LOS ANGELES DEPARTMENT OF WATER AND POWER

POWER SYSTEM RATE ACTION REPORT

Chapter 6: Revised Proposed Rate Plan

December 2015

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REVISED PROPOSED POWER RATE ACTION PLAN

6.1 SUMMARY

In July 2015, the Los Angeles Department of Water and Power (LADWP or the Department) submitted its initial Power System rate action plan[1] to the Ratepayer Advocate (RPA). This plan included proposed new electric rates to provide the necessary additional funding to ensure reliability, comply with regulatory mandates, and provide services desired by customers. Subsequently, a FY 2015-16 Power System budget was approved by the Board of Water and Power Commissioners (Board) and City Council (Council). In addition, LADWP has actively pursued discussions about the proposed rates and underlying rate drivers with the Ratepayer Advocate and other stakeholders. A revised financial plan[2] has now been developed to reflect the approved budget and other changes made in response to stakeholder input. This updated financial plan, provided in Appendix A, underlies the Department's revised proposed Power System rate action plan (revised proposed rate plan).[3]

The purpose of this chapter is to discuss the Department's revised proposed rate plan and explain the major changes from the initial Power System proposed rate plan (initial proposed rate plan). In developing the revised proposed rate plan, the Department has solicited feedback from the public, the Ratepayer Advocate, and other external stakeholders. Modifications to LADWP's financial plan include updates to the Power System Reliability Program (PSRP), certain financial assumptions, rate effective dates, and the proposed power rate ordinance. These changes have had a very slight impact to the overall revenue requirement and associated rate drivers. However, there were no changes to the cost of service study,[4] which is used to allocate rates for each major class of customers to recover approximately the portion of the revenue requirement assigned to each class. The new rates are now expected to take effect around April 1, 2016.

One key change to the proposed rates is a change to schedule R1 Rate A for Residential service; the Department shall measure the customer's maximum historical consumption for determining the power access charge using only the energy delivered to customers instead of measuring the higher of delivered or received energy. This is designed so as not to penalize Residential customers who export large quantities of energy through distributed generation back to LADWP's Power System.

[1] The initial Power System rate action plan was based on Power Financial Case No. 19.

[2] Throughout this chapter, "revised financial plan" is in reference to Power Financial Case No.143.

[3] The revised Power System rate action plan is based on Power Financial Case No.143.

[4] The Power System Cost of Service Study is presented in Chapter 4.

6.1.1 Major Changes between the Initial and Revised Rate Action Plans

There are several major changes reflected in the revised proposed rate plan as shown in Figure 1. In developing the revised plan, the Department continues to strike a balance between providing reliable service, meeting regulatory requirements, promoting customer choice, and maintaining reasonable rates.

Figure 1: Major Changes between Initial and Revised Rate Plans

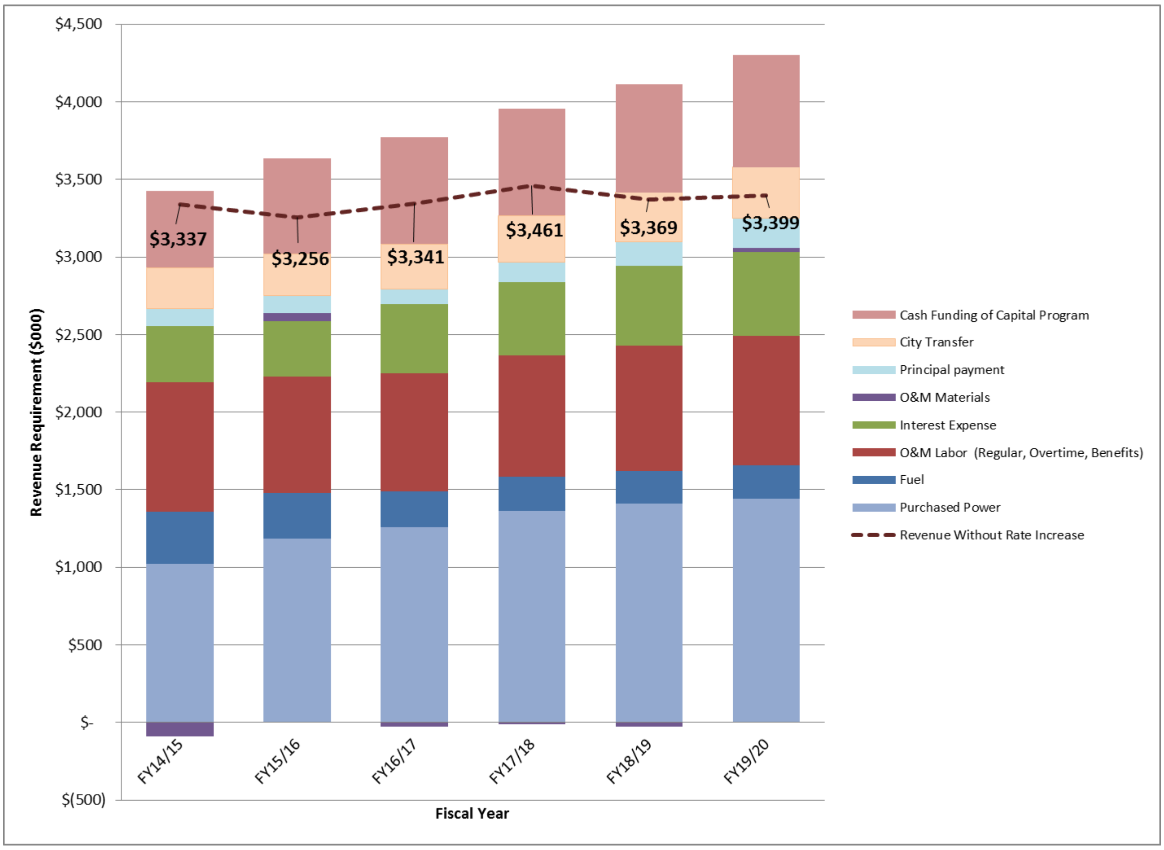
Change	Description
Delayed Rate Action Effective Date	The Revised Proposed Rates will now be effective around April 1, 2016.
Updated FY 2014-15 Financial Results	Actual financial data for FY 2014-15 has been updated as of June 30, 2015.
Approved Power System FY 2015-16 Budget	The Board approved Power System budget is now the basis for the revised financial plan.
Infrastructure and Power System Reliability Program (PRSP) Budget Cuts	In response to input from the RPA, a revised budget for the capital programs geared toward updating and replacing aging electric system infrastructure has been developed.
Fuel and Purchased Power Forecast	The variable cost of fuel for the Department's power plants as well as Power Purchase Agreements (PPAs) that LADWP establishes with third parties have been updated to reflect lower commodity price forecasts.

In addition to the major changes outlined above, this chapter will also address various other miscellaneous changes from the initial proposed rate plan in Section 6.6.

6.1.2 Revised Five-Year Revenue Requirement

The Department's revised financial plan includes several modifications to program budgets and related forecasts which impact the overall revenue requirement as shown in the revised proposed rate plan. The core rate drivers remain the same; however, some of the values have been updated. Figure 2 illustrates the revised potential revenue shortfall the Department expects with no rate increase over the proposed five-year rate period.

Figure 2: Revised Expense Distribution/Revenue Requirement and Projected Gap from FY 2014-15 to FY 2019-20



In comparison to the initial proposed rate plan, the increase in the overall average annual revenue requirement has decreased by approximately $36 million. This change translates into a 0.15 cents per kWh lower system average annual rate increase which equates to an approximately 0.83% lower average annual percentage increase. These changes are relatively minor in light of the Power System's $3.6 billion FY 2015-16 overall revenue requirement. Figure 3 and Figure 4 present the revenue requirement and rate impacts for the initial and revised plans, respectively. In both the initial and revised proposed rate plans, the revenue requirement and average rate increases are presented from a year over year (YOY) standpoint.

Figure 3: Initial Component Breakdown of Revenue Requirement and YOY System Average Rate Increase for FY 2015-16 through FY 2019-20 Compared to FY 2014-15

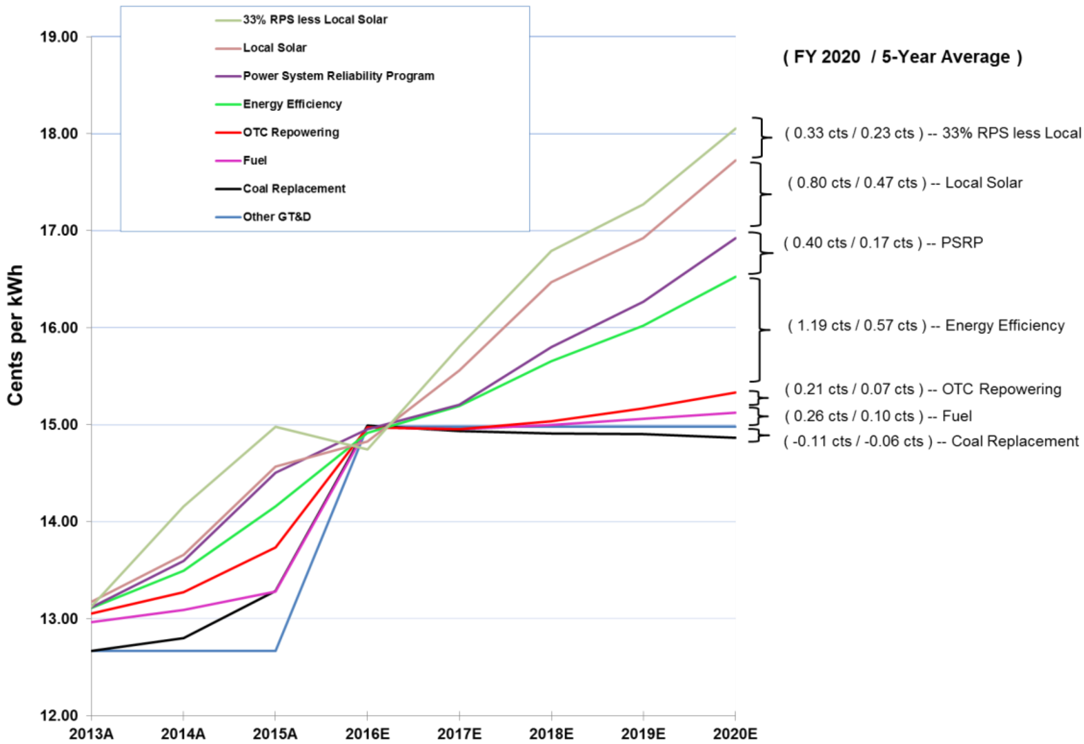
Program	Rate Driver	Regulatory (or Other External) Requirement	Average Annual Revenue Requirement Increase ($M)	System Average Annual Increase (Cents/kWh)	Avg. Annual Percentage Increase (%)
Power System Reliability Program	Power System Reliability		26	0.11	0.68%
Power Supply Transformation Program	Coal Replacement	✓	17	0.07	0.48%
	Once- Through Cooling	✓	4	0.02	0.09%
	Renewable Energy	✓	36	0.15	0.96%
	Subtotal – Increase		57	0.24	1.53%
Customer Opportunities Program	Energy Efficiency	✓	60	0.26	1.54%
	Local Solar Programs	✓	18	0.07	0.46%
	Subtotal – Increase		78	0.33	2.01%
Fuel			18	0.08	0.46%
Total Average Annual Increase			$180	0.76	4.68%

Figure 4: Revised Component Breakdown of Revenue Requirement and YOY System Average Rate Increase for FY 2015-16 through FY 2019-20 Compared to FY 2014-15

Program	Rate Driver	Regulatory (or Other External) Requirement	Average Annual Revenue Requirement Increase ($M)	System Average Annual Increase (Cents/kWh)	Avg. Annual Percentage Increase (%)
Power System Reliability Program	Power System Reliability		19	0.08	0.48%
Power Supply Transformation Program	Coal Replacement	✓	-5	-0.02	-0.14%
	Once-Through Cooling	✓	10	0.04	0.25%
	Renewable Energy	✓	16	0.07	0.44%
	Subtotal – Increase		**20**	**0.09**	**0.55%**
Customer Opportunities Program	Energy Efficiency	✓	56	0.24	1.48%
	Local Solar Programs	✓	38	0.16	1.04%
	Subtotal – Increase		**94**	**0.40**	**2.51%**
Fuel			12	0.05	0.31%
Total Average Annual Increase			**$144**	**0.61**	**3.86%**

Figure 5 illustrates the corresponding cumulative impact of each major program over the proposed five-year rate period.

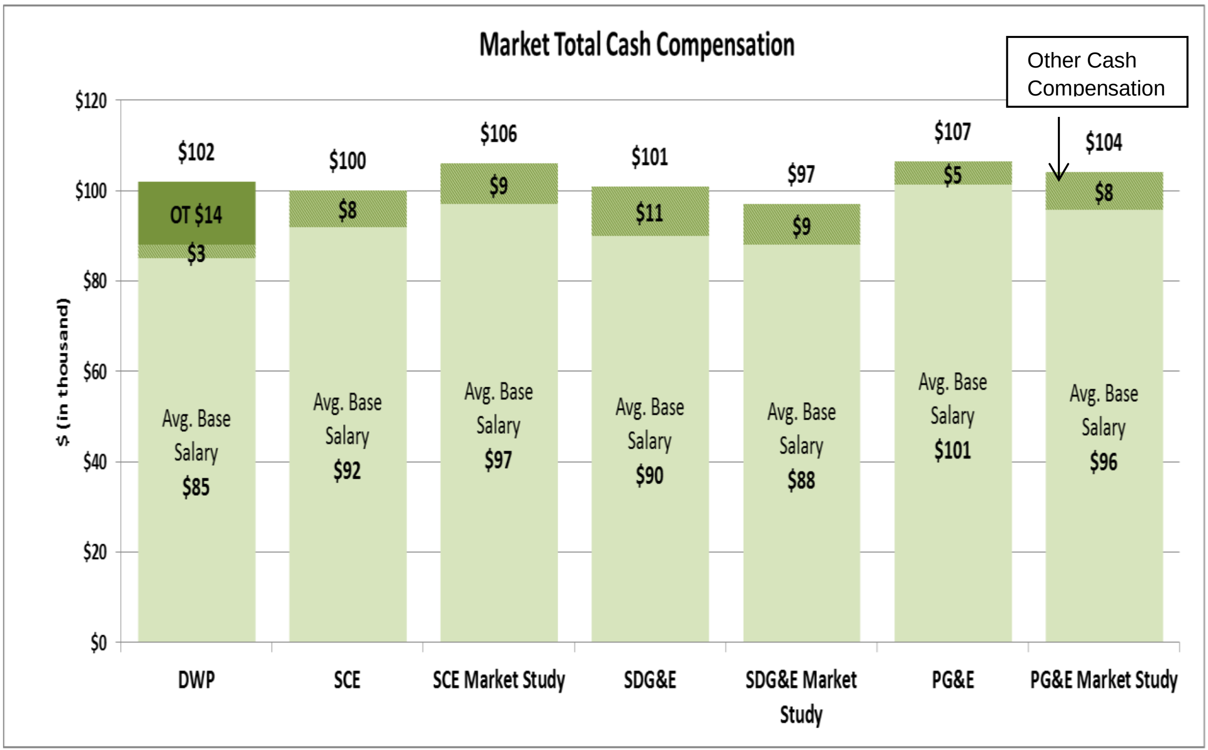
Figure 5: Revised Cumulative Contribution by Rate Driver to Proposed Rate Increase



6.1.3 Comparison of Total Cash Compensation to Neighboring Investor Owned Utilities

Total cash compensation provides one useful measure to compare the LADWP to other similarly situated utilities. The LADWP and others in the utility industry are facing increasing challenges in recruiting and retaining skilled employees. This leads to increased competition for the employees possessing the necessary skills and training. The closest Investor Owned Utilities (IOUs) to LADWP are Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E). As part of their recent rate case filings with the California Public Utilities Commission, both of these utilities were required to file a Total Compensation Study that included actual compensation and a market study of compensation levels for jobs within each of these utilities. While the comparison to data contained in these studies shown below in Figure 6 is not meant to be a comprehensive comparison, it does indicate that LADWP employee total cash compensation is in line with at least two of the large IOUs located in the Southern California area. LADWP intends to work collaboratively with the OPA and their outside expert consultants to perform the second phase of a planned three-phase benchmarking effort.

Figure 6: Labor Cost Comparison Analysis



* SCE data source: p.53 of 2015 General Rate Case for SCE - HR Volume 2, Part 2 - Total Compensation Study/Table D-2 Competitive Analysis - by Total Compensation Dollars (000s) for SCE
* SDG&E data source: Appendix D of SDG&E Direct Testimony of Debbie Robinson Compensation, Health & Welfare - November 2014/Table D-2 SDG&E Study Summary (including Corporate Center): Aggregate Compensation Dollars (000s)
* PG&E data source: Pacific Gas and Electric Company, 2017 General Rate Case, Exhibit (PG&E-8), Human resources, Workpapers Supporting Chapters 5-7, 2017 General Rate Case Total Compensation Study: Volume II - Supporting Documentation - Appndix D, Table D: PG&S Study SummaryL Aggregate Compensation Dollars ($000s)
* LADWP: use class average salary applied to sample of job classes

6.2 UPDATED FY 2014-15 FINANCIAL RESULTS

The revised plan reflects the updated FY 2014-15 financial results, which are now based on close to final audited accounting records. Where applicable, budget data reflects updated actuals as of June 30, 2015, the end of the most recent fiscal year.

6.3 POWER SYSTEM APPROVED FY 2015-16 BUDGET

To complete the final Board approved Power System budget, the Department has undergone a meticulous planning, budgeting, and forecasting process since the submission of the initial proposed rate plan. Completing this effort involves balancing a variety of competing priorities while adhering to the Department's financial planning policies and Board approved financial metrics.

The revised financial plan underlying proposed rates for the five-year rate period is based on the Department's Board approved FY 2015-16 budget. In addition, the revised financial plan includes further changes to certain program assumptions made subsequent to completion of the budget for rate making purposes. These additional changes are discussed separately in this chapter. A comprehensive overview of the revised financial plan is included in Appendix A.

6.3.1 Major Financial Plan Changes

The key financial assumptions that have guided the development of the Department's revised FY 2015-16 financial plan include:

- Updated FY 2014-15 actuals as of June 30, 2015;
- Use of Board approved budget for FY 2015-16;
- Board approved pass-through factors effective in October 2015;
- Rate action effective date of around April 1, 2016 with decoupling for FY 2015-16 under-collection over a two-year period starting January 1, 2017;
- Load forecasts as of October 2014;
- Fuel price forecast as of September 16, 2015;
- Reflected latest refunding bond issue (2015B);
- Updated interest income rate assumptions for IPA subordinated bonds;
- Reflected rate design for adjustment factors (VEA, IRCA, VRPSEA, CRPSEA) and Incremental Base in accordance with the proposed Power Rate Ordinance provided to the RPA;
- Annual Base Rate Revenue Targets set at same values as Financial Case No. 19;
- Net wholesale revenue and contributions in aid of construction (CIAC) exceeding budgeted amounts used to reduce Base Rate Revenue Targets;
- Revised PSRP Program Budgets; and
- Navajo Generating Station (NGS) divestment by the end of FY 2015-16.

These assumptions have governed the development of the revised financial plan, which determines the overall revised revenue requirement.

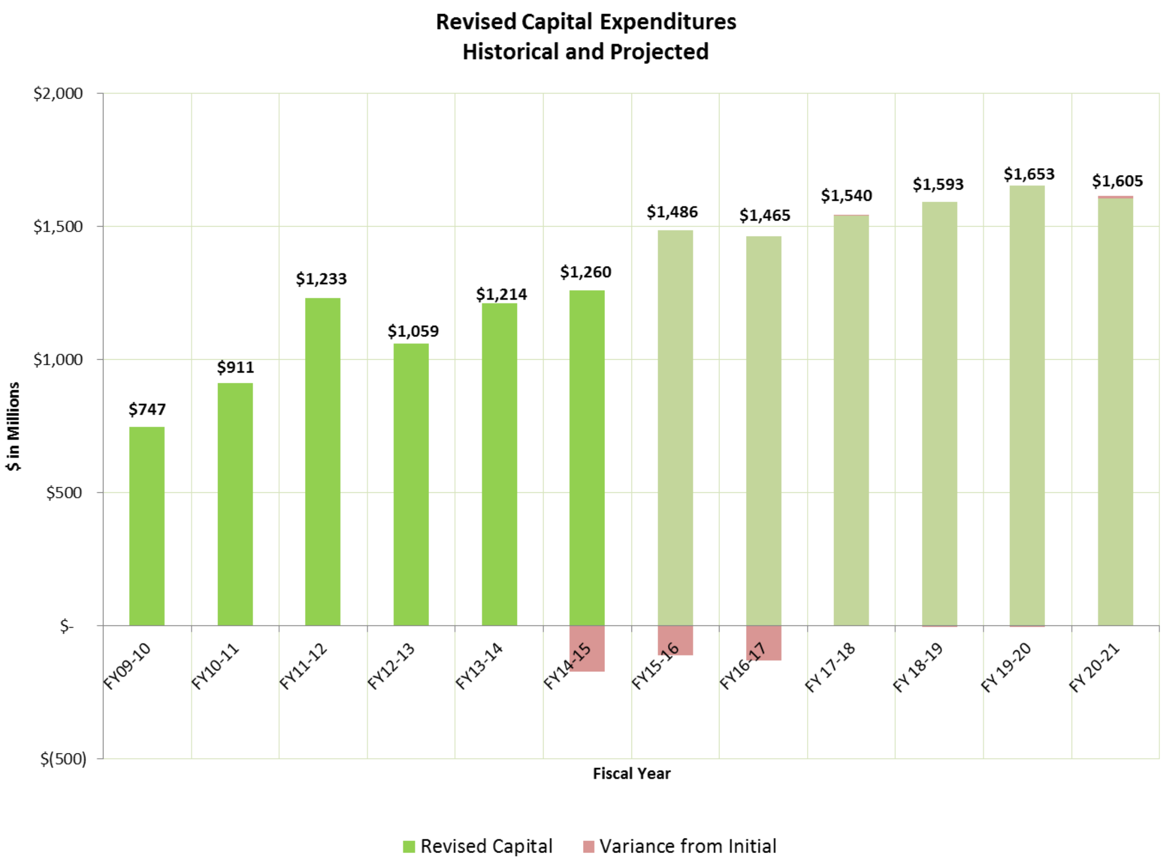
6.3.2 Major Program Budgets

Projected spending for some major programs has been adjusted in the development of the Department's Board approved budget and subsequent updates for the revised financial plan; however, the resulting changes are minor.

Based on the final FY 2015-16 budget, proposed capital spending will increase by an average of $79 million annually over the next five years (FY 2015-16 through FY 2019-20). This annual increase represents overall average annual capital expenditures of $1.55 billion over the next five years. This revised forecast shows minimal variance from the initial proposed rate plan, which proposed an approximate $1.60 billion average annual capital spending budget.

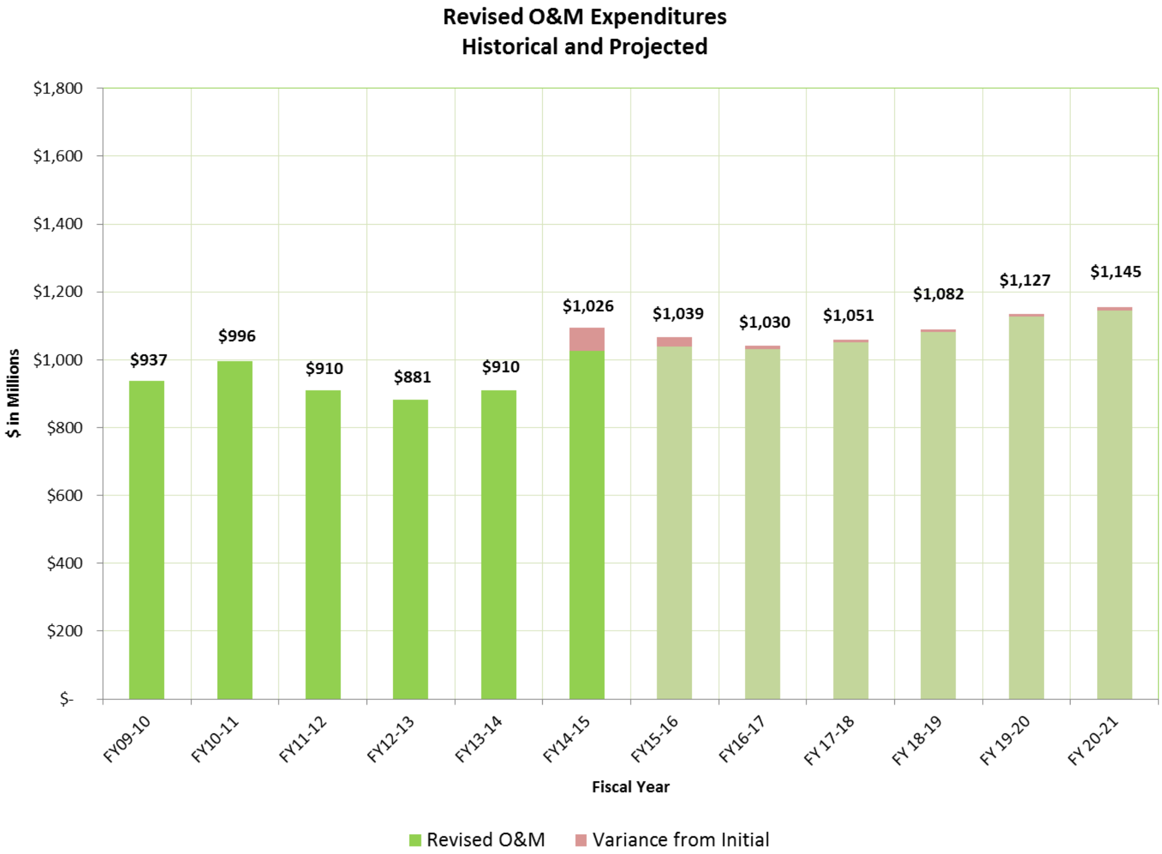
For FY 2015-16, the total Power System projected capital expenditures reflected in the revised proposed rate plan are $112 million less than in the initial rate plan, as shown in Figure 7. This decrease is largely due to an inability to meet planned spending as a result of the delay in securing the needed rate increase.

Figure 7: Revised Capital Expenditures (Historical and Projected)



The revised total Power System O&M expenses, shown in Figure 8, increase at an average annual rate of $20 million per year from FY 2015-16 through FY 2019-20. The average annual increase in O&M expenditures is $13 million more than the initial proposed rate plan. For FY 2015-16, the revised projected O&M expenditures reflected in the revised proposed rates are $29 million more than the initial proposed rate plan. The increased projected O&M spending is partially connected to the reductions in planned capital expenditures as assets no longer scheduled for replacement over the next few years require additional maintenance instead.

Figure 8: Revised O&M Expenditures (Historical and Projected)



6.4 FUEL AND PURCHASED POWER FORECAST

The Department procures, stores, and utilizes various forms of fuel for its portfolio of traditional thermal generation units. LADWP must budget for costs associated with physical commodities including natural gas, coal, and nuclear fuel and power purchase agreements (PPAs). Other considerations are the costs of emissions controls, greenhouse gas reductions, and retirements of assets past their working life.

Free market forces govern the price of these fuels, which exposes LADWP to considerable commodity risk. The Department manages its exposure to price volatility in part through a natural gas hedging program[5].

Natural gas prices have been at historic lows for the past couple of years and are forecasted to maintain a favorable position in the near term, longer than reflected in the initial proposed rate plan. This is beneficial to LADWP, as it maintains and operates a sizable portfolio of peaking and base load natural gas generation assets.

[5] The Department's Natural Gas Hedging Program is discussed in Chapter 3, Section 3.5.1.

The lower fuel costs in the revised financial plan translate into a lower revenue requirement and rates by driving down the fuel cost allocation in the Variable Energy Adjustment (VEA) pass-through rate component. While LADWP is not proposing to change the rates from the initial proposed rate plan, customers will benefit from lower fuel prices through future reductions in the VEA which ensures customers pay only the actual cost for fuel and PPAs. Figure 9 depicts the initial and revised forecasted fuel budgets for the Department during the proposed five-year rate period, along with the variance between the two plans. Notably, the Department forecasts spending 13% less on natural gas during the five-year period in the revised proposed rate plan.

Figure 9: Revised Annual Fuel Expenditures ($M)

($Million)	**Current**	**Initial Proposed Budget[6]**						***FY 20-21***
	FY 14-15	**FY 15-16**	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**	**Total**	
Biomethane	$25.27	$24.12	$24.32	$24.32	$24.32	$24.38	$121.46	*$24.32*
Natural Gas	$129.79	$108.62	$150.13	$145.77	$150.12	$153.43	$708.07	*$172.20*
Gas MTM	$31.56	$27.98	$14.47	$8.17	$0.00	$0.00	$50.62	*$0.00*
Transportation	$41.46	$40.86	$46.58	$44.86	$44.65	$44.56	$221.51	*$46.23*
Coal	$73.58	$77.80	$0.00	$0.00	$0.00	$0.00	$77.80	*$0.00*
Nuclear	$18.18	$18.03	$17.95	$17.41	$17.81	$18.35	$89.56	*$18.85*
Total	**$320**	**$297**	**$253**	**$240.53**	**$236.90**	**$240.72**	**$1,269.00**	***$215.41***
		Revised Proposed Budget						
	FY 14-15	**FY 15-16**	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**	**Total**	***FY 20-21***
Biomethane	$25.65	$24.12	$24.32	$24.32	$24.32	$24.38	$121.45	$24.32
Natural Gas	$167.48	$100.86	$133.15	$126.25	$129.03	$129.78	$619.06	$143.03
Gas MTM	$22.01	$29.35	$15.04	$8.78	$0.00	$0.00	$53.18	$0.00
Transportation	$38.80	$39.62	$44.78	$42.95	$42.82	$42.35	$212.52	$43.53
Coal	$67.29	$77.80	$0.00	$0.00	$0.00	$0.00	$77.80	$0.00
Nuclear	$14.01	$18.03	$17.95	$17.41	$17.81	$18.35	$89.55	$18.85
Total	**$335.24**	**$289.77**	**$235.24**	**$219.72**	**$213.97**	**$214.87**	**$1,173.56**	**$229.73**
		Percent Difference Between Initial and Revised Budget						
	FY 14-15	**FY 15-16**	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**	**Total**	***FY 20-21***
Biomethane	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Natural Gas	22.5%	-7.7%	-12.8%	-15.5%	-16.3%	-18.2%	-14.4%	-20.4%
Gas MTM	-43.4%	4.7%	3.8%	7.0%	N/A	N/A	4.8%	N/A
Transportation	-6.9%	-3.1%	-4.0%	-4.4%	-4.3%	-5.2%	-4.2%	-6.2%
Coal	-9.3%	0.0%	N/A	N/A	N/A	N/A	0.0%	N/A

[6] The values presented here are the budgeted fuel expenditures for Case 19, on which the initial proposed rate requirement and rates are based. These values are different than the previously presented fuel expenditures in Chapter 2.

($Million)	Current	Initial Proposed Budget[6]						FY 20-21
	FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Total	
Nuclear	-29.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total	**4.6%**	**-2.6%**	**-7.7%**	**-9.5%**	**-10.7%**	**-12.0%**	**-8.1%**	**6.2%**

Figure 10 presents the PPA breakdown for renewable and other sources of power in the revised proposed rate plan.

Figure 10: Revised Annual Purchased Power Expenditures ($M)[7]

($Million)	Current	Proposed Rate Period						*FY 20-21*
	FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Total	
Total Renewables	$194.0	$373.2	$520.1	$585.7	$615.3	$635.3	$2,729.8	*$649.5*
Total Non-Renewables	$830.0	$814.5	$736.2	$777.5	$793.0	$809.0	$3,930.4	*$792.5*
Total	**$1,024.1**	**$1,187.7**	**$1,256.3**	**$1,363.2**	**$1,408.4**	**$1,444.4**	**$6,660.3**	***$1,442.1***

In the revised proposed rate plan, the projected fuel and PPA expenditures result in an annual average revenue requirement increase of $12 million and an increase in total system average cost of 0.05 cents per kWh (0.31%), as shown in Figure 11. When compared to the initial proposed rate plan, the revised amounts equate to a $6 million lower average annual revenue requirement and 0.03 cents per kWh (0.16%) lower total system average rate.

Figure 11: Revised Revenue Requirement and Rate Impacts from Traditional Generation and Purchased Power Budget

	Initial YOY Increase						*FY 20-21*
	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Average	
Total System Revenue Requirement ($M)	1	10	19	41	20	18	*6*
Total System Average Cost per kWh (Cents/kWh)	0.01	0.04	0.08	0.17	0.09	0.08	*0.02*
System Average Annual Percent Increase (%)	0.04%	0.28%	0.50%	1.01%	0.49%	0.46%	*0.13%*
	Revised YOY Increase						

[7] Excludes direct fuel expenditures.

	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20	Average	*FY 20-21*
Total System Revenue Requirement ($M)	-5	10	16	17	23	12	25
Total System Average Cost per kWh (Cents/kWh)	-0.02	0.04	0.07	0.07	0.10	0.05	0.11
System Average Annual Percent Increase (%)	-0.14%	0.27%	0.44%	0.42%	0.57%	0.31%	0.60%
	Difference Between Initial and Revised YOY Increase						
	FY 15-16	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**	**Average**	***FY 20-21***
Total System Revenue Requirement ($M)	-6	0	-3	-24	3	-6	19
Total System Average Cost per kWh (Cents/kWh)	-0.03	0.00	-0.01	-0.10	0.01	-0.03	0.09
System Average Annual Percent Increase (%)	-0.18%	-0.01%	-0.06%	-0.59%	0.08%	-0.16%	0.47%

6.5 INFRASTRUCTURE AND POWER SYSTEM RELIABILITY PROGRAM (PSRP) BUDGET UPDATES

Investing in reliability improvement to address aging infrastructure remains imperative to the Department. LADWP allocates capital spending for new and updated infrastructure judiciously and strategically, ensuring that funding for replacement and maintenance initiatives is optimal in the face of competing priorities and financial considerations.

The PSRP program is designed to cover a prolonged period with specific projects identified to help develop the overall expected capital expenditure and timelines. These projects are often long-term in nature and require lengthy procurement cycles to contract for materials and construction services. Large multi-year contracts typically provide the best terms for the Department but require sufficient funding to negotiate and execute these contracts and cover any corresponding delays. Also, it is vital to have necessary funding to address unexpected equipment failures and outages.

In their review of the Department's initial proposed rate plan, the RPA recommended that the capital expenditures budgeted for the PSRP during the five-year rate action period be scaled back to less aggressive spending targets that the RPA believed to be more realistic. The RPA also recommended eliminating the cap on the IRCA, the pass-through rate component that provides revenue for the PSRP. These proposals have been reflected in the revised financial plan.

6.5.1 PSRP Cumulative Capital and O&M Budget Updates

Planned PSRP capital spending in FY 2015-16 and FY 2016-17 has been reduced in the revised rate plan to align with the ability to secure resources to perform the work considering the delay in approval of the rates, with greater funding allocated to future years (FY 2017-18 through FY 2019-20). Figure 12 compares the revised capital and O&M spending to the initial proposed rate plan levels during the proposed five-year rate period.

Figure 12: Comparison of Revised and Initial PSRP Capital and O&M Costs Over Five-Year Rate Period

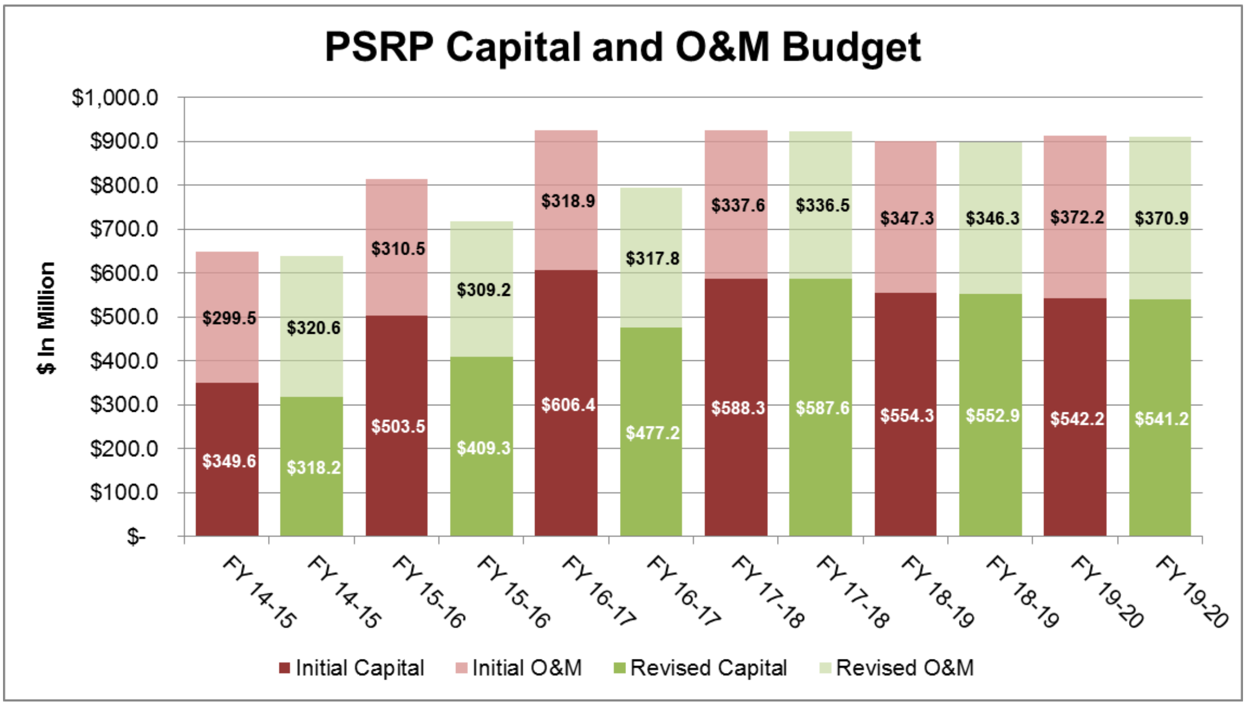
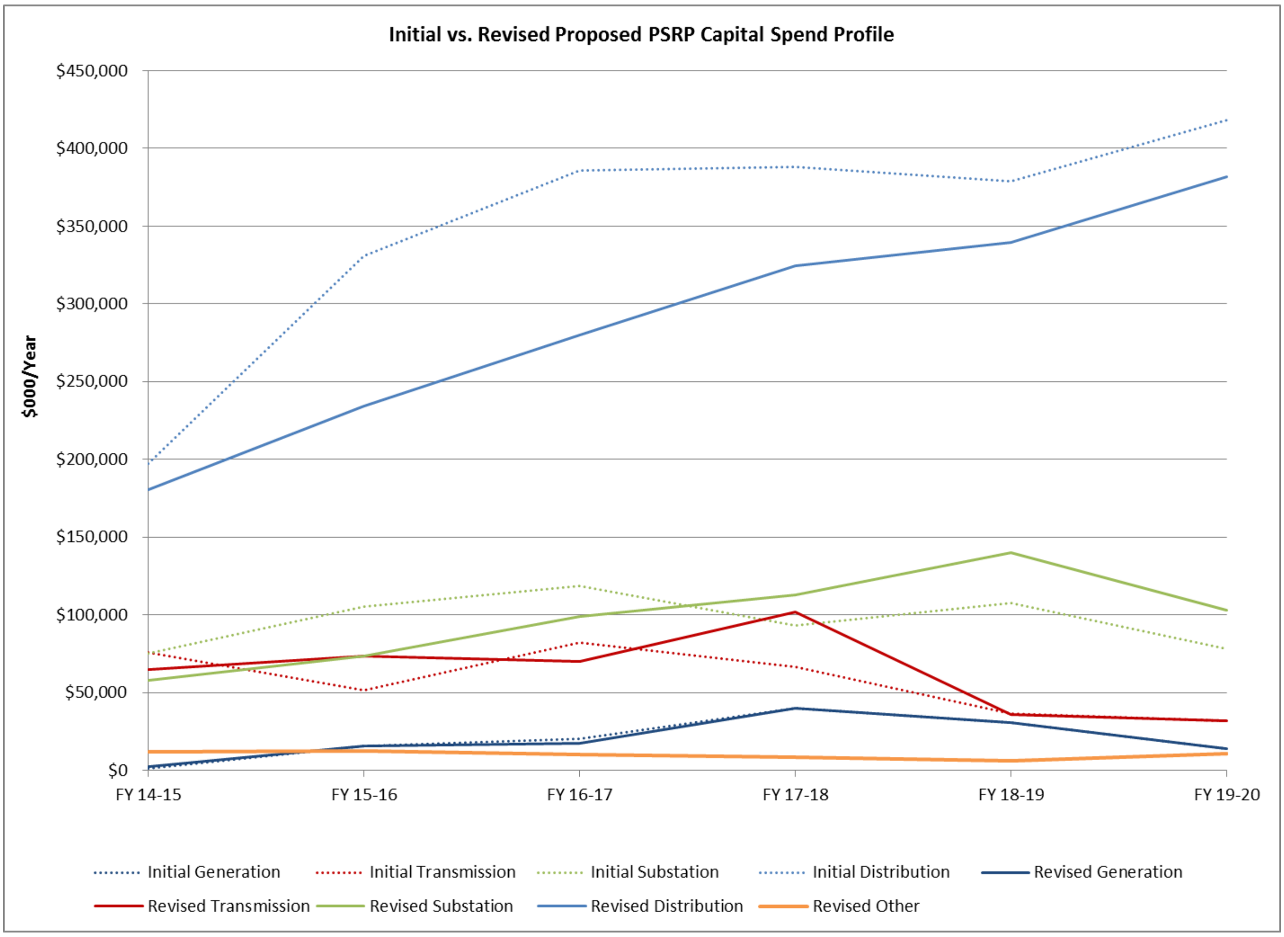


Figure 13 details the revised proposed capital spending profile by asset type over the proposed five-year rate period as compared to the initial plan. While the overall capital spending has been reduced by an average annual amount of $45.3 million over the five-year period, a large portion of the PSRP is still allocated to distribution upgrades to enhance reliability.

Figure 13: Initial vs. Revised Projected Capital Spend by Asset Type



The revised PSRP program level budget is summarized in Figure 14. When compared to the initial proposed plan, the revised plan includes approximately $226.6 million and $5.7 million less capital and O&M expenditures respectively in total during the proposed five-year rate period. This variance represents a relatively minor total spending adjustment, with capital budget cuts in FY 2015-16 and FY 2016-17 making up the vast majority of the difference between initial and revised plans.

Figure 14: Revised and Initial PSRP Capital and O&M Program Budgets

Initial Proposed PSRP Budgets							
($000)	**Actuals[8]**	**Forecast**					**5-Year Total**
Capital:	**FY 14-15**	**FY 15-16**	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**	
Generation	$1,347	$15,549	$20,141	$39,954	$30,975	$14,110	$120,729
Transmission	$75,955	$51,583	$82,212	$66,828	$36,399	$31,699	$268,721

[8] Include actuals through September 2014 with estimates through the remainder of the fiscal year.

Substation	$75,245	$105,625	$118,461	$93,485	$107,835	$78,168	$503,574
Distribution	$197,098	$330,729	$385,597	$388,054	$379,074	$418,234	$1,901,688
Total Capital	**$349,645**	**$503,486**	**$606,410**	**$588,320**	**$554,282**	**$542,210**	**$2,794,708**
O&M:							
Transmission	$26,591	$25,970	$27,238	$32,704	$33,637	$35,426	$154,975
Substation	$11,912	$10,860	$11,415	$11,814	$12,222	$12,030	$58,341
Distribution	$188,188	$201,006	$206,966	$219,885	$227,562	$244,020	$1,099,439
Journeyman Training	$24,114	$23,762	$25,383	$26,998	$27,752	$28,100	$131,995
Power System Training	$48,726	$48,891	$47,934	$46,180	$46,111	$52,638	$241,754
Total O&M	**$299,533**	**$310,491**	**$318,937**	**$337,583**	**$347,285**	**$372,216**	**$1,686,512**
Revised Proposed PSRP Program Budgets							
	Actual	**Forecast**					
Capital:	**FY 14-15**	**FY 15-16**	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**	**5-Year Total**
Generation	$2,175	$15,471	$17,484	$39,928	$30,965	$14,090	$117,938
Transmission	$64,961	$73,570	$70,290	$101,609	$35,719	$31,643	$312,831
Substation	$58,125	$73,570	$99,061	$112,907	$140,273	$103,289	$529,100
Distribution	$180,782	$234,255	$279,982	$324,677	$339,567	$381,506	$1,559,986
Other[9]	$12,145	$12,373	$10,344	$8,482	$6,406	$10,655	$48,260
Total Capital	**$318,189**	**$409,238**	**$477,161**	**$587,604**	**$552,930**	**$541,182**	**$2,568,115**
O&M:							
Transmission	$25,412	$25,448	$26,715	$32,190	$33,122	$34,857	$152,331
Substation	$72,845	$74,324	$74,820	$74,778	$77,086	$90,363	$391,371
Distribution	$142,258	$136,948	$143,227	$156,610	$162,406	$165,250	$764,441
Journeyman Training	$23,695	$23,695	$25,307	$26,926	$27,683	$28,017	$131,627
Power System Training	$47,520	$48,727	$47,773	$46,038	$45,973	$52,461	$240,971
Total O&M	**$311,731**	**$309,141**	**$317,841**	**$336,542**	**$346,269**	**$370,949**	**$1,680,741**
Percentage Difference Between Initial and Revised							
	Actual	**Forecast**					
	FY 14-15	**FY 15-16**	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**	**5-Year Total**
Capital:							
Generation	61.5%	-0.5%	-13.2%	-0.1%	0.0%	-0.1%	-2.3%
Transmission	-14.5%	42.6%	-14.5%	52.0%	-1.9%	-0.2%	16.4%

[9] This category includes capital costs for IT system investments and other capital expenditures necessary to support infrastructure upgrades and reliability. In the initial proposed rate plan, these costs were appropriated across the various PSRP programs and not represented as a separate budget line item.

Substation	-22.8%	-30.3%	-16.4%	20.8%	30.1%	32.1%	5.1%
Distribution	-8.3%	-29.2%	-27.4%	-16.3%	-10.4%	-8.8%	-18.0%
Other	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Capital	**-9.0%**	**-18.7%**	**-21.3%**	**-0.1%**	**-0.2%**	**-0.2%**	**-8.1%**
O&M:							
Transmission	-4.4%	-2.0%	-1.9%	-1.6%	-1.5%	-1.6%	-1.7%
Substation	511.5%	584.4%	555.5%	533.0%	530.7%	651.1%	570.8%
Distribution	-24.4%	-31.9%	-30.8%	-28.8%	-28.6%	-32.3%	-30.5%
Journeyman Training	-1.7%	-0.3%	-0.3%	-0.3%	-0.2%	-0.3%	-0.3%
Power System Training	-2.5%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%
Total O&M	**4.1%**	**-0.4%**	**-0.3%**	**-0.3%**	**-0.3%**	**-0.3%**	**-0.3%**

6.5.2 Generation Reliability Program (GRP) Update

The Power System has made minor adjustments to planned Generation Reliability Program (GRP) replacement units. The unit level budget for the GRP is presented in Figure 15.

Figure 15: Revised Unit Costs and Replacement Units for Generation Reliability Program

	Total Existing LADWP Count[10]	**Unit Cost ($000)**	**Proposed Replacement Units[11]**					
			FY 14-15	**FY 15-16**	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**
Generator Transformer	168	Up to $5,000	0	0 (2)	2	4	4	4
Major Inspection (Thermal)	24	$4,000	1	1 (4)	0 (4)	4	4	4
Major Inspection (Hydro)	22	$4,000	1	0 (2)	2	2	2	2
Major Inspection (Pump)	7	$4,000	1	1	1	1	1	1

(X) – Initial proposed rate plan unit replacement target

[10] This number represents the current number of units the Department has of this equipment.

[11] This number is the planned units to undergo inspection, maintenance, or replacement per the PSRP. These numbers serve as a best estimate to inform PSRP budgeting and forecasting but may change throughout the five-year period due to various financial and operational factors.

6.5.3 Transmission Reliability Program (TRP) Update

The Power System has made minor adjustments to amount of planned Transmission Reliability Program (TRP) replacement units. The unit level budget for the TRP is presented in Figure 16.

Figure 16: Revised Unit Costs and Replacement Units for Transmission Reliability Program

	Total Existing LADWP Count	Unit Cost ($000)	Proposed Replacement Units					
			FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20
138kV UG Transmission Circuit	17	$12,600	1	2 (1)	2	2	2	2
138kV Stop Joints	31	$300	2	5	5	5	5	5
Maintenance Hole Restraints	238	$27	10	20	30	40	40	40

(X) – Initial proposed rate plan unit replacement target

6.5.4 Substation Reliability Program (SRP)

The Power System has made minor adjustments to planned Substation Reliability Program (SRP) replacement units in the revised proposed rate plan, as depicted in Figure 17.

Figure 17: Revised Unit Costs and Replacement Units for Substation Reliability Program

	Total Existing LADWP Count	Unit Cost ($000)	Proposed Replacement Units					
			FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20
Transformer (RS) secondary voltage>138kV	70	$4,000	0	0 (1)	0 (1)	1	1	1
Transformer (RS) secondary voltage>34.5kV	88	$4,500	3	3 (1)	3 (1)	1	1	1
Local Substation Transformer (DS)	930	$1,200	4	12 (18)	16 (18)	18	18	18
Substation Transmission Breakers	612	$550	3	0 (6)	0 (6)	6	6	6
34.5kV Substation Circuit Breaker	1,878	$200	10	4 (10)	21 (15)	20	20	20
4.8kV Substation Circuit Breaker	2,406	$80	10	5 (20)	16 (30)	40	40	40

(X) – Initial proposed rate plan unit replacement target

6.5.5 Distribution Reliability Program (DRP) Updates

The Power System has made minor adjustments to planned Distribution Reliability Program (DRP) replacement units in the revised proposed rate plan. The unit level revised budget for the DRP includes less planned pole and crossarm replacements, as depicted in in Figure 18.

Figure 18: Revised Unit Costs and Replacement Units for Distribution Reliability Program

	Total Existing LADWP Count	Unit Cost ($000)	Proposed Replacements					
			FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19	FY 19-20
Poles	321,780	$45	1,560	2,000 (4,000)	2,500 (5,000)	6,000	6,000	6,000
Crossarms	1,287,120	$4	4,500	7,000	7,000 (8,000)	10,000	10,000	10,000
Cables	3597 miles	$1,000	28	46 (60)	48 (60)	60	60	60
Transformers	126,000	$20	450	600	700	800	800	800
Substructures	54,099	$400	7	12	12 (16)	20	20	20

(X) – Initial proposed rate plan unit replacement target

6.5.6 PSRP Budget Impact on Revenue Requirement and Rates

Comparing the total portion of the revenue requirement attributed to the PSRP in the initial proposed rate plan to the revised plan shows minimal variance. Over the five-year proposed rate period, the revised plan forecasts an increase in the revenue requirement by an annual average of $19 million per year and an annual increase in the system average rate of 0.08 cents per kWh (0.48%). Cumulatively over the proposed five-year rate period, these amounts are close to the initial rate plan's average annual revenue requirement increase of $26 million and a 0.11 cents per kWh (0.68%) increase in system average rate. A comparison of the proposed and initial plans' projected PSRP revenue requirement and rate impacts is presented in Figure 19.

Figure 19: Revised PSRP Impact on Revenue Requirement and Rates

	Initial Year Over Year Increase						*FY 20-21*
	FY 15-16	**FY 16-17**	**FY 17-18**	**FY 18-19**	**FY 19-20**	**Average**	
Total System Revenue Requirement ($M)	5	14	49	19	44	26	*46*
Total System Average Cost per kWh (Cents/kWh)	0.02	0.06	0.21	0.08	0.19	0.11	*0.20*
System Average Annual Percent Increase (%)	0.15%	0.39%	1.31%	0.47%	1.06%	0.68%	*1.05%*
	Revised Year Over Year Increase						
Total System Revenue Requirement ($M)	9	-7	32	25	34	19	*35*
Total System Average Cost per kWh (Cents/kWh)	0.04	-0.03	0.14	0.10	0.15	0.08	*0.15*
System Average Annual Percent Increase (%)	0.26%	-0.20%	0.86%	0.63%	0.85%	0.48%	*0.82%*
	Difference Between Initial and Revised YOY Increase						
Total System Revenue Requirement ($M)	4	-21	-17	6	-10	-7	*-11*
Total System Average Cost per kWh (Cents/kWh)	0.02	-0.09	-0.07	0.02	-0.04	-0.03	*-0.05*
System Average Annual Percent Increase (%)	0.11%	-0.59%	-0.45%	0.16%	-0.21%	-0.20%	*-0.23%*

As noted earlier, since customers will only be charged for the actual amount of the PSRP costs, LADWP is not proposing changes to the customer rates presented in the initial proposed rate plan to reflect the minor changes in the revenue requirement. The decrease in projected PSRP expenditures during the five-year rate period will impact the Incremental Reliability Cost Adjustment (IRCA), the component of the proposed rate design dedicated to collect funds to support the replacement or upgrade of Power System infrastructure. The IRCA will be set and trued up over time based on actual expenditures, ensuring customers pay for only actual PSRP costs.

6.6 OTHER MISCELLANEOUS CHANGES

In addition to the major impacts mentioned previously in Section 6.1.1, several other additional changes that have a minor impact on rates are reflected in the revised proposed rates. These financial assumptions and measures are taken to ensure adequate revenue, maintain the Department's credit rating, and fulfill debt obligations when developing the revised financial plan. These changes include:

- Other rate driver contribution changes from FY 2015-16 revised budget;
- Board approved adjustment factors (effective in October 2015);

- Bond refunding;
- Updated interest income rate assumptions on IPA subordinated notes; and
- Recovery of revenue shortfall for July 2015 – March 2016.

6.6.1 Rate Driver Contribution Changes from FY 2015-16 Revised Budget Allocations

The overall revenue requirement has been reduced, and several components have changed due to projects being implemented and budget allocations being updated since the previous revenue requirement was developed in the initial proposed rate plan. Updates in the revised plan include:

- Coal Transition Plan: The revised proposed rate plan reflects impacts from the divestment of the coal Navajo Generating Station (NGS). Replacing the baseload energy generated by NGS with capacity from the natural gas Apex generating facility has allowed the Department to take advantage of historically low natural gas prices and reduce the expected coal transition plan costs. The revised proposed rate plan forecasts an average annual revenue requirement decrease of $6 million over the five-year period, compared to the initial plan's proposed $17 million average annual increase.
- Renewable Portfolio Standard: To comply with California Energy Commission (CEC) requirements, the Department must substitute a subset of customer sited solar PV capacity due to the CEC's changing RPS guidebook with other renewable resources. Approximately 340 GWh will be replaced with lower cost renewable generation from stations like the Hudson Ranch Geothermal facility for which the Department established a PPA as part of the NGS divestment. Thus, the revised proposed rate plan forecasts an average annual revenue requirement increase of $16 million over the five-year period, compared to the initial plan's proposed $36 million average annual increase.
- Local Solar: The initial plan included a scheduled ramp up of two large LADWP owned solar installations - Moapa and Copper Mountain. These facilities have since gone "on-line." The revised plan now shows an increase in other local solar spending to meet interim and final capacity targets, with an average annual revenue requirement increase of $44 million during the proposed five-year rate period.

6.6.2 Board Approved Adjustment Factors

On December 1, 2015, the Board passed a resolution approving the Energy Cost Adjustment Factor (ECAF) expenditures for the 12-month period commencing January 1, 2016. This action approves cost recovery for fuel, purchased power, demand-side management (DSM), and renewables portfolio standard (RPS) expenditures through a revision to the calculation of Energy Cost Adjustment (ECA), Variable Energy Adjustment (VEA), Capped Renewable Portfolio Standard Energy Adjustment (CRPSEA), and Variable Renewable Portfolio Standard Energy Adjustment (VRPSEA). For the three-month period commencing January 1, 2016, the composite ECAF related costs applied to actual billing of customers will be 6.488 cents per kWh compared to 7.012 cents per kWh for the prior 3 months.

6.6.3 Bond Refunding

Issued on October 1, 2015, the LADWP Power System 2015B bonds are a new debt issue of $269.9 million used to pay the principle of the maturing LADWP 2012C bonds and provide LADWP a more favorable interest rate. Bond refunding allows the Department to take advantage of low interest rate conditions and replace higher-cost bonds with cheaper debt. This process in turn reduces the borrowing costs LADWP incurs to fund infrastructure and other critical investments. It is important to note that such financial measures are made possible by the strong credit rating the Department preserves by maintaining the Board approved financial metrics. Future refunding bond issues are also planned.

6.6.4 Updated Interest Income Rate Assumptions on IPA Subordinate Notes

The Department's short term interest rate income from the debt it is owed from providing financing for the Intermountain Power Plant (IPP) has increased. The additional amount has been reflected in the revised financial plan yielding an additional $92.1 million in projected cumulative net income which will contribute to lowering the revenue requirement over this period. The variable rate and year over year dollar amount is shown in Figure 20.

Figure 20: Revised Interest Income Rate Assumptions and IPA Subordinated Notes

	Proposed Rate Period				
	FY 2015-16	**FY 2016-17**	**FY 2017-18**	**FY 2018-19**	**FY 2019-20**
Variable Rate (%)	1.21%	1.70%	2.12%	2.38%	2.56%
Cash ($M)	$23.1	$35.9	$10.7	$17.9	$4.7

6.6.5 Recovery of Revenue Shortfall for July 2015 – March 2016

The initial proposed rates were based on an effective date of July 2015. To account for the shortage of income from rates during this time period, funds will be recovered through the revenue decoupling mechanism in the VEA adjustment factor over a 2-year period (January 1, 2017 – December 31, 2018).

6.6.6 Net Wholesale Revenue and CIAC

As a result of input from the Mayor, E&E Committee Chair, and the Office of Public Accountability (OPA), LADWP has reduced its proposed rate increase by utilizing any actual amounts exceeding budgeted amounts for the following items to lower the Base Rate Revenue Target Adjustment (BRRTA):

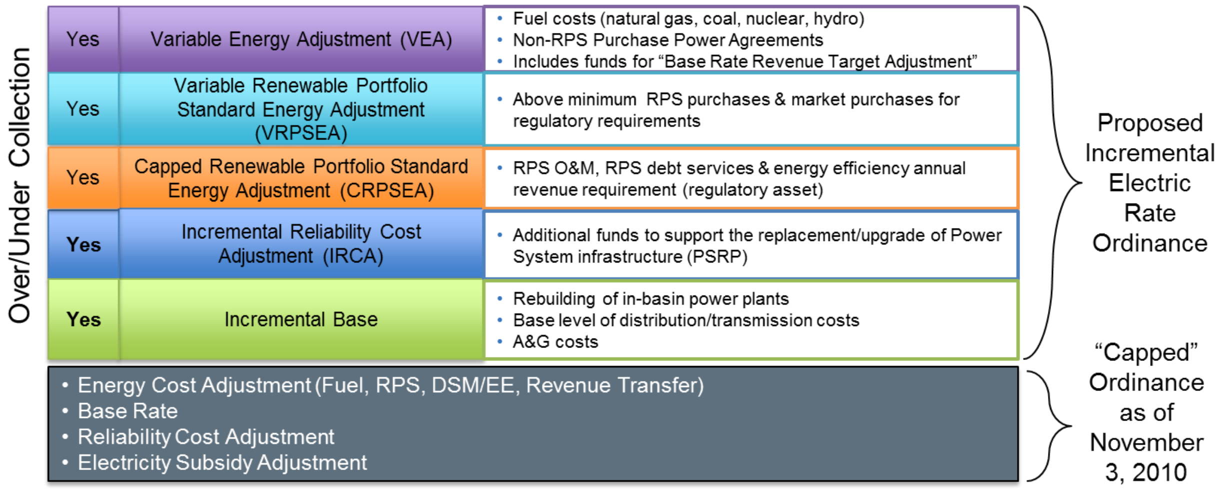
- Net wholesale revenue; and
- Contributions in aid of construction (CIAC), which are basically amounts paid by large customers for upgrades and equipment for new developments.

This is estimated to result in an approximately 0.51% lower system average annual rate increase and equates to a $105 million lower revenue requirement over the five-year period. In the past, LADWP has utilized additional revenues from these sources to cash fund capital expenditures. At the suggestion of the previously mentioned parties, these funds will now be returned directly to customers in the form of lower rates. However, it is important to note that this requires the Department to borrow more money to fund capital projects and is somewhat offset by higher debt service costs.

6.7 KEEPING WITH THE INITIAL RATE STRUCTURE

The proposed rate structure accounts for fluctuating revenues in comparison to forecasted amounts through variable pass-through adjustment factors. Figure 21 shows a visual representation of the Department's proposed rate structure. A detailed presentation of the Department's initial proposed rate structure and rates is contained in Chapter 5.

Figure 21: LADWP Proposed Electric Rate Structure (Detail)



Under the latest proposal, the VEA will be adjusted to account for lower fuel costs and reduced PSRP expenditures will be accounted for through changes in the IRCA that will reflect actual spending during the proposed rate period.

The pass-through adjustment factors are calculated and set on a quarterly basis, with exception of the IRCA that is set annually, to reflect the appropriate level of cost recovery needed.

6.8 FINAL REVISED RATES

As a result of the aforementioned impacts from fuel savings, PSRP expenditure cuts, and other miscellaneous financial plan changes, the revised proposed rates are lower than the initial proposed plan. The updated detail on the revised rates is included in this section.

6.8.1 Revised Proposed Residential Rates and Bill Impacts

The components of the revised proposed LADWP residential rate design are summarized in Figure 22 below.

Figure 22: Revised Proposed Residential Rates

Tiers	Monthly Zone 1 Usage Allocation (kWh)	Monthly Zone 2 Usage Allocation (kWh)	Monthly Tiered Fixed Charge ($)	Summer Energy Charge ($/kWh)	Winter Energy Charge ($/kWh)
FY 2015-16					
Tier 1	0 ≤ and ≤ 350	0 ≤ and ≤ 500	$0.55	$0.13617	$0.13617
Tier 2	350 < and ≤1050	500 < and ≤1500	$2.00	$0.16835	$0.16835
Tier 3	> 1050	> 1500	$6.00	$0.21731	$0.16835
FY 2016-17					
Tier 1	0 ≤ and ≤ 350	0 ≤ and ≤ 500	$0.85	$0.14557	$0.14557
Tier 2	350 < and ≤1050	500 < and ≤1500	$3.00	$0.18086	$0.18086
Tier 3	> 1050	> 1500	$9.00	$0.23663	$0.18086
FY 2017-18					
Tier 1	0 ≤ and ≤ 350	0 ≤ and ≤ 500	$1.30	$0.15066	$0.15066
Tier 2	350 < and ≤1050	500 < and ≤1500	$4.90	$0.19809	$0.19809
Tier 3	> 1050	> 1500	$15.00	$0.25879	$0.19809
FY 2018-19					
Tier 1	0 ≤ and ≤ 350	0 ≤ and ≤ 500	$1.75	$0.15103	$0.15103
Tier 2	350 < and ≤1050	500 < and ≤1500	$6.25	$0.19936	$0.19936
Tier 3	> 1050	> 1500	$18.50	$0.27546	$0.19936
FY 2019-20					
Tier 1	0 ≤ and ≤ 350	0 ≤ and ≤ 500	$2.50	$0.15283	$0.15283
Tier 2	350 < and ≤1050	500 < and ≤1500	$8.00	$0.21142	$0.21142
Tier 3	> 1050	> 1500	$23.50	$0.29843	$0.21142

The monthly tiered Power Access charge has remained mostly unchanged, with the revised proposed rates reflecting a minor increase in FY 2019 – 20. As with the initial plan, proposed increases to tier 2 and 3 prices are higher than proposed increases to tier 1 prices in the revised plan to reflect marginal costs, which sends a conservation price signal. Overall, the revised proposed rates are lower than those proposed in the initial plan. For example, in the revised plan a typical single-dwelling unit Residential customer (500 kWh average monthly usage) can expect a median monthly bill of $78.75 in FY 2019-20, which represents a 1.56% average annual rate increase. Further details on Residential customer bill impacts from the revised proposed rates are presented in Figure 23.

Figure 23: Revised Residential (R1A) Customer Bill Impacts by kWh Usage (Detail)

Average kWh	Customers	Average Median Bill						Average Annual % Change
		FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20	
0	3708	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	0.00%
100	60596	$11.00	$10.89	$11.38	$11.85	$12.12	$12.70	2.90%
200	220476	$20.51	$19.63	$21.20	$22.35	$22.83	$23.80	3.02%
300	259076	$33.97	$32.25	$34.90	$36.83	$37.52	$38.84	2.72%
400	206920	$48.72	$46.88	$50.86	$54.29	$55.57	$57.87	3.50%
500	149560	$64.57	$62.44	$67.68	$72.48	$74.03	$77.15	3.62%
600	105846	$81.12	$78.41	$84.81	$90.94	$92.61	$96.59	3.55%
700	75711	$98.13	$94.96	$102.58	$110.23	$112.03	$117.04	3.59%
800	53999	$115.47	$112.08	$121.04	$130.37	$132.32	$138.47	3.70%
900	39739	$133.04	$129.87	$140.36	$151.77	$154.04	$161.54	3.96%
1000	29704	$150.83	$148.10	$160.67	$175.24	$178.45	$188.22	4.53%
1100	22077	$168.81	$166.41	$180.71	$198.25	$202.79	$215.77	5.03%
1200	17209	$187.27	$185.03	$200.99	$221.11	$226.23	$240.66	5.14%
1300	12908	$205.75	$203.47	$221.01	$243.11	$248.76	$264.66	5.16%
1400	10128	$224.83	$222.31	$241.33	$265.38	$271.47	$288.87	5.14%
1500	7992	$243.54	$240.70	$261.22	$287.19	$294.07	$313.20	5.16%
1600	6298	$262.73	$259.62	$281.65	$309.47	$317.15	$337.83	5.16%
1700	5040	$281.95	$278.56	$302.11	$331.86	$340.17	$362.48	5.15%
1800	3975	$301.14	$297.61	$322.75	$354.68	$363.69	$387.82	5.19%
1900	3375	$320.15	$316.27	$342.87	$376.59	$386.41	$412.16	5.18%
2000	2719	$338.99	$335.05	$363.21	$398.86	$409.30	$436.54	5.19%
2100	2350	$358.78	$354.47	$384.16	$421.89	$433.34	$462.47	5.21%
2200	1910	$377.49	$373.13	$404.42	$444.08	$456.18	$486.84	5.22%
2300	1589	$396.32	$391.63	$424.39	$466.02	$478.56	$510.75	5.20%
2400	1377	$415.79	$410.76	$445.07	$488.58	$502.12	$536.27	5.22%
2500	1112	$435.24	$429.99	$465.84	$511.11	$525.66	$561.52	5.23%
2600	955	$453.88	$448.28	$485.61	$533.29	$548.03	$585.58	5.23%
2700	859	$472.65	$466.90	$505.67	$555.14	$570.82	$609.60	5.22%
2800	737	$492.16	$486.28	$526.70	$578.00	$594.57	$635.09	5.23%
2900	620	$510.21	$503.74	$545.58	$598.67	$615.99	$658.30	5.23%
3000	577	$530.35	$523.69	$567.14	$622.21	$639.78	$683.64	5.21%
3100	470	$548.67	$541.85	$586.63	$643.62	$662.15	$707.26	5.21%
3200	460	$567.66	$560.61	$607.18	$666.14	$685.33	$732.45	5.23%
3300	365	$587.94	$580.52	$628.58	$689.65	$709.49	$758.69	5.23%
3400	370	$605.70	$597.98	$647.13	$710.31	$730.80	$781.32	5.22%
3500	4343	$809.65	$799.03	$864.30	$947.98	$974.19	$1,042.48	5.19%

6.8.2 Revised Proposed Commercial and Industrial Rates and Bill Impacts

Figure 24, Figure 25, and Figure 26 show the revised proposed rates for Commercial and Industrial customers, which reflect a gradual increase over the five-year rate period.

Figure 24: Revised Proposed Small Commercial Rates (Small General Service A1A)

	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20
Monthly Fixed Charge	$6.50	$7.00	$7.00	$7.00	$7.00	$7.00
Facilities Charge ($/kW)	$7.48	$7.48	$7.48	$7.98	$8.48	$8.98
High Season Consumption ($/kWh)	$0.14043	$0.12882	$0.13677	$0.15271	$0.15405	$0.15827
Low Season Consumption ($/kWh)	$0.11753	$0.10540	$0.11247	$0.12726	$0.12799	$0.13123

Figure 25: Proposed Medium Commercial Rates (Primary Service A2B)

		FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20
Monthly Fixed Charge		$28.00	$28.00	$28.00	$28.00	$28.00	$28.00
Facilities Charge ($/kW)		$7.48	$7.48	$7.48	$7.98	$8.48	$8.98
High Season	**Demand High Peak (HP) ($/kW)** [12]	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00
	Demand Low Peak (LP) ($/kW)	$3.75	$3.75	$3.75	$3.75	$3.75	$3.75
Low Season	**Demand HP ($/kW)**	$4.75	$4.75	$4.75	$4.75	$4.75	$4.75
	Demand LP ($/kW)	$ -	$ -	$ -	$ -	$ -	$ -
High Season	**Consumption HP ($/kWh)**	$0.11818	$0.11818	$0.13673	$0.13733	$0.13735	$0.14389
	Consumption LP ($/kWh)	$0.11091	$0.11091	$0.12946	$0.13006	$0.13008	$0.13662
	Consumption Base ($/kWh)	$0.09018	$0.09018	$0.10873	$0.10933	$0.10935	$0.11589
Low Season	**Consumption HP ($/kWh)**	$0.11184	$0.11184	$0.13039	$0.13099	$0.10529	$0.13755
	Consumption LP ($/kWh)	$0.11184	$0.11184	$0.13039	$0.13099	$0.10529	$0.13755
	Consumption Base ($/kWh)	$0.09391	$0.09391	$0.11246	$0.11306	$0.08736	$0.11962

[12] There are three TOU periods for LADWP Commercial customers, high peak, low peak, and base. High peak represents the highest cost period (weekday afternoon), base represents lowest cost period (late evening-early morning and weekends), low peak period represents remaining time periods.

Figure 26: Revised Proposed Large Commercial Rates (Sub-transmission A3A)

	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20
Monthly Fixed Charge	$75.00	$75.00	$75.00	$75.00	$75.00	$75.00
Facilities Charge ($/kW)	$6.68	$6.68	$6.68	$7.18	$7.68	$8.18
Demand HP Summer ($/kW)	$9.70	$9.70	$9.70	$9.70	$9.70	$9.70
Demand LP Summer ($/kW)	$3.30	$3.30	$3.30	$3.30	$3.30	$3.30
Demand HP Winter ($/kW)	$4.30	$4.30	$4.30	$4.30	$4.30	$4.30
Demand LP Winter ($/kW)	$ -	$ -	$ -	$ -	$ -	$ -
Consumption HP Summer ($/kWh)	$0.11577	$0.11577	$0.13400	$0.13460	$0.13485	$0.14200
Consumption LP Summer ($/kWh)	$0.10951	$0.10951	$0.12774	$0.12834	$0.12859	$0.13574
Consumption Base Summer ($/kWh)	$0.08942	$0.08942	$0.10765	$0.10825	$0.10850	$0.11565
Consumption HP Winter ($/kWh)	$0.11050	$0.11050	$0.12873	$0.12933	$0.12958	$0.13673
Consumption LP Winter ($/kWh)	$0.11050	$0.11050	$0.12873	$0.12933	$0.12958	$0.13673
Consumption Base Winter ($/kWh)	$0.09384	$0.09384	$0.11207	$0.11267	$0.11292	$0.12007

Figure 27, Figure 28, and Figure 29 show the revised proposed bill impacts for small, medium, and large Commercial customers. In all cases, the revised proposed rates are lower than the initial proposed rates.

Figure 27: Revised Small Commercial Customer (Small General Service A1A) Bill Impacts by Load Factor (Detail)

Load Factor	Customers	Average Median Bill						Average Annual Increase (%)
		FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20	
0.05	34,780	$44.68	$44.37	$44.86	$47.87	$49.94	$52.17	3.2%
0.10	29,376	$67.09	$64.69	$66.48	$72.18	$74.44	$77.32	2.9%
0.15	25,947	$96.74	$92.04	$95.26	$104.24	$107.03	$110.97	2.8%
0.20	20,867	$147.95	$139.25	$144.91	$159.58	$163.32	$169.07	2.7%
0.25	14,665	$199.95	$187.02	$195.34	$215.90	$220.47	$227.99	2.7%
0.30	10,372	$256.47	$238.72	$250.01	$277.08	$282.47	$291.80	2.6%
0.35	7,960	$324.23	$300.61	$315.50	$350.47	$356.68	$368.12	2.6%
0.40	6,768	$402.03	$371.53	$390.65	$434.73	$441.76	$455.73	2.5%
0.50	9,816	$526.08	$484.48	$510.55	$569.10	$577.85	$595.80	2.5%
0.60	4,891	$627.44	$576.11	$607.99	$678.97	$688.39	$709.18	2.5%
0.70	1,862	$604.28	$553.89	$585.10	$654.06	$662.51	$682.25	2.5%
0.80	642	$426.69	$391.03	$413.28	$461.95	$467.58	$481.17	2.4%
0.90	266	$367.61	$337.08	$356.46	$398.24	$402.81	$414.32	2.4%
1.00	115	$386.58	$354.18	$374.79	$418.71	$423.49	$435.61	2.4%
2.00	361	$480.66	$439.00	$465.09	$520.78	$526.14	$540.83	2.4%

Figure 28: Revised Medium Commercial Customer (Primary Service A2B) Annual Bill Impacts by Load Factor (Detail)

Load Factor	Customers	Average Median Bill						Average Annual Increase (%)
		FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20	
0.02	12	$5,006.55	$5,006.55	$5,008.97	$5,172.19	$5,335.35	$5,499.35	1.9%
0.03	12	$736.07	$736.07	$740.65	$776.97	$808.58	$848.15	2.9%
0.04	17	$927.22	$927.22	$941.33	$970.63	$984.04	$1,033.30	2.2%
0.05	17	$686.56	$686.56	$701.63	$725.65	$735.50	$778.05	2.5%
0.06	34	$602.04	$602.04	$612.13	$638.23	$653.61	$693.33	2.9%
0.07	28	$805.23	$805.23	$829.59	$856.94	$858.37	$912.51	2.5%
0.08	27	$731.33	$731.33	$759.81	$780.73	$775.56	$830.79	2.6%
0.09	43	$725.20	$725.20	$756.38	$777.57	$768.71	$828.97	2.7%
0.10	39	$956.78	$956.78	$994.68	$1,025.34	$1,038.76	$1,097.61	2.8%
0.20	1,056	$815.02	$815.02	$855.50	$876.51	$857.93	$930.23	2.7%
0.30	2,274	$1,019.09	$1,019.09	$1,086.00	$1,110.79	$1,080.02	$1,181.66	3.0%
0.40	2,441	$1,412.44	$1,412.44	$1,538.26	$1,568.66	$1,487.31	$1,662.18	3.3%
0.50	2,331	$1,720.61	$1,720.61	$1,905.54	$1,935.89	$1,808.11	$2,050.48	3.6%
0.60	1,919	$2,147.49	$2,147.49	$2,398.85	$2,437.36	$2,248.15	$2,582.45	3.8%
0.70	1,431	$2,434.06	$2,434.06	$2,746.28	$2,781.18	$2,539.89	$2,943.59	3.9%
0.80	1,234	$2,882.67	$2,882.67	$3,274.20	$3,317.65	$2,994.60	$3,507.94	4.0%
0.90	482	$2,910.16	$2,910.16	$3,313.77	$3,351.89	$3,014.81	$3,551.81	4.1%
1.00	72	$3,039.72	$3,039.72	$3,477.93	$3,518.84	$3,141.49	$3,727.29	4.2%
1.10	17	$3,491.39	$3,491.39	$4,018.38	$4,057.85	$3,600.07	$4,289.06	4.2%
1.20	16	$2,118.08	$2,118.08	$2,420.02	$2,452.45	$2,203.79	$2,604.56	4.2%
1.30	6	$1,352.72	$1,352.72	$1,533.90	$1,556.89	$1,420.82	$1,657.88	4.2%
1.40	7	$2,889.58	$2,889.58	$3,278.39	$3,334.30	$3,008.03	$3,558.46	4.3%
1.50	2	$1,404.48	$1,404.48	$1,604.56	$1,627.33	$1,445.17	$1,730.68	4.3%
1.60	2	$1,172.42	$1,172.42	$1,309.51	$1,339.34	$1,225.70	$1,438.61	4.2%
1.70	2	$1,756.52	$1,756.52	$2,009.47	$2,038.06	$1,822.19	$2,168.32	4.3%
1.80	5	$1,714.96	$1,714.96	$1,941.52	$1,978.38	$1,800.46	$2,117.55	4.3%
1.90	3	$1,531.83	$1,531.83	$1,747.28	$1,783.98	$1,581.22	$1,897.65	4.4%
2.00	11	$2,896.84	$2,896.84	$3,322.61	$3,370.64	$2,996.87	$3,589.74	4.4%

Figure 29: Revised Large Commercial and Industrial Customer (Sub-transmission A3A) Bill Impacts by Load Factor (Detail)

Load Factor	Customers	Average Median Bill						Average Annual Increase
		FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19	FY 2019-20	
0.01	8	$754.11	$754.11	$755.35	$792.88	$824.90	$857.92	2.6%
0.02	3	$802.21	$802.21	$804.64	$845.72	$886.68	$928.53	3.0%
0.03	6	$988.16	$988.16	$1,000.80	$1,040.29	$1,079.17	$1,122.65	2.6%
0.04	7	$287.65	$287.65	$289.50	$303.31	$317.03	$331.43	2.9%
0.05	7	$508.85	$508.85	$523.42	$539.99	$555.86	$577.03	2.5%
0.06	10	$209.01	$209.01	$214.85	$219.79	$224.45	$231.24	2.0%
0.07	10	$1,926.93	$1,926.93	$1,999.57	$2,062.92	$2,122.81	$2,209.12	2.8%
0.08	7	$1,367.23	$1,367.23	$1,417.95	$1,467.95	$1,515.53	$1,581.56	3.0%
0.09	8	$650.78	$650.78	$679.56	$697.18	$713.43	$740.15	2.6%
0.10	14	$1,622.04	$1,622.04	$1,697.21	$1,737.33	$1,773.87	$1,837.74	2.5%
0.20	166	$1,717.38	$1,717.38	$1,840.96	$1,889.81	$1,932.55	$2,017.15	3.3%
0.30	500	$2,718.78	$2,718.78	$2,980.20	$3,039.73	$3,087.20	$3,226.22	3.5%
0.40	827	$3,181.27	$3,181.27	$3,526.67	$3,587.59	$3,632.72	$3,798.08	3.6%
0.50	1043	$5,223.91	$5,223.91	$5,886.63	$5,966.22	$6,014.19	$6,303.18	3.8%
0.60	945	$7,172.54	$7,172.54	$8,051.54	$8,191.97	$8,290.45	$8,708.62	4.0%
0.70	744	$9,744.63	$9,744.63	$11,086.89	$11,228.89	$11,306.83	$11,872.93	4.0%
0.80	633	$12,896.54	$12,896.54	$14,664.86	$14,863.56	$14,977.87	$15,735.30	4.1%
0.90	361	$11,921.95	$11,921.95	$13,690.08	$13,840.28	$13,906.09	$14,614.94	4.2%
1.00	101	$10,924.19	$10,924.19	$12,578.56	$12,714.26	$12,771.01	$13,429.43	4.2%
1.10	38	$4,821.49	$4,821.49	$5,537.18	$5,595.98	$5,620.62	$5,905.55	4.1%
1.20	11	$3,473.16	$3,473.16	$4,011.38	$4,048.68	$4,060.29	$4,267.64	4.2%
1.30	10	$5,495.36	$5,495.36	$6,094.59	$6,256.69	$6,390.20	$6,741.64	4.2%
1.40	10	$6,974.18	$6,974.18	$8,071.68	$8,144.55	$8,165.04	$8,584.67	4.2%
1.50	4	$1,402.48	$1,402.48	$1,601.58	$1,623.90	$1,636.72	$1,721.95	4.2%
1.60	7	$5,557.63	$5,557.63	$6,460.66	$6,516.45	$6,529.14	$6,870.25	4.3%
1.70	3	$24,571.04	$24,571.04	$28,572.97	$28,811.05	$28,858.14	$30,360.69	4.3%
1.80	1	$899.03	$899.03	$1,042.07	$1,050.78	$1,052.66	$1,106.57	4.2%
1.90	1	$6,302.15	$6,302.15	$7,147.22	$7,300.48	$7,413.42	$7,833.69	4.4%
2.00	16	$2,882.72	$2,882.72	$3,376.82	$3,402.27	$3,404.15	$3,585.72	4.5%