Southern California Edison Company
SB 695 Report To Energy Division
Year: 2016

1. Opening Comments

In support of Senate Bill (SB) 695, SCE is providing the following information to assist the Commission in preparing its annual report to the Governor and Legislature. Specifically, SB 695 requires:

> "that by May 1, 2010, and by May 1 of each year thereafter, the commission also report to the Governor and Legislature with its recommendations for actions that can be undertaken during the upcoming year to limit cost and rate increases, consistent with the state's energy and environmental goals, including the state's goals for reduction in emissions of greenhouse gases. The bill would require the commission to annually require electrical and gas corporations to study and report to the commission on measures that they recommend be undertaken to limit costs and rate increases."

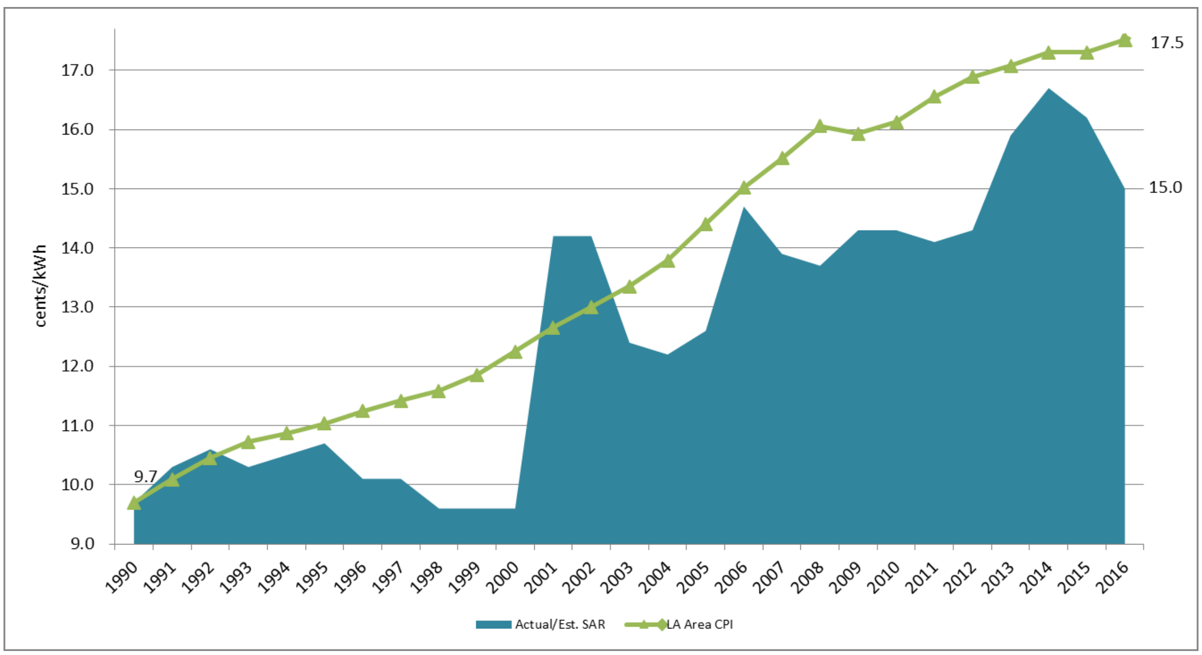
The information provided includes SCE's overall rate policy, a discussion of SCE management's policies to control costs and control rate increases for customer's and, a discussion of SCE's policies and recommendations for limiting rate increases while meeting the State's energy and environmental goals for reducing greenhouse gases.

In addition, SCE has provided data contained in Appendix A to this Report that describes SCE's revenue requirements and provides an outlook for pending revenue requirement and rate changes from May 1, 2016 to April 30, 2017.

2. Overall Rate Policy

SCE's overall rate policy is to fully recover the authorized revenue requirement in an equitable manner while considering public policy objectives. SCE designs its rates to meet the traditional design objectives (e.g., recovery of authorized revenue requirement, marginal cost of service foundation, and rate stability) while supporting the various public policy objectives established by the legislature and regulators. By recovering its authorized revenue requirement through cost based rates, SCE can properly maintain and rebuild its distribution system, provide power as needed, and meet customer service needs as they arise. Recovering these costs equitably from customers ensures that those customers who are more costly to serve pay appropriately higher rates. Rates that are equitable and cost-based also send the correct price signals to customers and prevent uneconomic decisions regarding energy usage.

Figure 1 below shows a comparison of SCE's actual System Average Rate as compared to what the average rate would have been if it had changed commensurate with the Consumer Price Index.[1]



[1] CPI based on US Bureau of Labor Statistics for all urban consumers in LA-Riverside-Orange County, CA.

At the customer class level, SCE establishes its revenue allocation and rate design based on the marginal cost of service associated with each respective class. By applying cost of service principles, more revenue is recovered from customer classes that contribute at a higher level to the utility's cost of service; and conversely, less is recovered from customer classes that have a lower cost impact to the utility. This general methodology helps to reduce subsidization across and within customer classes, and is rigorously reviewed in each GRC Phase 2 proceeding.

In SCE's 2015 GRC Phase 2 proceeding (A.14-06-014), Parties settled on a proposal that resulted in lower subsidization across and within classes, while also providing some measure of rate stability for affected customer classes. In this particular instance, Parties agreed to a three-year phase out of an Agricultural and Pumping rate provision which provided customers a 10-year discounted rate in exchange for converting their water pumps from internal combustion to electric motors as part of an effort to reduce statewide emissions levels. A multi-year phase out policy, rather than the abrupt elimination, of a program that would have otherwise expired at the end of December 2015 represents an example of balancing the rate impact of participating customers and the revenue shift burden to the non-participating customers.

Tables 1 and 2, shown in nominal and real values, respectively, provide a view of the trends in rates for SCE's different customer classes. Average rates are based on recorded revenues and sales for bundled service customers through time. Table 3 provides an alternative view of this data by expressing this information as a percent of the system average rate.

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TABLE 1: Historical Average Rates by Rate Group (Nominal ¢/kWh)
Based on Recorded Revenue and Sales

Bundled Service

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Residential	Domestic	11.4	11.4	11.5	13.0	13.5	12.8	12.5	12.9	15.7	15.3	15.0	15.2	15.5	15.6	15.9	16.7	16.4	16.6
Small C&I (< 20 kW)	TOU-GS-1	12.1	12.1	12.0	16.2	17.5	15.8	14.8	15.2	17.6	17.6	17.0	16.9	17.5	17.3	17.6	17.5	18.3	18.0
Traffic Control	TC-1	7.3	7.4	7.4	10.3	13.5	12.4	12.0	11.5	13.4	13.5	13.8	14.5	15.8	15.9	15.6	16.9	18.6	19.0
Medium C&I (20 kW - 200 kW)	TOU-GS-2	9.9	10.2	10.1	13.2	15.5	14.1	13.3	13.5	15.6	14.3	14.3	14.8	15.7	15.4	14.9	16.2	17.4	17.3
Medium C&I (200 kW - 500 kW)	TOU-GS-3	9.7	8.9	10.2	13.1	14.7	13.0	11.8	10.8	13.6	14.2	14.1	14.3	13.7	13.2	12.7	14.3	15.9	15.8
Total Lighting/Small/Medium C&I	Sm. and Medium Comm.	10.3	10.5	10.4	13.7	15.8	14.4	13.5	13.6	15.6	14.9	14.7	15.0	15.5	15.2	14.9	16.0	17.2	17.1
Large C&I (Sec)	TOU-8-Sec	8.1	8.2	8.7	12.2	14.3	12.6	11.2	11.3	13.2	12.5	12.4	12.7	13.1	12.7	12.3	13.7	15.0	14.9
Large C&I (Pri)	TOU-8-Pri	7.2	7.4	7.9	10.9	13.0	11.5	10.3	10.7	12.6	11.9	11.8	11.7	11.8	11.5	10.9	12.1	13.2	13.1
Large C&I (Sub)	TOU-8-Sub	4.9	5.1	5.7	8.3	9.4	8.4	7.4	7.5	9.1	8.3	8.1	7.9	8.0	7.6	7.0	8.1	9.1	9.1
Total Large C&I	Large Power	6.8	7.1	7.7	10.6	12.6	11.2	9.9	10.0	11.8	11.1	10.9	10.9	11.1	10.6	10.1	11.7	12.9	12.8
Small Ag & Pump (<200 kW)	PA-1	12.8	12.1	12.1	14.3	15.3	14.9	14.0	15.1	18.2	16.9	17.5	17.8	19.4	19.7	18.5	12.3	14.4	13.8 [1]
	PA-2	8.7	8.5	8.7	10.7	11.3	10.5	10.4	10.7	12.8	12.5	12.8	13.1	14.8	14.9	14.2			
Large Ag & Pump (≥ 200 kW)	AG-TOU	7.4	6.9	7.5	9.4	10.1	9.0	8.5	8.5	10.0	9.6	9.7	9.9	10.9	10.3	9.3	12.0	13.2	12.3 [2]
	TOU-PA-5	6.9	6.3	7.0	8.8	9.4	8.2	7.8	7.8	9.4	9.0	8.9	9.1	9.9	10.3	9.1			
Total Ag & Pumping	Ag. and Pumping	8.8	8.5	8.7	10.6	11.1	9.9	9.4	9.5	11.3	10.9	10.8	11.0	12.0	11.6	10.8	12.1	13.8	13.1
Total Street & Area Lighting	St. and Area Lighting	17.0	14.1	13.9	15.8	17.3	15.5	14.7	14.0	15.3	16.9	17.9	18.7	19.0	18.9	18.1	18.2	18.7	19.1
Standby (Sec)	STANDBY/SEC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	11.2	12.7	13.3
Standby (Pri)	STANDBY/PRI	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	11.9	12.5	13.0
Standby (Sub)	STANDBY/SUB	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	7.9	9.3	9.5
Total Standby	Standby	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	9.1	10.1	10.5
Total Bundled	Total Bundled	9.6	9.9	10.0	12.5	14.0	12.9	12.2	12.4	14.6	14.0	13.8	14.0	14.4	14.2	14.1	15.0	15.7	15.6

[1] 2012 GRC Phase 2 Rate Group Change for Ag/Pumping Customers with Demands < 200 kW (PA-1 and PA-2 mapped to TOU-PA-2)
[2] 2012 GRC Phase 2 Rate Group Change for Ag/Pumping Customers with Demands ≥ 200 kW (AG-TOU and TOU-PA-5 mapped to TOU-PA-3)

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TABLE 2: Historical Average Rates by Rate Group (Real ¢/kWh)
Based on Recorded Revenue and Sales

Bundled Service

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Residential	Domestic	17.2	16.9	16.4	18.0	18.2	16.8	15.9	15.6	18.3	17.2	16.3	16.7	16.8	16.4	16.4	17.1	16.5	16.6
Small C&I (< 20 kW)	TOU-GS-1	18.2	17.8	17.1	22.3	23.5	20.7	18.7	18.4	20.5	19.8	18.5	18.5	18.9	18.3	18.2	17.9	18.4	18.0
Traffic Control	TC-1	11.0	10.9	10.5	14.2	18.1	16.3	15.2	14.0	15.6	15.2	15.0	15.9	17.1	16.8	16.1	17.3	18.8	19.0
Medium C&I (20 kW - 200 kW)	TOU-GS-2	15.0	15.1	14.4	18.2	20.8	18.5	16.9	16.4	18.1	16.1	15.6	16.2	17.0	16.2	15.4	16.6	17.6	17.3
Medium C&I (200 kW - 500 kW)	TOU-GS-3	14.6	13.2	14.6	18.0	19.8	17.0	15.0	13.1	15.9	16.0	15.3	15.6	14.8	13.9	13.2	14.7	16.1	15.8
Total Lighting/Small/Medium C&I	Sm. and Medium Comm.	15.5	15.5	14.8	18.9	21.3	18.8	17.1	16.5	18.1	16.8	16.0	16.5	16.8	16.0	15.4	16.4	17.4	17.1
Large C&I (Sec)	TOU-8-Sec	12.1	12.1	12.4	16.8	19.2	16.5	14.2	13.8	15.3	14.1	13.5	13.9	14.2	13.4	12.7	14.0	15.1	14.9
Large C&I (Pri)	TOU-8-Pri	10.9	10.8	11.3	15.0	17.4	15.0	13.0	13.0	14.6	13.4	12.8	12.8	12.8	12.1	11.2	12.4	13.3	13.1
Large C&I (Sub)	TOU-8-Sub	7.4	7.6	8.1	11.5	12.6	11.0	9.4	9.1	10.6	9.4	8.8	8.6	8.7	8.1	7.2	8.2	9.2	9.1
Total Large C&I	Large Power	10.2	10.5	11.0	14.6	16.9	14.7	12.6	12.2	13.7	12.5	11.9	12.0	12.0	11.2	10.4	11.9	13.0	12.8
Small Ag & Pump (<200 kW)	PA-1	19.4	17.9	17.2	19.7	20.6	19.4	17.7	18.3	21.1	19.1	19.1	19.5	21.0	20.7	19.1	12.6	14.5	13.8 [1]
	PA-2	13.1	12.5	12.5	14.8	15.1	13.8	13.2	12.9	14.9	14.0	13.9	14.3	16.0	15.8	14.7			
Large Ag & Pump (≥ 200 kW)	AG-TOU	11.1	10.1	10.6	13.0	13.6	11.7	10.8	10.3	11.6	10.8	10.5	10.9	11.8	10.9	9.6	12.3	13.3	12.3 [2]
	TOU-PA-5	10.3	9.2	10.0	12.1	12.7	10.8	9.9	9.5	10.9	10.2	9.7	10.0	10.8	10.9	9.5			
Total Ag & Pumping	Ag. and Pumping	13.3	12.5	12.4	14.6	14.9	12.9	11.9	11.6	13.2	12.3	11.7	12.1	13.0	12.3	11.1	12.4	14.0	13.1
Total Street & Area Lighting	St. and Area Lighting	25.6	20.8	19.8	21.8	23.2	20.3	18.6	17.0	17.7	19.0	19.5	20.5	20.6	19.9	18.7	18.6	18.9	19.1
Standby (Sec)	STANDBY/SEC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	11.4	12.8	13.3
Standby (Pri)	STANDBY/PRI	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	12.2	12.6	13.0
Standby (Sub)	STANDBY/SUB	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	8.1	9.4	9.5
Total Standby	Standby	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	9.3	10.2	10.5
Total Bundled	Total Bundled	14.5	14.6	14.3	17.2	18.8	16.9	15.4	15.0	16.9	15.7	15.0	15.3	15.5	15.0	14.5	15.3	15.8	15.6
	CPI Deflator (LA Area)	1.51	1.47	1.43	1.38	1.34	1.31	1.27	1.21	1.16	1.13	1.09	1.10	1.08	1.05	1.03	1.02	1.01	1.00 [3]

[1] 2012 GRC Phase 2 Rate Group Change for Ag/Pumping Customers with Demands < 200 kW (PA-1 and PA-2 mapped to TOU-PA-2)
[2] 2012 GRC Phase 2 Rate Group Change for Ag/Pumping Customers with Demands ≥ 200 kW (AG-TOU and TOU-PA-5 mapped to TOU-PA-3)
[3] CPI based on US Bureau of Labor Statistics for all urban consumers in LA-Riverside-Orange County, CA; annual CPI averages are used

Southern California Edison
TABLE 3: Historical Average Rates by Rate Group (% of System Average Rate)
Based on Recorded Revenue and Sales
Bundled Service

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	
Residential	Domestic	118%	115%	114%	104%	96%	99%	103%	104%	108%	109%	109%	109%	108%	110%	113%	111%	104%	106%	
Small C&I (< 20 kW)	TOU-GS-1	125%	122%	120%	130%	125%	122%	121%	123%	121%	126%	123%	120%	122%	122%	125%	117%	116%	115%	
Traffic Control	TC-1	76%	74%	74%	83%	96%	96%	99%	93%	92%	96%	100%	103%	110%	112%	111%	113%	118%	122%	
Medium C&I (20 kW - 200 kW)	TOU-GS-2	103%	103%	100%	106%	110%	109%	109%	109%	107%	103%	104%	106%	110%	108%	106%	108%	111%	111%	
Medium C&I (200 kW - 500 kW)	TOU-GS-3	100%	90%	102%	105%	105%	100%	97%	87%	94%	102%	102%	102%	95%	93%	91%	96%	101%	101%	
Total Lighting/Small/Medium C&I	Sm. and Medium Comm.	107%	106%	104%	110%	113%	111%	111%	110%	107%	107%	107%	107%	108%	107%	106%	107%	110%	109%	
Large C&I (Sec)	TOU-8-Sec	84%	83%	87%	98%	102%	98%	92%	92%	90%	90%	90%	91%	91%	89%	87%	91%	95%	95%	
Large C&I (Pri)	TOU-8-Pri	75%	74%	79%	87%	92%	89%	84%	86%	86%	85%	86%	83%	82%	81%	77%	81%	84%	84%	
Large C&I (Sub)	TOU-8-Sub	51%	52%	56%	67%	67%	65%	61%	61%	62%	60%	59%	56%	56%	54%	50%	54%	58%	58%	
Total Large C&I	Large Power	70%	72%	77%	85%	90%	87%	82%	81%	81%	79%	79%	78%	77%	75%	72%	78%	82%	82%	
Small Ag & Pump (<200 kW)	PA-1	133%	122%	120%	115%	109%	115%	115%	122%	125%	121%	127%	127%	135%	138%	131%	82%	92%	88%	[1]
	PA-2	90%	86%	87%	86%	80%	82%	86%	86%	88%	89%	93%	93%	103%	105%	101%				
Large Ag & Pump (≥ 200 kW)	AG-TOU	76%	69%	74%	75%	72%	69%	70%	69%	69%	69%	70%	71%	76%	73%	66%	80%	84%	78%	[2]
	TOU-PA-5	71%	63%	70%	70%	67%	64%	64%	63%	65%	65%	64%	65%	69%	73%	65%				
Total Ag & Pumping	Ag. and Pumping	92%	85%	87%	85%	79%	76%	77%	77%	78%	78%	78%	79%	84%	82%	77%	81%	88%	84%	
Total Street & Area Lighting	St. and Area Lighting	176%	142%	138%	127%	123%	120%	121%	114%	105%	121%	130%	134%	132%	133%	129%	122%	119%	122%	
Standby (Sec)	STANDBY/SEC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	75%	81%	85%	
Standby (Pri)	STANDBY/PRI	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	79%	80%	83%	
Standby (Sub)	STANDBY/SUB	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	53%	59%	61%	
Total Standby	Standby	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	60%	65%	67%	
Total Bundled	Total Bundled	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	

[1] 2012 GRC Phase 2 Rate Group Change for Ag/Pumping Customers with Demands < 200 kW (PA-1 and PA-2 mapped to TOU-PA-2)
[2] 2012 GRC Phase 2 Rate Group Change for Ag/Pumping Customers with Demands ≥ 200 kW (AG-TOU and TOU-PA-5 mapped to TOU-PA-3)

3. Management Control of Rate Components

SCE requests in CPUC and FERC General Rate Cases[2] funding to operate its generation, transmission and distribution businesses in order to provide safe, reliable, and affordable electric service to all customers in its service territory. Based on the funding authorized by the Commission, SCE has the ability to manage those core utility businesses. However, funding has not always been adequate to fulfill all infrastructure replacement requirements on the company's planned schedule. Another portion of SCE's total revenue requirement is associated with its power procurement function. Based on a set of assumptions that reflect regulatory and legislative requirements, SCE requests funding to procure enough power to meet its customers' load. Although there are procurement cost components that are driven by market forces outside of SCE's control, such as natural gas prices, SCE has been given some authority by the CPUC to use

[2] SCE's FERC transmission revenue requirement is currently established through a formula rate mechanism.

hedging tools to reduce the variability in cost of power to its customers. A third category of costs are associated with policies driven by Commission and the Legislature for funding programs such as Demand Response, Energy Efficiency, Solar Initiatives, Self-Generation and Low Income programs. In compliance with these policies, SCE makes initial requests for funding these programs but the final authorized funding amounts are determined by the Commission based on its policy objectives. Finally, there are costs included in the total revenue requirement that are fully outside of SCE's management control such as DWR Power and Bond Charge revenue requirements and other costs whose magnitude are prescribed by the legislature or a regulatory agency (e.g., while the requirement in Assembly Bill (AB) 1890 to collect revenue for the California Energy Commission to fund its Renewable, and Research, Development and Demonstration programs expired at the end of 2011, the CPUC issued a decision that continues funding for RD&D programs through 2020).

As previously stated, SCE relies on a policy of marginal cost based allocation in order to control the level of costs allocated to the various customer classes. This policy helps to limit the burden of any particular costs on a given customer class, and helps to direct a larger allocation of those costs to customer classes who are driving the marginal expenditures. In other circumstances, the allocation of costs may be governed by statute or Commission order.

It should be noted, that SCE is committed to fulfill its core mission of providing safe, reliable, affordable and clean electricity to its customers through operating and service excellence across all business and functional areas.

4. Utility's Policies and Recommendations For Limiting Costs and Rate Increases While Meeting the State's Energy and Environment Goals for Reducing Greenhouse Gases

First, SCE believes that it is important for the State to understand what its environmental goals are so that they can be pursued most effectively and efficiently. Since the goals appear to be primarily focused on GHG reduction, then our policymakers must consider the fact that if businesses and residents leave the "clean" State of California, and move to a higher emitting State or country (almost anywhere else), then the net impact on the environment will be negative while the appearance of a cleaner California might belie this. Conversely, attracting businesses and people to California will have a clear net positive effect on GHG in almost all circumstances.

The current focus on achieving state policy should be the implementation of SB350. This new law will require the use of 50% of utility sales to be served by renewable power by 2030, increase energy efficiency goals, expand the electricity sector role in electrifying transportation, and implement an integrated resource plan focused on achieving GHG targets in the electricity sector. Accomplishing these tasks, just as achieving the goals of AB-32, will require careful thought, broad market solutions, and flexibility so as to avoid undue cost implications, and continue to establish California as a model for others to follow in responsible GHG reductions.

California's environmental policies need to be coordinated to be effective. Simultaneously pursuing GHG reduction, local air emissions reductions, water use restrictions, and land use restrictions requires a comprehensive and coordinated process. Otherwise, we waste time, money, and resources resolving conflicts, and we risk the reliability and affordability of electricity. The State wants to mitigate the impact of oncethrough cooling on marine habitat, so we may need to build some new efficient gas generation facilities to maintain electric system reliability. But developers will struggle to license the new gas generation due to particulate emissions restrictions, even though the emissions meet the federal standards. There are not sufficient permits for particulate emissions because one agency's program for such was found through the courts to violate another California environmental law. However, the State wants to add more renewable power to displace fossil fuel generation, but siting renewable facilities encounters costs and delays due to land use restrictions or habitat impacts from the transmission needed to bring the generation to customers. But, even if successful in adding more renewable projects, the State will need additional conventional resources to integrate these projects. The costs associated with conflicting environmental policies are substantial, whether looking at customer costs, time, or the resources of those working in this space. The only solution is a more coordinated effort to establish consistent and comprehensive goals, and determine least cost and most efficient means to achieve these goals. Such is not the current process.

Generally, market solutions will tend to lead to lower cost solutions to meet policy goals. As such, the goals should be broadly defined, such as "reduction of GHG to 1990 levels by 2020," as opposed to mandates to procure specific technologies. Furthermore, the impacts on the ability to maintain a reliable electric grid should be part of the original debate in developing State policies, rather than an afterthought whose solutions either conflict with other State mandates, or receive broad opposition from parties who are not knowledgeable or concerned about maintaining a reliable grid.

Broader markets will lead to lower costs. As we develop and implement market solutions, we should seek to achieve broader market solutions wherever possible, if we want to minimize the rate impacts of achieving State environmental policy goals. This means allowing out of State resources to help California meet its goals if they are lower cost. This means allowing any GHG reductions means to be used, including broad use of offsets, as long as they can be appropriately verified.

Aligning incentives with desired outcomes will lead to greater success in reaching targets. California is the nation's leaders in energy efficiency, due in no small part to its decoupling of utility revenues from electricity sales. This was the result of recognition that entities will always be resistant to acting against their own interests, and in this case fiduciary responsibilities. The converse of this example is to impose a mandate with serious financial consequences such that it provides an incentive to reach the goal at any cost. Such structures are not conducive to reaching State environmental goals at least cost.

Market design and rules matter. In the case of AB-32 cap & trade regulations, there are elements of the market design that could result in excessive costs of the program. One danger in relying on market solutions is that if the markets are competitive, then low costs will result, but if they are subject to manipulation or generally are not competitive then high cost solutions are possible. This situation can be addressed by having effective rules and oversight. For example, if the goal of AB-32 is to put in place a GHG reduction program that can be an example for the rest of the nation or world to follow, then we must succeed in achieving GHG reduction goals without undue costs. One very visible measure of the cost of the program will be the GHG price that results from the cap & trade market structure. Currently, there is no limit (other than an ever increasing floor price) on the range of prices that can result from that market. Yet we know that if the price rises to too great a level, the program will not be viewed as an example to be followed, but - like California's electricity market that failed - an example to be avoided. As such, it only makes sense to design this market so as to not allow prices to rise to unreasonable levels. While the California Air Resources Board (CARB) has put in several mitigation measures in place, (such as reserve auctions and CARB's ability to borrow from future auctions) ultimately there is no limit on market prices. And in turn, no guarantee of rate impacts mitigation or that the program will not "blow up".

To minimize the rate impact of a cap & trade system SCE and the other IOUs advocated in Rulemaking (R.) 11-03-012 that cap & trade related revenues be returned to the utility's customers in form of lower rates and are not spent on additional state-or Commission-mandated programs. However, the Commission issued a decision in R.11-03-012 that primarily returns the majority of cap & trade revenue to residential customers and excludes many businesses including universities, and hospitals.

Achieving environmental goals without undue rate impacts requires flexibility: the flexibility to relax time constraints on achieving goals if doing so prevents undue cost implications; the flexibility to change rules when we learn there were unintended and adverse consequences of the rules we originally imposed; the flexibility to change to incorporate new ideas that will help achieve our environmental and cost goals, even if those ideas arise after our programs are already in place; the flexibility to adapt California's programs to National programs as they emerge.

Currently, SCE is focusing on finding an effective path to meet each of the goals established by SB350. Although it is early in the process of designing the path from 2020 to 2030, much effort is already underway to expand renewable procurement, increase the effectiveness and reach of energy efficiency programs including the development of programs to move customers who are not achieving today's codes and standards to reach those, increase infrastructure for charging electric vehicles so as to accelerate the adoption of this technology that is critical to reaching overall State GHG targets, and designing an integrated resource planning process that looks across all available options to meet future customer needs while meeting reliability requirements and GHG targets.

Some of the key actions that the CPUC, Legislature, and Governor can do to help manage and minimize rate increases in the future are described below. These generally fall into the categories of finding least cost solutions to meeting GHG reduction goals, maintaining fair and efficient rate structures for customers, and effectively adapting to changing technologies, particularly those impacting the distribution grid, as advances in this space are potentially rapidly transforming how customer needs will be met in the future.

In the area of renewable procurement to meet SB350 goals, providing as much flexibility to use least cost options is critical to ensuring the clean power used to serve future customer needs is affordable. This means limiting the technology based targets and restrictions sometimes used to satisfy the needs of subsets of the renewable community, appropriately expanding the geographic scope of new renewable development to incorporate out of State projects that help meet California's energy needs, while displacing higher emitting out of state resources in the process, and recognizing that many new renewable resources are connecting on the distribution grid, and achieving renewable expansion goals at least cost means relying on markets, and not artificial distinctions such as the interconnection points, to determine the mix of future renewable development.

Another critical factor in achieving GHG reduction policies in the State without an undue cost burden on customers is the transition away from substantial cross subsidies in rates between customer groups. For example, the current and successor tariff on Net Energy Metering will require substantial subsidies paid by non-participating customers to pay for the grid being used by participants in net energy metering. If this leads to excessive rates for non-participating customers such that some of them migrate to other parts of the country of world, it is highly likely that their GHG footprint would expand undermining the success of California’s programs.

As more and more new resources seek to connect to the distribution grid and provide and be compensated for services, the need for a modernized grid that can monitor and control the increasingly two way flow of power in the distribution system will be critical to maintaining and hopefully enhancing the reliability and resiliency of the grid. To prepare for this changing environment where GHG abating technologies such as photovoltaic generation, energy storage, demand side management, and transportation electrification play an increasing role in meeting future customer needs, California must have the electricity infrastructure capable of meeting these needs. The CPUC, Legislature, and Governor’s office must have consistent policies related to the expanding role of distributed energy resources as well as expanding distribution infrastructure capability to integrate these resources.

Whether or not utility sales decline, flatten, or grow slowly, utilities must be vigilant in finding least cost paths to meet current and future customer needs. Maintaining its focus on Operational Excellence is one of the means employed by SCE to control its budgets and revenue requirements.

Operational Excellence is the framework we have established to deliver on our mission of providing safe, reliable, and affordable power for our customers. Operational Excellence builds off our core value – Continuous Improvement. SCE has rededicated itself to exploring every opportunity to improve the operations across the company. Continuous improvement means improving everything from the way we set and communicate goals approved by our Board of Directors to challenging all employees to find ways of becoming more efficient and effective in their daily jobs. It also means being self-critical in all efforts across the company and asking ourselves what we do, why we do it, and whether there are ways to do it more efficiently. This involves looking at other companies to see if we are performing up to industry best practices. We describe this process as: Measure, Benchmark, Improve, and Repeat. Repeat is critical, as the industry will continue to improve. In SCE's 2015 GRC, a significant impact of implementing an Operational Excellence framework can be seen in the reductions in O&M expenses, particularly in the Administrative and General (A&G) accounts.

As seen in the Figure 1 above, SCE's system average rate has declined in the last couple of years for various reasons including low gas prices. Included in current rates are some sizable over-collections where SCE is refunding fuel and purchased power over-collections, as well as over-collections related to SCE's 2015 GRC. SCE has advocated for rate stabilization by requesting that these over-collections be amortized in customer's rates over a two-year period versus all in one year. This helps to minimize, or smooth out, the associated rate decreases and then increases when the refunds have been completed.

As noted before, seeking opportunities for flexibility in procurement rules is critical to minimizing the costs of satisfying current and future customer needs. Using market approaches rather than administrative approaches to energy procurement, and broadening the markets to achieve lowest costs are critical to long term control of revenue requirements. Recognizing future reliability needs and planning accordingly to satisfy future customer needs is also critical.

APPENDIX A

1. **<u>Description of Rate Components and Revenue Requirements</u>**

SCE recovers its revenue requirements through the following retail rate components: Generation, Cost Responsibility Surcharge (CRS), New System Generation, Distribution, Public Purpose Programs, Nuclear Decommissioning and Federal Energy Regulatory Commission (FERC) jurisdictional Transmission. In addition, SCE is authorized to include on customer bills the DWR Power Charge and Bond Charge on behalf of the California Department of Water Resources (DWR).

a. **<u>Generation</u>** – Through the Generation rate component, SCE recovers the costs of its generation portfolio which include the cost of SCE's Utility Owned Generation (UOG) consisting of the fuel, base O&M and capital-related revenue requirements associated with its nuclear, coal, gas, and hydro plants. In addition, SCE recovers all of its purchased power costs required to meet its load not met by its UOG.[3] The purchased power costs include the costs of Qualifying Facilities (QFs), and all other bilateral contracts that SCE has entered into since 2003 when the company was authorized to resume the power procurement function and make purchases and sales through the wholesale markets. The impact of renewable contracts entered into to meet the Renewables Portfolio Standard and Greenhouse Gas costs will be reflected in generation rates. Since January 1, 2015, SCE is also recovering the revenue requirement

[3] By the end of 2011, all of the DWR purchased power contracts that were allocated to SCE's bundled service customers expired. Therefore, beginning in 2012, SCE is supplying 100% of its bundled service customers' generation requirements.

associated with the SONGS 2 & 3 Order Instituting an Investigation Settlement Revenue Requirement in generation rates.

b. **Cost Responsibility Surcharge** – Through the CRS, SCE recovers from customers that have elected to purchase their generation service from other providers (e.g. Direct Access (DA) customers), the above market costs of the combined SCE and DWR generation portfolios. The revenue generated from the CRS is credited back to SCE's bundled service customers so that they remain indifferent to the departure of those customers, and are not burdened with paying for the above-market costs of the procurement SCE had planned and incurred to serve the departed customers.

c. **New System Generation** – Through the New System Generation (NSG) rate component, SCE recovers the costs of those "new generation" assets that the Commission has required SCE to procure in order to maintain system reliability for the benefit of all customers. The NSG revenue requirement includes the contracted procurement costs less the value of the energy produced. The net cost, or capacity cost, is recovered from all customers who benefit from the additional system capacity provided by the new generation, including DA and Community Choice Aggregation (CCA) customers.

d. **Distribution** – Through the Distribution rate component, SCE primarily recovers its base distribution O&M costs and its capital-related revenue requirement. In addition, the Commission has authorized SCE to recover its Edison SmartConnect revenue requirement, Demand Response program funding, California Solar Initiative program funding, Self-Generation Incentive Program funding, and some Energy

Efficiency incentives through the Distribution rate component. The Commission has authorized SCE to provide the California Alternate Rate for Energy (CARE) discount to the income-qualified customers through the Distribution rate component. As a result of the Commission's decision in the GHG Revenue Rulemaking (R.11-03-012) and the Residential Rate R.12-06-013, SCE returns proceeds that result from the cap-and-trade market to residential customers through a semi-annual Climate Credit (i.e. a credit included on customer's bills) and through the distribution rate component to certain small business customers.[4]

e. **Public Purpose Programs Charge (PPPC)** – Prior to 2012, SCE recovered the legislatively mandated Public Goods Charge funding for the California Energy Commission administered Research Development and Demonstration and Renewable programs, plus a portion of the SCE- administered Energy Efficiency programs, through the PPPC. The funding for these three programs expired on December 31, 2011 as mandated by P.U Code 399. The Commission issued a decision in December 2011 that continued this funding in 2012 through 2020 using the name Electric Program Investment Charge. In addition, through the PPPC rate component SCE recovers additional program funding authorized by the Commission for Procurement Energy Efficiency, and Low-Income programs. The Commission has authorized SCE to recover the costs of the CARE program including the discount provided to CARE-eligible customers from all non-CARE customers through the PPPC.

[4] The remainder of the proceeds will be certain large customers defined as Energy Intensive Trade Exposed through an annual bill credit.

f. **<u>Nuclear Decommissioning</u>** – Through the Nuclear Decommissioning rate component, SCE recovers the customers' portion of the Nuclear Decommission Trust funding authorized by the Commission to be used to decommission SCE's share of the San Onofre and Palo Verde Nuclear Generating Stations. In addition, SCE recovers costs associated with the storage of spent nuclear fuel through this rate component.

g. **<u>FERC-Jurisdictional Transmission</u>** – SCE's FERC-jurisdictional transmission rate is comprised of four components: 1) Base Transmission which recovers the O&M and capital-related revenue requirement associated with transmission assets under ISO operational control and subject to FERC's jurisdiction; 2) flow-through to customers of transmission revenues generated through wholesale customers' use of the transmission system; 3) Reliability Services costs related to contracts signed by the California Independent System Operator (CAISO) with certain generators needed to maintain system reliability; and 4) Transmission Access Charge which reflects the net contribution by SCE's customers to the transmission revenue requirements of all participating transmission owners in the CAISO system.

As SCE moves forward to meet the State's renewable goals, it must construct new transmission lines to bring the renewable generation from out-lying areas to the load centers. The construction of additional transmission facilities will increase SCE's FERC-jurisdictional Transmission rates.

h. **<u>DWR Power Charge and Bond Charge</u>** – In early 2001, as the result of the energy crisis and AB1X, DWR entered into long term power contracts that were necessary to meet the state's Investor Owned Utilities' (IOUs') net short requirements. The Commission authorized SCE to recover on behalf of DWR, the revenue requirement associated with these contracts through the DWR Power Charge. As mentioned above, all of the remaining DWR contracts that had been allocated to SCE's bundled service customers expired as of December 31, 2011. In addition, in order to recover the costs DWR incurred in early 2001 to purchase energy on behalf of IOUs' customers from dysfunctional wholesale markets which were initially financed by the State's General Fund, the Commission authorized SCE to bill the DWR Bond Charge. All of the revenues associated with the DWR Power and Bond Charges are collected by SCE and passed on to DWR.

Since 2001, DWR was required to maintain high levels of operating reserves such that DWR would have enough cash on hand to fulfill its contractual obligations in case power prices skyrocketed. As the power contracts are expiring, DWR no longer is required to maintain this level of reserves and is returning them to customers. As a result of returning the operating reserves to bundled service customers, the Commission-allocated DWR Power Charge Revenue Requirement to SCE's bundled service customers in 2016 is a negative $16 million. In other words, on behalf of DWR, SCE will refund $16 million to its bundled service customers in 2016 through a negative (i.e. or credit) DWR Power Charge. The DWR Bond Charge will remain at approximately $0.005/kWh in 2015.

2. Summary of Revenue Requirements by Rate Component

The table below shows SCE's Total System Revenue Requirements and Bundled System Average Rate for Bundled Service customers as of January 1, 2016:

Rate Component	Total System $ Millions	Total System %	Bundled SAR c/kWh
Generation	4,585	39.0%	6.2
New System Generation	373	3.2%	0.5
Distribution (inc. GHG revenue)	4,512	38.4%	5.6
Public Purpose Program	785	6.7%	1.0
Nuclear Decommissioning	(73)	-0.6%	-0.1
FERC Transmission	1,177	10.0%	1.4
DWR Power and Bond	405	3.4%	0.5
Total	11,763	100.0%	15.0

3. **<u>Sales Forecast</u>**

SCE's 2016 total sales forecast of 85,565 GWhs was approved in D.15-10-037 (A.15-05-007), SCE's 2016 ERRA Forecast Proceeding. This represents a decrease from recorded 2015 sales (86,856) of approximately 1.5%.

Southern California Edison Company
SB 695 Report To Energy Division
Year: 2016

Outlook from May 1, 2016 to April 30, 2017

Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Requested Dollar Amount ($millions)		Description	Impacted Rate Component
				2016 RRQ	2017 RRQ		
2015 GRC	D.15-11-021	11/1/16	1/1/17	5,385	5,663	2017Attrition year increase in O&M and capital revenue requirement.	Generation, Distribution, and New System Generation
2018 GRC	TBD	9/1/16	1/1/18	TBD	TBD	2018 GRC Increase in O&M and capital revenue requirement.	Generation, Distribution, and New System Generation
Tax Refunds	N/A Advice Letters	2/22/2016	1/1/17		-133	Reduction related to higher 2012-2014 repair deductions not reflected in GRC	Distribution
Tax Refunds	N/A Advice Letters	5/1/2016	1/1/17		-212	Tax Accounting Memorandum Account Refund	Distribution and Generation
2017 ERRA Forecast (Includes GHG Costs and Revenue Return)	TBD	5/1/16	1/1/17	3,783	TBD	Recovery of estimated fuel and purchased power costs	Mostly Generation, but also New System Generation, Distribution and Public Purpose
Demand Response	R.13-09-011	2/1/2016	1/1/17	86	44	2017 Bridge Funding	Distribution and Generation
Energy Efficiency	TBA	Sept. 2016	2017	333	TBD	10 year rolling portfolio of EE funding	Public Purpose
ESAP/CARE	A.14-11-007	11/18/2014	1/1/17	81	72	2017 Low Income Energy Efficiency and CARE Admin costs	Public Purpose
FERC Formula Rate Change	N/A (Advice Letter)	Nov. 2016	1/1/17	1,092	TBD	Base Transmission Revenue	Transmission
FERC Transmission Balancing Accounts	N/A (Advice Letter)	May (TACBAA) and Oct. 2016 (RSBAA and TRBAA)	6/1/16 and 1/1/17	85	TBD	Balancing Accounts	Transmission
DWR – Power and Bong Charge	TBD	Dec. 2016	1/1/17	405	TBD	Return of reserves and Bond Charge	Generation