or $0.47.

Note: See Use of Non-GAAP Financial Measures in Appendix

EIX Dividend Growth



2008 – 2013 CAGR	
SCE Core EPS	12%
EIX Dividend	2%

- EIX targets paying out 45 – 55% of SCE earnings
- Dividend growth rate slowed to help fund large utility capital program, which is plateauing
- EIX plans to return to target dividend range over time

In December, EIX increased its dividend for the 10th consecutive year to an annual rate of $1.42 per share for 2014

Note: See Use of Non-GAAP Financial Measures in Appendix for reconciliation of core earnings per share to basic earnings per share

Creating Shareholder Value

	Resolve Uncertainties	Create Sustainable Earnings and Dividend Growth	Position for Transformative Sector Change
What We've Done	• SCE 2013 cost of capital • SCE 2012 FERC formula rate settlement • EME restructuring • SONGS OII settlement reached	• 10% 5-year SCE rate base CAGR (2008 – 2013) • 12% Core SCE EPS growth (2008 – 2013) • 10 consecutive years of EIX dividend increases	• Acquired SoCore Energy (commercial solar) • Minority investments (energy efficiency, residential solar markets, transportation electrification)
What Remains	• SONGS OII settlement approval • SONGS third-party cost recovery	• SCE 2015 GRC • Execute wires-focused investment program • 7 – 9% projected rate base growth (2014 – 2017) • Optimize cost structure through operational excellence • Return to target dividend range over time	• Rate reform – AB 327 implementation • Evaluate new power sector business opportunities

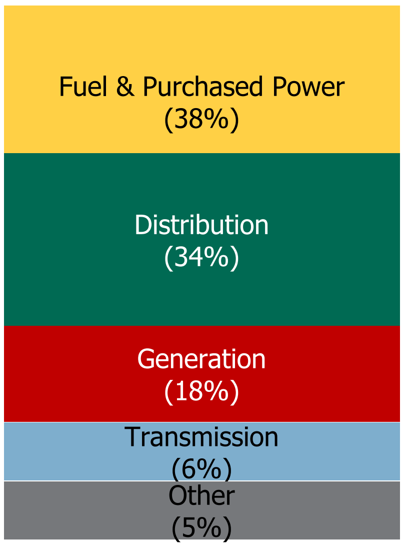
Note: See Non-GAAP Reconciliations and Use of Non-GAAP Financial Measures in Appendix

Changes Since Our Last Presentation

- Quarterly updates
- SCE 2015 CPUC General Rate Case (p. 8)
- 2014 Core and Basic Earnings Guidance (p. 10)
- Residential Rate Design OIR (p. 18) – new slide
- Rooftop Solar – Grid Interaction (p. 22)
- Energy Storage (p. 24)
- SONGS Settlement – Third-Party Recoveries (p. 37) – new slide
- SONGS Settlement – Accounting (p. 38)
- Updated Forecasted ERRA Recovery Forecast (p. 39) – new slide
- SONGS Settlement Impact (p. 41) – new slide
- SONGS Third-Party Recovery – NEIL Insurance (p. 43)
- 2014 Bulk Electricity Outlook (p. 45) – new slide

Appendix – Regulatory

SCE 2013 Bundled Revenue Requirement



	2013 Bundled Revenue Requirement $millions	2013 Bundled Revenue Requirement ¢/kWh
Fuel & Purchased Power – includes CDWR Bond Charge	4,285	5.8
Distribution – poles, wires, substations, service centers; Edison SmartConnect®	3,820	5.2
Generation – utility owned generation investment and O&M	2,012	2.7
Transmission – greater than 220kV	713	1.0
Other – CPUC and legislative public purpose programs, system reliability investments, nuclear decommissioning	539	0.7

Total Bundled Revenue Requirement ($millions)	**$11,369**	
÷ Bundled kWh (millions)	73,536	
= Bundled Systemwide Average Rate (¢/kWh)		**15.5¢**

Approximately 60% of SCE's revenue requirement consists of utility earnings activities: generation, distribution, and transmission

Note: Rates in effect as of October 1, 2013, based on forecast. Represents bundled service which excludes Direct Access customers that do not receive generation services.

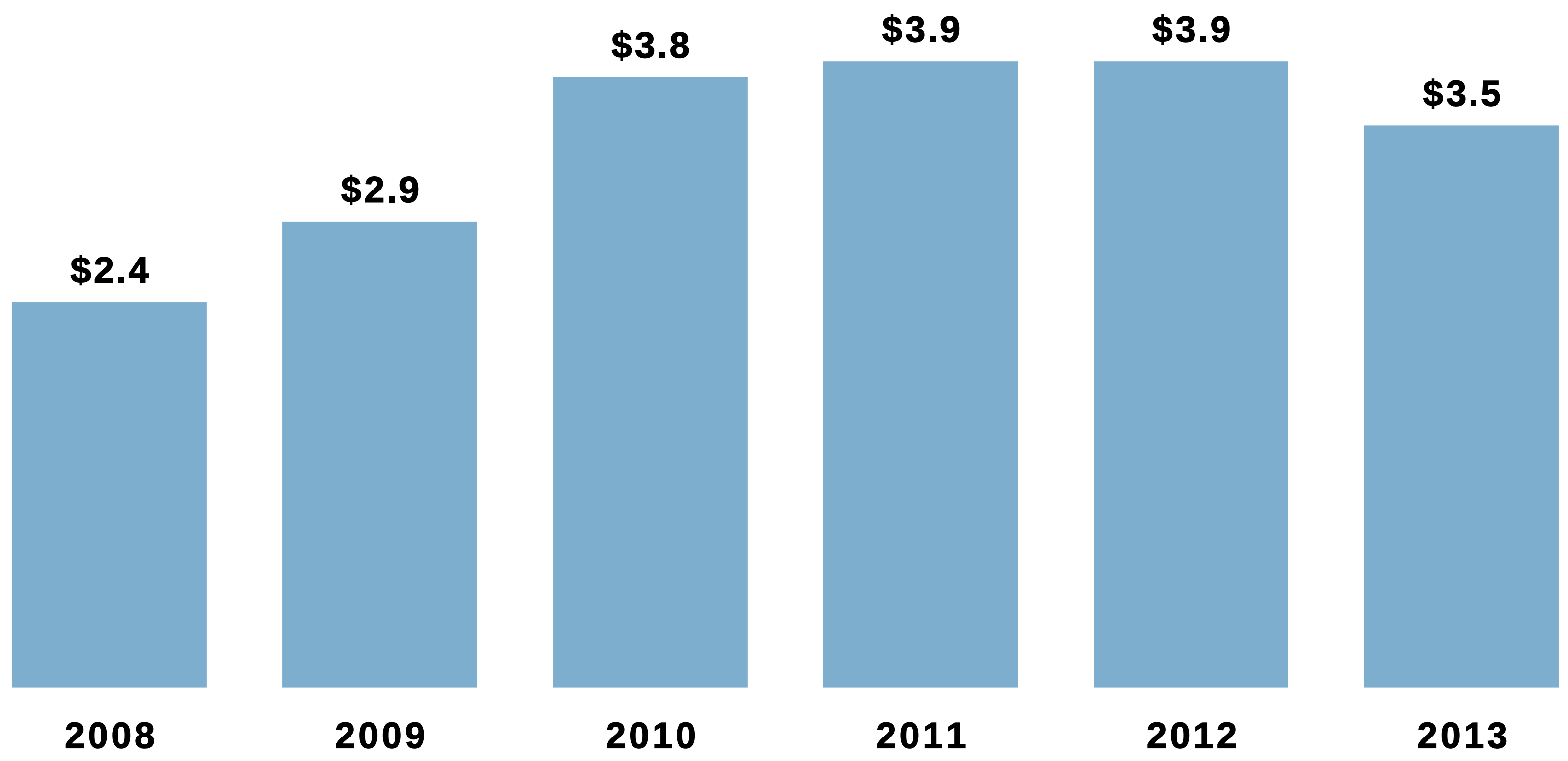
SCE Customer Demand Trends

Kilowatt-Hour Sales (millions of kWh)	2013	2012	2011	2010	2009
Residential	29,889	30,563	29,631	29,034	30,078
Commercial	40,649	40,541	39,622	39,318	40,076
Industrial	8,472	8,504	8,490	8,507	8,522
Public authorities	5,012	5,196	5,206	5,336	5,686
Agricultural and other	1,885	1,676	1,318	1,353	1,499
Resale	1,490	1,735	3,071	4,103	5,869
Total Kilowatt-Hour Sales	**87,397**	**88,215**	**87,338**	**87,651**	**91,730**
Customers					
Residential	4,344,429	4,321,171	4,301,969	4,285,803	4,262,966
Commercial	554,592	549,855	546,936	543,016	539,270
Industrial	10,584	10,922	11,370	11,708	12,244
Public authorities	46,323	46,493	46,684	46,718	46,902
Agricultural	21,679	21,917	22,086	22,321	22,315
Railroads and railways	99	83	82	73	67
Interdepartmental	23	24	22	23	23
Total Number of Customers	**4,977,729**	**4,950,465**	**4,929,149**	**4,909,662**	**4,883,787**
Number of New Connections	**27,370**	**22,866**	**19,829**	**25,566**	**32,145**
Area Peak Demand (MW)	**22,534**	**21,981**	**22,374**	**22,771**	**22,112**

Note: See Edison International Financial and Statistical Reports for further information

SCE Historical Capital Expenditures

($ billions)

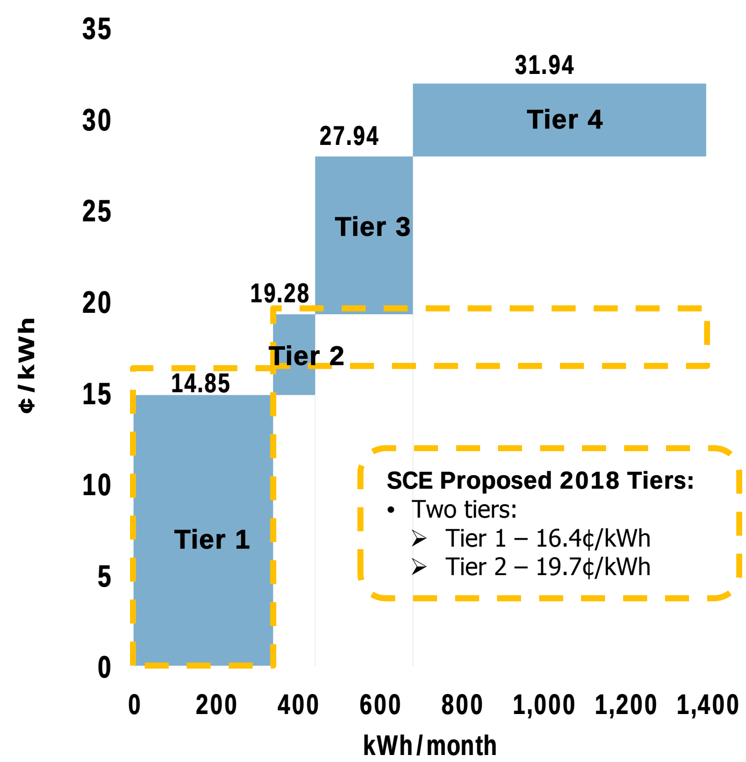


Note: 2013 distribution reliability spend up $300 million, offset by completion of SmartConnect in 2012 ($300 million); lower FERC ($300 million) and lower SONGS ($100 million)

Residential Rate Design OIR

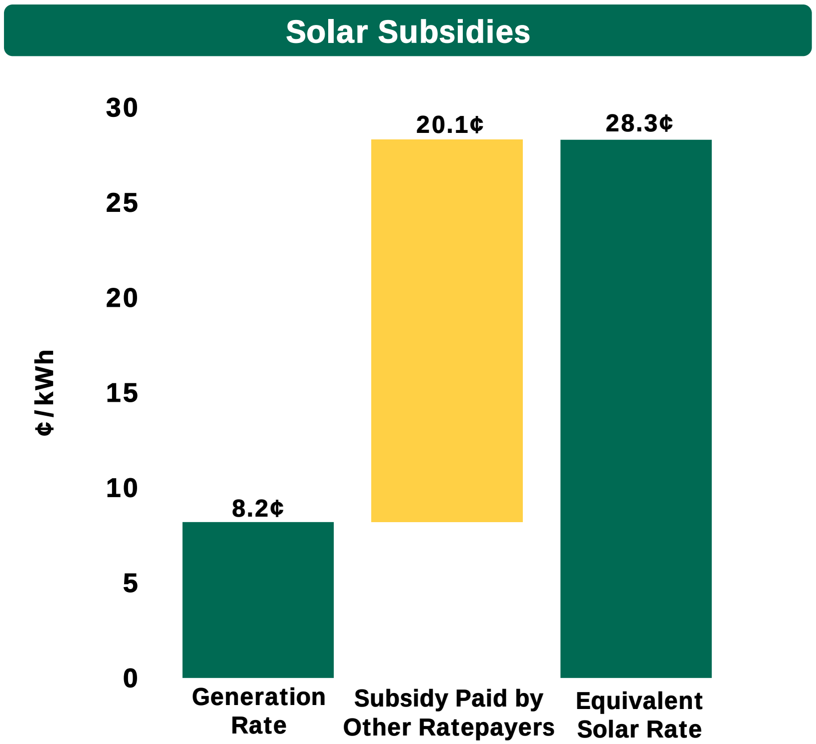
- June 2012, CPUC opened Order Instituting Rulemaking (OIR) R.12-06-013:
  - ➢ Comprehensive review of residential rate structure
  - ➢ Transition to Time of Use (TOU) rates
  - ➢ AB327 rate design
- Phase 2 (Summer 2014): simple tiered rate adjustments
  - ➢ Settlement filed in March 2014, expect approval to implement rates in July 2014
  - ➢ Tier 1 and Tier 2 rates to increase by 12% and 17% versus a 6% Systemwide Average Rate increase
- Phase 1 (2015 – 2018) – longer-term rates
  - ➢ Energy Division White Paper – 2 tiers (2017); TOU rates (2018)
  - ➢ Fixed charge or minimum bill (2015)
  - ➢ Decision expected Q4 2014
- Net Energy Metering
  - ➢ 20-year grandfathering of existing installations
  - ➢ Successor tariff needed by YE 2015

OIR Phase 2 Settlement Summary



Fixed Monthly Charge	
Current:	$0.94/month
SCE Proposed:	$10/month

SCE Residential Net Metering Rate Structure



- Residential solar customer generation offsets total retail rate
- Average retail rate of 28.3¢/kWh vs. actual generation cost of 8.2¢/kWh
- Resulting 20.1¢/kWh is a subsidy funded by all other non-solar customers in Tiers 3 and 4

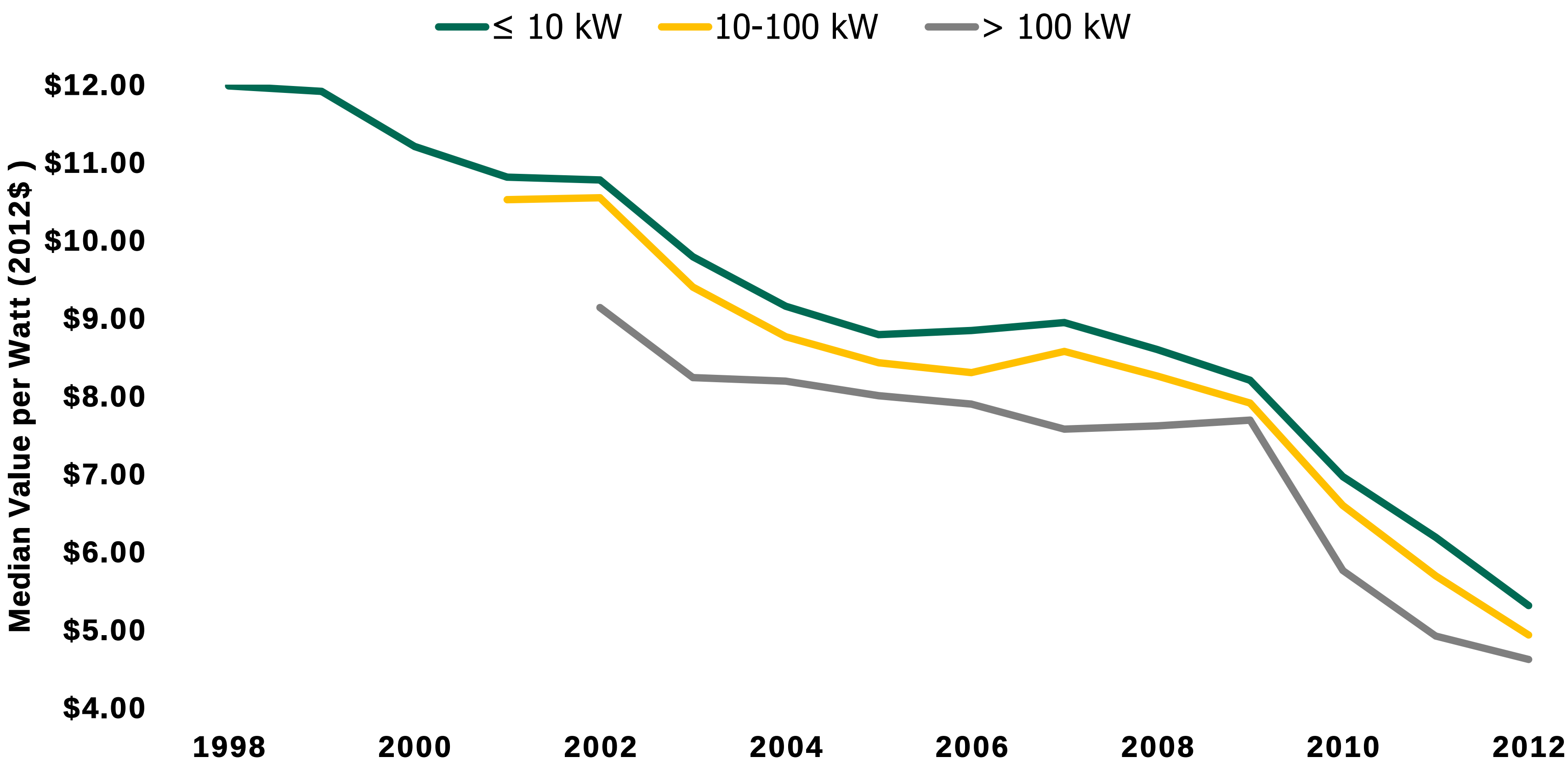
SCE 2013 Net Energy Metering Statistics:

- 76,400 combined residential and non-residential customers – 697 MW installed
  - ➢ 99.5% solar
  - ➢ 73,300 residential – 361 MW
  - ➢ 3,100 non-residential – 336 MW
- Approximately 1,000,000 mWh / year generated, or 1% of total sales

Residential solar customers receive a subsidy funded by all other non-solar customers in higher tiers

Note: Based on average home usage of 1,150 kwh/month, a 4-tier rate structure, and a 4.8kW solar system with a 18% capacity factor that generates 620 kWh per month of electricity

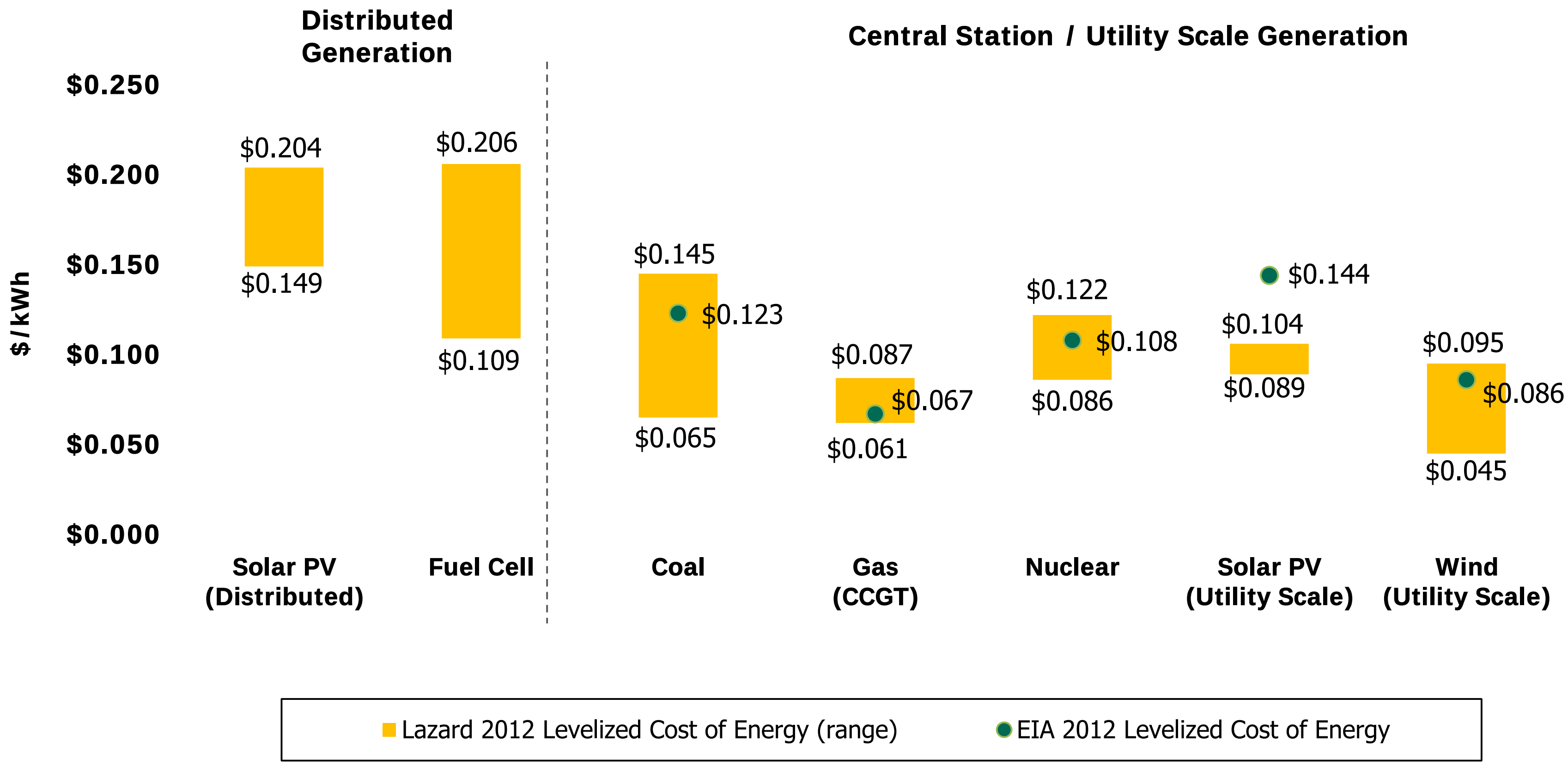
Solar PV Cost Trends



Over the past decade, real installed solar system prices fallen by nearly 50 %

Note: Dollar values are in real 2012 dollars before state/local incentives. Median installed prices are shown only if 15 or more observations are available for the individual size range.
Source: Lawrence Berkeley National Laboratory, "Tracking the Sun VI: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012," Figure 7

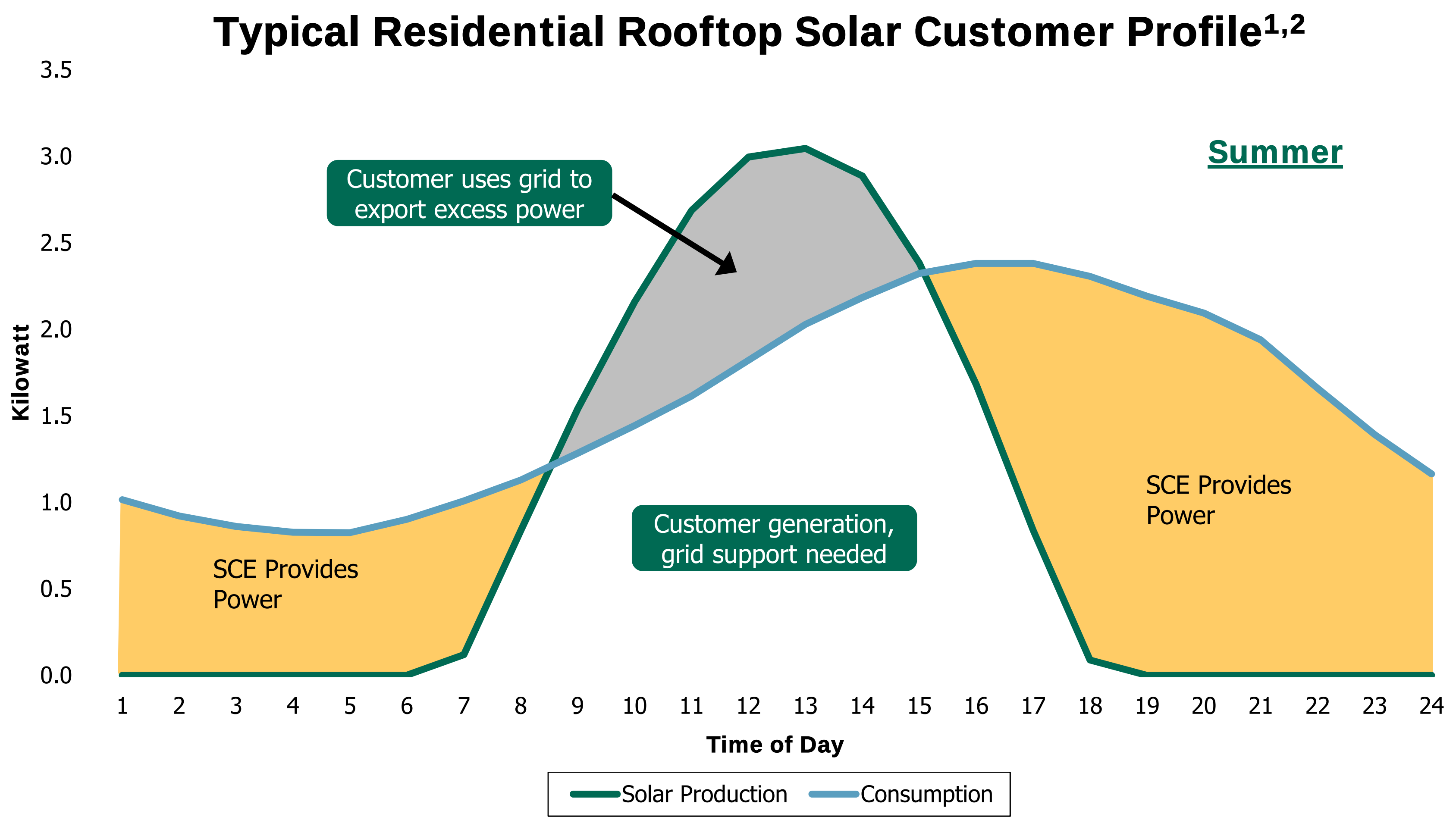
All Generation Cost Trends, Unsubsidized



Levelized cost of energy for distributed generation resources continues to move toward equilibrium with other generation sources

Sources: Lazard Levelized Cost of Energy Version 7.0 August 2013; EIA Levelized Cost of Energy Analysis 2013

Rooftop Solar – Grid Interaction



Solar customers benefit from the flexibility provided by the SCE grid

1 Solar production shape based on a 4.8 kW system expected summer performance (source: https://sam.nrel.gov/). Sizing to eliminate Tier 3 and 4 usage.
2 Residential consumption shape based on summer average for a high user (1,150 kWh/month) (source: SCE load research)

CAISO Net Load

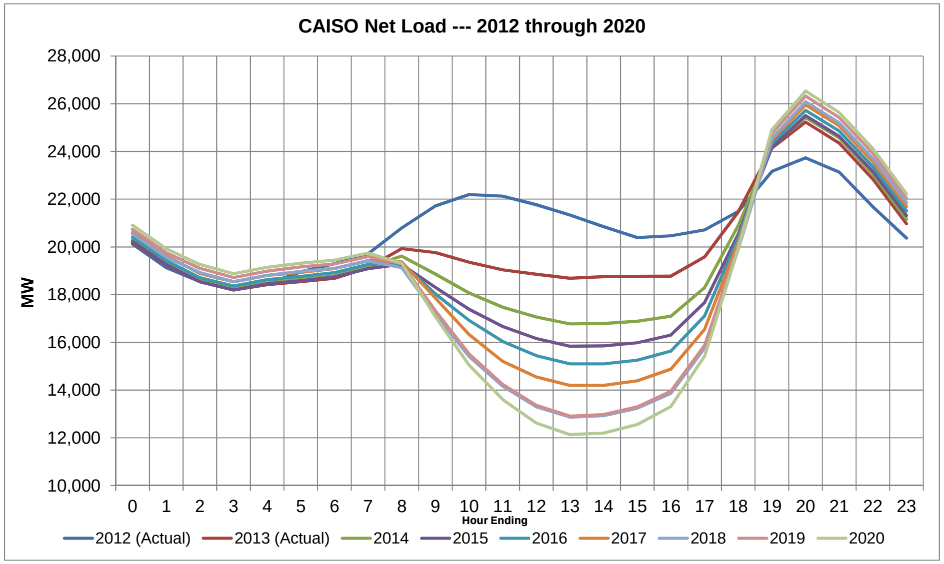
Renewables

- Current 33% RPS by 2020 set as floor for CPUC per AB327
- More variable and less predictable output
- Output does not fully match demand
- Need for flexible, dispatchable capacity

Resource Adequacy

- 1-year forward
- 10-year forward long-term procurement process for new resources
- Need intermediate (3 – 5 years) forward capacity market with right mix of operational attributes

CAISO 'Peaking' Duck Chart



Net Load = Load - Wind - Solar

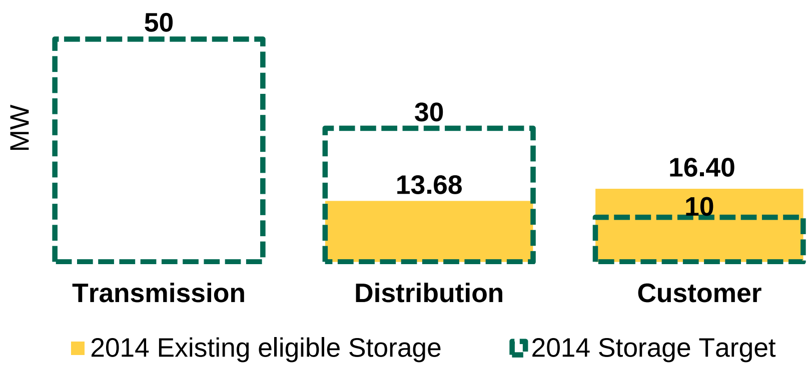
Increasing renewable generation creates need for substantial amount of flexible, dispatchable capacity

Source: CA Independent System Operator, "2013 Special Reliability Assessment", September 18, 2013 and represents a single day in March of each year

Energy Storage

- AB2514 directs CPUC to establish procurement targets and policies for energy storage
- CPUC final decision in Energy Storage OIR (R.10-12-007)
  - 1,325 MW target for IOUs by 2024 (580 MW SCE share)
  - Three types: transmission (53%), distribution (32%), customer-sited (15%)
  - Utility ownership limited to 50% of total target (290 MW SCE share)
  - First procurement cycle in December 2014
    - Existing storage and prior RFO storage expected to count for ~74MW of SCE's 90 MW target
  - Broad range of technologies as defined in AB2514, excluding large hydro (>50 MW)

SCE 2014 Existing Storage



- Tehachapi Storage Project
- Irvine Smart Grid Demonstration Projects
- Large Energy Storage Test Apparatus
- Discovery Science Center
- Catalina Island Battery System
- Vehicle-to-Grid Program – LA Air Force Base
- Self-Generation Incentive Program
- Permanent Load Shifting Program

SCE's energy storage investment opportunities will focus on distribution grid projects and will be integrated into future capital expenditure requests

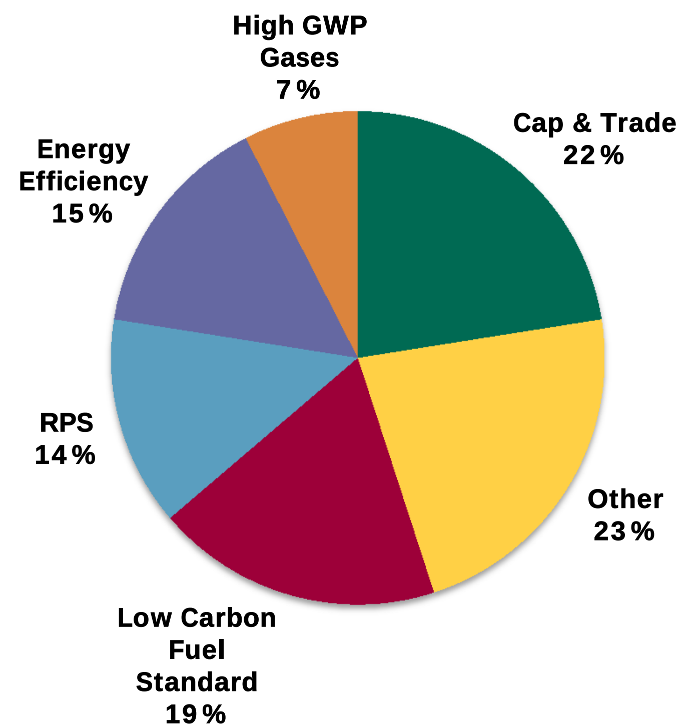
California Climate Change Policy

- Assembly Bill 32 (2006) – reduces State greenhouse gas (GHG) emissions to 1990 levels by 2020 (~16% reduction)
- Cap and trade program basics:
  - State-wide cap in 2013 – decreases over time
  - Compliance met through allowances, offsets, or emissions reductions
  - Excess allowances sold, or “banked” for future use
  - January 2014 – merger with Quebec cap and trade program
- SCE received 32.3 million 2013 allowances vs. 10.4 million metric tons 2012 GHG emissions
- Allowances sold into quarterly auction and bought back for compliance
  - SB 1018 (2012) – auction revenues used for rate relief for residential (~93%), small business, and large industrial customers

Quarterly Auction Results (Current Vintage)

11/2012	2/2013	5/2013	8/2013
$10.09/ton	$13.62/ton	$14.00/ton	$12.22/ton
11/2013	2/2014		
$11.48	$11.48		

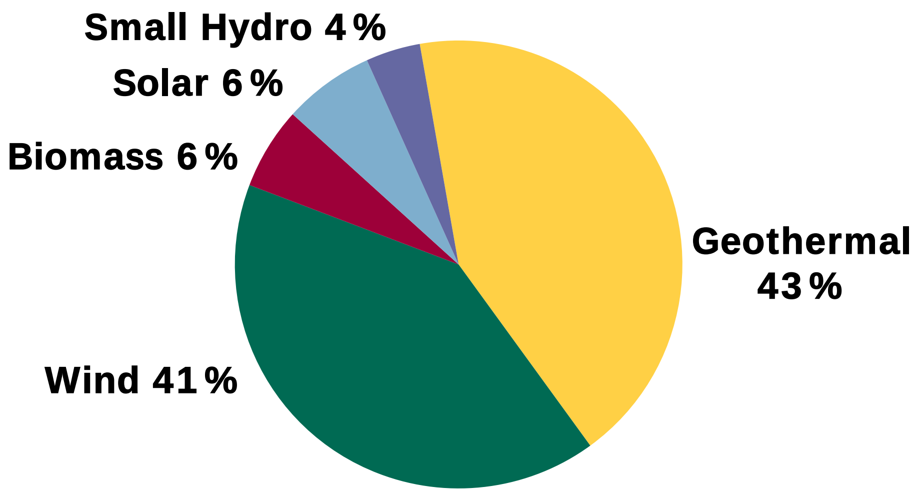
AB32 Emissions Reduction Programs



California Renewables Policy

- On April 12, 2011, Governor Brown signed SB X 1 2, which codifies a 33% Renewables Portfolio Standard (RPS) for California by 2020
  - Allows use of Renewable Energy Credits (RECs) for up to 25% of target with decreasing percentages over time
  - Applies similar RPS rules to all electricity providers (investor- and publicly-owned utilities, as well as Electric Service Providers)
- In order to meet the 33% RPS requirement by 2020, SCE will increase its renewable purchases by 10 billion kWh, or 67%

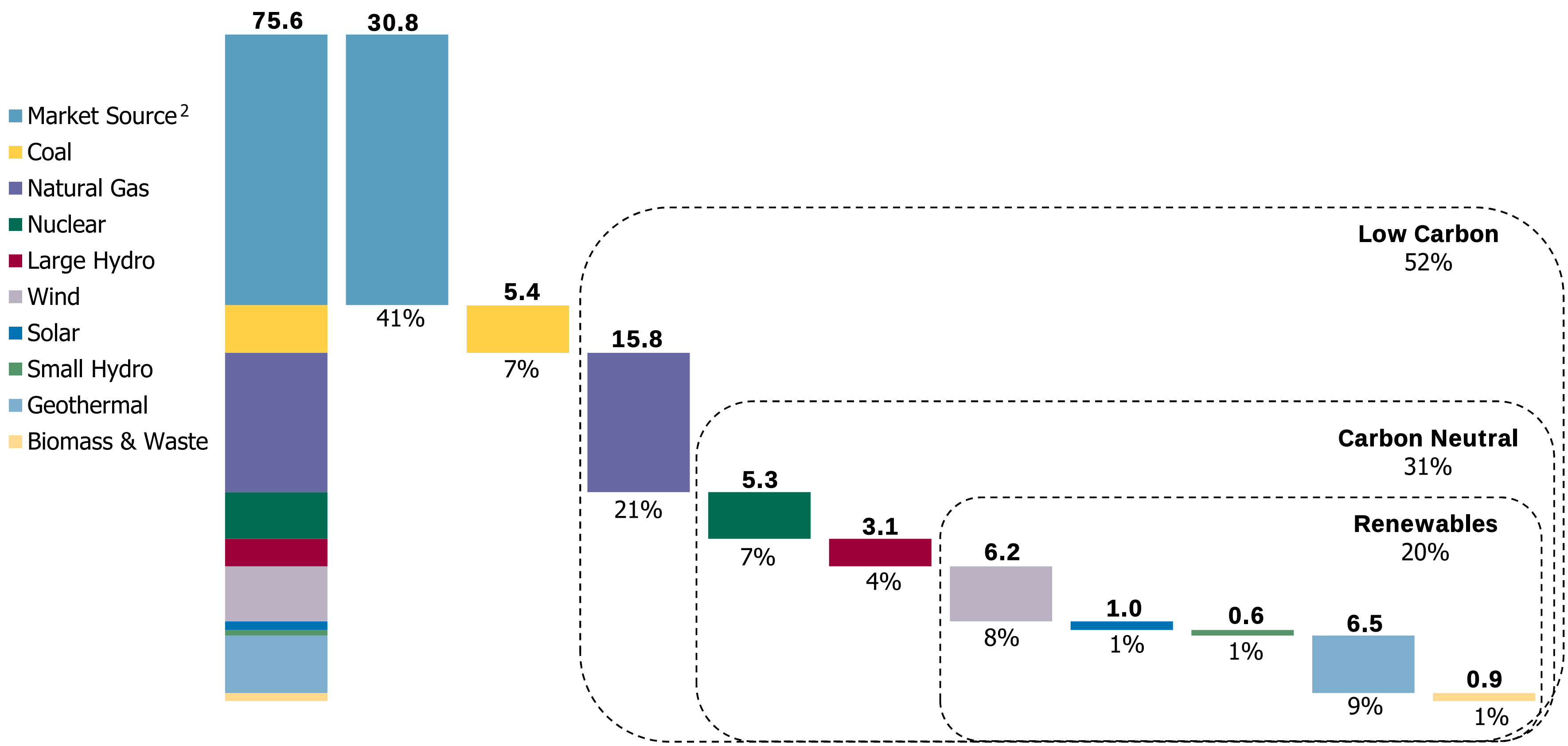
Actual 2012 Renewable Resources: 20% of SCE's portfolio



While SCE is on target to meet the 33% renewables mandate by 2020, the requirement will put upward pressure on customer rates

2012 SCE Energy Portfolio[1]

(Billion kWh – Retail Sales)



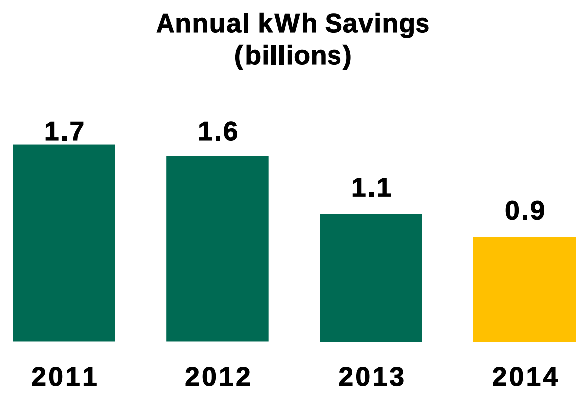
More than half of SCE's energy portfolio consists of low-carbon resources including renewables, hydro, and natural gas

1 CEC Power Source Disclosure Program
2 Accounts for non-technology specific energy procured from market

SCE Energy Efficiency Programs

Energy efficiency programs updated for 2013 – 2014

- SCE is a national leader
  - 2012 energy savings = 1.8% of retail sales[1]
- 2014 budget of $352 million[2]
- Target 0.9 billion kWh average annual savings for 2013-14 cycle[3] – Reduced goals reflect CPUC-identified market potential for energy efficiency



Energy efficiency earnings incentive mechanism modified

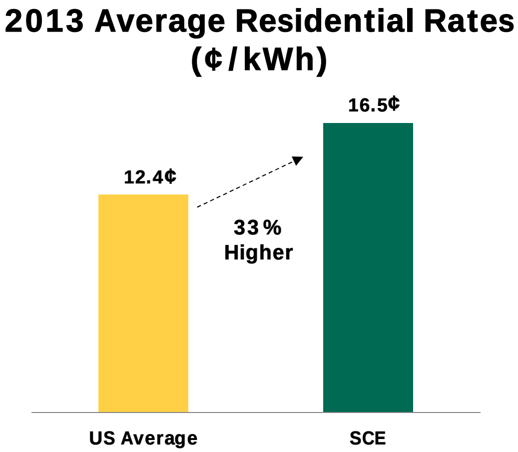
- New earnings mechanism for 2011, 2012 (payable in 2013, 2014) – 5% management fee + up to 1% performance bonus
- December 2013, $13.5 million awarded for 2011 program year – additional $5 million pending results of 2014 energy efficiency programs audit
- SCE to file earnings claim for 2012 and part of 2013 program activity this year – actual payment, if any, subject to CPUC approval
- CPUC approved new incentive mechanism for 2013 and 2014 activities (payable in 2014 and beyond) comprised of performance rewards and management fees

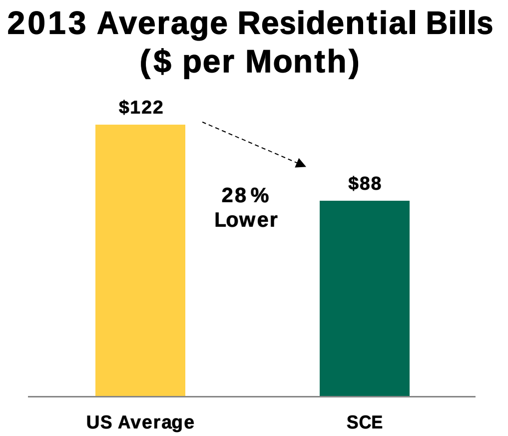
Future Directions

- SCE is identifying opportunities, such as SCE's Preferred Resources Pilot, to leverage EE and other demand side resources to meet grid reliability needs.

1 Does not include resale sales. Energy savings subject to ex-post CPUC review.
2 Excludes income qualified energy efficiency and integrated demand-side management program funding authorizations for 2013
3 Based on CPUC goals established for SCE. Market potential changes in response to program funding levels, customer participation assumptions, market influences and the implementation of new building codes and minimum appliance efficiency standards

SCE Rates and Bills Comparison





Key Factors

- SCE's residential rates are above national average due, in part, to a cleaner fuel mix – cost for renewables are higher than high carbon sources
- Average monthly residential bills are lower than national average – higher rate levels offset by lower usage
  - 45% lower SCE residential customer usage than national average, from mild climate and higher energy efficiency building standards
- Public policy mandates (33% RPS, AB32 GHG, Once-through Cooling) and electric system requirements will drive rates and bills higher

SCE's average residential rates are above national average, but residential bills are below national average due to lower energy usage

Source: EIA's Form 826 Data Monthly Electric Utility Sales and Revenue Data for the Data 12 Months Ending April 2013

Appendix – Financial

First Quarter Earnings Summary

	Q1 2014	Q1 2013	Variance
Core EPS[1]			
SCE	$0.93	$0.78	$0.15
EIX Parent & Other	(0.03)	(0.01)	(0.02)
Core EPS[1]	**$0.90**	**$0.77**	**$0.13**
Non-Core Items			
SCE	$(0.29)	$–	$(0.29)
EIX Parent & Other	–	0.02	(0.02)
Discontinued Operations	(0.07)	0.04	(0.11)
Total Non-Core	**$(0.36)**	**$0.06**	**$(0.42)**
Basic EPS	**$0.54**	**$0.83**	**$(0.29)**
Diluted EPS	**$0.54**	**$0.82**	**$(0.28)**

SCE Key Core Earnings Drivers	
Higher revenue	$0.15
SONGS impact	(0.02)
Lower O&M[2]	0.06
Higher depreciation	(0.05)
Higher net financing costs	(0.03)
Income taxes and other	0.04
Total	$0.15

EIX Key Core Earnings Drivers	
Higher corporate expenses and 2013 tax benefits	$(0.01)
Costs of new businesses	(0.01)
Total	$(0.02)

1 See Earnings Non-GAAP Reconciliations and Use of Non-GAAP Financial Measures in Appendix
2 Includes 2013 severance of $0.03

Non-GAAP Reconciliations

($ millions)

Reconciliation of EIX Core Earnings to EIX GAAP Earnings

Earnings Attributable to Edison International	Q1 2014	Q1 2013
Core Earnings		
SCE	$304	$256
EIX Parent & Other	(10)	(4)
Core Earnings	**$294**	**$252**
Non-Core Items		
SCE	$(96)	$–
EIX Parent & Other	–	7
Discontinued operations	(22)	12
Total Non-Core	**(118)**	**19**
Basic Earnings	**$176**	**$271**

Note: See Use of Non-GAAP Financial Measures. EME's financial results are reported as non-core for all periods

SCE Results of Operations

($ millions)

- Utility earning activities – revenue authorized by CPUC and FERC to provide reasonable cost recovery and return on investment
- Utility cost-recovery activities – CPUC- and FERC-authorized balancing accounts to recover specific project or program costs, subject to reasonableness review or compliance with upfront standards

	2013			2012		
	Utility Earning Activities	Utility Cost-Recovery Activities	Total Consolidated	Utility Earning Activities	Utility Cost-Recovery Activities	Total Consolidated
Operating revenue	$6,602	$5,960	$12,562	$6,682	$5,169	$11,851
Fuel and purchased power	—	4,891	4,891	—	4,139	4,139
Operation and maintenance	2,348	1,068	3,416	2,518	1,026	3,544
Depreciation, decommissioning and amortization	1,622	—	1,622	1,562	—	1,562
Property and other taxes	307	—	307	296	(1)	295
Asset impairment and disallowances	575	—	575	32	—	32
Total operating expenses	4,852	5,959	10,811	4,408	5,164	9,572
Operating income	1,750	1	1,751	2,274	5	2,279
Interest income and other	48	—	48	94	—	94
Interest expense	(519)	(1)	(520)	(494)	(5)	(499)
Income before income taxes	1,279	—	1,279	1,874	—	1,874
Income tax expense	279	—	279	214	—	214
Net income	1,000	—	1,000	1,660	—	1,660
Preferred and preference stock requirements	100	—	100	91	—	91
Net income available for common stock	$900	$—	$900	$1,569	$—	$1,569
Core earnings			$1,265			$1,338
Non-core earnings			(365)			231
Total SCE GAAP earnings			$900			$1,569

Note: See Use of Non-GAAP Financial Measures

SCE Core EPS Non-GAAP Reconciliations

Reconciliation of SCE Core Earnings Per Share to SCE Basic Earnings Per Share

Earnings Per Share Attributable to SCE	2008	2009	2010	2011	2012	2013	CAGR
Core EPS	**$2.25**	**$2.68**	**$3.01**	**$3.33**	**$4.10**	**$3.88**	**12%**
Non-Core Items							
Tax settlement	—	0.94	0.30	—	—	—	
Health care legislation	—	—	(0.12)	—	—	—	
Regulatory and tax items	(0.15)	0.14	—	—	0.71	—	
Asset impairment	—	—	—	—	—	(1.12)	
Total Non-Core Items	**(0.15)**	**1.08**	**0.18**	—	**0.71**	**(1.12)**	
Basic EPS	**$2.10**	**$3.76**	**$3.19**	**$3.33**	**$4.81**	**$2.76**	**6%**

Note: See Use of Non-GAAP Financial Measures

Appendix – SONGS & EME

SONGS Settlement – Summary

Term	Description
Steam Generators	• Steam Generator Replacement Project ("SGRP") removed from rates as of February 1, 2012, with book value balance disallowed. Revenues related to the SGRP collected after February 1, 2012, refunded to customers.
Power Costs	• Full recovery of replacement power costs
Regulatory Asset Recovery	• Non SGRP plant costs are recovered in rates over 10 years from February 1, 2012 • Weighted average return equal to authorized cost on debt and 50% of authorized cost on preferred; no return on equity. Results in current weighted average return of 2.62%. • Construction Work in Progress (CWIP) and materials and supplies are recovered with same return over same period • Nuclear Fuel amortized over same period; return at customary commercial paper rate • 5% of proceeds of any sales / dispositions of materials, supplies, and nuclear fuel accrue to shareholders, as well as 5% reduction in nuclear fuel commitments • Regulatory Asset can be removed from ratemaking capital structure, thus reducing equity requirement in excess of $300 million
Operations & Maintenance Costs	• Recorded O&M for 2013 recovered, including incremental inspection and repair costs • O&M recovery for 2012 limited to CPUC authorized amounts • Leaves $99 million incremental inspection and repair costs not recovered in rates (these costs were previously expensed)
Sharing of SCE Recovery Proceeds	• NEIL: 82.5% ratepayers / 17.5% Shareholders • MHI: Shareholders receive 85% of first $100 million; 2/3 of next $800 million; and 1/4 of amounts above $900 million • Litigation costs recovered before sharing starts

SONGS Settlement – Third-Party Recoveries

- SCE's share of recoveries from NEIL and MHI will be allocated between SCE and customers
- Litigation fees recovered prior to SCE / customer sharing

SCE Share

NEIL	All	→	17.5%
MHI			
• First	$100 million	→	85%
• Next	$800 million	→	66.67%
• Above	$900 million	→	25%

Non-Core Earnings

Customer Share

NEIL	All	→	82.5%
MHI			
• First	$100 million	→	15%
• Next	$800 million	→	33.33%
• Above	$900 million	→	75%

NEIL
- Credit to ERRA

MHI
- First $282 million – credit to General Rate Case Base Revenue Requirement Balancing Account (BRRBA)
- Above $282 million – reduce SONGS regulatory asset
- Credit to BRRBA after full SONGS regulatory asset recovered

SONGS Settlement – Accounting

- Q2 2013, SCE recorded $575 million pre-tax and $365 million after-tax impairment based on management's judgment of the recoverability of SONGS investment
  - Developed based on a range of possible outcomes
  - Each quarter, management must assess recoverability
- Q1 2014, SCE increased its total pre-tax impairment by $231 million to a total of $806 million (after-tax increase of $96 million to a total of $461 million) based on terms of Settlement Primary drivers of impairment charge:
  - Disallowance of SGRP investment – $542 million as of May 31, 2013
  - Refund of revenues related to SGRP previously recognized – $159 million
  - Implementation of other terms of the Settlement Agreement, including refund of authorized return in excess of the return allowed for non-SGRP investments
  - Refund of revenues to customers from flow-through tax benefits – increases effective tax rate
- If approved, the settlement would result in a core earnings benefit of approximately $0.03 per share in 2014 and $0.04 per share annually, declining over 10 years
- SCE has not recorded a receivable for potential recoveries from either MHI or NEIL

SCE recorded an additional pre-tax impairment of $231 million ($96 million after-tax, or $0.29 per share) in Q1 2014

Updated ERRA Recovery Forecast

($ millions)

	Dec 2013	June 2014	Jan 2015
SAR[1]	15.7	16.6	16.5 – 17.3

Key Items

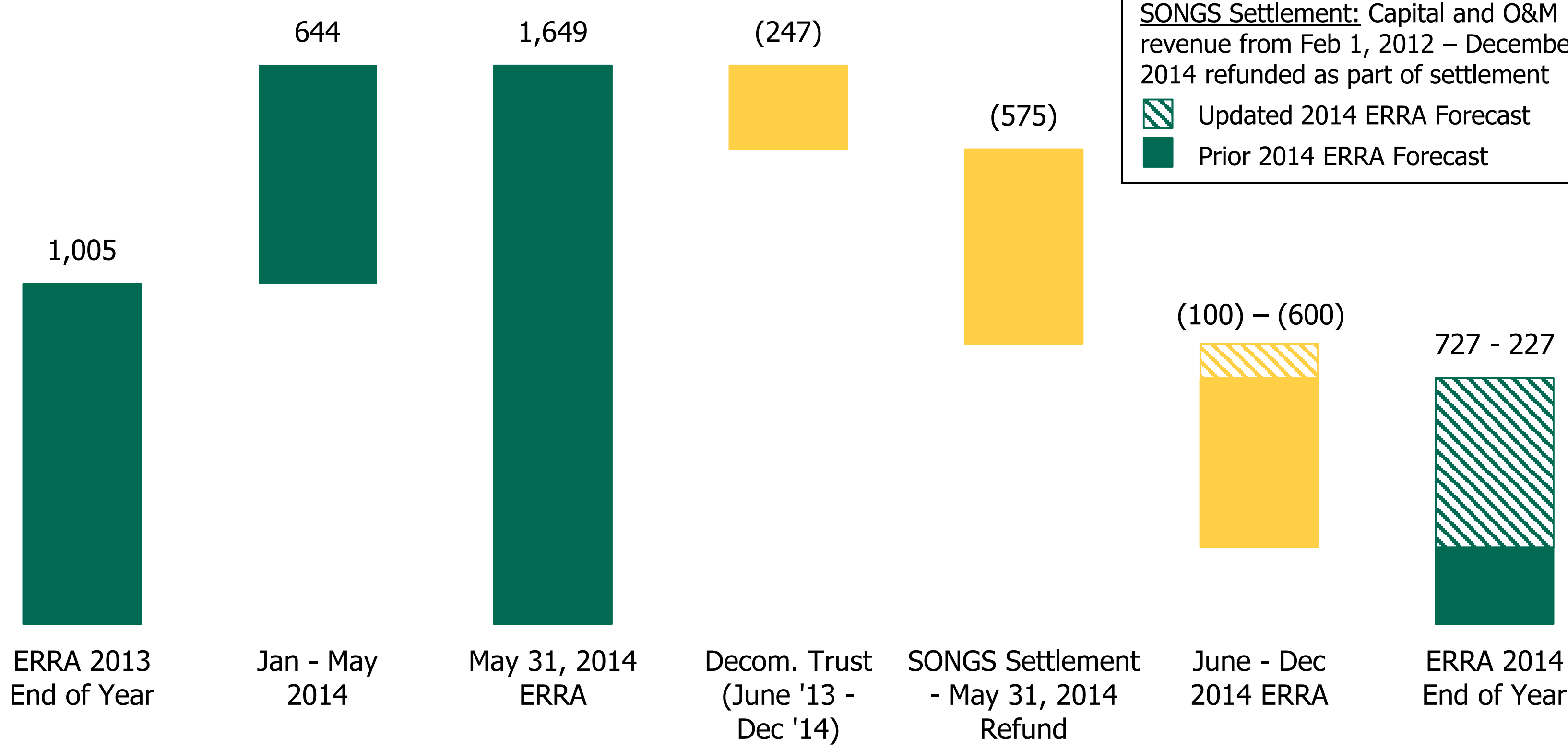
2014 ERRA: Based on final decision

Decommissioning Trust: recorded O&M recovered from Trust beginning June 2013

SONGS Settlement: Capital and O&M revenue from Feb 1, 2012 – December 31, 2014 refunded as part of settlement

Updated 2014 ERRA Forecast

Prior 2014 ERRA Forecast



1 SAR = Systemwide Average Rate in ¢/kWh

Note: Assumes June 1, 2014 Effective Date; settlement refunds include nuclear fuel amortization

SONGS Settlement – Regulatory Asset

($ millions)

Category	December 31, 2013[1]	March 31, 2014	Authorized Return
Base Plant	$2,166	$488	2.62%
SGRP		-	n/a
CWIP[2]		406	2.62%
Materials and Supplies		78	2.62%
Nuclear Fuel		404	Commercial Paper Rate
Asset Impairment	(575)	(5)	n/a
Regulatory Asset	**$1,591**	**$1,371**	

Estimated Revenue Refund

Authorized revenue in excess of recorded	(266)	(371)

As of March 31, 2014, SONGS regulatory assets under the Settlement Agreement are $1.4 billion, with recovery expected through January 31, 2022

1 December 31, 2013 balance of $2,166 million comprised of $2,096 million net investment at May 31, 2013 plus $70 million of costs recorded thereafter. Individual components not disclosed.

2 CWIP includes both completed and cancelled CWIP as defined by the Settlement Agreement

SONGS Settlement Impact

In Millions	Regulatory Asset	Regulatory Liability	Profit (Loss)
As of June 7, 2013	$2,096	$—	$—
Impairment	(575)	—	(575)
Additions	70	—	—
Authorized Revenues in excess of revenue recorded	—	266	—
As of December 31, 2013	1,591	266	(575)
Reductions	(3)	—	
Authorized Revenues in excess of revenue recorded	—	91	
As of March 31, 2014 – Before Settlement	1,588	357	(575)
Accounting impact of Settlement:			
Refund of revenues related to RSGs	—	159	(159)
Recovery of amortization of regulatory asset	(343)	(343)	—
Refund of depreciation recorded through plant shutdown	123	123	—
Refund of revenues from flow through tax benefits	—	71	(71)
All other	3	4	(1)
Impact of Settlement	(217)	14	(231)
As of March 31, 2014 – After Settlement	$1,371	$371	(806)
Income taxes[1]			(345)
Total after-tax impairment			(461)

Recorded 2QTR 2013	(365)
Recorded 1QTR 2014	(96)
	(461)

1 Includes $71 million income tax benefits related to flow through of tax repair deductions that will be refunded to customers

SONGS Third-Party Recovery – MHI

Warranty Summary

- 20-year warranty:
  - Repair or replace defective items
  - Specified damages for certain repairs
  - \$138 million liability limit, excluding consequential damages (e.g. replacement power)
  - Limits subject to applicable exceptions in the contract and under law
- 7 invoices submitted totaling \$149 million for repair costs through April 30, 2013
  - First invoice of \$45 million (\$36 million SCE share) paid, subject to audit, reservation of rights regarding documentation

Request for Arbitration

- October 2013, Request for Arbitration filed with the International Chamber of Commerce per MHI contract
- Claims for damages consistent with July 2013 Notice of Dispute that was unsuccessfully resolved with MHI
- Exceptions to damage limitations are argued to apply:
  - Direct Damages – \$138 million warranty cap does not apply due to, among other things, gross negligence
  - Consequential Damages – contract waiver does not apply due to, among other things, "failure of essential purpose"
- MHI responded in December 2013 countering SCE's claims and asserting \$41 million in counterclaims

SCE's position is that the steam generator tube leak and resulting damages represent a total and fundamental failure of performance by MHI

SONGS Third-Party Recovery – NEIL Insurance

- Accidental property damage and accidental outage insurance through Nuclear Electric Insurance Limited ("NEIL")
  - Accidental Property Damage Policies – $2.5 million deductible; $2.75 billion liability limit
  - Accidental Outage Policy – weekly indemnity up to $3.5 million per unit after 12-week deductible period ($2.8 million per unit per week if both are out due to same "accident"); $490 million limit per unit ($392 million each if both units are out due to the same "accident")
  - Exclusions and limitations may reduce or eliminate coverage
  - Proof of loss must be submitted within 12 months of damage or outage
- Accidental outage policy benefits are reduced to:
  - 80% of weekly indemnity after 52 weeks; and
  - 10% of weekly indemnity after early retirement announcement
- Separate proofs of loss have been filed for Unit 2 and Unit 3 under NEIL accidental outage policy totaling $409 million ($320 million SCE share) for amounts through December 31, 2013
  - SCE is continuing to make weekly indemnity claims post-shutdown decision at 10% value per the terms of the policy
  - SCE has not submitted a proof of loss under the accidental property damage policies – SCE has received an extension to file such a claim to June 30, 2014
- NEIL may make a coverage determination by end of Q2 2014, but it may take longer

SONGS – Decommissioning

Decommissioning Trusts

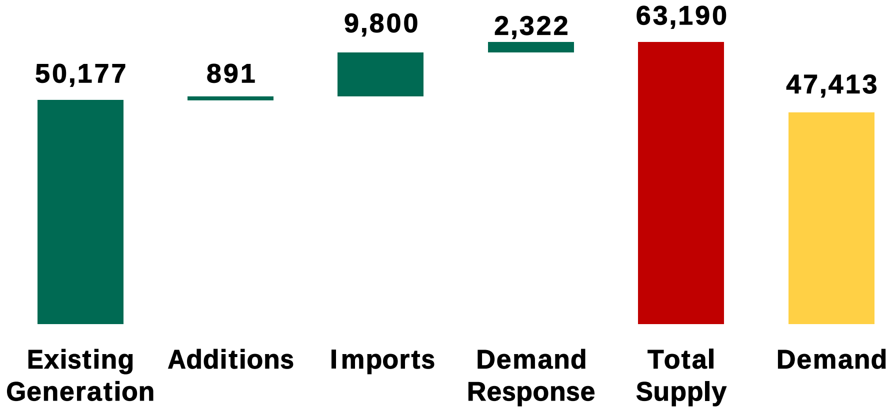
- Decommissioning Trust contributions recovered in rates approved by CPUC in triennial proceeding
- December 2012, A.12-12-013 Joint Filing with SDG&E submitted
- July 2013, updated early retirement scenario total decommissioning cost
  - Currently authorized annual decommissioning contributions of $23 million
  - Detailed site-specific decommissioning cost study expected to be completed by end of 2014

Decommissioning Process

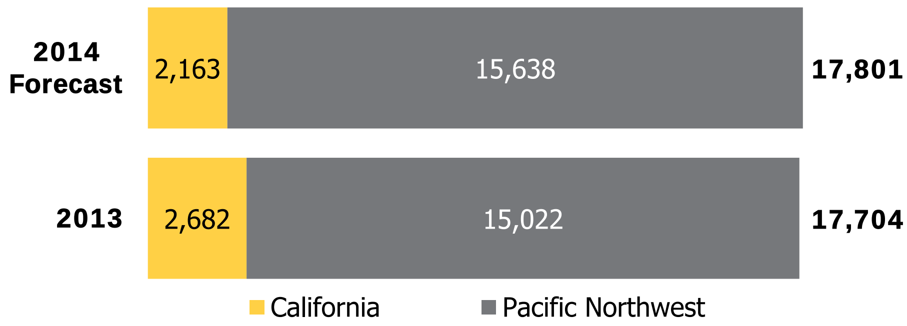
- June 2013, Certification of Permanent Cessation of Power Operations submitted to NRC
- All initial decommissioning activity phase plans and cost estimates will be provided by end of 2014
- Decommissioning involves three related activities: radiological decommissioning, non-radiological decommissioning and management of spent nuclear fuel
- Access to decommissioning trust funds dependent on CPUC approving SCE's advice letter requesting interim access, decommissioning process milestones, and NRC staff approval for non-radiological decommissioning

2014 Bulk Electricity Outlook

2014 CAISO On-Peak Resources (MW)



Hydro Capacity (Average MW)

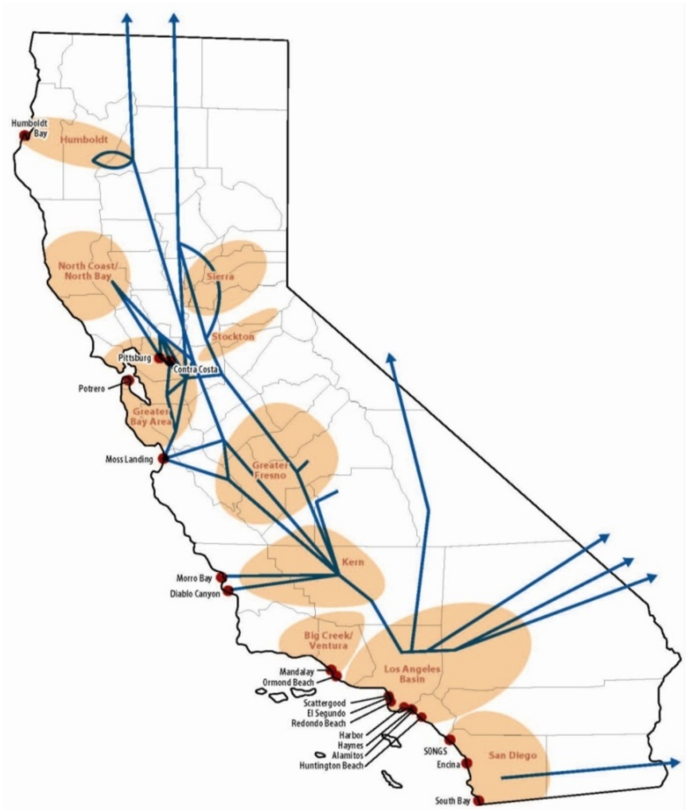


- California planning reserve margin is approximately 33% versus 15 – 17% target
- Local transmission constraints can still yield potential customer interruptions
- The drought's impact in California is largely offset by precipitation in the Northwest

California has sufficient generating capacity to meet summer 2014 demand; planning reserve margin is approximately 33% versus 15 – 17% target

Source: CA Independent System Operator, "2013 Summer Loads & Resources Assessment", May 6, 2013, updated by SCE to reflect anticipated 2014 conditions

SCE System Reliability



<u>CA Once Through Cooling Policy – Legend</u>

- Coastal Power Plants
- Local Reliability Areas (generalized)
- California Transmission System (partial, generalized)

- Short-term SONGS closure solutions
  - Transmission – 220 kV Barre-Ellis reconfiguration
  - Voltage support – Huntington Beach 3 and 4 synchronous condensers
  - Substations – Santiago, Viejo, Johanna capacitor bank upgrades
  - Generation – El Segundo repower (550 MW), Sentinel (728 MW), Walnut Creek (480 MW)
  - Conservation – EE, demand response, Flex Alerts
- Long-term issues
  - Once-through cooling – approximately 6,000 MW affected in SCE territory
  - Air quality and emissions – limitations on permits, cap and trade market
  - Distributed generation and renewables – integration, flexibility and net load

EME Bankruptcy Settlement Implementation

- April 2014, amended Plan of Reorganization completed
- EME emerged from bankruptcy and remains subsidiary of EIX Consolidated for tax purposes
- Reorganization Trust established to receive tax benefit payments from EIX

Cash Impact

- Based on current estimates:
  - EIX expects net benefits of approximately $200 million
  - EIX expects to utilize approximately $1.2 billion of EME tax benefits – 50% to Reorganization Trust
  - EIX would make an estimated $634 million in total payments through 2016 (including interest):
    - $225 million paid April 1, 2014
    - $199 million on September 30, 2015
    - $210 million on September 30, 2016
- Deferred payment amounts to be finalized by September 2014 after closing based on updated estimates

Accounting Treatment

- Accounting impact will be non-core
  - Approximately $48 million of net benefits recorded as non-core income through March 31, 2014
  - Based on current estimates, balance of net benefits of $152 million to be recorded as non-core income in Q2 2014

Use of Non-GAAP Financial Measures

Edison International's earnings are prepared in accordance with generally accepted accounting principles used in the United States. Management uses core earnings internally for financial planning and for analysis of performance. Core earnings are also used when communicating with investors and analysts regarding Edison International's earnings results to facilitate comparisons of the Company's performance from period to period. Core earnings are a non-GAAP financial measure and may not be comparable to those of other companies. Core earnings (or losses) are defined as earnings or losses attributable to Edison International shareholders less income or loss from discontinued operations and income or loss from significant discrete items that management does not consider representative of ongoing earnings, such as: exit activities, including sale of certain assets, and other activities that are no longer continuing; asset impairments and certain tax, regulatory or legal settlements or proceedings.

A reconciliation of Non-GAAP information to GAAP information is included either on the slide where the information appears or on another slide referenced in this presentation.

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