South San Joaquin Irrigation District Retail Electric Financial Analysis

Laura Norin
MRW & Associates, LLC
1814 Franklin Street, Suite 720
Oakland, CA 94612

June 2016

Contents

About MRW & Associates, LLC i

Executive Summary i

Chapter 1: Introduction to the MRW Analysis 1

Chapter 2: Methodology 2

- Structure of Analysis 2
- Summary of Primary Sources Used in the Analysis 4
- Summary of Key Assumptions 7
- SSJID Service Area Sales Forecast 8
- Distribution Asset Acquisition Price 9
- Assessment of SSJID's Ongoing Costs 9
- Rate Forecast for SSJID Customers 10
- Interest Payments and Revenue 12
- Assessment of Greenhouse Gas Cap-and-Trade Program Impacts 13
- SSJID Exit Fees to PG&E 13

Chapter 3: Results of the MRW Analysis 14

- MRW Analysis Base Case 14
- Stress Test Analyses 16
- Impact of Distribution Asset Acquisition Price 20
- Additional Uncertainties 21

Chapter 4: Opinion Regarding Financial Feasibility 22

Appendix A: Key Assumptions and Results of the MRW Analysis A-1

Appendix B: SSJID Power Supply Cost Forecast B-1

- Renewable Power Cost Forecast B-1
- Non-Renewable Power Cost Forecast B-3
- Capacity Cost Forecast for Non-Renewable Power B-4
- Transmission Costs B-5
- Contracting Adder B-5

Appendix C: Forecast of PG&E's Rates C-1

- Generation Charges C-1
- Transmission and Distribution Charges and Other Charges C-5
- Rate Development C-6

Appendix D: SSJID's Distribution Capital Expenditures D-1

- Difference between PG&E and SSJID Capital Expenditures D-2

Appendix E: Assessment of Cap-and-Trade Program Implications for Financial Analysis E-1
Allowance Provisions for SSJID E-2
Allowance Provisions for PG&E E-2
Greenhouse Gas Allowance Prices E-3
Post-2020 Allowance Allocation E-3
Appendix F: CARE Program Developments F-1
Appendix G: Community Choice Aggregation Evaluation G-1
Community Choice Aggregation Background G-1
Financial Feasibility Assessment of CCA Service G-1
Examination of CCA Plan Financial Infeasibility G-2
Additional Risks and Costs of CCA Service G-5
Conclusion G-8

About MRW & Associates, LLC

MRW & Associates, LLC ("MRW") is internationally recognized for its broad expertise in electric power and fuel markets. MRW consultants combine an in-depth knowledge of these markets with rigorous economic and technical analysis to help clients in the areas of power market analysis, regulatory and litigation support, natural gas market analysis, and retail market support.

MRW is widely respected for its independent, technical analysis of complex issues. Both the California Public Utilities Commission and the California Energy Commission have directly engaged MRW's support to evaluate highly controversial issues, including the costs, benefits, and risks of the Sunrise transmission project and the state's nuclear power plants. MRW consultants are known for having a deep knowledge of the utility, regulatory, and market structures in California and how these interface in areas such as energy costs, retail energy rates, and power plant development.

Established in Oakland, California in 1986, MRW early on built a solid reputation for delivering local insights on power and fuel markets in the western United States. Organizations turn to MRW to benefit from the knowledge and insights acquired over 30 years of deep involvement with the western U.S. energy markets and regulatory systems. MRW consultants employ the insights gained through this experience to advise clients on regulatory and business strategy and to provide expert testimony before regulatory agencies, courts, and arbitration panels.

Executive Summary

MRW has prepared a financial analysis of the South San Joaquin Irrigation District (SSJID) retail electric plan ("MRW Analysis"). This analysis reflects current assessments of future market and economic conditions, financial parameters, and regulatory requirements, including wholesale power prices, renewable power prices, greenhouse gas cap-and-trade costs, electricity sales forecasts, and financing rates. In developing this analysis, MRW has sought to apply a conservative set of assumptions that best reflects currently available public information. This report summarizes MRW's findings.

The MRW Analysis finds that SSJID's retail electric plan would be financially viable with a purchase price for PG&E's distribution assets set at the valuation amount determined by NewGen Strategies & Solutions ($92.7 million),[1] and also with a purchase price of more than double this amount. To be conservative, MRW's base case analysis uses a purchase price of $200 million. At this price, SSJID's retail electric plan has positive net cash flow (*i.e.*, revenue surpluses) over both 10-year and 30-year analysis terms, with revenues from the retail electric plan exceeding all costs associated with providing retail electric service by 10%-40% in each year. This holds true while restricting revenue from electric sales in order to provide customers with a discount of at least 15% off of PG&E's retail electric rates.

The financial model is structured to require SSJID to meet the requirements for (i) a debt service coverage ratio of at least 1.25[2] and (ii) a minimum cash on-hand balance to cover 120 days of expenses.[3] A violation of either condition would require SSJID to provide equity contributions sufficient to meet the requirements.[4] No equity contributions are required in the base case scenario, which has positive net cash flow in each year.

Annual net cash flows cumulate in the base case to provide cash balances of $140 million after ten years and $980 million after 30 years.[5] The minimum debt service coverage ratio over this period is 1.8, and the projected minimum end-of-year cash on-hand balance is 192 days. At the end of the 30-year analysis period, the debt service coverage ratio is projected to be 6.4, and cash on-hand is projected to be sufficient to cover expenses for more than five years.

---

[1] "Appraisal Summary Statement For South San Joaquin Irrigation District Acquisition of Electric Distribution System Facilities Owned by Pacific Gas & Electric Company," NewGen Strategies and Solutions, LLC, May 2016.

[2] Total income minus total operating expenses must exceed debt payment requirements by at least 25%.

[3] SSJID reports that no funds would need to be obtained to meet the 120-day cash-on-hand requirement at the start of service because the District's unrestricted reserve funds from other SSJID business units would be available for this purpose. However, to be conservative, MRW included these beginning cash funds as part of the bond issuance so as to evaluate the electric utility on a fully self-contained basis.

[4] To the extent that earnings exceed expenses, SSJID would invest up to $10 million in a rate stabilization fund that would be used to meet retail electric plan obligations prior to seeking equity contributions from other business areas. Any contributions needed from other business areas would be met from the District's available unrestricted cash reserves from non-rate revenue or from other sources of non-rate revenue.

[5] The cash balance is the sum of annual net cash flows. It is calculated by subtracting any contributions from outside the retail electric plan from the retail electric plan's ending cash balance.

The structure of the financial analysis and the base-case results for the initial and final years of the 30-year analysis period are summarized in Table 1. The key elements of the analysis are (i) revenues, (ii) expenses, (iii) costs to operate, maintain, and improve the distribution system, and (iv) debt service to pay for the purchase of PG&E's distribution assets.

As evident from Table 1, the cost of power is by far the greatest expense, representing about 47%-61% of annual costs (including operating expenses, capital expenditures, and debt service). The wholesale cost of power is therefore a key consideration for this analysis. Revenue from SSJID customers is by far the greatest revenue source, representing 84%-97% of annual revenues. The amount of these revenues is established based on forecasts of SSJID's sales and PG&E's retail rates, discounted by 15% consistent with SSJID's commitment to provide customers a 15% discount off of PG&E's retail rates. The SSJID sales forecast and PG&E rate forecast are therefore also key considerations for this analysis. Given the importance of the wholesale cost of power forecast and the PG&E retail rate forecast for the financial analysis, MRW has paid particular attention to developing these forecasts on a consistent basis.

Of the remaining expenses, Operations and Maintenance (O&M)/Administrative and General (A&G) costs[6] and debt service are the next largest categories, each comprising about 10%-20% of annual costs. Capital Expenditures comprise another 6% of annual costs, and the final 7%-11% of costs come from (i) payments to local municipalities to replace taxes and fees currently paid by PG&E, (ii) energy efficiency and other public benefits programming, and (iii) exit fees that SSJID will be required to pay PG&E.

[6] These categories include all the costs to operate and maintain the electric distribution system as well as personnel costs and other overhead costs associated with providing retail electric service, including the costs of customer metering and billing, customer service, legal services, staff salaries, etc.

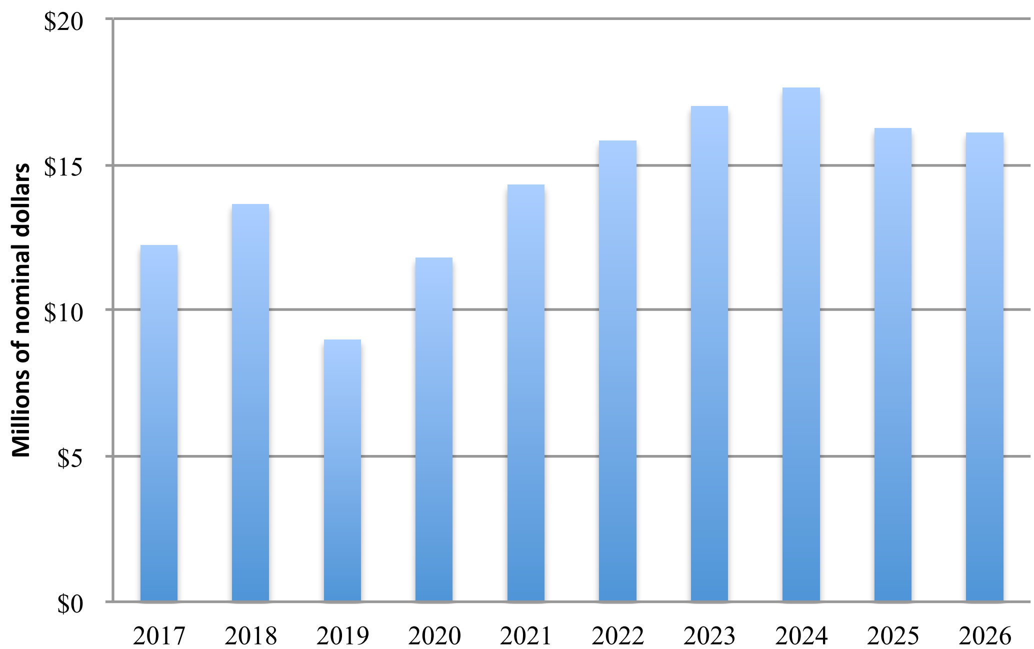
Table 1: Summary of Financial Analysis, Base Case ($000)[7]

	2017	2018	2019	2020	2045	2046
Revenues						
Revenues from SSJID Customers[8]	87,908	89,914	91,744	96,403	233,060	243,038
Revenues from Allowance Sales[9]	2,183	2,274	2,424	2,556	11,420	12,271
Interest Income[10]	518	1,124	1,846	2,199	30,648	33,289
Total Revenues	**90,608**	**93,312**	**96,014**	**101,158**	**275,127**	**288,598**
Operating Expenses						
Cost of Power	38,929	39,815	40,942	42,627	119,568	124,457
O&M/A&G Costs[11]	14,250	14,437	14,627	14,819	34,312	35,492
Public Benefit Costs[12]	3,516	3,597	3,670	3,856	9,322	9,722
Payments In Lieu of Taxes[13]	2,198	2,248	2,294	2,410	5,827	6,076
Exit Fees to PG&E[14]	3,267	3,244	3,225	3,213	239	246
Total Operating Expenses	**62,160**	**63,340**	**64,758**	**66,926**	**169,268**	**175,993**
Capital Expenditures[15]	4,391	4,516	4,651	4,806	11,128	11,511
Debt Service[16]	11,808	11,808	17,611	17,611	17,611	17,611
Net Cash Flow[17]	**12,249**	**13,649**	**8,994**	**11,815**	**77,120**	**83,484**
Cash Contributions by SSJID[18]	-	-	-	-	-	-
Cash Reserves Balance[19]	**32,686**	**46,334**	**55,329**	**67,144**	**919,463**	**1,002,946**
Days Cash on Hand[20]	*192*	*267*	*312*	*366*	*1,983*	*2,080*
Debt Service Coverage Ratio[21]	*4.1*	*2.5*	*1.8*	*1.9*	*6.0*	*6.4*
Value of 15% Discount[22]	*15,513*	*15,867*	*16,190*	*17,012*	*41,128*	*42,889*

7 Assumes a $200 million price to purchase PG&E's distribution assets
8 Revenues from the provision of electricity service to customers, calculated using retail rates that are 15% below the projected PG&E retail rates
9 Revenue from free greenhouse gas allowances that SSJID will receive. These allowances can be used to directly offset SSJID's cap-and-trade costs and/or to sell to other entities.
10 Interest on cash reserves balance
11 Cost to operate and maintain the distribution system and administrative and general costs; does not include capital expenditures or costs associated with the acquisition of PG&E's distribution assets
12 Costs of energy efficiency programs and other public benefit programming
13 Payments to local municipalities to replace tax and fee revenue provided by PG&E
14 Payments mandated by the California Public Utilities Commission to be provided to PG&E
15 Expenditures for repairs and improvements to the distribution system
16 Payments for debt entered into to acquire PG&E distribution assets
17 Total Revenues – Total Operating Expenses - Capital Expenditures – Debt Service
18 No cash contributions are required from SSJID over the term of the analysis.
19 Cumulative Net Cash Flow to-date + $20 million Beginning Cash Contribution
20 (Cash Reserves Balance / Total Expenses) * 365 days/year
21 Earnings Available for Debt Service / Debt Service
22 Value to SSJID customers of 15% discount off PG&E's rates

Figure 1 and Figure 2 show that the retail electric utility is expected to generate positive net cash flow in each year of operations. Of particular note are the income-generation projections during the early years of the forecast because this is the period for which there is greater relative certainty. Annual net cash flows in each of the first ten years of operations are shown in Figure 1. These net cash flows average $14 million per year from 2017 through 2026, totaling $140 million over this period.

Figure 1: Annual Net Cash Flow During First Ten Years of Operations, Base Case



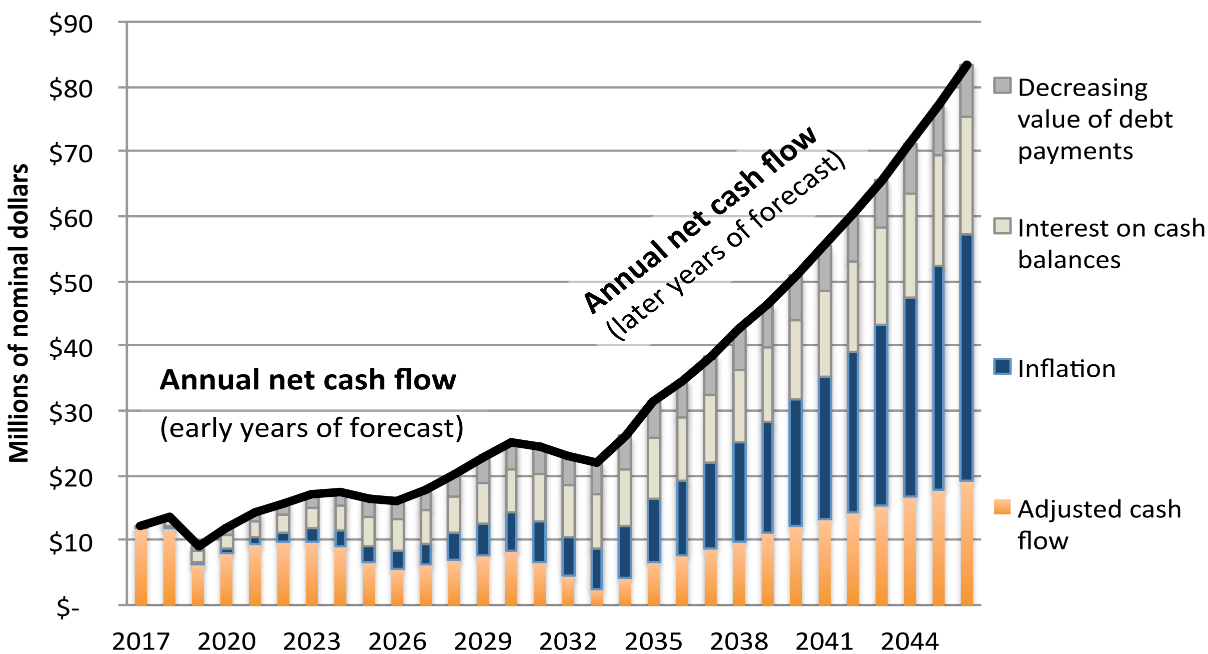
During years 11-30, projected net cash flows are significantly greater, averaging $42 million per year and increasing to $83 million in 2046 (see solid black line in Figure 2). Projected net cash flows increase with time in large part because (i) debt payments are constant in nominal terms (i.e., declining in real terms) throughout most of the forecast,[23] (ii) accumulating cash balances earn increasing amounts of interest, compounding their growth, and (iii) inflation. Of these factors, inflation is the most important: In constant 2017 dollars, the average annual net cash flow is $13 million in Years 1-10 and $27 million in Years 11-30.

The impacts of each of these factors on annual net cash flow are depicted in the vertical bars in Figure 2. The bottom set of bars, "Adjusted cash flow," shows the annual net cash flows without these three factors.[24] These adjusted annual cash flows fluctuate between $6 million and $12 million during the first ten years, averaging $9 million per year, and they fluctuate between $3 million and $19 million during the last 20 years, averaging $10 million per year. This demonstrates

[23] Debt payments are lower during the first two years because they do not include any principle.
[24] These results were developed by (i) increasing debt payments with inflation, (ii) removing interest income, and (iii) converting cash flows to constant 2017 dollars.

that (i) the large cash flows observed in the later years of the forecast, while strikingly higher than cash flows from earlier years, are consistent with the earlier-year results, and (ii) the apparent increase in net cash flow over time stems from the various effects of time on money. It is therefore reasonable to expect that cash flows would increase further after the forecast period given the cessation of debt payments after Year 30 and the continued effects of inflation and interest accruals.[25]

Figure 2: Annual Net Cash Flow During First 30 Years of Operations, Base Case

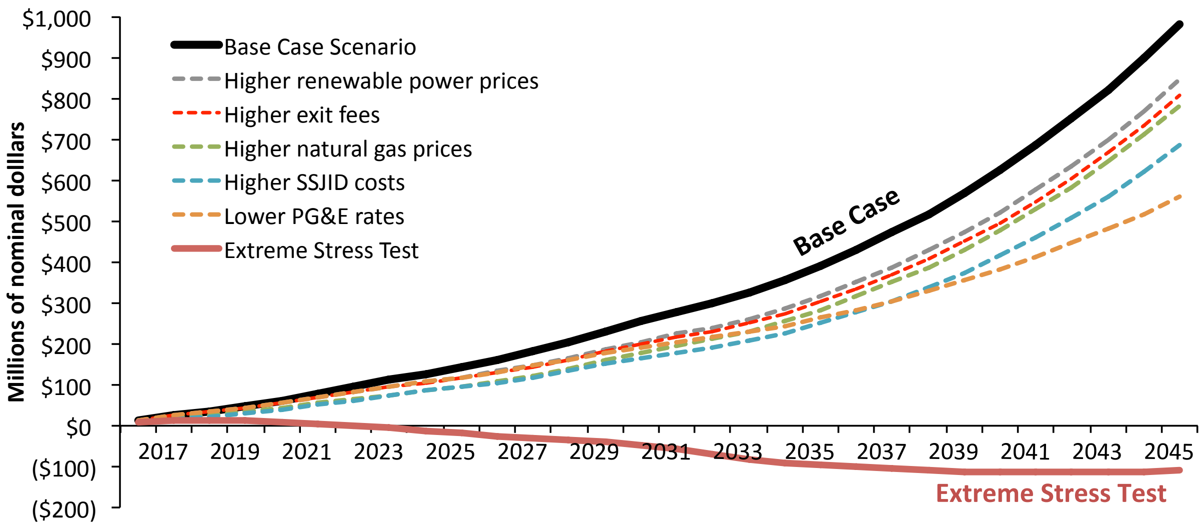


This base-case analysis represents a conservative forecast of the financial outcome of SSJID's plan to provide retail electric service, assuming a price of $200 million to purchase PG&E's distribution assets. MRW additionally conducted stress test analyses to consider lower PG&E rates (*i.e.*, lower customer revenue), higher SSJID operational costs, higher natural gas and renewable power prices, and higher PG&E exit fees. The financial plan remains healthy under each of these stress conditions, with positive net cash flows over both the 10-year and 30-year analysis periods, and no equity contributions required (Figure 3). MRW additionally considered an Extreme Stress Test, combining all the stress conditions. Under this scenario, the plan is self-sustaining for just seven years and, to continue operating, requires equity contributions from outside the electric utility averaging $5 million per year over the 30-year analysis period.[26]

---

[25] Interest would only accrue at the forecasted level if SSJID were to maintain the high cash balances that result from the base-case forecast. In practice, SSJID would be more likely to spend a share of the surplus on system improvements and/or to reduce customer rates. As this analysis is not intended to serve as a financial plan for SSJID's retail electric service, but instead as an evaluation of the feasibility of SSJID's plan, SSJID's future decisions with regard to how to spend surplus revenue are immaterial to the analysis.
[26] These contributions would be met from the District's available unrestricted cash reserves from non-rate revenue or from other sources of non-rate revenue.

Figure 3: Cumulative Net Cash Flow, all scenarios



These stress cases, considered together with the base case result, indicate the likelihood of a healthy program as long as the purchase price does not greatly exceed $200 million. As illustrated by the Extreme Stress Test, this is not a guarantee of project self-sufficiency, but an indication that the program is robust under a wide range of potential circumstances, including circumstances that are far more negative than would be expected. With a purchase price at the NewGen appraisal value of $92.7 million, base-case revenue surpluses increase to $1.4 billion over 30 years, and the utility is able to weather a more extensive set of negative circumstances while remaining self-sufficient, including the Extreme Stress Test.

These results are applicable only to SSJID's plan to provide full retail electric service. Under an alternative Community Choice Aggregation (CCA) plan, net cash flows were found to be negative in each year, with an annual average shortfall of 40%. With base case conditions, an SSJID CCA would lose more than $150 million over the first ten years, and the shortfall would increase to $625 million over the full 30-year period. While these results are subject to change with changes to underlying market or regulatory conditions, given the magnitude of the annual shortfalls predicted for an SSJID CCA, the CCA plan does not appear to be financially feasible.[27]

[27] See Appendix G for further discussion of the CCA results.

Chapter 1: Introduction to the MRW Analysis

The MRW Analysis is a comprehensive financial feasibility assessment of SSJID's plan to provide retail electric service, developed by Laura Norin of MRW & Associates, LLC (MRW). It considers all the costs to provide retail electric service, including costs to procure power for customers, costs associated with the acquisition of a portion of the Pacific Gas & Electric (PG&E) distribution system, ongoing costs to operate and maintain that system in good working order, and costs for public benefits programs and in-lieu tax payments to local municipalities. It also includes a full study of PG&E's retail electricity rates using a consistent set of market assumptions to forecast PG&E's costs and SSJID's costs.

The report is organized as follows:

1. Chapter 2 ("Methodology") describes the sources and methodologies used to develop the base-case analysis;
2. Chapter 3 ("Results of the MRW Analysis") presents the results of the base-case analysis and several stress test scenarios;
3. Chapter 4 ("Opinion Regarding Financial Feasibility") provides Ms. Norin's opinion regarding the feasibility of SSJID's plan;
4. Appendix A presents the key assumptions and results of the scenarios analyzed in the MRW Analysis;
5. Appendix B provides an overview of MRW's methodology for developing the SSJID power supply cost forecast;
6. Appendix C describes MRW's methodology for forecasting PG&E's retail electric rates;
7. Appendix D describes MRW's forecast of SSJID's distribution capital expenditures;
8. Appendix E provides an assessment of cap-and-trade program implications for SSJID's financial analysis;
9. Appendix F explains the impact of changes to CARE rates and program eligibility for the financial feasibility assessment; and
10. Appendix G provides an assessment of the feasibility of an SSJID Community Choice Aggregation (CCA) program.

Chapter 2: Methodology

This chapter describes the structure of the analysis, the primary sources relied on, and the assumptions adopted in the base-case analysis. The major areas addressed are: the SSJID service area sales forecast; SSJID's distribution asset purchase price; SSJID's costs to serve its customers; a long-term forecast of the rates SSJID will be able to charge while meeting its commitment to provide a 15% discount off of PG&E's rates; interest rate projections; and an analysis of the implications of California's greenhouse gas cap-and-trade regulations on the retail electric plan. Each of these topics is discussed in detail below.

Structure of Analysis

The MRW Analysis compares the revenues that will be made available to SSJID to the expenses and financial obligations that SSJID will incur. The components of the analysis can be seen in Table 2, which provides a snapshot of the first and last years of the analysis.

As is evident from Table 2, the cost of power is by far the greatest expense, representing about 47%-61% of annual costs (including operating expenses, capital expenditures, and debt service). The wholesale cost of power is therefore a key consideration for this analysis. Revenue from SSJID customers is by far the greatest revenue source, representing 84%-97% of annual revenues. The amount of these revenues is established based on forecasts of SSJID's sales and PG&E's retail rates, discounted by 15% consistent with SSJID's commitment to provide customers a 15% discount off of PG&E's retail rates. The SSJID sales forecast and PG&E rate forecast are therefore also key considerations for this analysis. Given the importance of the wholesale cost of power forecast and the PG&E retail rate forecast for the financial analysis, MRW has paid particular attention to developing these forecasts on a consistent basis.

Of the remaining expenses, Operations and Maintenance (O&M)/Administrative and General (A&G) costs[28] and debt service are the next largest categories, each comprising about 10%-20% of annual costs. Capital Expenditures comprise another 6% of costs, and the final 7%-11% of costs come from (i) payments to local municipalities to replace taxes and fees currently paid by PG&E, (ii) public benefits programming, and (iii) exit fees that PG&E will assign to SSJID customers.

In addition to direct expenses, SSJID has a financial obligation to maintain a minimum cash on-hand balance to cover 120 days of expenses,[29] and SSJID must also maintain a debt service coverage ratio of at least 1.25.[30]

To the extent that earnings exceed expenses, SSJID will invest up to $10 million in a rate stabilization fund and will accumulate additional funds as reserves. If the costs of SSJID's expenses and financial obligations were to exceed earnings and available fund balances, equity from other SSJID business areas would be required. This situation does not arise in the base-case scenario.

---

[28] These categories include all the costs to operate and maintain the electric distribution system as well as personnel costs and other overhead costs associated with providing retail electric service.
[29] SSJID reports that no funds would need to be obtained to meet this requirement because the District's unrestricted reserve funds from other SSJID business units would be available for this purpose. However, to be conservative, MRW included the funds required to meet the 120-day cash-on-hand requirement at the start of service as part of the bond issuance so as to evaluate the electric utility on a fully self-contained basis.
[30] Income minus operating expenses must exceed debt payment requirements by a margin of at least 25%.

Table 2: Snapshot of Financial Analysis, Base Case (nominal $000)[31]

	2017	2018	2019	2020	2045	2046
Revenues						
Revenues from SSJID Customers[32]	87,908	89,914	91,744	96,403	233,060	243,038
Revenues from Allowance Sales[33]	2,183	2,274	2,424	2,556	11,420	12,271
Interest Income[34]	518	1,124	1,846	2,199	30,648	33,289
Total Revenues	**90,608**	**93,312**	**96,014**	**101,158**	**275,127**	**288,598**
Operating Expenses						
Cost of Power	38,929	39,815	40,942	42,627	119,568	124,457
O&M/A&G Costs[35]	14,250	14,437	14,627	14,819	34,312	35,492
Public Benefit Costs[36]	3,516	3,597	3,670	3,856	9,322	9,722
Payments In Lieu of Taxes[37]	2,198	2,248	2,294	2,410	5,827	6,076
Exit Fees to PG&E[38]	3,267	3,244	3,225	3,213	239	246
Total Operating Expenses	**62,160**	**63,340**	**64,758**	**66,926**	**169,268**	**175,993**
Capital Expenditures[39]	4,391	4,516	4,651	4,806	11,128	11,511
Debt Service[40]	11,808	11,808	17,611	17,611	17,611	17,611
Net Cash Flow[41]	**12,249**	**13,649**	**8,994**	**11,815**	**77,120**	**83,484**
Cash Contributions by SSJID[42]	-	-	-	-	-	-
Cash Reserves Balance[43]	**32,686**	**46,334**	**55,329**	**67,144**	**919,463**	**1,002,946**
Days Cash on Hand[44]	*192*	*267*	*312*	*366*	*1,983*	*2,080*
Debt Service Coverage Ratio[45]	*4.1*	*2.5*	*1.8*	*1.9*	*6.0*	*6.4*
Value of 15% Discount[46]	*15,513*	*15,867*	*16,190*	*17,012*	*41,128*	*42,889*

---

[31] Assumes a $200 million price to purchase PG&E's distribution assets.
[32] Revenues from the provision of electricity service to customers, calculated using retail rates that are 15% below the projected PG&E retail rates
[33] Revenue from free greenhouse gas allowances that SSJID will receive. These allowances can be used to directly offset SSJID's cap-and-trade costs and/or to sell to other entities.
[34] Interest on cash reserves balance
[35] Cost to operate and maintain the distribution system and administrative and general costs; does not include capital expenditures or costs associated with the acquisition of PG&E's distribution assets
[36] Costs of energy efficiency programs and other public benefit programming
[37] Payments to local municipalities to replace tax and fee revenue provided by PG&E
[38] Payments mandated by the California Public Utilities Commission to be provided to PG&E
[39] Expenditures for repairs and improvements to the distribution system
[40] Payments for debt entered into to acquire PG&E distribution assets
[41] Total Revenues – Total Operating Expenses - Capital Expenditures – Debt Service
[42] No cash contributions are required from SSJID over the term of the analysis.
[43] Cumulative Net Cash Flow to-date + $20 million Beginning Cash Contribution
[44] (Cash Reserves Balance / Total Expenses) * 365 days/year
[45] Earnings Available for Debt Service / Debt Service
[46] Value to SSJID customers of 15% discount off PG&E's rates

Summary of Primary Sources Used in the Analysis

In developing the MRW Analysis, MRW relied to the extent possible on publicly available data and forecasts. The major sources used in the analysis are summarized below. Additional sources are cited elsewhere in this report.

- Market data: Where available, MRW relied on NYMEX futures data for natural gas to forecast natural gas prices.
- PG&E filings and reports: The PG&E rate forecast is based to a large extent on public filings and reports that PG&E has made to the California Public Utilities Commission (CPUC), to the California Energy Commission, and to the Federal Energy Regulatory Commission (FERC). These include the following documents:
  - PG&E 2017 Energy Resource Recovery Account and Generation Non-Bypassable Charges ("ERRA") Forecast, filed with the CPUC in proceeding A.16-06-003 on June 1, 2016, provides PG&E's projected fuel and purchased power costs, exit fees, and greenhouse gas revenue allocation data for 2017.
  - PG&E 2016 ERRA Forecast Update, filed with the CPUC in proceeding A.15-06-001 on November 5, 2015, provides the fuel and purchased power costs that were used in developing 2016 rates.
  - PG&E Final 2015 Renewable Portfolio Standard (RPS) Procurement Plan, filed with the CPUC in proceeding R.15-02-020 on January 14, 2016, provides PG&E's long-term projections of its renewable power procurement plans.
  - PG&E Advice Letter 4696-E, filed with the CPUC on December 30, 2015, provides information on PG&E rates and costs as of January 1, 2016.[47]
  - PG&E Advice Letter 4805-E, filed with the CPUC on March 22, 2016, provides information on PG&E rates and costs as of March 24, 2016.[48]
  - PG&E Advice Letters 2706-E-A (December 30, 2005), 3773-E (December 6, 2010), 4459-E (July 14, 2014), 4647-E (June 10, 2015), and 4755-E (December 11, 2015) provide information on historic PG&E rates and costs for utility-owned assets.[49]
  - PG&E 2017 General Rate Case (GRC) application, filed with the CPUC in proceeding A.15-09-001 on September 1, 2015, provides PG&E's projected costs related to its distribution system and PG&E-owned generation (excluding fuel costs).
  - *PG&E Capacity Supply Plan (Form S-1)* and *PG&E Energy Supply Plan (Form S-2),*[50] submitted to the California Energy Commission in September 2015, provide forecasts of PG&E's capacity and energy supply and demand.
  - PG&E 2015 FERC Form 1 filing, filed with FERC on February 24, 2016,[51] provides PG&E's fuel costs in 2015 for its natural gas, nuclear, and hydroelectric power plants.

---

[47] Available at https://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4696-E-A.pdf
[48] Available at https://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4805-E.pdf
[49] Available at https://www.pge.com/nots/rates/tariffs/advice.shtml
[50] Available at http://energyalmanac.ca.gov/electricity/s-2_supply_forms_2015/
[51] Available at http://www.ferc.gov/docs-filing/forms.asp#1

- U.S. Energy Information Administration (EIA) forecasts: The mission of the EIA, which is an office of the U.S. Department of Energy, is to collect, analyze, and disseminate independent and impartial energy information.[52] As part of this work, EIA develops an *Annual Energy Outlook*, which provides long-term regional and nationwide projections of energy and fuel prices, energy consumption levels by source and sector, and emissions by energy source. These projections are developed via an in-depth energy-economy modeling system entitled the National Energy Modeling System. Not all of the modeling inputs are provided in the *Annual Energy Outlook*, but input data are typically made available by EIA staff in response to a request.

  MRW relied on a number of EIA long-term forecasts for this analysis, some of which were provided in the *Annual Energy Outlook 2015* and *Annual Energy Outlook 2016,*[53] and some of which were provided by EIA staff. These include California-specific forecasts of natural gas prices, natural gas heat rates, and the nationwide Gross Domestic Product Chain-type Price Index, which is used to project inflation rates.

- CPUC reports and models:
  - *2013-2014 Resource Adequacy Report (August 2015)*. This CPUC staff report provides historic data on the cost of resource adequacy resources.[54] MRW used these data to project near-term capacity costs.
  - *Scenario Tool 2014.* This CPUC model, last updated in October 2015, is used for long-term infrastructure planning at the CPUC and the California Independent System Operator (CAISO).[55] MRW used the capacity supply and demand forecasts in this model to project the load-resource balance year for system-wide generation capacity.

- California Energy Commission analyses and filings: The California Energy Commission conducts numerous assessments related to the electricity sector in California. MRW relied on the following assessments:
  - *California Energy Demand Forecast: 2016-2026* and associated Demand Forecast Forms, published December 14, 2015, pursuant to the 2015 *Integrated Energy Policy Report.*[56] MRW used this forecast as the basis for the SSJID and PG&E load forecasts.
  - *Estimated Cost of New Renewable and Fossil Generation in California,*[57] published in March 2015. MRW used data from this report for its capacity price forecast and to assess the share of the cost of natural gas generation that derives from fuel.

---

[52] U.S. EIA website. http://www.eia.gov/about/
[53] Available at http://www.eia.gov/forecasts/aeo/index.cfm
[54] Available at http://www.cpuc.ca.gov/ra/
[55] Available at http://www.cpuc.ca.gov/General.aspx?id=6617
[56] This report and associated forms are available from the California Energy Commission website at http://www.energy.ca.gov/2015_energypolicy/
[57] Available at http://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SF.pdf

- California Air Resources Board regulatory documents: The California Air Resources Board has jurisdiction over California's greenhouse gas cap-and-trade program. In analyzing the financial implications of this program for PG&E and SSJID, MRW followed the rules described in the California Code of Regulations Subchapter 10 Article 5: Final Regulation Order for the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms, April 2013.[58] In addition, MRW used the Air Resources Board's auctions prices for Vintage 2015 allowances.[59]
- CPUC decisions: MRW relied on CPUC decision D.12-12-033 (December 2012), which adopted the methodology for distributing greenhouse gas allowance revenues among PG&E customers, and CPUC decision D.13-10-040 (October 2013), which adopted PG&E's electric storage requirements. Other decisions were incorporated via the advice letter filings that implemented them (see *PG&E filings and reports*, above).
- CAISO data and analysis:
    - *CAISO's 2014-2015 Transmission Access Charge model* (October 26, 2015) provides the CAISO's forecast of its Transmission Access Charge.[60]
    - *CAISO 2015 hourly prices (NODE: TH_NP15_GEN-APND) extracted from OASIS platform.*[61] MRW used 2015 local marginal prices to estimate the market heat rate.
- Other key sources
    - National Renewable Energy Laboratory report, *Impact of Federal Tax Policy on Utility-Scale Solar Deployment Given Financing Interactions* (September 2015).[62] MRW used this report in developing the renewable power price forecast.
    - *California Energy Markets* (news publication): MRW compiled renewable power purchase prices reported in this publication in 2015 through early 2016 for use in the PG&E and SSJID renewable cost estimates.[63]
    - Municipal Utility Financial Filings: MRW used information from public filings made by northern California municipal utilities to develop an estimate of SSJID's capital expenditure requirements.
- SSJID-Specific Information: MRW obtained information on projected demand in SSJID's service area and on projected SSJID power supply costs, financing costs, and interest rates from the following documents:
    - *SSJID Draft Subsequent Environmental Impact Report*, prepared for the San Joaquin Local Agency Formation Commission (LAFCo) by Aspen Environmental Group, November 2011.[64]

[58] Available at http://www.arb.ca.gov/cc/capandtrade/ct_rf_april2013.pdf
[59] Available at http://www.arb.ca.gov/cc/capandtrade/auction/results_summary.pdf
[60] Available at https://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=234F116B-FE42-4CAF-9115-
[61] Available at http://oasis.caiso.com/mrioasis/logon.do
[62] Available at http://www.nrel.gov/docs/fy16osti/65014.pdf
[63] Renewable power prices compiled from Energy NewsData's *California Energy Markets* publications in 2015 (*see* July 31, August 14, October 16, and October 30 issues) and on January 15, 2016.
[64] Available at http://www.sjgov.org/lafco/SSJID/DEIR%20CD/index.htm

- *SSJID load information*: 2013 data provided by PG&E as part of the 2014 proceedings at the San Joaquin LAFCo regarding SSJID's proposed retail electric service plan. Load data for 2014-2015 obtained from PG&E's Energy Data Request Program.[65]
- *Indicative Power Supply Products & Pricing*, prepared for SSJID by Shell Energy North America ("Shell Energy"), January 19, 2016, provides an estimate of SSJID's power supply costs based on prevailing market conditions in January 2016.
- *SSJID Financing Analysis – Power Project*, prepared for SSJID by Public Finance Resources, January 22, 2016.
- *SSJID November 2015 Investment Report*, presented to the SSJID Board of Directors on December 10, 2015.
- Appraisal value for PG&E distribution assets to be purchased by SSJID, developed by NewGen Strategies & Solutions (NewGen) on behalf of SSJID, May 2016.
- Distribution and Administration Expense cost study, developed by Mark Beauchamp, Utility Financial Solutions, on behalf of SSJID, June 16, 2016.

Summary of Key Assumptions

The methodology used to develop the financial analysis is described further below and in the appendices. Some of the key assumptions are additionally summarized in **Table 3** and Appendix A.

Table 3: Select Assumptions

Discount off of PG&E's retail rates	15%
Percent of SSJID residential customers qualifying for low-income CARE rates	31%. Low-income customers are provided a 15% discount off the already-discounted CARE rates
SSJID meets 33%-by-2020 and 50%-by-2030 renewable requirements?	Yes; SSJID meets same requirements as PG&E
SSJID meets resource adequacy requirements?	Yes; SSJID meets same requirements as PG&E
SSJID meets greenhouse gas cap-and-trade requirements?	Yes; SSJID meets same requirements as PG&E. SSJID and PG&E additionally each receive free cap-and-trade allowances.
SSJID sales forecast	Based on California Energy Commission forecast for the Central Valley Region; consistent with the PG&E sales forecast methodology.
SSJID power supply costs	Based on bottoms-up assessment of conventional and renewable power supply costs; consistent with indicative pricing provided by Shell Energy for the period through 2021 and with the forecast of PG&E's power supply costs
Cost to purchase PG&E distribution assets	$200 million estimate used in the base case; also considered the effects of using the NewGen appraisal value

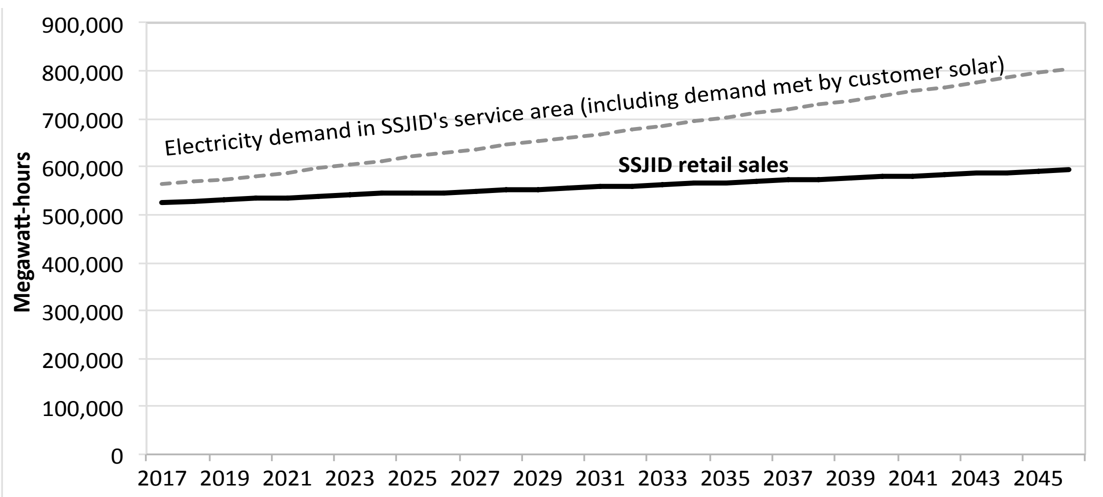
[65] Available (by zip code) at https://pge-energydatarequest.com/

SSJID Service Area Sales Forecast

The SSJID service area sales forecast is a key factor in determining the amount of rate revenue that SSJID can expect to receive as well as the amount of costs it can expect to incur to serve its customers. In order to develop a forecast of electric sales in SSJID's service area, MRW started from PG&E's estimate of electric sales to each customer segment in SSJID's service area during 2013, as reported to SSJID by PG&E.[66] For 2014 and 2015, MRW adjusted the 2013 data based on historic growth rates in SSJID's service area, as estimated from PG&E 2013-2015 usage reports for each customer segment in the SSJID zip codes.[67] MRW forecasted sales levels for the remainder of the analysis period using growth rates for each customer segment from the California Energy Commission's most recently adopted electricity demand forecast for the Central Valley Region.[68]

The Energy Commission forecast incorporates an expectation for significant growth in customer solar in the Central Valley Region, from 5% of electrical demand in 2015 to 13% in 2026.[69] MRW fully incorporated this expected growth in customer solar and continued to incorporate additional solar growth throughout the analysis period.[70] This resulted in a projected increase in SSJID's retail sales of only 13% over the 30-year period. By the end of the analysis period, MRW projects that more than 25% of electricity demand in SSJID's area will be met by customer solar, rather than by SSJID. Electricity demand met by customer solar can be seen in Figure 4 as the difference between the dashed line (total demand) and the solid line (SSJID's retail sales).

Figure 4: Forecast of Annual SSJID Retail Sales and Total Customer Demand, 2017-2046



[66] Data provided by PG&E during the course of the 2014 proceeding at the San Joaquin LAFCo that approved SSJID's proposed retail service plan. In the past, PG&E has "corrected" historical data, so these figures should be understood as estimates of actual 2013 energy sales to SSJID customers.
[67] Data obtained from PG&E's Energy Data Request Program for zip codes 95320, 95336, 95337, and 95366. These zip codes include areas outside of SSJID's jurisdiction.
[68] California Energy Commission. Demand Forecast for the 2015 IEPR. PG&E Forecast Zone Results Mid Demand Case, Central Valley Region. December 14, 2015. (Results cited are specific to SSJID's load profile.)
[69] Calculated by comparing the Consumption and Sales forecasts in the California Energy Commission demand forecast for the Central Valley Region.
[70] For years following the end of the California Energy Commission's forecast in 2026, MRW used the 10-year average annual growth rate from the Energy Commission sales forecast, which is only 0.4%. Without the growth in solar, the annual average growth rate would instead be 1.2%.

Distribution Asset Acquisition Price

For the base case, MRW estimated a compromise purchase price for the distribution assets that SSJID would need to acquire from PG&E of $200 million, which is more than double the $92.7 million appraisal value developed by NewGen Strategies and Solutions (NewGen) on behalf of SSJID.[71] This figure is not intended to prejudge the outcome of condemnation proceedings or any settlement negotiations between PG&E and SSJID. It is simply one potential outcome of such proceedings, selected as a possible compromise outcome between the PG&E and SSJID positions. MRW added to this amount the cost for separation and impairment that SSJID would owe PG&E, estimated at 50% above the values calculated by NewGen, and the separation costs that SSJID would bear, as estimated by SSJID.[72]MRW used 30-year bond rates provided to SSJID by Public Finance Resources to calculate financing payments of $17.5 million per year to cover the cost of these assets.[73]

Assessment of SSJID's Ongoing Costs

SSJID's largest ongoing cost will be the cost to procure power for its customers. MRW developed a bottoms-up calculation of SSJID's power supply costs, separately calculating the costs of fossil-fueled energy (including greenhouse gas costs), renewable energy to meet renewable portfolio standard (RPS) requirements, and resource adequacy capacity. SSJID additionally obtained an indicative pricing quote from Shell Energy to reflect current market pricing for electric power over the next five years. This full-requirements pricing quote includes all the cost elements list above, as well as the costs to manage load variability of up to 25% and the price risk assumed by the supplier over the five-year period.[74] MRW compared the bottoms-up cost assessment to the Shell Energy indicative pricing quote to estimate the cost increment included in the Shell Energy quote to cover the cost of the medium-term price risk and load variability risk borne by the supplier ("contracting adder"). MRW applied this contracting adder to the bottoms-up supply cost assessment in each year of the forecast.[75] MRW then added in transmission costs. The methodologies and input assumptions used for this power supply cost forecast are consistent with those used for the PG&E rate forecast. These are discussed further in Appendix B, "SSJID Power Supply Cost Forecast," and in Appendix C, "Forecast of PG&E's Rates."

In addition to power supply costs, SSJID will have costs to maintain and improve its distribution system, administrative costs to operate the retail electric utility, and in-lieu tax obligations to local municipalities:

---

[71] "Appraisal Summary Statement For South San Joaquin Irrigation District Acquisition of Electric Distribution System Facilities Owned by Pacific Gas & Electric Company," NewGen Strategies and Solutions, LLC, May 2016.

[72] MRW included the cost to finance the $20 million beginning cash requirement along with the SSJID separation costs. This is a conservatism of the model because, as noted in footnote 29, SSJID plans to use available SSJID unrestricted cash reserves to meet this cash requirement and does not plan to issue debt for this amount.

[73] Financing payments during the first two years are calculated as interest-only payments of $11.8 million per year; principal payments begin in 2019.

[74] *Indicative Power Supply Products & Pricing*, prepared for SSJID provided by Shell Energy North America, January 19, 2016.

[75] It is likely that SSJID would not have to contract for all of these services after it has provided service for several years and developed customer load information. As a result, SSJID may pay less for variability-related charges in the long-term. This potential cost reduction has not been incorporated into the MRW Analysis.

- For distribution system O&M costs and for A&G costs for operating the utility, MRW used a 2017 cost assessment developed on behalf of SSJID by Utility Financial Solutions.[76] For subsequent years, MRW escalated the 2017 costs with inflation and load growth.
- For distribution system capital expenditures, MRW developed a forecast of SSJID's costs based on a review of distribution system capital expenditures at existing northern California publicly owned utilities (POUs) (Table 4). This assessment is discussed further in Appendix D, "Forecast of SSJID's Distribution Capital Expenditures."
- For Payments in Lieu of Taxes, MRW estimated payments as 2.5% of rate revenues.

Table 4: SSJID 2016 Capital Expenditure Forecast from POU Capital Spending Data

	Average Distribution Capital Spending for Operating POU[77]		Corresponding Spending for SSJID Millions of Dollars		
	$/MWh	$/Customer	$/MWh basis	$/customer basis	Average
SMUD	$6.7	$146	$3.5	$4.9	$4.2
Modesto	$7.8	$169	$4.1	$5.7	$4.9
Alameda	$9.2	$102	$4.8	$3.4	$4.1
Redding	$6.2	$108	$3.2	$3.6	$3.4
Lodi	$5.9	$101	$3.1	$3.4	$3.2
Average	**$7.1**	**$125**	**$3.7**	**$4.2**	**$4.0**

Rate Forecast for SSJID Customers

SSJID's retail rates in the MRW Analysis are set at a 15% discount to PG&E's retail rates. MRW applied this 15% discount to all PG&E rates, including the already discounted CARE rates that are applicable to 31% of SSJID's residential usage.[78]

Long-Term PG&E Rate Forecast

To ensure a consistent and reliable financial analysis, MRW developed a 30-year forecast of PG&E rates using market prices for renewable energy purchases, market power purchases, greenhouse gas allowances, capacity, and transmission that are consistent with those used in the forecast of SSJID's supply costs. MRW additionally forecast the cost of PG&E's existing resource portfolio, adding in market purchases only when necessary to meet projected demand, and also forecast the cost to maintain PG&E's distribution system.

To develop this forecast, MRW examined the key cost drivers of each of PG&E's rate components, separately evaluating costs for renewable and non-renewable energy purchases, for PG&E-owned generation facilities, and for capacity purchases. MRW assumed that near-term changes to PG&E's generation portfolio would be driven primarily by increases to the RPS requirement in the years

[76] "Estimate Distribution and Administration Expense," Letter report from Mark Beauchamp, Utility Financial Solutions, to Don Geiger, SSJID counsel. June 16, 2016.
[77] Data collected from utility budget reports and financial reports or obtained from the utility. Analysis covers 2006-2014, with data for two of the utilities covering only the last six or seven years of this period.
[78] SSJID's CARE usage of 31% was calculated from 2013 billing data provided by PG&E.

leading up to 2030[79] and by the retirement of the Diablo Canyon units at the end of their current license periods in 2024 and 2025.[80] MRW additionally relied on the CPUC's modeling from the long-term procurement planning proceeding to forecast a need for capacity additions to meet resource adequacy requirements beginning in 2036.[81]

MRW developed price forecasts for PG&E's generation resources based on publicly available data and forecasts. Major inputs include NYMEX gas price forwards, a long-term natural gas price forecast from the U.S. EIA,[82] PG&E's January 2016 forecast of the cost of its current portfolio of renewable generation,[83] recent publicly reported market prices for renewable generation sales in California,[84] a National Renewable Energy Laboratory forecast of solar prices,[85] a CPUC report on recent Resource Adequacy capacity prices in northern California,[86] and a California Energy Commission forecast of the price to build a new power plant.[87] MRW additionally relied on a rate forecast from the CAISO to project transmission rate increases[88] and used historic PG&E distribution rate changes as a basis for estimating future distribution rate increases.[89] More information about this forecast is provided in Appendix C.

Over the 30-year period, MRW forecasts that PG&E's rates will escalate by an average of 3.1% per year in nominal dollars, which represents 1.0% annual average real escalation. This is just shy of PG&E's historic annual average rate growth of 3.2% since 2004.[90] As shown in Table **5**, escalation rates are expected to vary significantly over the course of this period. During the initial period from 2017-2023, rates are generally expected to increase by an average of 2.3% per year, which is close to the level of inflation. This rate growth is lower than PG&E's historic average growth rate due to the expiration of expensive power contracts that PG&E entered into when prices were higher than current market prices and, around 2020, the expiration of bond charges associated with power contracts entered into by the State on behalf of PG&E during the 2000-2001 energy crisis. With the closure of Diablo Canyon

---

[79] We maintained a 50% RPS requirement in each year starting in 2030.
[80] This assumption is consistent with the CPUC's proposed assumptions for long-term transmission planning. "Administrative Law Judge's Ruling Seeking Comment on Assumptions and Scenarios for use in the California Independent System Operator's 2016-17 Transmission Planning Process and Future Commission Proceedings," CPUC proceeding R.13-12-010, February 8, 2016, page 41.
[81] The CPUC's modeling finds that the system-wide load-resource balance will be nearly reached in 2035, with total system supply just 15.4% higher than system demand. This signifies that there is anticipated to be just enough capacity to meet customer demand plus resource adequacy requirements in 2035, which indicates a likely need for capacity additions beginning in 2036. CPUC. Scenario Tool 2014 in Excel v5, proceeding R.13-12-010, October 15, 2015. http://www.cpuc.ca.gov/General.aspx?id=6617
[82] U.S. Energy Information Administration. *Annual Energy Outlook 2016*, Table 13.
[83] PG&E. *Renewables Portfolio Standard 2015 Renewable Energy Procurement Plan (Final Version)*. January 14, 2016. Appendix D.
[84] Compiled from Energy NewsData's *California Energy Markets* publications in 2015 (*see* July 31, August 14, October 16, and October 30 issues) and on January 15, 2016.
[85] National Renewable Energy Laboratory. "Impact of Federal Tax Policy on Utility-Scale Solar Deployment Given Financing Interactions," September 28, 2015, Slide 16. http://www.nrel.gov/docs/fy16osti/65014.pdf
[86] CPUC. *2013-2014 Resource Adequacy Report Final*, August 5, 2015.
[87] California Energy Commission. *Estimated Cost of New Renewable and Fossil Generation in California*, March 2015, Table E-10.
[88] California Independent System Operator. 2014-2015 Transmission access charge model, October 26, 2015.
[89] PG&E Annual Electric True-Ups for 2016 (Advice Letter 4696 E-A) and 2006 (AL-2706-E-A), Table 2.
[90] PG&E's average rate was 12.73 cents per kWh in September 2004 and 18.23 cents per kWh in March 2016. PG&E Advice Letters 2533-E, page 3, and 4805-E-A, Attachment 2.

in 2024-2025, rates are expected to increase by only 0.7% per year. Beginning in 2026, with the Diablo Canyon closure already incorporated in rates, rates are expected to rebound to about the average PG&E growth rate (3.2%), and then in 2034, rate growth is expected to increase to 3.9% per year. This increase is due primarily to the need for new power plants to meet system-wide resource adequacy requirements and to higher natural gas price escalation, per the U.S. EIA's forecast.

Table 5: PG&E Annual Average Rate Changes

	Nominal Dollars	Constant Dollars
2017-2046	3.1%	1.0%
2017-2023	2.3%	0.2%
2024-2025	0.7%	-1.1%
2026-2033	3.2%	1.1%
2034-2046	3.9%	1.7%

On June 20, 2016, PG&E entered into an agreement with a number of environmental and labor organizations to retire the Diablo Canyon units at the under of their current license periods, consistent with the assumption used in MRW's analysis. The agreement additionally requires PG&E to replace the nuclear units with a portfolio of greenhouse gas-free resources (primarily energy efficiency and renewable power) and requires PG&E to a meet a 55% RPS commitment in each year from 2031-2045.[91] Given that this agreement was first made public as MRW's report was being finalized and that it remains subject to CPUC approval, MRW's analysis does not reflect the details of the agreement. Instead, MRW's analysis more conservatively replaces the nuclear power with lower-cost gas-fired power and requires PG&E to meet an RPS target of just 50% in each year starting 2030. All else equal, this agreement, if implemented, can be expected to increase PG&E's rates above the rates forecasted in MRW's analysis beginning in 2025. This is an additional conservatism of MRW's analysis.

Interest Payments and Revenue

MRW used SSJID-specific information to determine input assumptions for SSJID's financing costs and interest on cash balances.

MRW assumed that SSJID would finance the entire purchase price of PG&E's distribution assets (including severance costs) via SSJID-issued bonds. SSJID obtained an assessment of bond rates from Public Finance Resources.[92] The assessment, which was customized for the financial and risk characteristics of SSJID's proposed project, projected rates of 4.16% for taxable bonds and 3.24% for non-taxable bonds. MRW used this bond rate projection for the analysis.

---

[91] "Joint Proposal of Pacific Gas and Electric Company, Friends of the Earth, Natural Resources Defense Council, Environment California, International Brotherhood of Electrical Workers Local 1245, Coalition of California Utility Employees and Alliance for Nuclear Responsibility to Retire Diablo Canyon Nuclear Power Plant at Expiration of the Current Operating Licenses and Replace it with a Portfolio of GHG Free Resources," signed by the parties on June 30, 2016. http://www.pge.com/includes/docs/pdfs/safety/dcpp/JointProposal.pdf

[92] *SSJID Financing Analysis – Power Project*, prepared for SSJID by Public Finance Resources, January 2016.

MRW also evaluated the interest rate that SSJID can expect to receive on its cash balances. As of the end of November 2015, SSJID was receiving a combined interest rate of 0.73% on its cash and cash investments,[93] which was just over half a point above the Federal Funds Rate.[94] MRW assumed that SSJID's interest rate would continue to have this same relationship with the Federal Funds rate and used an EIA projection of the Federal Funds Rate to forecast SSJID's interest rate over the analysis period. This interest rate averages 3.8% over the analysis period.

Assessment of Greenhouse Gas Cap-and-Trade Program Impacts

California has had a mandatory greenhouse gas cap-and-trade program in place since 2012. MRW conducted a review of the impacts of the program for SSJID and incorporated these impacts into the MRW Analysis.

As discussed further in Appendix E, both PG&E and SSJID will be eligible to receive free greenhouse gas allowances, which can be monetized via auctions or bilateral deals and which are intended to offset the utilities' cap-and-trade program liabilities. These costs will be both indirect, via increases to the cost of purchased power, and for PG&E will also be direct, via the requirement to purchase allowances for utility-owned generation. The PG&E rate forecast described above and in Appendix C accounts for these cap-and-trade-related costs and for the rate reductions afforded by PG&E's free allowances.[95] The SSJID power price forecast described in Appendix B likewise accounts for these cap-and-trade-related costs (using the same allowance prices as used in the PG&E rate forecast) and also accounts for the revenue that SSJID will obtain from its free allowances. The assessment of SSJID's free allowances and the development of the allowance price forecasts are described in Appendix E.

SSJID Exit Fees to PG&E

PG&E charges exit fees to customers that depart its service for alternate service providers. For customers departing to a newly formed municipal utility, such as SSJID's retail service, exit fees vary depending on the size of the municipal utility. Given that SSJID load makes up less than 1% of PG&E's load, MRW assumed that SSJID will be considered a "small municipalization" by the CPUC and that SSJID customers will therefore not be responsible for the costs of power procured by PG&E after 2001. This is consistent with the District's legal opinion. Under this scenario, the exit fees owed by SSJID customers (which SSJID plans to pay) will be approximately $3.2 million per year through 2020 and $150,000-$300,000 per year after that.[96] MRW additionally considered a sensitivity scenario in which SSJID is held responsible for the cost of new PG&E generation (see "Higher Exit Fee Scenario" in Chapter 3).

---

[93] *SSJID November 2015 Investment Report*, presented to the Board of Directors on December 10, 2015.

[94] The Federal Funds Rate was 0.08% on November 30, 2015. Federal Reserve Bank of Saint Louis. FRED Economic Data. https://research.stlouisfed.org/fred2/series/FEDFUNDS

[95] MRW's forecast assumes that PG&E will receive additional free allowances upon the retirement of the Diablo Canyon units to cover the emissions associated with replacement power. However, in light of the agreement that PG&E entered into with environmental and labor groups to replace the Diablo Canyon power with greenhouse-gas free resources (see discussion above), it is less certain that PG&E will receive additional free allowances when the nuclear units are retired. All else equal, if PG&E does not receive additional free allowances, PG&E's rates will increase above the rates forecasted in MRW's analysis. Including these additional free allowances in the model is therefore another conservatism of the analysis.

[96] During the initial years of SSJID service, the exit fees include payment of a bond charge stemming from the 2000-2001 energy crisis; exit fees drop substantially after this charge expires, which is expected to happen around the start of 2021.

Chapter 3: Results of the MRW Analysis

In developing this financial analysis, MRW sought to provide a conservative base case forecast of the financial outcome of SSJID's retail electric plan using the assumptions described in Chapter 2. MRW also assessed alternative scenarios to evaluate the sensitivity of the results to possible conditions that would have a negative impact on the program's finances and also to a lower asset purchase price.

MRW Analysis Base Case

As noted above, the MRW Analysis base case takes into account current market and regulatory data related to electricity demand, PG&E rates, power prices, the greenhouse gas cap-and-trade program, CARE enrollment, and interest rates. Furthermore, it uses conservative forecasts of SSJID's capital costs, O&M costs, and payments in lieu of taxes and an estimated distribution asset purchase price of $200 million.

Under the base-case scenario, net cash flow in each year is positive, and the retail electric plan is entirely self-sufficient. This means that SSJID is able to meet all the financial obligations associated with its retail electric plan without providing equity contributions. Furthermore, revenues are found to exceed costs (including capital expenditures and debt service) by 10%-40% in each year, with annual revenue surpluses averaging more than 20% over the 30-year period. Annual net cash flows cumulate in the base case to provide a cash reserve balance of $980 million at the end of the 30-year analysis period.[97]

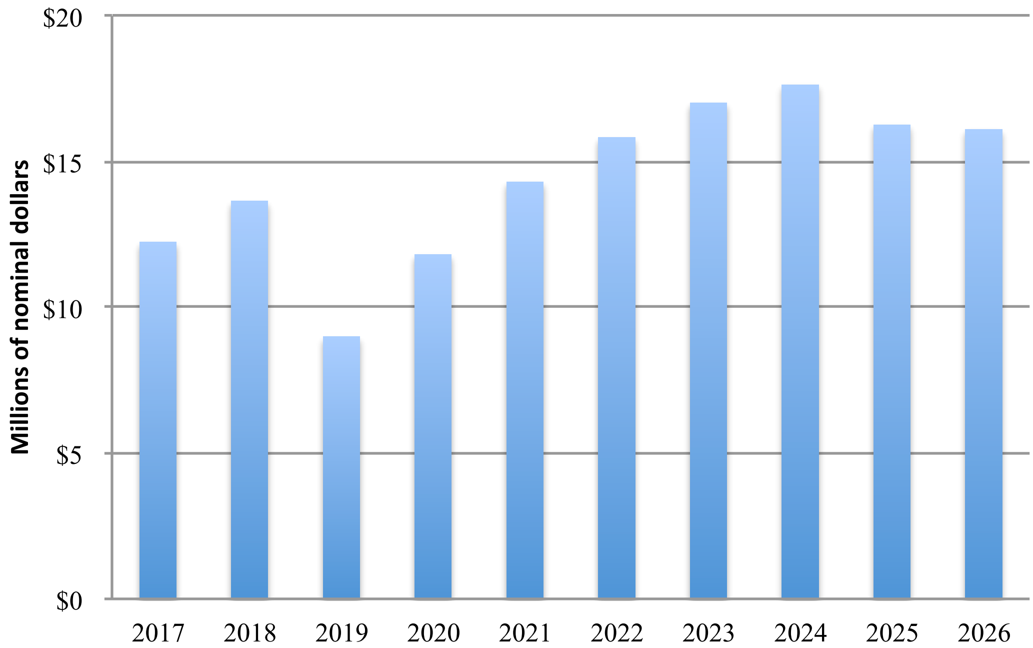
MRW modeled SSJID's revenues based on the assumption that SSJID provides a 15% discount off of PG&E's rates while maintaining a minimum of 120 days cash on-hand and a minimum debt service coverage ratio of 1.25.[98] In the base case, the projected minimum debt service coverage ratio over the analysis period is 1.8, and the projected minimum end-of-year cash on-hand balance is 192 days (in Year 1). At the end of the analysis period, the debt service coverage ratio is projected to be 6.4, and cash on-hand is projected to be sufficient to cover expenses for more than five years.

In the event that cash flow and reserve funds from the retail electric utility are unable to meet the financial requirements in a given year of the forecast, the model includes a provision for equity contributions to be made by SSJID. The MRW Analysis base case finds that the retail electric utility will be entirely self-funding and that no equity contributions will be needed.

Figure 5 and Figure 6 show that the retail electric utility is expected to generate positive net cash flow in each year of operations. Of particular note are the income-generation projections during the early years of the forecast because this is the period for which there is greater relative certainty. Annual net cash flows in each of the first ten years of operations are shown in Figure 5 below. These net cash flows average $14 million per year from 2017 through 2026, totaling $140 million over this period.

[97] The net cash reserve balance is calculated by subtracting cumulative equity contributions (if any) from the cash reserve balance at the end of the analysis period. In the base case, no equity contributions are required.
[98] SSJID reports that the required beginning cash reserves would be found in SSJID's surplus of unrestricted reserve funds from non-rate revenues. As noted in Chapter 2, to be conservative, MRW nonetheless included the beginning cash requirement in the bond issuance so as to evaluate the electric utility on a fully self-contained basis.

Figure 5: Annual Net Cash Flow During First Ten Years of Operations, Base Case



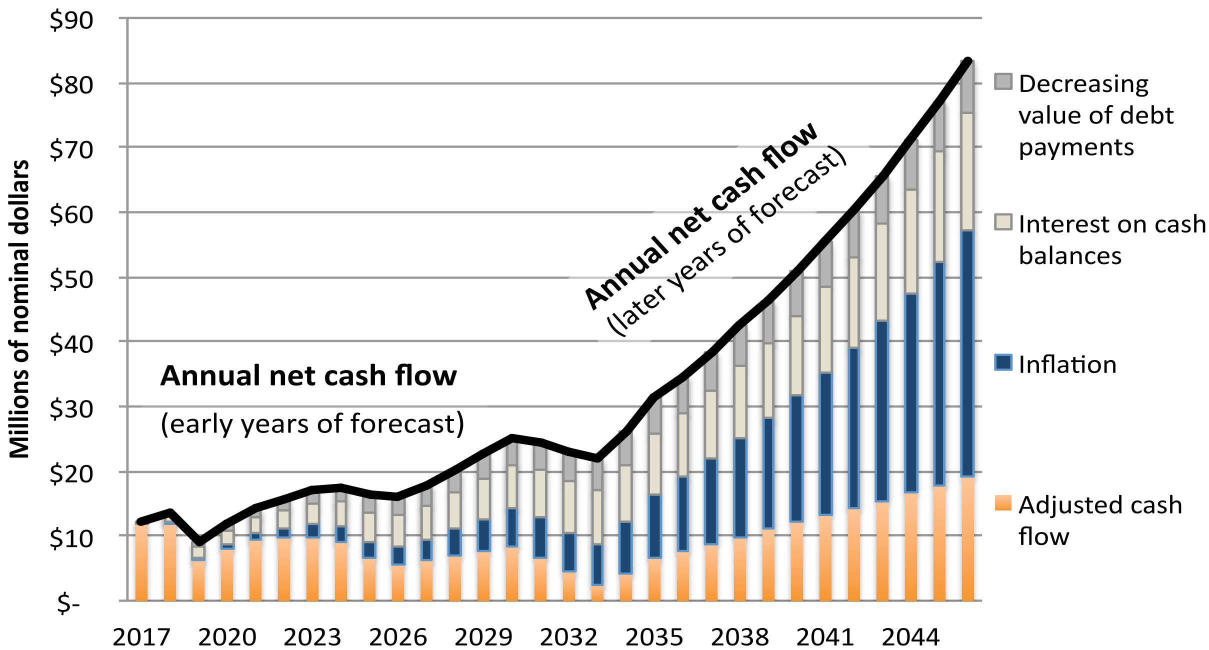
During years 11-30, projected net cash flows are significantly greater, averaging $42 million per year and increasing to $83 million in 2046 (see solid black line in Figure 6). Projected net cash flows increase with time in large part because (i) debt payments are constant in nominal terms (i.e., declining in real terms) throughout most of the forecast,[99] (ii) accumulating cash balances earn increasing amounts of interest, compounding their growth, and (iii) inflation. Of these factors, inflation is the most important: In constant 2017 dollars, the average annual net cash flow is $13 million in Years 1-10 and $27 million in Years 11-30.

The impacts of each of these factors on annual net cash flow are depicted in the vertical bars in Figure 6. The bottom set of bars, "Adjusted cash flow," shows the annual net cash flows without these three factors.[100] These adjusted annual cash flows fluctuate between $6 million and $12 million during the first ten years, averaging $9 million per year, and they fluctuate between $3 million and $19 million during the last 20 years, averaging $10 million per year. This demonstrates that (i) the large cash flows observed in the later years of the forecast, while strikingly higher than cash flows from earlier years, are consistent with the earlier-year results, and (ii) the apparent increase in net cash flow over time stems from the various effects of time on money. It is therefore reasonable to expect that cash flows would increase further after the forecast period given the cessation of debt payments after Year 30 and the continued effects of inflation and interest accruals.[101]

---

[99] Debt payments are lower during the first two years because they do not include any principle.
[100] These results were developed by (i) increasing debt payments with inflation, (ii) removing interest income, and (iii) converting cash flows to constant 2017 dollars.
[101] Interest would only accrue at the forecasted level if SSJID were to maintain the high cash balances that result from the base-case forecast. In practice, SSJID would be more likely to spend a share of the surplus on system

Figure 6: Annual Net Cash Flow During First 30 Years of Operations, Base Case



Stress Test Analyses

The base-case analysis was developed as a reasonable and conservative assessment of the possible outcome of SSJID's retail electric plan. In addition to the base-case analysis, MRW analyzed five stress-test cases that address the potentials for lower PG&E rates, higher SSJID operational costs, higher gas prices, higher exit fees for SSJID customers, and higher renewable power prices. Each of these scenarios is described below.

Lower PG&E Rates

MRW examined the sensitivity of the financial analysis to reductions in PG&E's costs associated with operations, maintenance, capital improvements, and administration of PG&E's distribution and generation assets, resulting in lower PG&E retail rates. In the base case, MRW assumes that PG&E's costs for these activities increase consistent with PG&E's annual average cost increases over the last ten years. For this stress test, MRW assumes that PG&E's annual cost increases are 15% below these historic levels.

PG&E's annual average rate increase in this scenario is just 1.7% for the first 10 years and 2.7% for the full 30-year analysis period. This is much lower than PG&E's annual average rate increase over the last 12 years of 3.2%.[102] This scenario therefore represents a significant departure from historic PG&E rate

improvements and/or to reduce customer rates. As this analysis is not intended to serve as a financial plan for SSJID's retail electric service, but instead as an evaluation of the feasibility of SSJID's plan, SSJID's future decisions with regard to how to spend surplus revenue are immaterial to the analysis.

[102] PG&E's average rate was 12.73 cents per kWh in September 2004 and 18.23 cents per kWh in March 2016. PG&E Advice Letters 2533-E, page 3, and 4805-E-A, Attachment 2.

patterns, and it would likely require substantial changes to PG&E's operational practices for this scenario to unfold.

These lower PG&E rates were found to reduce SSJID's 30-year net cash flow by $420 million relative to the base case scenario. SSJID's plan was found to remain entirely self-sufficient under this stress condition with healthy surpluses over both the 10-year ($120 million) and 30-year ($560 million) analysis periods.

Higher SSJID Operational Costs
MRW examined the sensitivity of the financial analysis to increases in SSJID costs associated with operations, maintenance, capital expenditures, and administration of the retail electric utility by creating a stress case in which these costs are 20% higher than in the base case.

These higher operational costs were found to reduce SSJID's 30-year net cash flow by $300 million relative to the base case scenario. SSJID's plan was found to remain entirely self-sufficient under this stress condition, with healthy surpluses over both the 10-year ($90 million) and 30-year ($680 million) analysis periods.

Higher Natural Gas Prices
If market prices for natural gas increase above current expectations, SSJID is likely to face higher power costs from suppliers, and PG&E's retail rates are likely to rise. Since the nuclear and hydroelectric capacity in PG&E's resource mix makes PG&E less sensitive than SSJID to changes in natural gas prices, the increase in SSJID's procurement costs due to higher natural gas prices is likely to be only partially offset by an increase in PG&E's rates as long as the Diablo Canyon nuclear plant continues to operate and PG&E's hydroelectric plants are productive.

To assess the risk of higher natural gas prices for the SSJID plan, MRW evaluated the plan using the gas price forecast developed by the U.S. Energy Information Administration for the *Annual Energy Outlook 2016.* From 2017-2019, this forecast is 13%-36% higher than the base case natural gas price forecast, and starting in 2020, it is an average of 45% higher than the base case forecast.[103]

These higher natural gas prices were found to reduce SSJID's 30-year net cash flow by $200 million relative to the base case scenario. SSJID's plan was found to remain entirely self-sufficient under this stress condition, with healthy surpluses over both the 10-year ($100 million) and 30-year ($780 million) analysis periods.

Higher Exit Fee Scenario
As noted earlier, the base case assumes that SSJID will be categorized as a "small municipalization" and that SSJID customers will therefore be exempt from paying exit fees associated with the cost of recent PG&E power procurement. MRW additionally examined the effects of a scenario in which SSJID customers do not receive this exemption.[104] MRW assumed for this scenario that PG&E would enter into an agreement with SSJID for reduced exit fee payments in return for a lump-sum payment from SSJID in 2017. (As noted in Appendix G, PG&E has previously entered into such an agreement with

[103] The base case forecast uses market price expectations from NYMEX natural gas trades through 2028 and annual escalation from the *Annual Energy Outlook 2016* forecast for subsequent years.
[104] While SSJID does make up a small share of PG&E's load, the CPUC criteria for determining which entities should be considered small municipalizations are not based solely on system size, and PG&E and SSJID disagree as to whether SSJID would be considered a small municipalization. See Appendix F for further discussion.

Merced Irrigation District and Modesto Irrigation District and is likely to do so with SSJID, as well, to reduce the risk of non-payment.[105])

This scenario increases exit fee payments from $18 million spread out over 30 years to $69 million in 2017 (with no subsequent payments).[106] MRW assumed that SSJID would include the cost of this lump-sum payment in the bond issuance and finance it over a 30-year period. This results in a reduction to the 30-year net cash flow of $170 million relative to the base case scenario. SSJID's plan was found to remain entirely self-sufficient under this scenario, with healthy surpluses over both the 10-year ($120 million) and 30-year ($810 million) analysis periods.

Higher Renewable Power Prices
If market prices for renewable power increase above current expectations, SSJID is likely to be affected more strongly than PG&E because PG&E has significant amounts of renewable resources under long-term contract. MRW considered a scenario in which average renewable power prices are 0-10% higher than in the base case scenario through 2021, about 20% higher in 2021 and 2022, and 30% higher after 2022.[107]

These higher renewable power prices were found to reduce SSJID's 30-year net cash flow by $130 million relative to the base case scenario. SSJID's plan was found to remain entirely self-sufficient under this stress condition, with healthy surpluses over both the 10-year ($120 million) and 30-year ($850 million) analysis periods.

Extreme Stress Test
In order to evaluate the robustness of the SSJID financial plan, MRW implemented an Extreme Stress Test that combines the other five stress tests (i.e., lower PG&E rates, higher SSJID operational costs, higher gas prices, higher exit fees, and higher renewable power prices). Under this Extreme Stress Test, SSJID's annual net cash flow is negative from 2019-2043, and the project is not financially viable without outside equity contributions of $30 million over the first ten years and $155 million over the first 30 years.[108] The 30-year net cash flow in this scenario is -$110 million, which is $1,090 million less than in the base case scenario.

---

[105] PG&E provided a 40% discount to Merced Irrigation District and Modesto Irrigation District off the net present value of expected costs. (See CPUC decision D.10-11-011 in proceeding A.09-06-023, page 10.) MRW applied this same discount to SSJID.
[106] Exit fee costs increase in this scenario primarily due to the addition of the Power Charge Indifference Adjustment ("PCIA"), which is intended to pay for the above-market costs of generation resources that PG&E acquired, or committed to acquire, prior to the customer's departure from PG&E service. ("Small municipalization" customers are exempt from this charge.) To forecast PCIA costs for this scenario, MRW evaluated expected changes to PG&E's PCIA-eligible resources and to a market-based price benchmark in each year of the forecast, using assumptions consistent with those used in the forecast of PG&E's retail rates and following the CPUC-approved methodology.
[107] These increases are associated with the planned expiration of federal renewable energy tax credits. As discussed in Appendix B, the base case scenario assumes that underlying renewable development cost reductions will offset these increases.
[108] These contributions would be met from the District's available unrestricted cash reserves from non-rate revenue or from other sources of non-rate revenue.

Summary of Scenario Results

Figure 7 summarizes the results of the scenario analysis by showing the cumulative net cash flows from each scenario on an annual basis. Ending cash surpluses range from $980 million in the base case (top line) to -$110 million in the Extreme Stress Test (bottom line). Results of the other scenarios are shown in the dashed lines between these scenarios.

Figure 7: Cumulative Net Cash Flow, all scenarios

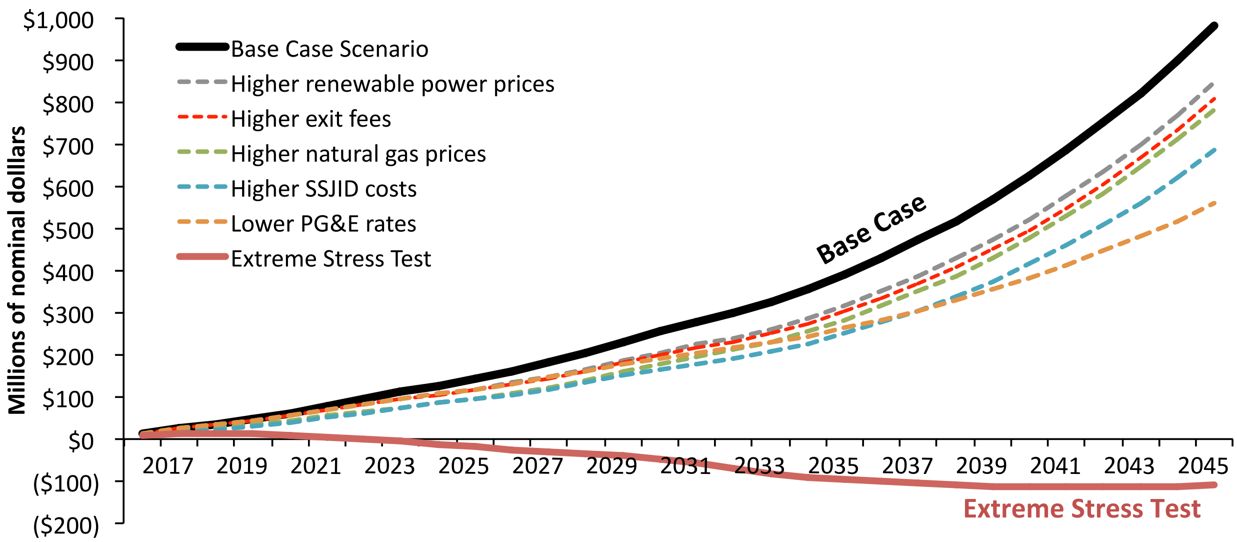
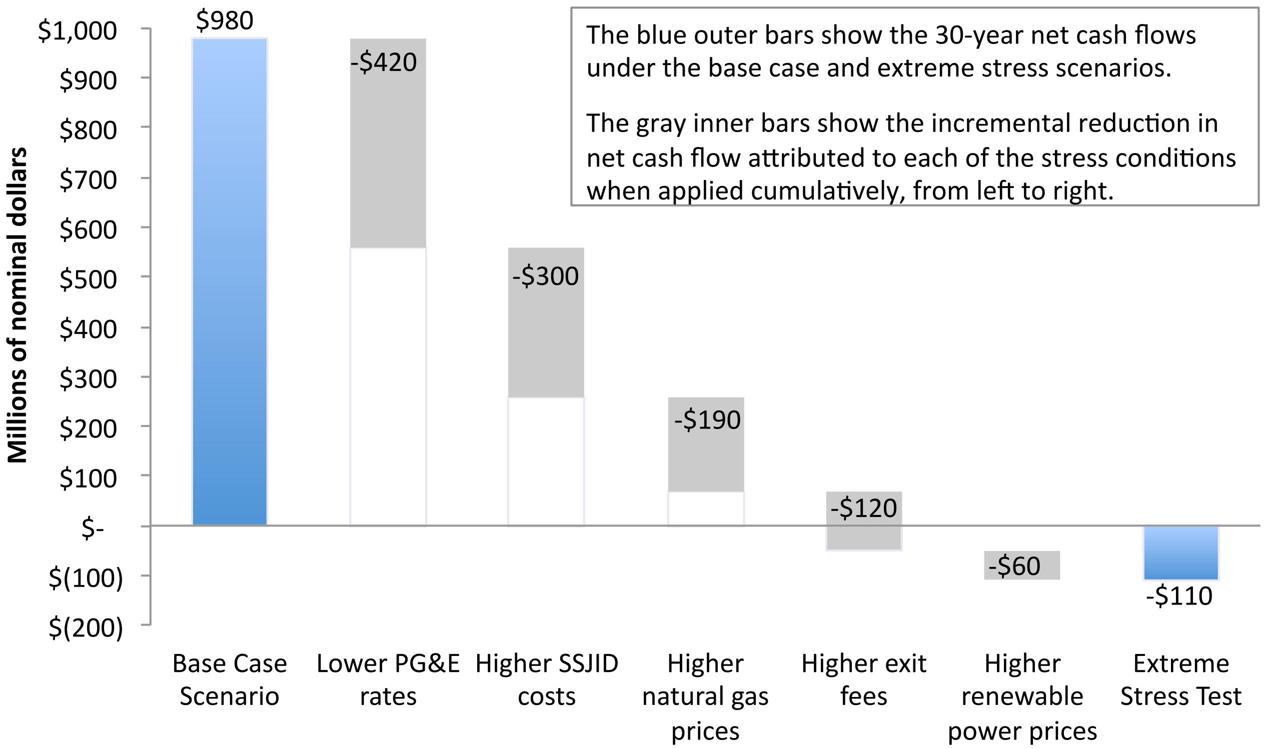


Figure 8 illustrates the cumulative effect of each of the stress conditions when they are applied together. The leftmost bar shows the 30-year net cash flow in the base case, and the rightmost bar shows the 30-year net cash flow in the Extreme Stress Test scenario. The gray bars in between show the path between these two scenarios, with each bar representing the impact of an individual stress scenario. For example, the second bar from the left indicates that the lower PG&E rates reduce the 30-year net cash flow by $420 million relative to the base case scenario, and the subsequent bar indicates that adding on the higher SSJID costs (while keeping the lower PG&E rates) reduces the 30-year net cash flow by an additional $300 million. Given interactions between scenarios, the amounts indicated by these bars are in some cases different from the scenario impacts noted in the discussion above.[109]

It is evident from Figure 8 that, of the five stress conditions considered, the lower PG&E rates and higher SSJID costs have the largest impacts, and the higher renewable power prices have the smallest impact. It can also be seen that the 30-year net cash flows do not become negative until at least four of the stress conditions are considered together.

[109] For example, the impact on the 30-year net cash flow from the Higher Exit Fee scenario is described above as a reduction of $170 million relative to the base case, but is shown in Figure 8 as a reduction of $120 million from the prior scenario. The difference in the impact amount arises because the Higher Exit Fee scenario in Figure 8 is applied together with the Higher Natural Gas Price scenario, and higher natural gas prices reduce the PCIA exit fees, blunting the impact of the Higher Exit Fee scenario.

Figure 8: Scenario Results: 30-Year Net Cash Flows[110]



Impact of Distribution Asset Acquisition Price

The analyses discussed above use a price of $200 million for SSJID to purchase the PG&E distribution assets that are in SSJID's service area. This is more than double SSJID's appraised value for these assets.[111] If SSJID were instead to purchase the assets at the appraised value of $92.7 million, with the separation and impairment charges to PG&E also set at the appraised value ($23.3 million), the financial results of SSJID's plan would be significantly more favorable:

- Under base case assumptions: $225 million in total net cash flow during the first ten years of service and $1.4 billion over the first 30 years; and
- Under the Extreme Stress Test: $60 million in total net cash flow during the first ten years of service and nearly $165 million over the first 30 years.

No equity contributions are required under any of the scenarios when this lower asset acquisition price is used.

[110] Given interactions between scenarios, the amounts indicated by these bars are in some cases different from the scenario impacts noted in the discussion above, where stress conditions were applied individually (see footnote 109).

[111] "Appraisal Summary Statement For South San Joaquin Irrigation District Acquisition of Electric Distribution System Facilities Owned by Pacific Gas & Electric Company," NewGen Strategies and Solutions, LLC, May 2016.

Additional Uncertainties

In addition to the uncertainties addressed in the stress tests, there are additional regulatory uncertainties that have not been explicitly considered. For example, California's post-2020 renewable portfolio standards are currently under development. While the overall requirement for 50% renewables by 2030 is set, the phasing in of that requirements and rule changes associated with meeting that requirement are still being evaluated. Similarly, there remains uncertainty with regard to post-2020 greenhouse gas prices and allowance allocations. In addition, the rules regarding exit fees for former-PG&E customers are currently being re-evaluated. Given the limited information and the complexities involved, MRW did not attempt to evaluate the implications of potential changes to these regulatory requirements and potential utility and market responses to these changes. Many of these changes would affect both PG&E and SSJID, blunting the net impact on SSJID's financial plan, and some, such as exit fee reform, may be beneficial to SSJID. Overall, SSJID expects that these uncertainties fall within the window of uncertainties considered in the stress test scenarios.

MRW also did not present a scenario that considers the retirement of PG&E's hydroelectric power plants. Based on current market prices, this scenario would further increase the cost-effectiveness of SSJID's retail electric plan by increasing PG&E's rates relative to those in the base case. For the purpose of this feasibility assessment, this scenario is therefore not considered a risk and does not need to be evaluated.

Chapter 4: Opinion Regarding Financial Feasibility

The MRW Analysis base case represents a reasonable, but conservative, forecast. On the revenue side, most of the inputs to the PG&E rate forecast were obtained from PG&E regulatory filings or public market data, and the annual average rate increase projected for the 30-year analysis period is just shy of PG&E's long-term annual average historic rate increase. On the cost side, MRW used market price assumptions that underlie the PG&E rate forecast to develop SSJID's cost of power forecast, and the resulting forecast is consistent with a Shell Energy indicative pricing quote obtained by SSJID. MRW relied on other SSJID experts to estimate the cost to operate the utility and the value of PG&E's distribution assets. To be conservative, in the base case MRW used a $200 million purchase price for PG&E's distribution assets, which is more than double this appraised value. In additional conservatisms, MRW included the $20 million beginning cash requirement in the bond issuance in order to evaluate the electric plan on a fully self-contained basis even though SSJID plans to use available SSJID unrestricted cash reserves to meet this requirement and does not plan to issue debt for this amount. MRW also assumed that the Diablo Canyon nuclear plant would be replaced with least-cost power and that PG&E would meet a 50% RPS requirement in each year beginning 2030, whereas a recent agreement between PG&E and labor and environmental groups, if approved by the CPUC, would require PG&E to use greenhouse gas-free resources to replace Diablo Canyon power and to meet a 55% RPS requirement for the 2031-2045 period.

Under this base-case scenario, no equity contributions are needed from SSJID, the utility's cash flow is positive in each year of operation, and annual revenues exceed annual costs (including the cost of debt) by an average of more than 20%. Barring additional spending or further rate discounts, the utility amasses nearly a billion dollars in surplus revenue over the course of the 30-year planning period.

In addition to the conservative base-case scenario, MRW additionally considered stress scenarios with lower rate revenue (*i.e.*, lower PG&E rates), higher SSJID operational costs, higher power prices, and higher PG&E exit fees. Under any one of these stress conditions, the program is found to remain self-sufficient over both the 10-year and 30-year analysis periods with healthy net cash flows and no equity contributions required. When all the stress scenarios are considered together ("Extreme Stress Test"), annual net cash flow is negative in most years, and equity contributions averaging $5 million per year are needed to maintain operations over the 30-year forecast period. While this Extreme Stress Test is not necessarily a worst-case scenario, it is far from the expected scenario given that it applies a number of significant stressors to an already-conservative base case and does so in each year of the analysis. Notably, SSJID's retail electric plan generally remains self-sustaining when a few of the stress conditions are applied together; it is only when at least four stress conditions are applied in combination that meaningful equity contributions may be required and negative cash flows accrue.[112]

These stress scenarios, considered together with the base case result, indicate the likelihood of a healthy program as long as the purchase price does not greatly exceed $200 million. This is not a guarantee of project viability, as illustrated by the Extreme Stress Test result, but it is an indication that the program is robust under a wide range of potential circumstances, including circumstances that are far more negative than would be expected. With a purchase price at the NewGen appraisal

[112] With three stress conditions considered in combination, total equity contributions of up to $8 million may be required over the 30-year analysis period; however, these contributions are needed only in a few years at most and, when needed, can be repaid with surplus revenues from subsequent years.

value of $92.7 million, base-case revenue surpluses increase to $1.4 billion over 30 years, and the utility's ability to weather negative circumstances increases further, with the program showing positive net cash flows even under the Extreme Stress Test. Acquiring PG&E's assets at the a price near the NewGen appraisal value would therefore provide meaningful risk reduction benefits.

Prior to making a decision as to whether to proceed with the retail electric utility, it would be beneficial to re-evaluate the program risk given the final purchase price. It would additionally be beneficial to have a bottoms-up assessment of SSJID's operational costs and, if possible, guidance from the CPUC as to whether SSJID would be considered a large municipalization. Other cost and revenue elements should be reevaluated with the most recent market and regulatory information available, but will ultimately remain uncertain throughout the 30-year analysis period.

In conclusion, with a purchase price of up to $200 million, SSJID retail electric plan appears robust. Under the conservative base case assumptions, SSJID would have significant funds available to invest in power supplies in order to reduce long-term utility costs and increase cost certainty. SSJID would also have the option to reduce customer rates by even more than the targeted 15% discount or to invest in energy storage, electric vehicle charging, or other improvements that would enhance customer service and/or benefit the electrical system. While these base case conditions might not ensue, within a few years of operations, SSJID would know its exit fee obligation and would have a stronger sense of its ongoing costs. At that point, SSJID would be well positioned to ascertain how much it could spend on further rate reductions or utility investments while retaining sufficient reserve funds to cover unexpected cost increases or revenue shortfalls. By deferring major spending decisions until SSJID's costs are better known and by maintaining sufficient reserve funds, SSJID could prudently manage ongoing risks while building a strong, customer-serving utility.

Appendix A: Key Assumptions and Results of the MRW Analysis[113]

Base Case Scenario

	SSJID Cost of Power, $/MWh	Natural Gas Price (delivered), $/MMBtu	Greenhouse Gas Price, $/tonne CO2	SSJID Capacity Costs, $/kW-year[114]	PG&E Capacity Costs, $/kW-year	SSJID Sales, MWh
2017	67.83	4.12	14.07	34.15	34.15	525,325
2018	69.13	4.10	15.14	34.83	34.83	527,165
2019	70.76	4.16	16.31	35.52	35.52	529,571
2020	73.20	4.28	17.56	36.28	36.28	533,008
2021	75.37	4.43	18.91	37.14	37.14	536,220
2022	77.62	4.59	20.34	37.98	37.98	539,248
2023	80.24	4.76	21.83	38.72	38.72	542,415
2024	82.88	4.93	23.40	39.45	39.45	544,111
2025	85.35	5.09	25.08	40.20	40.20	545,118
2026	88.15	5.27	26.90	40.99	40.99	546,061
2027	91.02	5.45	28.86	41.80	41.80	548,307
2028	94.12	5.65	30.96	42.64	42.64	550,564
2029	97.09	5.80	33.23	43.52	43.52	552,833
2030	100.07	5.93	35.68	44.43	44.43	555,114
2031	107.69	6.02	38.33	63.50	63.50	557,407
2032	117.95	6.17	41.20	90.74	90.74	559,712
2033	128.39	6.26	44.30	118.93	129.67	562,028
2034	131.95	6.38	47.63	121.59	185.31	564,357
2035	135.57	6.48	51.19	124.34	264.82	566,699
2036	139.36	6.62	55.01	127.09	270.69	569,052
2037	143.19	6.70	59.10	129.91	276.69	571,418
2038	147.08	6.79	63.54	132.77	282.78	573,796
2039	151.50	7.00	68.27	135.65	288.91	576,187
2040	155.88	7.17	73.35	138.55	295.10	578,590
2041	161.21	7.30	78.82	141.59	301.56	581,006
2042	166.80	7.44	84.69	144.68	308.16	583,435
2043	172.66	7.58	91.01	147.85	314.90	585,876
2044	178.79	7.73	97.80	151.09	321.79	588,330
2045	185.24	7.88	105.09	154.39	328.84	590,797
2046	192.01	8.03	112.93	157.77	336.04	593,277

[113] All results are shown in nominal dollars.
[114] As discussed in Appendix B and Appendix C, beginning in 2033, SSJID's capacity cost is based on the levelized fixed cost of a new advanced combustion turbine developed by a publicly owned utility, whereas PG&E's capacity cost is based on the levelized fixed cost of a new advanced combustion turbine developed by an investor-owned utility.

Extreme Stress Test

	SSJID Cost of Power, $/MWh	Natural Gas Price (delivered), $/MMBtu	Greenhouse Gas Price, $/tonne CO2	SSJID Capacity Costs, $/kW-year[115]	PG&E Capacity Costs, $/kW-year	SSJID Sales, MWh
2017	69.87	4.50	14.07	34.15	34.15	525,325
2018	75.16	5.15	15.14	34.83	34.83	527,165
2019	79.60	5.68	16.31	35.52	35.52	529,571
2020	84.93	6.27	17.56	36.28	36.28	533,008
2021	88.14	6.29	18.91	37.14	37.14	536,220
2022	90.96	6.46	20.34	37.98	37.98	539,248
2023	97.32	7.05	21.83	38.72	38.72	542,415
2024	101.28	7.49	23.40	39.45	39.45	544,111
2025	104.31	7.78	25.08	40.20	40.20	545,118
2026	106.41	7.77	26.90	40.99	40.99	546,061
2027	109.12	7.88	28.86	41.80	41.80	548,307
2028	112.49	8.10	30.96	42.64	42.64	550,564
2029	115.93	8.33	33.23	43.52	43.52	552,833
2030	119.32	8.51	35.68	44.43	44.43	555,114
2031	127.28	8.64	38.33	63.50	63.50	557,407
2032	138.03	8.86	41.20	90.74	90.74	559,712
2033	148.81	8.98	44.30	118.93	129.67	562,028
2034	152.79	9.15	47.63	121.59	185.31	564,357
2035	156.79	9.29	51.19	124.34	264.82	566,699
2036	161.01	9.47	55.01	127.09	270.69	569,052
2037	165.21	9.58	59.10	129.91	276.69	571,418
2038	169.45	9.70	63.54	132.77	282.78	573,796
2039	174.50	10.02	68.27	135.65	288.91	576,187
2040	179.40	10.25	73.35	138.55	295.10	578,590
2041	185.45	10.45	78.82	141.59	301.56	581,006
2042	191.77	10.64	84.69	144.68	308.16	583,435
2043	198.38	10.84	91.01	147.85	314.90	585,876
2044	205.30	11.05	97.80	151.09	321.79	588,330
2045	212.55	11.25	105.09	154.39	328.84	590,797
2046	220.15	11.46	112.93	157.77	336.04	593,277

[115] As discussed in Appendix B and Appendix C, beginning in 2033, SSJID's capacity cost is based on the levelized fixed cost of a new advanced combustion turbine developed by a publicly owned utility, whereas PG&E's capacity cost is based on the levelized fixed cost of a new advanced combustion turbine developed by an investor-owned utility.

PG&E Rates, cents per kWh
Base Case Scenario

	Industrial	Small Commercial	Large Commercial	Residential	Agriculture	Street Lighting
2017	17.14	22.85	19.93	19.72	23.00	21.54
2018	17.46	23.36	20.35	20.07	23.51	22.12
2019	17.73	23.79	20.69	20.37	23.93	22.53
2020	18.52	24.86	21.62	21.25	24.98	23.54
2021	18.57	25.25	21.79	21.43	25.32	23.85
2022	19.10	26.04	22.46	22.06	26.14	24.67
2023	19.55	26.75	23.03	22.64	26.89	25.43
2024	19.83	27.31	23.42	23.07	27.49	26.07
2025	19.67	27.43	23.35	23.01	27.68	26.34
2026	19.84	27.91	23.64	23.31	28.22	26.93
2027	20.47	28.88	24.43	24.12	29.21	27.91
2028	21.18	29.95	25.30	25.02	30.30	28.99
2029	21.87	31.00	26.16	25.91	31.38	30.06
2030	22.60	32.12	27.07	26.85	32.53	31.19
2031	23.23	33.13	27.85	27.62	33.58	32.24
2032	24.02	34.33	28.81	28.54	34.83	33.47
2033	24.97	35.71	29.94	29.62	36.25	34.86
2034	26.12	37.32	31.30	30.88	37.89	36.45
2035	27.52	39.21	32.93	32.38	39.79	38.28
2036	28.46	40.63	34.06	33.45	41.26	39.74
2037	29.47	42.15	35.28	34.60	42.83	41.28
2038	30.48	43.68	36.50	35.74	44.42	42.86
2039	31.57	45.32	37.82	36.96	46.12	44.53
2040	32.70	47.02	39.19	38.22	47.88	46.28
2041	33.93	48.86	40.67	39.59	49.78	48.15
2042	35.24	50.79	42.23	41.01	51.77	50.11
2043	36.60	52.81	43.87	42.49	53.86	52.17
2044	38.04	54.93	45.59	44.04	56.05	54.33
2045	39.55	57.15	47.39	45.65	58.34	56.58
2046	41.14	59.48	49.29	47.33	60.74	58.95

PG&E Rates, cents per kWh
Extreme Stress Test[116]

	Industrial	Small Commercial	Large Commercial	Residential	Agriculture	Street Lighting
2017	17.06	22.73	19.83	19.62	22.88	21.42
2018	17.47	23.29	20.34	20.02	23.42	22.00
2019	17.77	23.72	20.71	20.32	23.83	22.40
2020	18.54	24.74	21.61	21.15	24.81	23.33
2021	18.50	24.98	21.67	21.20	25.00	23.49
2022	19.01	25.71	22.30	21.79	25.74	24.22
2023	19.50	26.41	22.91	22.35	26.47	24.94
2024	19.86	27.01	23.38	22.83	27.08	25.57
2025	20.05	27.45	23.67	23.05	27.55	26.07
2026	20.31	27.96	24.04	23.38	28.09	26.63
2027	20.84	28.75	24.70	24.04	28.90	27.43
2028	21.47	29.67	25.48	24.80	29.82	28.32
2029	22.11	30.60	26.26	25.58	30.76	29.23
2030	22.76	31.56	27.07	26.40	31.72	30.17
2031	23.38	32.48	27.82	27.09	32.67	31.10
2032	24.16	33.58	28.75	27.92	33.78	32.17
2033	25.06	34.81	29.80	28.87	35.02	33.37
2034	26.14	36.25	31.06	29.99	36.46	34.74
2035	27.45	37.93	32.57	31.32	38.14	36.33
2036	28.29	39.13	33.57	32.20	39.36	37.52
2037	29.18	40.40	34.62	33.13	40.65	38.76
2038	30.04	41.65	35.66	34.03	41.93	40.01
2039	30.99	43.01	36.79	35.01	43.31	41.35
2040	31.96	44.40	37.95	36.00	44.73	42.73
2041	33.02	45.90	39.21	37.07	46.25	44.21
2042	34.13	47.46	40.53	38.18	47.84	45.75
2043	35.29	49.09	41.90	39.33	49.50	47.35
2044	36.50	50.79	43.33	40.51	51.22	49.02
2045	37.77	52.56	44.83	41.73	53.02	50.76
2046	39.09	54.41	46.39	43.00	54.89	52.57

[116] This scenario includes some assumptions that reduce PG&E rates relative to the base case scenario, which results in less rate revenue for SSJID (*e.g.,* lower PG&E operational costs). It also includes some assumptions that increase both PG&E rates and SSJID costs relative to the base case scenario, resulting in a net cost increase for SSJID (*e.g., higher market power prices)*.

Financing Assumptions

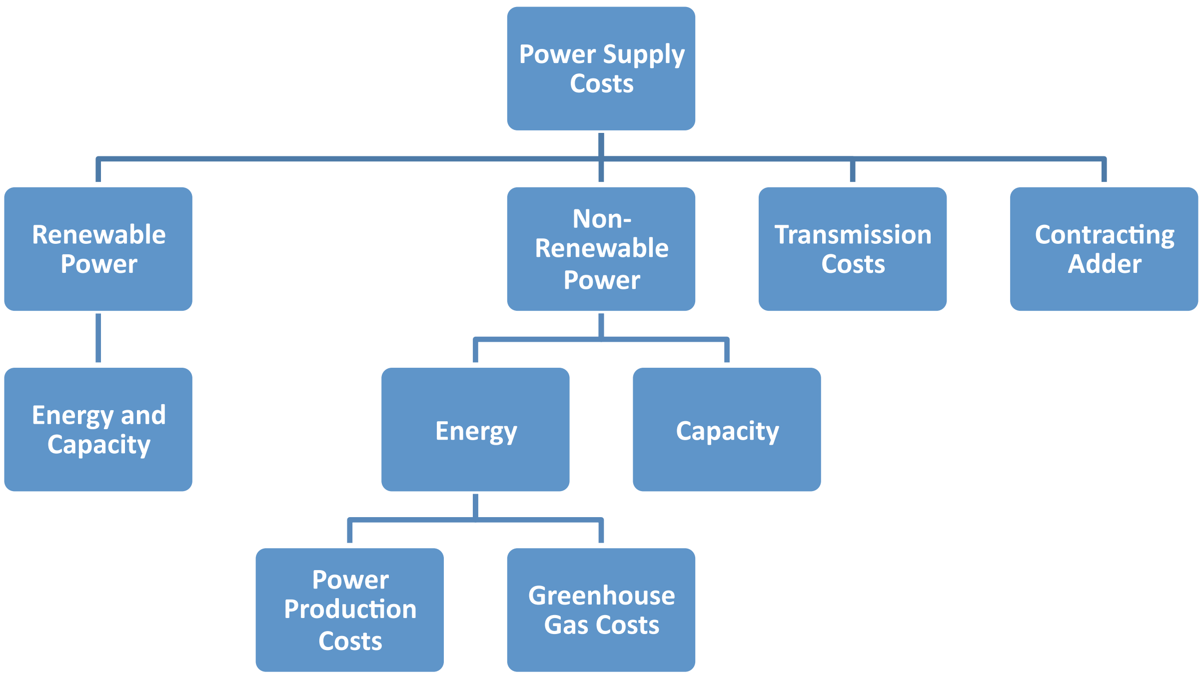
	Base Case Scenario	Extreme Stress Test
Bond Rates		
Interest on Taxable Bonds	4.16%	4.16%
Interest on Non-Taxable Bonds	3.24%	3.24%
Distribution Asset Costs ($ millions)		
Distribution Assets Purchase Price	$200	$200
Separation, Impairment, and Transaction Costs[117]	$97	$162
Total Cost to Acquire Distribution Assets	$297	$362
Funding Sources ($ millions)		
Equity	$0	$0
Taxable Bond	$237	$302
Non-Taxable Bond	$60	$60
Total	$297	$362

[117] Includes beginning cash for the reserve fund and, in the Extreme Stress Test scenario, also includes the lump-sum exit fee payment.

Appendix B: SSJID Power Supply Cost Forecast

MRW developed a bottoms-up calculation of SSJID's power supply costs, separately forecasting the cost of each power supply element. These elements are renewable power (both energy and capacity), non-renewable energy (including power production costs and greenhouse gas costs), non-renewable capacity, and the transmission of power to SSJID's distribution grid. We also included a price adder to account for the cost of obtaining a full requirements contract that places medium-term price risk and load variability risk on the supplier (Figure 9).

Figure 9: Power Supply Cost Forecast



Renewable Power Cost Forecast

MRW developed a forecast of renewable generation prices starting from an assessment of the current market price for renewable power.[118] For the current market price, MRW relied on wind and solar contract prices reported by California municipal utilities and Community Choice

[118] MRW relied exclusively on prices from municipal utilities and CCAs for the market price assessment because there is limited public data available on invest-owned utility (IOU) contract prices over this period. In addition, the available data show higher prices for IOU contracts approved in 2015 than for contracts signed with public entities during this same year, which may indicate that the IOU prices are not applicable to SSJID. By using prices from public entity contracts for both the SSJID and PG&E renewable power cost forecasts, the MRW forecast may underestimate PG&E's renewable power costs, which makes the financial analysis more conservative (by reducing the revenue from SSJID's customers).

Aggregation (CCA) entities in 2015 and early 2016, finding an average price of $52 per MWh for these contracts.[119]

To forecast the future price of renewable purchases, MRW considered a number of factors:

- Researchers from the National Renewable Energy Laboratory (NREL) and Lawrence Berkeley National Laboratory (LBNL) developed a set of forecasts of utility-scale solar costs based on market data and preliminary data from other research efforts.[120] Their base case forecast predicts a 3.6% annual decline in utility-scale solar capital costs on a nominal basis, from $1,914/kW-DC in 2016 to $1,652/kW-DC in 2020, with costs then remaining roughly constant in nominal dollars through 2030.[121] Additional scenarios predict even steeper price declines, with the most aggressive scenario predicting an 11% annual nominal decline through 2020, with increases at the rate of inflation after that.
- The federal Investment Tax Credit (ITC), which is commonly used by solar developers, is scheduled to remain at its current level of 30% through 2019 and then to fall over three years to 10%, where it is to remain.[122] The federal Production Tax Credit, which is commonly used by wind developers, is scheduled to be reduced for facilities commencing construction in 2017-2019 and eliminated for subsequent construction.[123] The loss of these credits would put upward pressure on prices.
- NREL and LBNL researchers predicted in 2015 that the cost increase associated with an ITC reduction would be roughly offset by other cost reductions even if the full reduction to 10% were implemented by 2018, rather than spread out through 2022 as currently planned.[124]
- The production tax credit has been extended six times from 2000-2014,[125] and the solar ITC has been extended three times since 2007.[126] Further tax credit extensions are plausible.
- SSJID has the option of fulfilling part of its RPS requirement through unbundled RECs, which have been trading at less than $1 per MWh (excluding the price of electricity).[127]

---

[119] This prices includes all reported wind and solar power purchase agreements, excluding local builds (which generally come at a price premium), as reported in California Energy Markets, an independent news service from Energy Newsdata, from January 2015-January 2016 (see issues dated July 31, August 14, October 16, October 30, 2015, and January 15, 2016).

[120] National Renewable Energy Laboratory. *Impact of Federal Tax Policy on Utility-Scale Solar Deployment Given Financing Interactions*, September 28, 2015, Slide 16. http://www.nrel.gov/docs/fy16osti/65014.pdf

[121] Ibid. Costs converted to nominal dollars using the inflation forecast used throughout the rate forecast model (U.S. EIA's forecast of the Gross Domestic Product Implicit Price Deflator).

[122] U.S. Department of Energy. *Business Energy Investment Tax Credit (ITC).* http://energy.gov/savings/business-energy-investment-tax-credit-itc

[123] U.S. Department of Energy. *Electricity Production Tax Credit (PTC).* http://energy.gov/savings/renewable-electricity-production-tax-credit-ptc

[124] National Renewable Energy Laboratory. *Impact of Federal Tax Policy on Utility-Scale Solar Deployment Given Financing Interactions*, September 28, 2015, Slide 28.

[125] Union of Concerned Scientists. *Production Tax Credit for Renewable Energy*. http://www.ucsusa.org/clean_energy/smart-energy-solutions/increase-renewables/production-tax-credit-for.html

[126] Solar Energy Industries Association. *Solar Investment Tax Credit*. http://www.seia.org/policy/finance-tax/solar-investment-tax-credit; and U.S. Department of Energy. Business Energy Investment Tax Credit (ITC). http://energy.gov/savings/business-energy-investment-tax-credit-itc

[127] Platts' Megawatt Daily. March 4, 2016, page 12.

- The major California investor-owned utilities have significantly slowed their renewable procurement because lower-than-expected customer sales and higher-than-expected contracting success rates have led to procurement in excess of the RPS requirements through 2020. When the utilities start ramping their procurement back up to meet the 50%-by-2030 RPS requirement, the supply-demand balance in the market may shift, resulting in higher-than-expected prices unless an increase in suppliers and development opportunities matches the increase in demand.

Given the potential upward price pressures from tax credits that are currently expected to expire and from higher demand for renewable power to meet the 50%-by-2030 requirement and the potential downward price pressures from falling renewable development costs, the possibility for lower cost procurement through the use of RECs, and the possibility that the expiry of the tax credits will be further delayed, it is unclear whether renewable prices will continue to fall (as NREL, LBNL, and others are predicting) or will start to stabilize and rise. MRW addressed this uncertainty by assuming moderate price declines. In particular, in the base case forecast, MRW used the $52 per MWh average price of recent municipal utility and CCA wind and solar contracts as the price through 2022 (in nominal dollars), increasing the price with inflation in subsequent years. This results in a price of $86 per MWh in 2046. MRW also considered a stress test scenario in which the base case prices are increased to account for the expected expiration of the tax credits, resulting in a price of $112 per MWh in 2046. Lower prices, which are also reasonably achievable, would improve the financial outcome of SSJID's plan and therefore were not considered in the stress tests.

MRW used these same renewable prices to calculate PG&E's renewable power costs. However, as described in Appendix C, in the PG&E forecast, these renewable energy prices were used only for incremental power that will be needed above PG&E's existing RPS contracts. For SSJID, these prices were used for SSJID's entire RPS-eligible portfolio.

Non-Renewable Power Cost Forecast

MRW separately considered two elements of non-renewable power costs: power production costs and greenhouse gas costs. The forecast methodologies for these cost elements, described below, are consistent with the forecast methodologies used for these cost elements in the PG&E rate forecast.

Since natural gas generation is typically on the margin in the California wholesale power market, power production costs for market power are driven by the price for natural gas. MRW forecasted natural gas prices based on current NYMEX market futures prices for natural gas, projected long-term natural gas prices in the EIA's *Annual Energy Outlook 2016,*[128] and PG&E's tariffed natural gas transportation rates.[129] MRW used a standard methodology of multiplying the natural gas price by the expected heat rate for a gas-fired unit and adding in variable operations and maintenance costs to calculate total power production costs.

In addition to power production costs, the cost of energy generated in or delivered to California also includes the cost of greenhouse gas allowances that, per the state's cap-and-trade program, must be procured to cover the greenhouse gases emitted by the energy generation. MRW developed a forecast of the prices for these allowances based on auction prices for Vintage 2015 allowances,[130]

---

[128] U.S. Energy Information Administration. *Annual Energy Outlook 2016*, Table 13.
[129] PG&E. Tariff G-EG and Tariff G-SUR, April 2016.
[130] Auction results available at http://www.arb.ca.gov/cc/capandtrade/auction/results_summary.pdf.

increased annually in proportion to the auction floor price increases stipulated by the cap-and-trade regulations.[131] MRW estimated the emissions rate of SSJID's non-renewable power supply based on an estimated heat rate for market power multiplied by the emissions factor for natural gas combustion.[132]

Capacity Cost Forecast for Non-Renewable Power

To estimate SSJID's capacity requirements, MRW developed a forecast of SSJID's peak demand in each year and subtracted the net qualifying capacity credits provided by SSJID's renewable power purchases. This is appropriate because the renewable energy prices used in this analysis reflect prices for contracts that supply both energy and capacity. If SSJID purchases renewable energy via energy-only contracts, SSJID's need for capacity will be greater than forecasted here, but these higher costs will be fully offset by the lower costs for the renewable energy.

MRW estimated current peak demand for SSJID's load using a 35% load factor, which was calculated from the energy consumption and peak demand forecasts provided in SSJID's 2011 Draft Supplement Environmental Impact Report.[133,134] We forecasted changes to the peak demand based on the California Energy Commission's forecast of changes to peak demand in the Central Valley planning area.[135] We calculated capacity requirements as 115% of the expected peak demand in order to include sufficient capacity to fulfill resource adequacy requirements. We applied a consistent methodology to calculate peak demand growth rates and capacity requirements for PG&E (see Appendix C).

To estimate the cost of SSJID's capacity needs, MRW considered two time periods: the period before system load-resource balance when there is excess capacity on the system, and the period following system-load resource balance when additional supply must be developed. MRW assumed a system load-resource balance year of 2035, which is the assumption adopted by the CPUC in December 2015 for long-term forecasting purposes.[136] Through 2030, MRW priced capacity at the median price of recent resource adequacy purchases, escalated with inflation.[137] MRW increased the capacity price incrementally starting in 2031 to reflect an increase in the market price for capacity during the transition from the lower near-term prices to the higher post-load-resource balance prices. MRW assumed that SSJID would build its own power plant (alone or in combination with other public entities) in place of purchasing market capacity when market prices rise above the cost of a new self-build. In MRW's model, this occurs in 2033. From this point on, MRW assumed that the market price for SSJID's capacity would be equal to the levelized fixed cost of a new advanced

[131] California Code of Regulations, Title 17, Article 5, Section 95911.
[132] Emissions factor obtained from U.S. EIA. Electric Power Annual (EPA), February 16, 2016, Table A.3. https://www.eia.gov/electricity/annual/html/epa_a_03.html
[133] San Joaquin Local Agency Formation Commission. "Draft Supplement Environmental Impact Report for the South San Joaquin Irrigation District (SSJID) Plan to Provide Retail Electric Service, Sphere Plan, MSR, and Annexation," November 15, 2011, pages 3.13-2 and 3.13-4.
[134] This load factor is similar to the 38% load factor calculated from the California Energy Commission's most recent Central Valley Planning Area load forecasts. California Energy Commission. Demand Forecast. PG&E Forecast Zone Results Mid Demand Case, Central Valley Region. December 14, 2015.
[135] California Energy Commission. Demand Forecast. PG&E Forecast Zone Results Mid Demand Case, Sales Forecast, Central Valley Region. December 14, 2015.
[136] CPUC ruling R.13-12-010, LTPP Scenario Tool 2014 v5 spreadsheet. October 15, 2015.
[137] CPUC 2013-2014 Resource Adequacy Report Final, August 5, 2015, page 23 Table 11.

combustion turbine developed by a publicly owned utility,[138] minus levelized gross margins from energy sales.[139] A similar methodology was used to forecast the cost of capacity for PG&E; however, PG&E's post-load-resource balance price forecast is based on the price of a combustion turbine developed by a merchant developer (see Appendix C).

Transmission Costs

In addition to power supply costs, SSJID will be responsible for the cost to deliver the power to SSJID's service area. SSJID anticipates that it will receive about 85% of its power deliveries over transmission lines operated by the California Independent System Operator (CAISO) and the remaining power over transmission lines operated by Modesto Irrigation District (MID). Both grid operators charge fees for wheeling power over their lines. In addition to operator fees, MRW included 8% delivery losses in the assessment of SSJID's power supply needs, consistent with the losses assumed in the PG&E rate forecast.[140]

The primary fee to the CAISO is the Transmission Access Charge (TAC). As a starting point, MRW used the CAISO's January 2016 TAC rate and extended it through 2021 using the CAISO's most recent rate forecast.[141] For 2022-2030, MRW escalated the TAC rate at the 2017-2021 annual average escalation rate from the CAISO's forecast, and MRW reduced the annual growth rate by half for subsequent years to account for a reduced need for incremental transmission investments after the 50% RPS has been met. MRW additionally added a fee for other transmission charges based on PG&E's projected 2016 costs for ancillary services, CAISO grid management charges, FERC fees, and unaccounted for energy and neutrality fees.[142] MRW escalated these costs with inflation for subsequent years. MRW used these same transmission costs for the PG&E rate forecast.

For power obtained through MID, SSJID expects to pay wheeling charges both to MID and to the Western Area Power Administration (Western). For the MID charges, MRW used MID's current wheeling rates, escalated with inflation. For the Western charges, MRW used Western's forecast of 2017 and 2018 wheeling rates, escalated with inflation for subsequent years.[143] MRW additionally added ancillary services, grid management charges, FERC fees, and unaccounted for energy and neutrality fees at the same rate as used for power obtained through the CAISO.

Contracting Adder

SSJID does not plan at present to act as its own power broker. Instead, SSJID is likely to purchase medium-term, full-service requirements power supply contracts from a third party, at least initially. This approach will allow SSJID to shift some of the risk of energy price fluctuations and load variability risk onto another party and to avoid the disadvantage of competing with much larger

[138] California Energy Commission. *Estimated Cost of New Renewable and Fossil Generation in California*, March 2015, Table E-6 and E-12.
[139] To estimate levelized gross margins, MRW used data from PG&E's testimony in CPUC proceeding A.13-04-012, Exhibit 5, August 16, 2013, pages 2-16 and 2-17, Tables 2-6 and 2-8.
[140] This loss factor was calculated from PG&E's 2017 Energy Resource Recovery Account (ERRA) Forecast Application in CPUC proceeding A.16-06-003, June 2016 testimony, Table 2-3.
[141] CAISO 2014-2015 Transmission access charge model, October 26, 2015.
[142] PG&E 2017 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast, filed with the CPUC in proceeding A.16-06-003 on June 1, 2016 ("2017 ERRA Forecast"), Tables 2-3 and 6-1.
[143] Western Area Power Administration. "Central Valley Project Transmission Capacity Change and Rate Change Effective April 1, 2016," February 10, 2016.

entities for wholesale market supplies. In return, SSJID's power supply costs will include a contracting adder to pay for the third-party's services.

To estimate the amount of this contracting adder, MRW compared the 2017-2021 power supply costs obtained through a bottoms-up calculation of renewable and non-renewable energy and capacity prices to the price offered to SSJID for a five-year fixed price power supply contract for this time period.[144] From this comparison, we obtained a contracting adder of 5.75%, which we applied to each year of the forecast.

[144] Shell Energy North America. Confidential Indicative Power Supply Products & Pricing for SSJID. January 19, 2016.

Appendix C: Forecast of PG&E's Rates

PG&E's retail electric rates are comprised primarily of generation, distribution, and transmission charges. MRW developed a separate forecast for each of these rate components for each of the years 2017-2046 based on the specific cost drivers for each component. To build this forecast, MRW used publicly available inputs, including cost and procurement data from PG&E, market price data, and data from California state regulatory agencies and the U.S. Energy Information Administration. The structure of the rate forecast model and the basic assumptions and inputs used are described below.

Generation Charges

PG&E's generation costs fall into four broad categories: (1) renewable generation costs, (2) fixed costs of non-renewable utility-owned generation, (3) fuel and purchased power costs for non-renewable generation, and (4) capacity costs. Each of these categories is evaluated separately in the rate forecast model, and underlying these forecasts is a forecast of PG&E's generation sales.

Sales Forecast

PG&E's generation cost forecast is driven in large part by the amount of generation that PG&E will need to meet customer demand. To forecast PG&E's electricity sales, MRW started with the 2016-2030 sales forecast that PG&E provided in its January 2016 Renewable Energy Procurement Plan ("RPS Plan") filing with the CPUC.[145] This forecast predicts 4% annual sales reductions through 2020 and anemic sales growth of 0.2% per year from 2020-2025, before increasing to close to 1% per year from 2025-2030.[146] For subsequent years, we used the 0.5% per year average annual 2016-2026 growth rate from the California Energy Commission's 2015 forecast of electricity sales in the PG&E planning area.[147] This is nearly the same as the annual average rate of sales growth from 2020-2030 in PG&E's forecast.

Renewable Generation

The starting point for MRW's analysis is PG&E's "RPS Plan," in which PG&E discusses its plan for meeting California's Renewable Portfolio Standard (RPS) targets and provides the annual amount and cost of renewable generation currently under contract through 2030. PG&E's RPS Plan shows that PG&E's current renewable procurement is in excess of the RPS requirement in each year through 2022. After 2022, PG&E's renewable generation from current contracts falls below the RPS requirements, but PG&E is projected to have enough banked Renewable Energy Credits (RECs) from excess renewable procurement in prior years to meet RPS requirements until 2025.

---

[145] PG&E. *Renewables Portfolio Standard 2015 Renewable Energy Procurement Plan (Final Version)*. January 14, 2016. Appendix D.

[146] The near-term decline in sales in PG&E's forecast is likely attributable to the growth in CCA, in which a municipality procures electric power on behalf of its constituents instead of having them purchase their power from PG&E. While customers in the jurisdictions of these municipalities have the option to opt-out of CCA and to continue to procure power from PG&E, so far, most CCA-eligible customers have not elected for this option. CCA customers continue to procure electricity delivery services from PG&E; it is only generation services that they obtain through the CCA (see Appendix G for further discussion).

[147] California Energy Commission Demand Forecast for the 2015 IEPR, Form 1.1b (Mid demand case), PGE Planning Area, December 14, 2015. http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN206976_20151214T105217_PGE_Mid_Demand_Case.xls

MRW used the amount and cost of renewable generation currently under contract as shown in PG&E's RPS Plan forecast. For the period starting in 2026 when PG&E's RPS Plan shows a need for incremental renewable procurement to meet RPS requirements, MRW added in the necessary renewable generation to meet current statutory requirements (i.e., 33% of procurement in 2020, increasing to 50% of procurement in 2030).[148] To project PG&E's cost of this incremental renewable generation, MRW used the same renewable power prices used for SSJID's renewable power cost forecast (see Appendix B).

Fixed Cost of Non-Renewable Utility-Owned Generation

PG&E's rates include payment for the fixed costs of the PG&E-owned non-renewable generation facilities, which are primarily natural gas, nuclear, and hydroelectric power plants. Because these costs are not tied to the volume of electricity that PG&E sells, their annual escalation is not driven by the price of fuel and other variable inputs. Instead, they escalate at a rate that stems from a combination of cost increases and depreciation reductions. These escalation rates are determined in General Rate Case (GRC) proceedings, which occur roughly every three years.

As a starting point for the forecast, MRW used the adopted 2016 fixed costs for these facilities.[149] For the period between 2017 and 2019, MRW estimated escalation rates based on PG&E's proposal in its 2017 GRC application,[150] estimating in the base case that PG&E will receive 2/3 of its requested increases.[151] For subsequent years, MRW estimated in the base case that PG&E's generation fixed costs would increase at an annual rate of 6.2%,[152] which is the annual average growth rate of these cost over the last ten years (Table 6).[153] This escalation rate is in nominal dollars (*i.e.*, some of the escalation is accounted for by inflation).

Table 6: PG&E's Generation Fixed Costs, 2006-2016[154]
(billions of nominal dollars)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Cost	$1.01	$1.01	$1.05	$1.19	$1.26	$1.40	$1.53	$1.55	$1.71	$1.86	$1.84
Annual Increase		0%	4%	14%	6%	11%	9%	1%	10%	9%	-1%

[148] MRW additionally allowed for the purchase of additional renewable generation when renewable prices are below market prices, subject to some purchase limits, including a 50% cap on renewable generation relative to the entire generation portfolio. This leads to additional renewable purchases from 2027-2029 in the Low Renewable Price scenario. Starting in 2030, the RPS requirement is 50%, and no additional renewable purchases are allowed, per the rules of the model, in order to maintain grid reliability.
[149] PG&E. Annual Electric True-Ups for 2016. Advice Letter 4696 E-A. January 4, 2016. Table 2.
[150] PG&E. 2017 GRC Request, CPUC proceeding A.15-09-001, Exhibit PG&E-10, Tables E-3 and E-4.
[151] In the "Low PG&E Operational Costs" stress test scenario, we assumed that PG&E would receive 50% of its requested increases.
[152] In the "Low PG&E Operational Costs" stress test scenario, we applied a 5.2% annual average growth rate, which is 15% below the base case growth rate.
[153] Historic growth rates were calculated from PG&E Advice Letters 2706-E-A, AL 3773-E, 4459-E, 4647-E, and 4755-E. New power plant costs were excluded from these calculations since the costs of new plants are offset, at least in part, by a reduction in fuel and purchased power costs.
[154] PG&E Advice Letters 2706-E-A, AL 3773-E, 4459-E, 4647-E, and 4755-E

MRW adjusted the GRC forecast to account for the expected retirement of the Diablo Canyon nuclear units at the end of the units' current licenses in 2024 and 2025. While PG&E does have the option to pursue a 20-year license extension for the Diablo Canyon units, as of April 2015, PG&E was undecided as to whether it would do so.[155] There are a number of pressures pushing against relicensing. For example, PG&E will be required by the CPUC to present a thorough assessment of the cost-effectiveness of relicensing, including a number of studies exploring reliability, security, and safety implications;[156] PG&E will also be required to undertake a massive cooling system modification project before operating the nuclear plant past 2024 (per state regulations implementing the Federal Clean Water Act, Section 316(b));[157] an independent panel of peer reviewers to recent federal- and state-required PG&E seismic studies has unresolved concerns over these studies;[158] and the U.S. Nuclear Regulatory Commission is requiring PG&E to conduct additional earthquake hazard analysis because initial post-Fukushima studies showed a hazard level above the original design basis for the plant.[159] Given the uncertainty of license renewal, MRW assumed in the base case that the Diablo Canyon units would be shut down at the end of their current licenses. Based on current market conditions, this appears to be the lower-cost option for PG&E, making it the more conservative assumption to use in the analysis.

Fuel and Purchased Power Costs for Non-Renewable Generation

Each spring, PG&E files a forecast with the CPUC of its fuel and purchased power costs for the upcoming year in its "ERRA" filing, which PG&E updates and finalizes in November. MRW relied on PG&E's June 2016 ERRA testimony,[160] adjusted to remove renewable generation costs, as the starting point for the forecast of fuel and purchased power costs for PG&E's non-renewable generation.

To escalate these costs through the forecast period, MRW forecasted changes to natural gas prices and to greenhouse gas cap-and-trade program compliance costs. The natural gas price forecast is based on current NYMEX market futures prices for natural gas, forecasted natural gas prices in the U.S. EIA's *Annual Energy Outlook 2016*, and PG&E's tariffed natural gas transportation rates. This forecast is the same forecast used in the forecast of SSJID wholesale power costs (see Appendix B).

Cap-and-trade program compliance costs are estimated based on (1) PG&E's forecast of greenhouse gas emissions in 2017;[161] (2) a forecast of PG&E's fossil generation supply, developed by subtracting expected renewable, hydroelectric, and nuclear generation from PG&E's projected wholesale power requirement; and (3) a forecast of greenhouse gas allowance prices. The greenhouse gas allowance price forecast is the same as used in the forecast of SSJID wholesale power costs and is based on the results of the California Air Resources Board's (ARB's) most recent allowance auctions, increased annually in proportion to the auction floor price increases stipulated by the cap-and-trade regulation (see Appendix B).

---

[155] California Energy Commission. "2015 Integrated Energy Policy Report," February 24, 2016 ("2015 IEPR"), pages 177-178. http://www.energy.ca.gov/2015_energypolicy/
[156] California Energy Commission. 2015 IEPR, page 178.
[157] California State Water Resources Control Board. "Fact Sheet: Once-Through Cooling Policy Protects Marine Life And Insures Electric Grid Reliability,"
http://www.swrcb.ca.gov/publications_forms/publications/factsheets/docs/oncethroughcooling.pdf
[158] California Energy Commission. 2015 IEPR, pages 180-183.
[159] California Energy Commission. 2015 IEPR, page 184.
[160] PG&E 2017 ERRA Forecast, Tables 2-3 and 11-3.
[161] PG&E 2017 ERRA Forecast, Table A-1.

MRW calculated total fuel and purchased power costs by escalating natural gas prices based on the natural gas price forecast described above, escalating nuclear fuel prices based on the EIA forecast of fuel costs for nuclear plants, escalating water costs for hydroelectric projects with inflation, escalating the capacity costs of power purchase contracts with the capacity cost escalator (discussed below), and pricing market power at the same market power price used for SSJID's purchases. MRW then summed the cost for each of these resources and added in projected cap-and-trade compliance costs to obtain PG&E's total non-renewable fuel and purchased power cost.

Capacity Costs

PG&E must procure capacity to meet 115% of its anticipated peak demand in order to fulfill its resource adequacy requirement. PG&E's own power plants can be used to meet this requirement, as can power plants with which PG&E has contracts.

To estimate PG&E's capacity requirements, MRW started with the Capacity Supply Plan that PG&E submitted to the California Energy Commission in 2015,[162] which forecasts PG&E's peak demand and existing capacity resources for each of the years 2013-2024. With limited exception,[163] MRW used PG&E's data where publicly available and extended the forecasts to 2046. In extending these forecasts, MRW used resource assumptions that are consistent with those used in our assessments of energy costs, including the projected retirement of the nuclear facilities. We also added in anticipated capacity from new renewable procurement and new energy storage, and adjusted the calculation to account for the portion of resource adequacy credits that is allocated to non-bundled customers.

As with the SSJID capacity cost forecast, to estimate the cost of the net capacity requirement, MRW considered two time periods: the period before system load-resource balance when there is excess capacity on the system, and the period following system-load resource balance when additional supply is needed. MRW used the load-resource balance assessment adopted by the CPUC in October 2015 as the source of a system load-resource balance in 2035.[164] Through 2030, MRW priced capacity at the median price of recent resource adequacy capacity sales, escalated with inflation.[165] Beginning in 2035, MRW priced capacity at the levelized fixed cost of a new advanced combustion turbine developed by a merchant generator,[166] minus levelized gross margins from energy sales.[167] MRW increased the capacity price incrementally between 2030 and 2035 to produce a steady escalation from the lower near-term prices to the higher post-load-resource balance prices.

This assessment is conservative in that it excludes the cost to meet local resource adequacy requirements for PG&E areas with transmission congestion. (The SSJID area is not currently subject to local resource adequacy requirements.)

---

[162] California Energy Commission, Energy Almanac, Utility Capacity Supply Plans from 2015. September 4, 2015

[163] The main exception is that we increased energy efficiency and demand response growth to comply with SB 350 requirements to double energy efficiency by 2030 and the anticipated continuation of CPUC demand response initiatives.

[164] CPUC ruling R.13-12-010, LTPP Scenario Tool 2014 v5 spreadsheet. October 15, 2015.

[165] CPUC. *2013-2014 Resource Adequacy Report Final*, August 5, 2015, page 23 Table 11.

[166] California Energy Commission. *Estimated Cost of New Renewable and Fossil Generation in California*, March 2015, Table E-10.

[167] To estimate levelized gross margins, MRW used data from PG&E's testimony in CPUC proceeding A.13-04-012, Exhibit 5, August 16, 2013, pages 2-16 and 2-17, Tables 2-6 and 2-8.

Transmission and Distribution Charges and Other Charges

Several non-generation costs are incorporated into PG&E's rates. These include costs related to transmission, distribution, public purpose programs, and bond charges stemming from purchases made during California's energy crisis.

PG&E is interconnected to the CAISO-managed transmission grid. MRW forecasted changes to PG&E's transmission charges consistent with the rate of CAISO cost increases identified for SSJID. As described in Appendix B, this estimate was derived based on a CAISO forecast of Transmission Access Charges and PG&E's estimated costs for ancillary services and other charges.

PG&E additionally incurs substantial costs to operate and maintain its electric distribution system. As a starting point for the forecast, MRW used the adopted 2016 fixed costs for these facilities.[168] For the period between 2017 and 2019, MRW estimated escalation rates based on PG&E's proposal in its 2017 GRC application,[169] estimating in the base case that PG&E would receive 2/3 of its requested GRC increases.[170] For subsequent years, MRW estimated in the base case that PG&E's distribution costs would increase each year by 4.9%,[171] which is the annual average growth rate for these cost over the last ten years.[172] These escalation rates are in nominal dollars (i.e., some of the escalation is accounted for by inflation).

Table 7: PG&E's Distribution Revenue Requirement Growth[173]
(Nominal $ Million)

	2006	2011	2016
Distribution Revenue Requirement	$2,810	$3,520	$4,540
Annual-Average Growth through 2016	4.9%	5.2%	

PG&E's rates include a number of additional charges. The California Department of Water Resources (DWR) bond charge recovers costs associated with bonds that were issued over a decade ago during the California energy crisis. This charge is set at approximately 0.5 cents per kWh until cost recovery is completed in 2020.[174] PG&E's Public Purpose Program (PPP) charge collects revenues that fund a variety of programs, including energy efficiency and energy-related research and demonstration projects, and PG&E's Nuclear Decommissioning charge collects costs to complete the decommissioning of the Humboldt Bay Power Plant (which last operated in 1976) and

[168] PG&E. Advice Letter 4696 E-A. January 4, 2016. Table 2.
[169] PG&E. 2017 GRC Request, A.15-09-001, Exhibit PG&E-10, Tables E-3 and E-4.
[170] In the "Low PG&E Operational Costs" stress test scenario, we assumed that PG&E would receive 50% of its requested increases.
[171] In the "Low PG&E Operational Costs" stress test scenario, we applied a 4.2% annual average growth rate, which is 15% below the base case growth rate.
[172] Historic growth rates calculated from Pacific Gas & Electric Advice Letters 2706-E-A and 4696-E-A.
[173] 2006: PG&E. Advice Letter 2706 E-A. February 15, 2006. Table 2; 2011: PG&E. Advice Letter 3727-E-A. February 9, 2011. Table 2; 2016: PG&E. Advice Letter 4696 E-A. January 4, 2016. Table 2.
[174] Bond payments expire at the end of 2022. However, PG&E explained in a meeting with MRW and the San Joaquin LAFCo in 2014 that customers have already provided substantial amounts in reserve accounts that are being held by DWR, and that the last two years of payments will be offset by the return of these reserve amounts to customers and will not require new customer payments.

to fund the future decommissioning of the Diablo Canyon Power Plant. The rate model escalates these charges at the annual inflation rate throughout the forecast period.

Rate Development

Following the methodologies described above, MRW developed a forecast of PG&E's generation and distribution expenses. We then divided these expenses by the expected PG&E sales in order to obtain a forecast of system-average generation and distribution rates. MRW forecasted rate escalators for other rate elements using the methodologies described above. MRW then applied the component-specific escalator to each of the charges currently in effect for each of the major customer classes represented in SSJID's service area. In other words, instead of applying a single system-average rate escalator to each customer class's total rate, MRW applied specific escalators to each of the applicable charges for each customer class (e.g., a generation escalator, a distribution escalator, a transmission escalator, a public purpose escalator, a bond charge escalator, etc.). This specificity is needed because the total rate for each customer class is comprised of different shares of each of the rate components.[175] Applying the escalators by rate component accounts for differences between the system-average rate and the rates in effect for SSJID's customer base.[176]

[175] For example, generation charges comprise 43% of residential customers' electric rates, 54% of industrial customers' electric rates, and 49% of the system-average rate. Applying the system-average escalator to all customer classes would therefore over-weight the generation escalator for residential customers and under-weight it for industrial customers.

[176] MRW additionally considered changes to the low-income CARE program in developing the rates for SSJID's customer base. These changes are discussed in Appendix F.

Appendix D: SSJID's Distribution Capital Expenditures

MRW developed a forecast of SSJID's distribution system capital expenditures based on the capital expenditures incurred by a sample of nearby publicly owned utilities (POUs) to maintain their distribution systems. Municipal utilities were selected for this analysis based on geographical location (i.e., northern California) and were limited further by data availability.[177] The following steps were taken to develop this analysis:

1. Each distribution capital expenditure was converted to 2014-equivalent costs using the Handy-Whitman Index of Public Utility Construction Costs for distribution costs in the Pacific region;
2. The annual average distribution capital expenditure per-customer and per-MWh of electricity sales were calculated for each utility;[178]
3. A total average per-customer capital expenditure was obtained by averaging the results from each of the utilities;
4. A total average per-MWh capital expenditure was obtained by averaging the results from each of the utilities;[179]
5. The two results were scaled to SSJID's projected customer base and power usage; and
6. The two SSJID-scaled results were averaged together.

The result is an SSJID distribution capital expenditure forecast of $4.2 million for 2016 (in 2016 dollars). To obtain the forecast for the 2017-2046 period, MRW escalated the 2016 expenditure level with inflation and load growth.

The full results for the five utilities evaluated are shown in Table 8. The results fall in a reasonably narrow range of $3.2 million to $4.9 million for SSJID-equivalent spending. Both the per-MWh and per-customer results show relatively high levels of consistency across these utilities, even though the utilities have quite different population densities, topographies, and overall system sizes. Given this level of consistency, it is fitting to use these results as the basis for forecasting SSJID's capital expenditures.[180]

[177] Many municipal utilities report expenditures for generation, distribution, and transmission assets in a consolidated manner. Utilities for which distribution expenditures were not separately reported were excluded from the analysis.
[178] These metrics were selected because they are among the fundamental drivers of distribution capital expenditures. Spending per non-coincident peak-demand may have been a preferable metric; however, data on total energy sales were more readily available than data on peak demand. Total sales were therefore used as a proxy for peak demand.
[179] The number of years of data available varied by utility. For the Sacramento Municipal Utility District (SMUD), Redding, and Alameda: 2006-2014, for Lodi: 2008-2014, and for Modesto: 2009-2014. A simple average of the different utilities' data was taken in order to capture a range of public utility practices. (Weighting the average by size would mostly capture SMUD's costs.)
[180] These results may be higher than anticipated for SSJID because, at least in some cases, they include the cost of new development, which, under SSJID's line extension policies, would be borne almost exclusively by the developer.

Table 8: SSJID 2016 Capital Expenditure Forecast (2014 dollars)

	Average Distribution Capital Spending for Operating POU[181]		Corresponding Spending for SSJID *Millions of 2014 Dollars*		
	$/MWh	**$/Customer**	**$/MWh basis**	**$/customer basis**	**Average**
SMUD	$6.7	$146	$3.5	$4.9	$4.2
Modesto	$7.8	$169	$4.1	$5.7	$4.9
Alameda	$9.2	$102	$4.8	$3.4	$4.1
Redding	$6.2	$108	$3.2	$3.6	$3.4
Lodi	$5.9	$101	$3.1	$3.4	$3.2
Average	**$7.1**	**$125**	**$3.7**	**$4.2**	**$4.0**

Difference between PG&E and SSJID Capital Expenditures

MRW developed this estimate of SSJID's capital expenditures based on the spending levels of nearby publicly owned utilities, rather than from PG&E's spending in SSJID's area, for two reasons:

1. **PG&E's spending in SSJID's area in recent years may not be predictive of investment levels that will be needed in the coming decades:** PG&E has been undertaking significant investment in SSJID's area in recent years. When SSJID examined PG&E's facilities in 2004, numerous deficiencies were evident, including overloaded circuits on many of the overhead substation feeders, particularly out of Manteca substation. Much of this was apparently due to undersized conductors that had never been upsized as the City of Manteca expanded out into the rural areas. In addition, many of the distribution poles were well beyond their useful lives and needed to be replaced with larger poles to maintain proper ground clearance (because of the extreme joint pole usage that had occurred). The PG&E service reliability indices for the Manteca service area were accordingly very poor, showing service outages to be well above acceptable levels, particularly when measured against publicly owned utilities in the area (e.g., Merced Irrigation District and Turlock Irrigation District). In the years since, PG&E has made considerable investments in the SSJID service area to improve reliability.[182] Upon completion of these major investments, the spending requirements in SSJID's area should return to lower, baseline levels.[183]

---

[181] Data collected from utility budget reports and financial reports or obtained from the utility. Analysis covers 2006-2014, with data for two of the utilities covering only the last six or seven years of this period.
[182] See, for example, "PG&E's May 11, 2012 Submission to LAFCo Concerning Two Siemens Reports," Page 1. Provided as Appendix D to PG&E's Comments to the San Joaquin LAFCo, filed April 21, 2014.
[183] It should also be noted that in addition to valid reliability drivers, PG&E has had an incentive to increase its near-term spending in SSJID's area as a way to combat SSJID's push for municipalization (both to counter the claim that PG&E's service in its area is unreliable and to increase the cost of its system). It therefore should not be assumed that PG&E's investments over the last decade all strictly needed to be undertaken in this timeframe. Had SSJID been operating this system, SSJID may have prudently spread out these investments over a longer period of time.

2. **SSJID is likely to require less spending than PG&E to achieve the same capital improvements:** There are several differences between PG&E's cost structure and SSJID's cost structure that result in higher PG&E costs:

a) PG&E includes overhead adders to its project costs. SSJID's overhead costs are already included in the assessment of SSJID's O&M costs and should therefore not be included in SSJID's capital expenditure forecast. Furthermore, SSJID's overhead costs are expected to be significantly lower than PG&E's given that SSJID is a smaller organization with fewer layers of management, and, to some extent, existing SSJID infrastructure and personnel can be used for the retail electric utility at little incremental cost. While, to MRW's knowledge, PG&E's average overhead rate is not a readily available figure, recent data from PG&E's counterpart in southern California show an overhead adder of 54%.[184] PG&E's overhead adder is likely to be similar given that the overhead rates for both utilities are approved by the CPUC.
b) PG&E offers ratepayer-funded allowances to developers to help defray the cost of line extensions and certain other distribution investments. Under SSJID's line extension policies, the cost of new development would be borne almost exclusively by the developer.
c) In transactions where a land developer builds distribution facilities and contributes them to the utility, as is the standard practice for new developments, the FERC-prescribed accounting method used by PG&E is to record the new distribution facilities as an addition to capital assets and as revenue. In addition to the direct contribution of facilities, PG&E charges developers a 34% assessment on the value of the contribution in order to pay for the income taxes that PG&E will owe on the contribution.[185] Direct contributions would be borne by developers, not SSJID, if SSJID were to assume operation of the system, and there would be no income tax liability due to SSJID's tax-exempt status.
d) As a public agency, SSJID has a lower cost of capital than PG&E and is exempt from income taxes. PG&E's 2014 General Rate Case decision authorized $483 million in distribution-related taxes and $975 million in distribution-related shareholder return, amounting to 37% of PG&E's electric distribution costs.[186] SSJID would be exempt from most taxes and would have financing costs that are much lower than shareholders' 8.06% rate of return.

When PG&E's capital spending amounts are adjusted to reflect the costs that would be borne by SSJID or another publicly owned utility, the gap between the MRW spending estimates and PG&E's 2014 spending in SSJID's area is bridged. PG&E previously estimated that it spent $8.5 million on capital additions in SSJID's area in 2014.[187] The adjustments to remove PG&E's overhead costs and developers' allowances and contributions reduce this amount to an SSJID-equivalent cost of $4.4 million.[188] Additional adjustments to reflect the tax and cost of capital advantages of a POU would further reduce the PG&E spending amount and bring it even closer to the POU-based projection of SSJID's spending requirements (e.g., $4.0 million in 2016). While these adjustments are high-level estimates and are not likely to be exact, this assessment further indicates that SSJID's capital costs are likely to be similar to the costs borne by other POUs and much lower than PG&E's costs.

[184] Southern California Edison's Response to Data Request TURN 48 Q4f in CPUC proceeding A.13-11-003.
[185] PG&E Electric Preliminary Statement, Part J: Income Tax Component Of Contributions Provision
[186] Decision 14-08-032 in PG&E's 2014 General Rate Case, Phase 1, A.12-11-009, Appendix C, Table 3-A.
[187] Data provided in response to SSJID Data Request 002 (from 2014 deliberations at the San Joaquin LAFCo) and adjusted to correct an error in the Handy-Whitman escalation calculation.
[188] This calculation is based on estimated adders of 54% associated with overhead and 20% associated with developers' allowances and contributions.

Appendix E: Assessment of Cap-and-Trade Program Implications for Financial Analysis

In 2006, the California Legislature passed Assembly Bill 32 (AB 32), which requires California to reduce its greenhouse gas emissions to 1990 levels by 2020 and to begin work toward a longer-term goal of reducing greenhouse gas emissions to 80 percent below 1990 levels by 2050. Senate Bill 350 (SB 350), passed in 2015, requires the CPUC to develop a procurement process consistent with the statewide goal of reducing greenhouse gas emissions to 40 percent below 1990 levels by 2030. The California Air Resources Board (ARB) was assigned to develop and implement polices to meet these greenhouse gas reduction goals. One of these policies is a greenhouse gas cap-and-trade program, adopted in December 2011 and implemented on a mandatory basis at the start of 2013.

Under the cap-and-trade program, statewide greenhouse gas emissions are capped at a level that declines annually. ARB creates carbon "allowances" for each year in an amount equal to this cap. Entities that are subject to the program are called "covered entities" and must obtain allowances for each metric ton of greenhouse gas that they emit. Some covered entities obtain free allowances to cover all or part of their requirement from ARB. Covered entities may also trade allowances through bilateral deals or at ARB-run auctions and may use offset credits to reduce the quantity of allowances needed for compliance by up to 8%. Offset credits are created through the reduction of greenhouse gas emissions not covered in the cap-and-trade program, following specific protocols developed by ARB.[189]

Entities that generate non-renewable power in California or that deliver power to the California electrical grid are considered covered entities unless they emit less than the equivalent of 25,000 metric tons of CO_2 per year. The requirement for covered entities to procure allowances has increased the wholesale cost of power and creates an extra cost for utility generators. To offset this cost, ARB has distributed no-cost allowances to the state's investor-owned and municipal utilities. The investor-owned utilities must sell their free allowances in the quarterly ARB-run auctions and use the proceeds from these sales to reduce retail electric rates for residential customers, small businesses, and certain large businesses that are considered trade-exposed. Municipal utilities may use their free allowances to meet their cap-and-trade obligations, to reduce customer rates, or for other purposes determined by the utility that are for the benefit of retail ratepayers and consistent with the goals of AB 32.[190]

Allowances in ARB's auctions are subject to a floor price that increases annually. Over time, the floor price will continue to increase, and the supply of allowances (i.e., the greenhouse gas cap) will decline. It is expected that these factors will increase the cost of allowances over the duration of the program. This, in theory, will provide covered entities with an economic incentive to improve operating efficiency or otherwise reduce emissions.

Initially, only generators located in California, entities that sold imported electricity in-state, and certain large industrial facilities were considered covered entities. In 2015, the cap-and-trade system expanded to cover distributors of transportation fuels, natural gas, and other fuels. When these fuels distributors joined the program, the cap on greenhouse gas emissions increased to accommodate the expanded program scope.

[189] A forestation project that sequesters carbon is an example of a project that could produce offset credits.
[190] California Code of Regulations, Title 17, Subchapter 10 (Climate Change), Article 5, Section 95892d.

Allowance Provisions for SSJID

ARB has specified the following criteria for an entity to receive free allowances as part of the electricity sector allocation:[191]

1. Entities must provide electricity;
2. Entities must serve end-use customer load; and
3. Entities must receive payment for that load from end-use customers.

The Final Regulation Order for the cap-and-trade program additionally specifies that the entity must comply with ARB's greenhouse gas mandatory reporting regulations,[192] which involves reporting annual retail sales and associated greenhouse gas emissions. No further eligibility requirements are specified. Accordingly, as long as SSJID complies with reporting requirements, SSJID will be eligible to receive free allowances once it begins serving retail electric customers.

To calculate the amount of SSJID's free allowances, MRW estimated that ARB would assign to SSJID the share of PG&E's allowances that are associated with SSJID's customer base. Based on the size of SSJID's system relative to PG&E's, MRW assumed that SSJID would be allocated 0.6% of PG&E's allowances.[193] In 2017 SSJID's allowances can be expected to yield roughly $2.2 million in revenue.

Allowance Provisions for PG&E

Prior to the start of the cap-and-trade program, ARB allocated free allowances to each operating electric distribution utility in California for each of the years 2013 through 2020.[194] In describing the allowance allocation methodology, staff explicitly stated that the allocations were intended to fully compensate customers of each utility for the utility's cap-and-trade related costs:[195]

> A central principle of the allowance allocation to the electricity sector is the incorporation of customer cost burden. Cost burden is expected to result from emissions costs associated with fossil, [Qualifying Facility], and non-emitting resources priced at market being passed from generators and marketers to utility customers. Under this proposal, the complete annual expected cost burden for each utility is initially allocated. Expected cost burden is calculated by first assigning an emission factor to each fossil generation resource type and non-emitting resources prices at market. Then an annual emissions profile for each utility is calculated by summing the emissions associated with the reported quantities of each resource type. <u>In this way, each utility can expect to be able to fully compensate their</u>

[191] California Air Resources Board. *Appendix A: Staff Proposal for Allocating Allowances to the Electric Sector*, July 2011 ("ARB Appendix A"), page 16. See ARB's *Final Statement of Reason for California Cap-and-Trade Program*, October 2011, page 25 (http://www.arb.ca.gov/regact/2010/capandtrade10/fsor.pdf) for a reference to Appendix A as the adopted methodology for allocating allowances.
[192] California Code of Regulations, Title 17, Subchapter 10 (Climate Change), Article 5, Section 95890b. April 2013.
[193] Electricity sales in SSJID's area are about 0.6% of PG&E's total retail delivery sales.
[194] The fact that ARB has already specified the number of allowances to be distributed to other utilities through 2020 does not impact SSJID's eligibility to receive free allowances for earlier compliance years. ARB has established provisions for the 2013-2020 allocations to be updated over time given "unforeseen changes in the electric sector." ARB Appendix A, page 2.
[195] ARB Appendix A, page 5 *(emphasis added)*.

customers for the costs associated with the cap and trade program that are expected to be passed through to customers.

After freely providing allowances to fully cover customers' cap-and-trade cost burdens, ARB then allocated additional allowances to reward projected investments in energy efficiency and early investments in renewable energy ("early action"). As a result, each utility received allowances in excess of its anticipated cost burden.[196] For example, ARB anticipated that the allowances it provided PG&E would be 5.5% more than PG&E would need to meet its anticipated cost burden.[197]

For PG&E and other investor-owned utilities, the use of auction revenues is highly restricted by California law and CPUC Decision 12-12-033 (as modified by Decision 15-07-001). PG&E is required first to provide bill credits to certain trade-exposed entities in order to minimize leakage risk,[198] and then to provide bill credits to small businesses customers in order to offset the electricity rate increases caused by the cap-and-trade program. PG&E is then required to return all remaining greenhouse gas allowance revenue directly to residential customers on a per-account basis via a semi-annual bill credit termed the "California Climate Credit."[199]

Because the SSJID retail electric business model bases its electric rates on PG&E's electric rates, MRW assessed the impact that these bill credits and California Climate Credit payments will have on PG&E rates in SSJID's service area and adjusted the PG&E rate forecast accordingly. For this calculation, MRW assumed that the allowance allocation previously assigned to PG&E would be reduced by 0.6% to account for the allowance transfer to SSJID.

Greenhouse Gas Allowance Prices

ARB has been holding quarterly auctions for greenhouse gas allowances since November 2012. Since the start of 2014, allowances have sold, on average, at 2% above the floor price. In the most recent auction in May 2016, allowances sold at the floor price of $12.73 per allowance.[200] The cost of allowances in the future will be driven by the complex relationship between the cost of greenhouse gas emissions reduction measures and the demand for greenhouse gas emitting activities. As a proxy, MRW assumed that allowance prices will escalate in tandem with the floor price, which is set to increase annually at 5% plus the rate of inflation.

Post-2020 Allowance Allocation

Current regulations address California's cap-and-trade program only through the 2020 requirement of reaching 1990-level emissions, and ARB is in the early stages of determining regulations for meeting the statewide target of reducing emissions 40% below 1990 levels by 2030. In a public workshop on March 29, 2016, ARB said that their provisional plan is to continue to provide allowances to distribution utilities at the 2020 level, adjusted for changes to the RPS and for major planned changes in electricity sources.

---

[196] ARB Appendix A, page 11.
[197] Calculated from ARB Appendix A, pages 12-13.
[198] "Leakage" in this context refers to companies moving out-of-state or losing market share to out-of-state competition as a result of cap-and-trade-related cost increases in California.
[199] CPUC decision 15-07-001 in proceeding R.12-06-013, July 3, 2015, pages 251-254, and 337.
[200] California Air Resources Board. California Cap-and-Trade Program and Québec Cap-and-Trade System May 2016 Joint Auction #7 Summary Results Report, May 25, 2016.

MRW applied ARB's provisional methodology to allocate allowances to both PG&E and SSJID in the post-2020 period. This resulted in annual reductions to both utilities' allowance allocations through 2030 to account for the increase in the RPS requirement after 2020 (*i.e.*, the reduction in allowable non-RPS energy). For PG&E, these reductions were offset in part by an increase in allowances beginning in 2024 to account for the closure of the Diablo Canyon nuclear plant. Since replacement of nuclear generation with gas-fired generation would be inconsistent with the goals of AB32, for this assessment, MRW assumed that PG&E would receive incremental allowances sufficient to cover the replacement of 50% of Diablo Canyon generation with gas-fired generation.

The incremental allowances for the Diablo Canyon retirement provide a significant benefit to PG&E: while SSJID's allowances fall by 25% from 2020-2030 to account for the 25% reduction in allowable non-RPS energy,[201] PG&E's allowances fall by just 11%. In light of the agreement that PG&E entered into with environmental and labor groups to replace Diablo Canyon power with greenhouse-gas free resources,[202] it is now less certain that PG&E will receive additional free allowances when the nuclear units are retired. MRW's assumption that PG&E would receive additional free allowances to cover 50% of Diablo Canyon replacement power is therefore likely conservative.

[201] -25% = 50%/67%-1, where 67% is the allowable non-RPS energy under the 33% RPS in 2020, and 50% is the allowable non-RPS energy under the 50% RPS in 2030.

[202] Joint Proposal of Pacific Gas and Electric Company, Friends of the Earth, Natural Resources Defense Council, Environment California, International Brotherhood of Electrical Workers Local 1245, Coalition of California Utility Employees and Alliance for Nuclear Responsibility to Retire Diablo Canyon Nuclear Power Plant at Expiration of the Current Operating Licenses and Replace it with a Portfolio of GHG Free Resources," signed by the parties on June 30, 2016. http://www.pge.com/includes/docs/pdfs/safety/dcpp/JointProposal.pdf

Appendix F: CARE Program Developments

California state law shields low-income customers from bearing burdensome electricity and natural gas costs. Section 739.1 of the California Public Utilities Code requires that electric and natural gas rates be discounted by at least 20% for households with incomes up to 200 percent of federal poverty guideline levels via the CARE ("California Alternate Rates for Energy") program. In addition, the Public Utilities Code strictly limits the CPUC's ability to increase CARE program rates. As a result, there was a 43 percent inflation-adjusted reduction to the cost of electricity to PG&E's CARE customers from 1991 to 2012.[203]

Legislation approved by the California legislature in 2013 (AB 327) partially addressed these concerns by setting new provisions for CARE rates and program eligibility. The legislation requires the CPUC to reduce PG&E's CARE discount over time to between 30% and 35%. The legislation additionally allows PG&E to require proof of income eligibility for CARE participants whose usage exceeds 400% of baseline in any billing period and to condition continued CARE eligibility on participation in PG&E's low-income energy efficiency program. It also allows PG&E to remove from the CARE program any customer whose usage continues to exceed 600% of baseline after participation in the low-income energy efficiency program.[204]

The CPUC adopted a six-year transition schedule for PG&E to meet the CARE discount reductions required by AB 327 (Table 9). MRW used this transition schedule in the rate model. For the post-2020 period, MRW maintained the 2020 subsidy level of 35%. This is the maximum subsidy level allowed under AB 327.

Table 9: PG&E's CARE Discount Levels[205]

2015	2016	2017	2018	2019	2020
37.6%	37.0%	36.5%	36.0%	35.5%	35.0%

The CARE eligibility provisions of AB 327 could have the effect of reducing the amount of CARE usage in SSJID's service area. To be conservative, MRW assumed that CARE usage (as a share of total residential usage) would remain unchanged throughout the forecast period.

[203] PG&E. *Comments of Pacific Gas and Electric Company on Refined List of Questions and Scope of Proceeding*, filed in CPUC proceeding R.12-06-013. October 5, 2012, page 5.
[204] AB 327, Section 3.
[205] PG&E Advice Letter 4697-E, September 1, 2015, page 2.

Appendix G: Community Choice Aggregation Evaluation

This appendix considers the feasibility of instituting a Community Choice Aggregation (CCA) plan in place of SSJID's plan for full retail electric service. It first describes CCAs and how they differ from SSJID's retail service plan. It then addresses the financial feasibility of an SSJID CCA using assumptions and approaches that are consistent with those used in the assessment of the full retail service plan. Finally, it discusses the incremental risks associated with the CCA plan.

Community Choice Aggregation Background

CCA was established in California in the aftermath of the state's energy crisis as a way of providing local governments the opportunity to procure electric power for their constituents.[206] The responsibilities of CCAs are generally limited to procuring power on behalf of their constituents and setting rates for generation service. CCAs may also apply for approval to serve as energy efficiency administrators using public purpose program funds collected by PG&E. CCA is fundamentally different from SSJID's full retail service plan, which would establish SSJID as a municipal electric utility. Key differences include the following:

- CCA providers procure power on behalf of their customers, but they do not own distribution assets and do not deliver power to their customers. Municipal utilities provide full retail electric service to their customers, including power procurement, power delivery, energy efficiency programming, and all other electric utility functions.
- CCA customers continue as PG&E customers for the purpose of power delivery and are billed for their CCA power on their PG&E bills; municipal utility customers cease being PG&E customers for all electric service.
- CCAs are regulated by the California Public Utilities Commission (CPUC); municipal utilities are regulated by local governing boards.
- Customers in the service area of a CCA have the option to opt out of CCA service and obtain full retail service from PG&E; customers in the service area of a municipal utility generally do not have this option.
- PG&E remains the provider of last resort for CCAs, meaning that PG&E would take over full retail service for all CCA customers in the event the CCA could no longer do so. PG&E does not retain this obligation with respect to municipal utilities.
- CCA customers may have higher exit fee liabilities than customers of new municipal utilities (see the exit fee discussion below).

Financial Feasibility Assessment of CCA Service

Generally speaking, the financial feasibility of CCA service hinges on a comparison between the rates that customers would pay if they took generation service from the CCA versus the rates they would pay if they took full retail service from PG&E as "bundled service" customers. If rates are consistently higher under CCA, customers can be expected to opt out of CCA service and to remain bundled service customers (or to return to bundled service if they had already become CCA customers), eroding the CCA customer base. In the case of an SSJID CCA, the bar for CCA is set higher because, for CCA to be a viable alternative to SSJID's full retail electric service plan, the CCA must provide the same 15% reduction off of PG&E's total rates that would be provided under the full retail service plan.

[206] California Assembly Bill 117 (2002).

CCA customers pay the same PG&E delivery rates that they would as bundled service customers, and, in place of the PG&E generation rate, they additionally pay a generation rate charged by their CCA provider and an exit fee charged by PG&E. The CCA generation rate must be sufficient to cover the power to serve customers, grid charges related to that power, and CCA administration costs.

As a CCA provider, the only element of the CCA customer rate that SSJID would have control over would be the generation rate. In order for SSJID to provide an equivalent discount as offered via the full retail plan, SSJID would need to set the CCA generation rate far enough below PG&E's generation rate so that SSJID's generation rate plus PG&E's exit fee plus PG&E's delivery rates would be 15% below PG&E's bundled service rates. On average, the CCA generation rate would need to be 45% below PG&E's generation rate in order to achieve a discount of 15% off the total PG&E electric bill. In the early years of the program when the exit fee is highest, the CCA generation rate would need to be even lower, at 55% below PG&E's generation rate.

In order to evaluate the feasibility of this plan, MRW used the same PG&E rate forecast and SSJID cost assumptions that were used in the assessment of the full retail service plan, using only the rates and costs associated with PG&E generation service, exit fees, and SSJID's power supply.[207] MRW also added in administrative fees from PG&E and other administrative costs of running the CCA, including billing and metering fees from PG&E and costs for data management and staffing. As was done for the assessment of SSJID's full retail service plan, MRW calculated the revenue that would be available to the CCA if its rates were set such that customers received a discount of 15% off their total PG&E electric bills. MRW subtracted the CCA's costs from this revenue in order to obtain the CCA net cash flow.

The CCA net cash flow was found to be negative in each year, with an annual average shortfall of 40%. Over the first ten years, the CCA would lose more than $150 million; the shortfall would increase to $630 million over the full 30-year period. While these results are subject to change with changes to underlying market or regulatory conditions, given the magnitude of the shortfalls predicted for an SSJID CCA, the CCA plan does not appear to be financially feasible.

Examination of CCA Plan Financial Infeasibility

The result that an SSJID CCA would be infeasible may seem surprising in light of the finding that SSJID's full retail service plan is highly feasible and considering the explosion of interest in CCA from other entities. This result can be understood by examining the differences between SSJID's CCA plan, on the one hand, and SSJID's full retail service plan and other entities' CCA plans, on the other. These differences are discussed below.

Structural Differences between SSJID's CCA Plan and SSJID's Full Retail Service Plan
SSJID's objective of providing a 15% discount off of PG&E's total rate is structurally much more difficult under CCA than under a full retail service plan because CCA customers continue to pay PG&E rates for all non-generation services and also must pay substantial exit fees that are not paid by PG&E customers. As noted above, given that CCAs have control over just a fraction of customers' electric bills, CCA generation rates must, on average, be 45% below PG&E's generation rates in order to obtain a 15% total discount for CCA customers. This level of discount is highly aggressive and does not appear feasible, particularly if SSJID is precluded from using its own hydroelectric

[207] Since the same PG&E delivery rates are charged to CCA customers and to bundled service customers, delivery rates do not need to be considered for this assessment.

resources to serve its customers so as not to impact water rates, as assumed for this analysis (and also for the full retail service analysis). By contrast, under the full retail service plan, SSJID could meet its goal by providing a discount of about 15% off of each service element.[208] Furthermore, SSJID would have more opportunities to obtain these cost savings, given that SSJID would be taking over more service functions. These conditions make it much easier to meet SSJID's rate discount objectives under the full retail service plan.

Additional Exit Fees and Hidden Costs for Customers under CCA Service

Since CCA customers retain the right to opt out of CCA service and return to PG&E service at any time,[209] PG&E remains in competition with the CCAs in its service area throughout the life of the CCAs. From a rate perspective, this competition is driven by the comparison between PG&E's generation rate for bundled service customers and the CCA generation rate + PG&E exit fee for CCA customers.[210] This situation provides PG&E the incentive to reduce its generation rates by allocating as many costs as it can to delivery rates and exit fees.

PG&E has two authorized mechanisms for doing so:[211]

1. The Power Charge Indifference Adjustment (PCIA): The PCIA is an exit fee charged to CCA customers to meet the statutory requirement to prevent cost shifting between customers who depart from PG&E's generation service and "bundled service" customers who continue to obtain all their electrical service from PG&E.[212]It is designed to share stranded costs from PG&E's power procurement among all customers on whose behalf the costs were incurred.[213] For example, if a CCA formally commits to become the generation service provider for a CCA customer between July 2016 and June 2017, that customer becomes responsible for the stranded costs of all PG&E PCIA-eligible procurement commitments that were entered into through the end of 2016.[214] For renewable contracts, this commitment extends for the life of the contract, which can be in excess of 25 or even 30 years.

The Cost Allocation Mechanism (CAM):[215] When a system-wide need for additional generation capacity is anticipated, PG&E is required to enter into long-term contracts with new power plants in order to maintain enough generation capacity on the system to serve customers and to meet resource adequacy requirements. When PG&E enters into such a

[208] Exit fees under the full retail service plan are expected to be quite small and to have negligible impact on the rate discount or feasibility assessment.

[209] Subject to minimum stay provisions and any exit fees imposed by the CCA.

[210] As noted above, CCA customers pay the same PG&E delivery rates as PG&E bundled service customers, so delivery rates do not need to be considered in this assessment.

[211] In addition to these authorized mechanisms for charging a share of PG&E's generation-related costs to CCA customers, PG&E may also be able to increase CCA costs by disproportionately allocating costs that serve the entire utility or that provide both generation and distribution benefits to delivery rates. These costs include shared overhead functions, such as accounting and legal, shared infrastructure, such as computers and buildings, and certain power resources, such as demand response and energy storage. As part of PG&E's General Rate Cases, PG&E allocates these costs among its generation and delivery functions on a cost-causation basis. However, the ambiguous nature of cost-causation for these sorts of functions opens up an opportunity for PG&E to over-allocate these costs to delivery rates.

[212] *See* California Public Utilities Code § 366.2(a)(4) and § 366.2(d).

[213] CPUC Decision D. 08-09-012, pp. 9-10.

[214] PG&E Electric Schedule CCA-CRS, Sheet 1.

[215] The CAM is referred to as the New System Generation Charge on PG&E tariffs.

contract and a new plant is built, supply-demand principles dictate that capacity prices for other plants on the system should fall, providing a benefit to other capacity purchasers on the system, including CCAs. To avoid the situation in which PG&E and the other investor-owned utilities would be "solely responsible for the cost of new generation capacity that benefits the system as a whole,"[216] the CPUC requires the capacity costs of PG&E's new generation to be shared by all CCA customers in PG&E's service area via the CAM charge and, in return, provides CCAs with the resource adequacy credits associated with this capacity.[217] Notably, this charge is applied even if the CCA has secured long-term contracts with new power plants and has fulfilled its full resource adequacy requirement. The CPUC has since expanded this mechanism to include costs associated with certain energy storage purchases that the investor-owned utilities are obligated to make, and the utilities have requested further expansions.[218] CCA customers do not see the CAM charge as a separate exit fee; instead, the CAM charge is billed to CCA customers as part of the delivery component of their rates even though it covers generation costs.

CCA customers must pay the PCIA and CAM charges associated with PG&E generation service in addition to the full costs of CCA generation service. These PG&E charges makes it difficult for CCAs to reduce customer bills much lower than PG&E bills (and sometimes even to match PG&E bills) even when PG&E's average cost of power is above the market price for power. Indeed, the more that PG&E's average cost of power exceeds the market price for power, the higher CCA customers' exit fees rise, offsetting the benefit that the CCA may have had from access to lower cost power.

Customers of full retail service providers are generally shielded from most of these costs.[219] Unless considered to be part of a "large municipalization,"[220] they are fully exempt from PCIA and CAM charges. They do pay a small exit fee to cover costs related to specific older power purchases (which CCA customers must also pay), but this fee is relatively minor and mostly falls off after 2020.

Even customers of "large municipalizations" are partially shielded from these costs. While they must pay CAM charges for generation that was procured while they were PG&E customers, they are not required to pay CAM charges for generation that is procured after they leave PG&E service. (CCA customers must pay CAM charges for all ongoing CAM-eligible purchases.) In addition, while they are charged the same PCIA rate as CCA customers, they are likely to have the option to pay a smaller fee in exchange for the municipal utility bearing the liability and providing an upfront

---

[216] CPUC decision D.06-07-029 in R.06-02-013, July 20, 2006, page 46.

[217] Direct Access customers are treated the same as CCA customers with respect to CAM charges.

[218] PG&E and the other major utilities have requested permission to include costs associated with drought-related tree mortality in the CAM charge or an equivalent charge. *See* Petitions to Modify Decision 10-12-048 in CPUC Rulemaking R.08-08-009, April 2016.

[219] Customers of full retail service providers also cannot be allocated PG&E generation-related charges through PG&E delivery rates as CCA customers can.

[220] By default, SSJID would be considered a "small municipalization;" however, PG&E has the option to initiate a proceeding to contest this designation. Should PG&E do so and prevail (even though SSJID comprises less than 1% of PG&E's load), SSJID customers would be subject to the "large municipalization" exit fees.

payment to PG&E.[221] No such discount is likely for CCA customers because PG&E does not face the same non-payment risk from CCA customers that it does from municipal utility customers.[222]

Experience of other CCAs in PG&E's Service Area

There has been an outpouring of interest in CCA in PG&E's service area, with a number of entities finding that CCA appears to be financially feasible for their jurisdictions. The key difference between the SSJID CCA plan evaluated here and these other CCA plans is that the SSJID CCA plan is the only one that seeks to offer a 15% discount off of total PG&E rates. Other CCAs aim to be competitive with PG&E rates and perhaps to provide a cleaner power mix or other local benefits, but none has promised a set discount, let alone such a large one. In fact, the most recent rate comparisons between PG&E and the two existing CCAs in PG&E's service area, Marin Clean Energy (MCE) and Sonoma Clean Power (SCP), corroborate the difficulty of providing such a discount: Average PG&E bills are currently lower than average MCE bills for nearly all customers (by 4%- 6% for most residential rate schedules and about 2%-5% for most commercial rate schedules) and are about the same as the average SCP bills (with PG&E bills about 1% higher for most residential and small commercial rate schedules and within about ±2% of SCP bills for most large commercial rate schedules).[223] A 15% rate discount is far more ambitious than what has been achieved by existing CCAs to-date.

Additional Risks and Costs of CCA Service

In addition to the financial considerations discussed above, there are incremental risks and costs of CCA service that are not present (or not present to the same degree) for the full retail electric service plan and that must be considered as part of a CCA program evaluation.

Regulatory Requirements

CCAs and municipal utilities are subject to many of the same requirements. For example, they are both required to meet the statutory Renewable Portfolio Standards (RPS) and, for those in the California Independent System Operator's control area, the applicable resource adequacy requirements. However, as CPUC-regulated entities, CCAs are subject to additional procurement requirements and reporting requirements imposed by the CPUC. For example, CCAs are subject to CPUC rules as to which renewable power contracts qualify for the RPS program in each time period and how unused renewable energy credits may be banked, and they must submit to the CPUC annual Renewable Energy Procurement plans.[224] In addition, per Senate Bill 350 (2015), CCAs will be required to submit Integrated Resource Plans to the CPUC for certification that the plans are consistent with California's requirements for greenhouse gas reductions of 40 percent below 1990

[221] PG&E has previously done this with Merced Irrigation District and Modesto Irrigation District, providing a discount of 40% off the net present value of expected costs. See CPUC decision D.10-11-011 in proceeding A.09-06-023, page 10.

[222] Since CCA customers remain PG&E electric customers, PG&E can include the exit fees on existing bills and retains the ability to shut off electric service if exit fees are not paid. PG&E lacks this leverage over municipal utility customers, making fee payment much less certain.

[223] These comparisons are based on the CCAs' standard rate offerings. Rate comparisons are available at http://www.pge.com/en/myhome/customerservice/energychoice/communitychoiceaggregation/index.page.

[224] CCA's Renewable Energy Procurement plans must meet the requirements set forth in Public Utilities Code, Section 399.13(a)(5). See further discussion in "Assigned Commissioner and Assigned Administrative Law Judge's Ruling Identifying Issues and Schedule of Review for 2016 Renewables Portfolio Standard Procurement Plans," issued in CPUC Rulemaking R. 15-02-020, May 17, 2016, pages 7-20.

levels by 2030 and for renewable power procurement of 50 percent by 2030. In addition, they will need to demonstrate that the plans minimize local air pollutants, meet resource adequacy requirements, and consist of both short-term and long-term contracts for both generation and demand-reduction products, while providing for reliable service at reasonable rates.[225] The CPUC is in the process of developing rules associated with these Integrated Resource Plans.[226] These incremental requirements both impose reporting costs on the CCAs and also restrict a s CCA's latitude to make its own procurement decisions.

In addition to regulatory reporting costs, being under CPUC regulation and in ongoing competition with PG&E imposes risks that costs could increase or rules modified in ways that would make it difficult to cost-effectively run the CCA. For example, CCAs face the risks that RPS implementation rules could increase CCA expenses, that the CPUC could allow PG&E to recover more generation-related costs in distribution rates, and that the CPUC could impose other rules on CCAs that increase their costs or make it harder to compete against PG&E. One potential cost increase arises from the CPUC's requirement that the CCAs provide a bond to insure against "such costs as potential re-entry fees, penalties for failing to meet operational deadlines, and errors in forecasting."[227] The bond amount is currently set at $100,000; however, this is an interim amount, and a calculation methodology or final CCA bonding requirement has not yet been established.[228] There is a risk that this bond amount may be substantially increased, particularly since the equivalent bonding calculation methodology approved for Direct Access service providers includes a provision that would increase bonding requirements significantly (potentially by millions of dollars) if market rates rise significantly above PG&E's average portfolio cost.[229] While this would likely be only a short-term cost until market prices stabilized and/or PG&E's average portfolio costs increased in response to the market price increases, and this cost could be offset to some extent by a lower PG&E exit fee, this is just one example of a potential significant cost increase that a CCA could be exposed to solely due to its regulatory position. Municipal utilities are not subject to bonding requirements because they are not under CPUC jurisdiction, and PG&E does not retain the responsibility to serve as the provider of last resort for municipal utilities, as it does for CCAs. More broadly, municipal utilities are not subject to the regulatory risk that will always be present for CCAs on account of the CPUC's regulatory authority over CCAs.

Load Uncertainty

If SSJID proceeds with its full retail electric plan, all customers in its jurisdiction will be served by SSJID, generally without the option to take service from PG&E or any other service provider. If SSJID were a CCA provider, customers would have the option at the start of the program to opt out of the CCA and to remain on PG&E's service, and they would retain the right to switch back and forth

---

[225] SB 350, Section 27 (Public Utilities Code, Section 454.52 (a)(1) and (a)(3)). Per Section 35, large municipal utilities with annual loads exceeding 700 gigawatt-hours will have similar requirements under the jurisdiction of the California Energy Commission. Based on current SSJID load expectations, SSJID as a municipal electric utility would be exempt from this requirement.
[226] CPUC Rulemaking R.16-02-007.
[227] Re-entry fees are the costs that PG&E would bear if the CCA were to fail and all its customers were to be returned at once to PG&E's generation service. CPUC Decision D.05-12-041, page 18.
[228] In May 2008, this issue became part of the scope of CPUC proceeding R.03-10-003. A number of parties arrived at a settlement agreement concerning the calculation methodology; however, the settlement was vigorously opposed by Marin Clean Energy and the City of San Francisco and has not been adopted.
[229] The provision requires the bond to cover any positive difference between market-based costs for PG&E to serve the Direct Access load and PG&E's retail generation rates.

between PG&E and CCA service (subject to any minimum stay provisions and exit fee requirements from PG&E and the CCA). If PG&E rates were to fall notably below SSJID rates or to remain consistently below PG&E rates, or if SSJID went through a period of poor reliability or other operational constraint that affected customers, SSJID could therefore face a large exodus of customers. This would reduce SSJID's customer base and revenue flow, limiting SSJID's ability to reduce rates and to remedy any operational problems. Furthermore, a large exodus could substantially increase costs in the short-term since SSJID would likely remain liable for the full amount of the power contracts that SSJID had obtained to serve these customers. Such a condition could start a downward spiral that could lead to the failure of the CCA.

In addition to the potential for this extreme result (which has not yet been experienced by a California CCA), ongoing uncertainty regarding the CCA load forecast imposes a more modest cost by making it more difficult to procure the right amount of power to serve load. This is particularly a concern for the initial power contracts, which must be structured with the flexibility to accommodate an unknown number of customers opting out of the CCA to remain with PG&E. It will also remain a concern throughout the life of the CCA: since customers will retain the option to leave CCA service, the CCA needs to accommodate the risk of load loss. This can be done in a number of ways, such as by procuring more flexible power contracts, by setting aside reserve funds to self-insure against this risk, or by off-loading this risk onto a third party. Regardless of the manner in which the risk is handled, it will impose additional cost on the CCA, such as more expensive power contracts or the cost of hedging contracts or of tying up CCA capital. Municipal utilities also face load uncertainty from customer solar generation, economic cycles, and other natural variations in loads, but because their customers do not have the option to return to PG&E service, the level of uncertainty is much lower than that experienced by CCAs.

PCIA Risk

The PCIA is established based on an assessment of how much of PG&E's portfolio is "stranded," which is calculated by comparing the cost of PG&E's portfolio to a theoretical market price. This calculation is far from exact and also lacks transparency: many of the calculation inputs are considered confidential, so CCA providers cannot audit the calculations to ascertain whether their customers are being charged more or less than their fair share of costs, whether PG&E's procurement decisions were reasonable, and whether PG&E did everything it could to reduce stranded costs. The calculation is also highly sensitive to changes in market prices in ways that can be difficult to predict since the calculation depends on both market prices and on how these market prices affect PG&E's costs. As a result, CCA provider are very limited in their ability to manage these costs or even to plan for them, given that the fees can change dramatically from year to year.[230]

The difficulties in predicting and managing PCIA fees were highlighted late last year when CCA providers were informed that PG&E's PCIA fees would double at the start of 2016.[231] PG&E now anticipates additional sizable PCIA increases for 2017.[232] These exit fees add considerable cost for CCA customers without providing any offsetting benefit. They also reduce costs for PG&E bundled

[230] PG&E is working with the CCAs on a framework under which PG&E would provide estimated five-year forecasts of PCIA fees; however, these forecasts would not be binding and would be subject to change.
[231] The PCIA increased from 1.16 cents per kWh for new residential CCA customers in 2015 to 2.32 cents per kWh for new CCA residential customers in 2016. PG&E Electric Schedule E-1, Sheet 5 (January 2015 and January 2016).
[232] A PG&E June 2016 rate filing predicts a 23% increase in exit fees for new residential CCA customers in 2017, to 2.87 cents per kWh. PG&E 2017 ERRA forecast, Table 15-3.

service against which the CCAs are competing. PCIA risk can therefore be very difficult for CCA providers to manage: the costs are unpredictable, highly variable, and can be significant.

PCIA Risk from Widespread CCA Adoption

In addition to the ongoing PCIA fee risk discussed above, there is a particular risk for PCIA exit fee increases in the event of widespread CCA adoption. In recent years, there has been an explosion of interest in CCA from municipal governments in PG&E's service area. Every coastal county in PG&E's service area, as well as a number of more inland areas, are exploring (or have launched) CCA. With the launch of each CCA, PG&E's customer base for generation shrinks, and if many of these CCAs are successful, PG&E's generation load may be much smaller than anticipated. For example, a scenario in which PG&E's generation load falls over the next few years to half its current level is plausible, and this could have significant impacts for both PG&E's bundled customers and for CCA customers. The nature and scale of these impacts are currently highly uncertain, presenting a risk for the CCA that cannot yet be readily quantified and that requires continued attention. Municipal service customers are shielded from this risk unless they are considered to be customers of "large municipalizations."

Conclusion

It does not appear feasible for SSJID to meet its goal of providing a 15% discount off of PG&E rates by providing CCA service. Furthermore, CCA service presents a number of risks that are not present under the full retail service model, mostly due to the CPUC regulation and ongoing competition with PG&E. Any decision to establish a CCA program should be done only after careful consideration of these risks.