NEW ISSUE—FULL BOOK-ENTRY ONLY **RATINGS: (See "RATINGS" herein.)**

In the opinion of Orrick, Herrington & Sutcliffe LLP, Bond Counsel to NCPA, based on an analysis of existing laws, regulations, rulings and court decisions and assuming, among other matters, the accuracy of certain representations and compliance with certain covenants, interest on the 2012 Series A Bonds is excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986 (the "Code"). In the further opinion of Bond Counsel, interest on the 2012 Series A Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes, although Bond Counsel observes that such interest is included in adjusted current earnings when calculating corporate alternative minimum taxable income. Bond Counsel also observes that interest on the 2012 Series B Bonds is not excluded from gross income for federal income tax purposes under Section 103 of the Code. Bond Counsel is also of the opinion that interest on the 2012 Bonds is exempt from State of California personal income taxes. Bond Counsel expresses no opinion regarding any other federal or state tax consequences relating to the ownership or disposition of, or the accrual or receipt of interest on, the 2012 Bonds. See "TAX MATTERS" herein.

Northern California Power Agency
Hydroelectric Project Number One Revenue Bonds

$76,665,000
2012 Refunding Series A

$7,120,000
2012 Taxable Refunding Series B

Dated: Date of Delivery **Due: July 1, as shown on the inside cover**

This cover page contains certain information for general reference only. It is not intended to be a summary of the security or terms of the 2012 Bonds. Investors are advised to read the entire Official Statement to obtain information essential to the making of an informed investment decision. Capitalized terms used on this cover page not otherwise defined will have the meanings set forth herein.

Northern California Power Agency ("NCPA") is offering $76,665,000 of its Hydroelectric Project Number One Revenue Bonds, 2012 Refunding Series A (the "2012 Series A Bonds") and $7,120,000 of its Hydroelectric Project Number One Revenue Bonds, 2012 Taxable Refunding Series B (the "2012 Series B Bonds" and together with the 2012 Series A Bonds, the "2012 Bonds"). The 2012 Bonds are being issued by NCPA pursuant to an Indenture of Trust, dated as of March 1, 1985, as amended and supplemented, including as supplemented by the Twenty-Second Supplemental Indenture of Trust, dated as of February 1, 2012, and by the Twenty-Third Supplemental Indenture of Trust, dated as of February 1, 2012 (collectively, the "Indenture"), by and between NCPA and U.S. Bank National Association, as successor trustee (the "Trustee") for the purpose of providing funds to refund NCPA's Outstanding Hydroelectric Project Number One Revenue Bonds, 1998 Refunding Series A, to make a deposit to the debt service reserve account for the 2012 Bonds and to pay costs of issuance of the 2012 Bonds. See "PLAN OF REFUNDING" herein.

The 2012 Bonds are being issued as fully registered bonds and, when issued, will be registered in the name of Cede & Co., as nominee of The Depository Trust Company, New York, New York ("DTC"). DTC will act as securities depository for the 2012 Bonds, and individual purchases of the 2012 Bonds will be made in book-entry form only. Interest on the 2012 Bonds of each Series is payable on each January 1 and July 1, beginning on July 1, 2012. Principal is payable on July 1 of the years and in the amounts set forth on the inside cover page hereof. The 2012 Bonds of each Series may be purchased in authorized denominations of $5,000 and any integral multiple thereof. Principal, premium, if any, and interest on the 2012 Bonds is payable by the Trustee to DTC, which is obligated in turn to remit such principal, premium, if any, and interest to its DTC Participants for subsequent disbursement to the beneficial owners of the 2012 Bonds. See "APPENDIX C – BOOK-ENTRY ONLY SYSTEM" hereto.

The 2012 Bonds are subject to redemption prior to maturity as described herein.

THE 2012 BONDS ARE SPECIAL, LIMITED OBLIGATIONS OF NCPA PAYABLE SOLELY FROM THE TRUST ESTATE, AND SECURED SOLELY BY A PLEDGE AND ASSIGNMENT OF THE TRUST ESTATE, CONSISTING PRIMARILY OF THE NCPA REVENUES (AS DEFINED HEREIN) AND THE OTHER FUNDS PLEDGED BY NCPA UNDER THE INDENTURE. THE 2012 BONDS DO NOT CONSTITUTE A CHARGE AGAINST THE GENERAL CREDIT OF NCPA. THE 2012 BONDS ARE NOT DEBTS, LIABILITIES OR OBLIGATIONS OF THE STATE OF CALIFORNIA, ANY PUBLIC AGENCY THEREOF (OTHER THAN NCPA), ANY MEMBER OF NCPA OR ANY PROJECT PARTICIPANT, AND NEITHER THE FAITH AND CREDIT NOR THE TAXING POWER OF ANY OF THE FOREGOING (INCLUDING NCPA) IS PLEDGED FOR THE PAYMENT OF THE 2012 BONDS. NCPA HAS NO TAXING POWER.

MATURITY SCHEDULES
(see inside cover)

The 2012 Bonds are offered when, as and if issued and delivered to the Underwriters, subject to the approval of legality by Orrick, Herrington & Sutcliffe LLP, Los Angeles, California, Bond Counsel to NCPA, and certain other conditions. Certain legal matters will be passed upon for NCPA by Meyers, Nave, Riback, Silver & Wilson, Sacramento, California, General Counsel to NCPA, by Spiegel & McDiarmid LLP, Washington, D.C., Washington Counsel to NCPA. Certain legal matters will be passed upon for the Underwriters by Fulbright & Jaworski L.L.P., Los Angeles, California, Counsel to the Underwriters. It is expected that the 2012 Bonds in definitive form will be available for delivery through the facilities of DTC in New York, New York, by Fast Automated Securities Transfer (FAST) on or about February 7, 2012.

Citigroup

Goldman, Sachs & Co. **Morgan Stanley**

January 24, 2012

MATURITY SCHEDULES

Northern California Power Agency
Hydroelectric Project Number One Revenue Bonds

$76,665,000
2012 Refunding Series A Bonds

Maturity Date (July 1)	Principal Amount	Interest Rate	Yield	CUSIP†
2024	$ 4,475,000	5.00%	3.05%[c]	664845EB6
2025	11,265,000	5.00	3.15[c]	664845EC4
2026	11,830,000	5.00	3.27[c]	664845ED2
2027	12,425,000	5.00	3.39[c]	664845EE0
2028	13,040,000	5.00	3.51[c]	664845EF7
2029	4,570,000	5.00	3.61[c]	664845EG5
2030	4,800,000	5.00	3.71[c]	664845EH3
2031	5,040,000	5.00	3.76[c]	664845EJ9
2032	9,220,000	5.00	3.86[c]	664845EK6

$7,120,000
2012 Taxable Refunding Series B

Maturity Date (July 1)	Principal Amount	Interest Rate	Price	CUSIP†
2024	$7,120,000	4.32%	100%	664845EA8

[c] Yield based on price to par call date of July 1, 2022.

NORTHERN CALIFORNIA POWER AGENCY
651 Commerce Drive
Roseville, California 95678
Telephone: (916) 781-3636

NCPA Commissioners And Members

Gary Plass, Chairman ....Mayor, Healdsburg
Roger Firth, ...Mayor, Biggs
Larry Hansen, ... Councilmember, Lodi
Yiaway Yeh ....Mayor, Palo Alto
Carol Garcia....................................Councilmember, Roseville
Benj Thomas.. Councilmember, Ukiah
Tony Laliotis..........................Board Member, Truckee Donner Public Utility District
Dan Boeger..Councilmember, Gridley

John McCahan, Vice Chairman .... Commissioner, Public Utilities Board City of Alameda
Bob Lingl..Councilmember, Lompoc
Rick Bosetti ....Councilmember, Redding
Patrick Kolstad.............................Councilmember, Santa Clara
Vacant..Port of Oakland
Frank Schultz..........................Energy Manager, San Francisco Bay Area Rapid Transit District
Daniel Kenney ....Vice President, Board of Directors Plumas-Sierra Rural Electric Cooperative, (Associate Member)

Management

General Manager..James H. Pope
Assistant General Manager, Finance and Administrative Services; Chief Financial Officer .... Donna I. Stevener
Assistant General Manager, Legislative & Regulatory .... Jane Dunn Cirrincione
Assistant General Manager, Business Development ....Donald Dame
Assistant General Manager, Power Management...David Dockham
Assistant General Manager, Generation Services .... Ken Speer
Human Resources Manager .... Lynn Bianchi-Rossi

Project Participants

Participant	Project Entitlement Percentage
Alameda	10.00%
Biggs	0.10
Gridley	1.06
Healdsburg	1.66
Lodi	10.37
Lompoc	2.30
Palo Alto	22.92
Roseville	12.00
Santa Clara	35.86
Ukiah	2.04
Plumas-Sierra Rural Electric Cooperative	1.69
	100.00%

Special Services

General Counsel to NCPA
Meyers, Nave, Riback, Silver & Wilson
Sacramento, California

Bond Counsel
Orrick, Herrington& Sutcliffe LLP
Los Angeles, California

Washington Counsel
Spiegel & McDiarmid LLP
Washington, D.C.

Auditor
Moss Adams LLP
Portland, Oregon

Trustee
U.S. Bank National Association
New York, New York

Verification Agent
Grant Thornton LLP
Minneapolis, Minnesota

Financial Advisor
Public Financial Management, Inc.
San Francisco, California

No dealer, broker, salesperson or any other person has been authorized by NCPA, the Project Participants or the Underwriters to give any information or to make any representation, other than the information and representations contained herein, in connection with the offering of the 2012 Bonds and, if given or made, such information or representations must not be relied upon as having been authorized by any of the foregoing. This Official Statement does not constitute an offer to sell or the solicitation of an offer to buy, nor will there be any sale of, the 2012 Bonds in any jurisdiction in which it is unlawful to make such offer, solicitation or sale. This Official Statement is not to be construed as a contract with the purchasers of the 2012 Bonds.

Statements contained in this Official Statement, which include estimates, forecasts or matters of opinion, are intended solely as such and are not to be construed as representations of fact. The information set forth herein has been furnished by NCPA, the Project Participants or other sources which are believed to be reliable. The information and expressions of opinion herein are subject to change without notice, and neither the delivery of this Official Statement nor any sale made hereunder shall, under any circumstances, create any implication that there has been no change in the matters described herein since the date hereof. This Official Statement, including any supplement or amendment hereto, is intended to be filed with the Municipal Securities Rulemaking Board through the Electronic Municipal Marketplace (EMMA) website.

U.S. Bank National Association accepts its duties as Trustee for the 2012 Bonds. Notwithstanding the foregoing, however, the Trustee has not reviewed this Official Statement and makes no representations as to the information contained herein, including, but not limited to, any representations as to the financial feasibility of NCPA or its Members, the Project or any related activities.

The Underwriters have provided the following sentence for inclusion in this Official Statement: The Underwriters have reviewed the information in this Official Statement in accordance with, and as part of, its responsibilities to investors under the federal securities laws as applied to the facts and circumstances of this transaction, but the Underwriters do not guarantee the accuracy or completeness of such information.

IN CONNECTION WITH THE OFFERING OF THE 2012 BONDS THE UNDERWRITERS MAY OVERALLOT OR EFFECT TRANSACTIONS THAT STABILIZE OR MAINTAIN THE MARKET PRICE OF THE 2012 BONDS AT LEVELS ABOVE THOSE WHICH MIGHT OTHERWISE PREVAIL IN THE OPEN MARKET. SUCH STABILIZING, IF COMMENCED, MAY BE DISCONTINUED AT ANY TIME.

CAUTIONARY STATEMENTS REGARDING
FORWARD-LOOKING STATEMENTS IN
THIS OFFICIAL STATEMENT

Certain statements included or incorporated by reference in this Official Statement constitute "forward-looking statements." Such statements are generally identifiable by the terminology used such as "plan," "expect," "estimate," "budget" or other similar words. Such forward-looking statements include, but are not limited to, certain statements contained in the information under the captions "RATE REGULATION," "DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS" and "OTHER FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY" in this Official Statement and in the description of each of the Significant Share Project Participant's operations set forth in APPENDIX A hereto. Forward-looking statements in APPENDIX A and elsewhere in this Official Statement are subject to risks and uncertainties, including particularly those relating to natural gas costs and availability, wholesale and retail electric energy and capacity prices, federal and state legislation and regulations, competition and industry restructuring, and the economies of the service areas of the Project Participants.

The achievement of certain results or other expectations contained in such forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. NCPA does not plan to issue any updates or revisions to those forward-looking statements if or when its expectations or events, conditions or circumstances on which such statements are based occur.

NCPA maintains a website. However, the information presented therein is not part of this Official Statement and should not be relied upon in making investment decisions with respect to the 2012 Bonds.

TABLE OF CONTENTS

TABLE OF CONTENTS
(Continued)

TABLE OF CONTENTS
(Continued)

Page

[THIS PAGE INTENTIONALLY LEFT BLANK]

OFFICIAL STATEMENT
OF
NORTHERN CALIFORNIA POWER AGENCY

Relating to its

Hydroelectric Project Number One Revenue Bonds

$76,665,000	**$7,120,000**
2012 Refunding Series A	**2012 Taxable Refunding Series B**

INTRODUCTION

This Introduction is qualified in its entirety by reference to the more detailed information included and referred to elsewhere in this Official Statement. The offering of the 2012 Bonds to potential investors is made only by means of the entire Official Statement. Capitalized terms used in this Introduction and not otherwise defined herein will have the respective meanings assigned to them elsewhere in this Official Statement. See "APPENDIX D – SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE—Certain Definitions."

Purpose

The purpose of this Official Statement, which includes the cover page and appendices hereto, is to set forth certain information concerning (i) the Northern California Power Agency ("NCPA"); (ii) NCPA's $76,665,000 Hydroelectric Project Number One Revenue Bonds, 2012 Refunding Series A (the "2012 Series A Bonds") and $7,120,000 Hydroelectric Project Number One Revenue Bonds, 2012 Taxable Refunding Series B (the "2012 Series B Bonds" and together with the 2012 Series A Bonds, the "2012 Bonds"); and (iii) the eleven NCPA Members which have entered into the Third Phase Agreement (hereinafter defined) with NCPA (collectively, the "Project Participants") relating to NCPA's Hydroelectric Project Number One (the "Project"), including in particular the five principal Project Participants (the "Significant Share Project Participants").

The 2012 Bonds are being issued by NCPA for the purpose of providing funds to refund NCPA's Outstanding Hydroelectric Project Number One Revenue Bonds, 1998 Refunding Series A (the "Refunded 1998 Bonds"), to make a deposit to the debt service reserve account for the 2012 Bonds and to pay costs of issuance of the 2012 Bonds. See "PLAN OF REFUNDING."

NCPA

NCPA is a joint exercise of powers agency formed under the Act and an Amended and Restated Northern California Power Agency Joint Powers Agreement (the "NCPA Joint Powers Agreement") now among the City of Alameda ("Alameda"), the City of Biggs ("Biggs"), the City of Gridley ("Gridley"), the City of Healdsburg ("Healdsburg"), the City of Lodi ("Lodi"), the City of Lompoc ("Lompoc"), the City of Palo Alto ("Palo Alto"), the City of Redding ("Redding"), the City of Roseville ("Roseville"), the City of Santa Clara ("Santa Clara"), the City of Ukiah ("Ukiah"), the City of Oakland acting by and through its Board of Port Commissioners ("Port of Oakland"), the Truckee Donner Public Utility District ("Truckee Donner"), and the San Francisco Bay Area Rapid Transit District ("BART") as members, and the Plumas-Sierra Rural Electric Cooperative ("Plumas-Sierra"), as an associate member (herein collectively referred to as the "Members" and individually as a "Member"). The Placer County Water Agency ("PCWA") is also an "associate member" of NCPA by separate agreement, although it is not a signatory to the NCPA Joint Powers Agreement and does not participate in any NCPA projects. The terms “Member” or “Members” as used herein do not include PCWA. The Project Participants and their Project Entitlement Percentages are shown on page (a) hereof. The five principal Project Participants (the “Significant Share Project Participants”), representing in aggregate over 90% in Project Entitlement Percentages, are Alameda, Lodi, Palo Alto, Roseville and Santa Clara.

Authority for Issuance

The 2012 Bonds are being issued pursuant to the provisions of Article 4 of the Act and Articles 10 and 11 of Chapter 3 of Part 1 of Division 2 of Title 5 of the Government Code of the State of California and under and in accordance with an Indenture of Trust, dated as of March 1, 1985, as amended and supplemented, including as supplemented by the Twenty-Second Supplemental Indenture of Trust, dated as of February 1, 2012, and by the Twenty-Third Supplemental Indenture of Trust, dated as of February 1, 2012 (collectively, the “Indenture”), by and between NCPA and U.S. Bank National Association, as successor trustee (the “Trustee”), the Agreement for Construction, Operation and Financing of the North Fork Stanislaus River Hydroelectric Development Project, dated as of September 1, 1982, as amended (the “Third Phase Agreement”), by and among NCPA and the Project Participants, and the Power Purchase Contract dated July 6, 1981, as amended and revised by the Revised Power Purchase Contract, dated as of March 1, 1985 (the “Power Purchase Contract”), by and between NCPA and Calaveras County Water District (“Calaveras”).

The 2012 Bonds and all Hydroelectric Project Number One Revenue Bonds Outstanding under the Indenture are referred to herein as the “Hydroelectric Project Bonds.”

The Project

The Project consists of a 248.5 megawatt (“MW”) hydroelectric project and related facilities, described under the caption “THE PROJECT.” NCPA is entitled, under the Power Purchase Contract (i) to receive the electric output of the Project for 50 years from February 1982, with an option to purchase Project capacity and energy in excess of Calaveras’ requirements thereafter, subject to Federal Energy Regulatory Commission (“FERC”) approval, and (ii) to operate the generating facilities of the Project. In February 1990, the operating portions of the Project were declared substantially complete and commercially operable. The Project is used for load-following by NCPA to balance the baseload of the Project Participants and the generation from the Project and other resources available to the Project Participants through NCPA.

Third Phase Agreement

Under the Third Phase Agreement, NCPA has agreed to provide, and each Project Participant has agreed to take or cause to be taken, the Project Participant’s Project Entitlement Percentage of the capacity and energy of the Project. The Project Participants pay for such capacity and energy on a cost-of-service basis. Each Project Participant has agreed to make payments for such capacity and energy solely from the revenues of, and as an operating expense of, such Project Participant’s electric system. Such payments must be made regardless of whether or not the Project is operable, operating or retired and notwithstanding the suspension, interruption, interference, reduction or curtailment of Project output or the capacity and energy contracted for in whole or in part for any reason whatsoever. See “SECURITY AND SOURCES OF PAYMENT FOR THE 2012 BONDS—Third Phase Agreement.”

Security and Sources of Payment for the 2012 Bonds

The 2012 Bonds are special, limited obligations of NCPA. The 2012 Bonds are payable solely from, and secured solely by a pledge and assignment of, the Trust Estate, consisting primarily of the NCPA Revenues, and the other funds pledged by NCPA under the Indenture as described under the caption "SECURITY AND SOURCES OF PAYMENT FOR THE 2012 BONDS."

The 2012 Bonds are not debts, liabilities or obligations of the State of California, any public agency thereof (other than NCPA), any Member of NCPA or any Project Participant and neither the faith and credit nor the taxing power of any of the foregoing (including NCPA) is pledged for the payment of the 2012 Bonds. NCPA has no taxing power.

2012 Series A and B Debt Service Reserve Account

Pursuant to the Indenture, a 2012 Series A and B Debt Service Reserve Account (the "2012 Series A and B Debt Service Reserve Account") will be established in the Debt Service Fund to secure the 2012 Bonds. The 2012 Series A and B Debt Service Reserve Account is required to be maintained in an amount equal to the 2012 Series A and B Debt Service Reserve Requirement. The 2012 Series A and B Debt Service Reserve Requirement is defined in the Indenture to mean an amount equal to twenty-five percent (25%) of the greatest aggregate amount of Debt Service for the 2012 Bonds coming due in the then current or any future Fiscal Year (initially, $3,933,958.50). Upon the issuance of the 2012 Bonds, the 2012 Series A and B Debt Service Reserve Account will be funded from a portion of the proceeds of the 2012 Bonds in an amount equal to the 2012 Series A and B Debt Service Reserve Requirement. Amounts on deposit in the 2012 Series A and B Debt Service Reserve Account will be applied to make up any deficiency in the Debt Service Account for the payment of principal of and interest on the 2012 Bonds.

In lieu of funding the 2012 Series A and B Debt Service Reserve Account with cash, pursuant to the Indenture, NCPA may cause to be deposited in the 2012 Series A and B Debt Service Reserve Account, a Financial Guaranty or Financial Guaranties in an amount equal to the difference between the 2012 Series A and B Debt Service Reserve Requirement and the funds, if any, then on deposit in the 2012 Series A and B Debt Service Reserve Account or being deposited in the 2012 Series A and B Debt Service Reserve Account concurrently with such Financial Guaranty or Guaranties.

See "SECURITY AND SOURCES OF PAYMENT FOR THE 2012 BONDS—2012 Series A and B Debt Service Reserve Account."

Risk Factors

For a description of certain risks associated with the purchase of the 2012 Bonds, see "SECURITY AND SOURCES OF PAYMENT FOR THE 2012 BONDS—Limitations on Remedies," "RATE REGULATION," "CONSTITUTIONAL CHANGES IN CALIFORNIA," "DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS," "OTHER FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY" and "LITIGATION."

Continuing Disclosure

NCPA and the Significant Share Project Participants have each agreed, pursuant to Continuing Disclosure Agreements with the Trustee, to provide to the Municipal Securities Rulemaking Board (the "MSRB") through its Electronic Municipal Market Access System (the "EMMA System") a copy of their respective annual audited financial statements, as well as certain operating data relating to the Project and the Significant Share Project Participants' respective electric systems. Such audited financial statements are required to be prepared in accordance with generally accepted accounting principles. NCPA will provide to the MSRB through the EMMA System such Project information and its financial statements (unaudited if audited financial statements are not then available) within 180 days after the end of its fiscal year, and each Significant Share Project Participants will provide to the MSRB through the EMMA System their respective financial statements (unaudited if audited financial statements are not then available) and operating data relating to their respective electric systems within 210 days after the end of their respective fiscal years. If unaudited financial statements are provided, audited financial statements will be provided as soon as available. In addition, NCPA has agreed to give timely notice to the MSRB through the EMMA System, of the occurrence of certain enumerated events. These agreements have been made in order to assist the Underwriters in complying with Securities and Exchange Commission Rule 15c2-12(b)(5) (the "Rule"). As of the date hereof, NCPA has not failed to comply in all material respects with any previous undertakings with regard to the provision of annual reports or notices of specified events as required by the Rule. See "APPENDIX E – PROPOSED FORMS OF CONTINUING DISCLOSURE AGREEMENTS."

Other Matters

The summaries of and references to all documents, statutes, reports and other instruments referred to herein do not purport to be complete, comprehensive or definitive, and each such summary and reference is qualified in its entirety by reference to each document, statute, report or instrument. The capitalization of any word not conventionally capitalized or otherwise defined herein indicates that such word is defined in a particular agreement or other document and, as used herein, has the meaning given to it in such agreement or document. In preparing this Official Statement, NCPA has relied upon certain information relating to the Project Participants furnished to NCPA by the Project Participants.

Attached to this Official Statement is a summary of certain provisions of the Indenture. Copies of the Indenture, the Escrow Agreement, the Third Phase Agreement and the Continuing Disclosure Agreements are available for inspection at the offices of NCPA in Roseville, California, and will be available upon request and payment of duplication costs from the Trustee.

PLAN OF REFUNDING

Prior Financing

The 1998 Bonds were originally issued in the aggregate principal amount of $301,490,000 pursuant to the Indenture for the purpose of refinancing a portion of the costs of the Project. As of the date hereof, $88,355,000 principal amount of the 1998 Bonds remains Outstanding.

Refunding Plan

The Refunded 1998 Bonds consist of all of the $88,355,000 principal amount of the 1998 Bonds remaining Outstanding. The 2012 Bonds are being issued for the purpose of providing funds to redeem the Refunded 1998 Bonds on or about March 9, 2012. The 2012 Bonds are also being issued to fund a deposit to the 2012 Series A and B Debt Service Reserve Account and to pay costs of issuance of the 2012 Bonds.

Pursuant to an Escrow Agreement (the "Escrow Agreement"), to be entered into by NCPA and U.S. Bank National Association, as Trustee, a portion of the proceeds of the 2012 Bonds will be deposited into an escrow fund (the "Escrow Fund") and will either be held as cash or will be used to purchase defeasance securities (the "Escrow Securities") that will bear interest at such rates and will be scheduled to mature at such times and in such amounts so that, when paid in accordance with their respective terms, and together with the cash held in the Escrow Fund, sufficient moneys will be available to pay when due the interest on the Refunded 1998 Bonds to the redemption date and the redemption price (100.0% of the principal amount) of the Refunded 1998 Bonds on the redemption date.

On the date of delivery of the 2012 Bonds, NCPA will receive a report from Grant Thornton LLP, verifying the adequacy of the cash deposited and held in the Escrow Fund, together with the maturing principal amounts of and interest earned on the Escrow Securities, to pay when due the interest on the Refunded 1998 Bonds to the redemption date and the redemption price of the Refunded 1998 Bonds on the redemption date. See "VERIFICATION OF MATHEMATICAL COMPUTATIONS."

Upon such deposit, the Refunded 1998 Bonds will no longer be deemed to be Outstanding under the Indenture, and all obligations of NCPA with respect to the Refunded 1998 Bonds shall cease and terminate, except for the obligation of NCPA to cause the amounts due on the Refunded 1998 Bonds to be paid from funds on deposit in the Escrow Fund.

ESTIMATED SOURCES AND USES OF FUNDS

The estimated sources and uses of funds with respect to the 2012 Bonds and other amounts are as follows:

	2012 Series A Bonds	2012 Series B Bonds	Total
Sources of Funds			
Par amount	$76,665,000	$7,120,000	$83,785,000
Original Issue Premium	10,323,500	--	10,323,500
Transfer from Refunded 1998 Bonds funds and accounts	343,966	28,178	372,145
Total	$87,332,466	$7,148,178	$94,480,645
Uses of Funds			
Deposit to Escrow Fund	$82,444,662	$6,753,876	$89,198,539
Transferred Proceeds Penalty	659,849	--	659,849
Deposit to 2012 Series A and B Debt Service Reserve Account	3,599,653	334,305	3,933,958
Costs of Issuance(1)	628,302	59,997	688,299
Total	$87,332,466	$7,148,178	$94,480,645

(1) Costs of issuance include legal, financing and consulting fees, underwriters' discount, fees of the verification agent, trustee and escrow agent, rating agency fees, printing costs and other miscellaneous expenses.

OTHER OBLIGATIONS OF NCPA

Each NCPA project is separately financed. As of December 1, 2011, in addition to the $440.8 million Hydroelectric Project Bonds Outstanding under the Indenture (of which $88.355 million is being refunded by the 2012 Bonds), NCPA had outstanding approximately $55.1 million Capital Facilities Revenue Bonds, $33.8 million outstanding Geothermal Project Number 3 Revenue Bonds and $395.7 million Lodi Energy Center Revenue Bonds. For further information on NCPA projects and related bond issues, see "OTHER NCPA PROJECTS." Each Project Participant is also a direct or indirect participant in one or more of such other NCPA projects.

In 2004, NCPA entered into an interest rate swap agreement (the "2004 Swap Agreement") with Citigroup Financial Products Inc. ("CFPI") in an initial notional amount of $85.16 million in anticipation of refunding $85.87 million principal amount of NCPA's then outstanding 1998 Bonds (the "Previously Refunded 1998 Bonds"). The Previously Refunded 1998 Bonds were refunded with the issuance of NCPA's Hydroelectric Project Number One Revenue Bonds, 2008 Refunding Series A (the "2008 Series A Bonds") and 2008 Refunding Series B (Taxable) (the "2008 Series B Bonds").

The 2008 Series A Bonds and the 2008 Series B Bonds are variable rate obligations secured by respective letters of credit. The existing letters of credit for the 2008 Series A Bonds and the 2008 Series B Bonds have been provided by Citigroup, N.A. and have a scheduled expiration date of September 27, 2014. The reimbursement agreements for such letters of credit obligate NCPA to repay Citibank, N.A. for amounts drawn under the respective letter of credit. The interest rate payable by NCPA for unreimbursed draws under the letters of credit may be considerably higher than the interest rate on the 2008 Series A Bonds and the 2008 Series B Bonds. While NCPA may attempt in such event to refinance the 2008 Series A Bonds and 2008 Series B Bonds to avoid this additional debt burden, there can be no assurance that NCPA will have access to the debt markets.

Pursuant to the 2004 Swap Agreement, the floating rate interest payments that NCPA is obligated to make with respect to the 2008 Series A Bonds were converted into substantially fixed rate payments. In general, the terms of the 2004 Swap Agreement provide that, on a same-day net-payment basis determined by reference to a notional amount equal to the principal amount of the Outstanding 2008 Series A Bonds, NCPA will pay a fixed interest rate on the notional amount. In return, CFPI will pay a variable rate of interest under the 2004 Swap Agreement on a like notional amount. The agreement by CFPI to make payments under the 2004 Swap Agreement does not affect NCPA's obligation to make payment of the 2008 Series A Bonds. Under certain circumstances, the 2004 Swap Agreement is subject to termination and NCPA may be required to make a substantial termination payment to the counterparty thereunder. Payments due from NCPA under the 2004 Swap Agreement, including any amounts payable upon early termination thereof, are payable from amounts on deposit in the General Reserve Account on a basis that is junior and subordinate to the payment of the Hydroelectric Project Bonds and are insured by National Public Finance Guarantee Corporation (formerly MBIA Insurance Corporation).

THE 2012 BONDS

The following is a summary of certain provisions of the 2012 Bonds. Reference is made to the Indenture for a more detailed description of such provisions. The discussion herein is qualified by such reference.

General

The 2012 Bonds of each Series are being issued in the respective aggregate principal amounts indicated on the inside cover page of this Official Statement, will mature on July 1 in the years and in the amounts, and will bear interest at the rates per annum, as shown on the inside cover page of this Official Statement. The 2012 Bonds of each Series will be dated their date of delivery. Interest on the 2012 Bonds of each Series is payable on January 1 and July 1 of each year, commencing July 1, 2012 (calculated on the basis of a 360-day year comprised of twelve 30-day months).

The 2012 Bonds are being issued in fully registered form, and, when issued, will be registered in the name of Cede & Co., as nominee for The Depository Trust Company, New York, New York ("DTC"), such registered owner of 2012 Bonds being hereinafter referred to as the "Holder." DTC will act as securities depository for the 2012 Bonds. Ownership interests in the 2012 Bonds may be purchased in book-entry form only. Ownership interests in the 2012 Bonds of each Series may be purchased in authorized denominations of $5,000 and any integral multiple thereof. Purchasers will not receive securities certificates representing their interests in the 2012 Bonds purchased. Payments of principal of, premium, if any, and interest on the 2012 Bonds is payable by the Trustee to DTC, which is obligated in turn to remit such principal, premium, if any, and interest to its DTC Participants for subsequent disbursement to the beneficial owners of the 2012 Bonds. See “APPENDIX C – BOOK-ENTRY ONLY SYSTEM.”

Redemption of 2012 Bonds

Optional Redemption

2012 Series A Bonds. The 2012 Series A Bonds are subject to redemption prior to their stated maturity, at the option of NCPA, in whole or in part, in such amounts as may be specified by NCPA, on any date on or after July 1, 2022, from any source of available funds, at a redemption price equal to the principal amount of 2012 Series A Bonds called for redemption, plus unpaid accrued interest to the date fixed for redemption, without premium.

2012 Series B Bonds. The 2012 Series B Bonds are subject to redemption prior to their stated maturity, at the option of NCPA, in whole or in part, in such amounts as may be specified by NCPA, on any date, from any source of available funds, at a redemption price equal to 100% of the principal amount of such 2012 Series B Bonds plus the Make Whole Premium (as defined below), if any, plus unpaid accrued interest, if any, thereon to the redemption date.

The “Make-Whole Premium” with respect to any 2012 Series B Bond to be redeemed will be equal to the positive difference, if any, between:

(1) the sum of the present values, calculated as of the date fixed for redemption of: (a) each interest payment that, but for such redemption, would have been payable on the 2012 Series B Bonds or portion thereof being redeemed on each regularly scheduled interest payment date occurring after the dated fixed for redemption through the maturity date of the Series 2012 Series B Bonds (excluding any accrued interest for the period prior to the redemption date); provided, that if the date fixed for redemption is not a regularly scheduled interest payment date with respect to such 2012 Series B Bonds, the amount of the next regularly scheduled interest payment will be reduced by the amount of the interest accrued on such 2012 Series B Bond to the date fixed for redemption, plus (b) the principal amount that, but for such redemption, would have been payable at the final maturity of the 2012 Series B Bonds or portion thereof being redeemed; minus

(2) the principal amount of the 2012 Series B Bonds or portion thereof being redeemed.

The present values of interest and principal payments referred to in paragraph (1) above will be determined by discounting the amount of each interest or principal payment from the date that each such payment would have been payable, but for the redemption to the date fixed for redemption on a semiannual basis (assuming a 360-day year consisting of twelve 30-day months) at a discount rate equal to the “comparable treasury yield” (as defined below) plus 40 basis points.

The Make Whole Premium will be calculated by an independent investment banking institution or independent financial advisor of national standing appointed by NCPA.

For purposes of determining the Make-Whole Premium, “comparable treasury yield” means a rate of interest per annum equal to the weekly average yield to maturity for the preceding week appearing in the most recently published statistical release designated “H.15(519) Selected Interest Rates” under the heading “Treasury Constant Maturities,” or any successor publication that is published weekly by the Board of Governors of the Federal Reserve System and that establishes yields on actively traded United

States Treasury securities adjusted to constant maturity, for the maturity corresponding to the remaining term to maturity of the 2012 Series B Bonds ("the H.15 statistical release"). The comparable treasury yield will be determined as of the third business day immediately preceding the applicable redemption date. If the H.15 statistical release sets forth a weekly average yield for United States Treasury Securities having a constant maturity that is the same as the remaining term calculated as set forth above, then the comparable treasury yield will be equal to such weekly average yield. In all other cases, the comparable treasury yield will be calculated by interpolation on a straight-line basis, between the weekly average yields on the United States Treasury Securities (in each case as set forth in the H.15 statistical release) that have a constant maturity (i) closest to and greater than the remaining term to maturity of the 2012 Series B Bonds being redeemed; and (ii) closest to and less than the remaining term to maturity of the 2012 Series B Bonds being redeemed. Any weekly average yields calculated by interpolation will be rounded to the nearest 1/100th of 1%, with any figure of 1/200th of 1% or above being rounded upward.

If, and only if, weekly average yields for United States Treasury securities for the preceding week are not available in the H.15 statistical release, then the comparable treasury yield will be the rate of interest per annum equal to the semiannual equivalent yield to maturity of the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price (each as defined herein) as of the date fixed for redemption.

"Comparable Treasury Issue" means the United States Treasury security selected by the independent investment banking institution or independent financial advisor of national standing appointed by NCPA as having a maturity comparable to the remaining term to maturity of the 2012 Series B Bond being redeemed that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term to maturity of the 2012 Series B Bond being redeemed.

"Comparable Treasury Price" means, with respect to any date on which a 2012 Series B Bond or portion thereof is being redeemed, either (a) the average of five Reference Treasury Dealer quotations for the date fixed for redemption, after excluding the highest and lowest such quotations, and (b) if the independent investment banking institution or independent financial advisor of national standing appointed by NCPA is unable to obtain five such quotations, the average of the quotations that are obtained. The quotations will be the average, as determined by the independent investment banking institution or independent financial advisor of national standing appointed by NCPA, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of principal amount) quoted in writing to the independent investment banking institution or independent financial advisor of national standing appointed by NCPA, at 5:00 p.m. New York City time on the third business day preceding the date fixed for redemption.

"Reference Treasury Dealer" means a primary United States Government securities dealer in the United States appointed by NCPA (which may be one of the Underwriters) and reasonably acceptable to the independent investment banking institution or independent financial advisor of national standing appointed by NCPA.

Extraordinary Redemption

The 2012 Bonds are subject to redemption prior to their stated maturity, at the option of NCPA, in whole or in part (in such amounts as may be specified by NCPA) on any date, from: (i) insurance or condemnation proceeds and (ii) from any source of money if all or substantially all of the Initial Facilities are damaged or destroyed, taken by any public entity in the exercise of its powers of eminent domain or disposed of or abandoned, at a redemption price equal to the principal amount thereof, plus unpaid accrued interest to the date fixed for redemption, without premium; provided that the option of NCPA to call the 2012 Bonds for redemption from insurance or condemnation proceeds will expire 90 days following the receipt of such insurance or condemnation proceeds.

Selection of 2012 Bonds for Redemption

NCPA may select the Series of the 2012 Bonds, the maturities of the 2012 Bonds and the principal amount of each such maturity to be redeemed in its sole discretion. Whenever provision is made in the Indenture for the redemption of less than all of the 2012 Bonds of like maturity of any Series, the Trustee will select the 2012 Bonds to be redeemed from all 2012 Bonds of such Series and maturity subject to redemption and not previously called for redemption, at random in any manner which the Trustee in its sole discretion will deem appropriate and fair.

Notice of Redemption

The Indenture requires the Trustee to give notice of the redemption of any 2012 Bonds by mailing a notice of redemption of such 2012 Bonds, postage prepaid, not less than 30 days before the redemption date, to the Holders of any 2012 Bonds or portions of 2012 Bonds which are to be redeemed, at their last address appearing upon the registry books. Among other things, such notice will state that on the redemption date there will become due and payable on each 2012 Bond to be redeemed the redemption price thereof, or the redemption price of the specified portions of the principal thereof in the case of 2012 Bonds to be redeemed in part only, together with unpaid accrued interest to the redemption date, and that on and after such date, interest thereon will cease to accrue and be payable. Receipt of such notice will not be a condition precedent to such redemption and failure so to receive such notice or any defect in such notice will not affect the validity of the proceedings for the redemption of 2012 Bonds. So long as the 2012 Bonds are in book-entry form, such notice of redemption by the Trustee to the Holders will be mailed only to DTC (or its nominee).

SECURITY AND SOURCES OF PAYMENT FOR THE 2012 BONDS

Pledge Effected by the Indenture

The 2012 Bonds are special, limited obligations of NCPA payable solely from, and secured solely by a pledge and assignment of, the following pursuant to the Indenture, which constitutes the Trust Estate: (a) subject only to the provisions of the Indenture permitting the application thereof for the purposes and on the terms and conditions set forth therein, (i) the proceeds of the sale of the Hydroelectric Project Bonds, (ii) (a) all revenues, income, rents and receipts derived or to be derived by NCPA from or attributable to the Project or the Power Purchase Contract or to the payment of the costs of the Project received or to be received by NCPA under the Third Phase Agreement or the Power Purchase Contract or under any other contract for the sale by NCPA of the Project or any part thereof or any contractual arrangement with respect to the use of the Project or any portion thereof or the services or capacity thereof, (b) the proceeds of any insurance, including the proceeds of any self-insurance fund, covering business interruption loss relating to the Project, and (c) interest received or to be received on any moneys or securities (other than in the Construction Fund) held pursuant to the Indenture and required to be paid into the Revenue Fund established thereunder ("NCPA Revenues"), and (iii) all amounts on deposit in the Funds established by the Indenture, including the investments, if any, thereof to the extent held by the Trustee and (b) all right, title and interest of NCPA in, to and under the Third Phase Agreement and the Power Purchase Contract.

The 2012 Bonds and the interest thereon are payable solely from the funds provided therefor under the Indenture and will not constitute a charge against the general credit of NCPA. The 2012 Bonds are not secured by a legal or equitable pledge of, or lien or charge upon, any

property of NCPA or any of its income or receipts except the Trust Estate pledged pursuant to the Indenture which is subject to the provisions of the Indenture permitting the application thereof for the purposes and on the terms and conditions set forth therein. Neither the faith and credit nor the taxing power of the State of California or any public agency thereof or any Member of NCPA or any Project Participant is pledged to the payment of the principal of, or interest on, the 2012 Bonds. NCPA has no taxing power. Neither the payment of the principal of, or interest on, the 2012 Bonds constitutes a debt, liability or obligation of the State of California or any public agency thereof (other than NCPA) or any Member of NCPA or any Project Participant. The Commissioners, directors, officers and employees of NCPA will not be individually liable on the 2012 Bonds or in respect of any undertakings by NCPA under the Indenture.

The 2012 Bonds are payable from and secured by the Trust Estate on a parity basis with all other Hydroelectric Project Bonds Outstanding under the Indenture. As of December 1, 2011, there was $440,760,000 aggregate principal amount of Hydroelectric Project Bonds Outstanding under the Indenture, of which $88,355,000 are being refunded by the 2012 Bonds.

Order of Application of NCPA Revenues

Pursuant to the Indenture, all NCPA Revenues received are to be deposited promptly in the Revenue Fund upon receipt thereof. Amounts in the Revenue Fund are to be paid monthly in the following order of priority for application therefrom as follows:

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK.]

Revenue Fund

First → Operating Reserve Fund[1]

Second → Operating Fund[2]

Third → Debt Service Fund
- Debt Service Account
- Debt Service Reserve Account[3]
- Series Debt Service Reserve Accounts

Fourth → Subordinated Indebtedness Fund[4]

Fifth → Note Fund[5]

Sixth → Reserve and Contingency Fund[6]
- Renewal and Replacement Account
- Reserve Account

Seventh → General Reserve Fund
- Rate Stabilization Account
- General Account

---

(1) To be maintained in such amount as recommended by a Consulting Engineer. The Consulting Engineer has recommended that such amount be set to $0, provided that NCPA has established a common special reserve fund for the operating and maintenance expenses of the Project and the NCPA Geothermal Project in an amount not less than $3,000,000. Such special reserve has been established.

(2) To be applied for the payment of NCPA Operating Expenses.

(3) The Debt Service Reserve Account is maintained in an amount equal to the Debt Service Reserve Requirement as defined in APPENDIX D. Amounts in the Debt Service Reserve Account are available to fund deficiencies in the Debt Service Account for Participating Bonds. The 2012 Bonds are Non-Participating Bonds and are not secured by amounts in the Debt Service Reserve Account. See “SECURITY AND SOURCES OF PAYMENT FOR THE 2012 BONDS—2012 Series A and B Debt Service Reserve Account.”. NCPA’s Outstanding Hydroelectric Project Number One Revenue Bonds, 1992 Refunding Series A will be the only Participating Bonds following the refunding of the Refunded 1998 Bonds described herein. The 2012 Bonds, the 2008 Series A Bonds, the 2008 Series B Bonds and NCPA’s Hydroelectric Project Number One Revenue Bonds, 2008 Refunding Series C, 2008 Taxable Refunding Series D, 2010 Refunding Series A and 2010 Taxable Refunding Series B are not Participating Bonds. The Indenture provides that Future Bonds will be Participating Bonds unless otherwise provided in the Supplemental Indenture authorizing such Future Bonds. Future Bonds may be supported by amounts in a Debt Service Reserve Account established for such Future Bonds or may be issued with no debt service reserve.

(4) To be applied to the payment of Subordinated Indebtedness under the Indenture. There is currently no Subordinated Indebtedness Outstanding under the Indenture.

(5) To be applied to the payment of Notes. There are currently no Notes Outstanding under the Indenture.

(6) Amounts in the Renewal and Replacement Account (currently $0) are to be applied to the costs of Capital Improvements. The Reserve Account is to be maintained amount as recommended by the Consulting Engineer. Amounts in the Reserve Account, if any, are to be applied to the costs of Capital Improvements not funded from the Renewal and Replacement Account, to the payment of extraordinary operating and maintenance costs of the Project and to contingencies. Amounts in the Reserve and Contingency Fund, if any (currently $0) are available to fund deficiencies in Operating Fund or Debt Service Fund.

See "APPENDIX D – SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE" for further discussion of certain of the terms and provisions of the Indenture relating to the application of NCPA Revenues.

NCPA Rate Covenant

Pursuant to the Indenture, NCPA has covenanted, at all times, to establish and collect rates and charges with respect to the Project to provide NCPA Revenues at least sufficient in each Fiscal Year, together with other available funds, for the payment of all of the following: (i) NCPA Operating Expenses, (ii) Aggregate Debt Service, (iii) all other required deposits to any Funds under the Indenture, and (iv) all other charges or other amounts whatsoever payable out of NCPA Revenues during such Fiscal Year. See "APPENDIX D – SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE—Rate Covenant."

2012 Series A and B Debt Service Reserve Account

Upon issuance of the 2012 Bonds, the 2012 Series A and B Debt Service Reserve Requirement for the 2012 Bonds will be $3,933,958.50. A portion of the proceeds of the 2012 Bonds of each Series will be deposited into the 2012 Series A and B Debt Service Reserve Account concurrently with the issuance of the 2012 Bonds in an amount equal to the 2012 Series A and B Debt Service Reserve Requirement. Amounts on deposit in the 2012 Series A and B Debt Service Reserve Account will be applied to make up any deficiency in the Debt Service Account for the payment of principal of and interest on the 2012 Bonds.

Pursuant to the Indenture, in lieu of the required deposits and transfers of money to the 2012 Series A and B Debt Service Reserve Account, NCPA may cause to be deposited to the 2012 Series A and B Debt Service Reserve Account a Financial Guaranty or Financial Guaranties in an amount equal to the difference between the 2012 Series A and B Debt Service Reserve Requirement and the funds, if any, then on deposit in the 2012 Series A and B Debt Service Reserve Account or being deposited in the 2012 Series A and B Debt Service Reserve Account concurrently with such Financial Guaranty or Guaranties. "Financial Guaranty" is defined to mean any of the following: (i) an irrevocable, unconditional and unexpired letter of credit issued by a bank, a trust company, a national banking association, a corporation subject to registration with the Board of Governors of the Federal Reserve System under the Bank Holding Company Act of 1956 or any successor provision of law, a federal branch pursuant to the International Banking Act of 1978 or any successor provision of law or a domestic branch or agency of a foreign bank which branch or agency is duly licensed or authorized to do business under the laws of any state or territory of the United States of America, the unsecured or uncollateralized long-term debt obligations of which, or long-term obligations secured or supported by a letter of credit issued by such person, are rated at the time such letter of credit is delivered, without regard to qualification of such rating agency by symbols such as "+" or "-" or numerical notation, in at least the second highest rating category by each rating agency then providing a rating on Outstanding Hydroelectric Project Bonds and which also rates such persons or such obligations; or (ii) an irrevocable and unconditional policy of insurance or surety bond in full force and effect issued by an insurance company or association duly authorized to do business in the State of New York and the State of California (y) the claims paying ability of which, at the time of purchase, is rated the highest rating accorded by a nationally recognized insurance rating agency or (z) obligations insured by a surety bond or an insurance policy issued by such company or association are rated at the time such surety bond or insurance policy is delivered, without regard to qualification of such rating by symbols such as "+" or "-" or numerical notation, in the highest rating category by each rating agency then providing a rating on 2012 Bonds and which also rates such companies and associations or such obligations; in each case providing for the payment thereunder of moneys when required pursuant to the terms of the Indenture.

Any cash on deposit in the 2012 Series A and B Debt Service Reserve Account may be invested in securities described in Investment Securities as defined in the Indenture (see "APPENDIX D – SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE—Certain Definitions") and in the following: (a) shares in a California common law trust established pursuant to Title 1, Division 7, Chapter 5 of the Government Code of the State of California which invests exclusively in investments permitted by Section 53601 of Title 5, Division 2, Chapter 4 of the Government Code of California, as it may be amended; (b) Money market funds rated at least AAAm by S&P; (c) Local Agency Investment Fund (LAIF); (d) commercial paper rated at the time of purchase in the highest short-term rating category by Moody's and by S&P. Any commercial paper shall have a maximum maturity of 270 days or less. The entity that issues the commercial paper shall meet all of the following conditions described in either (1) or (2) as follows: (1) such entity (i) is organized and operating in the United States as a general corporation; (ii) has total assets in excess of five hundred million dollars ($500,000,000); and (iii) has debt other than commercial paper, if any, that is rated "A" or higher by a nationally recognized statistical-rating organization; or (2) such entity (i) is organized within the United States as a special purpose corporation, trust, or limited liability company; (ii) has program wide credit enhancements including, but not limited to, over collateralization, letters of credit, or surety bond and (iii) has commercial paper that is rated "A-1" or higher, or the equivalent, by a nationally recognized statistical-rating organization. Any investments credited to the 2012 Series A and B Debt Service Reserve Account shall be valued at the times and in the manner provided with respect to investments credited to the Debt Service Reserve Account as provided in the Indenture. Pursuant to the Indenture, the investments of cash in the 2012 Series A and B Debt Service Reserve Account shall have such maturities or be subject to redemption at the option of the owner of the investments as shall provide moneys in the 2012 Series A and B Debt Service Reserve Account at the time or times NCPA expects such moneys to be required for purposes of the 2012 Series A and B Debt Service Reserve Account.

Pursuant to the Indenture, certain prior Series of Hydroelectric Project Bonds were secured by, and all future Series of Hydroelectric Project Bonds other than Hydroelectric Project Bonds authorized by a Supplemental Indenture that provides that such Hydroelectric Project Bonds are not "Participating Bonds" will be secured by, the Debt Service Reserve Account. The Indenture provides that a Supplemental Indenture authorizing a Series of Hydroelectric Project Bonds may provide that such Hydroelectric Project Bonds are not Participating Bonds (all such Hydroelectric Project Bonds being referred to as "Non-Participating Bonds") and may be secured by a Series Debt Service Reserve Account. Amounts on deposit in any Series Debt Service Reserve Account for any Series of Non-Participating Bonds shall be used and withdrawn as provided in the Supplemental Indenture of Trust authorizing the issuance of such Non-Participating Bonds. Amounts on deposit in the 2012 Series A and B Debt Service Reserve Account for the 2012 Bonds does not secure in any manner any other Series of Hydroelectric Project Bonds. Amounts on deposit in the Debt Service Reserve Account secure only Participating Bonds. Amounts on deposit in any Series Debt Service Reserve Account other than the 2012 Series A and B Debt Service Reserve Account do not secure in any manner the 2012 Bonds.

See "APPENDIX D – SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE—Debt Service Reserve Fund."

Additional Hydroelectric Project Bonds

NCPA may issue Hydroelectric Project Bonds under and secured by the Indenture to refund bonds previously issued and Outstanding under and secured by the Indenture and may, although it does not expect to, issue Additional Bonds to finance Capital Improvements to the Project. For further information, see "APPENDIX D – SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE—Additional Bonds" and "– Refunding Bonds."

Third Phase Agreement

Project Participants' Take-or-Pay Obligation. The Third Phase Agreement authorizes NCPA to fix charges thereunder equal to the amounts anticipated to be needed to provide capacity and energy from the Project, including but not limited to debt service, operation, maintenance and replacement costs, a reasonable reserve for contingencies, and all other costs of the Project. The Third Phase Agreement further provides that, to the extent that the funds provided thereunder and described in the preceding sentence are not sufficient for such purposes, the Project Participants will pay an amount equal to their Project Entitlement Percentage of debt service on bonds, notes and other evidences of indebtedness (including an applicable percentage of the 2012 Bonds), reserves therefor, and all other payments required to be made under the Indenture and the Power Purchase Contract, whether or not the Project is completed, operable, operating or retired and notwithstanding the suspension, interruption, interference, reduction or curtailment of Project output or the power and energy contracted for in whole or in part for any reason whatsoever.

Operating Expense. Each Project Participant will make payments under the Third Phase Agreement solely from the Revenues of, and as an operating expense of, its electric system. Nothing in the Third Phase Agreement prohibits any Project Participant from using any other funds and revenues to satisfy the provisions thereof.

Project Participants' Rate Covenant. Each Project Participant agrees to establish and collect fees and charges for electric capacity and energy furnished through facilities of its electric system sufficient to provide Revenues adequate to meet its obligations under the Third Phase Agreement and to pay any and all other amounts payable from or constituting a charge and lien upon any or all such Revenues.

Increase in Non-defaulting Project Participants' Original Project Entitlement Percentage. Upon the failure of any Project Participant to make any payment, which failure constitutes a default under the Third Phase Agreement, and except as sales and transfers are made pursuant thereto, the Third Phase Agreement provides that the Project Entitlement Percentage of each non-defaulting Project Participant will be automatically increased for the remaining term of the Third Phase Agreement, pro rata with those of the other non-defaulting Project Participants thereunder; provided, however, that the sum of such increases for any non-defaulting Project Participant will not exceed, without written consent of such non-defaulting Project Participant, an accumulated maximum of 25% of the non-defaulting Project Participant's original Project Entitlement Percentage.

Transfer, Sale or Assignment. Each Project Participant has the right to make transfers, sales and/or assignments of its interests in Project capacity and energy and rights thereto; provided that no such transfer, sale or assignment shall adversely affect the tax-exempt status of interest on Hydroelectric Project Bonds issued under the Indenture. No such transfer, sale or assignment shall relieve the Project Participant of its obligations under the Third Phase Agreement. No Project Participant shall transfer its electric system unless the Project Participant provides assurance that its obligations under the Third Phase Agreement will be promptly and adequately met, including providing sufficient moneys for such purpose if no other adequate assurance is available.

Limitations on Remedies

The rights of the owners of the 2012 Bonds are subject to the limitations on legal remedies against cities and other public agencies in the State. Additionally, enforceability of the rights and remedies of the owners of the 2012 Bonds, and the obligations incurred by the NCPA and the Project Participants, may become subject to the following: the Federal Bankruptcy Code and applicable bankruptcy, insolvency, reorganization, moratorium, or similar laws relating to or affecting the enforcement of creditor's rights generally, now or hereafter in effect; equity principles which may limit the specific enforcement under State law of certain remedies; the exercise by the United States of America of the powers delegated to it by the Constitution; and the reasonable and necessary exercise, in certain exceptional situations, of the police powers inherent in the sovereignty of the State and its governmental bodies in the interest of serving a significant and legitimate public purpose. Bankruptcy proceedings, or the exercise of powers by the federal or State government, if initiated, could subject the owners of the 2012 Bonds to judicial discretion and interpretation of their rights in bankruptcy or otherwise, and consequently may entail risks of delay, limitation, or modification of their rights.

NORTHERN CALIFORNIA POWER AGENCY

Background

NCPA is a joint exercise of powers agency formed under the Act and the NCPA Joint Powers Agreement now among Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc, Oakland (acting by and through its Board of Port Commissioners), Palo Alto, Redding, Roseville, Santa Clara, Ukiah, Truckee Donner, and BART as members, and Plumas-Sierra, as an associate member (herein collectively referred to as the "Members" and individually as a "Member").

Under the terms of the NCPA Joint Powers Agreement entered into by all Members, NCPA possesses the general powers to acquire, purchase, generate, transmit, distribute and sell electrical capacity and energy. Specific powers include the power to enter into contracts, acquire and construct electric generating facilities, set rates, issue revenue bonds and notes and acquire property by eminent domain.

The Member Services Agreements, dated as of February 12, 1981, and the Facilities Agreement, dated as of September 22, 1993 and which has superseded the Member Services Agreements, provide for the development of all projects undertaken by NCPA in three separate phases: (i) the initial phase of general investigation funded by NCPA's general fund; (ii) the second phase whereby Members of NCPA electing to participate in the project execute a project agreement to provide for the cost of development of the project (now referred to as an "NCPA Project"); and (iii) the third phase during which all remaining aspects, including financing, construction and operation of the NCPA Project are undertaken.

Members of NCPA have no financial or other responsibility or liability associated with the acquisition, construction, maintenance, operation or financing of any NCPA project pursuant to the NCPA Joint Powers Agreement. Members become obligated for payments with respect to a NCPA project only as participants with respect to such project as set forth in an agreement with NCPA separate from the NCPA Joint Powers Agreement.

NCPA has supplied many services to its Members in the past and expects to continue to do so in the future. NCPA has been instrumental in litigating and negotiating with Pacific Gas and Electric Company ("PG&E"), the California Independent System Operator (the "ISO") and the Western Area Power Administration of the federal government ("Western") to keep wholesale power and transmission and other ancillary services rates at levels which have resulted in substantial savings when compared to rates sought by each of those suppliers. It is anticipated that NCPA will continue to litigate and/or negotiate on behalf of its Members to maintain rates at levels which will result in continued advantage to its Members.

NCPA's audited financial statements for the fiscal years ended June 30, 2011 and 2010 are attached as APPENDIX B.

Organization and Management

NCPA's governing body (the "Commission") is composed of one representative from each Member, each such representative being designated a Commissioner. The Commission is given the general management of the affairs, property and business of NCPA and is vested with all powers of NCPA. Under the NCPA Joint Powers Agreement, associate Members do not have a voting seat on the Commission, except as may be provided in a project agreement.

The management of NCPA is responsible for various areas of administration and planning of NCPA's operations and affairs. The overall management is under the direction of NCPA's General Manager, who serves at the discretion of the Commission. NCPA is organized into four separate divisions: (i) generation services, (ii) power management, (iii) legislative and regulatory, and (iv) administrative services.

Set forth below is a brief biography of each of NCPA's senior managers.

JAMES H. POPE, General Manager, was appointed General Manager of NCPA in January 2004. Prior to the appointment Mr. Pope served as the Director of Electric Utility for the City of Santa Clara since December 1996. Mr. Pope has experience in the electric and gas industry with a background in general management, operations, engineering and construction for PG&E serving as Vice President, Technical and Construction Services; Vice President for Sacramento Valley Region; and Manager, Gas Transmission and Distribution Construction. Mr. Pope has been in various public power leadership roles, including positions as Chairman and Vice Chairman of the Transmission Agency of Northern California (TANC) where he started the process to get Path 15 built. Mr. Pope now serves on the Board of Governors of the California Municipal Utilities Association (CMUA), and the Board of Directors of the California Foundation on the Environment and the Economy (CFEE). He also served as a member of the Board of Governors of the California Independent System Operator (ISO). In March 2002, he was appointed by Secretary of Energy Spencer Abraham to serve on the Secretary's Electricity Advisory Board.

Mr. Pope has a Bachelor of Science degree from Oregon State University and a Master's of Science degree in Civil Engineering from Stanford University. He attended the Harvard University Business School (Program for Management Development) Executive Program.

DONNA I. STEVENER, Assistant General Manager, Finance/Administrative Services, Chief Financial Officer, received a Bachelor of Science degree in Business Administration/Accounting with high honors from California Baptist University. Ms. Stevener is a retired Certified Public Accountant in the State of California and has over 29 years of finance experience, including 20 years specializing in the power industry. Before joining NCPA in April 2005, Ms. Stevener was employed by Riverside Public Utilities as a member of the executive management team. At NCPA, Ms. Stevener oversees the Administrative Services division which includes finance, accounting, power settlements, information services and facilities management and performs as the Chief Financial Officer of NCPA.

JANE DUNN CIRRINCIONE, Assistant General Manager, Legislative and Regulatory, received a Masters degree in Public Administration from the University of Southern California, and a Bachelor of Science degree in Political Science from the University of Santa Clara in Santa Clara, California and the London School of Economics. Ms. Cirrincione has over 24 years of experience in the energy and environmental policy arena. Prior to joining NCPA, she was a Senior Government Relations Representative for the American Public Power Association ("APPA") in Washington, D.C. APPA is the national trade association representing the country's over 2,000 public power systems. Before joining APPA, she was the Director of Legislative Programs for the National Hydropower Association, representing all sections of the U.S. hydroelectric industry. She also spent several years on Capitol Hill as a Legislative Assistant for Congressman Don Edwards working on environmental and wildlife issues impacting the San Francisco Bay. Before moving to Washington, D.C., she worked for the U.S. Fish and Wildlife Service at the Sacramento National Wildlife Refuge. Ms. Cirrincione was the 2006 recipient of the Robert E. Roundtree Rising Star Award recognizing future leaders of public power systems.

DAVID DOCKHAM, Assistant General Manager, Power Management, has worked in the electric utility industry since 1982 on a broad range of utility industry projects, activities and issues. Mr. Dockham's experience includes contract development and negotiation, engineering design, system planning, policy and procedure development, public presentations to boards, commissions and industry work groups; and participation in regional and state level policy and technical working groups. From 2001 through 2007, Mr. Dockham managed NCPA's activities and interactions with the ISO and associated regulatory proceedings on behalf of the NCPA's Members utilizing services under the Second Amended and Restated NCPA Metered Subsystem Aggregation Agreement and the NCPA-PG&E Interconnection Agreement. He currently manages planning, contracts, fuel purchases, and pooling arrangements for NCPA. Mr. Dockham has a Bachelor of Science degree in Electrical and Electronic Engineering from California State University, Sacramento, a Masters degree in Business Administration from the University of California, Davis and is a registered Professional Engineer in the State of California.

DONALD DAME, Assistant General Manager, Business Development, received his Bachelor's degree in Economics with honors from the University of California in 1975, and a Master's degree in Regulatory Economics from the University of Wyoming in 1978. Mr. Dame joined NCPA in November 1992. Prior to that time, he worked in various gas and power planning and contracting positions at the California Department of Water Resources, PacifiCorp, Bonneville Power Administration, and the Colorado Interstate Gas Company. His primary focus at NCPA is to assist its Members as a member liaison and to meet with other public agencies to find mutually beneficial business opportunities to expand or more fully utilize NCPA service capabilities for the enhancement and advancement of public power in northern California.

KEN SPEER, Assistant General Manager, Generation Services, has over 30 years of experience in the generation resource management field, having also managed significant generation facilities for the City of Santa Clara (Silicon Valley Power) and PG&E. Mr. Speer also served as the Director of Capital Investment for Duke Energy North America, where he oversaw the capital investment program for the company's California-based assets. Mr. Speer has a Bachelor of Science degree in Mechanical and Nuclear Engineering from the University of California, Berkeley, and is a Registered Mechanical Engineer.

LYNN BIANCHI-ROSSI, Human Resources Manager received a Bachelor of Science degree from the school of Business and Public Administration at California State University, Sacramento in 1979. Ms. Bianchi-Rossi has over 30 years of experience in human resources in a variety of industries, with over 27 of those years in a management role. Ms. Bianchi-Rossi assumed her duties with NCPA in May 2001. Prior to joining NCPA, she was the Corporate Services Director for Jones & Stokes Environmental Consulting. She also has prior work experience with the County of Sacramento and a nation-wide gas company.

NCPA Power Pool

NCPA operates a power pool that includes the following Members: Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc, Palo Alto, Plumas Sierra Rural Electric Cooperative, the Port of Oakland and Ukiah (each, an "NCPA Pool Member"). The ten NCPA Pool Members' service areas are connected to the ISO-controlled grid. NCPA operates a central dispatch facility (the "Central Dispatch Center") at NCPA's headquarters. The Central Dispatch Center balances loads and resources pursuant to the Second Amended and Restated NCPA Metered Subsystem Aggregation Agreement (the "MSSA") with the ISO (as described below) for the ten NCPA Pool Members, and Santa Clara. The Central Dispatch Center separately coordinates with Roseville to schedule Roseville's entitlement to Project output across the ISO-controlled grid as requested by Roseville. The Central Dispatch Center also monitors and controls load and voltage levels, operates generating facilities, enters into buy and sell transactions with other utilities throughout the western United States and Canada and regulates hydroelectric facilities in coordination with the ISO to maintain a safe and reliable interconnected system.

NCPA operates according to the terms and conditions of the ISO tariff and the MSSA, the original form of which was approved by FERC in 2002 and was amended and restated to conform to the market restructuring that became effective in 2009. The MSSA identifies operational terms and conditions that vary from the ISO tariff, largely allowing NCPA Members to continue to operate as a vertically integrated utility by generally self-providing for resources and services otherwise procured through the ISO's markets. In conjunction with the execution of the MSSA, NCPA and PG&E entered into an Interconnection Agreement (the "NCPA-PG&E Interconnection Agreement") that provided for the terms and conditions for connecting NCPA resources and member loads to the ISO-controlled grid, where such ISO-controlled grid facilities are owned by PG&E and transferred to ISO operational control through a Transmission Control Agreement between PG&E and the ISO.

In April 2009, the ISO implemented a complete overhaul of its tariff, replacing the market design embodied under the ISO tariff with an updated market design and tariff which has been entitled the Market Redesign and Technology Upgrade ("MRTU"). This overhaul largely changes how generation units are scheduled, transmission rights are allocated, and wholesale energy, capacity and ancillary service costs are allocated to NCPA and its Members. NCPA was an active participant in FERC proceedings, ISO-led stakeholder meetings, and market simulations to test market participant scheduling and settlement systems in advance of MRTU implementation to ensure that Member interests were protected and that NCPA would be able to operate successfully under the new market design. NCPA and the ISO negotiated amendments to the MSSA to adapt to the changes resulting from MRTU.

Santa Clara has separate agreements for the services provided under the MSSA and NCPA-PG&E Interconnection Agreement. See "APPENDIX A – SELECTED INFORMATION RELATING TO THE SIGNIFICANT SHARE PROJECT PARTICIPANTS—CITY OF SANTA CLARA."

Wholesale Power Trading

NCPA trades in the Western wholesale electricity markets to maximize the value of its transmission and generation assets and to minimize its cost of power supply for its Members. NCPA has engaged in wholesale market transactions since 1984. While there have from time to time been bankruptcies among participants in those markets, NCPA claims against those bankruptcy estates have all been resolved and NCPA does not have any additional financial exposure due to past bankruptcies in the electric utility industry. See "LITIGATION—California Energy Market Dysfunction, Refund Dispute and Related Litigation."

Investment of NCPA Funds

All funds of NCPA (except bond proceeds which are invested pursuant to the indenture under which such bonds are issued) are invested in accordance with NCPA's investment policy and guidelines (the "Investment Policy") as authorized by Sections 53600 et seq. of the Government Code of the State of California. The Investment Policy and monthly activity reports are approved by the NCPA Commission.

The following securities, if and to the extent the same are at the time legal and in compliance with the applicable bond covenants and agreements for investment of NCPA's funds, are authorized investments under the Investment Policy: (i) securities of the U.S. Government, or its agencies, (ii) certificates of deposit (or time deposits) placed with commercial banks and/or savings and loan companies, (iii) negotiable certificates of deposit, (iv) bankers acceptances, (v) Local Agency Investment Fund (State Pool) demand deposits, (vi) repurchase agreements, (vii) passbook savings account demand deposits, (viii) municipal bonds, and (ix) commercial paper.

The Investment Policy provides the following guidelines, among others. All rated securities must be rated by Moody's or S&P as "A" or better. All certificates of deposit must mature within one year. All collateralized certificates of deposit must mature within one year. Certificates of deposit with a face value in excess of $100,000 will be collateralized by Treasury Department securities or first mortgage loans. The Treasury bills or notes must be at least 110% of the face value of the certificate of deposit collateralized in excess of the first $100,000. The value of first mortgages must be at least 150% of the face value of the certificate of deposit balance secured in excess of the first $100,000. The portfolio will be diversified with holdings from at least several of the major eligible market sectors. Except for obligations issued or guaranteed by the U.S. Government, federal agencies or Government-sponsored corporations and the Local Agency Investment Fund, no more than 10% of an NCPA construction project or of the NCPA operating funds portfolio will be invested in the securities of any one issuer. Unless otherwise restricted, all holdings will be of sufficient size and held in issues which are actively traded to facilitate transactions at a minimum cost and accurate market valuation. Buying and selling securities before settlement or the use of reverse repurchase agreements for speculative purposes is not authorized. A reverse repurchase agreement may be used only in infrequent circumstances and only to prevent a material loss that would otherwise result from the sale of an investment for liquidity purposes. Any reverse repurchase agreements must be specifically reported to the Commission along with the reasons therefor on a timely basis.

The Investment Policy may be changed at any time at the discretion of the Commission subject to the State law provisions relating to authorized investments. Any exception to the Investment Policy must be formally approved by the Commission. There can be no assurance, therefore, that the State law and/or the Investment Policy will not be amended in the future to allow for investments which are currently not permitted under such State law or the Investment Policy, or that the objectives of NCPA with respect to investments will not change.

CALAVERAS COUNTY WATER DISTRICT

Calaveras County Water District is a county water district formed under the laws of the State of California. Calaveras' primary objective is to provide water and wastewater service to the residents of Calaveras County. In so doing, Calaveras is engaged in the development of hydroelectric power for financial support and water supplies. Calaveras' operational activities of providing water and wastewater service include approximately 13,000 customers. Calaveras has no obligation on the 2012 Bonds.

On November 25, 1997, the Calaveras County Water District Board of Directors determined that the Limited Obligation Improvement Bonds, New Hogan/La Contenta Regional Development Sewer and Water Assessment District No. 604, would ultimately have insufficient funds in the redemption fund to discharge the unpaid bonds and interest and that, an ultimate loss to the bondholders would occur. The AD 604 bonds are a land-secured debt obligation of the individual property owners, not that of the Calaveras. The bonds were originally issued in 1990 and matured on September 2, 2011. NCPA does not believe that such default will have a material adverse impact on the operations of the Project or NCPA's rights under the Power Purchase Contract.

THE HYDROELECTRIC PROJECT

The Project consists of (a) three diversion dams, (b) the 243-MW Collierville Powerhouse, (c) the Spicer Meadow Dam with a 5.5-MW powerhouse, and (d) associated tunnels located essentially on the North Fork Stanislaus River and on the Stanislaus River in Alpine, Tuolumne and Calaveras Counties, California, together with required transmission and related facilities.

The Project, with the exception of certain transmission facilities, is owned by Calaveras and is licensed by FERC, pursuant to a 50-year License (Project No. 2409) issued in 1982 to Calaveras. Pursuant to the Power Purchase Contract, NCPA (i) is entitled to the electric output of the Project until February 2032, (ii) managed the construction of the Project, and (iii) operates the generating and recreational facilities of the Project. Under a separate FERC-issued license with an expiration date coterminous with the Project No. 2409 license (Project No. 11197), NCPA holds the license and owns the 230 kV Collierville-Bellota and the 21 kV Spicer Meadows-Cabbage Patch transmission lines for Project No. 2409. NCPA also has a separate FERC license for Project No. 11563 (Upper Utica Project), which consists of three storage reservoirs that mainly feed the New Spicer Meadow Reservoir. This license expires in 2033. *Northern California Power Agency*, 104 F.E.R.C. ¶ 62,163 (2003). After the present FERC License for Project No. 2409 expires in the year 2032, NCPA has the option to continue to purchase Project capacity and energy during a subsequent license renewal period. It is estimated that the price will be significantly less than the comparable alternatives at that time. The purchase option includes all capacity and energy which is surplus to Calaveras' needs for power within the boundaries of Calaveras County.

As with any hydroelectric generation project, the operation of the Project is determined by consideration of its storage capacity and available stream flows. The Project has a 98-year record (1913 to 2011) of streamflows. Based upon the record, the Project's average production is estimated to be 554 GWh annually. Using the driest period of record (1976-1977), the Project is estimated to produce 176 GWh annually. The Project is optimized together with NCPA's other resources as determined by NCPA to economically meet the load requirements of the respective Project Participants. The load-following characteristics of the Project, together with the ability to schedule Western energy deliveries, give NCPA a great degree of flexibility in meeting the hourly and daily variations which occur in the Project Participants' loads. The net Project generation for the fiscal year ended June 30, 2011 was approximately 852 GWh, an above average hydrological year, compared with 533 GWh for the prior fiscal year (an average hydrological year).

NCPA financed the Project through the issuance of Hydroelectric Project Number One Revenue Bonds, of which approximately $440.8 million aggregate principal amount was outstanding as of December 1, 2011. See "Indebtedness" for each of the Significant Share Project Participants in "APPENDIX A – SELECTED INFORMATION RELATING TO THE SIGNIFICANT SHARE PROJECT PARTICIPANTS" for a discussion of the obligations of each of the Significant Share Project Participants with respect to the Project.

NCPA has sold the capacity of the Project to certain of its Project Participants (described below) pursuant to "take-or-pay" power sales contracts which require payments to be made whether or not the project is completed or operable. Each purchaser is responsible under its power sales contract for paying its entitlement share in the Project of all of NCPA's costs of the Project, including debt service on the aforementioned bonds as well as a "step-up" of up to 25% in the event of the unremedied default of another Project Participant.

Biggs and Gridley have transferred their shares of Project output to Santa Clara. Each Project Participant remains obligated for all payments due from such Project Participant under the Third Phase

Agreement in the event moneys received from transferees pursuant to such arrangements are insufficient to satisfy all payments. Redding, Truckee Donner, Port of Oakland and BART, which are Members of NCPA, are not Project Participants, and have no financial or other responsibility or liability associated with the acquisition, construction, maintenance, operation or financing of the Project.

NCPA has estimated the average cost per kWh of power generated from the Project to be approximately 8.7 cents/kWh in 2011-12 (based on an average water year). The average cost per kWh of power generated from the Project over the prior five fiscal years is shown in the following table:

Fiscal Year	Average Cost of Power (cents/kWh)
2006-07	9.342
2007-08	13.211
2008-09	10.709
2009-10	7.068
2010-11	4.604

THE PROJECT PARTICIPANTS

General

The Project Participants and their Project Entitlement Percentages are shown on page (a) of this Official Statement.

The governing body of each Project Participant has approved the Third Phase Agreement. The California Public Utilities Code authorizes the municipal Project Participants to "acquire...any public utility," including the supply of light and power. In furtherance of such powers, a municipal corporation "may acquire...rights of every nature...when necessary to supply the municipality, or its inhabitants or any portion thereof, with the service desired."

Members of NCPA have no financial or other responsibility or liability associated with the acquisition, construction, maintenance, operation or financing of a particular project other than as project participants with respect to such project as set forth in the related third phase agreement.

Descriptions of the Significant Share Project Participants

The five Project Participants with the largest Project Entitlement Percentages are Alameda (10.00%), Lodi (10.37%), Palo Alto (22.92%), Roseville (12.00%) and Santa Clara (35.86%), which, in the aggregate, comprise over 90% of the Project. None of the remaining Project Participants has a Project Entitlement Percentage in excess of 3%. Alameda, Lodi, Palo Alto, Roseville, and Santa Clara are sometimes referred to herein as the "Significant Share Project Participants." Brief descriptions of the Significant Share Project Participants, their service areas, existing power supply resources, customers, energy sales and revenues and expenses are set forth in "APPENDIX A – SELECTED INFORMATION RELATING TO THE SIGNIFICANT SHARE PROJECT PARTICIPANTS."

Electric Systems

Each Project Participant owns and operates an electric system for distribution of electric power and energy together with the general plant necessary to conduct its business. The electric systems of some of the Project Participants are among the oldest electric utilities in operation in California and some predate the existence of PG&E. The electric systems were founded during the period from 1887 to 1937. The Project Participants are all experienced in operating electric distribution systems.

All of the Project Participants provide, through NCPA projects, for a portion of their own power needs. In addition, Alameda, Healdsburg, Lodi, Lompoc and Ukiah obtain a portion of their power needs from Western. Biggs, Gridley, Palo Alto, Plumas-Sierra and Roseville are also wholesale customers of Western and obtain a larger portion of their power needs from that source. Roseville also derives a portion of its power from its own generating facility. Santa Clara receives part of its power requirements from Western, part from PG&E and part from other power agencies, the power markets and its own generating projects. NCPA also purchases power from the market for certain of its Members (the Project Participants, exclusive of Santa Clara and Roseville) for periods of up to 30 days and for periods of up to five years (under separate project agreements) for Biggs, Gridley, Healdsburg, Lodi, Lompoc and Ukiah. Delivery of all such power is made over the ISO controlled grid, Western transmission facilities, the California-Oregon Transmission Project ("COTP") or combinations of those three transmission facilities.

Service Areas

The municipal Project Participants provide retail electric service within their service areas pursuant to the authority of the Constitution of the State of California, Article XI, Section 9. Under California law, the municipal Project Participants have authority to acquire, construct, establish, enlarge, improve, maintain, own and operate electric distribution systems. Plumas-Sierra provides electric service pursuant to its Articles and Bylaws.

The retail customers of the municipal Project Participants are located within their respective city boundaries and environs. Plumas-Sierra serves rural areas in Plumas, Lassen and Sierra Counties in California and in Washoe Township in Washoe County, Nevada.

OTHER NCPA PROJECTS

Set forth below is a brief description of the NCPA resources in addition to the Project. Each such resource is financed under a separate agreement with the Members participating in such resource. No Member not a party to such agreement has any obligation to make payments in connection with such resources.

Participating Members occasionally make short-term and long-term assignments of entitlement rights to NCPA resources. Such assignment would not impact the underlying project participant obligations contained in the related agreement relating to such NCPA resource and each project participant remains obligated for all payments due from such project participant in the event moneys received from transferees pursuant to such arrangements are insufficient to satisfy all payments.

Lodi Energy Center Project

NCPA is currently undertaking construction of a natural gas-fired, combined-cycle power generation plant to be located in the City of Lodi, San Joaquin County, California (the "Lodi Energy Center"). The electric generation components (the "Power Island") of the Lodi Energy Center will consist of the following components: (1) one natural gas-fired Siemens STGS-5000F combustion turbine-generator ("CTG"), with an evaporative cooling system and dry low-NOx combustors to control air emissions; (2) one 3-pressure heat recovery steam generator ("HRSG"), (3) a selective catalytic reduction ("SCR") and carbon monoxide (CO) catalyst to further control NOx and CO emissions, respectively; (4) one Siemens SST-900RH condensing steam turbine generator ("STG"); (5) one natural gas-fired auxiliary boiler; (6) one 7-cell draft evaporative cooling tower; and (7) associated support equipment. The Lodi Energy Center plant will be capable of operating at 296 MW (it has been permitted to operate at this level and it has arranged for the equipment necessary to operate at this level) but is expected to operate at 280 MW under the terms of the transmission interconnection agreement with the ISO and PG&E.

The Lodi Energy Center has a designed net heat rate of 6,804 Btu/kWh at 94 degrees F. This heat rate is low in comparison to other natural gas-fired generating facilities, and means that this plant will be very efficient and will utilize less natural gas than most gas-fired plants to generate electric energy. Even when gas prices are high, NCPA believes that the Lodi Energy Center will be competitive to other, less-efficient, gas-fired plants in the region.

Construction of the Lodi Energy Center commenced in August 2010 and commercial operation is expected to occur in the Summer of 2012. The estimated costs of construction of the Lodi Energy Center are approximately $381 million.

Pursuant to a Lodi Energy Center Power Sales Agreement (the "LEC Power Sales Agreement"), by and among NCPA and (i) the NCPA Member project participants: Biggs, Gridley, Healdsburg, Lodi, Lompoc, Plumas-Sierra, Santa Clara, Ukiah and BART; and (ii) the non-NCPA Member project participants: the City of Azusa, the Modesto Irrigation District, the Power and Water Resources Pooling Authority and the California Department of Water Resources (such entities other than NCPA, collectively the "LEC Project Participants"), NCPA has agreed to construct and operate the Lodi Energy Center and has sold the capacity and energy of the Lodi Energy Center to the thirteen LEC Project Participants, in accordance with their respective generation entitlement shares to the capacity and energy of the Lodi Energy Center. Each LEC Project Participant is responsible for the payment of its respective share of the costs of construction of the Lodi Energy Center. In order to provide funding for a portion of the costs of the Lodi Energy Center, in June 2010, NCPA issued two series of revenue bonds, its $254.995 million Lodi Energy Center Revenue Bonds, Issue One, issued on behalf of eleven of the thirteen participants in the Lodi Energy Center (being all of the above-named LEC Project Participants other than the Modesto Irrigation District and the California Department of Water Resources) and its $140.765 million Lodi Energy Center Revenue Bonds, Issue Two, issued on behalf of the California Department of Water Resources. See "Indebtedness" for each of the Significant Share Project Participants in "APPENDIX A – SELECTED INFORMATION RELATING TO THE SIGNIFICANT SHARE PROJECT PARTICIPANTS" for a discussion of the obligations of each of Lodi and Santa Clara with respect to the Lodi Energy Center Project. The Modesto Irrigation District provided its own financing for its share of the estimated costs of construction of the Lodi Energy Center.

The Lodi Energy Center will be operated and maintained by NCPA under the general direction of the LEC Project Participants pursuant to the LEC Power Sales Agreement and the Lodi Energy Center Project Management and Operations Agreement among NCPA and the LEC Project Participants.

Geothermal Project

NCPA has developed a geothermal project (the "Geothermal Project") located on federal land in certain areas of Sonoma and Lake Counties, California (the "Geysers Area"). In addition to the geothermal leasehold, wells, gathering system and related facilities, the Geothermal Project consists of two electric generating stations (Plant 1 and Plant 2), each with two 55 MW (nameplate rating) turbine generator units utilizing low pressure, low temperature geothermal steam, associated electrical, mechanical and control facilities, a heat dissipation system, a steam gathering system, a transmission tapline and other related facilities. Geothermal steam for the project is derived from the geothermal property, which includes wellpads, access roads, steam wells and reinjection wells. NCPA formed two not-for-profit corporations controlled by its Members to own the generating plants of the Geothermal Project. NCPA manages the Geothermal Project for the corporations and is entitled to all the capacity and energy generated by the Geothermal Project.

As noted above, the Geothermal Project consists of two operating electric generating stations (Plant 1 and Plant 2), each with two 55 MW (nameplate rating) turbine generator units. Plant 1 and Plant 2 were originally developed and operated as separate projects referred to as "Geothermal Project Number 2" and "Geothermal Project Number 3," respectively. Plant 1 and Plant 2 are now operated together as the Project pursuant to the terms of the Amended and Restated Geothermal Operating Agreement.

Steam for NCPA's geothermal plants comes from lands in the Geysers Area, which are leased by NCPA from the federal government. NCPA operates these steam-supply areas. Operation of the geothermal plants at high generation levels, together with high steam usage by others in the same area, resulted in a decline in the steam production from the steam wells at a rate greater than expected. As a result, by April 1988, for the purpose of slowing the decline in the steam field capability, NCPA changed its steam field production from base-load to load-following and reduced average annual generation. These changes were effective in reducing the decline in steam production.

Beginning in 1991, along with other steam field operators in the area, NCPA began implementing various operating strategies to further reduce the rate of decline in steam production. NCPA has modified all of the steam turbines and the associated steam collection system to enable generation with lower pressure steam at higher mass-flow rates to optimize the utilization of the available steam resource.

NCPA also entered into agreements with other producers in the Geysers Area to finance and construct the Southeast Geysers Effluent Pipeline Project, which was completed in September 1997 and began operating soon thereafter. The 26-mile pipeline collects waste-water from Lake County Sanitation District treatment plants at Clearlake and Middletown and delivers the waste water to NCPA and the other Geysers steam field operator for injection into the steam field. A second pipeline enhancement project to further augment the waste-water injection program was completed in 2004. Contractual changes made in connection with the project have increased NCPA's entitlement to receive waste-water for reinjection from 33% to 44%.

NCPA financed the Geothermal Project with Geothermal Project Number 3 Revenue Bonds, of which $33.8 million were outstanding as of December 1, 2011. Each of the Significant Share Project Participants, together with Biggs, Gridley, Healdsburg, Lompoc, Ukiah and Plumas Sierra, along with non-NCPA Member Turlock Irrigation District, participate in the Geothermal Project. See "Indebtedness" for each of the Significant Share Project Participants in "APPENDIX A – SELECTED INFORMATION RELATING TO THE SIGNIFICANT SHARE PROJECT PARTICIPANTS" for a discussion of the obligations of each of the Significant Share Project Participants with respect to the Geothermal Project.

Average annual generation of the Project was approximately 107.9 MW gross ("MWG") for calendar year ("CY") 2011. Based on current operating protocols and forecasted operations, after CY 2011 both the average and peak capacity are expected to continue to decrease, reaching approximately 104 MWG in CY 2012 and 62 MWG by CY 2035. Under terms of the federal geothermal leasehold agreements, which became effective August 1, 1974, the leasehold had a 10-year primary term with provision for renewal as long thereafter as geothermal steam is produced or utilized, but not longer than 40 years. At the expiration of that period, if geothermal steam is still being produced, NCPA has preferential right to renew the leasehold for a second term. The leasehold also requires NCPA to remove its leasehold improvements including the geothermal plants and steam gathering system when and if NCPA abandons the leasehold. These decommissioning costs are currently estimated to total approximately $24.1 million. NCPA has been collecting monies to pay the expected decommissioning costs since 2007 and holds $4.0 million in a reserve for such purpose as of June 30, 2011. Collections towards future decommissioning costs are expected to be approximately $2.0 million for fiscal year 2011-12.

Geysers Transmission Project

In order to meet certain obligations required of NCPA to secure transmission and other support services for the Geothermal Project, NCPA has undertaken a geysers transmission project (the "Geysers Transmission Project") with the Geysers Transmission Project participants. The Geysers Transmission Project includes (i) an ownership interest in PG&E's 230 kV line from Castle Rock Junction in Sonoma County to the Lakeville Substation (the "Castle Rock to Lakeville Line"), (ii) additional firm transmission rights in the Castle Rock to Lakeville Line and (iii) the Central Dispatch Facility.

NCPA financed the Geysers Transmission Project through the issuance of Transmission Project Number One Revenue Bonds, which bonds were retired as of August 15, 2010. Alameda, Lodi, Palo Alto and Roseville, together with Biggs, Gridley, Healdsburg, Lompoc, Ukiah and Plumas Sierra, are participants in the Geysers Transmission Project.

Capital Facilities Project

The NCPA Capital Facilities Project, known as Combustion Turbine Project Number Two, currently consists of one power generating station, Unit One, with a design rating of 49.9 MW located in the City of Lodi. Such power generating station consists of a single natural gas-fired steam injected gas turbine (STIG), generator, and required auxiliary and electrical interconnection systems. NCPA financed the Capital Facilities Project with Capital Facilities Revenue Bonds, of which approximately $55.1 million were outstanding as of December 1, 2011. The Cities of Alameda, Lodi, Lompoc and Roseville are the project participants in the Capital Facilities Project. See "Indebtedness" for each of the Significant Share Project Participants in "APPENDIX A – SELECTED INFORMATION RELATING TO THE SIGNIFICANT SHARE PROJECT PARTICIPANTS" for a discussion of the obligations of each of Alameda, Lodi and Roseville with respect to the Capital Facilities Project.

Unit One is economically dispatched to meet the project participants' load, depending on the amount of generation available from NCPA's hydroelectric project and prices of alternative electric energy supplies, to meet other NCPA Members' load or to sell power to third parties depending on natural gas prices and electric energy prices.

Combustion Turbine Project Number One

The Combustion Turbine Project Number One (the "Combustion Turbine Project") originally consisted of five combustion turbine units, each nominally rated 25 MW, with two units located in each of Roseville and Alameda and one in Lodi. Sale of the two units located in Roseville to the City of Roseville was effective on September 1, 2010.

The Combustion Turbine Project provides capacity (i) that is economically dispatched during the peak load period to the extent permitted by air quality restrictions and (ii) to be used to meet the capacity reserve requirements. Such reserve capacity is operated only during emergency periods when other resources are unexpectedly out of service. As is typical of reserve and peaking resources, the average cost per kWh of power delivered to the participants in the Combustion Turbine Project is comparatively expensive.

NCPA financed the Combustion Turbine Project through the issuance of Combustion Turbine Project Number One Revenue Bonds, which bonds were retired as of August 15, 2010. Alameda, Lodi, Roseville and Santa Clara, together with Healdsburg, Lompoc, Ukiah and Plumas-Sierra, are participants in Combustion Turbine Project Number One.

Gas Purchase Contracts

NCPA, on behalf of the project participants of Combustion Turbine Project Number One and of the Capital Facilities Project's Unit One has entered into a Consolidated Natural Gas Purchase and Management Agreement (the "Consolidated Natural Gas Agreement"), effective September 1, 2007, with Constellation NewEnergy—Gas Division, LLC and Constellation NewEnergy—Canada, Inc. (collectively, "Constellation"). In accordance with the terms of the agreement, Constellation provided NCPA with a six-month notice of termination, as a result of which the Constellation Natural Gas Agreement terminated on December 31, 2011. NCPA entered into replacement agreements with Sequent Energy Management, L.P. ("Sequent") effective January 1, 2012 to provide gas supply and management services, including the following:

- Supply of gas for the full daily output of Combustion Turbine Project Number One, Unit One of the Capital Facilities Project (approximately 35,136 MMBtu/day). The gas may be purchased on a daily basis or for a forward time period with the gas price fixed at the time of commitment.

- Scheduling, nomination, balancing and settlement services for NCPA gas supplies from third parties, along with gas supplies from Sequent for Unit One and Combustion Turbine Project Number One only. Surplus gas is to be purchased by Sequent. Gas related services for the Lodi Energy Center are discussed below.

- Management of NCPA's 2,743 MMBtu/day of pipeline capacity (four pipeline segments) from AECO to PG&E Citygate and release of certain other pipelines while NCPA is transporting gas from AECO to PG&E Citygate. NCPA is paid the value of the unused pipeline capacity by Sequent.

NCPA and J.P. Morgan Ventures Energy Corporation ("JPMVEC") have executed a contract to provide the gas supply and the nomination, imbalance and settlement services for NCPA's Lodi Energy Center, a gas-fired plant scheduled to begin operation in summer 2012. See "– Lodi Energy Center Project" above.

Power Purchase and Other Contracts

Seattle City Light Exchange Agreement. NCPA, on behalf of Healdsburg, Palo Alto, Ukiah, Lodi and Roseville, has negotiated a seasonal exchange agreement with Seattle City Light for 60 MW of summer capacity and energy and a return of 46 MW of capacity and energy in the winter. Deliveries under the agreement began June 1, 1995. NCPA has provided notice to terminate the agreement to Seattle City Light effective in 2018. Effective May 31, 2008, Healdsburg, Palo Alto and Roseville assigned their participation percentages to Santa Clara.

Henwood Power Purchase Agreement. NCPA, on behalf of Alameda, entered into a power purchase agreement with Henwood Associates, Inc for 440 kW of capacity and energy. The energy source for the facility is hydroelectric and the facility meets the qualifying facilities requirements, established by FERC. The facility output, which varies with hydrological conditions, has averaged about

2,000 megawatt hours ("MWhs") per year. Deliveries under the agreement began February 1, 2010 and will terminate on January 31, 2030.

Western GeoPower Power Purchase Agreement. NCPA, on behalf of Santa Clara, Roseville, Palo Alto, Lompoc, and Port of Oakland, negotiated an Amended and Restated Renewable Power Purchase Agreement in May 2011 (the "2011 PPA") , with Western GeoPower Incorporated ("Western Geo"), a wholly owned subsidiary of Ram Power Corp of Reno, Nevada. Under the 2011 PPA, NCPA is to purchase renewable energy for $113 per megawatt hour of power, fixed for 25 years, from a proposed 26 MW net capacity geothermal power project to be constructed in Sonoma County, California (the "Western Geo Project"). The 2011 PPA is a "take and pay" contract, pursuant to which NCPA is obligated to purchase energy at $113 per megawatt hour only when the energy is delivered from the Western Geo Project to NCPA. The Western Geo Project's commercial operation date was scheduled for the fall of 2013, however Ram Power has delayed financing and construction of the project as it reassesses its financial position and how the project will impact overall corporate financial health.

Pursuant to one of the terms of the 2011 PPA, if Western Geo decides to sell any portion of its assets, prior to entering into any material negotiations to carry out such a sale, Western Geo is required to provide notice of such proposed sale and a right of first offer ("ROFO") to NCPA. On July 13, 2011, Western Geo, issued to NCPA such a ROFO notice. NCPA conducted thorough due diligence on the Western Geo Project and opted not to tender an offer to Western Geo for its assets. Even though NCPA elected not to pursue the purchase of Western Geo's assets in response to Western Geo's July 13 ROFO notice, the 2011 PPA specifically precludes Western Geo from selling all or a portion of its assets to any third party if doing so would compromise NCPA's right to output under the 2011 PPA.

Ram Power is currently evaluating its options with respect to the Western Geo Project. A decision on future action is anticipated in early 2012. Given the delay in project financing and the associated construction start date, the earliest the Western Geo Project is expected to be capable of first delivering energy would be the first quarter of 2014. Ram Power has already failed to meet two contractual milestone dates set forth in the 2011 PPA (such milestones being to execute a construction contract and order a turbine-generator by October 31, 2011). Per the terms of the 2011 PPA, Western Geo has eighteen (18) months (until April 30, 2013) to meet these missed construction contract and turbine-generator order milestones before Western Geo's failure to meet these milestones can be declared an event of default, at which time NCPA may terminate the 2011 PPA.

BART Services Agreement. NCPA provides power supply and scheduling services to BART under a ten year Single Member Services Agreement which was executed on December 1, 2005. Under this agreement, NCPA procures power to meet BART's power supply needs utilizing Commission approved Edison Electric Institute and WSPP Inc. Purchase Agreements.

Market Purchase Program. NCPA, on behalf of Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc and Ukiah may enter into supply agreements for terms of up to five years utilizing Commission approved Edison Electric Institute and WSPP Inc. Purchase Agreements. Procurement terms and conditions are governed by a Market Purchase Program agreement between NCPA and the participating Members listed in the preceding sentence. Purchase amounts are limited to 115% of each participating members forecast net open position associated with the period of the procurement. The Program was approved by the NCPA commission on July 26, 2007, with a term of five years, which is extended for one year on each anniversary of the agreement as to each participant that does not withdraw from the agreement or have their participation terminated.

Natural Gas Program. NCPA, on behalf of Biggs, Gridley, Healdsburg, Lodi, Lompoc and Ukiah may enter into gas supply agreements using competitive bids submitted in response to a NCPA

Request For Proposals ("RFP Process"), or (ii) through direct purchases from the State of California Department of General Services Natural Gas Services Program. Procurement terms and conditions are governed by a Natural Gas Program agreement between NCPA and the participating Members identified in the preceding sentence. Purchases are subject to limits as may be changed from time to time as outlined in the NCPA Energy Risk Management Policy and/or Regulations. The Natural Gas Program was approved by the NCPA commission on March 24, 2011, with an initial term of five years, which is extended for two years on every other anniversary of the agreement as to each participant that does not withdraw from the agreement or have their participation terminated.

RATE REGULATION

Each Project Participant and NCPA sets rates, fees and charges for electric service. The authority of the Project Participants or NCPA to impose and collect rates and charges for electric power and energy sold and delivered is not subject to the general regulatory jurisdiction of the California Public Utilities Commission ("CPUC") and presently neither the CPUC nor any other regulatory authority of the State of California nor FERC approves such rates and charges. Although the retail rates of the Project Participants and NCPA are not subject to approval by any federal agency, the Project Participants and NCPA are subject to certain ratemaking provisions of the federal Public Utility Regulatory Policies Act of 1978 ("PURPA") and Sections 211-213 of the Federal Power Act ("FPA"). It is possible that future legislative and/or regulatory changes could subject the rates and/or service areas of the Project Participants or NCPA to the jurisdiction of the CPUC or to other limitations or requirements.

FERC could potentially assert jurisdiction over rates of licensees of hydroelectric projects and customers of such licensees under Part I of the Federal Power Act, although it has not as a practical matter exercised or sought to exercise such jurisdiction to modify rates that would legitimately be charged. If it did assert such jurisdiction, the result might have some significance for NCPA and its Project Participants.

Under Sections 211, 211A, 212 and 213 of the FPA, FERC has the authority, under certain circumstances and pursuant to certain procedures, to order any utility (municipal or otherwise) to provide transmission access to others at FERC-approved rates. In addition, the Energy Policy Act of 2005 expanded FERC's jurisdiction to require municipal utilities that sell more than eight million MWhs of energy per year to pay refunds under certain circumstances for sales into organized markets. To date, neither NCPA nor any of the Project Participants meet this threshold requirement.

On May 29, 2009, FERC issued an order asserting that it had the authority to "reset" rates at which energy had been previously sold in the organized California ISO and PX markets. That order is now on appeal in the United States Court of Appeals for the Ninth Circuit, and was argued before that Court in September 2010. If FERC is determined to be correct in its assertion, NCPA would be subject to such refund authority (under certain limitations) for sales into organized markets without regard to the eight million MWhs statutory limitation discussed above. The May 29, 2009 order itself applied to the disputes discussed in "LITIGATION—California Energy Market Dysfunction, Refund Dispute and Related Litigation" which have since been resolved as to NCPA through a Settlement Agreement. While NCPA has, as a result of its settlement, withdrawn from the Ninth Circuit review of FERC's May 29, 2009 order, the appeal has gone forward without NCPA's active further participation, so the issue will be finally resolved in the future.

The California Energy Commission (the "CEC") is authorized to evaluate rate policies for electric energy as related to the goals of the Energy Resources Conservation and Development Act and to make recommendations to the Governor, the Legislature and publicly owned electric utilities.

CONSTITUTIONAL CHANGES IN CALIFORNIA

Proposition 218

Proposition 218, a State ballot initiative known as the "Right to Vote on Taxes Act," was approved by the voters of the State of California on November 5, 1996. Proposition 218 added Articles XIIIC and XIIID to the State Constitution. Article XIIID creates additional requirements for the imposition by most local governments (including the Project Participants) of general taxes, special taxes, assessments and "property-related" fees and charges. Article XIIID explicitly exempts fees for the provision of electric service from the provisions of such article. Nevertheless, Proposition 218 could indirectly affect some California municipally-owned electric utilities. For example, to the extent Proposition 218 reduces a city's general fund revenues, that city could seek to increase the transfers from the electric utilities of that city to the city's general fund.

Article XIIIC expressly extends the people's initiative power to reduce or repeal previously-authorized local taxes, assessments, and fees and charges. The terms "fees and charges" are not defined in Article XIIIC, although the California Supreme Court held in *Bighorn-Desert View Water Agency v. Verjil*, 39 Cal. 4th 205 (2006), that the initiative power described in Article XIIIC may apply to a broader category of fees and charges than the property-related fees and charges governed by Article XIIID. Moreover, in the case of *Bock v. City Council of Lompoc*, 109 Cal. App. 3d 52 (1980), the Court of Appeal determined that electric rates are subject to the initiative power. Thus, even electric service charges (which are expressly exempted from the provisions of Article XIIID) might be subject to the initiative provision of Article XIIIC, thereby subjecting such fees and charges imposed by each Project Participant to reduction by the electorate. However, NCPA and the Project Participants believe that even if the electric rates of any Project Participants are subject to the initiative power, under Article XIIIC or otherwise, their respective electorates would be precluded from reducing electric rates and charges in a manner adversely affecting the payment of the 2012 Bonds by virtue of the "impairments clause" of the United States Constitution.

Proposition 26

Proposition 26 was approved by the electorate at the November 2, 2010 election and amended California Constitution Articles XIIIA and XIIIC. The proposition imposes a two-thirds voter approval requirement for the imposition of fees and charges by the State. It also imposes a majority voter approval requirement on local governments with respect to fees and charges for general purposes, and a two-thirds voter approval requirement with respect to fees and charges for special purposes. Proposition 26, according to its supporters, is intended to prevent the circumvention of tax limitations imposed by the voters pursuant to Proposition 13, approved in 1978, and other measures through the use of non-tax fees and charges. Proposition 26 expressly excludes from its scope a charge imposed for a specific government service or product provided directly to the payor that is not provided to those not charged, and which does not exceed the reasonable cost to the State or local government of providing the service or product to the payor. Proposition 26 may, however, be interpreted to limit fees and charges for electric utility services charged by governmental entities such as the Project Participants to preclude future transfers of electric utility generated funds to a local government's general fund, if applicable, and/or to require stricter standards for the allocation of costs among customer classes. A lawsuit was filed against NCPA member City Redding in the Superior Court in Shasta County alleging that Redding's transfers of funds from its electric utility to its city general fund violated Proposition 26. (*Citizens for Fair REU Rates et al. v. City of Redding, et al.* Shasta Superior Court no. 171377.) The case was tried on November 8, 2011 and on December 22, 2011, the Court determined that the local legislation authorizing the transfer predated Proposition 26 and since Proposition 26 did not apply retroactively, the transfer was unaffected by Proposition 26. The Court further held that the resolution approving electric rate increases at issue in the case did not affect the general fund transfers and therefore did not impose or increase any tax, and therefore did not require any voter approval (without making any determination with respect to whether the transfer would constitute a tax under Proposition 26). The Plaintiffs have indicated that they intend to appeal the decision. Following the filing of first lawsuit, the Plaintiffs initiated a related lawsuit challenging the resolution adopting Redding's biennial City Budget for fiscal years 2012 and 2013 and raising similar issues. (*Fee Fighter LLC et al. v. City of Redding, et al*. Shasta Superior Court no. 172960.) The parties have filed a stipulation that the two cases should be consolidated for all purposes. A trial on the second case is scheduled for April 3, 2012. NCPA and the Project Participants are unable to predict at this time how Proposition 26 will be interpreted by other courts or what its ultimate impact will be.

Other Initiatives

Articles XIIIC and XIIID were adopted as measures that qualified for the ballot pursuant to California's initiative process. From time to time, other initiatives have been, and could be, proposed, and if qualified for the ballot, could be enacted affecting NCPA's and/or the Project Participants revenues or operations. Neither the nature and impact of these measures nor the likelihood of qualification for ballot or passage can be anticipated by NCPA and the Project Participants.

DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS

Background; California Electric Market Deregulation

In 1996, California partially deregulated its electric energy market. As a consequence of the partial deregulation, the California investor-owned utilities (the "IOUs") sold a large portion of their generation resources and began to purchase significant amounts of electricity. During portions of 2000 and 2001, the market price of electricity in California went through significant fluctuations, the impacts of which are well documented.

A number of State and federal proceedings began as a result of the market dysfunction of 2000 and 2001. These included investigations into alleged market manipulation, which for the most part have either ended or are in the final appellate stages. Other proceedings are ongoing, such as litigation at FERC regarding the need for refunds due to the alleged overcharging for the sale of electricity (which proceedings initially included sales by municipal utilities but were dismissed for lack of jurisdiction) (the "Refund Cases"). Although it was ultimately found that FERC lacked jurisdiction to order refunds for alleged overcharging by non-jurisdictional entities, several plaintiffs have pursued remedies in State and federal courts based on a contract and quasi-contract theory. See "LITIGATION—California Energy Market Dysfunction, Refund Dispute and Related Litigation" for a discussion of the Refund Cases. While NCPA has settled with the plaintiffs in that related litigation, and that settlement has been approved by FERC, there are still some claims by others that remain ongoing. While those claims are considered by NCPA to be lacking in merit, neither NCPA nor the Project Participants are able to provide assurance of that result until all of the proceedings are finally concluded.

During 2000 and 2001, California experienced extreme fluctuations in the prices and supplies of natural gas and electricity in much of the State. While there has been some progress in addressing these issues, uncertainty remains. As a result of the foregoing and other factors, no assurance can be given that measures undertaken during the last several years, together with measures to be taken in the future, will prevent the recurrence of shortages, price volatility or other energy problems that have adversely affected the Project Participants and other California electric utilities in the past.

State Legislation

A number of bills affecting the electric utility industry have been introduced or enacted by the California Legislature in recent years. In general, these bills regulate greenhouse gas emissions and provide for greater investment in energy-efficiency and environmentally friendly generation alternatives through more stringent renewable resource portfolio standards. The following is a brief summary of certain of these bills.

Greenhouse Gas Emissions. On June 1, 2005, then Governor Arnold Schwarzenegger signed Executive Order S-3-05, which placed an emphasis on efforts to reduce greenhouse gas emissions by establishing statewide greenhouse gas reduction targets. The targets are: (i) a reduction to 2000 emissions levels by 2010; (ii) a reduction to 1990 levels by 2020; and (iii) a reduction to 80% below 1990 levels by 2050. The Executive Order also called for the California Environmental Protection Agency to lead a multi-agency effort to examine the impacts of climate change on California and develop strategies and mitigation plans to achieve the targets. On April 25, 2006, then Governor Schwarzenegger also signed Executive Order S-06-06 which directs the State to meet a 20% biomass utilization target within the renewable generation targets of 2010 and 2020 for the contribution to greenhouse gas emission reduction.

Then Governor Schwarzenegger signed Assembly Bill 32, the Global Warming Solutions Act of 2006 (the "GWSA"), which became effective as law on January 1, 2007. The GWSA prescribed a statewide cap on global warming pollution with a goal of reaching 1990 greenhouse gas emission levels by 2020. In addition, the GWSA establishes a mandatory reporting program for all IOUs, local publicly-owned electric utilities ("POUs") and other load-serving entities (electric utilities providing energy to end-use customers ("LSEs")) to inventory and report greenhouse gas emissions to the California Air Resources Board ("CARB"), requires CARB to adopt regulations for significant greenhouse gas emission sources (allowing CARB to design a "cap-and-trade" system) and gives CARB the authority to enforce such regulations beginning in 2012.

On December 11, 2008, CARB adopted a "scoping plan" to reduce greenhouse gas emissions. The scoping plan set out a mixed approach of market structures, regulation, fees and voluntary measures. The scoping plan included a cap-and-trade system covering approximately 85% of all greenhouse gas emissions in California. In 2011, the scoping plan was revised in response to the litigation discussed below, and CARB adopted a revised scoping plan on August 24, 2011. The revised scoping plan continues to include a cap-and-trade system.

On November 24, 2009, CARB released a preliminary draft regulation for the cap-and-trade program for public review and comment, and on December 16, 2010, it approved a resolution adopting a cap-and-trade regulation for California. CARB released revised versions of the cap-and-trade regulation on July 25 and September 12, 2011, for 15-day public comment. CARB adopted the revised cap-and-trade regulation at a board meeting on October 20, 2011 and filed it with the California Office of Administrative Law ("OAL") on October 27, 2011. The OAL approved the regulation on December 13, 2011.

The cap-and-trade program covers sources accounting for 85% of California's greenhouse gas emissions, the largest program of its type in the United States. The cap-and-trade regulation became effective on January 1, 2012 and it provides for emission compliance obligations to begin on January 1, 2013.

The cap-and-trade program will be implemented in phases. The first phase of the program (January 1, 2013 to December 31, 2014) will introduce a hard emissions cap that covers emissions from electricity generators and large industrial sources emitting more than 25,000 metric tons of carbon dioxide-equivalent greenhouse gases ("CO_2e") per year. In 2015, the program will be expanded to cover emissions from transportation fuels, natural gas, propane and other fossil fuels. The cap will decline each year. The cap-and-trade program will include the distribution of carbon allowances. Each allowance will be equal to one metric ton of CO_2e. As part of a transition process, initially, most of the carbon allowances will be distributed for free. The remaining allowances will be auctioned. Auctions will occur quarterly, beginning in the second half of 2012. IOUs will be required to auction their allowances and either: (i) purchase allowances to meet their own compliance obligations or (ii) use the auction proceeds from the sale of IOU allowances for the benefit of their ratepayers. POUs have three options available once their allowances are freely distributed to them. They can either: (i) place allowances in their compliance accounts to meet compliance obligations for plants they operate directly, (ii) place allowances in the compliance account of a joint powers agency or public power utility that generates power on their behalf, or (iii) make the allowances available for auction, using the proceeds of any sale to benefit the customers they serve.

The cap-and-trade program will also allow covered entities to use offset credits for compliance purposes (not exceeding 8% of a covered entity's compliance obligation). Offsets must be obtained from certified projects in sectors that are not regulated under the cap-and-trade program. These include urban forest projects, reforestation projects, destruction of ozone-depleting substances, and methane management projects. CARB is considering additional offset protocols, including conversion of pneumatic controllers and N_2O reductions from changes in fertilizer management. These protocols may be approved in 2012.

There are a number of issues remaining to be addressed prior to the start of emission compliance obligations in 2013, including reviewing provisions relating to electricity importers, developing rules to minimize emissions leakage through "resource shuffling," developing market parameters to prevent market participants from gaming the system, and developing and testing a trading and tracking computer system. CARB will work on these issues in 2012, as well as determining whether and how to link California's program to cap-and-trade programs currently under development in Canadian provinces, as part of the Western Climate Initiative. The Western Climate Initiative is a regional effort consisting of California and four Canadian provinces which is in the process of establishing a greenhouse gas reduction trading framework.

On March 18, 2011, the San Francisco Superior Court issued its final decision in *Association of Irritated Residents, et al. ("AIR") v. California Air Resources Board*, Case No. CPF-09-509562. The decision found that CARB failed to conduct a sufficient environmental impact review under the California Environmental Quality Act ("CEQA") prior to adopting its "scoping plan" under the GWSA, in that CARB did not adequately analyze all potential alternatives and prematurely adopted the plan prior to fully responding to public comment. On May 20, 2011, the Superior Court issued a peremptory writ of mandate enjoining implementation of the cap-and-trade program until CARB complies with its obligations under CEQA. CARB appealed the decision in the First Appellate District of the California Court of Appeal, and the Court of Appeal allowed CARB to proceed with finalizing the cap-and-trade regulation. CARB also prepared a revised CEQA analysis as required by the Superior Court. On December 5, 2011, the Superior Court discharged the writ of mandate and shortly thereafter CARB's appeal was dismissed, as it was no longer necessary.

In addition to the GWSA, Senate Bill 1368 also became effective as law on January 1, 2007 and provides for an emission performance standard, restricting new investments in baseload fossil fuel electric generating resources that exceed the rate of emissions for greenhouse gases for existing combined-cycle natural gas baseload generation and seeks to allow the CEC to establish a regulatory framework necessary to enforce the greenhouse gas emission performance standard for POUs such as the Project Participants.

The CPUC has a similar responsibility for the IOUs. The regulations promulgated by the CEC were approved by the Office of Administrative Law on October 16, 2007. The CEC regulations prohibit any investment in baseload generation that does not meet the emission performance standard of 1,100 pounds of CO_2 per MWh of electricity, with limited exceptions for routine maintenance, requirements of pre-existing contractual commitments, or threat of significant financial harm. In December 2011 the CEC decided to undertake a review of these regulations to ensure there is adequate review of investments in facilities that do not meet the emission performance standard. Changes to these regulations may affect some of the Project Participants.

Additionally, Assembly Bill 1925, signed by then Governor Schwarzenegger on September 26, 2006, requires the CEC to develop a cost effective strategy for the geologic sequestration and management of industrial carbon dioxide.

Legislation regarding greenhouse gas emissions will impact all California electric utilities as the State begins to reduce its reliance on coal-fired generation. The Project Participants are committed to renewable energy, demand side management and energy efficiency; however, it is widely recognized that there will still be a large demand for traditional, baseload fossil fuel power plants in order to meet projected load growth. Currently, there is a ban in California prohibiting the development of nuclear power plants until there is a permanent storage solution of spent fuel rods. Large hydroelectric plant development is also unlikely to occur in California as a result of resistance from environmental interests. Since the greenhouse gas emission standards established under SB 1368 have the effect of prohibiting new coal power resources, natural gas-fired, combined cycle power plants would appear to be the primary viable option for fossil fuel baseload power plant development absent the implementation of new technologies in connection with other resource options. The reliance on a single fuel source will continue to put pressure on the already volatile natural gas market in the United States.

Santa Clara, Lodi and Palo Alto, among other Project Participants, have each signed a set of principles through the California Municipal Utilities Association and each is participating in the process in order to position itself to meet the State's greenhouse gas reduction targets.

Energy Procurement and Efficiency Reporting. Senate Bill 1037 ("SB 1037"), signed by then Governor Schwarzenegger on September 29, 2005. It requires that each POU, including the Project Participants, prior to procuring new energy generation resources, first acquire all available energy efficiency, demand reduction, and renewable resources that are cost effective, reliable and feasible. SB 1037 also requires each POU to report annually to its customers and to the CEC its investment in energy efficiency and demand reduction programs. Each of the Project Participants is in compliance with such reporting requirements.

Further, Assembly Bill 2021 ("AB 2021"), signed by then Governor Schwarzenegger on September 29, 2006, requires that POUs establish, report, and explain the basis of the annual energy efficiency and demand reduction targets by June 1, 2007 and every three years thereafter for a ten-year horizon. Each of the Project Participants has complied with this reporting requirement under AB 2021. Future reporting requirements under AB 2021 include: (i) the identification of sources of funding for the investment in energy efficiency and demand reduction programs; (ii) the methodologies and input assumptions used to determine cost-effectiveness; and (iii) the results of an independent evaluation to measure and verify energy efficiency savings and demand reduction program impacts. The information obtained from the POUs is being used by the CEC to present the progress made by the POUs towards the State's goal of reducing electrical consumption by 10% within ten years and the greenhouse gas targets presented in Executive Order S-3-05. In addition, the CEC will provide recommendations for improvement to assist each POU in achieving cost-effective, reliable, and feasible savings in conjunction with the established targets for reduction.

Renewable Portfolio Standards. In September 2002, the California Legislature enacted and then Governor Gray Davis signed into law Senate Bill 1078 ("SB 1078"). SB 1078 required that the IOUs adopt a Renewable Portfolio Standard ("RPS") to meet a minimum increase of 1% of retail energy sales needs each year from renewable resources and to meet a goal of 20% of their retail energy needs from renewable energy resources by the year 2017. SB 1078 also directed the State's POUs to implement and enforce an RPS that recognizes the intent of the Legislature to encourage development of renewable resources, taking into consideration the impact on a utility's standard on rates, reliability, financial resources, and the goal of environmental improvement. On September 26, 2006, then Governor Schwarzenegger signed Senate Bill 107 ("SB 107") into law, which requires IOUs to have 20% of their electricity produced by renewable sources by 2010 and prescribes that POUs meet the intent of the legislation. See "APPENDIX A – SELECTED INFORMATION RELATING TO THE SIGNIFICANT SHARE PROJECT PARTICIPANTS" for information regarding each of the Significant Share Project Participant's adopted RPS.

On November 17, 2008, then Governor Schwarzenegger signed Executive Order S-14-08. Among other things, Executive Order S-14-08 provides that the RPS target established for California shall require retail electricity sellers to serve 33% of their loads with eligible renewable energy resources by 2020.

Since the implementation of SB 1078, the CPUC and the CEC have taken a number of actions that have had an impact on the renewable energy goals set by the legislation. In order to help utilities overcome the challenges associated with meeting accelerated RPS goals, the CPUC and the CEC supported the implementation of a renewable energy credit ("REC") trading system. SB 107 allows RECs to be used for RPS compliance, with the condition that the renewable energy is delivered to an in-state trading hub. In parallel, pursuant to SB 1078, the CEC, collaboratively with the Western Governors' Association and the Western Electricity Coordination Council ("WECC"), established the WREGIS, to ensure the integrity of RECs and prevent the double counting of the certificates. The electronic tracking system became operational in 2007.

Senate Bill X1 2 ("SBX1 2"), the "California Renewable Energy Resources Act," was signed into law by Governor Jerry Brown on April 12, 2011. SBX1 2 codifies the RPS target for retail electricity sellers to serve 33% of their loads with eligible renewable energy resources by 2020 as provided in Executive Order S-14-08. As enacted, SBX1 2 makes the requirements of the RPS program applicable to POUs (rather than just prescribing that POUs meet the intent of the legislation as under previous statutes). However, the governing boards of POUs are responsible for implementing the requirements, rather than the CPUC, as is the case for the IOUs. In addition, certain enforcement authority with respect to POUs is given to the CEC and CARB, including authority to impose penalties. SBX1 2 requires each POU is required to adopt and implement a renewable energy resource procurement plan. The plan must require the utility to procure a minimum quantity of electricity products from eligible renewable energy resources, including RECs, as a specified percentage of total kilowatt hours sold to the utility's retail end-use customers to achieve the following targets: (i) an average of 20% for the period January 1, 2011 to December 31, 2013, inclusive; (ii) 25% by December 31, 2016; and (iii) 33% by December 31, 2020 and for all subsequent years. SBX1 2 grandfathers any facility approved by the governing board of a POU prior to June 1, 2010 for procurement to satisfy renewable energy procurement obligations adopted under prior law if the facility is a "renewable electrical generation facility" as defined in the bill (subject to certain restrictions). Renewable electrical generation facilities include certain out-of-state renewable energy generation facilities if the facility: (i) will not cause or contribute to any violation of a California environmental quality standard or requirement, (ii) participates in the accounting system to verify compliance with the RPS program requirements, and (iii) either (a) commenced initial commercial operation after January 1, 2005 or (b) either (x) the electricity is from incremental generation resulting from expansion or repowering of the facility or (y) electricity generated by the facility was procured by a retail seller or POU as of January 1, 2010. The percentage of a POU's RPS requirements that may be met with unbundled RECs from generating facilities outside California declines over time, beginning at 25% through 2013 and declining to 10% in 2017 and beyond.

Solar Power. On August 21, 2006, then Governor Schwarzenegger signed into law California Senate Bill 1 (also known as the "California Solar Initiative"). This legislation requires POUs, including the Project Participants, to establish a program supporting the stated goal of the legislation to install 3,000 MW of photovoltaic energy in California. POUs are also required to establish eligibility criteria in collaboration with the CEC for the funding of solar energy systems receiving ratepayer funded incentives. The legislation gives a POU the choice of selecting an incentive based on the installed capacity, starting at $2.80 per watt, or based on the energy produced by the solar energy system, measured in kilowatt-hours. Incentives would be required to decrease at a minimum average rate of 7% per year. POUs also have to meet certain reporting requirements regarding the installed capacity, number of installed systems, number of applicants, amount of awarded incentives and the contribution toward the program's goals.

Each of the Project Participants is meeting the requirements of the California Solar Initiative through incentive programs that meet the incentive level for the technology as stipulated under the legislation.

Future Regulation

The electric industry is subject to continuing legislative and administrative reform. States routinely consider changes to the way in which they regulate the electric industry. Recently, both further deregulation and forms of additional regulation have been proposed for the industry, which has been highly regulated throughout its history. NCPA and the Project Participants are unable to predict at this time the impact any such proposals will have on the operations and finances of the Project Participants, the Project or the electric utility industry generally.

Impact of State Developments on NCPA and the Project Participants

The effect of the developments in the California energy markets described above on NCPA and the Project Participants cannot be fully ascertained at this time. Also, volatility in energy prices in California may return due to a variety of factors that affect both the supply and demand for electric energy in the western United States. These factors include, but are not limited to, the adequacy of generation resources to meet peak demands, the availability and cost of renewable energy, the impact of greenhouse gas emission legislation and regulations, fuel costs and availability, weather effects on customer demand, transmission congestion, the strength of the economy in California and surrounding states and levels of hydroelectric generation within the region (including the Pacific Northwest). See "OTHER FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY." This price volatility may contribute to greater volatility in the Project Participants' costs and revenues of their respective electric systems from the sale (and purchase) of electric energy and, therefore, could materially affect each of the Project Participants' financial condition. Each of the Project Participants, individually and/or through NCPA or other joint powers agencies in which it participates, undertakes resource planning and risk management activities and manages its resource portfolio to mitigate such price volatility and spot market rate exposure. For a discussion of each of the Significant Share Project Participant's current resource planning activities, see "Power Supply Resources" in each of the Significant Share Project Participants sections in "APPENDIX A – SELECTED INFORMATION RELATING TO THE SIGNIFICANT SHARE PROJECT PARTICIPANTS."

OTHER FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY

Federal Energy Legislation

Energy Policy Act of 2005. Under the federal Energy Policy Act of 2005 ("EPAct 2005"), FERC was given refund authority over municipal utilities if they sell into short-term markets, like the ISO markets, and sell 8 million MWhs or more of electric energy on an annual basis. In addition, FERC was given authority over the behavior of market participants. Under FERC's authority it can impose penalties on any seller for using a manipulative or deceptive device, including market manipulation, in connection with the purchase or sale of energy or of transmission service. See also "RATE REGULATION."

EPAct 2005 authorizes FERC to issue permits to construct or modify transmission facilities located in a national interest electric transmission corridor if FERC determines that the statutory conditions are met. EPAct 2005 also requires the creation of an electric reliability organization ("ERO") to establish and enforce, under FERC supervision, mandatory reliability standards (the "Reliability Standards") to increase system reliability and minimize blackouts. Failure to comply with such mandatory standards exposes a utility to significant fines and penalties by the ERO.

NERC Reliability Standards. As discussed above, EPAct 2005 required FERC to certify an ERO to develop mandatory and enforceable Reliability Standards, subject to FERC review and approval. The Reliability Standards apply to users, owners and operators of the Bulk-Power System, as more specifically set forth in each Reliability Standard. On February 3, 2006, FERC issued Order 672, which certified the North American Electric Reliability Corporation ("NERC") as the ERO. Many Reliability Standards have since been approved by FERC.

The ERO or the entities to which NERC has delegated enforcement authority through an agreement approved by FERC ("Regional Entities"), such as the WECC, may enforce the Reliability Standards, subject to FERC oversight, or FERC may independently enforce Reliability Standards. Potential monetary sanctions include fines of up to $1 million per violation per day. FERC Order 693 further provided the ERO and Regional Entities with the discretion necessary to assess penalties for such violations, while also having discretion to calculate a penalty without collecting the penalty if circumstances warrant.

Other Federal Legislation. Numerous bills have been under consideration in Congress addressing United States energy policies and various environmental matters, including bills relating to energy supplies, global warming and water quality. Many of these bills, if enacted into law, could have a material impact on the Project Participants and the electric utility industry generally. The United States Congress has considered and/or is considering various energy and climate change-related pieces of legislation that propose, among other things, a federal clean energy portfolio standard. The impact that federal clean energy portfolio standard legislation will have on the electric utility industry and business generally, and on the Project Participants, in particular, depends largely on the specific provisions of the legislation that ultimately become law. Some of the important factors to be addressed in federal clean energy legislation include clean energy targets and timelines, the list of fuel types accepted as "clean energy", and whether or not existing clean energy sources can be used to meet the targets. The timeline and impact of any climate change legislation cannot be accurately assessed at this time, but it is expected that any such federal action will have a significant impact on fossil-fueled generation facilities. In light of the variety of issues affecting the utility sector, federal energy legislation in other areas such as reliability, transmission planning and cost allocation, operation of markets, environmental requirements and cybersecurity is also possible. However, NCPA and the Project Participants are unable to predict the outcome or potential impacts of any possible legislation at this time.

ISO Markets

The California ISO markets are subject to continued change in response to FERC orders, the increased integration of intermittent renewable resources, changing environmental constraints, the ongoing efforts to combat market manipulation, evolving reliability requirements and the potential for some types of electricity and gas transactions to be regulated by the Commodity Futures Trading Commission ("CFTC"). California ISO Tariff changes related to these and other issues are currently under discussion in California ISO stakeholder processes and in ongoing FERC proceedings and CFTC rulemaking proceedings. In most cases, these proposals are not sufficiently final in order to determine their likely impact on NCPA or the Project Participants. However, the following proposals may have significant impacts on NCPA, the Project Participants or electric utilities generally:

Increased Granularity of LMP. FERC has ordered the ISO to increase the granularity of its locational marginal pricing ("LMP") framework. Although the ISO has received permission from FERC to delay the timeline for this change until the last quarter of 2014, increased granularity has the potential to increase cost differentials among NCPA members (including the Project Participants) and between NCPA members and others. However, no concrete proposal has yet been put forward.

Increased Integration of Renewables. As part of the effort to integrate increased levels of intermittent renewable resources into the grid, the ISO has proposed an array of changes to existing markets, which could include doing away with the Hour Ahead Scheduling Procedure ("HASP"). This proposal could increase the costs of imports at the ties.

Centralized Capacity Market. Although the CPUC has decided against implementing a centralized capacity market in California for now, some market participants continue to advocate the adoption of such a market. Centralized capacity markets in other parts of the country have shown potential for significant impacts on the costs of LSEs and have raised issues about implications for the traditional utility model. However, at present, there is no concrete plan to analyze.

CFTC Regulation of Energy Transactions. The passage of the Dodd-Frank legislation in response to the financial crisis amended the Commodities Exchange Act to permit the CFTC to regulate certain energy transactions called "swaps." The CFTC is presently writing the rules to implement the law, but currently key terms (such as "swap") remain undefined. It is too soon to determine whether or to what extent NCPA's transactions will be affected, but there is potential for increased costs (such as margin requirements, exchange clearing requirements and reporting obligations) for the entire industry.

Resource Adequacy Requirements. Resource Adequacy requirements apply to NCPA and its members, including the Project Participants. For example, to the extent that a LSE fails to procure sufficient capacity resources to meet its loads, it is subject to payment of ISO procurement costs of replacement capacity. To the extent that a shortfall cannot be attributed to a specific LSE, the costs will be spread as part of market uplift charges. These risks apply in the same manner to all LSEs.

Environmental Issues

General. Electric utilities are subject to continuing environmental regulation. Federal, state and local standards and procedures which regulate the environmental impact of electric utilities are subject to change. These changes may arise from continuing legislative, regulatory and judicial action regarding such standards and procedures. Consequently, there is no assurance that any NCPA or Project Participant facility or project will remain subject to the laws and regulations currently in effect, will always be in compliance with future laws and regulations or will always be able to obtain all required operating permits. An inability to comply with environmental standards could result in additional capital expenditures, reduced operating levels or the shutdown of individual units not in compliance. In addition, increased environmental laws and regulations may create certain barriers to new facility development, may require modification of existing facilities and may result in additional costs for affected resources. NCPA and the Project Participants cannot predict at this time whether any additional legislation or rules will be enacted that will affect their operations, and if such laws and rules are enacted, what the cost to any of them might be in the future because of such actions.

Greenhouse Gas Regulations Under the Clean Air Act. The United States Environmental Protection Agency (the "EPA") has taken steps to regulate greenhouse gas emissions under existing law. In 2009, the EPA issued a final "endangerment finding," in which it declared that the weight of scientific evidence requires a finding that six identified greenhouse gases, namely, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, cause global warming, and that global warming endangers public health and welfare. The final rule for the "endangerment finding" was published in the Federal Register on December 15, 2009. As a result of this finding, the EPA is authorized to issue regulations limiting carbon dioxide emissions from, among other things, stationary sources such as electric generating facilities, under the federal Clean Air Act. The "Tailoring Rule," states that greenhouse gas emissions will be regulated from large stationary sources, including electric generating facilities, if the sources emit more than the specified threshold levels of the tons per year of CO_2e. Large sources with the potential to emit in excess of the applicable threshold will be subject to the major source permitting requirements under the Clean Air Act. Permits would be required in order to construct, modify and operate facilities exceeding the emissions threshold. Examples of such permitting requirements include, but are not limited to, the application of Best Available Control Technology (known as "BACT") for greenhouse gas emissions, and monitoring, reporting, and recordkeeping for greenhouse gases.

On September 22, 2009, the EPA issued the final rule for mandatory monitoring and annual reporting of greenhouse gas emissions from various categories of facilities including fossil fuel suppliers, industrial gas suppliers, direct greenhouse gas emitters (such as electric generating facilities and industrial processes), and manufacturers of heavy-duty and off-road vehicles and engines. This rule does not require controls or limits on emissions, but required data collection to begin on January 1, 2010, and initially provided that the first annual reports would be due March 31, 2011. However, the EPA extended the initial reporting deadline until September 30, 2011, in order to finalize development of software to be utilized for such reporting. Such data collection and reporting lays the foundation for controlling and reducing greenhouse gas emissions in the future, whether by way of the EPA regulations under existing Clean Air Act authority or under a new climate change federal law.

On December 23, 2010, the EPA announced two settlements with a number of states and environmental groups. The settlements (as amended on June 13, 2011) commit the EPA to issuing final regulations by May 26, 2012, setting performance standards for greenhouse gas emissions from new, modified, and existing power plants. These standards are to be based on the best demonstrated control technology. The EPA is expected to issue proposed performance standard regulations for public comment in early 2012.

On May 20, 2011, the State of Texas filed, on behalf of itself, certain other state petitioners and supporting intervenors, a petition for review of the EPA's endangerment finding in the United States Court of Appeals for the District of Columbia in a proceeding consolidating several similar challenges to the endangerment finding and subsequent EPA rulemaking. On September 28, 2011, the EPA's Office of Inspector General issued a report concluding that the EPA should have followed a more rigorous peer review process in relation to the endangerment finding. The EPA disagreed with this conclusion. In addition, legislation has been introduced in the United States Congress which would repeal the EPA's endangerment finding or otherwise prevent the EPA from regulating greenhouse gases as air pollutants.

NCPA and the Project Participants are unable to predict the outcome of these legal and legislative challenges to the EPA's endangerment finding and subsequent rulemaking or the effect that any final rules promulgated by the EPA regulating greenhouse gas emissions from electric generating units and other stationary sources would have on any NCPA project or any of the projects of the Project Participants or their respective electric systems.

Air Quality–National Ambient Air Quality Standards. The Clean Air Act requires that the EPA establish National Ambient Air Quality Standards ("NAAQS") for certain air pollutants. When a NAAQS has been established, each state must identify areas in its state that do not meet the EPA standard (known as "non-attainment areas") and develop regulatory measures in its state implementation plan to reduce or control the emissions of that air pollutant in order to meet the standard and become an "attainment area." The EPA has recently increased the stringency of the NAAQS for three pollutants, nitrogen dioxide, sulfur dioxide and particulate matter. A proposed rule for the secondary NAAQS for nitrogen dioxide and sulfur dioxide was published in the Federal Register on August 1, 2011. On September 2, 2011, President Obama directed the EPA to withdraw its proposal to lower the NAAQS for ozone. As a result of this withdrawal, the EPA will now resume the process of issuing non-attainment designations for the ozone NAAQS. Even without lower standards, non-attainment areas for ozone are likely to be designated. This may result in stringent permitting processes for new sources of emissions, and additional state restrictions on existing sources of emissions.

Mercury and Air Toxics Standards. On December 16, 2011, the EPA signed a rule establishing new standards to reduce air pollution from coal- and oil-fired power plants under sections 111 (new source performance standards, or "NSPS") and 112 (toxics program) of the Clean Air Act. Under section 111, the NSPS revises the standards that new coal- and oil-fired power plants must meet for particulate matter, sulfur dioxide, and nitrogen oxides. Under section 112, the new toxics standards set limits on emissions of heavy metals, including mercury, arsenic, chromium, and nickel; and acid gases, including hydrochloric acid and hydrofluoric acid, from existing and new power plants larger than 25 megawatts that burn coal or oil. Power plants have up to four years to meet these standards. While many plants already meet some or all of these new standards, some plants will be required to install new equipment to meet the standards. The Project Participants that purchase power from coal-fired power stations may be affected by these new rules, and such Project Participants may be exposed to increased costs.

Other Factors

The electric utility industry in general has been, or in the future may be, affected by a number of other factors which could impact the financial condition and competitiveness of many electric utilities and the level of utilization of generating and transmission facilities. In addition to the factors discussed above, such factors include, among others, (a) effects of compliance with rapidly changing environmental, safety, licensing, regulatory and legislative requirements other than those described above (including those affecting nuclear power plants), (b) changes resulting from conservation and demand-side management programs on the timing and use of electric energy, (c) changes resulting from a national energy policy, (d) effects of competition from other electric utilities (including increased competition resulting from a movement to allow direct access or from mergers, acquisitions, and "strategic alliances" of competing electric and natural gas utilities and from competitors transmitting less expensive electricity from much greater distances over an interconnected system) and new methods of, and new facilities for, producing low-cost electricity, (e) the repeal of certain federal statutes that would have the effect of increasing the competitiveness of many IOUs, (f) increased competition from independent power producers and marketers, brokers and federal power marketing agencies, (g) "self-generation" or "distributed generation" (such as microturbines and fuel cells) by industrial and commercial customers and others, (h) issues relating to the ability to issue tax-exempt obligations, including severe restrictions on the ability to sell to nongovernmental entities electricity from generation projects and transmission service from transmission line projects financed with outstanding tax-exempt obligations, (i) effects of inflation on the operating and maintenance costs of an electric utility and its facilities, (j) changes from projected future load requirements, (k) increases in costs and uncertain availability of capital, (l) shifts in the availability and relative costs of different fuels (including the cost of natural gas and nuclear fuel), (m) sudden and dramatic increases in the price of energy purchased on the open market that may occur in times of high peak demand in an area of the country experiencing such high peak demand, such as has occurred in California, (n) inadequate risk management procedures and practices with respect to, among other things, the purchase and sale of energy and transmission capacity, (o) other legislative changes, voter initiatives, referenda and statewide propositions, (p) effects of the changes in the economy, (q) effects of possible manipulation of the electric markets, (r) natural disasters or other physical calamities, including, but not limited to, earthquakes and floods and (s) changes to the climate. Any of these factors (as well as other factors) could have an adverse effect on the financial condition of any given electric utility, including the Project Participants, and likely will affect individual utilities in different ways.

NCPA and the Project Participants are unable to predict what impact such factors will have on the business operations and financial condition of the Project Participants, but the impact could be significant. This Official Statement includes a brief discussion of certain of these factors. This discussion does not purport to be comprehensive or definitive, and these matters are subject to change subsequent to the date hereof. Extensive information on the electric utility industry is available from the legislative and regulatory bodies and other sources in the public domain, and potential purchasers of the 2012 Bonds should obtain and review such information.

LITIGATION

There is no controversy or litigation of any nature now pending or threatened restraining or enjoining the issuance, sale, execution or redelivery of the 2012 Bonds, or in any way contesting or affecting the validity of the 2012 Bonds or any proceedings of NCPA taken with respect to the issuance or sale thereof.

Upon the basis of information presently available, NCPA and its General Counsel believe that there is no litigation pending or threatened against NCPA which will materially adversely affect the Project or the respective sources of payment for the 2012 Bonds.

Market Redesign

Most of the matters being contested at FERC or being discussed in California ISO stakeholder processes involving NCPA or the Project Participants concern the current operation or potential changes to the ISO market. For a discussion of potential changes in the ISO market, see "OTHER FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY—ISO Markets."

California Energy Market Dysfunction, Refund Dispute and Related Litigation

Following the 1998 operation of the ISO and the California Power Exchange (the "PX"), the deregulated electricity and natural gas markets in California became increasingly dysfunctional, with very high prices in 2000-2001, resulting in the eventual bankruptcy of the PX, PG&E (and others) and a number of orders from FERC. The IOUs—PG&E, Southern California Edison Company ("Edison") and San Diego Gas & Electric Company ("SDG&E")—and the State of California and the CPUC have been pursuing claims for refunds against all sellers into the market, including NCPA and other power-producing municipally owned utilities ("MOUs"), including Santa Clara.

Those claims for refunds against varying groups of sellers have been pursued in a number of *fora* since early Fall, 2000, and have been through numerous FERC proceedings, several Court of Appeals decisions, and the U.S. Supreme Court. The claims are still being pursued both at FERC and California state court in Los Angeles County. While NCPA considered the claims against it to be lacking in legal merit, NCPA has now entered into a settlement with the plaintiffs which provides the terms of a final resolution of all of these claims and of the bankruptcy claims held by NCPA against PG&E and the PX. The settlement agreement was approved by FERC on April 29, 2010. That approval by FERC was the last regulatory step necessary to resolve these disputes between those parties in their entirety, as well as a separate lawsuit filed by the State of California. The state court proceeding against NCPA was dismissed with prejudice on May 20, 2010.

While the FERC refund proceedings remain ongoing, and it is anticipated that NCPA may have to participate from time to time to protect its interests, NCPA anticipates that its high level of activity in the past will be significantly reduced for the future.

Other Proceedings

NCPA is involved in various other state court proceedings incidental to its operations. Based on its review of those proceedings with its General Counsel, NCPA believes that the ultimate aggregate liability, if any, resulting from those proceedings will not have a material adverse effect on its financial position.

RATINGS

Standard & Poor's, a Division of The McGraw-Hill Companies, Inc. ("S&P") and Fitch Ratings ("Fitch") have assigned to the 2012 Bonds the ratings of "A" and "A," respectively. Such ratings reflect only the views of such organizations and are not a recommendation to buy, sell or hold the 2012 Bonds. Explanations of the significance of such ratings may be obtained only from the respective organizations at: Standard & Poor's Rating Services, 55 Water Street, New York, New York 10041; and Fitch Ratings, One State Street Plaza, New York, New York 10004. Generally, a rating agency bases its rating on the information and materials furnished to it and on investigations, studies and assumptions of its own. There is no assurance that either rating will continue for any given period or that it will not be revised downward or withdrawn entirely by the respective rating agency, if in the judgment of such rating agency, circumstances so warrant. NCPA undertakes no responsibility to oppose any such revision or withdrawal. Any such downward revision or withdrawal of such ratings may have an adverse effect on the market price of the 2012 Bonds. A securities rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time.

UNDERWRITING

Citigroup Global Markets Inc., on behalf of itself and the other underwriters noted on the cover page of this Official Statement (the "Underwriters"), has agreed to purchase the 2012 Series A Bonds from NCPA at a price of $86,629,958.42 (which reflects the $76,665,000 par amount of the 2012 Series A Bonds, plus original issue premium of $10,323,499.75, and less an Underwriters' discount of $358,541.33) and to purchase the 2012 Series B Bonds from NCPA at a price of $7,086,701.69 (which reflects the $7,120,000 par amount of the 2012 Series B Bonds less an Underwriters' discount of $33,298.31), subject to certain conditions set forth in the Contract of Purchase between NCPA and the Underwriters.

The Underwriters may offer and sell the 2012 Bonds to certain dealers and others at prices lower than the offering prices or at yields higher than the offering yields stated on the inside cover page. The offering prices and yields may be changed from time to time by the Underwriters. The Contract of Purchase for the 2012 Bonds provides that the Underwriters will purchase all of the 2012 Bonds, if any are purchased, the obligation to make such purchases being subject to certain terms and conditions set forth in the Contract of Purchase.

The Underwriters and their respective affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, principal investment, hedging, financing and brokerage activities. Certain of the Underwriters and their respective affiliates have, from time to time, performed, and may in the future perform, various investment banking services for NCPA for which they received or will receive customary fees and expenses.

In the ordinary course of their various business activities, the Underwriters and their respective affiliates may make or hold a broad array of investments and actively trade debt and equity securities (or related derivative securities) and financial instruments (which may include bank loans and/or credit default swaps) for their own account and for the accounts of their customers and may at any time hold long and short positions in such securities and instruments. Such investment and securities activities may involve securities and instruments of NCPA.

Citigroup Global Markets Inc. and Morgan Stanley & Co. LLC have informed NCPA that Citigroup Inc. and Morgan Stanley, the respective parent companies of Citigroup Global Markets Inc. and Morgan Stanley & Co. LLC, each an Underwriter of the 2012 Bonds, entered into a retail brokerage joint venture. As part of the joint venture each of Citigroup Global Markets Inc. and Morgan Stanley & Co. LLC will distribute municipal securities to retail investors through the financial advisor network of a new broker-dealer, Morgan Stanley Smith Barney LLC. This distribution arrangement became effective on June 1, 2009. As part of this arrangement, each of Citigroup Global Markets Inc. and Morgan Stanley & Co. LLC will compensate Morgan Stanley Smith Barney LLC for its selling efforts in connection with their respective allocations of 2012 Bonds.

FINANCIAL ADVISOR

Public Financial Management Inc. (the "Financial Advisor") has assisted NCPA with various matters relating to the planning, structuring and delivery of the 2012 Bonds. The Financial Advisor is a financial advisory firm and is not engaged in the business of underwriting or distributing municipal securities or other public securities. The Financial Advisor assumes no responsibility for the accuracy, completeness or fairness of this Official Statement. The Financial Advisor will receive compensation from NCPA contingent upon the sale of the delivery of the 2012 Bonds.

TAX MATTERS

2012 Series A Bonds

In the opinion of Orrick, Herrington & Sutcliffe LLP, bond counsel to NCPA ("Bond Counsel"), based on an analysis of existing laws, regulations, rulings and court decisions, and assuming, among other matters, the accuracy of certain representations and compliance with certain covenants, interest on the 2012 Series A Bonds is excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986 (the "Code") and is exempt from State of California personal income taxes. Bond Counsel is of the further opinion that interest on the 2012 Series A Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes, although Bond Counsel observes that such interest is included in adjusted current earnings when calculating corporate alternative minimum taxable income. A complete copy of the proposed form of opinion of Bond Counsel is set forth in Appendix F hereto.

To the extent the issue price of any maturity of the 2012 Series A Bonds is less than the amount to be paid at maturity of such 2012 Series A Bonds (excluding amounts stated to be interest and payable at least annually over the term of such 2012 Series A Bonds), the difference constitutes "original issue discount," the accrual of which, to the extent properly allocable to each Beneficial Owner thereof, is treated as interest on the 2012 Series A Bonds which is excluded from gross income for federal income tax purposes and State of California personal income taxes. For this purpose, the issue price of a particular maturity of the 2012 Series A Bonds is the first price at which a substantial amount of such maturity of the 2012 Series A Bonds is sold to the public (excluding bond houses, brokers, or similar persons or organizations acting in the capacity of underwriters, placement agents or wholesalers). The original issue discount with respect to any maturity of the 2012 Series A Bonds accrues daily over the term to maturity of such 2012 Series A Bonds on the basis of a constant interest rate compounded semiannually (with straight-line interpolations between compounding dates). The accruing original issue discount is added to the adjusted basis of such 2012 Series A Bonds to determine taxable gain or loss upon disposition (including sale, redemption, or payment on maturity) of such 2012 Series A Bonds. Beneficial Owners of the 2012 Series A Bonds should consult their own tax advisors with respect to the tax consequences of ownership of 2012 Series A Bonds with original issue discount, including the treatment of Beneficial Owners who do not purchase such 2012 Series A Bonds in the original offering to the public at the first price at which a substantial amount of such Bonds is sold to the public.

2012 Series A Bonds purchased, whether at original issuance or otherwise, for an amount higher than their principal amount payable at maturity (or, in some cases, at their earlier call date) ("Premium Bonds") will be treated as having amortizable bond premium. No deduction is allowable for the amortizable bond premium in the case of obligations, like the Premium Bonds, the interest on which is excluded from gross income for federal income tax purposes. However, the amount of tax-exempt interest received, and a Beneficial Owner's basis in a Premium Bond, will be reduced by the amount of amortizable bond premium properly allocable to such Beneficial Owner. Beneficial Owners of Premium Bonds should consult their own tax advisors with respect to the proper treatment of amortizable bond premium in their particular circumstances.

The Code imposes various restrictions, conditions and requirements relating to the exclusion from gross income for federal income tax purposes of interest on obligations such as the 2012 Series A Bonds. NCPA has made certain representations and covenanted to comply with certain restrictions, conditions and requirements designed to ensure that interest on the 2012 Series A Bonds will not be included in federal gross income. Inaccuracy of these representations or failure to comply with these covenants may result in interest on the 2012 Series A Bonds being included in gross income for federal income tax purposes, possibly from the date of original issuance of the 2012 Series A Bonds. The opinion of Bond Counsel assumes the accuracy of these representations and compliance with these covenants. Bond Counsel has not undertaken to determine (or to inform any person) whether any actions taken (or not taken), or events occurring (or not occurring), or any other matters coming to Bond Counsel's attention after the date of issuance of the 2012 Series A Bonds may adversely affect the value of, or the tax status of interest on, the 2012 Series A Bonds. Accordingly, the opinion of Bond Counsel is not intended to, and may not, be relied upon in connection with any such actions, events or matters.

Although Bond Counsel is of the opinion that interest on the 2012 Series A Bonds is excluded from gross income for federal income tax purposes and is exempt from State of California personal income taxes, the ownership or disposition of, or the accrual or receipt of interest on, the 2012 Series A Bonds may otherwise affect a Beneficial Owner's federal, state or local tax liability. The nature and extent of these other tax consequences depends upon the particular tax status of the Beneficial Owner or the Beneficial Owner's other items of income or deduction. Bond Counsel expresses no opinion regarding any such other tax consequences.

Current and future legislative proposals, if enacted into law, clarification of the Code or court decisions may cause interest on the 2012 Series A Bonds to be subject, directly or indirectly, to federal income taxation or to be subject to or exempted from state income taxation, or otherwise prevent Beneficial Owners from realizing the full current benefit of the tax status of such interest. As one example, on September 12, 2011, the Obama Administration announced a legislative proposal entitled the American Jobs Act of 2011. For tax years beginning on or after January 1, 2013, the American Jobs Act of 2011 generally would limit the exclusion from gross income of interest on obligations like the 2012 Series A Bonds to some extent for taxpayers who are individuals and whose income is subject to higher marginal income tax rates. Other proposals have been made that could significantly affect, or reduce the benefit of, the exclusion from gross income of interest on obligations like the 2012 Series A Bonds. The introduction or enactment of any such legislative proposals, clarification of the Code or court decisions may also affect, perhaps significantly, the market price for, or marketability of, the 2012 Series A Bonds. Prospective purchasers of the 2012 Series A Bonds should consult their own tax advisors regarding any pending or proposed federal or state tax legislation, regulations or litigation, as to which Bond Counsel expresses no opinion.

The opinion of Bond Counsel is based on current legal authority, covers certain matters not directly addressed by such authorities, and represents Bond Counsel's judgment as to the proper treatment of the 2012 Series A Bonds for federal income tax purposes. It is not binding on the Internal Revenue Service ("IRS") or the courts. Furthermore, Bond Counsel cannot give and has not given any opinion or assurance about the future activities of NCPA, or about the effect of future changes in the Code, the applicable regulations, the interpretation thereof or the enforcement thereof by the IRS. NCPA has covenanted, however, to comply with the requirements of the Code.

Bond Counsel's engagement with respect to the 2012 Series A Bonds ends with the issuance of the 2012 Series A Bonds, and, unless separately engaged, Bond Counsel is not obligated to defend NCPA or the Beneficial Owners regarding the tax-exempt status of the 2012 Series A Bonds in the event of an audit examination by the IRS. Under current procedures, parties other than NCPA and its appointed counsel, including the Beneficial Owners, would have little, if any, right to participate in the audit examination process. Moreover, because achieving judicial review in connection with an audit examination of tax-exempt bonds is difficult, obtaining an independent review of IRS positions with which NCPA legitimately disagrees, may not be practicable. Any action of the IRS, including but not limited to selection of the 2012 Series A Bonds for audit, or the course or result of such audit, or an audit of bonds presenting similar tax issues may affect the market price for, or the marketability of, the 2012 Series A Bonds, and may cause NCPA or the Beneficial Owners to incur significant expense.

2012 Series B Bonds

General

In the opinion of Bond Counsel, based on an analysis of existing laws, regulations, rulings and court decisions and assuming compliance with certain covenants, interest on the 2012 Series B Bonds is exempt from State of California personal income taxes. Interest on the 2012 Series B Bonds is not excluded from gross income for federal income tax purposes under Section 103 of the Code. Bond Counsel expresses no opinion regarding any other tax consequences related to the ownership or disposition of, or accrual or receipt of interest on, the 2012 Series B Bonds. The proposed form of opinion of Bond Counsel is contained in Appendix F hereto.

The following discussion summarizes certain U.S. federal tax considerations generally applicable to holders of the 2012 Series B Bonds that acquire their 2012 Series B Bonds in the initial offering. The discussion below is based upon laws, regulations, rulings, and decisions in effect and available on the date hereof, all of which are subject to change, possibly with retroactive effect. Prospective investors should note that no rulings have been or are expected to be sought from the IRS with respect to any of the U.S. federal income tax consequences discussed below, and no assurance can be given that the IRS will not take contrary positions. Further, the following discussion does not deal with all U.S. federal income tax consequences applicable to any given investor, nor does it address the U.S. federal income tax considerations applicable to categories of investors some of which may be subject to special taxing rules (regardless of whether or not such persons constitute U.S. Holders), such as certain U.S. expatriates, banks, REITs, RICs, insurance companies, tax-exempt organizations, dealers or traders in securities or currencies, partnerships, S corporations, estates and trusts, investors that hold their 2012 Series B Bonds as part of a hedge, straddle or an integrated or conversion transaction, or investors whose "functional currency" is not the U.S. dollar. Furthermore, it does not address (i) alternative minimum tax consequences or (ii) the indirect effects on persons who hold equity interests in a holder. In addition, this summary generally is limited to investors that acquire their 2012 Series B Bonds pursuant to this offering for the issue price that is applicable to such 2012 Series B Bonds (i.e., the price at which a substantial amount of the 2012 Series B Bonds are sold to the public) and who will hold their 2012 Series B Bonds as "capital assets" within the meaning of Section 1221 of the Code.

As used herein, "U.S. Holder" means a beneficial owner of a 2012 Series B Bond that for U.S. federal income tax purposes is an individual citizen or resident of the United States, a corporation or other entity taxable as a corporation created or organized in or under the laws of the United States or any state thereof (including the District of Columbia), an estate the income of which is subject to U.S. federal income taxation regardless of its source or a trust where a court within the United States is able to exercise primary supervision over the administration of the trust and one or more United States persons (as defined in the Code) have the authority to control all substantial decisions of the trust (or a trust that has made a valid election under U.S. Treasury Regulations to be treated as a domestic trust). As used herein, "Non-U.S. Holder" generally means a beneficial owner of a 2012 Series B Bond (other than a partnership) that is not a U.S. Holder. If a partnership holds 2012 Series B Bonds, the tax treatment of such partnership or a partner in such partnership generally will depend upon the status of the partner and upon the activities of the partnership. Partnerships holding 2012 Series B Bonds, and partners in such partnerships, should consult their own tax advisors regarding the tax consequences of an investment in the 2012 Series B Bonds (including their status as U.S. Holders or Non-U.S. Holders).

For U.S. Holders

The 2012 Series B Bonds are not expected to be treated as issued with original issue discount ("OID") for U.S. federal income tax purposes because the stated redemption price at maturity of the 2012 Series B Bonds is not expected to exceed their issue price, or because any such excess is expected to only be a de minimis amount (as determined for tax purposes).

Prospective investors that are not individuals or regular C corporations who are U.S. persons purchasing the 2012 Series B Bonds for investment should consult their own tax advisors as to any tax consequences to them from the purchase, ownership and disposition of the 2012 Series B Bonds.

Disposition of the 2012 Series B Bonds. Unless a nonrecognition provision of the Code applies, the sale, exchange, redemption, defeasance, retirement (including pursuant to an offer by NCPA) or other disposition of a 2012 Series B Bond, will be a taxable event for U.S. federal income tax purposes. In such event, in general, a U.S. Holder of a 2012 Series B Bond will recognize gain or loss equal to the difference between (i) the amount of cash plus the fair market value of property received (except to the extent attributable to accrued but unpaid interest on the 2012 Series B Bond which will be taxed in the manner described above) and (ii) the U.S. Holder's adjusted tax basis in the 2012 Series B Bond (generally, the purchase price paid by the U.S. Holder for the 2012 Series B Bond). Any such gain or loss generally will be capital gain or loss. In the case of a noncorporate U.S. Holder of the 2012 Series B Bonds, the maximum marginal U.S. federal income tax rate applicable to any such gain will be lower than the maximum marginal U.S. federal income tax rate applicable to ordinary income if such U.S. holder's holding period for the 2012 Series B Bonds exceeds one year. The deductibility of capital losses is subject to limitations.

For Non-U.S. Holders

Interest. Subject to the discussion below under the heading "Information Reporting and Backup Withholding," payments of principal of, and interest on, any 2012 Series B Bond to a Non-U.S. Holder, other than (1) a controlled foreign corporation, as such term is defined in the Code, which is related to NCPA through stock ownership and (2) a bank which acquires such 2012 Series B Bond in consideration of an extension of credit made pursuant to a loan agreement entered into in the ordinary course of business, will not be subject to any U.S. withholding tax provided that the beneficial owner of the 2012 Series B Bond provides a certification completed in compliance with applicable statutory and regulatory requirements, which requirements are discussed below under the heading "Information Reporting and Backup Withholding," or an exemption is otherwise established.

Disposition of the 2012 Series B Bonds. Subject to the discussion below under the heading "Information Reporting and Backup Withholding," any gain realized by a Non-U.S. Holder upon the sale, exchange, redemption, retirement (including pursuant to an offer by NCPA) or other disposition of a 2012 Series B Bond generally will not be subject to U.S. federal income tax, unless (i) such gain is effectively connected with the conduct by such Non-U.S. Holder of a trade or business within the United States; or (ii) in the case of any gain realized by an individual Non-U.S. Holder, such holder is present in the United States for 183 days or more in the taxable year of such sale, exchange, redemption, retirement (including pursuant to an offer by NCPA) or other disposition and certain other conditions are met.

U.S. Federal Estate Tax. A 2012 Series B Bond that is held by an individual who at the time of death is not a citizen or resident of the United States will not be subject to U.S. federal estate tax as a result of such individual's death, provided that at the time of such individual's death, payments of interest with respect to such 2012 Series B Bond would not have been effectively connected with the conduct by such individual of a trade or business within the United States.

Information Reporting and Backup Withholding. U.S. information reporting and "backup withholding" requirements apply to certain payments of principal of, and interest on the 2012 Series B Bonds, and to proceeds of the sale, exchange, redemption, retirement (including pursuant to an offer by NCPA) or other disposition of a 2012 Series B Bond, to certain noncorporate holders of 2012 Series B Bonds that are United States persons. Under current U.S. Treasury Regulations, payments of principal and interest on any 2012 Series B Bonds to a holder that is not a United States person will not be subject to any backup withholding tax requirements if the beneficial owner of the 2012 Series B Bond or a financial institution holding the 2012 Series B Bond on behalf of the beneficial owner in the ordinary course of its trade or business provides an appropriate certification to the payor and the payor does not have actual knowledge that the certification is false. If a beneficial owner provides the certification, the certification must give the name and address of such owner, state that such owner is not a United States person, or, in the case of an individual, that such owner is neither a citizen nor a resident of the United States, and the owner must sign the certificate under penalties of perjury. If a financial institution, other than a financial institution that is a qualified intermediary, provides the certification, the certification must state that the financial institution has received from the beneficial owner the certification set forth in the preceding sentence, set forth the information contained in such certification, and include a copy of such certification, and an authorized representative of the financial institution must sign the certificate under penalties of perjury. A financial institution generally will not be required to furnish to the IRS the names of the beneficial owners of the 2012 Series B Bonds that are not United States persons and copies of such owners' certifications where the financial institution is a qualified intermediary that has entered into a withholding agreement with the IRS pursuant to applicable U.S. Treasury Regulations.

In the case of payments to a foreign partnership, foreign simple trust or foreign grantor trust, other than payments to a foreign partnership, foreign simple trust or foreign grantor trust that qualifies as a withholding foreign partnership or a withholding foreign trust within the meaning of applicable U.S. Treasury Regulations and payments to a foreign partnership, foreign simple trust or foreign grantor trust that are effectively connected with the conduct of a trade or business within the United States, the partners of the foreign partnership, the beneficiaries of the foreign simple trust or the persons treated as the owners of the foreign grantor trust, as the case may be, will be required to provide the certification discussed above in order to establish an exemption from withholding and backup withholding tax requirements. The current backup withholding tax rate is 28% (subject to future adjustment).

In addition, if the foreign office of a foreign "broker," as defined in applicable U.S. Treasury Regulations pays the proceeds of the sale of a 2012 Series B Bond to the seller of the 2012 Series B Bond, backup withholding and information reporting requirements will not apply to such payment provided that such broker derives less than 50% of its gross income for certain specified periods from the conduct of a trade or business within the United States, is not a controlled foreign corporation, as such term is defined in the Code, and is not a foreign partnership (1) one or more of the partners of which, at any time during its tax year, are U.S. persons (as defined in U.S. Treasury Regulations Section 1.1441-1(c)(2)) who, in the aggregate hold more than 50% of the income or capital interest in the partnership or (2) which, at any time during its tax year, is engaged in the conduct of a trade or business within the United States. Moreover, the payment by a foreign office of other brokers of the proceeds of the sale of a 2012 Series B Bond, will not be subject to backup withholding unless the payer has actual knowledge that the payee is a U.S. person. Principal and interest so paid by the U.S. office of a custodian, nominee or agent, or the payment by the U.S. office of a broker of the proceeds of a sale of a 2012 Series B Bond, is subject to backup withholding requirements unless the beneficial owner provides the nominee, custodian, agent or broker with an appropriate certification as to its non-U.S. status under penalties of perjury or otherwise establishes an exemption.

Circular 230

Under 31 C.F.R. part 10, the regulations governing practice before the IRS (Circular 230), NCPA and its tax advisors are (or may be) required to inform prospective investors that:

i. any advice contained herein is not intended or written to be used, and cannot be used, by any taxpayer for the purpose of avoiding penalties that may be imposed on the taxpayer;

ii. any such advice is written to support the promotion or marketing of the 2012 Series B Bonds and the transactions described herein; and

iii. each taxpayer should seek advice based on the taxpayer's particular circumstances from an independent tax advisor.

APPROVAL OF LEGAL PROCEEDINGS

The issuance of the 2012 Bonds is subject to the approval of legality of Orrick, Herrington & Sutcliffe LLP, Los Angeles, California, Bond Counsel to NCPA. Certain legal matters will be passed upon for NCPA by Meyers, Nave, Riback, Silver & Wilson, Sacramento, California, General Counsel to NCPA, by Spiegel & McDiarmid LLP, Washington, D.C., Washington Counsel to NCPA. Certain legal matters will be passed upon for the Underwriters by Fulbright & Jaworski L.L.P., Los Angeles, California, Counsel to the Underwriters.

VERIFICATION OF MATHEMATICAL COMPUTATIONS

On the date of delivery of the 2012 Bonds, NCPA will receive a report from Grant Thornton LLP verifying the adequacy of the cash deposited and held in the Escrow Fund, and the maturing principal amounts of and interest earned on the Escrow Securities initially deposited in the Escrow Fund (if any), to pay when due the interest on the Refunded 1998 Bonds to the redemption date and the redemption price of the Refunded 1998 Bonds on the redemption date.

INDEPENDENT AUDITORS

The combined financial statements of Northern California Power Agency and Associated Power Corporations as of and for the years ended June 30, 2011 and June 30, 2010 have been audited by Moss Adams LLP, independent auditors, as stated in their report. Moss Adams LLP has not been engaged to perform and has not performed, since the date of its report included therein, any procedures on the financial statements addressed in such report. Moss Adams LLP has also not performed any procedures relating to this Official Statement.

INCLUSION BY SPECIFIC REFERENCE

When delivered by the Underwriters, in their capacity as such, this Official Statement shall be deemed to include by specific reference all documents previously provided to the Municipal Securities Rulemaking Board (through EMMA) by NCPA or a Significant Share Project Participant with respect to its electric system to the extent that statements in such documents are material to the offering made hereby. Any statements in a document included by specific reference herein shall be modified or superseded for purposes of this Official Statement to the extent that it is modified or superseded by statements contained in this Official Statement or in any other subsequently provided document included by specific reference herein.

MISCELLANEOUS

This Official Statement includes descriptions of the terms of the 2012 Bonds, the Indenture, the Escrow Agreement, the Third Phase Agreement, the Continuing Disclosure Agreements, certain other agreements and certain provisions of state and federal legislation. Such descriptions do not purport to be complete and all such descriptions and references thereto are qualified in their entirety by references to each such document, copies of which may be obtained from NCPA or, during the period of the offering, from the Underwriters.

Any statements herein involving matters of opinion, whether or not expressly so stated, are intended as such and not as representations of fact.

NORTHERN CALIFORNIA POWER AGENCY

By: /s/ James H. Pope
James H. Pope
General Manager

[THIS PAGE INTENTIONALLY LEFT BLANK]

APPENDIX A

SELECTED INFORMATION RELATING TO THE SIGNIFICANT SHARE PROJECT PARTICIPANTS

The following information has been supplied by the respective Project Participants, and includes selected historical operating data and data taken from their electric system balance sheets. Neither NCPA nor any Project Participant makes any representation as to the accuracy or completeness of this information with respect to any other Project Participants.

TABLE OF CONTENTS

CITY OF ALAMEDA

Introduction

The City of Alameda ("Alameda") is a charter city in the State of California. Alameda is an island community of 22.8 square miles located across the bay from San Francisco and to the west of the City of Oakland. Alameda was incorporated in 1854.

Alameda provides electric utility service through its Bureau of Electricity. The Alameda Bureau of Electricity began operation in 1887. The Bureau of Electricity, did business as "Alameda Power & Telecom" beginning in 1999. On January 26, 2009, the name was changed to "Alameda Municipal Power." The Alameda electric utility was the first municipal electric utility in California and is one of the oldest in the nation.

Alameda Municipal Power serves the entire area of the City of Alameda and has about 93 pole miles of overhead lines and over 173 cable miles of underground lines. During the fiscal year 2010-11, it served an average of 34,281 customers, comprised of an average of approximately 30,171 residential customers, an average of approximately 3,757 commercial and industrial customers and an average of approximately 353 public authority and other customers, with a peak demand of approximately 70.8 MW.

Alameda joined NCPA in 1968, is a participant in most NCPA projects, and has procured other power supply resources independently. In addition, NCPA has developed electric scheduling, dispatch and transmission capabilities that are utilized in the provision of Alameda Municipal Power's electric utility services. All of Alameda Municipal Power's rights to electric energy, capacity, environmental attributes and transmission are scheduled by NCPA. Alameda participates in the NCPA power pool. See "NORTHERN CALIFORNIA POWER AGENCY—NCPA Power Pool" in the front part of this Official Statement.

From June 2001 until November 21, 2008, Alameda also provided cable television and internet services through its telecommunications system. On November 18, 2008, the City Council of the City of Alameda unanimously authorized the sale of the telecommunications business line effective November 21, 2008. See "Litigation" and "Condensed Operating Results and Selected Balance Sheet Information" below.

Only the revenues of the Alameda electric system will be available to pay amounts owed by Alameda under the Third Phase Agreement.

Alameda Municipal Power is under the policy control of the Alameda Public Utilities Board, in accordance with the Alameda City Charter. The Public Utilities Board consists of four commissioners appointed by the Mayor with concurrence of the City Council, and the City Manager of the City (as an ex-officio member), who may not hold any office on the Board.

Pursuant to the Alameda City Charter, the Alameda Public Utilities Board has the power to control and manage the electric system, including the power to fix rates for the services of the electric system. The Public Utilities Board establishes goals and policies, approves major purchases and creates the framework for local control of the utility.

Alameda Municipal Power's main office is located at 2000 Grand Street, Alameda, California 94501, (510) 748-3901. For more information about Alameda and its electric system, contact Girish Balachandran, General Manager at the above address and telephone number. A copy of the most recent comprehensive annual financial report of Alameda Municipal Power (the "Annual Report") is available on Alameda Municipal Power's website at http://www.alamedamp.com. The Annual Report is incorporated herein by this reference. However, the information presented on such website or referenced therein other than the Annual Report is not part of this Official Statement and is not incorporated by reference herein.

Power Supply Resources

The following table sets forth information concerning Alameda's power supply resources and the energy supplied by each during the fiscal year ended June 30, 2011.

CITY OF ALAMEDA
ALAMEDA MUNICIPAL POWER
POWER SUPPLY RESOURCES
For the Fiscal Year Ended June 30, 2011

Source	Capacity Available (MW)[1]	Actual Energy (MWh)	% of Total Energy
Purchased Power[2]:			
Western	16.3	36,254.0	9.06%
High Winds Project	10.0	24,700.0	6.17
Morgan Stanley	15.0	65,520.0	16.38
Landfill Gas Projects			
Richmond	2.0	15,576.7	3.89
Keller Canyon	1.9	15,196.2	3.80
Santa Cruz	1.3	10,009.4	2.50
Half Moon Bay	5.7	43,497.4	10.87
Graeagle	0.4	2,809.7	0.70
NCPA			
Geothermal Plant 1	8.1	64,289.3	16.07
Geothermal Plant 2	10.2	80,483.8	20.12
Hydroelectric Project	24.3	82,455.9	20.61
Combustion Turbine Project No. 1	16.4	161.4	0.04
Combustion Turbine Project No. 2	9.5	2,392.7	0.60
Other Purchases (net)	--	16,338.5	4.08
Total[3]	121.1	459,685.0	114.90%
Total Capacity and Energy Sold at Wholesale	N/A	(59,599.4)	(14.90)
Alameda's System Requirement for Retail	70.8	400,085.6	100.0%

(1) Non-coincident capacity available.
(2) Entitlements, firm allocations and contract amounts.
(3) Totals may not add due to rounding.

Source: Alameda Municipal Power.

In the fiscal year ended June 30, 2011, Alameda's average cost of power for 382.6 GWh of energy sales was 6.60 cents per kWh, and its average cost of power for the 400.0 GWh purchased was 6.37 cents per kWh.

Purchased Power

Western. Alameda has power purchase agreements with the Western Area Power Administration ("Western") that continue through December 31, 2024. Alameda's Western power is assigned to NCPA for scheduling and delivery to Alameda. Power purchased under these agreements is generated by the Central Valley Project ("CVP"), a series of federal hydroelectric facilities in Northern California operated by the United States Bureau of Reclamation (the "Bureau").

On October 5, 2000, Alameda signed a 20-year Base Resource agreement with Western with initial service beginning January 1, 2005. Service under the Western contract will continue through December 31, 2024, with Alameda receiving a "slice of the system" allocation from Western. Alameda's allocation is currently 1.08075% of the CVP output. In 2009, Alameda applied for and was awarded an increase to its allocated percentage of Western Base Resource hydroelectric deliveries. Effective January 1, 2015, Alameda's current allocation of 1.08075% will increase to 1.20622%. This increased allocation will result in increased deliveries of hydroelectric energy to Alameda customers. Power provided to Alameda under the Western contract is on a take-or-pay basis; Alameda is obligated to pay its share of Western costs whether or not it receives any power.

Other Purchases. Alameda has also entered into certain other power purchase agreements: (i) a power purchase agreement with Morgan Stanley Capital Group for the delivery of 15 MW of power from January 1 through March 31 and from October 1 through December 31 during each of the calendar years 2005-2014; (ii) a power purchase agreement with PPM Energy, Inc. (now Iberdrola Renewables, Inc.) for power supplied from the Highwinds Project in Solano County, California under which Alameda Municipal Power will receive 6.17% (approximately 10 MW of the 162 MW project) until June 30, 2028; and (iii) five long-term power purchase agreements for power supplied by multiple existing and proposed generating facilities utilizing combustible gaseous emissions from landfills located in or near the San Francisco Bay area, under which Alameda has received approximately 3.5 MW of baseload power from two facilities since early 2006 and 7.3 MW of baseload output from two additional facilities since 2009, with a fifth facility scheduled for an 1.9 MW beginning in 2012. In addition, Alameda makes short-term market purchases as necessary or economical to meet its native load requirements.

Generally, Alameda has entered into power purchase agreements solely or primarily for use within its own system. However, from time to time, Alameda has entered into purchases for resale. Such purchases have not involved significant payments, nor have they been for significant amounts of power or periods of time. Alameda currently does not expect to significantly increase the amount, frequency or duration of any such purchases for resale, although it has the authority to do so.

Joint Powers Agency Resources

NCPA. Alameda does not independently own any generation assets but, in addition to power purchased from Western and others, Alameda is a participant in most NCPA projects. Alameda has purchased from NCPA a 10.00% entitlement share in the Hydroelectric Project. Alameda has purchased from NCPA a 19.00% entitlement share in the Capital Facilities Project, Unit One. Alameda has purchased from NCPA a 13.092% entitlement share in the Combustion Turbine Project Number One. Alameda has purchased from NCPA a 16.8825% entitlement share in the Geothermal Project. Alameda has purchased from NCPA a 30.36% entitlement share in the Geysers Transmission Project. For a description of such resources, see "THE HYDROELECTRIC PROJECT" and "OTHER NCPA PROJECTS" in the front part of this Official Statement. For each of these NCPA projects in which Alameda participates, Alameda is obligated to pay, on an unconditional take-or-pay basis, its entitlement share of the debt service on NCPA bonds issued for the project, as well as its share of the operation and maintenance expenses of the project. See also "Indebtedness" below.

Through NCPA, Alameda also participates in certain power purchase agreements entered into by NCPA, including a power purchase agreement with Henwood Associates, Inc. to purchase 100% of the power produced by the Graeagle Hydroelectric Project, a small 440 kW hydroelectric project (replacing a prior agreement under which Alameda received 50% of the project output). The energy source for the facility is hydroelectric and the facility meets the qualifying facilities requirements established by FERC. The facility output, which varies with hydrological conditions, has averaged about 2,000 MWh per year. Deliveries under the agreement began on February 1, 2010 and will terminate on January 31, 2030. See also "OTHER NCPA PROJECTS" in the front part of this Official Statement.

TANC California-Oregon Transmission Project. Alameda, together with thirteen other northern California cities and districts and one rural electric cooperative, is a member, or associate member, of a California joint powers agency known as the Transmission Agency of Northern California ("TANC"). TANC, together with the City of Redding, California ("Redding"), Western, two California water districts and PG&E (collectively, the "COTP Participants") own the California–Oregon Transmission Project (the "COTP"), a 339 mile long, 1,600 MW, 500 kV transmission project between southern Oregon and central California. The COTP was placed in service on March 24, 1993, at a cost of approximately $430 million. In April 2008, TANC purchased the COTP transmission assets (approximately 121 MW) of Vernon Light & Power of the City of Vernon, California ("Vernon"), one of the original owners of the COTP. Alameda did not participate as an acquiring TANC Member for an additional share of the purchased assets from Vernon.

TANC financed its interest in the COTP through the issuance of California-Oregon Transmission Project Revenue Bonds and commercial paper notes, of which approximately $396.7 million principal amount of revenue bonds was outstanding as of December 1, 2011. See “Indebtedness” below.

Pursuant to Project Agreement No. 3 for the COTP (the “TANC Agreement”), TANC has agreed to provide to Alameda and 12 other members of TANC (the “TANC Member-Participants”) a participation percentage of TANC’s entitlement of COTP transfer capability. In return, each TANC Member-Participant has severally agreed to pay TANC a corresponding percentage of TANC’s share of the COTP construction costs, including debt service on TANC’s outstanding revenue bonds and other obligations issued by TANC to finance its ownership share of the COTP. A TANC Member-Participant’s obligations to make payments to TANC are not dependent upon the operation of the COTP and are not subject to reduction. Upon an unremedied default by one TANC Member-Participant in making a payment required under the TANC Agreement, the nondefaulting TANC Member-Participants are required to increase pro-rata their participation percentage by the amount of the defaulting TANC Member-Participant’s entitlement share, provided that no such increase can result in a greater than 25% increase in the participation percentage of the nondefaulting TANC Member-Participants.

Pursuant to the TANC Agreement, Alameda is obligated to pay 1.2272% of TANC’s COTP operating and maintenance expenses and 1.33% of TANC’s COTP debt service (on bonds other that TANC’s 2009 Series A Bonds on which it is obligated for 1.4496% of debt service and TANC’s 2009 Series B Bonds on which it has no obligation for debt service) and is entitled to 1.2272% of TANC’s share of COTP transfer capability (approximately 17 MW net of third-party layoffs of TANC) on an unconditional take-or-pay basis. Alameda’s share of annual operating and maintenance expenses and debt service for the COTP is approximately $0.7 million per year.

To utilize the full transfer capability of the COTP and the Intertie (described below) on a firm basis between the Pacific Northwest and California, it is necessary to coordinate the operation of all three transmission lines. The Pacific AC Intertie (the “Intertie”) is a two line system which, like the COTP, connects California utilities with those in a Pacific Northwest. The Intertie lines are owned by certain of the California investor-owned utilities and Western and are operated by the California Independent System Operator (the “ISO”). Rate schedules are on file with FERC to accomplish this coordination. The three-line system comprised of the COTP and the Intertie is collectively referred to as the California-Oregon Intertie (“COI”).

The COTP became a part of the Sacramento Municipal Utility District Western balancing authority area effective December 1, 2005. As a result, the TANC Member-Participants are able to undertake direct scheduling of the COTP within the control area substantially free of the ISO tariff, charges, congestion and encumbrances.

The costs and operation of the COTP are impacted by various FERC proceedings. Alameda management does not believe any of these proceedings are material to its operations or its operating performance.

TANC Tesla–Midway Transmission Service. The southern physical terminus of the COTP is near PG&E’s Tesla Substation near Tracy, California. The COTP is connected to Western’s Tracy and Olinda Substations. PG&E provides TANC and its members with 300 MW of firm bi-directional transmission capacity in its transmission system between its Tesla Substation and its Midway Substation near Buttonwillow, California (the “Tesla Midway Transmission Service”) under a long-term agreement known as the South of Tesla Principles. Alameda’s share of Tesla Midway Service is 6.0 MW. Alameda may utilize its full allocation of Tesla–Midway Transmission Service for firm and non-firm power transactions when economic to do so and if available.

Energy Efficiency and Conservation; Renewable Resources

AB 1890, the electric utility deregulation law, required the establishment of public benefit programs for investor-owned and public power utilities through 2001. On September 30, 2000, the governor signed into law SB 1194 and AB 995, which extend the requirement to support public benefit electricity programs through January 1, 2012. Alameda Municipal Power funds its qualifying programs at levels significantly beyond those required by these laws.

Alameda Municipal Power has a full portfolio of public benefits programs, addressing the four areas of concentration required by State law: low income assistance programs, renewable energy production, advanced electric technology demonstration and research and development, as well as energy efficiency programs. It has continually funded new renewable resources including geothermal, wind, landfill gas, and hydroelectric generation. Currently, more than 64% of the energy for Alameda Municipal Power's retail electric sales are provided from these renewable resources.

Alameda Municipal Power has had energy efficiency programs in place since the 1990s. These energy efficiency programs focus on the unique end-uses in Alameda with its coastal climate, and the resulting lack of air conditioning load. Alameda Municipal Power offers energy efficiency programs for all of its customer classes and has established an aggressive target for reducing future consumption by nearly 8% during the next ten years.

Future Power Supply Resources

Alameda is currently investigating options to meet future resources requirements in an environmentally beneficial manner including additional renewable resources and energy efficiency savings. Alameda has joined NCPA's Market Purchase Program under which NCPA may purchase power for Alameda for up to five year terms.

Interconnections, Transmission and Distribution Facilities

Alameda's electric system is interconnected with the system of PG&E at two PG&E substations. Alameda owns facilities for the distribution of electric power within the city limits of Alameda, which includes approximately 8.70 miles of 115 kV power lines, approximately 257.5 miles of 12 kV distribution lines (approximately 66% of which are underground) and fourteen substations. Alameda's electric system experienced approximately 32.3 minutes of outage time per customer in fiscal year 2010-11.

Forecast of Capital Expenditures

Alameda's current five-year capital plan for electric facilities contemplates capital expenditures in the following years and amounts:

CITY OF ALAMEDA
ALAMEDA MUNICIPAL POWER
ESTIMATED CAPITAL EXPENDITURES

Fiscal Year Ended June 30,				
2012	2013	2014	2015	2016
$4,604,000	$3,332,200	$5,509,500	$4,507,200	$5,727,200

Source: Alameda Municipal Power.

The capital expenditures are for distribution system improvements and extensions, the underground conversion program, additions for new loads, replacements and maintenance, computer equipment and software and vehicles. Alameda anticipates funding the majority of such costs from current year revenues.

Insurance

As a member of the California Joint Powers Risk Management Authority ("CJPRMA") and the Local Agency Workers' Compensation Excess Joint Powers Authority ("LAWCX"), Alameda carries both liability and property coverage in excess of self-insurance at varying levels. Through CJPRMA, Alameda carries $40 million in general liability coverage subject to a $500,000 self-insured retention. As a member of CJPRMA, Alameda is a participant in both the vehicle physical damage and property programs. Alameda carries physical damage coverage for vehicles worth $25,000 or more, subject to a $10,000 deductible. In the property program, Alameda carries "all risk" (excluding flood and earthquake) replacement cost property coverage for both real and personal property, subject to a $25,000 deductible. Associated with that coverage, AMP carries $10 million in boiler and machinery coverage. Finally, Alameda carries workers' compensation coverage with statutory limits, in excess of a $350,000 self-insured retention through LAWCX.

Employees

As of December 1, 2011, approximately 91 City of Alameda employees were assigned specifically to the Alameda electric utility. Management personnel are represented by the Management and Confidential Employees Association ("MCEA"). Non-management personnel are represented either by the International Brotherhood of Electrical Workers ("IBEW") or the Alameda City Employees Association ("ACEA"). The current Memoranda of Understanding with each of MCEA, ACEA and IBEW expired in December 2011. Negotiations are ongoing for successor agreements. There have been no strikes or other work stoppages at the City of Alameda, including Alameda Municipal Power, since the early 1970s.

Retirement benefits to City of Alameda employees, including those assigned to Alameda Municipal Power, are provided through the City of Alameda's participation in the California Public Employees Retirement System ("CalPERS"), an agent multiple employer defined benefit pension plan which acts as a common investment and administrative agent for its participating plan members. CalPERS determines contribution requirements using a modification of the Entry Age Normal Method. Under this method, the City of Alameda's total normal benefit cost for each employee from date of hire to date of retirement is expressed as a level percentage of the relatelated total payroll cost. Normal benefit cost under this method is the level amount the employer must pay annually to fund an employee's projected retirement benefit. This level percentage of payroll method is used to amortize any unfunded actuarial liabilities. The actuarial assumptions used to compute the contribution requirements are also used to compute the actuarial accrued liability. CalPERS uses the market related value method of valuing the plan's assets. An investment rate of return of 7.75% is assumed, including inflation at 3.00%. Annual salary increases are assumed to vary by duration of service. Changes in liability due to plan amendments, changes in actuarial assumptions, or changes in actuarial methods are amortized as a level percentage of payroll on a closed basis within twenty years. Investment gains and losses are accumulated as realized, 10% of the net balance is amortized annually. CalPERS issues a separate comprehensive annual financial report. Copies of the CalPERS annual financial report may be obtained from the CalPERS Executive Office, 400 Q Street, Sacramento, California 95814.

The City of Alameda's actuarially required contributions for fiscal year 2010-11, fiscal year 2009-10 and fiscal year 2008-09 were $12,082,061 (of which $850,135 was contributed by the electric utility), $10,368,070 (of which $877,049 was contributed by the electric utility) and $11,094,649 (of which $1,012,276 was contributed by the electric utility), respectively. The City of Alameda made these contributions as required, together with certain additional immaterial amounts required as a result of the payment of employee compensations. As of June 30, 2010 (the most recent actuarial data available), the entry age accrued liability for the Miscellaneous Plan (in which City of Alameda employees assigned to Alameda Municipal Power participate) was $210,927,819, the actuarial value of assets was $187,904,871, resulting in an unfunded liability of $23,022,948, with a funded ratio of 98.17%. The portion of the plan allocable to Alameda Municipal Power employees, which is part of the City of Alameda's liability pool, is not separately calculated.

In addition, the City of Alameda provides certain post-employment benefits other than pensions (OPEB) to City employees, including those assigned to the Alameda Municipal Power, who retire from the City and receive a CalPERS pension through its participation in the CalPERS medical and dental benefits program. Contribution requirements of the postemployment benefit are based on pay-as-you-go financing. The City's annual required contribution of the employer ("ARC") was determined as part of a January 1, 2011 actuarial valuation using the entry age normal actuarial cost method. This is a projected benefit cost method which takes into account those benefits that are expected to be earned in the future as well as those already accrued. The actuarial assumptions include (a) a 4.5% investment rate of return; (b) a 3.25% projected salary increase; (c) 3% general inflation increase; and (d) a healthcare trend of declining annual increases ranging from 9% in 2013 to 5% for years starting 2021. The actuarial methods and assumptions use techniques that "smooth" the effects of short-term volatility in actuarial accrued liabilities and the actuarial vale of assets. The City's OPEB unfunded actuarial accrued liability as of June 30, 2009 is being amortized using a 30-year closed amortization period. Assumption changes, plan changes and gains or losses are being amortized using a 15-year closed period. For the fiscal years 2010-11, 2009-10 and 2008-09, the City of Alameda contributed 36%, 34% and 33%, respectively, of the annual OPEB cost of $6,193,000, $5,793,820 and $5,938,466, respectively. Amounts contributed for fiscal years 2010-11, 2009-10 and 2008-09 were

$2,255,039 (of which $46,862 was contributed by the electric utility), $1,995,112 (of which $44,206 was contributed by the electric utility) and $1,954,602 (of which $44,206 was contributed by the electric utility), respectively. As of January 1, 2011, the entry age actuarial accrued liability for the health care benefits plan was $86,416,000, the actuarial value of assets was $0, resulting in an unfunded liability of $86,416,000.

Additional information regarding the City of Alameda 's retirement plans and other post-employment benefits can be found in the City's comprehensive annual financial reports, which may be obtained at http://www.cityofalamedaca.gov.

Service Area

The largest employers in Alameda as of June 30, 2011 are as follows:

CITY OF ALAMEDA
2010-11 LARGEST EMPLOYERS

Employer	Business	Number of Employees
UT Starcom Inc	Internet Protocol Television Products	2,400
US Coast Guard	Military	2,200
Telecare Corp	Mental Health Provider	2,100
Wind River Systems Inc	Computer Software Development	1,673
Alameda Unified School District	Education	1,068
City of Alameda	Local Government	562
Celera Corp	Surgical and Medical Instrument Mfg	551
Alameda Hospital	Hospital	492
Bay Ship & Yacht Company	Construction and Repair	250
Bay View Nursing & Rehab Center	Managed Care Facility	180

(1) Wind River Systems Inc. was purchased by Intel in June 2009.
Source: City of Alameda Finance Department.

The following table reflects the five-year history of building permit valuation for the City:

CITY OF ALAMEDA
BUILDING PERMITS AND VALUATIONS
Calendar Years 2007 through 2011
(dollars in thousands)

	2007	2008	2009	2010	2011
Permit Valuation					
New Single-family	$39,598	$ 408	$ 879	$ 5,985	$ 8,199
New Multi-family	380	0	0	0	0
Res. Alterations/Additions	24,314	14,510	10,553	11,466	18,478
Total Residential	$64,297	$14,918	$11,432	$17,451	$26,677
New Commercial	$14,517	$ 0	$ 0	$ 0	$15,967
New Industrial	3,342	0	0	0	0
New Other	6,774	969	727	528	1,328
Comm. Alterations/Additions	22,469	6,928	1,417	1,266	19,879
Total Nonresidential	$47,102	$7,897	$2,144	$1,794	$37,174
New Dwelling Units					
Single Family	110	2	3	16	24
Multiple Family	2	0	0	0	0
Total	112	2	3	16	24

Source: Construction Industry Research Board.

The five-year history of assessed valuations in Alameda is as follows:

CITY OF ALAMEDA
TOTAL ASSESSED VALUATIONS
(Fiscal Years 2007-08 through 2011-12)

2007-08	2008-09	2009-10	2010-11	2011-12
$8,776,677,592	$9,226,664,742	$9,436,632,497	$9,356,898,048	$9,387,095,373

Source: City of Alameda Finance Department.

Shown below is certain population data for the City of Alameda, the County of Alameda and the State of California:

CITY OF ALAMEDA, COUNTY OF ALAMEDA,
STATE OF CALIFORNIA POPULATION
(1970-2000 as of April 1; 2007-2011 as of January 1)

	City of Alameda	County of Alameda	State of California
1970	70,968	1,071,446	19,971,069
1980	63,852	1,105,379	23,668,562
1990	73,979	1,276,702	29,760,021
2000	73,713	1,453,053	34,095,209
2007	75,077	1,527,163	37,655,193
2008	75,823	1,551,713	38,155,534
2009	74,736	1,568,817	38,476,724
2010	73,835	1,509,240	37,223,900
2011	74,081	1,521,157	37,510,766

Sources: U.S. Bureau of Census and California State Department of Finance.

Litigation

There is no action, suit or proceeding known to be pending or threatened, restraining or enjoining Alameda in the execution or delivery of, or in any way contesting or affecting the validity of any proceedings of Alameda taken with respect to the Third Phase Agreement.

On November 18, 2008, the City Council of the City unanimously authorized the sale of Alameda's telecommunications business line effective as of November 21, 2008. The sale price of the telecommunications business line was significantly less than the aggregate carrying values of the telecommunications division's assets. The telecommunications division capital assets and operations were financed in part from proceeds of the utility's Telecom System Revenue Taxable Certificates of Participation, Series 2002A (the "2002 Telecom COPs") and Telecom System Revenue Bonds Anticipation Notes, Series 2004 (the "2004 Telecom Notes").

Vectren Communications Services, Inc. ("VCS"), holder of the 2002 Telecom COPs in the amount of $6.3 million, sued Alameda in 2008 in the United States District Court in San Francisco, for breach of contract, alleging that Alameda had not complied with its obligations under the installment sale agreement entered into in 2002, and amended and restated in 2004, to properly manage the telecommunications system and to charge appropriate rates, resulting in the non-payment of installments from net telecom revenues to sufficiently fund payment of the 2002 Telecom COPs. During discovery, VCS expanded its claims to include various alleged deficiencies in how Alameda accounted for its net telecom revenues. Including prejudgment interest, VCS claimed damages against Alameda of approximately $10.3 million. The case proceeded to a jury trial in February and March 2010, following which the Court entered judgment in VCS's favor for $1.9 million. In addition to the award, Vectren claimed costs of suit against Alameda totaling approximately $115,000, which was subsequently reduced by the Court Clerk to $79,688. Both sides appealed the jury verdict and the denial of certain post-trial motions with the Ninth Circuit Court of Appeals. Briefing commenced in August 2011 and is expected to be completed no later than February 2012.

Nuveen Municipal High Income Opportunity Fund, the Nuveen High Yield Municipal Bond Fund, Pacific Specialty Insurance Company (collectively, "Nuveen"), and the Bernard Osher Trust ("Osher") filed separate litigation against Alameda Municipal Power based on their purchases of the 2004 Telecom Notes. Nuveen and Osher asserted state and federal law securities fraud claims alleging that Alameda failed to fully disclose material facts relating to issuance of the 2004 Telecom Notes in 2004. Nuveen and Osher claimed combined damages in excess of $15 million, in addition to prejudgment interest and other items that, if allowed, could have exceeded $4 million. Alameda disputed Nuveen's and Osher's entitlement to any such amounts. In September 2010 and January 2011, Alameda filed motions for summary judgment against all of Nuveen's and Osher's claims. On May 16, 2011, the Court granted Alameda's motions as to all of Nuveen and Osher's claims. Following summary judgment, Alameda sought recovery of legal fees against Nuveen and Osher. The district court denied both of Alameda's motions. Nuveen has appealed the district court's summary judgment ruling to the Ninth Circuit Court of Appeals. Alameda has cross-appealed the district court's denial of Alameda's motion for attorneys' fees against Nuveen. Nuveen's opening brief is due in late January 2012. Neither side has appealed the Osher judgment.

Although no assurances can be given and no determination can be made at this time as to the ultimate outcome of the above-described litigation, Alameda believes that there are meritorious defenses to all of the claims and that any liability which may finally be determined should not have a material adverse effect on Alameda Municipal Power's financial position, results of operations or cash flows.

Other present lawsuits and other claims concerning Alameda's electric system are incidental to the ordinary course of operations of the electric system and are largely covered by Alameda's self-insurance program. In the opinion of Alameda Municipal Power's management and, with respect to such litigation, the Alameda City Attorney, such claims and litigation will not have a materially adverse effect upon the financial position of Alameda Municipal Power.

Rates and Charges

Alameda Municipal Power has the exclusive jurisdiction to set electric rates within its service area by action of the Alameda Public Utilities Board. These rates are not subject to review by any state or federal agency.

Alameda's fiscal year 2010-11 average rate per kWh sold for residential service was 13.0 cents. Alameda's average rate for commercial and industrial service sold was 13.6 and 12.2 cents per kWh, respectively. Alameda's average rate for municipal and public authority service sold was 13.7 cents. On April 18, 2011, the Alameda Public Utilities Board approved a 3.85% average rate increase for fiscal year 2011-12 that took effect on July 1, 2011. For fiscal year 2011-12, the average rate for all electric service is projected to be 13.5 cents per kWh. The average rate per kWh sold for residential service in fiscal year 2011-12 is projected to be 13.5 cents. The average rates for commercial and industrial service are projected to be 13.7 and 12.9 cents per kWh, respectively. Alameda's average rate for municipal and public authority service for fiscal year 2011-12 is projected at 14.0 cents per kWh. In general, the rate adjustment for fiscal year 2011-12 is designed to increase revenue in each service category by 0.5 cents per kWh. Currently, Alameda management estimates that Alameda's electric rates are approximately 17% below those in the surrounding area on average.

The following table presents a recent history of Alameda's rate changes. Alameda also imposes a solar surcharge in conjunction with its electric rates which is applied to fund its photovoltaic incentive programs as required by Senate Bill 1 (the California Solar Initiative).

CITY OF ALAMEDA
ALAMEDA MUNICIPAL POWER
ELECTRIC RATE CHANGES

Date	Percent Change
July 1, 2011	3.85%
July 1, 2010	3.70
July 1, 2009	2.50 (MU-1 rate only)
July 1, 2006	0.60
July 1, 2005	0.90

Source: Alameda Municipal Power.

Largest Customers

Alameda's ten largest electric customers in terms of kWh sales for the fiscal year ended June 30, 2011 accounted for 20.2% of total kWh sales and 19.8% of total revenues. The largest customer accounted for 4.7% of total kWh sales and 4.4% of total revenues. The smallest of the ten largest customers accounted for 0.7% of total kWh sales and 0.7% of revenues.

Customers, Sales, Revenues and Demand

The average number of customers, kWh sales, revenues derived from sales by classification of service and peak demand during the past five fiscal years, are listed below.

CITY OF ALAMEDA
ALAMEDA MUNICIPAL POWER
ELECTRIC CUSTOMERS, SALES, REVENUES AND DEMAND

	Fiscal Years Ended June 30,				
	2007	2008	2009	2010	2011
Number of Customers:					
Residential	29,997	30,084	30,119	30,191	30,171
Commercial	3,634	3,750	3,782	3,818	3,744
Industrial	9	12	11	18	13
Public Authority	330	333	333	342	330
Other	19	38	27	30	23
Total Customers	33,989	34,217	34,272	34,399	34,281
Kilowatt-Hour Sales:					
Residential	142,352,676	142,718,493	140,048,081	142,109,998	142,305,884
Commercial	187,611,044	187,720,577	184,300,489	179,960,145	174,717,111
Industrial	41,255,006	43,966,176	45,611,047	44,243,371	49,235,786
Public Authority	14,916,186	15,202,494	14,675,829	13,598,342	13,138,014
Other	3,151,663	3,212,483	3,041,330	3,207,924	3,240,179
Total kWh sales	389,286,575	392,820,223	387,676,776	383,119,780	382,636,974
Revenues from Sale of Energy:					
Residential	$17,786,579	$17,783,232	$17,365,563	$17,647,604	$18,257,650
Commercial	24,129,480	24,021,704	23,644,464	23,090,891	23,352,114
Industrial	4,720,055	4,982,103	5,175,117	5,026,286	5,861,554
Public Authority	1,847,716	1,897,547	1,820,996	1,749,835	1,753,399
Other	585,516	625,081	1,039,061	449,194	641,967
Total Revenues from Sale of Energy	$49,069,346	$49,309,667	$49,045,201	$47,963,811	$49,866,684
Peak Demand (kW)	70,891	71,937	76,250	73,712	70,800

Source: Alameda Municipal Power.

Indebtedness

As of December 1, 2011, Alameda had outstanding obligations under an Installment Sale Agreement, dated as of August 1, 2010 (the "Electric System Installment Sale Agreement"), by and between the Alameda Public Financing Authority and Alameda Municipal Power, in the aggregate principal amount of $30,790,000, the installment payments payable by Alameda under which are payable from and secured solely by a pledge of and lien on net revenues of the electric system of Alameda Municipal Power. These obligations are subordinate to the payments required to be made with respect to Alameda's obligations to NCPA and TANC as described below. Obligations relating to Alameda's telecommunications enterprise are payable solely from revenues of the telecommunication enterprise and therefore are not included in this total.

As previously discussed, Alameda participates in certain joint powers agencies, including NCPA and TANC. Obligations of Alameda with respect to TANC and NCPA constitute operating expenses of Alameda payable prior to any of the payments required to be made by Alameda's under the Electric System Installment Sale Agreement described above. The agreements with NCPA and TANC are on a "take-or-pay" basis, which requires payments to be made whether or not projects are completed or operable, or whether output from such projects is suspended, interrupted or terminated. Certain of these agreements contain "step up" provisions obligating Alameda to pay a share of the obligations of a defaulting participant. Alameda's participation and share of debt service obligation (without giving effect to any "step up" provisions) for each of the joint powers agency projects in which it participates are shown in the following table.

CITY OF ALAMEDA
ALAMEDA MUNICIPAL POWER
OUTSTANDING DEBT OF JOINT POWERS AGENCIES
(Dollar Amounts in Millions)
(As of December 1, 2011)

	Outstanding Debt(1)	Alameda's Participation(2)	Alameda's Share of Outstanding Debt(1)
NCPA			
Geothermal Project	$ 33.8	16.88%	$ 5.7
Hydroelectric Project	440.8	10.00	44.1
Capital Facilities Project Unit One	55.1	19.00	10.5
TANC			
Bonds	396.7	1.33(3)	4.7
TOTAL*	$926.4		$65.0

* Columns may not add to totals due to independent rounding.
(1) Principal only. Does not include obligation for payment of interest on such debt.
(2) Participation obligation is subject to increase upon default of another project participant. Such increase shall not exceed, without written consent of a non-defaulting participant, an accumulated maximum of 25% of such non-defaulting participant's original participation.
(3) As described herein, Alameda's actual obligation differs slightly from this percentage due to varying shares of certain series of TANC bonds relating to each TANC Member-Participant's taxable portion and each TANC Member-Participant's participation or non-participation in acquisition of assets from Vernon.

Source: Alameda Municipal Power.

For the fiscal year ending June 30, 2011, Alameda estimates its obligations for debt service on its joint powers agency debt obligations aggregated approximately $4.5 million. A portion of the joint powers agency debt obligations are variable rate debt, liquidity support for which is provided through liquidity arrangements with banks. Unreimbursed draws under liquidity arrangements supporting joint powers agency variable rate debt obligations bear interest at a maximum rate substantially in excess of the current interest rates on such obligations. Moreover, in certain circumstances, the failure to reimburse draws on the liquidity agreements may result in the acceleration of scheduled payment of the principal of such variable rate joint powers agency obligations. In connection with certain of such joint power agency obligations, the respective joint powers agency has entered into interest rate swap agreements relating thereto for the purposes of substantially fixing the interest cost with respect thereto. There is no guarantee that the floating rate payable to the respective joint powers agency pursuant to each of the interest rate swap agreements relating thereto will match the variable interest rate on the associated variable rate joint powers agency debt obligations to which the respective interest rate swap agreement relates at all times or at any time. Under certain circumstances, the swap providers may be obligated to make payments to the applicable joint powers agency under their respective interest rate swap agreement that is less than the interest due on the associated variable rate joint powers agency debt obligations to which such interest rate swap agreement relates. In such event, such insufficiency will be payable as a debt service obligation from the obligated joint powers agency members (a corresponding amount of which proportionate to its debt service obligations to such joint powers agency could be due from Alameda). In addition, under certain circumstances, each of the swap agreements is subject to early termination, in which event the joint powers agency could be obligated to make a substantial payment to the applicable swap provider (a corresponding amount of which proportionate to its debt service obligations to such joint powers agency could be due from Alameda).

Transfers to the General Fund

The Alameda City Charter provides that Alameda Municipal Power transfer to the City General Fund certain excess earnings of the Electric System after payment of bond interest and sinking fund requirements and operating expenses (exclusive of depreciation) and certain amounts authorized to be retained by the Alameda Municipal Power from earnings of the Electric System, all as defined in and provided pursuant to the terms of the City Charter. In the absence of such transfer of excess earnings as determined under the City Charter, the Public Utilities Board has authorized by resolution certain contributions from the Electric System to the City General Fund in accordance with the provisions of the City Charter.

The following table sets out the transfers from the Electric System Alameda Municipal Power's General Fund for the last five fiscal years.

CITY OF ALAMEDA
ALAMEDA MUNICIPAL POWER
TRANSFERS TO THE GENERAL FUND
(Dollar Amounts in Thousands)

Fiscal Year	Transfer Amount
2006-07	$2,500,000
2007-08	2,500,000
2008-09	2,800,000
2009-10	2,800,000
2010-11	2,800,000

Source: Alameda Municipal Power.

Significant Accounting Policies

Alameda's most recent Component Unit Financial Statements for the fiscal years ended June 30, 2011 and 2010 were audited by Vavrinek, Trine, Day & Company, LLP, Pleasanton, California, in accordance with generally accepted auditing standards. The audited financial statements contain opinions that the financial statements present fairly the financial position of Alameda Municipal Power. The reports include certain notes to the financial statements which are not described herein. Such notes constitute an integral part of the audited financial statements. Copies of these reports are available upon request from the City of Alameda, Alameda Municipal Power, 2000 Grand Street, Alameda, California 94501 and from their website at www.AlamedaMP.com. It is the policy of Alameda Municipal Power to periodically bid, select and retain independent auditors.

Governmental accounting systems are organized and operated on a fund basis. A fund is defined as an independent fiscal and accounting entity with a self-balancing set of accounts recording cash and other financial resources, together with all related liabilities and residual equities or balances, and changes therein. Funds are segregated for the purpose of carrying on specific activities or attaining certain objectives in accordance with special regulations, restrictions or limitations.

Alameda Municipal Power's operations are accounted for as an Enterprise Fund. Enterprise funds are used by municipalities to account for operations which are financed and operated similar to private business enterprises, where the intent of the governing body is that the costs and expenses, including depreciation, of providing goods and services to the public on a continuing basis be recovered primarily through user charges.

Alameda Municipal Power's accounting records and financial statements are on the accrual basis and are substantially in accordance with the Uniform System of Accounts for Class A and B Electric Utilities prescribed by the FERC, as required by the Alameda City Charter.

Condensed Operating Results and Selected Balance Sheet Information

The following table sets forth summaries of operating results and selected balance sheet information of Alameda's electric utility for the five fiscal years ended June 30, 2011. The information for the fiscal years ended June 30, 2007 through June 30, 2011 was prepared by Alameda on the basis of its audited financial statements for such years. The historical debt service coverage ratios have been calculated in accordance with Alameda's Electric System Installment Sale Agreement.

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK.]

CITY OF ALAMEDA
ALAMEDA MUNICIPAL POWER
CONDENSED OPERATING RESULTS AND SELECTED BALANCE SHEET INFORMATION

	Fiscal Years Ended June 30				
	2007	2008	2009	2010	2011
Electric System Revenues					
Sales of Electricity	$48,928,815	$49,140,906	$48,457,664	$47,976,563	$49,866,684
Other Revenues [(1)]	1,316,203	2,068,300	1,512,819	1,563,939	616,190
Total Electric System Revenues	$50,245,018	$51,209,206	$49,970,483	$49,540,502	$50,482,874
Operation and Maintenance Costs					
Purchased Power [(2)(3)]	$27,729,141	$27,316,014	$30,700,344	$29,147,084	$25,159,235
Transmission & Jobbing Expense	21,400	27,189	991,287	289,607	184,245
Distribution- Operations	2,484,258	2,998,729	3,705,148	3,005,612	3,219,257
Customer Accounts & Sales Expense	1,996,986	2,010,916	2,659,956	3,359,085	3,167,469
Administrative & General	6,735,174	7,205,310	6,917,547	6,160,199	6,164,149
Balancing Account	1,969,418	--	(434,508)	(2,211,428)	(303,406)
Total Operation and Maintenance Costs	$40,936,377	$39,558,158	$44,539,774	$39,750,159	$37,590,949
Net Revenues[(4)]	$ 9,308,641	$11,651,048	$ 5,430,709	$ 9,790,343	$12,891,925
Rate Stabilization Fund Transfers	--	--	--	--	--
Use of Reserves	--	--	--	--	--
Adjusted Annual Net Revenues	$ 9,308,641	$11,651,048	$ 5,430,709	$ 9,790,343	$12,891,949
Debt Service	$ 2,401,292	$ 2,476,808	$ 2,925,766	$ 2,996,590	$ 8,997,194[(8)]
Debt Service Coverage [(5)]	3.88	4.70	1.86	3.27	1.43[(8)]
Amount Available After Debt Service	$ 6,951,881	$ 9,218,772	$ 3,553,499	$ 6,785,001	$6,785,001
Selected Balance Sheet Information:			**($ in thousands)**		
Unrestricted Cash & Investments[(6)]	$ 39,711	$ 46,443	$ 43,809	$ 47,603[(9)]	$ 42,101[(9)]
Rate Stabilization Fund Balance	--	--	--	--	--
Net Plant in Service	39,496	41,247	39,275	39,058	37,267
Construction Work in Progress	3,799	1,381	3,208	2,262	1,719
Electric Utility Plant-Net	43,295	42,628	42,483	41,320	38,987
Outstanding Electric System Debt[(7)]	39,045	39,045	39,045	39,045[(8)]	31,685[(8)]

(1) Other Revenues includes miscellaneous services, plant leased to others, interest income, Alameda Point services-net, jobbing sales and miscellaneous non-operating revenue.
(2) Includes purchased power costs and payments to NCPA and TANC.
(3) Purchased Power for the period July 2009 to April 2010 reflects inclusion of a refund of $1,109,717 from NCPA for fiscal year 2008-09 budget settlement. Excluding the refund, Purchased Power costs would have been $25,113,017. Increase in Purchase Power costs in fiscal year 2008-09 primarily reflects increased amortization of NCPA geothermal project bonds for such fiscal year. Purchased Power for Fiscal Year 2011 reflects inclusion of a refund of $1,289,824 from NCPA for fiscal year 2009-10 budget settlement. Excluding the refund, Purchased Power costs for fiscal Year 2010-11 would have been $26,449,059 and Purchased Power costs for fiscal year 2009-10 would have been $27,857,260.
(4) Excluding Payments in lieu of taxes and depreciation.
(5) Adjusted Annual Net Revenues divided by debt service.
(6) Includes General Reserve balance held at NCPA. See also "Available Reserves" below.
(7) Represents outstanding par amount of electric system certificates of participation.
(8) Includes debt service related to electric system certificates of participation retired from reserves as described in footnote (9) below.
(9) Alameda Municipal Power used approximately $8.8 million of the cash and equivalents held for Alameda Municipal Power in its NCPA General Reserve in August 2010 in connection with the refunding of its then outstanding $39.0 million electric system certificates of participation. In August 2010, Alameda Municipal Power refunded its then outstanding electric system revenue certificates of participation through the issuance of $31.7 million aggregate principal amount of Alameda Public Financing Authority Revenue Bonds, 2010 Series A (Alameda Municipal Power Refinancing) and Taxable Revenue Bonds, 2010 Series B (Alameda Municipal Power Refinancing). See "Indebtedness" above.

Source: Alameda Municipal Power.

Interfund Transfers. During the fiscal year 2008-09, $1,095,614 in interfund transfers (*i.e,*. no repayment expected) from the Electric System enterprise fund to the telecommunications system enterprise fund were recorded for expenses due to the sale of the Alameda's telecommunications system on November 21, 2008. During the fiscal year 2009-10, additional interfund transfers from the Electric System enterprise fund to the telecommunications system enterprise fund amounted to $2,734,279 for expenses. During the fiscal year 2010-11, additional interfund transfers from the Electric System enterprise fund to the telecommunications system enterprise fund amounted to approximately $3,000,000 for expenses. Alameda Municipal Power has indicated that additional amounts will be paid by the Electric System enterprise fund for telecommunications system enterprise fund litigation expenses during fiscal year 2011-12. See "Litigation" above.

Available Reserves. As of June 30, 2011, the balance in cash and equivalents available at Alameda Municipal Power was $29,829,172. In addition, Alameda had available in reserve accounts held by NCPA an additional $12,271,583 as of such date.

CITY OF LODI

Introduction

The City of Lodi ("Lodi") is a general law city in the State of California incorporated in 1906. Lodi is located in the San Joaquin Valley of California, 35 miles south of the State capital of Sacramento, and 90 miles east of San Francisco. Lodi's boundaries encompass approximately 13.92 square miles.

Lodi provides electric utility service through an electric utility department. The legal responsibilities and powers of the electric utility department, including the establishment of rates and charges, are exercised through the five-member Lodi City Council. The members of the City Council are elected City-wide for staggered four year terms. The Lodi electric utility department is under the direction of the Electric Utility Director who is appointed by the City Manager.

Lodi joined NCPA at its founding in 1968. Lodi participates in several NCPA generation projects and member service programs. In addition, NCPA's operations center in Roseville provides real-time dispatching and scheduling of all available resources to serve Lodi's electric load.

The electric system serves the entire area of the City of Lodi (approximately 13.92 square miles) and has over 146 miles of overhead lines and over 157 miles of underground lines. During the fiscal year ended June 30, 2011, the Lodi electric system served 26,360 customers, comprised of 22,870 residential customers, 3,234 commercial/industrial customers and 256 other customers. On July 24, 2006, an all-time, historical high peak demand of 140.4 MW was reached.

Only the revenues of the Lodi electric system will be available to pay amounts owed by Lodi under the Third Phase Agreement.

The Lodi electric department's main office is located at 1331 South Ham Lane, Lodi, California 95242, (209) 333-6762. For more information about Lodi and its electric system, contact Liz Kirkley, Electric Utility Director, at the above address and telephone number. A copy of the most recent comprehensive annual financial report of the City of Lodi (the "Annual Report") is available on Lodi's website at http://www.lodi.gov. The Annual Report is incorporated herein by this reference. However, the information presented on such website or referenced therein other than the Annual Report is not part of this Official Statement and is not incorporated by reference herein.

Power Supply Resources

The following table sets forth information concerning Lodi's power supply resources and the energy supplied by each during the fiscal year ended June 30, 2011.

CITY OF LODI
ELECTRIC UTILITY DEPARTMENT
POWER SUPPLY RESOURCES[1]
For the Fiscal Year Ended June 30, 2011

Source	Capacity Available (MW)[2][5]	Actual Energy (MWh)	% of Total Energy
Purchased Power[3]:			
Western	4.7	16,270	3.04%
NCPA			
Geothermal Project	13.3	89,025	16.63
Hydroelectric Project	26.2	88,361	16.51
Combustion Turbine Project No. 1	9.4	85	0.02
Capital Facilities, Unit One	19.6	4,974	0.93
Contracts, Exchanges and Bilaterals[4]	70.0	336,558	62.87
Total	143.2	535,273[5][6]	100.00%
Total Capacity and Energy Sold at Wholesale	N/A	91,794	
Lodi System Requirement for Retail	143.2	443,479	

(1) Columns may not add to totals due to rounding.
(2) Non-coincident capacity available.
(3) Entitlements, firm allocations and contract amounts.
(4) Includes participation in NCPA/Seattle City Light exchange. See "OTHER NCPA PROJECTS—Power Purchase Contracts" in the front part of this Official Statement.
(5) Units at Backbone Output.
(6) Includes supply from exchanges.
Source: City of Lodi.

In the fiscal year ended June 30, 2011, Lodi's average cost of power delivered to the Lodi electric system was 8.3 cents per kWh.

Purchased Power

Western. Lodi has an agreement with Western, which expires December 31, 2024, to purchase a base resource of 0.49049% of the Central Valley Project output. On January 1, 2015, Lodi's allocation will increase to 0.55189%. Energy provided to Lodi under the Western contract is on a take-or-pay basis; Lodi is obligated to pay its share of Western costs whether or not it receives any power. Energy associated with the base resource from Western is scheduled by NCPA for Lodi's benefit. For the fiscal year ended June 30, 2011, the average melded cost of delivered power under contracts with Western was approximately $52 per MWh.

Other Purchases. Lodi has a 25 MW share of the NCPA Seattle City Light exchange arrangement which is included under Contracts, Exchanges and Bilaterals in the table above, which is transmitted to Lodi via its COTP scheduling entitlement (described below). NCPA has provided noticed to Seattle City Light of the termination of this arrangement effective in 2018. Other power purchases for fiscal year 2010-11 were short-term. NCPA schedules daily and hourly (spot) power purchases and sales to balance Lodi's resources with its native load requirements.

Lodi has entered into forward power purchase transactions with four different wholesale electric suppliers (Constellation, Powerex, Sempra, and Shell) that together provide a 25 MW baseload power supply. These power purchase transactions began on July 1, 2010 and extend to March 31, 2012 and are expected to be replaced by Lodi's 9.5% entitlement share in the NCPA Lodi Energy Center. See "Future Power Supply Resources" below.

Joint Powers Agency Resources

NCPA. Lodi does not independently own any generation assets but, in addition to power purchased from Western and others, Lodi is a participant in most NCPA projects. Lodi has purchased from NCPA a 10.37% entitlement share in the Hydroelectric Project. Lodi has purchased from NCPA a 39.50% entitlement share in the Capital Facilities Project, Unit One. Lodi has purchased from NCPA a 10.28% entitlement share in the Geothermal Project. Lodi has purchased from NCPA an 18.48% entitlement share in the Geysers Transmission Project. Lodi has purchased from NCPA a 13.39% entitlement share in the Combustion Turbine Project Number One (exclusive of the portion acquired by the City of Roseville). For a description of such resources, see "THE PROJECT" and "OTHER NCPA PROJECTS" in the front part of this Official Statement. For each of these NCPA projects in which Lodi participates, Lodi is obligated to pay, on an unconditional take-or-pay basis, its entitlement share of the debt service on NCPA bonds issued for the project as well as its share of the operation and maintenance expenses of the project. See also "Indebtedness" below.

In addition, through NCPA Lodi has a 25 MW participation in the NCPA Seattle City Light exchange contract as noted above. See also "OTHER NCPA PROJECTS" in the front part of this Official Statement.

TANC California – Oregon Transmission Project. Lodi is a member of the Transmission Agency of Northern California ("TANC") and has executed the TANC Agreement for a participation percentage of TANC's entitlement of the California-Oregon Transmission Project ("COTP") transfer capability. Lodi participated in the acquisition of an increased share of transfer capability of the COTP in connection with the acquisition by TANC in April 2008 of the COTP transmission assets (approximately 121 MW) of the City of Vernon, California ("Vernon"), one of the original owners of the COTP. TANC utilized a combination of cash and the issuance of commercial paper (which was subsequently refunded with bonds) to fund the acquisition of Vernon's COTP transmission assets (the "Vernon acquisition debt"). Lodi, as well as the other acquiring TANC Members, began scheduling the acquired COTP transmission transfer capability on April 8, 2008. Lodi has a participation share of 26.7 MW of TANC's entitlement to transfer capability of the COTP and is responsible for 1.92% of TANC's COTP operating and maintenance expenses and 1.89% of TANC's COTP debt service (non-Vernon) and 2.62% of the Vernon acquisition debt. See "CITY OF ALAMEDA—Joint Powers Agency Resources—*TANC California-Oregon Transmission Project*" for a further description of the COTP and the TANC Agreement.

TANC Tesla–Midway Transmission Service. TANC and certain TANC Members have arranged for PG&E to provide TANC and its members with 300 MW of firm bi-directional transmission capacity on its transmission system between its Midway Substation near Buttonwillow, California, and its Tesla Substation near Tracy, California, near the southern physical terminus of the COTP (the "Tesla–Midway Transmission Service") under an agreement known as the South of Tesla Principles. Lodi's share of this Tesla–Midway Transmission Service is 6.21 MW. Lodi has utilized its full allocation of Tesla–Midway Transmission Service for firm and non-firm power transactions. See "CITY OF ALAMEDA—Joint Powers Agency Resources—*TANC Tesla-Midway Transmission Service*" for a further description of the Tesla-Midway Transmission Service.

Future Power Supply Resources

Based upon its current forecasted sales growth, resource mix and market prices, Lodi believes its annual balance-of-month, day-ahead, and hour-ahead purchases will be less than 25% of total energy requirements for the next two years. Lodi's interest in NCPA's Multiple Capital Facilities Project Unit One and NCPA's Combustion Turbine Project Number One provide substantial capacity toward covering Lodi's net short position in the event that market prices rise above the respective unit's cost of production. Lodi has developed medium-term hedging strategies to reduce volatility associated with market purchases and the seasonal nature of its loads and resources. Lodi has committed to a 9.5% generation entitlement share in NCPA's Lodi Energy Center, a 280 MW combined-cycle plant currently being constructed and which is expected to reach commercial operation in the summer of 2012. See "OTHER NCPA PROJECTS—Lodi Energy Center" in the front part of this Official Statement. As discussed above in "Purchased Power," the Lodi Energy Center will replace the series of 25 MW contracts that extend through March 2012. In addition, due to the long lead time in acquiring certain resources, including renewable resources, Lodi, through NCPA, continues to consider additional projects that might be included in its resource mix. Lodi has joined NCPA's Market Purchase Program under which NCPA may purchase power for Lodi for up to five year terms.

Energy Efficiency and Conservation

Since 1998, Lodi has maintained a public benefits program as required by State law, a component of which is demand-side management (commonly referred to as energy efficiency and conservation). Under this program, Lodi offers customers utility rebates for insulation, improved air duct systems, high-efficiency air conditioners, attic fans, whole-house fans, white/cool roofing materials, radiant barriers, refrigeration efficiency improvements, EnergyStar appliances, pump/motor/process equipment improvements, lighting retrofits, and appliance recycling programs.

Lodi also provides energy education for residential and non-residential customers, including on-site and on-line energy audits, and hosts a number of programs to promote renewable energy education and outreach. As part of its education and outreach efforts, Lodi gives in-classroom presentations on solar and other renewable energy sources, co-sponsors the Youth Energy Summit, and offers the Lodi Energy Smart Workshop series.

Over the past 12 years, over 48,000 Lodi utility customers have been positively impacted by one or more of Lodi's public benefits programs, either in the form of a direct utility rebate or via one of its outreach and educational programs.

Interconnections, Transmission and Distribution Facilities

Lodi's electric system is interconnected with the system of PG&E (three 60 kV lines). Lodi owns facilities for the distribution of electric power within the city limits of Lodi, which includes approximately 13 miles of 60 kV power lines, approximately 290 miles of 12 kV distribution lines (approximately 54% of which are underground) and four substations. Lodi's system experiences approximately 25 minutes of outage time per customer per year.

Forecast of Capital Expenditures

Lodi's five-year capital projection for the electric facilities contemplates potential capital expenditures for substation upgrades, a new distribution substation, 60 kV power lines to interconnect an existing NCPA substation at NCPA's Capital Facilities Project (Combustion Turbine Project Number Two), and related system reliability projects. Lodi anticipates funding such costs from rate revenues, special development fees and possible new debt issuance as required. Over the next five years, total capital expenditures could range from $10 million to $25 million depending on the actual projects undertaken and their timing.

Employees

As of December 31, 2011, 42 full-time City of Lodi employees were assigned specifically to the electric utility department. Contract/temporary employees are hired as necessary. Substantially all of the non-management Lodi personnel assigned to the electric utility department are represented by the International Brotherhood of Electrical Workers, Union 1245 ("IBEW"). The current Memorandum of Understanding with the IBEW expires on December 31, 2013. There have been no strikes or other union work stoppages at the City of Lodi, including the electric utility department.

Retirement benefits to City of Lodi employees, including those assigned to the electric utility department, are provided through the City of Lodi's participation in the California Public Employees' Retirement System ("CalPERS"), an agent multiple-employer public employee defined benefit pension plan. The City of Lodi's contribution rate is determined by periodic actuarial calculations based on the benefit formula and the number of employees and their respective salary schedules. For the fiscal year ended June 30, 2011, the City of Lodi's annual pension costs for the Miscellaneous Plan (which includes all electric utility employees) was $2,080,303, which was equal to the City's required contribution. Actual contributions to CalPERS funded by the electric utility for electric utility staff costs for fiscal years 2009-10 and 2010- 11 were $694,200 and $697,200, respectively. Budgeted contributions to CalPERS to be funded by the electric utility for electric utility staff costs for fiscal year 2011-12 are $709,000. As of June 30, 2009, the most recent actuarial valuation date, the Miscellaneous Plan was 86.5% funded. The actuarial accrued liability for benefits was $127.5 million and the actuarial value of assets was $110.3 million, resulting in an unfunded actuarial accrued liability of $17.2 million. The actuarial value of CalPERS assets are determined using techniques that smooth the effects of short-term volatility in market value of investments over a fifteen -year period (smoothed market value). PERS unfunded actuarial accrued liability is being amortized as a level percentage of projected payroll on a closed basis. Amortization of the remaining period for the Miscellaneous Plan was 21 years as of June 30, 2010. CalPERS issues a separate comprehensive annual financial report. Copies of the CalPERS annual financial report may be obtained from the CalPERS Executive Office, 400 Q Street, Sacramento, California 95814.

In addition, the City of Lodi provides certain post-employment benefits other than pensions (OPEB) to City of Lodi employees, including those assigned to the electric utility department, who retire from the City of Lodi and receive a CalPERS pension through its participation in the CalPERS medical benefits program. Contribution requirements of the postemployment benefit are based on pay-as-you-go financing. For the fiscal years 2009-10 and 2010-11, the City of Lodi contributed 34.43% ($459,203) and 33.21% ($469,593), respectively, of the OPEB cost based on an actuarially determined annual required contribution of $1,333,881 and $1,414,182, respectively. The City of Lodi's budgeted OPEB contribution for fiscal year 2011-12 is $635,000. As of January 1, 2010**,** the most recent actuarial valuation date, the retiree health plan has an unfunded actuarial accrued liability of $17.7 million. The actuarial methods and assumptions used include techniques that "smooth" the effects of short-term volatility in actuarial accrued liabilities and the actuarial value of assets. The portion of the plan's assets allocable to the electric utility department employees, which is part of the City of Lodi's liability pool, has not been separately calculated. The electric utility employees represent approximately 10.5% of employees of the City of Lodi. As previously noted, the City of Lodi's OPEB funding is made on a pay-as-you-go basis.

Additional information regarding the City of Lodi's retirement plans and other post-employment benefits can be found in the City's comprehensive annual financial reports, which may be obtained at http://www.lodi.gov.

Service Area

Lodi is served by interstate highway 5 and State highways 12 and 99 and is located on the main line of the Southern Pacific Railroad. A deep water seaport and an airport are located approximately 15 miles south. The local economy is well-balanced among residential, agricultural, commercial and industrial sectors.

Lodi is a worldwide agricultural shipping center for the San Joaquin Valley. The surrounding prime agricultural land is a major producer of wine grapes.

There are several manufacturing plants in the community area with a wide variety of products: cereals, food mixes, wines, rubber products, steel framing and industrial shelving, foundry items, recreational vehicle components, electronic substrates, and plastic piping and injection molded products. In addition, Lodi has a number of small businesses located within the City of Lodi. The main businesses in Lodi, however, are food processes and plastics.

The largest employers in Lodi as of June 30, 2011 are as follows:

CITY OF LODI
LARGEST EMPLOYERS

Employer	Business	Number of Employees
Lodi Unified School District	Education	2,762
Lodi Memorial Hospital	Health Care	1,329
Pacific Coast Producers	Fruit Canning	1,000
Blue Shield	Insurance Claims Processing	850
Cottage Bakery	Baked Goods	540
General Mills	Cereals and Food Mixes	480
City of Lodi	Government	440
Farmers & Merchants Bank	Banking	353
Wal-Mart	Retail	245
Target	Retail	209

Source: City of Lodi, City Manager's Office.

A five-year history of building permits in Lodi is as follows:

CITY OF LODI
BUILDING PERMIT VALUATION
for Calendar Years 2007 through 2011

Type of Permit	2007	2008	2009	2010	2011
Residential:					
New Single-Dwelling	$ 4,631,976	$ 1,837,512	$ 734,783	$ 595,647	$ 667,031
New Multi-Dwelling	1,134,559	0	0	0	0
Additions/Alterations	2,906,158	1,659,378	2,323,010	2,240,255	2,693,616
Total Residential	$ 8,672,693	$ 3,496,890	$3,057,793	$2,835,902	$3,360,647
Non Residential:					
New Commercial	$ 5,508,296	$10,267,563	$ 942,077	$9,982,999	$14,956,189
New Industrial	496,455	0	0	0	0
Other	1,755,534	1,828,749	1,813,849	1,959,001	3,644,527
Additions/Alterations	2,833,350	9,699,507	1,862,030	2,718,583	9,311,211
Total Non Residential	$10,593,635	$21,795,819	$4,617,956	$14,660,583	$27,911,927
Total Valuation	$19,266,328	$25,292,709	$7,675,749	$17,496,485	$31,272,574

Source: Construction Industry Research Board.

A five-year history of assessed valuations in Lodi is as follows:

CITY OF LODI
ASSESSED VALUATIONS
For Fiscal Years 2007-08 through 2011-12
(Dollar Amounts in Thousands)

Fiscal Year	Land	Improvements	Personal Property	Total	Less Exemptions	Net Assessed Value
2007-08	$1,537,554	$3,503,186	$289,770	$5,330,510	$243,259	$5,087,251
2008-09	1,562,729	3,577,741	281,915	5,422,385	265,154	5,157,231
2009-10	1,345,815	3,600,824	312,792	5,259,431	332,701	4,926,730
2010-11	1,322,830	3,534,778	323,003	5,180,611	321,138	4,859,473
2011-12	1,264,884	3,401,792	301,180	4,967,856	314,448	4,653,408

Source: Fiscal Years 2008-2011 City of Lodi comprehensive annual financial report.

The following chart indicates the growth in the population of the City of Lodi, the County of San Joaquin and the State of California since 1970.

CITY OF LODI, COUNTY OF SAN JOAQUIN,
STATE OF CALIFORNIA POPULATION
(1970–2000 as of April 1; 2007-2011 as of January 1)

	City of Lodi	County of San Joaquin	State of California
1970	28,691	291,073	19,971,069
1980	34,850	343,500	23,668,562
1990	51,900	477,700	29,760,021
2000	58,600	569,076	34,095,209
2007	62,934	678,652	37,655,193
2008	63,362	686,214	38,155,534
2009	63,313	691,718	38,476,724
2010	62,095	684,057	37,223,900
2011	62,473	690,899	37,510,766

Source: U.S. Bureau of Census and California State Department of Finance.

Litigation

There is no action, suit or proceeding known to be pending or threatened, restraining or enjoining Lodi in the execution or delivery of, or in any way contesting or affecting the validity of any proceedings of Lodi taken with respect to the Third Phase Agreement.

There is no litigation pending, or to the knowledge of Lodi, threatened, questioning the existence of Lodi, or the title of the officers of Lodi to their respective offices. There is no litigation pending, or to the knowledge of Lodi, threatened, questioning or affecting in any material respect the financial condition of Lodi's electric system.

Present lawsuits and other claims against Lodi's electric system are incidental to the ordinary course of operations of the electric system and are largely covered by Lodi's self insurance program. In the opinion of Lodi's management and the Lodi City Attorney, such claims and litigation will not have a materially adverse effect upon the financial position of Lodi.

Rates and Charges

Lodi has the exclusive jurisdiction to set electric rates within its service area. These rates are not subject to review by any State or federal agency.

Lodi's fiscal year 2010-11 average rate per kWh for residential service was 16.99 cents. Lodi's fiscal year 2010-11 average rate for commercial and industrial service was 13.47 cents per kWh.

The following table presents a recent history of Lodi's rate increases since 2002. The last base rate increase was in December 2005.

CITY OF LODI
ELECTRIC UTILITY DEPARTMENT
RATE CHANGES

Effective Date	Percent Change
December 2007	Established Solar Initiative Surcharge of $0.00125 per kilowatt-hour
August 2007	Implemented monthly Energy Cost Adjustment
December 2005	Average 17% increase across all rate classes
December 2002	4.5% average rate increase

Source: City of Lodi.

The City Council reviews electric system rates periodically and makes adjustments as necessary. The City has adopted a number of rate policies which apply to contract rates with certain customers. See "Lodi's Operations Since Industry Restructuring" herein.

Lodi implemented an Energy Cost Adjustment ("ECA") in August 2007. The purpose of the ECA is to recover market power costs due to the fluctuations in power market conditions. The ECA is reviewed monthly and is either increased or decreased as market conditions dictate.

Largest Customers

The nine largest customers of Lodi's electric system in terms of kWh sales, as of June 30, 2011, accounted for 29.5% of total kWh sales and 22.8% of revenues. The largest customer accounted for 6.6% of total kWh sales and 4.8% of total revenues.

Lodi's Operations Since Industry Restructuring

Lodi's electric utility operations have been adversely affected by the lingering effects of the power crisis. Lodi has taken a number of actions in order to address challenges facing the electric utility industry that have occurred since the attempted deregulation of the California energy markets. See "DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS" in the front part of this Official Statement. These actions include the implementation of a number of revenue enhancements, cost containment measures and changes in operating procedures, including:

- **Energy Cost Recovery**. Implemented an Energy Cost Adjustment (ECA) for all customers. This rate action guarantees coverage of bulk power purchase costs. See "Rates and Charges" above.

- **The Risk Management Program**. City established a risk management policy. Consistent with the policy Lodi has established goals related to closing open power positions in the current, next and second following fiscal year to provide for orderly stabilization of future power costs.

Timeframe	Open Position
Current Fiscal Year	10%
Next Fiscal Year	25%
2nd Fiscal Year	50%

Customers, Sales, Revenues and Demand

The number of customers, kWh sales, revenues derived from sales by classification of service and peak demand during the past five fiscal years, are listed below.

CITY OF LODI
ELECTRIC UTILITY DEPARTMENT
CUSTOMERS, SALES, REVENUES AND DEMAND[1]

	Fiscal Years Ended June 30,				
	2007	**2008**	**2009**	**2010**	**2011**
Number of Customers:					
Residential	22,928	22,523	22,465	21,981	22,251
Commercial	2,423	2,714	2,696	3,194	2,865
Industrial	33	32	37	31	39
Other	182	187	188	194	229
Total	25,566	25,456	25,386	25,369	25,384
Kilowatt Hour (kWh) Sales:					
Residential	159,247,195	153,563,188	153,487,430	150,811,587	144,256,683
Commercial	153,963,719	155,146,983	155,206,324	146,644,990	137,584,723
Industrial	133,816,956	129,429,938	131,059,764	125,000,860	128,072,575
Other	11,712,875	12,267,600	12,322,036	11,563,550	11,216,348
Total	458,740,745	450,407,709	452,075,554	434,020,987[3]	421,130,329[3]
Revenues from Sale of Energy [2]					
Residential	$27,013,494	$27,127,049	$29,016,777	$27,642,199	$24,513,202
Commercial	23,241,809	25,173,286	26,883,557	24,901,256	21,870,624
Industrial	13,470,620	14,591,885	15,875,038	15,015,036	13,914,539
Other	2,071,324	2,132,120	2,224,567	2,105,196	1,868,985
Total	$65,797,247	$69,024,340	$73,999,939	$69,663,688	$62,167,350
Peak Demand (kW)	140.4	132.4	117.4	119.6	123.9

(1) Columns may not add to totals due to rounding.
(2) Excludes revenues from California Energy Commission Tax.
(3) Decline in kWh sales primarily due to mild weather, increased customer participation in energy efficiency and solar programs and general weaker economic conditions.
Sources: City of Lodi, comprehensive annual financial statements and Customer Information System reports.

Indebtedness

As of December 1, 2011, Lodi had outstanding $77.7 million principal amount of obligations (including accreted value of capital appreciation certificates) payable from net revenues of Lodi's electric utility system. These obligations are subordinate to the payments required to be made with respect to the Lodi's obligations to NCPA and TANC described below. Lodi has no variable rate or auction rate direct debt.

As previously discussed, Lodi participates in certain joint powers agencies, including NCPA and TANC. Obligations of Lodi under its agreements with respect to TANC and NCPA constitute operating expenses of Lodi. Such agreements are on a "take-or-pay" basis, which requires payments to be made whether or not projects are completed or operable, or whether output from such projects is suspended, interrupted or terminated. Certain of these agreements contain "step up" provisions obligating Lodi to pay a share of the obligations of a defaulting participant. Lodi's participation and share of debt service obligation (without giving effect to any "step up" provisions) for each of the joint powers agency projects in which it participates are shown in the following table.

CITY OF LODI
ELECTRIC UTILITY DEPARTMENT
OUTSTANDING DEBT OF JOINT POWERS AGENCIES
(Dollar Amounts in Millions)
(As of December 1, 2011)

	Outstanding Debt[1]	Lodi's Participation[2]	Lodi's Share of Outstanding Debt[1]
NCPA			
Geothermal Project	$ 33.8	10.28%	$ 3.5
Hydroelectric Project	440.8	10.37[3]	45.7
Capital Facilities Project	55.1	39.50	21.8
Lodi Energy Center, Issue One	255.0	17.03	43.4
TANC			
COTP	396.7	1.92[4]	7.6
TOTAL	$1,181.4		$122.0

(1) Principal only. Does not include obligation for payment of interest on such debt.
(2) Participation obligation is subject to increase upon default of another participant. Such increase shall not exceed, without the written consent of a non-defaulting participant, an accumulated maximum of 25% of such non-defaulting participant's original participation.
(3) Lodi's actual payments represent approximately 10.64% of outstanding debt service as a result of credit to non-participating members with respect to portion of debt obligation.
(4) As described herein, Lodi's actual obligation differs slightly from this percentage due to varying shares of certain series of TANC bonds relating to each TANC member-participant's taxable portion and each TANC member-participant's participation or non-participation in acquisition of assets from Vernon.

Source: City of Lodi.

Lodi estimates its obligations for debt service on its joint powers agency debt obligations aggregated approximately $7.7 million for the fiscal year ended June 30, 2011 and will aggregate approximately $9.6 million for the fiscal year ending June 30, 2012. A portion of the joint powers agency debt obligations are variable rate debt, liquidity support for which is provided through liquidity arrangements with banks. Unreimbursed draws under liquidity arrangements supporting joint powers agency variable rate debt obligations bear interest at a maximum rate substantially in excess of the current interest rates on such obligations. Moreover, in certain circumstances, the failure to reimburse draws on the liquidity agreements may result in the acceleration of scheduled payment of the principal of such variable rate joint powers agency obligations. In connection with certain of such joint power agency obligations, the respective joint powers agency has entered into interest rate swap agreements relating thereto for the purposes of substantially fixing the interest cost with respect thereto. There is no guarantee that the floating rate payable to the respective joint powers agency pursuant to each of the interest rate swap agreements relating thereto will match the variable interest rate on the associated variable rate joint powers agency debt obligations to which the respective interest rate swap agreement relates at all times or at any time. Under certain circumstances, the swap providers may be obligated to make payments to the applicable joint powers agency under their respective interest rate swap agreement that is less than the interest due on the associated variable rate joint powers agency debt obligations to which such interest rate swap agreement relates. In such event, such insufficiency will be payable as a debt service obligation from the obligated joint powers agency members (a corresponding amount of which proportionate to its debt service obligations to such joint powers agency could be due from Lodi). In addition, under certain circumstances, each of the swap agreements is subject to early termination, in which event the joint powers agency could be obligated to make a substantial payment to the applicable swap provider (a corresponding amount of which proportionate to its debt service obligations to such joint powers agency could be due from Lodi).

Significant Accounting Policies

Lodi's most recent Annual Financial Report for the fiscal year ended June 30, 2011 was audited by Macias, Gini & O'Connell, LLP, Sacramento, California, in accordance with generally accepted auditing standards, and contains opinions that the financial statements present fairly the financial position of the various funds maintained by Lodi. The reports include certain notes to the financial statements which may not be fully described below. Such notes constitute an integral part of the audited financial statements. Copies of these reports are available on request from the City of Lodi, Finance Department, 221 West Pine Street, Lodi, California 95240. Governmental accounting systems are organized and operated on a fund basis. A fund is defined as an independent fiscal and accounting entity with a self balancing set of accounts recording cash and other financial resources, together with all related liabilities and residual equities or balances, and changes therein. Funds are segregated for the purpose of carrying on specific activities or attaining certain objectives in accordance with special regulations, restrictions or limitations.

The electric system is accounted for as an enterprise fund. Enterprise funds are used to account for operations (i) that are financed and operated in a manner similar to private business enterprises (where the intent of the governing body is that the costs (expenses, including depreciation) of providing goods or services to the general public on a continuing basis be financed or recovered primarily through user charges) or (ii) where the governing body has decided that periodic determination of revenues earned, expenses incurred and/or net income is appropriate for capital maintenance, public policy, management control, accountability or other purposes.

The accounting policies of Lodi conform to generally accepted accounting principles (GAAP) as applicable to governments.

Condensed Operating Results and Selected Balance Sheet Information

The following table sets forth summaries of operating results and selected balance sheet information of Lodi's electric utility for the five fiscal years ended June 30, 2011. The information for the fiscal years ended June 30, 2007 through June 30, 2011 was prepared by Lodi on the basis of its audited financial statements for such years.

CITY OF LODI
ELECTRIC UTILITY DEPARTMENT
SUMMARY OF OPERATING RESULTS AND SELECTED BALANCE SHEET INFORMATION[(1)]
($ in 000s)

	Fiscal Year ended June 30,				
	2007[(2)]	**2008**	**2009**	**2010**	**2011**
OPERATING REVENUES					
Rate Revenue	$65,809	$65,110	$65,229	$62,613	$59,676
ECA Revenue	--	4,174	8,771	7,050	2,491
Other Revenue[(3)]	2,056	5,639	1,195	625	1,140
Total Operating Revenues	$67,865	$74,923	$75,195	$70,288	$63,307
OPERATING EXPENSES					
Purchased Power	43,362	42,862	46,405	37,943	35,282
Non-Power Costs[(4)]	9,622	11,575	11,965	12,006	13,115
Total Operating Expenses	$52,984	$54,437	$58,370	$49,949	$48,397
NET REVENUE	$14,881	$20,486	$16,825	$20,339	$14,910
Debt Service	(6,327)	(6,266)	(9,960)	(7,194)	(7,232)
Remaining After Debt Service	$ 8,554	$14,220	$ 6,865	$ 13,145	$ 7,678
OTHER REVENUES (EXPENSES)					
Payments in Lieu of Taxes	(6,779)	(6,873)	(6,942)	(6,977)	(6,977)
Other Changes in Working Capital[(5)]	(1,562)	--	--	--	--
Net Cash Flow Before Capital Expenditure	$ 213	$7,347	$ (77)	$ 6,168	$ 701
SELECTED BALANCE SHEET INFORMATION:					
Net Plant in Service	$34,582	$36,037	$37,386	$37,044	$36,067
Land and Construction Work in Progress	$ 4,465	$ 8,314	$ 6,418	$ 6,213	$ 6,464
Ending Operating Reserve Balance	$ 5,470	$14,513	$13,854	$25,899	$28,454
Long-Term Debt	$78,885	$74,673	$83,234	$80,525	$77,656
Debt Service Coverage Ratio[(1)]	2.35	3.27	1.69	2.83	2.06

(1) Columns may not add to totals due to rounding. Figures shown are calculated in accordance with the documents pursuant to which Lodi's outstanding electric system revenue obligations were issued, which may or may not be on the same basis as Generally Accepted Accounting Principles. See "Indebtedness."
(2) Certain amounts have been recast to reflect corrected coverage amounts.
(3) Other revenues in Fiscal Year 2008 includes $3.2 million for the layoff of the City's rights in NCPA Combustion Turbine Project Number One to Roseville.
(4) Non-power costs include costs of services provided by other departments and does not include depreciation and amortization expense.
(5) Consists of non-cash accounting entries.
Source: City of Lodi.

CITY OF PALO ALTO

Introduction

Palo Alto is a charter city of the State of California. Pursuant to its charter, Palo Alto has the power to furnish electric utility service to its inhabitants. In connection therewith, Palo Alto has the powers of eminent domain, to contract, to construct works, to fix rates and charges for commodities or services furnished and to incur indebtedness.

Palo Alto provides electric and other utility services through its Department of Utilities. The legal responsibilities and power of the Department of Utilities, including the establishment of rates and charges, are exercised through the nine-member Palo Alto City Council. The members of the City Council are elected city-wide for staggered four-year terms. The Palo Alto Department of Utilities is under the direction of the Director of Utilities who is accountable to the City Manager and who is appointed by the City Manager with the approval of the City Council.

Since 1900, Palo Alto has provided all electric service within the City of Palo Alto. For the fiscal year ended June 30, 2011, Palo Alto served 29,684 customers, had total sales of approximately 946.5 million kWh and a peak demand of 186.2 MW.

To provide electric service within its service area, Palo Alto owns and operates an electric system which includes power supply resources and transmission and distribution facilities. Palo Alto also purchases power and transmission services from others and participates in pooling and other utility-type arrangements. In addition, Palo Alto provides gas utility and other normal city services to its inhabitants such as police and fire protection and water and sewer service.

In March 2011, the Palo Alto City Council approved the updated Long-term Electric Acquisition Plan ("LEAP") Objectives, Strategies and Implementation Plan. LEAP provides high level policy direction for the pursuit of energy efficiency, demand resources, renewable energy, local generation and transmission resources. LEAP also sets direction for the management of hydroelectric resources and market exposure uncertainty.

Palo Alto has a comprehensive Energy Risk Management Program governing electric and natural gas transactions. The program consists of City Council approved policies, and operational guidelines approved by the Risk Oversight and Coordination Committee. The program segregates functions related to the front, middle and back offices.

Only the revenues of the Palo Alto electric utility will be available to pay amounts owed by Palo Alto under the Third Phase Agreement.

The main offices of the City of Palo Alto Department of Utilities are located at 250 Hamilton Avenue, 3rd Floor, Palo Alto, California 94301 (650) 329-2161. For more information about Palo Alto and its Department of Utilities, contact Valerie Fong**,** Director of Utilities, at the above address and telephone number. A copy of the most recent comprehensive annual financial report of the City of Palo Alto (the "Annual Report") is available on Palo Alto's website at http://www.cityofpaloalto.org. The Annual Report is incorporated herein by this reference. However, the information presented on such website or referenced therein other than the Annual Report is not part of this Official Statement and is not incorporated by reference herein.

Power Supply Resources

The following table sets forth information concerning Palo Alto's power supply resources and the energy supplied by each during the fiscal year ended June 30, 2011.

CITY OF PALO ALTO
DEPARTMENT OF UTILITIES
POWER SUPPLY RESOURCES
For the Fiscal Year Ended June 30, 2011

Source	Capacity Available (MW)	Actual Energy (GWh)	Percent of Total Energy
Purchased Power:			
Western	161	380	39%
Wind Energy	45	122	12
Landfill Gas Energy	8	69	7
Forward Market Purchases[(1)]	121[(3)]	274	28
NCPA			
Geothermal Project[(2)]	--	--	--
Hydroelectric Project	57	189	19
Seattle City Light Exchange[(4)]	--	--	--
Short-Term Market	--	(50)	(5)
Total	N/A[(5)]	984	100%
System Requirement for Retail	195		

(1) See "–Purchased Power–Other Power Purchases" below.
(2) Capacity and energy sold to TID. See "–Joint Powers Agency Resources–NCPA" below.
(3) Forward Market Purchase capacity not applicable to system or local reliability requirements.
(4) Assigned to City of Santa Clara effective June 2008. See "–Joint Powers Agency Resources–NCPA" below.
(5) Capacity availability varies by season and is not necessarily additive at any given time.

Source: City of Palo Alto.

In the fiscal year ended June 30, 2011, Palo Alto's average cost of power delivered to the Palo Alto electric system was approximately 6.1 cents per kWh.

Purchased Power

Western. Palo Alto receives a substantial portion of its supply of power from the CVP pursuant to a contract with the Western Area Power Administration ("Western").

In October 2000, Palo Alto signed a 20-year agreement with Western (the "Western Base Resource Contract") for the continued purchase of hydroelectricity from the CVP. Service under the new Western Base Resource Contract began on January 1, 2005 and continues through 2024, with Palo Alto receiving an 11.620% "slice of the system" allocation from Western. On January 1, 2015, Palo Alto's allocation will increase to 12.309%. The power marketed by Western to Palo Alto is provided on a take-or-pay basis where Western's annual costs are allocated to preference customers based on their CVP participation percentage. Western then allocates the annual take-or-pay charges to the preference customers based on a monthly percentage that is designed to reflect the anticipated seasonal energy deliveries. Palo Alto is obligated to its preference customer share (11.620%, increasing to 12.309% on January 1, 2015) of the costs associated with operating the CVP facilities. Palo Alto's energy allocation dropped from the prior levels of approximately 900 GWh/year prior to 2005, to about 380 GWh/year in an average hydrological year starting in January 2005. Palo Alto's annual cost obligation under the Western Base Resource Contract is approximately $11.5 million per year, resulting in an average cost of approximately $30 per MWh in an average hydrological year.

Wind Energy Contracts. Palo Alto currently has two long-term contracts for the output of wind electricity generation. Under a contract with Iberdrola Renewables (formerly PPM Energy, Inc.), for power from the High Winds I project (owned by NextEra Energy Resources, LLC (formerly FPL Energy, LLC)) in Solano County, Palo Alto is allocated available capacity of 20 MW and acquired a fixed unit price on expected generation of 52

GWh/year. The term of such contract ends in 2028. Under a separate contract with Iberdrola Renewables (formerly PPM Energy, Inc.), for power from the Shiloh project (owned by Iberdrola Renewables) in Solano County, Palo Alto is allocated available capacity of 25 MW and acquired a fixed unit price on expected generation of 74.8 GWh/year. The term of such contract ends in 2021.

Landfill Gas Energy Contracts. Palo Alto currently has six long-term contracts for the output of landfill gas electricity generation under separate contracts with Ameresco, Inc., for which Palo Alto is currently taking delivery under three of the contracts. Under the first contract with Ameresco Santa Cruz Energy, L.L.C., for power from the Santa Cruz project (at a landfill owned by County of Santa Cruz) in Watsonville, California, Palo Alto is allocated available capacity of 1.5 MW and acquired an initial fixed per-unit price with 1.5% annual increases on expected generation of 11.8 GWh/year. The Santa Cruz project began commercial operation in February 2006. The term of such contract ends in 2026. Under a second contract with Ameresco Half Moon Bay, L.L.C., for power from the Half Moon Bay project (at a landfill owned by Republic Services, Inc.) in Half Moon Bay, California, Palo Alto is allocated available capacity of 5.1 MW and acquired an initial fixed per-unit price with 1.5% annual increases on expected generation of 41.0 GWh/year. The Half Moon Bay project began commercial operation in April 2009. The term of such contract ends in 2029. Under a third contract with Ameresco Keller Canyon, L.L.C., for power from the Keller Canyon project (at a landfill owned by Republic Services) in Pittsburg, California, Palo Alto is allocated available capacity of 1.5 MW and acquired an initial fixed per-unit price with 1.5% annual increases on expected generation of 12.0 GWh/year. The Keller Canyon project began commercial operation in August 2009. The term of such contract ends in 2029.

The other three Ameresco contracts are still being developed and the planned start dates are uncertain. Under a fourth contract with Ameresco Johnson Canyon L.L.C., for power from a project at Johnson Canyon Landfill owned by Salinas Valley Solid Waste Authority in Gonzales, California, Palo Alto is allocated available capacity of 1.4 MW and acquired an initial fixed per-unit price with 1.5% annual increases on expected generation of 11 GWh/year. The Johnson Canyon project is in the permitting stage and is currently expected to begin operations in October 2012, with the term of such contract to end from 20 years from date of initial energy delivery. Under the Johnson Canyon contract Ameresco has the ability to allocate additional energy as developed at prices equal to 85% of the then current California Market Price Referent. Additional developments are estimated to be approximately 1.4 MW every four years. Under a fifth contract with Ameresco San Joaquin L.L.C., for power from a project at San Joaquin Landfill owned by San Joaquin County in Linden, California, Palo Alto is allocated available capacity of 4.3 MW and acquired an initial fixed per-unit price with 1.5% annual increases on expected generation of 32 GWh/year. The San Joaquin project is in the permitting stage and is currently expected to begin operations in April 2013, with the term of such contract to end from 20 years from date of initial energy delivery. Under a sixth contract with Ameresco Crazy Horse L.L.C., for power from a project at Crazy Horse Canyon Landfill owned by Salinas Valley Solid Waste Authority in Salinas, California, Palo Alto is allocated available capacity of 2.8 MW and acquired an initial fixed per-unit price with 1.5% annual increases on expected generation of 20 GWh/year. The Crazy Horse project is in the permitting stage and is currently expected to begin operations in September 2013, with the term of such contract to end from 20 years from date of initial energy delivery. By September 2013, Palo Alto expects to receive a total of 128 GWh from the landfill gas projects, representing approximately 12% of Palo Alto's load. Each of the foregoing landfill gas energy contracts is unit contingent.

Other Power Purchases. Palo Alto has six active Master Agreements with BP Energy, Shell Energy North America, Conoco Phillips, JP Morgan Ventures Energy, Pacific Summit Energy and Powerex Corp to facilitate competitive forward market purchases to meet Palo Alto's loads in the short- to medium-term. As of June 30, 2011, Palo Alto had outstanding electricity purchase commitments for the period July 2011 to June 2014 totaling 299 GWh. These market based purchases are made within the parameters of Palo Alto's Energy Risk Management Program.

In fiscal year 2010-11, market based purchases represented approximately 23% of Palo Alto's energy needs. The volume of market purchases however is highly dependent on hydro conditions and long-term commitments to renewable resource based supplies. During normal hydro conditions, market purchases are expected to meet approximately 30% of energy needs and will reduce to less than 20% as renewable energy targets are met. All purchase transactions and sales-incidental-to-purchases are designed to meet native load. NCPA serves as Palo Alto's scheduling and billing agent for all transactions, and acts as the interface with the California Independent System Operator ("ISO") under the Second Amended and Restated Metered Subsystem Aggregation Agreement (the

"MSSA"). See NORTHERN CALIFORNIA POWER AGENCY – NCPA Power Pool" in the front part of this Official Statement.

Joint Powers Agency Resources

NCPA. Except for a small 4.5 MW generator within the City of Palo Alto, Palo Alto does not independently own any generation assets. In addition to purchasing power from other sources, Palo Alto is a participant in several NCPA projects. Palo Alto has purchased from NCPA a 22.920% entitlement share in the NCPA Hydroelectric Project. Palo Alto has purchased from NCPA a 6.158% participation in the NCPA Geothermal Project. Palo Alto has sold its share of the Geothermal Project to Turlock Irrigation District ("TID") on a take-or-pay basis for the life of the plant since Palo Alto's need for base load generation at the time the sale was made was limited. For each of these NCPA projects in which Palo Alto participates, Palo Alto is obligated to pay, on an unconditional take-or-pay basis, its entitlement share of the debt service on NCPA bonds issued for the project as well as its share of the operation and maintenance expenses of the project. See also "Indebtedness" below.

In addition, in 1992, NCPA entered into an agreement with Seattle City Light to provide for a seasonal power exchange. The agreement entitles Palo Alto to 11 MW (10.3 MW at Palo Alto meter) during the summer and obligates it to return 8 MW (at Palo Alto meter) during the winter. Deliveries under this agreement began June 1, 1995. NCPA has provided notice to Seattle City Light to terminate this agreement effective in 2018. Changes in Palo Alto's electric portfolio needs and wholesale market conditions led Palo Alto to assign its full share and obligations in the Seattle City Light exchange to the City of Santa Clara effective June 2008.

Palo Alto also has a Third Phase Agreement with NCPA for a 15% share of output and costs from a Power Purchase Agreement between NCPA and Western GeoPower Inc. related to a new geothermal electric power project permitted for construction at the Geysers in Lake County, California. Palo Alto is allocated available capacity of approximately 3.5 MW and acquired a fixed per-unit price with no annual increases on expected generation of 31 GWh/year. The Western GeoPower project is in the financing stage and is expected to begin operations in the fall of 2013, with the term of such contract to end from 25 years from date of initial energy delivery.

For a description of such NCPA resources, see "THE HYDROELECTRIC PROJECT" and "OTHER NCPA PROJECTS" in the front part of this Official Statement.

TANC California-Oregon Transmission Project. Palo Alto is also a member of the Transmission Agency of Northern California ("TANC") and has a participation share of 4.00% (net of layoffs) of TANC's entitlement to transfer capability (approximately 50 MW) of the California-Oregon Transmission Project ("COTP") and is responsible for 4.032% of TANC's COTP operating and maintenance expenses and 4.00% of TANC's aggregate debt service. As a result of low utilization on Palo Alto's part of the transmission capacity and therefore low value relative to costs in addition to a focus on acquiring in-state renewable resources, in August 2008 Palo Alto effected a long-term assignment of its full share and obligations in COTP to Sacramento Municipal Utility District ("SMUD"), TID and Modesto Irrigation District ("MID"). The long-term assignment is for 15 years with an option to renew for five years. For a further description of the TANC COTP project, see "CITY OF ALAMEDA—Joint Powers Agency—*TANC California-Oregon Transmission Project*" herein.

Future Power Supply Resources

In accordance with LEAP, Palo Alto has entered into a number of electricity purchase contracts as described above. As of June 30, 2011, Palo Alto had procured approximately 102% of its total projected electricity needs for fiscal year 2011-12 and 81% of its total projected electricity needs for fiscal year 2012-13. Additional renewable generation contracts are expected to be in place to meet Palo Alto's energy needs.

Palo Alto's current renewable energy resource policy targets a 33% resource portfolio share by 2015. The policy also provides that such resource portfolio adjustments should not result in a rate increase of more than 0.5¢/kWh (equivalent to about $3.35/month for an average residential bill). Palo Alto also permits its customers to voluntarily participate in a green power program whereby participating customers pay renewable energy retail rates.

Palo Alto's customer participation rate in such programs was the highest for all similar programs in the United States, as determined by the U.S. Department of Energy National Renewable Energy Laboratory.

In July 2006, Palo Alto entered into an agreement with NCPA relating to the NCPA Green Power Project ("NGPP") to facilitate the joint purchase of renewable energy resources on behalf of eleven participating NCPA members. At present, no additional contracts are being negotiated as part of the NGPP on behalf of Palo Alto.

Palo Alto is also evaluating local cogeneration opportunities at customer sites and solar photovoltaic projects within Palo Alto. Palo Alto continues to procure energy supplies to meet Palo Alto's short and medium-term energy needs through market purchases with Palo Alto's pre-selected suppliers.

Energy Efficiency and Conservation

Palo Alto's Electric and Gas Public Benefits and Water Efficiency Programs include efficiency; renewable energy; low-income and research, development and demonstration (RD&D) of emerging technologies. Due to increasing supply costs, significant new regulatory requirements, and Palo Alto's desire to promote environmental stewardship, it has placed an increased emphasis on energy and water efficiency. Palo Alto continues to pursue cost-effective energy efficiency as a priority in reducing customer bills. The LEAP includes energy efficiency as the highest-priority goal and requires that an assessment of least total cost, which includes environmental costs and benefits, be conducted when acquiring any energy resource. The Gas Utility Long-term Plan ("GULP") also includes energy efficiency as an important contributor to the energy plan. The Ten-Year Efficiency Portfolio Plan and efficiency potential was first approved in 2007, with the second Ten-Year Electric Energy Efficiency Plan and goals approved in 2010.

Program Potential. California Assembly Bill 2021 ("AB 2021") required all publicly owned utilities to develop ten year plans for energy efficiency goals in 2007 and report on these goals to the California Energy Commission (the "CEC") with updates every three years. The reports were made by Palo Alto in 2007 and 2010, as required. The CEC has the obligation to develop energy efficiency goals for the entire State, after consultation with utilities and others. The second review of potential by Navigant Consulting (formerly Summit Blue) found that there is a market potential to save 7.2% of annual electric use over the next 10 years. This potential was approved as a goal by the City Council on May 3, 2010. The natural gas potential study was completed in early 2011 and increased goals for energy efficiency to 5.5% over 10 years. These goals were approved by the Palo Alto City Council on April 11, 2011.

Efficiency and Renewable Energy Programs. The following is a description of Palo Alto's gas and electric efficiency and renewable energy programs:

- ***Residential Programs:***

  Educational Programs and Workshops. A variety of educational programs and workshops are held throughout the year. Typically, residential workshops on water and energy programs occur in the spring near Earth Day and in June for the "Summer Workshop Series." Facility manager workshops are held about three times per year for large business customers. In addition, customers receive monthly emailed newsletters on a variety of efficiency matters.

  Green@Home. Palo Alto offers free in-home audits through a program coordinated by Acterra, a local, non-profit, volunteer environmental organization. At the end of the audit, participants receive personalized efficiency tips along with simple efficiency-improvement items, including compact fluorescent lights, faucet aerators and energy monitors.

  Home Energy Reports. Palo Alto provides City residents with individualized reports comparing their home energy use with that of 100 similarly sized homes with the assistance of the contractor OPOWER. A web portal also offers tips and suggestions on reducing electric and natural gas usage.

  New Construction Rebates and HERS Audits. Both residential and commercial utilities customers who exceed Green Building Program requirements when going through the permit process for new construction are eligible to receive incentive payments. Residents completing a retrofit are required to have a Home Energy Rating System (HERS) audit performed. The Palo Alto Planning Department and the Department of Utilities coordinate the customer application and payment processes.

PaloAltoGreen. Residents and businesses that are willing to pay a small price premium offset their own home or business electric use with 100% renewable energy. The Renewable Energy Certificates (RECs) come from wind (97.5%) and solar (2.5%) sources. This award-winning program continues to have over 21% of the customer base enrolled in this green pricing program.

Smart Energy Program. Palo Alto gives financial rebates to residents who install energy efficient appliances and equipment in their homes or on their property. Among these are home heating and cooling systems ("HVAC"), insulation, water heaters, insulation and power strips. Palo Alto also pays rebates to customers who have their older model, inefficient refrigerators and freezers recycled through a City program. Additionally, the City sponsors programs to encourage consumers to install compact fluorescent light and light emitting diode (LED) bulbs and fixtures, including LED holiday lights.

- ***Business Programs:***

Commercial Advantage Program. Business customers are offered rebates for many items of equipment, including the following: installing lighting upgrades, wall and ceiling mounted motion sensors, LED exit signs, boilers, pipe insulation, variable frequency drives, computer power management software, night covers for refrigerated display cases, anti-sweat heater controls for coolers/freezers, auto-closers for cooler doors, window film, and custom electric and natural gas saving projects. Non-profit organizations can get extra local assistance in working through the application and rebate process from the third-party "Connect the Dots" Program.

Commercial and Industrial Energy Efficiency Program. Large businesses are eligible for assistance with building commissioning services from the contractor Enovity. This assistance includes reviewing original lighting and heating/cooling systems and their operating specifications. Customers are then assisted in obtaining rebates for replacing chillers, controls, linear fluorescent lighting, occupancy sensors, boilers and insulation.

Keep Your Cool. Commercial kitchens can receive a free, no-obligation, inspection of commercial refrigerators and coolers to evaluate their efficiency. Generous cash incentives are available to make your equipment upgrades more efficient for a variety of motors, lighting and process equipment.

Hospitality Program. Rebates and assistance are offered to hotels through the contractor Synergy. The customers are assisted in installing efficiency measures, including lighting, HVAC tune-ups, exit signs and combination occupancy sensors and system operating controls for lighting, air conditioning and plug loads that reduce power use when rooms are unoccupied.

Labs Efficiency. Research facilities and labs can get assistance with custom efficiency projects through the contractor Wildan. This assistance includes reviewing systems and their operating specifications. Customers are then assisted in obtaining rebates for replacing equipment and controls.

New Construction Assistance. Architects and businesses are trained in how to achieve efficiency savings in Palo Alto. Businesses going through the permitting process get assistance from the contractor BASE Energy with making upgrades to their systems and obtaining rebates for this energy savings.

Right Lights+ Program. Through this program provided by the third party administrator, Ecology Action, small businesses receive extra assistance in implementing efficient equipment. Small business customers can request onsite audits and efficiency rebates on a variety of lighting, sensors and commercial kitchen upgrades, in addition to door gaskets, LED exit signs, vending machine controls, strip curtains for coolers and freezers, as well as customized projects.

Vending Miser Direct Installation. SBW Consulting installs vending misers for free on cold beverage vending machines located at businesses in Palo Alto.

Zero Interest Loan Program. This program provides businesses with no-interest loans to install electric energy efficient equipment. Loans can be up to 5 years in length and for between $5,000 and $50,000. The program is provided in partnership with QuEST.

- ***Programs Available to All Customers:***

Green Building Program. The Green Building Program places requirements for building permits issued based on a project's scope of work. The program mandates that all new construction achieve 15% energy savings beyond that required by the State energy code, and provides financial incentives to achieve additional savings for projects that exceed those minimum requirements. The program requires all non-residential renovation costing more than $100,000 to obtain an ENERGY STAR® Portfolio Manager Rating from the United States Environmental Protection Agency, allowing an owner or property manager to track future energy and water consumption of the building project. The applicant inputs utility data and receives an energy score on a scale of 1 to 100, relative to similar buildings nationwide. The program requires all residential renovations with a cost of more than $100,000 to receive a California Whole-House Home Energy Rating (HERS II) developed by the CEC. This rating provides on-site evaluation of the energy performance of the home and offers analysis of the cost-effectiveness of potential energy efficiency improvement projects.

PV Partners: The PV Partners Program encourages photovoltaic or solar electric (PV) installations on Palo Alto homes and businesses by providing a rebate based on the capacity, measured in watts, of newly installed PV systems. The PV Partners Program continues to be one of the most successful in the State. The Palo Alto Building Department and the Department of Utilities approved the installation of 19 systems in fiscal year 2010-11, for a total of 80 kilowatts of new installed solar electric capacity. As of June 30, 2011, there were 450 PV installations with the total capacity of 3.044 MW (1.6% of Palo Alto's system peak load).

Hot Water Solar Program: Palo Alto launched the solar water heating (SWH) program in May 2008, in advance of a State law requiring natural gas utilities to offer incentives. This program offers rebates of up to $1,500 for residential systems and up to $100,000 for commercial and industrial systems. The rebates are calculated based on three factors: $20 per square foot of collector area for closed-loop systems, solar orientation factor, and the production rating of the specific SWH collector. The rebate is paid to the contractor, who uses the rebate to reduce customers' upfront costs. Both contractors and customers are required to go through training on the process, what makes a good functioning SWH system, and how to ensure that systems are well maintained. All installations are inspected for quality and program compliance by an independent contractor. A total of 34 systems have been installed as of June 30, 2011; 33 of these are residential. The rebates paid totaled $56,673 and resulted in 7,241 therms saved each year.

Each efficiency program's budget, expenses and accomplishments are required to be evaluated by a third party M&V specialist both for legislative and regulatory reporting and in order to assure that the savings of each program are meeting expectations.

Low Income Programs

- ***Residential Energy Assistance Program (REAP)***. Provides qualifying very low-income residents with free energy efficiency measures and access to the Rate Assistance Program (RAP) rate discount. For qualifying customers, a Home Assessment, an application to the RAP, and an on-site customer evaluation for weatherization and energy efficiency measure installation, including insulation and lighting. Customers may have refrigerators and/or furnaces replaced if the need is found.

- ***Rate Assistance Program (RAP)***. Provides a 25% discount for electric and gas charges for qualified customers. Applicants can qualify based on medical or financial need.

- ***ProjectPLEDGE.*** Provides a one-time contribution of up to $750 applied to the utilities bill of qualifying residential customers. Eligibility criteria includes recent emergency events for employment and health. Administered by the Department of Utilities, this program is funded by voluntary customer contributions.

Interconnections, Transmission and Distribution Facilities

Palo Alto's electric system is directly interconnected with the system of Pacific Gas and Electric Company ("PG&E") by a single 115 kV delivery point at Palo Alto's Colorado substation. Palo Alto receives transmission services under the MSSA between NCPA and the ISO.

Palo Alto's distribution system consists of the 115 kV to 60 kV delivery point, two 60 kV switching station, 9 distribution substations, approximately 12 miles of 60 kV sub transmission lines, and approximately 446 miles of 12 kV and 4kV distribution lines.

Forecast of Capital Expenditures

Palo Alto's five-year capital plan for electric distribution facilities contemplates capital expenditures in the following years and amounts:

CITY OF PALO ALTO
DEPARTMENT OF UTILITIES
ESTIMATED CAPITAL EXPENDITURES
(Dollar Amounts in Thousands)

Fiscal Year Ended June 30,				
2012	2013	2014	2015	2016
$8,685	$11,415	$14,205	$12,710	$10,590

Source: City of Palo Alto.

The capital expenditures are for infrastructure replacement and new customer connections, Palo Alto anticipates funding the majority of such costs from current year revenues. Since the 1960's Palo Alto has followed a policy of funding its capital improvements primarily from revenues rather than debt financing.

Palo Alto does not currently plan to make further investment in new large-scale generation. Most of Palo Alto's anticipated energy deficits are expected to be met with renewable power purchase agreements, long-term and short-term market purchases, and customer site distributed generation and cogeneration. Palo Alto is in the initial phases of studying a transmission upgrade project.

Employees

As of December 1, 2011, 104.96 full-time equivalent ("FTE") staff and 3.77 temporary positions were assigned to the electric system of the Palo Alto Department of Utilities. All full-time employees, excluding those in management, confidential and professional classifications, are represented by the Service Employees' International Union ("SEIU") Local 521. Matters pertaining to wages, benefits and working conditions are governed by a memorandum of understanding between the City of Palo Alto and SEIU. The previous one-year agreement with this union expired on June 30, 2011. In June of 2011, the City of Palo Alto and SEIU agreed to extend that agreement for one additional year. Therefore, its terms will expire on June 30, 2012. Management employees receive substantially the same fringe benefit package as the SEIU members, and are represented by the newly formed Utilities Management and Professional Association of Palo Alto ("UMPAPA"). The City and UMPAPA are currently negotiating terms for an initial agreement. Palo Alto's wage and fringe benefits are generally comparable to those offered by other local public agencies.

Palo Alto covers substantially all of its permanent employees under pension plans offered by the California Public Employees Retirement System ("CalPERS"), an agent for multiple employer defined benefit pension plan, which acts as a common investment and administrative agent for its participating member employers. Pension costs are funded by monthly contributions to CalPERS by Palo Alto. Employees of the City of Palo Alto Department of Utilities participate in the Miscellaneous Plan, which is part of the Public Agency portions of CalPERS. CalPERS determines contribution requirements using a modification of the Entry Age Normal Method and uses the market related value method of valuing the plan's assets. An investment rate of return of 7.75% is assumed, including inflation at 3%. Annual salary increases are assumed to vary by duration of service. Changes in liability due to plan amendments, changes in actuarial assumptions, or changes in actuarial methods are amortized as a level percentage of payroll on a closed basis over 20 years. Investment gains and losses are tracked and amortized over 30 years. CalPERS issues a separate comprehensive annual financial report. Copies of the CalPERS annual financial report may be obtained from the CalPERS Executive Office, 400 Q Street, Sacramento, California 95814.

The City of Palo Alto's Annual Pension Cost, representing the payment of annual required contributions determined by CalPERS for the Miscellaneous Plan for fiscal year 2010-11, fiscal year 2009-10 and fiscal year 2008-09 were approximately $12,354,000, $10,891,000 and $10,963,000, respectively. The City of Palo Alto made these contributions as required. At June 30, 2010 (the most recent actuarial information available), the actuarial accrued liability for all City of Palo Alto employees under the Miscellaneous Plan was approximately $521,269,000, the actuarial value of assets (which differs from market value) was approximately $416,810,000 and the actuarial accrued unfunded liability was approximately $104,459,000, representing a funded ratio of 80.0%.

In addition to providing pension benefits, the City of Palo Alto participates in the California Public Employees Medical and Health Care Act to provide certain health care benefits for retired employees, including employees of the City of Palo Alto Department of Utilities. Employees who retire directly from the City of Palo Alto are eligible for benefits if they retire on or after age 50 with 5 years of service and are receiving a monthly pension from CalPERS. In fiscal year 2007-08, Palo Alto implemented the provisions of Governmental Accounting Standards Board Statement No. 45, Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions ("OPEB"), and elected to participate in an irrevocable trust to provide a funding mechanism for its OPEB liability. As a result, the City of Palo Alto maintains a Net OPEB Asset for funds placed in irrevocable trust in excess of its actuarial annual required contribution ("ARC"). The ARC was determined as part of a January 1, 2009 actuarial valuation using the entry age normal actuarial cost method, a projected benefit cost method, which takes into account those benefits that are expected to be earned in the future as well as those already accrued. The actuarial assumptions include: (i) a 7.75% investment rate of return, (ii) a 3.25% projected annual salary increase, and (iii) a 5.00% health inflation increase. The actuarial methods and assumptions used include techniques that smooth the effects of short-term volatility in actuarial accrued liabilities and the actuarial value of assets. The City of Palo Alto's OPEB unfunded actuarial accrued liability is being amortized over a 30-year amortization period. For each of the fiscal years 2010-11, 2009-10, and 2008-09, the City of Palo Alto contributed $9,786,227 (of which $943,097 was contributed by the electric utility), $9,786,227 (of which $943,097 was contributed by the electric utility) and $7,686,163 (of which $715,984 was contributed by the electric utility), respectively, representing 98%, 70% and 68%, respectively, of the Annual OPEB Cost for such fiscal years. The Annual OPEB cost is equal to the employer's annual required contribution to the plan (ARC), with certain adjustments if the employer has a net OPEB obligation for past under- or over-contributions As of June 30, 2011, the most recent actuarial valuation date, the City of Palo Alto's retiree health plan had an actuarial accrued liability for all City of Palo Alto employees of approximately $179,923,000, the actuarial value of assets (which differs from market value) was approximately $40,222,000 and the actuarial accrued unfunded liability was approximately $139,701,000, representing a funded ratio of 22.4%.

Additional information regarding the City of Palo Alto's retirement plans and other post-employment benefits can be found in the City's comprehensive annual financial reports, which may be obtained at http://www.cityofpaloalto.org.

Service Area

The main businesses in Palo Alto are manufacturing and industrial. There are numerous manufacturing plants producing electronic components, communications equipment, computer systems and similar products and general items such as pharmaceutical and aerospace systems.

The ten largest employers in Palo Alto as of June 30, 2011 are shown in the following table.

CITY OF PALO ALTO
LARGEST EMPLOYERS

Employer	Business	Number of Employees
Stanford University	Education	10,233
Stanford University Medical Center/Hospital	Hospital	5,813
Lucille Packard Children's Hospital	Health Care Delivery	3,549
Veteran's Affairs Palo Alto Health Care System	Health Care Delivery	3,500
Hewlett Packard Company	Computer Hardware and Software	2,001
Palo Alto Medical Foundation	Health Care Delivery	2,000
Space Systems Loral	Satellite System Design & Manufacturing	1,700
Wilson Sonsini Goodrich Rosati	Legal Services	1,500
Palo Alto Unified School District	Education	1,318
City of Palo Alto	Government	1,018

Source: City of Palo Alto.

A five-year history of building permits in Palo Alto is as follows:

CITY OF PALO ALTO
BUILDING PERMITS
For Calendar Years 2007-2011

	2007	2008	2009	2010	2011
Residential Valuation (in thousands)					
Single Family	$ 82,769	$50,213	$30,683	$50,946	$37,535
Multifamily	81,679	27,827	7,306	5,000	1,278
TOTAL	$164,448	$78,040	$37,989	$55,946	$38,813
New Dwelling Units					
Single Family	195	102	58	144	78
Multiple Family	294	125	27	35	4
TOTAL	489	227	85	179	82

Sources: Construction Industry Research Board.

Shown below is certain population data for Palo Alto, the County of Santa Clara and the State of California:

**CITY OF PALO ALTO, COUNTY OF SANTA CLARA,
STATE OF CALIFORNIA POPULATION
(1970-2000 as of April 1; 2007-2011 as of January 1)**

Year	City of Palo Alto	County of Santa Clara	State of California
1970	55,835	1,065,313	19,971,069
1980	55,200	1,290,000	23,668,562
1990	57,400	1,463,500	29,760,021
2000	58,917	1,692,957	34,095,209
2007	62,615	1,812,531	37,655,193
2008	63,367	1,848,781	38,155,534
2009	64,484	1,872,270	38,476,724
2010	64,417	1,781,427	37,223,900
2011	64,943	1,797,375	37,510,766

Sources: U.S. Bureau of Census and California State Department of Finance.

Palo Alto is served by freeways, interstate and state highways, bus service and trucking lines. Passenger rail transportation is provided by the Amtrak on a north/south commuter track. Air transportation is available at San Francisco International Airport, located approximately 25 miles to the north, and the San Jose International Airport which is approximately 15 miles from downtown Palo Alto.

Public education is provided in Palo Alto from kindergarten through high school. Palo Alto is also the location of Stanford University.

Litigation

There is no action, suit or proceeding known to be pending or threatened, restraining or enjoining Palo Alto in the execution or delivery of, or in any way contesting or affecting the validity of any proceedings of Palo Alto taken with respect to, the Third Phase Agreement.

There is no litigation pending, or to the knowledge of Palo Alto, threatened, questioning the existence of Palo Alto, or the title of the officers of Palo Alto to their respective offices. As of the date of this Official Statement, there is no litigation pending, or to the knowledge of Palo Alto, threatened, questioning or affecting in any material respect the financial condition of Palo Alto's electric utility system.

Lawsuits and other claims filed against Palo Alto as it relates to its Department of Utilities' electric utility system and operations arise in the ordinary course and scope of Palo Alto's municipal utility business and are largely covered by Palo Alto's self-insurance program. In the opinion of Palo Alto's management and attorneys, these lawsuits and other claims will not have a material adverse effect upon Palo Alto or the Department of Utilities electric utility system and operations.

Rates and Charges

The Palo Alto City Council is authorized by the Palo Alto Municipal Code to set charges, pay for and supply all electric energy and power to be furnished to customers according to such schedules, tariffs, rules and regulations as are adopted by the City Council. These rates are not subject to review by any State or federal agency.

The Municipal Code also provides that the City Council shall have the power to charge equitable rates for the electric services furnished and for building up the electric properties so as to conserve their value and increase their capacity as needed by Palo Alto. In addition, the City Charter provides for the maintenance of a separate fund for each utility into which is deposited receipts from the operations of such utilities and from which are payable the costs and expenses of such utility.

Palo Alto's fiscal year 2010-11 average rates per kWh for residential service was 12.24 cents. Palo Alto's fiscal year 2010-11 average rates for commercial and industrial service was 11.57 cents per kWh. There are no planned electric utility rate increases of fiscal year 2011-12.

The following table presents a history of Palo Alto's electric utility rate increases since 2006.

CITY OF PALO ALTO
DEPARTMENT OF UTILITIES
RATE CHANGES

Date	Percent Change
July 1, 2011	0.0
July 1, 2010	0.0
July 1, 2009	10.0
July 1, 2008	14.1
July 1, 2007	5.0[(1)]
July 1, 2006	0.0

(1) This increase reflects the average bill impact at the time of the increase.

Source: City of Palo Alto.

Palo Alto spends approximately 2.85% of gross electric revenues on the public benefit programs it has developed in response to California Assembly Bill 1890 was adopted in 1996 ("AB 1890"). In addition to funding available through the public benefits program, Palo Alto funds additional efficiency and renewable energy programs through the electric utility's supply resource acquisition budget.

Largest Customers

The ten largest customers of Palo Alto's electric utility system, based upon energy usage for the fiscal year ended June 30, 2011 accounted for approximately 35.4% of total kWh sales and approximately 32.8% of total electric revenues. The largest account consumed 8.6% of Palo Alto's total kWh sales and contributed 7.4% of total revenues and the smallest of the ten largest accounts consumed 1.6% of total kWh sales and 1.4% of revenues.

Palo Alto's Operations Since Industry Restructuring

Electric System Policies. In March 1997, the City Council of Palo Alto approved three electric utility policies relating to customer choice, stranded cost recovery and marketing beyond Palo Alto borders. Palo Alto undertook a number of actions in order to implement those policies. Direct access (discussed below) was offered to large commercial and industrial customers; however none of them exercised the option. Given the lack of interest in the community for direct access in combination with the instability of energy markets in 2001 and CPUC actions relating to direct access, direct access was suspended by the City Council effective August 1, 2001. There are no plans to re-implement direct access at this time.

Calaveras–Stranded Costs Reserve. In 1983, the City Council established the Calaveras Reserve in the Electric Fund to help defray a portion of the annual debt service costs associated with the NCPA Calaveras Hydroelectric Project, which was put in service at that time. As originally established, the Calaveras Reserve policy did not provide for a target balance and depletion of the reserve was anticipated by 2002.

AB 1890, adopted in 1996, provided for the deregulation of California's electric industry effective January 1, 1998. A key element of deregulation was the provision for "direct access", which would allow electric customers to choose their electric commodity supplier. Palo Alto, along with other California utilities, was faced with the prospect of losing customers and load to direct access and being saddled with expensive generation assets purchased or built to serve these customers. In response to such risk, PG&E and other investor- and municipally-owned utilities established stranded cost surcharges to collect funds from ratepayers to cover the amount that these uneconomic assets were projected to cost above their market value in the future (*i.e.*, "stranded cost").

In 1996, the City Council changed the purpose of the Calaveras Reserve and authorized collections from electric ratepayers to cover its stranded cost. In addition, the City Council approved a new Calaveras Reserve policy linking the reserve balance to an amount sufficient to cover potential stranded costs. The assets identified as stranded included the Seattle City Light Exchange contract, the Calaveras Hydroelectric Project and the COTP.

In 1997, the City Council revised the reserve target level to cover above-market, or "stranded," costs to $93 million by December 31, 2001 to be collected from a stranded cost surcharge imposed on electric rates. When the Calaveras Reserve balance reached $71 million in 1999, stranded costs were deemed fully collected. At that time, Council authorized the cessation of the collection of the stranded cost surcharge and established the Calaveras Reserve Target and Guidelines with a schedule to drawdown the funds and manage electric rates through transfers from the Calaveras Reserve to the Electric Supply Rate Stabilization Reserve (E-SRSR) through the end of fiscal year 2032-33, when the Calaveras Reserve would be exhausted.

In 2001, the California electric industry faced an energy crisis triggering wholesale power price spikes and rolling blackouts throughout the State. The crisis was blamed on poor deregulation market design and market manipulation by energy suppliers. As a result, direct access was suspended in California for the investor-owned utilities (although it is currently being phased in for non-residential end-use customers of the investor-owned utilities pursuant to Senate Bill 695, adopted in 2009) and subsequently, Palo Alto suspended its direct access program. Further, as a result of changing market conditions and the assignment of certain electric assets, the estimate of the City's stranded cost is lower now than when stranded cost collections stopped in 1999. Since then, electric market prices have increased significantly, reducing the stranded cost associated with the Calaveras Hydroelectric Project.

On June 15, 2009, the City Council adopted new guidelines to manage the Calaveras Reserve which required an annual calculation of short-term stranded costs during the annual budget process for the upcoming budget year(s) and set the minimum transfer from the Calaveras Reserve to the Electric Supply Operating Budget equal to this amount. The revised guidelines also called for an annual calculation of long-term stranded cost and identification of any excess funds in the Calaveras Reserve available to fund projects to the benefit of electric ratepayers.

On November 1, 2011, the City Council approved a new policy direction regarding the management of the Calaveras Reserve along with new guidelines as follows:

- Change the purpose of the Calaveras Reserve from partially funding above market electric costs and partially funding projects that benefit electric ratepayers to entirely funding projects that benefit electric ratepayers;
- Rename the Calaveras Reserve as the Electric Special Project (ESP) Reserve; and
- Adopt the following ESP Reserve guidelines:
    - The purpose of the ESP Reserve is to fund projects that benefit electric ratepayers;
    - ESP Reserve funds are to be used for projects of significant impact;
    - Projects proposed for funding must demonstrate a need and value to electric ratepayers. The projects must have verifiable value and not be speculative, or be high risk in nature;
    - Projects proposed for funding must be substantial in size, requiring funding of at least $1 million;
    - A goal is to identify preferred projects for funding from the ESP Reserve by end of fiscal year 2015; and
    - Any uncommitted funds remaining at the end of fiscal year 2020 will be transferred to the Electric Supply Rate Stabilization Reserve and the ESP Reserve will be closed.
    - Funds may be used for analysis and pilot projects which would be the basis for planned large projects.
- Staff will identify a process and criteria for identifying eligible projects.

The approximate balance of the Calaveras Reserve (since renamed the ESP Reserve as described above) for the last five fiscal years (in thousands of dollars) is set forth below:

	2006-07	2007-08	2008-09	2009-10	2010-11
Balance	$71,810	$70,397	$64,535	$59,865	$55,558

Source: For fiscal years 2006-07 through 2010-11 City of Palo Alto Audited Financial Statements.

Rate Stabilization Reserve. In June 1998, the City Council approved staff's recommendation to unbundle the Electric and Gas Rate Stabilization Reserves ("RSR"). The RSR was originally created to cover a number of unforeseen contingencies, including the need to supplement rates which cover distribution expenses, and commodity supply costs. The City Council has approved a set of guidelines for the Rate Stabilization Reserves based on a forecast of contingencies to be covered. In December 2003 and again in January 2007, the City Council updated the reserve guidelines taking into account, among other aspects, the increased cost volatility due to the electric portfolio cost exposure to hydroelectric production uncertainties that arose in 2005 with the new Western Base Resource Contract. As of December 1, 2011, the balance of RSR was estimated to be $60.2 million. The RSR is separate from the Calaveras Reserve.

Public Benefits Reserve. In June 1998, the City Council of Palo Alto approved the Public Benefits Reserve to be created for the purpose of establishing a separate reserve from the Electric Fund. The revenue collected for the Public Benefit programs that are not spent are deposited into this reserve for future use. The balance of the Public Benefits Reserve at June 30, 2011 was $3.14 million.

Unbundled Electric Rates. In June 1997, Palo Alto became the first electric utility in California to unbundle its electric rates on customers' bills. Palo Alto's unbundled electric rates are comprised of the following four components: (i) a power supply charge, (ii) a distribution charge; (iii) a transition cost recovery charge and (iv) a public benefits charge.

The distribution charge, transition cost recovery charge and public benefits charge are nonbypassable charges and therefore are paid to Palo Alto by the customer, regardless of energy supplier. On July 1, 1999, the transition cost recovery charge was discontinued.

Customers, Energy Sales, Revenues and Demand

The average number of customers, kWh sales, revenues derived from sales by classification of service and peak demand during the past five fiscal years, are listed below.

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK.]

CITY OF PALO ALTO
DEPARTMENT OF UTILITIES
CUSTOMERS, SALES, REVENUES AND DEMAND[1]

	2007	2008	2009	2010	2011
Number of Customers[2]:					
Residential	25,823	25,522	25,691	26,583	26,793
Commercial	2,453	2,441	2,431	2,439	2,488
Industrial	196	195	193	188	178
Other	212	210	212	220	225
Total	28,684	28,368	28,527	29,430	29,684
Kilowatt-Hour Sales (in thousands):					
Residential	197,663	196,487	192,109	196,286	193,236
Commercial	396,774	395,872	404,784	402,219	411,621
Industrial	302,408	308,324	309,716	284,568	258,613
Other	81,281	76,692	89,073	82,016	83,047
Total	978,126	977,375	995,682	965,089[3]	946,517[3]
Revenues from Sale of Energy:					
Residential	$18,906	$19,845	$ 21,984	$ 24,719	$ 24,391
Commercial	35,502	37,930	43,197	47,645	49,256
Industrial	25,469	27,116	31,233	31,192	28,977
Other	6,721	6,615	8,798	9,020	9,384
Total	$86,598	$91,506	$105,212	$112,576	$112,008
Peak Demand (MW)	190.3	189.0	195.0	186.5	186.2

(1) Columns may not add to totals due to rounding.
(2) Revenues are exclusive of wholesale sales.
(3) Decline in demand primarily due to slowing of the economy, milder weather and investment in energy efficient technologies by the electric utility customers.

Source: City of Palo Alto.

Indebtedness

In October 2007, the City issued $1.5 million of 2007 Electric Utility Clean Renewable Energy Tax Credit Bonds ("CREBs") to finance the City's photovoltaic solar panel project. The bonds do not bear interest and are scheduled to be fully paid by December 2021. In lieu of receiving the periodic interest payments, bondholders are allowed annual federal income tax credits in an amount equal to a credit rate for such CREBs multiplied by the outstanding principal amount of the CREBs owned by the bondholders. As of December 1, 2011, the remaining outstanding principal balance of the CREBs was $1.1 million.

The City issued Utility Revenue Bonds, 1995 Series A (the "1995 Utility Bonds") on February 1, 1995 to finance certain extensions and improvements to the City's Storm Drainage and Surface Water System. The 1995 Utility Bonds are special obligations of the City secured by a lien on net revenues of the City's entire "Enterprise," which consists of the City of Palo Alto water system, gas system, storm and surface water drainage system, sanitary sewer system, and electric utility system. The annual principal and interest debt service payments are solely paid by the City's storm and surface water drainage system. As of December 1, 2011, the outstanding principal amount of the 1995 Utility Bonds was $4.6 million.

As previously discussed, Palo Alto participates in two joint powers agencies, including NCPA and TANC. Obligations of Palo Alto under its agreements with respect to NCPA and TANC constitute operating expenses of Palo Alto payable prior to any of the payments required to be made on Palo Alto's utilities' revenue bonds or other obligations. Agreements with the joint powers agencies in which Palo Alto participates are on a "take-or-pay" basis, which requires payments to be made whether or not projects are completed or operable, and whether output from such projects is suspended, interrupted or terminated. These agreements contain "step-up" provisions obligating

Palo Alto to pay a share of the obligations of a defaulting participant. Palo Alto's participation and share of debt service obligation (without giving effect to any "step-up" provisions) for each of the joint powers agency projects in which it participates are shown in the following table.

CITY OF PALO ALTO
DEPARTMENT OF UTILITIES
OUTSTANDING DEBT OF JOINT POWERS AGENCIES
(Dollar Amounts in Millions)
(As of December 1, 2011)

	Outstanding Debt(1)	Palo Alto Participation(2)	Palo Alto Share of Outstanding Debt(1)
NCPA			
Geothermal Project	$ 33.8	0.0%(3)	$ 0.0(3)
Hydroelectric Project	440.8	22.92	101.0
TANC			
Bonds	396.7	0.0(4)	0.0(4)
TOTAL	$871.3		$101.0

(1) Principal only. Does not include obligation for payment of interest on such debt.
(2) Participation based on actual debt service obligation. Participation obligation is subject to increase upon default of another project participant. Such increase shall not exceed, without written consent of a non-defaulting participant, an accumulated maximum of 25% of such non-defaulting participant's original participation.
(3) Participant share of 6.16% was sold to TID in October 1984. Palo Alto remains contractually liable for its share. See "Power Supply Resources–Joint Powers Agency Resources–*NCPA*."
(4) Participation share of 4.00% was assigned to SMUD, TID and MID in August 2008. Palo Alto remains contractually obligated for its share. See "Power Supply Resources–Joint Powers Agency Resources–*TANC California-Oregon Transmission Project*."

Source: City of Palo Alto.

A portion of the joint powers agency debt obligations are variable rate debt, liquidity support for which is provided through liquidity arrangements with banks. Unreimbursed draws under liquidity arrangements supporting joint powers agency variable rate debt obligations bear interest at a maximum rate substantially in excess of the current interest rates on such obligations. Moreover, in certain circumstances, the failure to reimburse draws on the liquidity agreements may result in the acceleration of scheduled payment of the principal of such variable rate joint powers agency obligations. In connection with certain of such joint power agency obligations, the respective joint powers agency has entered into interest rate swap agreements relating thereto for the purposes of substantially fixing the interest cost with respect thereto. There is no guarantee that the floating rate payable to the respective joint powers agency pursuant to each of the interest rate swap agreements relating thereto will match the variable interest rate on the associated variable rate joint powers agency debt obligations to which the respective interest rate swap agreement relates at all times or at any time. Under certain circumstances, the swap providers may be obligated to make payments to the applicable joint powers agency under their respective interest rate swap agreement that is less than the interest due on the associated variable rate joint powers agency debt obligations to which such interest rate swap agreement relates. In such event, such insufficiency will be payable as a debt service obligation from the obligated joint powers agency members (a corresponding amount of which proportionate to its debt service obligations to such joint powers agency could be due from Palo Alto). In addition, under certain circumstances, each of the swap agreements is subject to early termination, in which event the joint powers agency could be obligated to make a substantial payment to the applicable swap provider (a corresponding amount of which proportionate to its debt service obligations to such joint powers agency could be due from Palo Alto).

Significant Accounting Policies

Palo Alto's most recent Annual Financial Report for the fiscal year ended June 30, 2011 has been audited by Macias Gini & O'Connell LLP, Walnut Creek, California, in accordance with generally accepted auditing standards, and contains opinions that the financial statements present fairly, in all material respects, the respective financial position of the various funds maintained by Palo Alto. The reports include certain notes to the financial statements which are not described below. Such notes constitute an integral part of the audited financial statements. Copies of these reports are available on request from the Administrative Services Department, City of Palo Alto, 250 Hamilton Avenue, Palo Alto, California 94301. Governmental accounting systems are organized and operated on a fund basis. A fund is defined as an independent fiscal and accounting entity with a self-balancing set of accounts recording cash and other financial resources, together with all related liabilities and residual equities or balances, and changes therein. Funds are segregated for the purpose of carrying on specific activities or attaining certain objectives in accordance with special regulations, restrictions or limitations.

The Palo Alto electric system is accounted for as an enterprise fund. Enterprise funds are used to account for operations (i) that are financed and operated in a manner similar to private business enterprises (where the intent of the governing body is that the costs (expenses, including depreciation) of providing goods or services to the general public on a continuing basis be financed or recovered primarily through user charges) or (ii) where the governing body has decided that periodic determination of revenues earned, expenses incurred and/or net income is appropriate for capital maintenance, public policy, management control, accountability or other purposes.

Condensed Operating Results and Selected Balance Sheet Information

The following table sets forth summaries of income and selected balance sheet information of Palo Alto's Department of Utilities electric utility system for the five fiscal years ended June 30, 2011. The information for the fiscal years ended June 30, 2007 through June 30, 2011 was prepared by Palo Alto on the basis of its audited financial statements for such years.

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK.]

CITY OF PALO ALTO
DEPARTMENT OF UTILITIES
CONDENSED OPERATING RESULTS AND SELECTED BALANCE SHEET INFORMATION[(1)]
(Dollar Amounts in Thousands)

	Fiscal Year ended June 30,				
	2007	**2008**	**2009**	**2010**	**2011**
Summary of Income:					
Operating Revenues	$102,549	$103,833	$122,656	$125,005	$122,109
Operating Expenses[(2)]	(89,607)	(98,992)	(121,865)	(110,667)	(93,257)
Other Income	(468)	1,844	8,172	6,238	(4,042)
Loss on Disposal of Fixed Assets	(1,193)	(109)	(1,069)	(173)	(49)
Transfers in	471	33	33	3,025	550
Transfers out[(3)]	(9,943)	(11,151)	(12,700)	(11,918)	(12,206)
Net Income	$ 1,809	$(4,542)[(4)]	$(4,773)[(5)]	$ 11,510	$13,105
Selected Balance Sheet Information:					
Net Property Plant and Equipment	$149,438	$156,011	$159,136	$164,484	$161,699
Unrestricted	156,424	145,309	137,411	143,573	142,653
Total Net Assets	$305,862	$301,320	$296,547	$308,057	$304,352

(1) Includes electric and fiber optics funds.
(2) Includes purchased power costs and payments to NCPA and TANC. Also includes depreciation.
(3) Composed primarily of transfers to Palo Alto general fund for costs incurred for the benefit of the Palo Alto utility system, transfers to fund retiree medical benefits and transfers to the capital projects fund.
(4) Net loss of $4.5 million due to an $8.6 million increase in purchased power costs due to unfavorable weather conditions.
(5) Net loss of $4.8 million due to an $11.3 million increase in purchased power costs due to unfavorable hydrologic conditions. This was an anticipated cost increase which was managed by a combination of a 14.1% retail rate increase and a drawdown of $7.6 million from Rate Stabilization Reserves.

Source: City of Palo Alto.

CITY OF ROSEVILLE

Introduction

The City of Roseville ("Roseville" or the "City") is located in southwestern Placer County, California, and is the largest city in the county. Roseville is included in the Sacramento Metropolitan Statistical Area, and because of this close proximity, Roseville's economy is closely tied to that of the State capital.

Roseville has owned and operated its electric distribution system since 1912. In 1956, Roseville entered into a contract with the Federal Bureau of Reclamation for 69 megawatts ("MW") of electric capacity from the Central Valley Project (the "CVP"), which consists of a system of dams, reservoirs and hydroelectric power plants within central and northern California (the contract is currently administered through the Western Area Power Administration ("Western")). In the early 1970s, Roseville's anticipated demand for electricity exceeded the Western resource allocation. To help meet this additional need, in 1968 Roseville became a charter member in NCPA. Roseville participates in several resources developed by NCPA, including its geothermal, combustion turbine, steam-injected gas turbine, and hydroelectric projects. Roseville also became a member of the Transmission Agency of Northern California ("TANC") in 1984 and participates in the California-Oregon Transmission Project (the "COTP").

In October of 2007, Roseville completed construction of a 160 MW natural gas-fired combined cycle power plant ("Roseville Energy Park"). Roseville Energy Park was built as a reliable, economic alternative to bulk power purchases. Roseville Energy Park has a base operating capacity of 120 MW with the ability to peak-fire up to 160 MW. On September 1, 2010, Roseville assumed full title and ownership of two of the NCPA Combustion Turbine Project Number One units (50 MW capacity), located in the City of Roseville, to meet reserve and capacity requirements.

Roseville's electric system is under the supervision of the City Council. A seven-member Roseville Public Utilities Commission (the "Commission") serves as an advisory board to the City Council on matters relating to all utilities owned and operated by Roseville. The City Council appoints all seven members of the Commission. The Electric Utility Director manages the Roseville Electric Department and reports to the Commission and the City Manager.

The Roseville electric utility serves an area of approximately 36.2 square miles, virtually coterminous with the City of Roseville borders, and has over 144 miles of overhead lines and over 664 miles of underground lines and 17 substations. For the fiscal year ended June 30, 2011, it served an annual average of approximately 53,457 customers, comprised of approximately 47,021 residential customers and approximately 6,436 commercial and industrial customers, with a peak demand of 331.4 MW.

Only the revenues of the Roseville Electric Department will be applicable to pay amounts owed by Roseville under the Third Phase Agreement.

The Roseville Electric Department's main office is located at 2090 Hilltop Circle, Roseville, California 95747, (916) 797-6937. For more information about Roseville and its electric system, contact Michelle Bertolino, Electric Utility Director, at the above address and telephone number. A copy of the most recent comprehensive annual financial report of the City of Roseville (the "Annual Report") is available on Roseville's website at http://www.roseville.ca.us/gov/finance/general_accounting/financial_statements.asp. The Annual Report is incorporated herein by this reference. However, the information presented on such website or referenced therein other than the Annual Report is not part of this Official Statement and is not incorporated by reference herein.

Power Supply Resources

General

Roseville has a diverse portfolio of resources that includes large hydro, geothermal, landfill gas, natural gas fired thermal, system power contracts, and additional contracts for renewable supply. In addition, Roseville purchases its incremental needs through open market purchases. Roseville owns and operates the Roseville Energy

Park and the Roseville Combustion Turbines (previously part of the NCPA Combustion Turbine Project Number One). Roseville has a long-term contract with Western for a share of the Central Valley Project net generation and has entitlements to the output of several NCPA projects.

The following table sets forth information concerning Roseville's power supply resources and the energy supplied by each during the fiscal year ended June 30, 2011.

CITY OF ROSEVILLE
ELECTRIC DEPARTMENT
POWER SUPPLY RESOURCES
For the Fiscal Year Ended June 30, 2011

Source	Type	Area	Capacity Available (MW)[1]	Actual Power Energy (GWh)[2]	% of Total
Generation:					
Roseville Energy Park[3]	Natural Gas	Local	155	342	28%
Roseville Power Plant 2[4]	Natural Gas	Local	48	1	0
Purchased Power:					
Western[4]	Large Hydro	Western	59	152	13
NCPA					
Geothermal Project	Geothermal	ISO	12	68	6
Hydroelectric Project	Large Hydro	ISO	29	117	10
Capital Facilities Project (Combustion Turbine Project Number Two)	Natural Gas	ISO	21	5	0
Open Market Purchases[6]	Various	Various	67	527	44
TOTAL*			392*	1,211*	100%*
Peak Demand (MW)			330		
Capacity Reserve Percent			16%		

(1) Capacity in MW and available for system peak.
(2) One gigawatt hour (GWh) equals 1 million kilowatt hours (kWh).
(3) Includes slight de-rating for summer (ambient temperatures).
(4) In September 2010, Roseville purchased Roseville Power Plant 2 from NCPA (previously the units of the NCPA project known as Combustion Turbine Project Number One located in Roseville).
(5) Includes reserve capacity.
(6) Capacity includes long-term and seasonable purchases only. Roseville also acquires capacity on a short-term basis as needed. Quantity of energy is net of a long-term sale.
* Numbers may not total due to rounding

Source: City of Roseville.

Roseville Energy Park

Roseville Energy Park, is a 160 MW rated capacity duct fired combined cycle, natural gas fueled power plant. The Roseville Energy Park power island is comprised of two Siemens SGT 800 combustion turbine units and a Siemens STG 900 steam turbine. Roseville Energy Park utilizes duct firing within the heat recovery steam generator (HRSG) and a zero liquid discharge (ZLD) wastewater system. The plant has been in commercial operation since October of 2007 and serves as an intermediate load resource for Roseville's electric power needs. Roseville Energy Park is owned and operated by Roseville.

Roseville Energy Park is directly connected to Roseville's distribution system and thus avoids transmission costs and losses. Roseville schedules and dispatches the plant against the avoided cost of electric market purchases to meet its load requirements, primarily from the California Independent System Operator ("ISO"), and taking into account all known costs and constraints. Roseville Energy Park is also used to provide load following reserves to the extent they are not available from the electric markets. In other words, Roseville operates Roseville Energy Park during periods where the alternative cost of supplying customer loads is higher, and idles the plant when alternative electric purchases are less expensive than Roseville Energy Park operations. The unaudited base capacity factor for Roseville Energy Park for year ending June 30, 2011 was 31%.

Roseville financed the Roseville Energy Park through the issuance of electric system revenue certificates of participation in 2005, with subsequent issues of refunding bonds in 2008 and 2010, approximately $192.8 million of which was outstanding as of December 1, 2011.

Roseville Power Plant 2

Purchased in September 2010 from NCPA, Roseville Power Plant 2 (previously known as the NCPA Combustion Turbine Project Number One) is used to provide load support (peaking generation) and aid in economic operations. The plant is comprised of two natural gas-fueled combustion turbines for a rated capacity of 48 MW (24 MW per turbine). Roseville Power Plant 2 is directly connected to Roseville's distribution system and thus avoids transmission costs and losses. Roseville schedules and dispatches the plant against the avoided cost of electric market purchases to meet its load requirements, primarily from the ISO, and taking into account all known costs and constraints. The plant is owned and operated by Roseville.

Western

Roseville has long-term contracts with Western that provide a 4.5817% share of the net output of the Central Valley Project ("CVP"), provide for interconnection and interconnected operations with Western's transmission system, and provide for transmission services. On January 1, 2015, Roseville's share of the net output of the CVP will increase to 4.85333%. The power supply contract provides varying amounts of capacity and energy depending upon hydrological and storage conditions of the CVP. The output is reduced by Western's project use, first preference customer allocations and control area obligations. Roseville is directly connected to Western's transmission system and acquires reserves under contract that include regulation and frequency response service, and spinning and non-spinning reserves. The term of the power supply contract extends through December 31, 2024.

Joint Powers Agency Resources

NCPA. In addition to generating and purchasing power from other sources, Roseville is a participant in a number of NCPA projects. Roseville has purchased from NCPA a 12.00% entitlement share in the Hydroelectric Project. Roseville has purchased from NCPA a 36.50% entitlement share in the Capital Facilities Project, Unit One. NCPA has entered into arrangements on behalf of NCPA Capital Facilities Project, Unit One project participants to provide for a gas supply for the Capital Facilities Project, Unit One project. Roseville has purchased from NCPA a 7.88% entitlement share in the Geothermal Project. For a description of such resources, see "THE PROJECT" and "OTHER NCPA PROJECTS" in the front part of this Official Statement. For each of these NCPA generation projects in which Roseville participates, Roseville is obligated to pay, on an unconditional take-or-pay basis, its entitlement share of the debt service on NCPA bonds issued for the project as well as its share of the operation and maintenance expenses of the project. See also "Indebtedness" below.

Open Market Term Purchase and Sale Agreements

Roseville enters into various fixed-price purchase or sale contracts on the open market at various times to meet its power supply requirements and hedge its portfolio costs consistent with its risk management policies. Electricity is generally sold or acquired in 25 MW increments on a seasonal or annual basis. Roseville has entered into several seasonal and short-term purchases for varying terms from a number of power suppliers. Roseville also typically enters into seasonal and short-term purchases for varying terms from a number of power suppliers. The short-term purchase terms range from 1 to 3 months.

Future Power Supply Resources

Roseville expects that it will obtain additional resources from market purchases or investment in generation facilities, either independently, through NCPA or other agencies. Roseville is participating in the Power Purchase Agreement between NCPA and Western GeoPower Inc. related to a new geothermal electric power project permitted for construction at the Geysers in Lake County, California, which currently is expected to begin operations in early 2014. See “OTHER NCPA PROJECTS—Power Purchase and Other Contracts Western—GeoPower Power Purchase Agreement” in the front part of this Official Statement. In accordance with recent legislation, Roseville expects that future energy purchases will increasingly be made from renewable energy sources. See also “Energy Efficiency and Conservation” below.

Natural Gas Prepayment

The Roseville Natural Gas Financing Authority entered into a 20-year pre-paid natural gas supply contract with Merrill Lynch Commodities Inc (“MLCI”), which extends through December 31, 2027. The natural gas purchased from MLCI is in turn sold to Roseville for use in the Roseville Energy Park. The natural gas Roseville is obligated to purchase under the prepaid gas supply agreement is expected to provide approximately 40% of Roseville’s expected gas requirements for Roseville Energy Park. The natural gas supply contract provides Roseville with seasonally adjusted fixed monthly quantities of gas at a discounted monthly index price. Under the contract, Roseville pays only for the amount of natural gas actually delivered. Roseville’s obligations in connection with the purchase of natural gas from the Roseville Natural Gas Financing Authority constitute operating expenses of the electric system.

Power Supply Risk Management

Roseville has in place a rigorous risk management program to ensure that customers will, to the best extent possible, be insulated from the volatility of supply prices. Roseville established a Risk Oversight Committee (“ROC”), risk management policies and procedures. The ROC meets quarterly to review energy trading activities and to ensure their adherence to the risk management policies.

All energy purchases are made to supplement existing resources to meet forecasted load requirements. Generally, Roseville purchases or sells energy that is deficit or surplus to its retail customer needs independently within a 12-month horizon and by using the scheduling and load following services of ACES Power Marketing within a 30-day horizon. Roseville’s risk management policies include short-term and long-term measures.

In general, short-term measures limit market price exposure for the fiscal budget year to 5% or less of Roseville’s budgeted purchased power cost and limit portfolio open volume to no more than +/- 10% of forecast load.

Roseville’s long-term risk management strategy encourages a balanced “layered” energy portfolio. The Energy Hedge Policy provides a ceiling and floor for the required hedged energy (electricity and natural gas) to meet expected loads as follows:

Rolling Year	Minimum Hedged Supply	Maximum Hedged Supply
1	90%	110%
2	80%	105%
3	70%	95%
4	55%	80%
5	40%	65%

The policy requires that Roseville purchase forward electric contracts and/or forward gas contracts to fulfill its long-term hedged supply requirement. In the event of decreases in expected sales levels, the policy may require that Roseville sell forward electric gas and/or electric contracts. Allowed instruments in the hedging program include:

- Electric forward sales or purchases with authorized counterparties
- Electric tolling arrangements with qualified counterparties
- Bi-lateral Gas contracts with qualified counterparties
- Gas futures, Floors and Caps through the NYMEX or other approved market
- Prepaid Gas Supply

Roseville's natural gas procurement strategy primarily involves purchasing natural gas for Roseville Energy Park's operation at a daily index price. Roseville hedges its daily index purchases with monthly financial fixed for floating swap contracts in accordance with its Energy Hedge Policy described above. For the period July 1, 2011 through December 31, 2016, Roseville has fixed the price of approximately 22.4 million MMBtu of natural gas in this manner and will pay the fixed price for the actual amount of natural gas that is delivered. These financial contracts are divided between Shell, ConocoPhillips, BP Corporation, Constellation Energy Commodities, J Aron and Company, Sempra Energy and JP Morgan Energy Ventures. No counterparty has more than a one-third share in this total natural gas hedge.

Transmission

Roseville is part of the Sacramento Municipal Utility District ("SMUD") Control Area. SMUD, Roseville, the Modesto Irrigation District ("Modesto") and the City of Redding executed a joint exercise of power agreement creating the Balancing Authority of Northern California ("BANC") on May 8, 2009. The transition to operation of the BANC occurred on May 1, 2011. SMUD acts as the balancing authority operator under contract and will continue to perform balancing authority functions on behalf of the BANC much as it previously did as the SMUD balancing authority.

Western Area Power Administration Network Integrated Transmission Service Agreement ("NITS"). Roseville's electrical system interconnects with the transmission system of Western. The Western transmission system is part of the SMUD Control Area and interconnects with the ISO Controlled Grid. Roseville imports all of its requirements not met by the Roseville Energy Park and the Combustion Turbine Project Number One over the Western transmission system. Roseville contracts for transmission service to meet its load under a NITS contract which expires on December 31, 2014. This contract provides for imports of electricity from various delivery points into Roseville's electric system. Roseville pays a proportionate share of Western's cost for operating and maintaining the system (currently approximately $2.1 million/year).

California Independent System Operator Controlled Grid. The ISO provides a market for Roseville to purchase its incremental energy needs, and in which to sell the output of its entitlements in NCPA's generating units, and contract purchases. Under current ISO operating protocols, Roseville pays per MWh charges for uses of the transmission system for exports from ISO. Roseville expects that approximately half of its future incremental short-term energy needs will be acquired from the ISO Controlled Grid.

TANC California-Oregon Transmission Project. Roseville is a member of the Transmission Agency of Northern California ("TANC") and has executed the TANC Agreement for a participation percentage of TANC's entitlement of COTP transfer capability. Pursuant to the TANC Agreement, Roseville has a participation share of 2.313% of TANC's entitlement to transfer capability of the COTP (approximately 29.35 MW) and is responsible for 2.313% of TANC's COTP operating and maintenance expenses and 2.295 % of TANC's aggregate debt service on a take-or-pay basis. Roseville's share of annual debt service continues to the year 2024 and is approximately $700,000 per year. However, Roseville has laid off its TANC entitlements and obligations as described below. See "—City Layoff of COTP and Tesla-Midway Service." See also "CITY OF ALAMEDA—Joint Powers Agency Resources—*TANC California-Oregon Transmission Project*" for a further description of the COTP and the TANC Agreement.

TANC Tesla-Midway Transmission Service. TANC and certain TANC members have arranged for PG&E to provide TANC and its members with 300 MW of firm bi-directional transmission capacity between its Tesla Substation and the Midway Substation pursuant to an agreement known as the South of Tesla Principles.

Roseville's share of this Tesla-Midway Transmission Service is 5 MW. Roseville has utilized its allocation of Tesla-Midway Transmission Service for firm and non-firm power transactions when available and economic to do so. However, Roseville has laid off its Tesla-Midway rights as described below. See "–City Layoff of COTP and Tesla-Midway Service." See also "CITY OF ALAMEDA—Joint Powers Agency—*TANC Tesla-Midway Transmission Service*" herein for additional information regarding the TANC Tesla-Midway Transmission Service.

City Layoff of COTP and Tesla-Midway Service. In 2009, with the assistance of TANC, Roseville reached an agreement with the SMUD, Turlock Irrigation District ("TID") and Modesto to layoff its COTP and Tesla-Midway rights to TANC, and subsequently for TANC to layoff these rights to SMUD, TID and Modesto. During the 15-year initial term of the agreement and the subsequent five-year extension if so elected by the parties, SMUD, TID and Modesto will be responsible for all rights and obligations associated with this entitlement and with the TANC Agreement as specified in the layoff agreement. For the same period, SMUD and TID will assume all rights and obligations and costs associated with Roseville's Tesla-Midway Service rights.

NCPA Geysers Transmission Project. In order to meet certain obligations required of NCPA to secure transmission and other support services for the NCPA Geothermal Project, NCPA and its transmission project participants (including Roseville) undertook the "Geysers Transmission Project," which includes (a) an ownership interest in PG&E's 230 kV line from Castle Rock Junction in Sonoma County to the Lakeville Substation, (b) additional firm transmission rights in this line, and (c) a central dispatch facility (see "Dispatch and Scheduling" below). Roseville is entitled to a 14.18% share of the Geysers Transmission Project transfer capability, and is responsible for 14.18% of the costs of such project. For a description of the Geysers Transmission Project, see "OTHER NCPA PROJECTS" in the front part of this Official Statement.

Distribution

Roseville owns and operates the electrical distribution system serving retail customers within the City of Roseville boundaries. The distribution system is connected to the Western transmission system at the two connection points, the 230-kV Berry Street Receiving Station and the 230-kV Fiddyment Station. The distribution system consists of over 144 miles of overhead lines, over 664 miles of underground lines and 17 substations. Roseville performs continued maintenance on its distribution system to sustain service reliability.

Dispatch and Scheduling

Roseville contracts with ACES Power Marketing ("APM") to provide scheduling services and has discontinued its participation in the NCPA Power Pool. NCPA continues to dispatch the NCPA power plants to meet the schedules of energy delivery prepared and submitted by APM on Roseville's behalf. NCPA provides dispatch service from its dispatch control center located at its headquarters in Roseville.

Energy Efficiency and Conservation

California Assembly Bill 1890 and Assembly Bill 995 provides the framework for California's Public Benefits Program. AB 1890 did not specify an end date for publicly owned utilities, only IOUs. AB 995, Sections 385 and 399.8. section 399.8, subsection b2 specifies that publicly owned utilities must continue to fund public benefits programs. In general, based on a formula contained in the statute, publicly-owned utilities are required to fund the program through the use of a non-bypassable surcharge on all local distribution service in an amount no less than 2.85% of annual utility revenues.

Roseville has developed a full portfolio of public benefits programs since 2001, addressing the four areas of concentration required by State law: energy efficiency programs, renewable energy production, advanced electric technology demonstration and research and development, as well as low income assistance programs. Residential and commercial energy efficiency offerings include programs for both existing facilities and new construction.

In September of 2009, Roseville received $1.07 million dollars in economic stimulus funds from the American Recovery and Reinvestment Act of 2009 (ARRA). A portion of these funds were used to install a pilot LED (light emitting diode) streetlight program and conduct an energy audit of city facilities. The remaining funds (over $920,000) went directly to small businesses in the form of energy efficiency rebates. Virtually all of the economic stimulus funds received were allocated by June 2011.

Additionally, in 2010, Roseville revised the new residential construction incentive program to coincide with the implementation of new Title 24 building code requirements. This program provides incentives to builders who install solar systems and efficiency measures that exceed Title 24 requirements in new residential homes.

Under California Assembly Bill 2021, Roseville is required to develop ten year plans for energy efficiency goals and report on these goals to the California Energy Commission ("CEC") with updates every three years. The CEC has the obligation to develop energy efficiency goals for the entire State, after consultation with utilities and others. The Roseville electric system is participating in the State effort, and the Roseville City Council approved the current ten-year energy efficiency goals in May 2010. The goals will be reviewed again in 2013.

California Senate Bill 1037, signed into law in September 2005, established several important policies regarding energy efficiency. Among the many provisions of the law is a Statewide commitment to cost-effective and feasible energy efficiency, with the expectation that all utilities consider energy efficiency before investing in any other resources to meet growing demand. Roseville is required to report annually to its customers and to the CEC, its investment in energy efficiency and demand reduction programs. Roseville continues its commitment to energy efficiency and is in compliance with these requirements.

For a more detailed discussion of recent California legislation relating to the electric energy market, see "DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS—State Legislation" in the front part of this Official Statement.

Forecast of Capital Expenditures

Roseville's approved capital improvement plan for the electric system primarily encompasses improvements to and expansion of Roseville's electricity distribution system. As shown below, Roseville is forecasting electric system capital spending of approximately $41 million over the current and next four years.

Fiscal Year Ending June 30	Capital Improvement Projects
2011-12	$ 9,928,000
2012-13	11,809,000
2013-14	10,560,000
2014-15	4,440,000
2015-16	4,410,000
Total:	$41,147,000

Source: City of Roseville.

Roseville expects to fund the capital expenditures with revenues collected from rates and development fees.

Employees

General. As of December 31, 2011, there were approximately 129 City of Roseville employees working specifically in the Electric Department. Certain functions supporting the electric system operations, including meter reading, customer billing, collections and accounting, are performed by the Finance Department of the City.

The bulk of the non-management City personnel working at the Roseville electric system are represented by the International Brotherhood of Electrical Workers ("IBEW"). The last signed Memorandum of Understanding (MOU) with IBEW expired on December 31, 2010. The parties did not reach a negotiated agreement, and in July 2011, the Roseville City Council imposed their last, best offer upon the IBEW. The imposed agreement was binding until December 31, 2011. As of the date of this Official Statement, negotiations between the IBEW and the City of Roseville for a successor agreement are ongoing. There have been no strikes or other work stoppages at Roseville, including at the electric system.

Retirement Benefits. Retirement benefits to City employees, including those assigned to the electric system, are provided through the City's participation in the California Public Employees Retirement System ("CalPERS"), an agent multiple employer defined benefit pension plan which acts as a common investment and administrative agent for its participating member employers. CalPERS determines contribution requirements using a modification of the Entry Age Normal Method. CalPERS uses the market related value method of valuing the plan's assets. An investment rate of return of 7.75% is assumed, including inflation at 3.00%. Investment gains and losses are accumulated as they are realized and 10% of the net balance is amortized annually. CalPERS issues a separate comprehensive annual financial report. Copies of the CalPERS annual financial report may be obtained from the CalPERS Executive Office, 400 Q Street, Sacramento, California 95814.

Funding contributions are determined annually on an actuarial basis as of June 30 by CalPERS. Actuarially required contributions, as well as the annual pension costs for the fiscal years 2010-11, 2009-10 and 2008-09 amounted to $23,659,235, $27,377,992 and $25,847,110, respectively. The City paid 100% of the contributions required by CalPERS for each of such fiscal years. The budgeted contribution for fiscal year 2011-12 is $24,673,821. As of June 30, 2010 (the most recent actuarial information available), the Entry Age Actuarial Accrued Liability for the Miscellaneous Plan, in which City employees assigned to the electric system participate, was $367,490,532 and the Actuarial Value of Assets was $261,053,910, with an Unfunded Actuarial Accrued Liability of $106,436,622 (of which approximately 13.18% was allocable to the electric system), resulting in a funded ratio of 71.0%.

Other Post-Employment Benefits. The City also provides post-employment medical benefits ("OPEB benefits") to its employees, including those assigned to the electric system, under the City of Roseville Other Post Employment Benefit Plan, a sole employer defined benefit healthcare plan. The City is responsible for establishing and amending the funding policy of the plan. As of June 30, 2011, there were 520 participants receiving OPEB benefits under the plan. The annual required contribution (ARC) was determined as part of a June 30, 2009 actuarial valuation using the entry age normal actuarial cost method. The actuarial assumptions included (a) a 4.25% investment rate of return, (b) a 3.25% projected annual salary increase, (c) 3.00% of general inflation increase and (d) a healthcare trend of declining annual increases ranging from 8.40% to 9.30% in 2011 to 4.50% for years starting 2017. The actuarial methods and assumptions used include techniques that smooth the effects of short-term volatility in actuarial accrued liabilities and the actuarial value of assets. The City's OPEB unfunded actuarial accrued liability is being amortized as a level percentage of projected payroll, on a closed basis, using a 30-year amortization period with 28 years remaining. Contribution requirements of the postemployment benefit are based on pay-as-you-go financing. For the fiscal years 2010-11, 2009-10 and 2008-09, the City contributed 415% ($38,457,645), 22% ($3,839,236) and 17% ($3,292,355), respectively, of the Annual OPEB Cost based on an actuarially determined Annual OPEB Cost of $9,272,292, $17,851,892 and $19,170,038, respectively. The City's fiscal year 2010-11 contribution included $4,457,645 for pay-as-you-go premiums and a $34,000,000 million contribution to the Post Retirement Health/Insurance Fund (the "OPEB Fund"), established in 2002 to set aside monies for the long-term liability for OPEB Benefits. The electric system has been transferring 3% of its portion of the cost of salaries to the OPEB Fund since that time. As of June 30, 2009 (the most recent actuarial information available), the Entry Age Actuarial Accrued Liability for the OPEB plan was $180,097,000 and the Actuarial Value of Assets was $34,000,000, with an Unfunded Actuarial Accrued Liability of $146,097,000, resulting in a funded ratio of 18.88%. The City does not separately calculate the portion of the City's OPEB liability which is attributable to the electric system.

The City entered into an Investment Advisory Agreement with PFM Asset Management on July 21, 2010, for the purpose of developing an irrevocable retiree health trust and managing the assets of the trust on behalf of the City. The City started funding the trust in February 2011 with the initial transfer of $34 million described above. It is anticipated that the UAAL will decrease to an estimated level of $82 million due to increased projected future investment earnings on the amount in the trust.

Additional information regarding the City of Roseville's retirement plans and other post-employment benefits can be found in the City's comprehensive annual financial reports, which may be obtained at www.roseville.ca.us.

Rates and Charges

Rate Setting Procedure. Roseville has, by City Charter and State law, the exclusive jurisdiction to ordain electric rates within its service area. These rates are not subject to review by any State or federal agency. The City Council reviews electric system rates periodically and makes adjustments as necessary.

The City Council is also authorized by the City Charter to set charges, pay for and supply all electric energy and power to customers according to such schedules, tariffs, rules and regulations as are adopted by the City Council. The City Charter provides that the City Council shall have the power to charge equitable rates for the electric services furnished and for building up the electric properties so as to conserve their value and increase their capacity as needed by Roseville. In addition, the City Charter provides for the maintenance of the electric funds for the electric system into which is deposited receipts from the operations of the electric system and from which are payable the costs and expenses of the electric system.

Service Charges and Demand Charge as of January 1, 2012. Roseville's monthly residential electric rates currently include a $10.00 basic service charge, $0.005 per kWh environmental compliance charge, plus $0.1083 per kWh consumed up to 500 kWh, $0.1541 per kWh consumed from 501-1000 kWh, and $0.1756 per kWh for consumption in excess of 1000 kWh.

For small and medium business customers, the monthly basic service charge ranges from $15.50 to $42.00, $0.005 per kWh environmental compliance charge, plus $0.1174 to $0.1121 per kWh consumed. Medium business customers are also subject to a demand charge of $4.48/KW-month.

For large business customers, the monthly basic service charge is $315.00, the environmental compliance charge is $0.005 per kWh; and depending on the season, day and hour, time of use energy charges vary from $0.0715 to $0.1418 per kWh. Large business customers are also subject to a seasonal demand charge of $3.28/KW-month in winter and $11.32/KW-month in summer.

For very large business customers, the monthly basic service charge is $380.00, the environmental compliance charge is $0.005 per kWh; and depending on the season, day and hour, time of use energy charges vary from $0.0695 to $0.1375 per kWh. Very large business customers are also subject to a seasonal demand charge of $ 3.18/KW-month in winter and $10.96/KW-month in summer.

A hydroelectric adjustment formula was adopted by the City Council in March 2009, to reflect deviations of precipitation from average conditions that significantly change hydroelectric production. This surcharge may change annually, based on annual hydroelectric conditions, and may range from a minimum of 1% to a maximum of 5% of total electric charges. In years when the adjustment formula results in a surcharge below 1%, no surcharge is implemented. As a result of high precipitation levels in 2010 and 2011, there is no surcharge in effect from July 2010 through June 2012.

Additionally, some large non-residential customers are eligible for a 2.0% rate discount when energy is delivered at primary service (as defined in the Roseville Municipal Code).

Recent History of Electric Rate Adjustments. From 2005 through 2011, Roseville's retail electric rates have increased an average of approximately 5.3% annually. Following is Roseville's recent rate change history:

- 2010-2011 adopted rates - on October 7, 2009, the City Council adopted three 6.2% rate increases for all customers, effective January 2010, July 2010, and January 2011.
- July 2009 – Implementation of automatic hydroelectric adjustment formula that determines the surcharge based on precipitation levels and market price for replacement energy. The flat monthly climate mitigation charge was changed to an energy based charge in kWh.

- February 2008 – two rate increases of 6.0% for all customers, effective February 2008 and February 2009 combined with a monthly climate change mitigation charge of $4.00 for residential and small commercial, and $25.00 for medium and large commercial users, effective February 2008.
- July 2007 – rate increase of 6.0% for all customers.
- July 2006 – rate increase of 5.0% for all customers.
- April 2005 – rate increase of 5.0% for all customers.

Additionally, on May 8, 1996, the City Council adopted Resolution No. 96-148, which provides for, among other policies, the establishment of a Rate Stabilization Fund, in order to remain competitive under industry-wide restructuring of the electric industry. Such policies also provide for the recovery of capital costs of Roseville's electric generating assets. On March 18, 2009 the City Council reviewed the financial policy that defines the range of the Rate Stabilization Fund balance, reducing the minimum balance from 60% to 40% of operating expenses. This action was taken in conjunction with the implementation of a rate adjustment mechanism that adjusts electric rates up to 5% without further City Council action when hydroelectric conditions increase or decrease electric operating expenses. The Rate Stabilization Fund had a balance of approximately $30.9 million as of June 30, 2011.

Customer Base

Between Fiscal Years 2007 and 2011, the electric system's customer base increased by almost 2.0% per year. During the same time, population growth increased about 3.0% each year. Residential and commercial growth continues, but at a slower pace than previous years. The City has added almost 4,500 new residential units over the past five years. Recent commercial growth includes the Fountains Lifestyle Center, South Placer Justice Center, and expansion of The Galleria at Roseville regional mall. Both Kaiser Hospital and Sutter Medical Center have also expanded. Residential growth includes over 2,000 new residences associated with approved projects anticipated to be constructed over the next five years. Additionally, the City has recently approved the proposed Sierra Vista annexation project, which includes 2,064 acres with 6,650 residential units and a projected start date in 2014. The City is also processing the Creekview Specific Plan, a 501 acre project that includes 2,011 residential units, and the 660 acre Amoruso Ranch Specific Plan that includes 2,785 residential units. The City anticipates that the effect of the annexation and expected increase in operating expenses needed to meet the increased electricity requirement on the electric system would be offset by increases in revenues.

Largest Customers

As of June 30, 2011, the ten largest customers of Roseville's electric system in terms of kWh sales accounted for 26.58% of total kWh sales and 20.76% of revenues. The largest customer accounted for 9.40% of total kWh sales and 7.18% of total revenues. The smallest of the ten largest customers accounted for 0.88% of total kWh sales and 0.81% of revenues.

Customers, Sales, Revenues and Demand

The average number of customers, kWh sales, revenues derived from sales by classification of service and peak demand during the past five fiscal years, is listed below.

CITY OF ROSEVILLE
ELECTRIC DEPARTMENT
CUSTOMERS, SALES, REVENUES AND DEMAND[(1)]

	Fiscal Year Ended June 30,				
	2007	2008	2009	2010	2011
Number of Customers:					
Residential	43,793	44,662	45,478	46,400	47,021
Commercial	5,950	6,200	6,349	6,411	6,436
Total	49,742	50,862	51,827	52,811	53,457
MWh Deliveries Average:					
Residential	435,922	434,093	435,036	433,494	422,949
Commercial	797,144	812,606	798,537	774,618	742,613
Total MWh sales	1,233,066	1,246,699	1,233,574	1,208,112[(3)]	1,165,859[(3)]
Revenues ($ in 000s):					
Residential	$ 44,302	$ 48,188	$ 52,359	$ 56,115	$ 60,941
Commercial	65,566	72,770	76,413	80,097	85,570
Total Revenues from Sale of Energy	$109,868	$120,959	$128,772	$136,212	$146,511
Peak Demand (MW)	344.0	338.4	335.7	323.7	331.4

(1) Columns may not add to totals due to rounding. Revenues listed are as billed.
(2) Commercial MWh sales declines in 2010 and 2011 primarily due to economy-related reductions in the large and medium commercial classes. Residential MWh sales declines in 2010 and 2011 primarily due to mild weather and the economy.

Source: City of Roseville.

Indebtedness

As of December 1, 2011, Roseville had outstanding approximately $254.8 million principal amount of certificates of participation and refunding revenue bonds (the "Outstanding Electric System Certificates and Bonds") that were executed and delivered to finance and refinance improvements to the electric system. The Outstanding Electric System Certificates and Bonds are payable from certain payments to be made by Roseville under an installment purchase contract (the "Installment Purchase Contract"), the payments under which are payable from and secured by the Net Revenues of the electric system ("Net Revenues" are defined generally as revenues of the electric system less the maintenance and operation costs of the electric system during any 12-month period). These obligations are subordinate to the payments required to be made with respect to Roseville's obligations to NCPA and TANC described below.

As previously discussed, Roseville participates in certain joint powers agencies, including NCPA and TANC. Obligations of Roseville under its agreements with NCPA and TANC constitute operating expenses of Roseville payable prior to any of the payments required to be made on Roseville's Outstanding Electric System Certificates. The agreements with NCPA and TANC are on a "take-or-pay" basis, which requires payments to be made whether or not projects are operable, or whether output from such projects is suspended, interrupted or terminated. Certain of these agreements contain "step up" provisions obligating Roseville to pay a share of the obligations of a defaulting participant and granting Roseville a corresponding increased entitlement to electricity (generally, Roseville's "step-up" obligation is limited to 25% of Roseville's scheduled payments on such obligations). Roseville's participation and share of debt service obligation (without giving effect to any "step-up" provisions) for each of the joint powers agency projects in which it participates are shown in the following table.

CITY OF ROSEVILLE
ELECTRIC DEPARTMENT
OUTSTANDING DEBT OF JOINT POWERS AGENCIES[1]
(Dollar Amounts in Millions)
(As of December 1, 2011)

	Outstanding Debt[2]	Roseville Participation[3]	Roseville Share of Outstanding Debt[2]
NCPA			
Geothermal Project	$ 33.8	7.88%	$ 2.7
Hydroelectric Project	440.8	12.00[4]	52.9
Capital Facilities Project	55.1	36.50	20.1
TANC			
Bonds	396.7	0.0[5]	0.0[5]
TOTAL*	$926.4		$75.7

(1) Excludes Roseville Natural Gas Financing Authority. See "Natural Gas Prepayment" above.
(2) Principal only. Does not include obligation for payment of interest on such debt.
(3) Participation based on actual debt service obligation. Participation obligation is subject to increase upon default of another project participant. Such increase shall not exceed, without written consent of a non-defaulting participant, an accumulated maximum of 25% of such non-defaulting participant's original participation.
(4) Roseville's actual payments represent approximately 9.9% of outstanding debt service as a result of credit received by it as a non-participating member with respect to portion of debt obligation.
(5) Roseville has laid off its COTP obligations to other TANC Members for an initial fifteen-year term. See "Transmission—TANC California-Oregon Transmission Project" above.

Source: City of Roseville.

A portion of the joint powers agency debt obligations are variable rate debt, liquidity support for which is provided through liquidity arrangements with banks. Unreimbursed draws under liquidity arrangements supporting joint powers agency variable rate debt obligations bear interest at a maximum rate substantially in excess of the current interest rates on such obligations. Moreover, in certain circumstances, the failure to reimburse draws on the liquidity agreements may result in the acceleration of scheduled payment of the principal of such variable rate joint powers agency obligations. In connection with certain of such joint powers agency obligations, the respective joint powers agency has entered into interest rate swap agreements relating thereto for the purposes of substantially fixing the interest cost with respect thereto. There is no guarantee that the floating rate payable to the respective joint powers agency pursuant to each of the interest rate swap agreements relating thereto will match the variable interest rate on the associated variable rate joint powers agency debt obligations to which the respective interest rate swap agreement relates at all times or at any time. Under certain circumstances, the swap providers may be obligated to make payments to the applicable joint powers agency under their respective interest rate swap agreement that is less than the interest due on the associated variable rate joint powers agency debt obligations to which such interest rate swap agreement relates. In such event, such insufficiency will be payable as a debt service obligation from the obligated joint powers agency members (a corresponding amount of which proportionate to its debt service obligations to such joint powers agency could be due from Roseville). In addition, under certain circumstances, each of the swap agreements is subject to early termination, in which event the joint powers agency could be obligated to make a substantial payment to the applicable swap provider (a corresponding amount of which proportionate to its debt service obligations to such joint powers agency could be due from Roseville).

Service Area

The largest employers in Roseville as of June 30, 2011 are as follows:

CITY OF ROSEVILLE
LARGEST EMPLOYERS
(As of June 30, 2011)

Employer	Business	Number of Employees
Kaiser Permanente	Health Care	4,430
Hewlett-Packard	Technology	3,200
Sutter Roseville Medical Center	Health Care	1,654
Roseville Joint Union High School District	Education	1,299
City of Roseville	Government	1,230
Union Pacific Railroad	Railroad	1,118
Roseville Elementary School District	Education	929
Wal-Mart (2 stores)	Retail	790
PRIDE Industries	Employment Service	661
Telefunken (formerly NEC)	Technology	640

Source: City of Roseville.

The five-year history of new construction permits in Roseville is as follows:

CITY OF ROSEVILLE
BUILDING PERMITS
For Calendar Years 2007-2011

	2007	2008	2009	2010	2011
Residential Valuation (in thousands)(1)					
Single Family	$233,673	$155,072	$125,257	$133,206	$91,310
Multifamily	10,045	25,534	3,747	0	0
TOTAL	$243,718	$180,606	$129,004	$133,206	$91,310
New Dwelling Units					
Single Family	1,050	676	602	635	411
Multiple Family	103	308	49	0	0
TOTAL	1,153	984	651	635	411

(1) Does not include residential alterations.
Source: Construction Industry Research Board.

The five-year history of assessed valuations of taxable property in Roseville is as follows:

CITY OF ROSEVILLE
TOTAL ASSESSED VALUATIONS
(Fiscal Year)
(Dollar Amounts in Thousands)

2007-08	2008-09	2009-10	2010-11	2011-12
$17,127,441	$16,691,780	$15,508,581	$14,773,035	$14,955,658

Source: City of Roseville and Placer County Assessor.

Shown below is certain population data for the City of Roseville, the County of Placer and the State of California:

CITY OF ROSEVILLE, COUNTY OF PLACER,
STATE OF CALIFORNIA POPULATION
(1970-2000 as of April 1; 2007-2011 as of January 1)

	City of Roseville	County of Placer	State of California
1970	18,221	77,632	19,971,069
1980	24,347	117,247	23,668,562
1990	45,189	175,290	29,760,021
2000	79,921	252,343	34,095,209
2007	107,097	330,195	37,655,193
2008	109,496	338,967	38,155,534
2009	112,826	344,871	38,476,724
2010	118,233	347,133	37,223,900
2011	120,593	352,380	37,510,766

Source: U.S. Bureau of Census and California State Department of Finance.

Litigation

There is no action, suit or proceeding known to be pending or threatened, restraining or enjoining Roseville in the execution or delivery of, or in any way contesting or affecting the validity of any proceedings of Roseville taken with respect to the Third Phase Agreement.

There is no litigation pending, or to the knowledge of Roseville, threatened, questioning the existence of Roseville, or the title of the officers of Roseville to their respective offices. There is no litigation pending, or to the knowledge of Roseville, threatened, questioning or affecting in any material respect the financial condition of Roseville's electric system.

Present lawsuits and other claims against Roseville's electric system are incidental to the ordinary course of operations of the electric system and are largely covered by Roseville's self-insurance program. In the opinion of Roseville's management and the Roseville City Attorney, such claims and litigation will not have a materially adverse effect upon the financial position of Roseville.

Financial Information

Audited Financial Statements. Roseville's most recent Annual Financial Report for fiscal year 2010-11 was audited by Maze & Associates, Walnut Creek, California, in accordance with generally accepted auditing standards. The audited financial statements contain opinions that the financial statements present fairly the financial position of the various funds maintained by Roseville. The reports include certain notes to the financial statements which may not be fully described below. Such notes constitute an integral part of the audited financial statements. Copies of these reports are available on request from the Roseville Clerk, City of Roseville, 311 Vernon Street, Roseville, California 95678.

Significant Accounting Policies. Governmental accounting systems are organized and operated on a fund basis. A fund is defined as an independent fiscal and accounting entity with a self-balancing set of accounts recording cash and other financial resources, together with all related liabilities and residual equities or balances, and changes therein. Funds are segregated for the purpose of carrying on specific activities or attaining certain objectives in accordance with special regulations, restrictions or limitations.

The electric system is accounted for as an enterprise fund. Enterprise funds are used to account for operations (i) that are financed and operated in a manner similar to private business enterprises (where the intent of the governing body is that the costs (expenses, including depreciation) of providing goods or services to the general public on a continuing basis be financed or recovered primarily through user charges) or (ii) where the governing body has decided that periodic determination of revenues earned, expenses incurred and/or net income is appropriate for capital maintenance, public policy, management control, accountability or other purposes.

The Roseville Electric Fund uses the accrual method of accounting. Revenues are recognized when they are earned and their expenses are recognized when they are incurred.

Investments are stated at cost. Inventories are valued at weighted average method. Capital assets are recorded at historical costs. Donated fixed assets are valued at their estimated fair market value on the date donated.

Historic Revenues, Expenses and Debt Service Coverage

The following table presents a five-year summary of the revenues, expenses, and debt service coverage for Roseville's Electric Fund for Fiscal Years 2007 through 2011. The table also includes a five-year history of balances in the Rate Stabilization Fund as reflected on the City's internal accounting records, and calculates debt service coverage both with and without taking into account the Rate Stabilization Fund balance.

The table below as it is presented is not available in the City's audited financial statements for the Electric System; it has been designed to reflect revenues and coverage in a manner which meets GAAP standards and is reflective of the definitions of revenues and maintenance and operation costs as defined in the Installment Purchase Contract relating to Roseville's Outstanding Electric System Certificates and Bonds. The figures shown in the table are accounted for in the City's audited financial statements (for fiscal years 2006-07 through 2010-11) but the presentation in the audited financial statements may not necessarily correlate to the line item designations in the table.

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK.]

CITY OF ROSEVILLE
ELECTRIC FUND
STATEMENT OF REVENUES AND EXPENSES
Fiscal Years 2006-07 through 2010-11
(Dollar Amounts in Thousands)

	2006-07	2007-08	2008-09	2009-10	2010-11
Revenues					
Charges for Services	$111,715	$120,668	$130,046	$137,661	$146,734
Sale of Wholesale Power	17,248	20,734	22,798	22,798	11,436
Other	1,301	2,498	2,999	2,857	5,065
Total Revenues	**$130,264**	**$143,900**	**$155,843**	**$163,488**	**$163,035**
Operating Expenses					
Power Supply[1]	$102,414	$120,802	$119,050	$124,791	$103,999
Distribution and Administration	16,792	17,790	17,221	16,164	14,184
Indirect Costs and Transfers[2]	7,800	8,327	9,166	8,493	8,252
Total Operating Expenses	**$127,006**	**$146,919**	**$145,436**	**$149,448**	**$126,435**
Net Revenue	$ 3,258	$ (3,019)	$ 10,407	$ 14,040	$ 36,600
Debt Service	$ 4,157	$ 11,784	$ 15,709	$ 14,608	$ 16,310
Adjusted Net Revenue					
Net Revenue	$ 3,258	$ (3,019)	$ 10,407	$ 14,040	$ 36,600
Operating Transfers and Other Expense (net) [3]	7,276	14,347	15,737	13,595	0
Interest Revenue (excluding unrealized gain/loss)	3,649	3,809	3,493	1,065	3,055
Adjusted Net Revenue	**$ 14,183**	**$ 15,137**	**$ 29,637**	**$ 28,700**	**$ 39,655**
Debt Service Coverage ratio	3.41	1.28	1.89	1.96	2.43
Rate Stabilization Fund Balance	$ 67,118	$ 52,799	$ 40,943	$ 24,215	$ 30,917
Debt Service Coverage ratio including Rate Stabilization Fund[4]	19.56	5.77	4.49	3.62	4.32

(1) Decrease in power supply costs in Fiscal Year 2011 is due to lower retail sales, above average hydro conditions and reduction in wholesale power expense.
(2) Represents payments to the City as reimbursement for the electric system's share of certain overhead expenses such as information technology, meter reading, retired employees' health costs, human resources, etc.
(3) Represents transfers from Rate Stabilization Fund to offset increasing energy costs and mitigate rate impacts, and transfers for rehabilitation projects. Fiscal Year 2006-07 includes transfer from the General Operating Reserve ("GOR") managed by NCPA.
(4) Funds on deposit in the Rate Stabilization Fund may be included in adjusted annual revenues for purposes of determining compliance with the City rate covenant pursuant to documents under which the Outstanding Electric System Certificates and Bonds were issued.

Source: City of Roseville

CITY OF SANTA CLARA

Introduction

The City of Santa Clara ("Santa Clara") is a charter city located in the State of California. Pursuant to its charter, Santa Clara has the power to furnish electric utility service within its service area. In connection therewith, Santa Clara has the powers of eminent domain, to contract, to construct works, to fix rates and charges for commodities or services it provides and to incur indebtedness.

Santa Clara provides electric utility service through its electric utility department. Santa Clara offers its electricity and energy services through the trademarked name of "Silicon Valley Power." In addition, Santa Clara provides other city services to its inhabitants, including police and fire protection, and water and sewer service.

The legal responsibilities and powers of Santa Clara, including the establishment of rates and charges for electric service, are exercised by the seven-member Santa Clara City Council. The members of Santa Clara City Council are elected city-wide for staggered four year terms. The Santa Clara electric utility department is under the direction of the Director of Electric Utility who, together with certain other senior managers of the electric utility department, is appointed by and reports to the Santa Clara City Manager.

Since 1896, Santa Clara has provided all electric service within an area coterminous with the City of Santa Clara's boundaries. As of January 1, 2011, Santa Clara had an estimated population of 118,169. For the fiscal year ended June 30, 2011, Santa Clara served an average of 52,495 customers per month, had total sales of 2,821 GWh and a peak demand of 471.4 MW. In fiscal year 2010-11, approximately 91% of Santa Clara's energy sales were made to commercial and industrial customers.

To provide electric service within its service area, Santa Clara owns and operates an electric system which includes generation, transmission and distribution facilities. Santa Clara also purchases power and transmission services from other providers and participates in other utility type arrangements.

Only the revenues of the Santa Clara electric utility department will be available to pay amounts owed by Santa Clara under the Third Phase Agreement.

The Santa Clara electric utility department's main office is located at Santa Clara City Hall, 1500 Warburton Avenue, Santa Clara, California 95050, (408) 261-5292. A copy of the most recent annual report of the Santa Clara electric utility fund (the "Annual Report") may be obtained from John C. Roukema, Director of Electric Utility, at the above address and telephone number, and is also available on Santa Clara's website at www.siliconvalleypower.com. The Annual Report is incorporated herein by this reference. However, the information presented on such website or referenced therein other than the Annual Report is not part of this Official Statement, is not incorporated by reference herein.

Power Supply Resources

The following table sets forth information concerning Santa Clara's power supply resources and the energy supplied by each during the fiscal year ended June 30, 2011.

CITY OF SANTA CLARA
ELECTRIC UTILITY DEPARTMENT
POWER SUPPLY RESOURCES*
(For the Fiscal Year Ended June 30, 2011)

Source	Capacity Available (MW)	Recorded Energy (GWh)	Percent of Total Energy
City-Owned Generating Facilities(1)			
Cogeneration	7.0	44.2	1.5%
Stony Creek Hydro System	11.6	33.3	1.1
Gianera Generating Station	49.5	0.0	0.0
Grizzly Project	17.7	57.3	1.9
Don Von Raesfeld Power Plant	147.8	427.6	14.5
Purchased Power:(2)			
Western(3)	136.0	297.0	10.1
Altamont Wind	17.1	25.2	0.9
G2 (Landfill)	1.6	9.3	0.3
Ameresco (Landfill)	0.5	4.9	0.2
Market Purchases	50.0	692.4	23.5
Joint Power Agencies:			
NCPA			
Geothermal Project	71.7	354.0	12.0
Combustion Turbine Project	30.9	0.3	0.0
Hydroelectric Project	93.7	304.8	10.3
M-S-R PPA			
San Juan	51.0	393.0(4)	13.3
Big Horn I Wind Energy	105.0	276.0	9.4
Big Horn II Wind Energy	17.5	31.1	1.0
Total	808.6	2,950.3	100.0%

* Columns may not add to totals due to rounding.
(1) Rated or name-plate capacities.
(2) Capacity Available from Purchased Power resources represents entitlements, firm allocations and contract amounts.
(3) Santa Clara purchased varying amounts of capacity from Western during the year.
(4) Figures represent energy delivered to Santa Clara net of sales to market.
Source: City of Santa Clara.

Generating Facilities

Cogeneration. Santa Clara owns and operates a cogeneration plant which began operation in 1981. The cogeneration plant provides steam for sale to a paperboard plant in Santa Clara and delivers power to Santa Clara's electric distribution system. Santa Clara upgraded this plant to obtain a new name-plate rating of 7.4 MW, effective July 1995. Fuel for the cogeneration plant (natural gas) is generally acquired under term contracts at prices fixed for the contract term.

Stony Creek Hydroelectric System. Santa Clara owns and operates three hydroelectric plants consisting of (i) a 4.9 MW hydroelectric generating plant located at the United States Bureau of Reclamation Stony Gorge Dam near Willows, California, which was completed in 1985, (ii) a 6.2 MW hydroelectric generating plant located at the United States Army Corps of Engineers' Black Butte Dam near Orland, California, which was completed in late

1988, and (iii) a 0.53 MW hydroelectric generating plant located at the Orland Unit Water Users' Association High Line Canal/South Side Canal drop near the Black Butte dam, which was completed in late 1988.

Gianera Generating Station. Santa Clara owns and operates a nominal 49.9 MW dual fuel (natural gas and fuel-oil) combustion turbine generating plant consisting of two 25 MW units, which were completed in 1986 and 1987, respectively. This generation station is used to help meet Santa Clara's peak load and resource adequacy requirements.

PG&E Grizzly Project. Pursuant to a 1990 settlement agreement with Pacific Gas and Electric Company ("PG&E"), Santa Clara agreed to finance and own 100% of a 20 MW hydroelectric facility (the "Grizzly Project") located on Grizzly Creek above the North Fork of the Feather River in Plumas County, California. The Grizzly Project operates in combination with the hydroelectric facilities of PG&E's Bucks Creek project. Pursuant to the settlement agreement, Santa Clara became a joint licensee in PG&E's Bucks Creek project. The construction of the Grizzly Project was financed (and refinanced) through the issuance by Santa Clara of electric system revenue bonds. Pursuant to the settlement agreement, PG&E constructed and operates the Grizzly Project, which was placed into operation in November 1993.

Until the date Santa Clara's ownership of the Grizzly Project is terminated (as described below), Santa Clara will own and receive all energy generated by the Grizzly Project, less transmission losses, as described in the settlement agreement (which reflects a contract capacity amount of 17.66 MW).

The Grizzly Project facilities include a tunnel intake structure, surge tank, steel penstock, powerhouse, turbine, transmission line (nominally rated at 115 kV) for interconnection with PG&E's transmission system and certain additional switchyard equipment and related facilities. Annual energy generation of the Grizzly Project is estimated at 57.3 GWh in an average water year and 26.1 GWh in dry years. For the fiscal year ended June 30, 2011, the Grizzly Project generated 57.3 GWh of energy.

Pursuant to the settlement agreement, Santa Clara's interest in the Grizzly Project may revert to PG&E under certain limited circumstances. In the event of such reversion, Santa Clara will be reimbursed by PG&E for the fair market value of the project or be reimbursed for costs advanced by Santa Clara as provided in the settlement agreement. The earliest possible reverter date under the settlement agreement is November 18, 2027.

Don Von Raesfeld Power Plant. Santa Clara constructed and placed into commercial operation on March 22, 2005, a 122 MW nominal/147 MW peak, natural gas-fired, combined cycle power plant known as the "Don Von Raesfeld Power Plant" (initially designated by the Santa Clara City Council as the Pico Power Plant). The Don Von Raesfeld Power Plant is located in an industrial area of the City of Santa Clara, on the site of Santa Clara's Kifer Receiving Station. The Don Von Raesfeld Power Plant includes its own switchyard, and connects to an existing 115 kV transmission line that currently crosses the plant site. Natural gas for the Don Von Raesfeld Power Plant is delivered through an approximately two mile gas pipeline from the local transmission main of PG&E. For the fiscal year ended June 30, 2011, the Don Von Raesfeld Power Plant generated 427.6 GWh of energy. Santa Clara has long-term agreements with Shell Energy North America and M-S-R Energy Authority (see "Joint Powers Agency Resources–*M-S-R Energy Authority–Gas Prepay*" below) in place for a significant portion of the plant's fuel requirements, and actively manages the quantity and price risks associated with fuel supply quantities not under long-term agreement. Fully baseloaded, the Don Von Raesfeld Power Plant could generate approximately 1,000 GWh of energy per year. However, Santa Clara substitutes market purchases when it is economical to do so.

Joint Powers Agency Resources

NCPA Geothermal Project. Santa Clara has purchased from NCPA, pursuant to power sales contracts, 54.65% and 34.13% entitlement shares, respectively, in the capacity of NCPA's Geothermal Project Plant 1 and Plant 2, and is obligated to pay 44.39% of the debt service and operating costs associated with such plants and steam field. Santa Clara is currently taking delivery of its share of the capacity and associated energy from the Geothermal Project. For the fiscal year ended June 30, 2011, Santa Clara received 354.0 GWh of electric energy from the Geothermal Project. Santa Clara's share of the current California Independent System Operator ("ISO") maximum rated capacity of the project is 71.7 MW.

Santa Clara has a 55 MW share in NCPA's Geysers Transmission Project, which provides a link from the Geysers to PG&E's bulk transmission system. Through a long-term contract with the California Department of Water Resources ("CDWR"), sufficient additional transmission capability on the same line is available for the balance of Santa Clara's share of the capacity and energy produced by the NCPA Geothermal Project. Santa Clara obtains additional transmission services to Santa Clara for its share of the output of NCPA Geothermal Project from arrangements with PG&E and the ISO.

NCPA Combustion Turbine Project No. 1. Santa Clara has purchased a 25% entitlement share in NCPA's Combustion Turbine Project No. 1 pursuant to a power sales contract with NCPA, which has recently been amended to reflect that Santa Clara's 25% share comes specifically from the two Alameda plants and the one Lodi plant. Santa Clara uses this entitlement for resource adequacy purposes and to meet peak load requirements. Santa Clara delivers this entitlement to its electric system in accordance with ISO tariffs. For the fiscal year ended June 30, 2011, Santa Clara received 301 MWh of electric energy from the Combustion Turbine Project No. 1.

NCPA Hydroelectric Project. Pursuant to a power sales contract, Santa Clara has purchased from NCPA a 37.02% entitlement share in NCPA's Hydroelectric Project (including a 1.16% entitlement share laid off to Santa Clara from the cities of Biggs and Gridley). Santa Clara is using this entitlement to serve peak load and to provide capacity to support non-firm purchases of energy at market prices. For the fiscal year ended June 30, 2011, Santa Clara received 304.8 GWh of electric energy from the NCPA Hydroelectric Project. Santa Clara receives this entitlement to its system by using transmission service available under its Metered Subsystem Agreement ("MSS Agreement") with the ISO.

For a description of such NCPA resources, see "THE HYDROELECTRIC PROJECT" and "OTHER NCPA PROJECTS" in the front part of this Official Statement. See also "Indebtedness" below.

TANC California–Oregon Transmission Project. Santa Clara is a member of the Transmission Agency of Northern California ("TANC") and has executed the TANC Agreement for a participation percentage of TANC's entitlement of COTP transfer capability. Santa Clara participated in the acquisition of an increased share of transfer capability of the COTP in connection with the acquisition by TANC in April 2008 of the COTP transmission assets (approximately 121 MW) of the City of Vernon, California ("Vernon"), one of the original owners of the COTP. TANC utilized a combination of cash and the issuance of commercial paper (which was subsequently refunded with bonds) to fund the acquisition of Vernon's COTP transmission assets (the "Vernon acquisition debt"). Santa Clara, as well as the other acquiring TANC members, began scheduling the acquired COTP transmission transfer capability on April 8, 2008. Pursuant to the TANC Agreement, Santa Clara is obligated to pay 20.47% of TANC's COTP operating and maintenance expenses and 20.70% of TANC's COTP debt service and 22.16% of the Vernon acquisition debt. Santa Clara is entitled to 20.4745% of TANC's share of COTP transfer capability (approximately 278 MW net of third party layoffs of TANC) on an unconditional take-or-pay basis. Santa Clara's share of annual operating and maintenance expenses and debt service for the COTP through TANC is approximately $12 million per year. Santa Clara's payment to TANC, including debt service on TANC's revenue bonds, constitute an operating expense of the electric system. Santa Clara is using a portion of its share of the project transfer capability of the COTP to provide transmission of energy generated from the Big Horn Projects and Santa Clara's share of the SCL-NCPA Exchange Agreement (described below under "Purchased Power"). Santa Clara also participates with other TANC members in offering unused and unencumbered transfer capability for use by other entities in an open and efficient manner in accordance with TANC posted tariffs. The costs and operation of the COTP are impacted by various FERC proceedings. Santa Clara management does not believe any of these proceedings are material to its operations or its operating performance. See "CITY OF ALAMEDA–Joint Powers Agency Resources–*TANC California-Oregon Transmission Project*" for a further description of the COTP and the TANC Agreement.

TANC Tesla–Midway Transmission Service. TANC and certain TANC members have arranged for PG&E to provide TANC and its members with 300 MW of firm bi-directional transmission capacity on its transmission system between its Midway Substation near Buttonwillow, California, and its Tesla Substation near Tracy, California, near the southern physical terminus of the COTP (the "Tesla Midway Transmission Service") under an agreement known as the South of Tesla Principles. Santa Clara's share of Tesla–Midway Transmission Service is 81 MW. Santa Clara has utilized its full allocation of Tesla–Midway Transmission Service for firm and non-firm power transactions. See "CITY OF ALAMEDA–Joint Powers Agency Resources–*TANC Tesla-Midway Transmission Service*" for a further description of the Tesla-Midway Transmission Service.

Santa Clara anticipates continuing to use its share of the TANC Tesla–Midway Transmission Service to provide access to power supplies located in the southwest, including delivery of power and energy from the San Juan Unit No. 4. See "*–M-S-R PPA Purchased Power–San Juan*" below. Santa Clara has agreed with SMUD to lay off 30 MW of its capacity of the Tesla-Midway Transmission Service, for the period beginning January 1, 2009 and going through June 30, 2013, to more closely align its service with that needed for the delivery of energy from San Juan Unit No. 4. The layoff will allow Santa Clara to procure more Congestion Revenue Rights in the ISO allocation process thus allowing Santa Clara to more effectively hedge congestion exposure under the ISO Market Redesign and Technology Upgrade (MRTU).

M-S-R PPA Purchased Power–San Juan. Santa Clara, along with the Modesto Irrigation District ("Modesto") and the City of Redding ("Redding"), is a member of a California joint powers agency known as the M-S-R Public Power Agency ("M-S-R PPA"). M-S-R PPA owns a 28.8% (approximately 146 MW) interest in the San Juan Unit No. 4 (the "M-S-R PPA San Juan Unit No. 4 Interest"). The San Juan Unit No. 4 is a coal-fired steam electric generating unit with a net generating capability of 507 MW, located in San Juan County, New Mexico, which was constructed and is operated by Public Service Company of New Mexico ("PNM"). The San Juan Unit No. 4 is one of four generating units that together make up the San Juan Generating Station. M-S-R PPA financed the acquisition of the M-S-R PPA San Juan Unit No. 4 Interest through the issuance of revenue bonds. See "Indebtedness" below.

Santa Clara has purchased from M-S-R PPA a 35% entitlement share in the M-S-R PPA San Juan Unit No. 4 Interest pursuant to a power sales agreement (the "M-S-R PPA Agreement"), which includes approximately 51.1 MW of capacity and associated energy from the M-S-R PPA San Juan Unit No. 4 Interest. Pursuant to the M-S-R PPA Agreement, Santa Clara, in exchange for its above-mentioned percentage purchased, is unconditionally obligated to pay its share of all of M-S-R PPA's costs associated with M-S-R PPA San Juan Unit No. 4 Interest, including debt service on revenue bonds which were issued to finance the acquisition of the M-S-R PPA San Juan Unit No. 4 Interest, and subject to a "step up" obligation of up to 25% upon the unremedied default of another M-S-R PPA participant.

Santa Clara uses its M-S-R PPA San Juan Unit No. 4 Interest capacity and energy to serve in its own system or for short-term layoffs to others based upon monthly economic dispatch considerations. M-S-R PPA obtains firm transmission to transmit to the M-S-R PPA members the capacity and energy of the M-S-R PPA San Juan Unit No. 4 Interest through firm transmission service agreements executed with Los Angeles Department of Water and Power ("LADWP") and Southern California Edison Company ("Edison") and via the M-S-R PPA Southwest Transmission Project (described below). For the fiscal year ended June 30, 2011, Santa Clara received 393.0 GWh of energy from the M-S-R PPA San Juan Unit No. 4 Interest.

In connection with the cap-and-trade program adopted by the California Air Resources Board pursuant to Assembly Bill 32 ("AB 32") to reduce greenhouse gas emissions, M-S-R PPA members will be required to account for carbon emissions of the M-S-R PPA San Juan Unit No. 4 Interest and provide off-setting allowances thereto for any electricity delivered to California. See "DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS–State Legislation–*Greenhouse Gas Emissions*" in the front part of this Official Statement.

There are various ongoing litigation proceedings (to which Santa Clara is not a party) relating to the San Juan Generating Station, including (i) a suit filed by the Sierra Club under the Resources Conservation and Recovery Act (the "RCRA") alleging that activities at the San Juan Generating Station and the San Juan mine that supplies coal to the generating station are causing imminent and substantial harm to the environment, including to ground and surface waters in the region, and the placement of coal combustion byproducts at the San Juan Mine constitute "Open Dumping" in violation of RCRA, and (ii) proceedings relating to the development of a federal implementation plan and/or state implementation plan, pursuant to the federal Clean Air Act (the "Clean Air Act") rules, to address regional haze and improve visibility in the region where the San Juan Generating Station is located. The Environmental Protection Agency (the "EPA") issued a federal implementation plan which became effective on September 21, 2011, although it is the subject of ongoing litigation. As adopted, the federal implementation plan will require the installation of additional pollution control equipment at the San Juan Generating Station, the costs of which would be significant. Although PNM is challenging the EPA's federal implementation plan, the plan contains a five-year compliance deadline which requires PNM to take immediate steps to commence the installation of the required improvements, which involve a large construction project requiring extensive advance planning. PNM expects to issue a request for proposals to prospective bidders for the installation of the required additional pollution control equipment in the near term. While Santa Clara is unable to predict the final outcome of any of these proceedings, Santa Clara management does not believe any of these proceedings will materially adversely affect its electric system operations or operating performance. However, as noted above, the costs of installation of additional pollution control equipment in accordance with the adopted federal implementation plan are substantial. PNM has, with the assistance of a leading engineering firm, further refined the conceptual design and cost estimates for the installation of selective catalytic reduction technology at the entire San Juan Generating Station as required by the adopted federal implementation plan. The current estimate for such construction is in the range of approximately $749 million to $897 million (exclusive of Allowance for Funds Used During Construction, which is estimated at approximately $38 million to approximately $45 million). M-S-R's share of such costs is estimated to not exceed $85 million (exclusive of Allowance for Funds Used During Construction), which costs would be the responsibility of the M-S-R PPA Participants in accordance with their respective participation percentage amounts.

M-S-R PPA Southwest Transmission Project. The Southwest Transmission Project consists of M-S-R PPA's acquisition of an interest in a 500 kV alternating current transmission project between the central Arizona area and the Los Angeles basin and certain other transmission facilities and arrangements to provide for the delivery of power and energy from the San Juan Unit No. 4 Interest to the M-S-R PPA members' systems in Northern California. Under the M-S-R PPA Agreement, Santa Clara is unconditionally obligated for 35% of the costs of the M-S-R PPA Southwest Transmission Project, subject to certain step up provisions. Transmission service from the Midway Substation to Santa Clara's electric system is provided by the TANC Tesla–Midway Service. See "*–TANC Tesla–Midway Transmission Service*" above. M-S-R PPA financed the acquisition of the Southwest Transmission Project through the issuance of San Juan Project revenue bonds. See "Indebtedness" below.

M-S-R PPA Purchased Power–Big Horn Projects. In 2005, M-S-R PPA entered into a series of power purchase agreements with Iberdrola Renewables, Inc. (formerly PPM Energy, Inc.) ("Iberdrola"), certain of which agreements have been assigned to Iberdrola's subsidiary, Big Horn I, LLC., for the purchase of energy from the Big Horn wind energy project (the "Big Horn I Project") located near the town of Bickleton, in Klickitat County, Washington. Santa Clara receives 52.5% of the power purchased by M-S-R PPA from the Big Horn I Project. Santa Clara's share equates to approximately a 105 MW share of the output at a cost comparable to combined cycle gas-fuel generation. Power deliveries commenced on October 1, 2006 and will continue through September 30, 2026. For the fiscal year ended June 30, 2011, Santa Clara received 276.0 GWh of energy from the Big Horn I Project. Santa Clara uses a portion of its transfer capability of the COTP to provide for transmission of the output from the Big Horn I Project from the California-Oregon border.

More recently, M-S-R PPA negotiated a 25-year agreement with Iberdrola for the purchase of the output from a 50 MW expansion of the Big Horn I Project, the Big Horn II Project. Santa Clara receives 35% of the output from this project, or approximately 17.5 MW of project capacity. Santa Clara began receiving deliveries from the Big Horn II Project in November 2010. For the fiscal year ended June 30, 2011, Santa Clara received 31.1 GWh of energy from the Big Horn II Project.

M-S-R Energy Authority – Gas Prepay. In 2009, Santa Clara participated in the M-S-R Energy Authority ("M-S-R EA") Gas Prepay Project. The Gas Prepay Project provides, through a Gas Supply Agreement between M-S-R EA and Santa Clara, for a secure and long-term supply of natural gas of 7,500 MMBtu daily (or 2,730,500 MMBtu annually) through December 31, 2012, and 12,500 MMBtu daily (or 4,562,500 MMBtu annually) thereafter until September 30, 2039. The Gas Supply Agreement provides this supply at a discounted price below the monthly market index price (the PG&E Citygate index) over the 30 year term. M-S-R EA entered into a prepaid gas purchase agreement with Citigroup Energy, Inc. ("CEI") to provide this gas supply, and issued $500.2 million of its Gas Project Revenue Bonds to finance the prepayment for Santa Clara. Under the terms of the Gas Supply Agreement, M-S-R EA will bill Santa Clara for actual quantities of natural gas delivered each month on a "take-and-pay" basis. Moreover, any default by CEI or the other participants in M-S-R EA's Gas Prepay Project, Modesto and Redding, is non-recourse to Santa Clara.

Purchased Power

Western Purchased Power. On December 14, 2000, Santa Clara signed a 20-year agreement with Western Area Power Administration ("Western") for the continued purchase of low-cost hydroelectricity from the Central

Valley Project ("CVP"), replacing a prior agreement which expired December 31, 2004. The CVP, for which Western serves as marketing agency, is a series of federal hydroelectric facilities in Northern California operated by the United States Bureau of Reclamation. Service under the successor agreement began on January 1, 2005 and continues through December 31, 2025, with Santa Clara receiving a 9.06592% "slice of the system" allocation from Western. The power marketed by Western to Santa Clara is provided on a take-or-pay basis where Western's annual costs are allocated to preference customers based on their CVP participation percentage. Western then allocates the annual take-or-pay charges to the preference customers based on a monthly percentage that is designed to reflect the anticipated seasonal energy deliveries. Santa Clara is obligated to its preference customer share (9.06592%) of the costs associated with operating the CVP facilities. Under the successor agreement, Santa Clara's energy allocation dropped from pre-2005 levels of approximately 1,257 GWh to about 359 GWh per year delivered to Santa Clara based upon the hydrology of the CVP. For the fiscal year ended June 30, 2011, Santa Clara received 297.0 GWh of energy from Western. Santa Clara's Don Von Raesfeld power project, which commenced operation on March 22, 2005, was designed, in part, to offset the expected decrease in energy to be received from Western under the successor agreement beginning in 2005. See "Generating Facilities–*Don Von Raesfeld Power Plant*" above.

AES Seawest Purchased Power–Altamont Wind Project. In 2006, Santa Clara and AES Seawest Inc. entered into five-year land lease and power purchase agreements, whereby AES Seawest Inc. rents 691 acres in the Altamont area of Alameda County from Santa Clara and sells wind power generated on the rented land to Santa Clara. The AES Seawest Inc. arrangement adds approximately 1% of eligible renewable energy to Santa Clara's annual power mix. The windplant achieved commercial operation on May 3, 2007. AES Seawest Inc. operates and maintains the windplant facility which includes 200 small wind turbines (of which approximately 178 are operational), approximately 100 kW each. Santa Clara acts as the Scheduling Coordinator for the facility and schedules the output from the facility into the ISO Participating Intermittent Resource Program, and the resulting energy is then traded to the NCPA Scheduling Coordinator portfolio which serves Santa Clara's load. For the fiscal year ended June 30, 2011, Santa Clara received 25.2 GWh of energy from the Altamont Wind Project. The AES Seawest Inc. power purchase agreements were originally scheduled to terminate in 2011. Santa Clara recently negotiated an extension of the arrangement with AES Seawest Inc. to July 31, 2016.

Seattle City Light ("SCL") NCPA Exchange Agreement. In 2008, Santa Clara took over a share of the SCL-NCPA Exchange Agreement from certain other NCPA members. As a result, Santa Clara receives 32.6 MW from SCL during the months of June through October each year, and is obligated to provide 25 MW to SCL from December through mid-April each year. See "OTHER NCPA PROJECTS–Power Purchase and Other Contracts" in the front part of this Official Statement.

G-2 Energy LLC – Wheatland Landfill. Santa Clara entered into a power purchase agreement for, and began taking delivery of energy in January 2009 from, a 1.6 MW landfill gas facility, G2, near Wheatland, California. For the fiscal year ended June 30, 2011, Santa Clara received 9.3 GWh of energy from the G2 project.

Ameresco. On May 25, 2010, Santa Clara entered into a 20-year power purchase agreement with Ameresco for landfill gas generated electricity for up to 9.2 MW from the Forward landfill in Manteca, California. On August 17, 2010, Santa Clara entered into a second 20-year power purchase agreement with Ameresco for landfill gas generated electricity for up to 5 MW from the Vasco Road landfill near Livermore, California. Both of these facilities are expected to be operational in June 2012.

Recurrent. On July 14, 2011, Santa Clara entered into a 25-year power purchase agreement for the entire output from the RE Rosamond One LLC project, a 20 net MW solar photovoltaic-powered project in Kern County, California, which is expected to start power deliveries at the end of 2013.

Future Power Supply Resources

Lodi Energy Center. Through NCPA, Santa Clara is participating in the Lodi Energy Center project currently being undertaken by NCPA. Santa Clara's participation share (approximately 72 MW) in the NCPA Lodi Energy Center will displace wholesale purchases at market prices with a cost-based resource. See "OTHER NCPA PROJECTS–Lodi Energy Center Project" in the front part of this Official Statement. The capacity and energy from the Lodi Energy Center are expected to provide an efficient and cost-effective power supply that will also complement Santa Clara's existing hydroelectric and renewable resources.

Other Resources. Santa Clara's current resources are anticipated to provide Santa Clara with sufficient capacity reserves. In addition to its participation in the Lodi Energy Center Project, Santa Clara will generally meet additional long-term energy and capacity needs through long-term agreements with creditworthy energy providers, or through participation in other power supply projects, as required. Santa Clara is also pursuing power purchase agreements with several other renewable energy projects, including a small hydroelectric project and a wind energy project. Santa Clara, along with NCPA, is also exploring a small landfill gas project. Together, these projects could result in approximately 44 MW gross of additional project capacity for Santa Clara. Santa Clara will continue to use portfolio and risk management strategies to manage its performance. See "Wholesale Power Trading" below.

Wholesale Power Trading

For a number of years, Santa Clara has used its energy and transmission resources together with its power scheduling capabilities to buy and sell energy in the western North American market. As deregulation unfolded, a greater need to manage resources on a day-to-day basis evolved, resulting in a more comprehensive approach to trading operations at Santa Clara. The principal reason for wholesale power trading is to optimize the value of the utility's assets and cost-effectively serve its retail load. For fiscal years ended June 30, 2007, 2008, 2009, 2010 and 2011 net trading revenues (wholesale power sales revenues less wholesale power purchase costs) were approximately $7.6 million, $(5.6) million, $(8.4) million, $(5.9) million and $(0.7) million, respectively. The results in fiscal years 2007-08 through 2009-10 are primarily related to wholesale purchases intended for retail use that, due to recorded sales falling short of those forecasted and generation from lower costs resources subsequently becoming available, were sold back to the market at prices lower than the original purchase prices. As prices for natural gas have continued to decline, since their peak in mid-2008, additional long-term gas supply contracts have been entered into by SVP. The blending of prices with existing term gas prices will ultimately result in lower production costs for SVP gas fired resources and should provide greater market opportunities for these resources beginning in fiscal year 2010-11 and beyond.

The Santa Clara City Council has approved a Risk Management Policy to provide policy guidance with respect to its wholesale power activities. In addition, Santa Clara has implemented procedures and regulations pursuant thereto (referred to collectively with the Risk Management Policy as the "Policy and Procedures") that are designed to establish the parameters under which trading operations may occur. The Policy and Procedures are intended to: (a) provide a common risk management infrastructure to facilitate management control and reporting; (b) create a procedure to evaluate the creditworthiness of the counterparties, and to monitor and manage the aggregate credit exposure; (c) establish a corporate culture exemplifying best practices in risk management; (d) create a mechanism to identify market-related opportunities within Santa Clara's overall exposure balance or "book" and opportunities to internalize related transactions; and (e) develop an effective, streamlined ability to timely commit to transactions. The Policy and Procedures also establish a Risk Oversight Committee (composed of the Santa Clara City Manager, the Director of Finance, the Director of Electric Utility and the Santa Clara City Attorney) and a Risk Management Committee, to oversee all proposed power purchase agreements, whether for retail or wholesale purposes.

Pursuant to the Policy and Procedures guidelines, Santa Clara has established regulations approved by the Risk Oversight Committee to govern the various functions of its trading operations. The guidelines establish, among other things, acceptable counterparty creditworthiness standards and requirements for limits on credit exposure to any individual counterparty. Most of the purchase and sale transactions entered into by the power trading operation are for 92 days or less.

Renewable Energy and Energy Efficiency

A significant portion of the energy received by Santa Clara customers comes from renewable energy. Santa Clara's power mix in calendar year 2010 consisted of 25% eligible renewable resources. When large hydroelectric resources are included, Santa Clara's power mix consisted of 41% renewable and large hydroelectric. On December 6, 2011, the Santa Clara City Council adopted revisions to Santa Clara's Environmental Stewardship and Renewable Portfolio Standard (RPS) Policy Statement, and adopted a new RPS Enforcement Program, to conform with the standards and timetable set forth in SBX1 2, signed by the Governor on April 12, 2011. Essentially, the revised policy expands Santa Clara's commitment to renewable energy by targeting 33% of Santa Clara's energy needs to be served by renewable resources (not including "large hydro") by 2020. See

"DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS–State Legislation–*Renewable Portfolio Standards*" in the front part of this Official Statement.

Santa Clara's energy efficiency programs are separated into residential and business programs, with the majority of funding toward its largest customer segment - the business sector. Total Public Benefits Charge funds are about $8 million per year. Residential programs include rate assistance for low-income customers, energy efficiency rebates (refrigerators, whole house fans, solar attic fans, attic insulation, and variable speed pool pumps), solar electric installations, energy audits, and programs for schools and libraries. Business programs include energy audits, installation management for small companies, rebates for a wide variety of equipment (lighting, air conditioning systems, chillers, programmable thermostats, washing machines, motors, new construction, photovoltaic systems and customized installations), and design and construction assistance. Over 272 million kilowatt hours in cumulative "first year" savings have been achieved since 1998.

Interconnections, Transmission and Distribution Facilities

Santa Clara's service area is surrounded by a portion of PG&E's service area and the two systems are interconnected at two Santa Clara-owned 115 kV receiving stations – Northern Receiving Station ("NRS") and Kifer Receiving Station ("KRS"), each located within Santa Clara's city limits. In addition, Santa Clara has a 230 kV interconnection with PG&E at PG&E's Los Esteros Substation ("LES") in the City of San Jose. Power received at LES is transmitted by Santa Clara approximately six miles to NRS. Santa Clara owns facilities for the distribution of electric power within its city limits (approximately 19.3 square miles), which includes approximately 29 miles of 60 kV power lines, approximately 510 miles of 12 kV distribution lines (approximately 64% of which are underground), and 24 stations. Santa Clara's electric system experiences approximately 0.5 to 1.5 hours of outage time per customer per year. This compares favorably with other utilities in California with reliability factors ranging from 1.0 to 2.5 hours outage per customer per year.

Historically, PG&E provided interconnection, partial power and other support services to Santa Clara under an interconnection agreement. Beginning March 31, 1998, the operation of the transmission facilities owned by California's investor-owned utilities, including PG&E, was undertaken by the ISO. In July 2002, FERC approved a series of agreements between Santa Clara, PG&E, the ISO and NCPA (which acts as scheduling coordinator for Santa Clara) to replace the Santa Clara's interconnection agreement with PG&E and to allow Santa Clara to operate within the ISO control area.

To the extent Santa Clara requires transmission/ancillary/power services beyond those contained in other remaining existing contracts or from Santa Clara's own generating resources, Santa Clara will procure such transmission/ancillary/power services from the ISO or via the ISO's markets.

Santa Clara is unable to predict how future industry changes, especially those concerning resource adequacy requirements, renewable fuels, greenhouse gas limitations and new transmission facilities to serve potential renewable energy projects, will affect future costs for the purchase of services under its interconnection, scheduling and ISO agreements.

Employees

As of June 30, 2011, Santa Clara had approximately 132 budgeted employees for its electric utility department. All of these electric utility department employees are represented either by the International Brotherhood of Electrical Workers ("IBEW") or one of the other Santa Clara employees' associations, in matters pertaining to wages, benefits and working conditions. The current labor agreements with the employee associations expire on various dates from December 22, 2012 to December 21, 2013. The current agreement with the IBEW expires on December 22, 2012. There have been no strikes or other union work stoppages at the City of Santa Clara, including its electric utility department.

City of Santa Clara's permanent employees, including those in the electric utility department, are covered by the Miscellaneous Plan public agency contract between the City of Santa Clara and the California Public Employees Retirement System ("CalPERS"). The cost of the pension is funded through bi-weekly contributions from employees and from employer contributions by the City of Santa Clara. The City of Santa Clara has funded the fiscal year 2010-11 actuarially required contribution (which totaled $20,485,589 for both Miscellaneous Plan and Safety Plan members for the fiscal year ended June 30, 2011), of which $2,613,617 was funded by the electric utility department. As of June 30, 2010 (the latest date for which actuarial information is available), the total actuarial accrued liability for the City of Santa Clara was $481,425,499 for the Miscellaneous Plan, the actuarial value of plan assets was $357,508,407, and the City of Santa Clara had an unfunded liability of $123,917,092, representing a funded ratio of 74.3%. The portion of the plan's assets allocable to the electric utility department employees, which is part of the City of Santa Clara's liability pool, has not been separately calculated.

The actuarial value of plan assets is determined utilizing a smoothing technique in order to dampen the effect of short term market value fluctuations on employer contribution rates. Under the smoothing technique, an expected value of assets is computed by bringing forth the prior year's actuarial value of assets and the contributions received and benefits paid during the year at the assumed actuarial rate of return. The actuarial value of assets is then computed as the expected value of assets plus 1/15th of the difference between the market value of assets and the expected value of assets as of the valuation date. In no case will the actuarial value of assets be less than 60% or more than 140% of the actual market value of assets. As of June 30, 2010, the market value of the plan assets (with receivables) was $279,537,438 (representing a funded status based on market valuation of 58.1%).

CalPERS issues a separate comprehensive annual financial report. Copies of the CalPERS annual financial report may be obtained from the CalPERS Executive Office, 400 Q Street, Sacramento, California 95814.

In addition, the City of Santa Clara provides certain post-employment benefits other than pensions (OPEB) to city employees, including those assigned to the electric utility department, who retire from the City of Santa Clara, through a single-employer defined benefit program established by the Santa Clara City Council in fiscal year 2007-08 which provides reimbursements to retirees for certain qualified expenses, subject to certain annual maximum reimbursement amounts. In fiscal year 2007-08, the City of Santa Clara established an irrevocable exclusive single-employer benefit trust which is administered by Public Agency Retirement Services. The City of Santa Clara has funded the fiscal year 2010-11 actuarially required contribution. Its contribution for fiscal year 2010-11 was $2,149,000, of which approximately $299,484 was funded by the electric utility. As of June 30, 2010 (the latest date for which actuarial information is available), the total actuarial accrued liability for the City of Santa Clara was $30,886,000, the actuarial value of plan assets was $7,031,000, and the City of Santa Clara had an unfunded liability of $23,855,000, representing a funded ratio of 22.8%.

Additional information regarding the City of Santa Clara's retirement plans and other post-employment benefits can be found in the City of Santa Clara's comprehensive annual financial reports, which may be obtained at http://www.santaclaraca.gov.

Rates and Charges

The Santa Clara City Council is authorized by the City Code of the City of Santa Clara to set charges, pay for and supply all electric energy and power to be furnished to customers according to such schedules, tariffs, rules and regulations as are adopted by the Santa Clara City Council. The authority of Santa Clara to impose and collect rates and charges for electric power and energy is not subject to the regulatory jurisdiction of the California Public Utilities Commission (the "CPUC") or any other regulatory authority. For the calendar years 2001-2005, Santa Clara rates were unchanged and averaged 7.8 cents per kWh. In December 2005, the City Council adopted a 5% rate increase effective January 2006, and a further 5% increase effective July 2006. The primary reason for this increase was the rise in cost and use of fuel for electric generation, combined with a significant reduction in energy available from Western. For calendar year 2007, Santa Clara maintained rates at year-end 2006 levels. Santa Clara was able to avoid a rate increase due to its significant cash reserves, which are permitted to be included in satisfying its rate covenants to its bondholders. On December 4, 2007, the Santa Clara City Council approved a rate increase of 3% in January 2008 and 3% in January 2009. On December 8, 2009, the Santa Clara City Council approved a rate increase of 7% in January 2010 and 7% in January 2011. See "Cash Reserves" below.

Largest Customers

The ten largest customers of Santa Clara's electric utility department, in terms of kWh sales for the fiscal year ended June 30, 2011 accounted for 36.6% of total kWh sales and 32.4% of revenues. Santa Clara is heavily dependent upon its industrial customers, which comprise approximately 87% of its load and 86% of its revenues (in fiscal year 2010-11). For reference, Santa Clara's industrial category includes all customers using more than 8,000 kWh per month. For many years, Santa Clara has been home to a number of the world's best known "high tech" firms involved in the design and production of computers and software. In the past few years, some of these firms have shifted production away from Santa Clara; however, this shift has been more than offset by the development of numerous data centers established to serve the data needs of corporate offices and of internet-related businesses.

To help retain its industrial customers, and thus assure the stability of Santa Clara's electric sales and revenue, Santa Clara has entered into power purchase contracts with a number of its largest customers. Currently, twelve customers, representing approximately 34% of Santa Clara's electric utility load and approximately 30% of annual sales revenues, are under contract. The contracts have varied terms, with expirations ranging from 2011 through 2014. No existing customer contract has a term exceeding five years.

Customers, Energy Sales, Revenues and Demand

The average number of customers, kWh sales and revenues derived from sales, by classification of service, and peak demand during the past five fiscal years, are listed below.

CITY OF SANTA CLARA
ELECTRIC UTILITY DEPARTMENT
CUSTOMERS, SALES, REVENUES AND DEMAND
(Fiscal Year Ended June 30)

	2007	2008	2009	2010	2011
Number of Customers:					
Residential	42,759	43,182	43,618	43,989	44,086
Commercial	5,867	5,862	5,900	5,957	6,030
Industrial	1,932	1,931	1,916	1,860	1,820
Other	553	558	559	558	559
Total	51,111	51,533	51,993	52,364	52,495
Kilowatt-hour Sales (000):					
Residential	243,747	246,115	245,884	247,202	242,431
Commercial	87,960	85,396	84,526	84,660	87,830
Industrial	2,455,735	2,481,277	2,492,849	2,411,087	2,470,311
Other	21,076	22,556	22,363	21,247	20,467
Total	2,808,518	2,835,344	2,845,622	2,764,196	2,821,039
Charges from Sale of Energy (000)(1):					
Residential	$ 21,063	$ 21,682	$ 22,270	$ 23,418	$ 24,572
Commercial	10,752	10,612	10,788	11,265	12,474
Industrial	200,332	205,753	215,688	222,071	245,356
Other	2,031	2,130	2,192	2,206	2,195
Total(2)	$234,178	$240,177	$250,938	$258,960	$284,597
Peak Demand (MW)	486.5	479.6	489.9	459.8	471.4

(1) Differs from Operating Revenues in Financial Operating Results and Balance Sheet information due to: (i) timing differences in accruals and billings; and (ii) exclusion of non-consumption based revenues.
(2) Includes public benefits charge and grid management charge revenues.
Source: Santa Clara.

Capital Requirements

Santa Clara expects net capital requirements for the current and next four fiscal years to aggregate up to $86 million. Such improvements include distribution system improvements and replacements of approximately $50 million, including several new distribution substations and significant upgrades to its internal bulk distribution loops and distribution feeders. These distribution facilities are needed to meet increased capacity requirements of new and existing customers. They are expected to be financed through a combination of load development fees, funds from Santa Clara's available cash reserves, and electric revenues.

Indebtedness

Electric Revenue Bonds. As of December 1, 2011, Santa Clara had outstanding electric revenue bonds in the aggregate principal amount of $217.665 million, payable from net revenues of the electric system. Such outstanding electric revenue bonds are comprised of $80.295 million aggregate principal amount of outstanding Electric Revenue Bonds, Series 2003 A, $82.540 million aggregate principal amount of outstanding Electric Revenue Refunding Bonds, Series 2008 B (the "Series 2008 B Bonds") and $54.830 million aggregate principal amount of Electric Revenue Refunding Bonds, Series 2011 A. The Series 2008 B Bonds are variable rate obligations secured by a letter of credit. The letter of credit for the Series 2008 B Bonds has been provided by Bank of America, N.A. and has a scheduled expiration date of May 12, 2014. Santa Clara has entered into a reimbursement agreement with Bank of America, N.A., pursuant to which it is obligated to repay the bank for amounts drawn under the letter of credit. The interest rate payable by Santa Clara for unreimbursed draws under the letters of credit may be considerably higher than the interest rate on the bonds. While Santa Clara may attempt in such event to refinance the bonds to avoid this additional debt burden, there can be no assurance that Santa Clara will have access to the debt markets. Prior to the issuance of the Series 2008 B Bonds, Santa Clara entered into an interest rate swap agreement (the "Swap Agreement") with Bear Stearns Capital Markets Inc., which agreement has been novated to JPMorgan Chase Bank, N.A. (the "Swap Provider"). Under the Swap Agreement, Santa Clara is obligated to make payments to the Swap Provider calculated on the basis of a fixed rate of 3.470% while it is to receive from the Swap Provider payments based upon 65% of the one month London InterBank Offering Rate. Santa Clara's obligation to make any net regularly scheduled payments due to the Swap Provider under the Swap Agreement is payable from net revenues of the electric system on a parity with its other outstanding subordinated electric bonds. Under certain circumstances, the Swap Agreement may be terminated and Santa Clara may be required to make a termination payment to the Swap Provider. Any such termination payment owed by Santa Clara would be payable from net revenues of the electric system subordinate to Santa Clara's outstanding electric revenue bonds.

Joint Powers Agency Obligations. As previously discussed, Santa Clara participates in several joint powers agencies, including TANC, NCPA and M-S-R PPA, which have issued indebtedness to finance the costs of certain projects on behalf of their respective project participants. Obligations of Santa Clara under its agreements with respect to TANC, NCPA and M-S-R PPA constitute operating expenses of Santa Clara's electric system payable prior to any of the payments required to be made on Santa Clara's electric revenue bonds described above. Agreements with TANC, NCPA and M-S-R PPA are on a "take-or-pay" basis, which requires payments to be made whether or not projects are completed or operable, or whether output from such projects is suspended, interrupted or terminated. Certain of these agreements contain "step-up" provisions obligating Santa Clara to pay a share of the obligations of a defaulting participant. As described herein, Santa Clara also participates in M-S-R EA and has certain payment obligation in connection therewith which constitute operating expenses of Santa Clara's electric system. However, Santa Clara's payment obligation to M-S-R EA is with respect to actual quantity of natural gas delivered each month on a take-and-pay (rather than take-or-pay) basis. Responsibility for bond repayment is non-recourse to Santa Clara. See "Joint Powers Agency Resources–*M-S-R Energy Authority–Gas Prepay*" above.

Santa Clara's participation and share of debt service obligation (without giving effect to any "step-up" provisions) for the TANC, NCPA and M-S-R PPA projects in which it participates are shown in the following table.

CITY OF SANTA CLARA
ELECTRIC UTILITY DEPARTMENT
OUTSTANDING DEBT OF JOINT POWERS AGENCIES
(as of December 1, 2011)
(Dollar Amounts in Millions)

	Outstanding Debt(1)	Santa Clara Participation(2)	Santa Clara Share of Outstanding Debt(1)
M-S-R PPA			
San Juan Unit No. 4	$ 303.3	35.00%	$106.2
Southwest Transmission Project	34.0	35.00	11.9
NCPA			
Geothermal	33.8	44.39	15.0
Calaveras Hydroelectric Project	440.8	37.02(3)	163.2
Lodi Energy Center, Issue One	255.0	46.16	117.7
TANC			
Bonds	396.7	20.84(4)	82.8
TOTAL*	$1,463.6		$496.8

* Columns may not add to totals due to independent rounding.
(1) Principal only. Does not include obligation for payment of interest on such debt. Excludes M-S-R EA as described above.
(2) Participation based on actual debt service obligation. Participation obligation is subject to increase upon default of another Participant. Such increase shall not exceed, without written consent of a non-defaulting participant, an accumulated maximum of 25% of such non-defaulting participant's original participation.
(3) Includes 1.16% additional share purchased from other NCPA participants.
(4) As described herein, Santa Clara's actual obligation differs slightly from this percentage due to varying shares of certain series of TANC bonds relating to each TANC member-participant's taxable portion and each TANC member-participant's participation or non-participation in acquisition of assets from Vernon.
Source: City of Santa Clara Electric Utility Department.

For the fiscal year ended June 30, 2011, Santa Clara's obligation for debt service on its joint powers agency aggregated obligations was approximately $37.4 million. Debt service on joint powers agency obligations is expected to range in each fiscal year through 2039-40 from a high of approximately $54.3 million to a low of approximately $7.9 million. This projection assumes that there are no future debt issuances, that swap counterparties on interest rate hedges continue to perform (all of Santa Clara's variable rate joint powers agency debt obligations are hedged). Santa Clara manages the total amount of variable rate debt exposure for its electric utility (including both direct and joint powers agency debt), and, by policy, has targeted up to approximately 25% as the appropriate variable rate exposure. Unreimbursed draws under liquidity arrangements supporting joint powers agency variable rate debt obligations bear interest at a maximum rate substantially in excess of the current interest rates on such variable rate debt obligations. Moreover, in certain circumstances, the failure to reimburse draws on the liquidity agreements may result in the acceleration of scheduled payment of the principal of such variable rate joint powers agency obligations. In connection with certain of such joint power agency obligations, the respective joint powers agency has entered into interest rate swap agreements relating thereto for the purposes of substantially fixing the interest cost with respect thereto. There is no guarantee that the floating rate payable to the respective joint powers agency pursuant to each of the interest rate swap agreements relating thereto will match the variable interest rate on the associated variable rate joint powers agency debt obligations to which the respective interest rate swap agreement relates at all times or at any time. Under certain circumstances, the swap providers may be obligated to make payments to the applicable joint powers agency under their respective interest rate swap agreement that is less than the interest due on the associated variable rate joint powers agency debt obligations to which such interest rate swap agreement relates. In such event, such insufficiency will be payable from the obligated joint powers agency members (a corresponding amount of which proportionate to its debt service obligations to such joint powers agency could be due from Santa Clara). In addition, under certain circumstances, each of the swap agreements is subject to early termination, in which event the joint powers agency could be obligated to make a substantial payment to the applicable swap provider (a corresponding amount of which proportionate to its debt service obligations to such joint powers agency could be due from Santa Clara).

Transfers to the General Fund

The Santa Clara City Charter provides that up to 5% of gross revenues (not including revenues from wholesale transactions) from the electric utility is paid to the City General Fund each year as a contribution in lieu of taxes.

The following table sets out the transfers from the electric utility to the City General Fund for the last five fiscal years.

CITY OF SANTA CLARA
ELECTRIC UTILITY DEPARTMENT
TRANSFERS TO THE GENERAL FUND
(Dollar Amounts in Thousands)

Fiscal Year	Transfer Amount
2006-07	$12,856
2007-08	12,724
2008-09	13,037
2009-10	13,448
2010-11	14,913

Source: City of Santa Clara.

Cash Reserves

Santa Clara maintains cash reserves for a number of reasons, including operating cash requirements, construction cash requirements, dealing with the cost impacts of dry hydroelectric conditions, gas and electric market volatility, and allowing Santa Clara the flexibility to increase rates on a scheduled basis. The Cost Reduction Fund is used to manage the cost impacts of dry year hydroelectric conditions and gas and electric market volatility, as well as the scheduling of rate increases. As of June 30, 2010, there was approximately $84.2 million in the Cost Reduction Fund. As of December 31, 2010, the balance of the Cost Reduction Fund was transferred to the Rate Stabilization Fund (as a subaccount therein) as described below.

In addition to the Cost Reduction Fund, Santa Clara has maintained a Rate Stabilization Fund (the "Rate Stabilization Fund"). Amounts in the Rate Stabilization Fund are available to pay costs of the electric utility subject to certain terms and conditions. As of June 30, 2011, approximately $109.20 million was on deposit in the Rate Stabilization Fund (including approximately $84.2 million on deposit in the Cost Reduction Account therein). As noted above, as of December 31, 2010, the balance of the Cost Reduction Fund was transferred to the Rate Stabilization Fund (as a subaccount therein). Further, in fiscal year 2001-02, Santa Clara established a policy of maintaining an additional cash reserve in the minimum amount of $65 million in operating cash which is equal to approximately two months' retail and wholesale cash requirements. As of June 30, 2011, Santa Clara had unrestricted operating cash reserves of $67.0 million. In addition, as of such date, Santa Clara had $57.5 million of cash reserves designated for construction purposes. Thus, as of June 30, 2011, Santa Clara's electric utility had restricted and unrestricted cash reserves totaling approximately $233.8 million.

Collectively, these reserves are designed to help insulate Santa Clara from market volatility. In addition, Santa Clara's bond indenture permits (and prior to its discharge in 2007-08, its senior bond indenture permitted) the use of unrestricted cash balances and reserves (including, prior to December 31, 2010, the Cost Reduction Fund and the Rate Stabilization Fund, and subsequent to December 31, 2010, the Rate Stabilization Fund) to satisfy Santa Clara's rate covenants with its bond holders. In fiscal year 2006-07, the City Council authorized the use of $27.7 million of unrestricted cash balances and reserves, of which $20.7 million was for operating expenses and $7.0 million was for certain non-bond funded capital expenditures and improvements. In fiscal year 2007-08, the City

Council authorized the use of $67.4 million of unrestricted cash balances and reserves, including $11.2 million to pay for the redemption of Series 1985 A, B and C Bonds, $28.9 million for operating expenses and $27.3 million to pay for certain non-bond funded capital expenditures and improvements. The transfer to operating revenues for fiscal year 2007-08 was higher than originally anticipated due to dry year conditions because lower-cost hydroelectric generation had to be replaced with power from higher cost resources. In fiscal year 2008-09, the City Council authorized the use of $65.3 million of unrestricted cash balances and reserves, including $50.2 million for operating expenses and $15.1 million to pay for certain non-bond-funded capital extensions and improvements. The 2009-10 budget anticipated (after taking into account the projected additional revenue from the budgeted 7.0% rate increase for January 2010 as described below), and the City Council authorized, the use of a further $17.4 million of drawdown of unrestricted cash balances and reserves for operating expenses. For fiscal year 2010-11, Santa Clara did not make any withdrawals from the Rate Stabilization Fund (Cost Reduction Account) for operating expenses or non-bond funded capital expenditures and improvements in such fiscal year.

Santa Clara has determined that it is appropriate to use a portion of its unrestricted cash balances and reserves to stabilize or subsidize its electric rates in the near term and to increase rates when appropriate. In December 2007, the City Council adopted a 3% rate increase effective January 2008, and a 3% rate increase effective January 2009. These rate increases were designed to provide that operating revenues would better reflect then-current operating costs, near term capital requirements would be funded primarily from cash reserves, and the Cost Reduction Fund would remain above $120 million, which Santa Clara has determined to be a prudent minimum level. In the May 2008 Budget Study Sessions with City Council, and the June Budget Adoption Public Hearing, staff advised City Council that staff would return to City Council with recommendations for the year 2010 after a thorough review of the financial performance and statements of the electric utility for fiscal year 2007-08. Continuing dry year conditions in fiscal years 2007-08 and 2008-09 resulted in drawing down the Cost Reduction Fund (now a part of the Rate Stabilization Fund) below Santa Clara's $120 million minimum target as of June 30, 2009. This result confirmed the need for rate increases beginning in 2010. Santa Clara's adopted budget for the 2010-11 fiscal year reflected a 7% increase in January 2010 and a 7% increase in January 2011. These increases, totaling 14.5% on a cumulative basis, were projected to produce revenues sufficient to cover future operating expenses and to restore the Cost Reduction Account balance (now a part of the Rate Stabilization Fund) to the $120 million level by the end of the 2014-2015 fiscal year. The Santa Clara City Council approved both budgeted rate increases by resolution at its December 8, 2009 City Council meeting. See "Condensed Operating Results and Selected Balance Sheet Information" below and "Rates and Charges" above. It is important to note that the impact of such increase or increases could be affected by future operating conditions, including factors outside the control of Santa Clara.

The Santa Clara City Council and the Redevelopment Agency of the City of Santa Clara (the "Redevelopment Agency') are in the process of exploring the possibility of a "public-private partnership" in order to construct a football stadium in the vicinity of Great America Parkway and Tasman Drive in Santa Clara in connection with a potential relocation of the San Francisco 49ers professional football team to this site. On April 24, 2007, representatives of the San Francisco 49ers presented a stadium proposal to the Santa Clara City Council, the Redevelopment Agency, City staff and the public. In addition, the City of Santa Clara has retained consultants to undertake a review of the economic analysis presented by the San Francisco 49ers to support such a project. These activities have been widely reported in the local media. A retired senior member of the City management team and a former City Councilmember wrote a letter to the media suggesting that certain electric utility reserves maintained in the Cost Reduction Fund be used as a potential funding source for Santa Clara's contribution to a stadium project. In the opinion of the City Attorney of the City of Santa Clara, any such application of certain electric utility funds to various aspects of a stadium project would require an amendment to the City Charter approved by a majority vote of the electorate. On January 9, 2007, the City Council adopted "Guiding Principles for Use in the Evaluation of the Feasibility of a Proposed Stadium." These guiding principles included the principle to "Maintain integrity of all City funds per the City Charter (utility funds may only be used for utility purposes: electric, water and sewer)."

On February 9, 2010, the City Council approved a resolution calling and giving notice of a special municipal election to be held on Tuesday, June 8, 2010 for a vote on a voter-initiative ballot measure. Such voter-initiative passed and it establishes the requirements for any ground lease of City property for the proposed stadium project. In addition, an Environmental Impact Report for the proposed stadium project has been approved. On February 22, 2011, the City Council authorized the execution of a joint powers agreement with the Redevelopment Agency in order to authorize the creation of the Santa Clara Stadium Authority, which joint powers agency is expected to be the lessee of any City property for the proposed stadium project and potential owner of the proposed stadium facility. Santa Clara is unable to predict at this time whether any stadium project will proceed. To the extent the stadium project does proceed, it is not expected to be completed before 2015. In the event the stadium project does proceed, it is expected that, in connection with any such project, the electric utility will undertake the relocation of its Tasman substation, currently located near the proposed stadium site. The estimated cost of such substation relocation is approximately $20 million.

Service Area

The main businesses in Santa Clara are manufacturing and industrial. There are numerous companies that manufacture electronic components, communications equipment, computer systems, electronic games and similar products, and general items such as fiberglass, paper and chemicals. As shown in the following table, these firms are among the largest employers in Santa Clara as of June 30, 2011.

CITY OF SANTA CLARA
TEN LARGEST EMPLOYERS

Employer	Business	Number of Employees
Applied Materials, Inc.	Nano Technology Mfg Services	8,500
Intel Corporation	Semiconductor Devices (Mfg.)	7,001
National Semiconductor Corporation	Semiconductor Devices (Mfg.)	3,500
California's Great America	Amusement Park	2,500
Oracle (formerly Sun Microsystems)	Computer Related Services	1,600
EMC Corporation	Semiconductors	1,338
Santa Clara University	Higher Education	1,200
Macy's	Retail	1,200
ON Semiconductor Corporation	Semiconductor Devices (Mfg.)	1,100
BAE Systems Land & Armaments	Military Defense and Security	1,000

Source. City of Santa Clara.

A five-year history of building permits in Santa Clara is as follows:

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK.]

CITY OF SANTA CLARA
Building Permit Valuations
Calendar years 2007 through 2011
(In Thousands)

	2007	2008	2009	2010	2011
Residential Valuation					
Single Family	$19,258	$10,152	$ 1,010	$3,550	$7,472
Multi-Family	890	87,104	11,840	1,897	1,952
Total	$20,148	$97,256	$12,850	$5,447	$9,424
Non-Residential					
New Commercial	$ 1,832	$ 20,324	$ 6,375	$ 0	$ 21,435
New Industrial	0	40,797	0	22,000	61,100
Other	33,380	3,018	11,858	1,905	16,387
Alterations/Additions	210,966	137,625	81,011	165,315	140,946
Total	$246,178	$201,764	$99,244	$189,220	$239,868
New Dwelling Units					
Single Family	80	45	9	18	35
Multi-Family	5	492	60	15	127
Total	85	537	69	33	162

Source: Construction Industry Research Board.

Population

Shown below is certain population data for Santa Clara, the County of Santa Clara and the State of California:

CITY OF SANTA CLARA, COUNTY OF SANTA CLARA,
STATE OF CALIFORNIA POPULATION
(1970, 1980, 1990, 2000 as of April 1;
2006-2011 as of January 1)

	City of Santa Clara	County of Santa Clara	State of California
1970	86,118	1,065,313	19,971,069
1980	87,700	1,295,071	23,668,562
1990	93,613	1,497,577	29,760,021
2000	102,800	1,698,800	33,873,086
2006	111,019	1,776,586	37,114,598
2007	114,066	1,805,314	37,559,440
2008	115,503	1,837,075	38,049,462
2009	114,795	1,767,204	37,966,713
2010	116,308	1,781,427	37,223,500
2011	118,169	1,797,375	37,510,766

Sources: 1970, 1980, 1990 and 2000 figures from U.S. Bureau of Census. Other figures from California State Department of Finance.

Transportation and Educational Facilities

Santa Clara is served by the Bayshore Freeway (U.S. Highway 101), which runs southeast from San Francisco to Los Angeles and is the major freeway connecting San Francisco and San Jose; Interstate 880, which runs north/south connecting San Jose and Oakland and becomes State Highway 17 (south of Interstate 280) and continues into Santa Cruz with access to Monterey; and Interstate 280, which runs north/south to San Francisco and State Highway 82. These freeways link Santa Clara to all parts of northern California.

Air transportation is available at both the San Francisco International Airport, approximately 40 miles to the north, and the San Jose International Airport, 2 miles from downtown Santa Clara. Rail service is provided by Union Pacific Railroad, on a north/south track linking San Jose and San Francisco, and CalTrain commuter service to Gilroy and San Francisco. The Guadalupe Corridor Light Rail has 20 completed miles of track from the Santa Clara Convention Center to the San Jose Convention Center, stretching to South San Jose. Extensions are planned to Mountain View and Milpitas.

The Santa Clara Valley Transportation Authority operates several lines within the City of Santa Clara with connections to major cities in the San Francisco Bay area. Interstate bus service is available via Greyhound Bus and Peerless. Most major trucking firms serve Santa Clara in addition to numerous local carriers.

The Santa Clara Unified School District provides public schooling from kindergarten through high school in most of the City of Santa Clara. Small geographical areas in the southern city limits are served by the Campbell Union Elementary School District and the Cupertino Union Elementary School District.

Santa Clara is also the home of the oldest institution of higher education in the West, Santa Clara University. Santa Clara residents are also in close proximity to San Jose State University, Stanford University and Mission College, as well as other units of the Community College System.

Litigation

General. There is no action, suit or proceeding known to be pending or threatened, restraining or enjoining Santa Clara in the execution or delivery of, or in any way contesting or affecting the validity of any proceedings of Santa Clara taken with respect to the Third Phase Agreement.

There is no litigation pending, or to the knowledge of Santa Clara, threatened, questioning the existence of Santa Clara, or the title of the officers of Santa Clara to their respective offices. There is no litigation pending, or to the knowledge of Santa Clara, threatened, questioning or affecting in any material respect the financial condition of Santa Clara's electric system.

Present lawsuits and other claims against Santa Clara's electric utility department are incidental to the ordinary course of operations of the electric utility department and are largely covered by Santa Clara's self insurance program. In the opinion of Santa Clara's management and, with respect to such litigation, the Santa Clara City Attorney, such claims and litigation will not have a materially adverse effect upon the financial position of Santa Clara.

California Energy Market Refund Dispute. The IOUs–PG&E, Edison and San Diego Gas & Electric Company ("SDG&E")–and the State of California, the California Electricity Oversight Board ("EOB") and the CPUC have been pursuing claims for refunds against Santa Clara and other power-producing municipally owned utilities ("MOUs"). Santa Clara, along with other similarly situated MOUs, sold electricity into the ISO and/or California Power Exchange (the "PX") markets during the California energy crisis of 2000 and 2001. At that time, as noted under "DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS – Background; California Electric Market Deregulation" in the front part of this Official Statement, the price of electricity was uncharacteristically high.

In July 2001, after initially concluding that it had no authority to require refunds of MOUs, FERC issued an order establishing an evidentiary hearing for the purpose of determining the amount of refunds, if any, due from entities selling into the ISO and PX organized spot markets from October 2, 2000 through June 20, 2001. During that time period, Santa Clara acted as both a seller and buyer in the PX market. The MOUs sought relief from the FERC order in the courts. The MOU position, that FERC had during that time period no jurisdiction to order refunds from Santa Clara, was upheld by the Ninth Circuit Court of Appeals on September 6, 2005, reversing FERC's prior order. *Bonneville Power Administration v. FERC*, 422 F.3d 908 (9th Cir., 2005). The Supreme Court denied the PG&E petition for review by certiorari on December 10, 2007.

In response to the Bonneville decision, however, in March 2006, the IOUs and the EOB filed lawsuits against Santa Clara and other MOUs (including NCPA) in the United States District Court, and when that proceeding was dismissed, the IOUs and the EOB re-filed the same claims against Santa Clara and such other MOUs in California state court in Los Angeles County. *Pacific Gas and Electric Co. v. Arizona Electric Power Cooperative, Inc.*, L.A. Superior Court No. BC369141. In addition, Santa Clara is involved in a separate dispute with PG&E with regard to sales between Santa Clara, PG&E and the ISO during the same 2000-2001 time period, a portion of which was litigated before the bankruptcy court administering PG&E's bankruptcy.

Santa Clara entered into a settlement agreement with the plaintiffs, which resolves all of these claims, including the separate disputes between Santa Clara and PG&E discussed above. The settlement agreement was executed by Santa Clara, the IOUs, the State of California acting through the State Attorney General, and CDWR (on behalf of the California Energy Resources Scheduling Division), and the CPUC. The terms include a mutual release of all refund claims by the parties, and it also requires the plaintiffs to assume any liability Santa Clara might ultimately have to any other parties in the refund proceeding. Accordingly the settlement resolves all claims against Santa Clara seeking refunds for sales it made to the ISO and PX markets during the 2000-2001 time period. The consideration exchanged includes cash, receivables, and certain claims for refunds, with a net out of pocket cost to Santa Clara of $7.6 million, plus interest from the date of execution through the date of approval and payment.

The settlement agreement was executed and filed with FERC for approval on December 21, 2010. Due to the joint liability asserted in some of the claims, a motion for determination of good faith settlement was submitted to the trial court on January 6, 2011, and the trial court approved the motion by order entered January 27, 2011. The settlement terms were subsequently approved by FERC in an order entered on June 16, 2011. Santa Clara paid the amounts owed under the settlement agreement on June 27, 2011, and the parties have proceeded with the process for withdrawing their various claims, including a notice of withdrawal submitted to FERC on July 6, 2011, and a request for dismissal with prejudice filed with the trial court by the Plaintiffs on July 13, 2011.

Condensed Operating Results and Selected Balance Sheet Information

The following table sets forth summaries of income and selected balance sheet information of Santa Clara's electric utility for the five fiscal years ended June 30, 2011. The information for the fiscal years ended June 30, 2007 through June 30, 2011 was prepared by Santa Clara on the basis of its audited financial statements for such years.

CITY OF SANTA CLARA
ELECTRIC UTILITY DEPARTMENT
SUMMARY OF FINANCIAL OPERATING RESULTS*
($ in 000s)

	Fiscal Year Ending June 30,				
	2007	**2008**	**2009**	**2010**	**2011**
Summary of Income					
Operating Revenues[(1)]	$229,319	$240,093	$243,889	$252,518	$277,769
Operating Expenses:					
Salaries, Wages and Benefits	17,329	17,036	18,402	20,060	20,040
Materials, Supplies and Services[(2)]	217,941	241,402	263,690	224,253	226,211
Depreciation	17,296	17,602	17,867	17,864	18,608
Total Operating Expenses	$252,565	$276,041	$299,959	$262,177	$264,859
Operating Income (Loss)	(23,246)	(35,948)	(56,071)	(9,659)	12,910
Other Income[(3)]	41,026	29,629	34,354	26,921	25,577
Interest Expense	(12,086)	(11,741)	(9,860)	(8,547)	(9,313)
Wholesale Power Sales	204,723	172,404	102,480	67,840	50,124
Wholesale Power Purchases	(197,076)	(177,973)	(110,879)	(73,727)	(50,754)
Other Expenses	(4,369)	(6,240)	(7,518)	(8,907)	(7,252)
Equity (Loss) in Joint Power Agencies[(4)]	3,913	(1,486)	1,223	1,736	5,002
Net Income Before Operating Transfers and Extraordinary Items	$ 12,885	$(31,356)	$(46,270)	$ (4,343)	$ 26,294
Selected Balance Sheet Information (as of June 30)					
Rate Stabilization Fund	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$109,244[(5)]
Cost Reduction Fund	233,726	158,733	98,739	84,207	N/A[(5)]
Cash Designated for Construction	50,564	71,757	64,017	54,857	57,487
Other Unrestricted Cash Balance(s)	72,026	77,037	72,684	65,282	67,028
Total Pooled & Cash Investments	$381,317	$332,527	$260,440	$229,346	$233,759

* Columns may not add to totals due to rounding.

(1) See "Rates and Charges" above. Exclude public benefit charge revenues.

(2) Includes purchased power payments and payments to joint power agencies. Also includes payment of a portion of gross revenues to City's General Fund as contribution in lieu of taxes which payment is subordinate to the payment of other operating expenses and debt service. Per the City Charter, up to 5% of gross revenues (not including revenues from wholesale transactions) from the electric utility is paid to the City General Fund each year.

(3) Primarily represents interest income, public benefit charge revenues, grants, rents, and other non-recurring miscellaneous income. Unrealized gains were included in fiscal years 2006-07 ($2.933 million), 2007-08 ($1.096 million) and 2008-09 ($9.558 million). Unrealized losses were included in fiscal years 2009-10 ($0.169 million) and 2010-11 ($4.745 million). In 2007 and 2011, also net of gain (loss) on retirement of fixed assets.

(4) Net loss in fiscal years 2007-08 as a result of NCPA refunds to participants.

(5) As described herein, as of December 31, 2010, the Cost Reduction Fund was transferred to the Rate Stabilization Fund (as a subaccount therein).

Source: City of Santa Clara.

Rate Covenant Compliance Under Electric Revenue Bond Indenture

The electric revenue bond indenture pursuant to which Santa Clara's electric revenue bonds are issued requires Santa Clara to produce revenues of the electric utility in each year such that adjusted net revenues (as defined in the electric revenue bond indenture) will be sufficient to pay debt service on all electric revenue bonds and parity debt for such fiscal year. The electric revenue bond indenture permits amounts in the Rate Stabilization Fund or (prior to December 31, 2010) other unrestricted funds of the electric enterprise to be used to satisfy the rate covenant. Santa Clara has elected to use such unrestricted funds for such purpose as described in "Cash Reserves" above. Santa Clara has satisfied its rate covenant in each year as shown below. In addition to operating expenses and debt service, the electric utility has other obligations which it is required to satisfy. Such obligations include payments in lieu of taxes as well as capital expenditures not otherwise financed with bond proceeds, which obligations are, in accordance with the Santa Clara City Charter, payable subordinate to the payment of debt service on the electric revenue bonds and parity debt. Capital expenditures not financed with bond proceeds are funded from a variety of sources, including reserves, developer contributions and electric system revenues. See "Cash Reserves" above. The coverage numbers shown below differ in certain years from those previously reported, and they more accurately reflect the effects of wholesale transactions, the discharge of Santa Clara's senior lien electric revenue bond indenture in fiscal year 2007-08, the priority of payments under the Santa Clara City Charter and the terms of the electric revenue bond indenture.

CITY OF SANTA CLARA
RATE COVENANT COMPLIANCE UNDER
ELECTRIC REVENUE BOND INDENTURE
($ in 000s)

	Fiscal Year Ending June 30,				
	2007	**2008**	**2009**	**2010**	**2011**
Debt Service Coverage:					
Adjusted Revenues[(1)]	$280,338	$278,945	$297,506	$274,705	$274,261
Adjusted Operating Expenses[(2)]	226,782	251,955	276,574	239,773	238,590
Adjusted Net Revenue Available for Debt Service	$ 53,556	$ 26,990	$ 20,932	$ 34,932	$ 35,671
Debt Service on Electric Revenue Bonds[(3)]	$ 23,379	$ 26,089	$ 14,643	$ 12,293	$ 14,240
Adjusted Revenues in Excess of Debt Service Requirements	$ 30,177	$ 901	$ 6,289	$22,639	$21,431
Debt Service Coverage Ratio[(4)]	2.29	1.03	1.43	2.84	2.50

* Numbers may not add up due to independent rounding.

(1) Adjusted Revenue includes operating revenues and non-operating revenues (other income excluding unrealized gains or losses and developer contributions), and net of wholesale transactions, excluding equity or loss on joint powers agency projects accounted for on the equity method of accounting. Also includes Cost Reduction Fund transfers related to operating expenses. In fiscal years 2006-07, 2007-08, 2008-09 and 2009-10, such fund transfers were $15.819 million, $18.230 million, $40.544 million and $6.240 million, respectively. No Cost Reduction Account (previously Cost Reduction Fund) transfers were made in fiscal year 2010-11. See "Rates and Charges" and "Cash Reserves" above.

(2) Adjusted Expenses are operating and other expenses, including joint powers agency obligations, less depreciation and amortization and less contribution-in-lieu to the General Fund.

(3) Includes letter of credit fees relating to variable rate electric revenue bonds. Prior to fiscal year 2008-09 also includes debt service on senior lien bonds prior to their discharge.

(4) Coverage of electric revenue bonds only. Excludes joint powers obligations, the costs of which are a component of Adjusted Operating Expenses. See footnote (2).

Source: City of Santa Clara.

APPENDIX B

NCPA AUDITED FINANCIAL STATEMENTS
FOR THE FISCAL YEARS ENDED JUNE 30, 2011 AND JUNE 30, 2010

[THIS PAGE INTENTIONALLY LEFT BLANK]

A PUBLIC AGENCY

NCPA

NORTHERN CALIFORNIA POWER AGENCY

AND ASSOCIATED POWER CORPORATIONS

Reports on Audit of Combined Financial Statements
and
Supplementary Information

For the Year Ended June 30, 2011 and 2010

NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS

Reports on Audit of Combined Financial Statements
and Supplementary Information

Table of Contents

For the Year Ended June 30, 2011 and 2010

MOSS-ADAMS LLP
Certified Public Accountants | Business Consultants

REPORT OF INDEPENDENT AUDITORS

The Board of Commissioners
Northern California Power Agency and Associated Power Corporations

We have audited the accompanying combined balance sheets of Northern California Power Agency and Associated Power Corporations (the Agency) as of June 30, 2011 and 2010 and the related combined statements of revenues, expenses and changes in net assets and cash flow for the years then ended. These financial statements are the responsibility of the Agency's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Agency's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the combined financial statements referred to above present fairly, in all material respects, the combined financial position of the Agency as of June 30, 2011 and 2010 and the combined results of its operations and cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

The management's discussion and analysis preceding the combined financial statements is not a required part of the basic combined financial statements but is supplementary information required by the Governmental Accounting Standards Board. We have applied certain limited procedures, which consisted principally of inquiries of management regarding the methods of measurement and presentation of the required supplementary information. However, we did not audit the information and express no opinion on it.

Moss Adams LLP

Portland, Oregon
October 27, 2011

MANAGEMENT'S DISCUSSION AND ANALYSIS

NORTHERN CALIFORNIA POWER AGENCY AND ASSOCIATED POWER CORPORATIONS

The following management's discussion and analysis of the Northern California Power Agency (the Agency) and its financial performance provides an overview of the Agency's financial activities for the years ended June 30, 2011 and 2010. This discussion should be read in conjunction with the Agency's financial statements and accompanying notes, which follow this section.

BACKGROUND

The Northern California Power Agency is a joint powers agency formed by member public entities under the laws of the State of California. The Agency is responsible for purchasing, generating, transmitting, and selling electrical energy and for providing other related services to its members as each may require. The Agency provides a portion of certain of its members' power needs and certain of its members also self-provide and or purchase power and transmission from other public and private sources.

The Agency is governed by a Commission comprised of one representative for each member. The Commission is responsible for the general management of the affairs, property, and business of the Agency. Under the direction of the General Manager, the staff of the Agency is responsible for providing various administrative, operating and planning services for the Agency.

The Agency's project construction and development programs have been individually financed by project revenue bonds that are collateralized by the Agency's assignment of all payments, revenues, and proceeds associated with its interest in each project. Each of the Agency's members may choose which projects in which it wishes to participate, as to each such project in which an Agency member participates, that member is known as a "project participant." Each project participant has agreed to pay its proportionate share of debt service and other costs of the related project, notwithstanding the suspension, interruption, interference, reduction or curtailment of output from the project for any reason (that is, the take-or-pay member agreements). Certain of the revenue bonds are additionally supported by municipal bond insurance credit enhancements.

Power sales by the Agency to its members for their resale include both sales of power to project participants generated by operating plants and power purchased from outside sources. Rates for power sales are designed to recover costs that include budgeted annual operating costs and debt service. Additional amounts for operating reserves or rate stabilization may be included in rates under the terms of bond indentures. The Agency's rates for electric service are not subject to the regulatory jurisdiction of the California Public Utilities Commission (CPUC) or the Federal Energy Regulatory Commission (FERC). Rather, the Agency's rates are established annually in connection with its budget, which is approved by its governing Commission.

Various legal and tax considerations caused the Agency to provide that separate not-for-profit corporations should be delegated by the Agency to own the geothermal electrical generating projects undertaken by the Agency ("the Associated Power Corporations"). The Associated Power Corporations, consisting of Northern California Municipal Power Corporation Nos. Two and Three, have delegated to the Agency the authority to construct, operate and manage their respective geothermal plants and related assets. The Agency, in return for financing the costs of acquisition and construction, acquires all the capacity and energy generated by the plants.

Because the Agency is a separate, governmental and not-for-profit organization that serves its participating members, who are also the Agency's principal customers, the net results of operations flow through to its participating members as either net revenues or net expenses.

MANAGEMENT'S DISCUSSION AND ANALYSIS

NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS

FINANCIAL REPORTING

For accounting purposes, the Agency is a special-purpose governmental entity that is engaged in a business-type activity, principally as a supplier of wholesale electricity and transmission to its member participants. As such, the Agency's financial statements are presented as an enterprise type fund.

The records of the Agency and the Associated Power Corporations are maintained substantially in accordance with the FERC Uniform System of Accounts. Accounting principles generally accepted in the United States of America are applied by the Agency in conformance with pronouncements of the Governmental Accounting Standards Board (GASB) and, where not in conflict with GASB pronouncements, the Financial Accounting Standards Board (FASB) pronouncements issued on or before November 30, 1989. The combined financial statements encompass the Agency and Associated Power Corporations on an accrual accounting basis. All significant intercompany balances and transactions have been eliminated from the combined amounts reported.

In accordance with FASB Accounting Standards Codification (ASC) 980, Regulated Operations, the Agency has deferred the net of certain items of expense and revenue that otherwise would have been charged to operations as such items will be recovered in the future years' operations. The Agency expects to recover these items in rates over the term of the related debt obligations it has issued.

GASB Statement No. 53, Accounting and Financial Reporting for Derivative Instruments, was implemented in fiscal year 2010. This accounting standard requires that all derivative financial instruments be reported at fair value on the balance sheets and tested for effectiveness. Ineffective hedges are deemed investment instruments under GASB 53, for which changes are reported in the statement of revenues, expenses and changes in net assets. The primary derivative instruments currently used by the Agency are interest rate swaps, which are used to reduce rate risk for variable rate debt. GASB Statement No. 53 and its impact on the financial statements are addressed in Note D – Projects and Related Financing.

COMBINED BALANCE SHEETS, COMBINED STATEMENTS OF REVENUES, EXPENSES AND CHANGES IN NET ASSETS, AND COMBINED STATEMENTS OF CASH FLOW

The combined balance sheets include all the Agency's assets and liabilities, using the accrual method of accounting, as well as information about which assets can be used for general purposes and which assets are restricted as a result of bond covenants and other commitments. The combined balance sheets provide information about the nature and amount of resources and obligations at a specific point in time. The combined statements of revenues, expenses, and changes in net assets report all the revenues and expenses during the time periods indicated. The combined statements of cash flow report the cash provided and used by operating activities as well as other cash sources, such as investment income and debt financing; and, other cash uses such as payments for debt service and capital additions.

NEW PROJECT

The Agency is currently developing a new Agency project – the Lodi Energy Center. The Lodi Energy Center (LEC) is a 280 MW base load, combined cycle, natural gas-fired, combustion turbine generating station (one gas turbine and one steam turbine) to be located in Lodi, California. Environmental review was completed through the Application For Certification Process (AFC) at the California Energy Commission in May 2010 and construction began in August 2010. Commercial operation is expected by summer 2012. Pursuant to the Lodi Energy Center Power Sales Agreement, the Agency has agreed to construct and operate the LEC and has sold all of the capacity and energy of the LEC to thirteen participants (including four non-members) in accordance with their respective generation entitlement shares (GES). Each participant has agreed to unconditionally provide for its share of the costs of construction of the LEC and all capital improvements and to pay its share of the operation and maintenance expenses based on its GES. Estimated cost of construction for the project is $375.3 million.

FINANCIAL HIGHLIGHTS

The following is a summary of the Agency's combined financial position and results of operations for the years ended June 30, 2011, 2010, and 2009.

Condensed Balance Sheets	June 30, (000's omitted) 2011	2010	2009 (as restated)
Assets			
Current assets	$ 65,552	$ 66,022	$ 73,916
Restricted assets	312,148	508,400	196,508
Electric utility plant, net	584,928	410,304	335,481
Other assets and deferred charges	197,328	186,839	218,760
	$ 1,159,956	$ 1,171,565	$ 824,665
Liabilities and Net Assets			
Long-term debt	$ 857,643	$ 866,874	$ 503,030
Current liabilities	78,070	84,654	134,145
Non-current liabilities and deferred credits	196,244	186,256	155,476
Net assets	27,999	33,781	32,014
	$ 1,159,956	$ 1,171,565	$ 824,665

Condensed Statements of Revenues, Expenses and Changes in Net Assets	Years Ended June 30, (000's omitted) 2011	2010	2009 (as restated)
Sales for resale	$ 268,469	$ 304,345	$ 350,755
Operating expenses	250,018	257,851	301,251
Net operating revenues	18,451	46,494	49,504
Other expenses	(27,423)	(29,903)	(30,475)
Future recoverable (refundable) costs	15,426	(5,251)	(2,871)
Refunds to participants	(12,236)	(9,573)	(10,048)
Increase (decrease) in net assets	(5,782)	1,767	6,110
Net assets, beginning of year	33,781	32,014	25,904
Net assets, end of year	$ 27,999	$ 33,781	$ 32,014

MANAGEMENT'S DISCUSSION AND ANALYSIS

NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS

2011 Compared to 2010

ASSETS

Restricted Assets

Restricted assets decreased $196.3 million or 38.6% from the prior year. This is primarily a result of expenditures related to the Lodi Energy Center Project of $147.1 million, a reduction of General Operating Reserve participant deposits of $11.3 million, reduction of geothermal construction funds of $3.0 million used for the completion of work on unit 4 turbine and steam path upgrades, and net reductions of approximately $34.9 million in debt service and reserve accounts resulting primarily from lower debt service requirements and the final maturities of certain Geothermal, Combustion Turbine and Transmission bond issues.

Electric Utility Plant, Net

The Agency has invested approximately $584.9 million in plant assets and construction work in progress, net of accumulated depreciation, at June 30, 2011. Net utility plant makes up approximately 50.4% of the Agency's assets. The $174.6 million increase from the prior year is a result of net capital additions of $21.4 million and an increase in construction work in progress of $178.8 million primarily related to the Lodi Energy Center Project, offset by $25.6 million in depreciation, net of retirements. Net capital additions were primarily related to the unit 4 turbine and steam path upgrades. For additional detail, refer to Note B.

Other Assets and Deferred Charges

Other assets and deferred charges increased $10.5 million compared to 2010. This was primarily due to reduced bond principal collections compared to scheduled asset depreciation and bond cost amortizations.

LIABILITIES

Long-Term Debt

Long-term debt decreased $9.2 million in 2011 as a result of scheduled principal payments of $41.7 million offset by the net change in current portion of long-term debt $30.3 million and approximately $2.2 million in amortization of deferred losses on bond refunding and net discounts. For additional detail, refer to Note D.

Current Liabilities

Current liabilities decreased by $6.6 million in 2011. This is primarily due to a decrease in current portion of long-term debt of $30.3 million, which was offset by increases in accounts and retentions payable - restricted of $21.4 million related to the Lodi Energy Center Project, and net increases of approximately $2.3 million in accrued interest, accounts payable, reserves and advances.

Non-Current Liabilities and Deferred Credits

Non-current liabilities and deferred credits increased by approximately $10.0 million in 2011. This was primarily due to a $20.8 million increase in deferred revenues related to the Lodi Energy Center Project offset by reductions of approximately $6.1 million in operating reserves and other deposits and $4.7 million of interest rate swap liability.

2011 Compared to 2010 - Continued

CHANGES IN NET ASSETS

The Agency is intended to operate on a not-for-profit basis. Therefore, net assets primarily represent differences between total revenues collected, using rates based on estimated operating expenses and debt service, and the total actual expenses incurred. In subsequent periods of operation, excess collections (net of encumbrances) may be refunded to participants or appropriated for other uses at the discretion of the Agency's governing Board of Commissioners. In the event the Agency incurs a net expense at year-end, the balance would be subject to recovery in participant rates under the terms of the related participating member agreements. See Notes A, B and D to Combined Financial Statements.

Sales For Resale

Sales for resale revenues for fiscal year 2011 were approximately $35.9 million or 11.8% less than in the prior fiscal year. This was the net result of the following: (1) lower sales for resale revenues from Agency participants by approximately $51.2 million or 17.4%, which was caused by reduced revenue requirements due to: $33.4 million lower budgeted plant costs; reduced power purchase requirements of $9.4 million due to a decline in participant demand with a lower average cost of power; reduced natural gas pass through sales of $4.3 million; a $4.1 million reduction of management services costs compared to 2010; and (2) higher other third-party revenues from electric power and ancillary services by $15.3 million or 159.0%, which was primarily caused by increased availability of excess energy for sale from the Agency's power resources.

Operating Expenses

Operating expenses decreased by approximately $7.8 million or 3.0% in fiscal year 2011, as compared with the prior year. This was the net result of the following: (1) the cost of the purchased power component decreased by $12.3 million or 9.7%, largely due to the reduced need for power previously noted above; (2) the transmission cost component increased by $10.2 million or 26.2% primarily due to rate increases for transmission services from the Independent System Operator; and (3) decreases in operations expense and depreciation totaling approximately $9.4 million were offset by a slight increase of $3.6 million in maintenance and administrative expenses.

2010 Compared to 2009

ASSETS

Current Assets

The Agency's current assets decreased $7.9 million or 10.7% during 2010 primarily due to cash used by operating, and non-capital financing activities offset by increases in accounts receivable.

Restricted Assets

Restricted assets increased $311.9 million or 158.7% from the prior year. This is primarily a result of Lodi Energy Center Project funds of $316.1 million received from the sale bonds and a net increase of $19.9 million in General Operating Reserve participant deposits, which were offset by reductions of geothermal construction funds of $12.4 million used for the completion of the Bear Canyon solar array and continuing work on unit 4 steam path upgrades, and net reductions of approximately $11.7 million in debt service and reserve accounts resulting primarily from lower debt service requirements and the refunding of certain Hydroelectric and Capital Facilities bonds.

2010 Compared to 2009- Continued

Electric Utility Plant, Net

The Agency has invested approximately $410.3 million in plant assets and construction work in progress, net of accumulated depreciation, at June 30, 2010. Net utility plant makes up approximately 32.5% of the Agency's assets. The $74.8 million increase from the prior year is a result of net capital additions of $10.6 million and an increase in construction work in progress of $98.0 million primarily related to the Lodi Energy Center Project, offset by $33.8 million in depreciation, net of retirements. Net capital additions were primarily related to the Bear Canyon photovoltaic array. For additional detail, refer to Note B.

Other Assets and Deferred Charges

Other assets and deferred charges decreased $31.9 million compared to 2009. This was primarily due to a $31.0 million transfer of Lodi Energy Center preliminary survey and investigation costs to construction work in progress.

LIABILITIES

Long-Term Debt

Long-term debt increased $363.8 million in 2010 as a result of the 2010 Lodi Energy Center Project bond issuance, which was offset by the effects of the refunding of certain Hydroelectric, Capital Facilities bonds and scheduled principal payments of $39.9 million. For additional detail, refer to Note D.

In January 2010, the Agency refunded all of 1999 Capital Facilities Refunding Revenue Bonds Series A totaling $62,525,000. The refunding was completed through the issuance of $3,640,000 fixed rate tax exempt debt (2010 Series A) and $51,480,000 fixed rate debt (2010 Series B) with yields of 0.95% to 4.70% with varying principal maturities ranging from $600,000 to $5,390,000 through August 1, 2025. The refunding is estimated to have decreased project debt service by an estimated $4.0 million over the next 15 years, which results in an estimated economic gain (difference between the present values of the old and new debt service payments) to the Agency of approximately $3.8 million.

In April 2010, the Agency refunded $109,145,000 principal amount of 1998 Hydroelectric Refunding Revenue Bonds Series A maturing on July 1 in each of the years 2011 through 2018 and in the year 2023. The refunding was completed through the issuance of $101,260,000 fixed rate tax exempt debt (2010 Series A) and $8,025,000 fixed rate taxable debt (2010 Series B) with yields of 1.62% to 4.31% with varying principal maturities ranging from $1,755,000 to $15,230,000 through July 1, 2023. The refunding is estimated to have decreased project debt service by an estimated $6.8 million over the next 14 years, which results in an estimated economic gain to the Agency of approximately $6.5 million.

In June 2010, the Agency issued four series of bonds for the purpose of providing funds to finance the costs of acquisition and construction of the LEC project for all participants, except Modesto Irrigation District. In addition to the costs of construction, financing included interest costs during the construction period, as well as contributions to the Debt Service Reserve Fund, Operating and Maintenance Reserve Account and to pay the costs of issuance of the bonds.

2010 Compared to 2009- Continued

Lodi Energy Center Revenue Bonds, Issue One provided financing for 11 project participants with 55.7857% GES. This financing consisted of $78,330,000 of fixed rate tax exempt bonds (Series A) and $176,625,000 of fixed rate federally taxable direct payment Build America Bonds (Series B). The bonds are of varying principal amounts ranging from $4,540,000 to $15,975,000 through June 1, 2040. The tax exempt bonds yield interest at rates from 1.95% to 4.75% through 2025. The Build America Bonds bear interest at 7.311%, with 35% interest subsidy payments due from the Federal Government semiannually, providing for net interest costs of 4.7522%, maturing on June 1, 2040.

Lodi Energy Center Revenue Bonds, Issue Two provided financing for the California Department of Water Resources' 33.5% GES. This financing consisted of $30,540,000 of fixed rate tax exempt bonds (Series A) and $110,225,000 of fixed rate federally taxable direct payment Build America Bonds (Series B). The bonds are of varying principal amounts ranging from $3,775,000 to $8,915,000 through June 1, 2035. The tax exempt bonds yield interest at rates from 0.96% to 2.86% through 2019. The Build America Bonds bear interest at rates of 4.63% to 5.679%, with 35% interest subsidy payments due from the Federal Government semiannually, providing for net interest costs of 3.671%, maturing on June 1, 2035.

Current Liabilities

Current liabilities decreased by $49.5 million in 2010. This is primarily due to; a net decrease in member advances of $40.1 million, which is primarily the refunding of Lodi Energy Center Phase 2 advances, and a decrease in accounts payable of $8.4 million.

Non-Current Liabilities and Deferred Credits

Non-current liabilities and deferred credits increased by $30.8 million in 2010. This was primarily due to: (1) a $17.0 million increase in operating reserves and other deposits; (2) a $9.9 million increase from the recognition of deferred revenues; and (3) a $3.9 increase in interest rate swap liability.

CHANGES IN NET ASSETS

The Agency is intended to operate on a not-for-profit basis. Therefore, net assets primarily represent differences between total revenues collected, using rates based on estimated operating expenses and debt service, and the total actual expenses incurred. In subsequent periods of operation, excess collections (net of encumbrances) may be refunded to participants or appropriated for other uses at the discretion of the Agency's governing Board of Commissioners. In the event the Agency incurs a net expense at year-end, the balance would be subject to recovery in participant rates under the terms of the related participating member agreements. See Notes A, B and D to Combined Financial Statements.

Sales For Resale

Sales for resale revenues for fiscal year 2010 were approximately $46.4 million or 13.2% less than in the prior fiscal year. This was the net result of the following: (1) lower sales for resale revenues from Agency participants by approximately $34.7 million or 10.5%, which was caused by reduced revenue requirements due to: $5.1 million lower budgeted plant costs; reduced power purchase requirements of $24.6 million due to a decline in participant demand with a lower average cost of power; reduced transmission costs of $4.8 million; and a $0.5 million reduction of management services costs compared to 2009; and (2) lower other third-party revenues from electric power and ancillary services by $11.7 million or 54.9%, which was primarily caused by reduced availability of excess energy for sale from the Agency's power resources.

2010 Compared to 2009- Continued

Operating Expenses

Operating expenses decreased by approximately \$43.4 million or 14.4% in fiscal year 2010, as compared with the prior year. This was the net result of the following: (1) the cost of the purchased power component decreased by \$28.7 million or 18.5%, largely due to the reduced need for power previously noted above; (2) the transmission cost component decreased by \$10.8 million or 21.6% primarily due to the reduced need for transmission services from the Independent System Operator; and (3) decreases in maintenance and administrative and depreciation totaling approximately \$4.1 million were offset by a slight increase of \$0.1 million in operations expense.

OUTLOOK

The Agency's vision is to provide reliable, affordable, and clean energy to our members in an environmentally responsible way. We partner with our state and federal governments to support forward thinking policies that promote clean energy sources, protect our environment, and reflect the interests of the consumers we serve.

SUMMARY

The management of the Agency is responsible for preparing the information in this management's discussion and analysis, combined financial statements and notes to combined financial statements. Financial statements were prepared according to accounting principles generally accepted in the United States of America, and they fairly portray the Agency's financial position and results of operations. The notes to the financial statements are an integral part of the basic financial statements and provide additional financial information.

COMBINED BALANCE SHEETS

NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS

	June 30, 2011	June 30, 2010
ASSETS	(000's omitted)	
CURRENT ASSETS		
Cash and cash equivalents	$ 57,518	$ 43,342
Investments	-	13,376
Accounts receivable		
Participants	52	559
Other	1,124	2,169
Interest receivable	29	59
Inventory and supplies – at average cost	5,807	5,630
Prepaid expenses	1,022	887
TOTAL CURRENT ASSETS	65,552	66,022
RESTRICTED ASSETS		
Cash and cash equivalents	161,352	396,637
Investments	150,467	110,707
Interest receivable	329	1,056
TOTAL RESTRICTED ASSETS	312,148	508,400
ELECTRIC PLANT		
Electric plant in service	1,073,021	1,068,841
Less: accumulated depreciation	(781,848)	(773,470)
	291,173	295,371
Construction work-in-progress	293,755	114,933
TOTAL ELECTRIC PLANT	584,928	410,304
OTHER ASSETS AND DEFERRED CHARGES		
Deferred expenses to be recovered in future years	183,686	173,003
Unamortized debt issuance expenses	12,492	12,759
Preliminary survey and investigation costs	1,150	1,077
TOTAL OTHER ASSETS AND DEFERRED CHARGES	197,328	186,839
TOTAL ASSETS	$ 1,159,956	$ 1,171,565

See notes to combined financial statements

COMBINED BALANCE SHEETS

NORTHERN CALIFORNIA POWER AGENCY AND ASSOCIATED POWER CORPORATIONS

	June 30, 2011	June 30, 2010
LIABILITIES	(000's omitted)	
CURRENT LIABILITIES		
Accounts payable	$ 22,060	$ 21,789
Accounts and retentions payable – restricted for construction	24,997	3,547
Member advances	1,954	2,108
Operating reserves	3,125	2,981
Current portion of long-term debt	11,175	41,475
Accrued interest payable	14,759	12,754
TOTAL CURRENT LIABILITIES	78,070	84,654
NON-CURRENT LIABILITIES AND DEFERRED CREDITS		
Operating reserves and other deposits	110,409	116,513
Deferred revenues	73,141	52,364
Deferred interest rate swap liability	12,694	17,379
Long-term debt, net	857,643	866,874
TOTAL NON-CURRENT LIABILITIES AND DEFERRED CREDITS	1,053,887	1,053,130
TOTAL LIABILITIES	1,131,957	1,137,784
NET ASSETS		
Invested in capital assets, net of related debt	(49,429)	(107,396)
Restricted	50,652	122,188
Unrestricted	26,776	18,989
TOTAL NET ASSETS	27,999	33,781
TOTAL LIABILITIES AND NET ASSETS	$ 1,159,956	$ 1,171,565

COMBINED STATEMENTS OF REVENUES, EXPENSES AND CHANGES IN NET ASSETS

NORTHERN CALIFORNIA POWER AGENCY AND ASSOCIATED POWER CORPORATIONS

	Years Ended June 30,	
	2011	2010
	(000's omitted)	
SALES FOR RESALE		
Participants	$ 243,463	$ 294,689
Other Third-Party	25,006	9,656
TOTAL SALES FOR RESALE	268,469	304,345
OPERATING EXPENSES		
Purchased power	114,428	126,743
Transmission	49,366	39,103
Operations	31,868	32,974
Depreciation	25,595	33,897
Administrative and general	16,001	14,393
Maintenance	12,760	10,741
TOTAL OPERATING EXPENSES	250,018	257,851
NET OPERATING REVENUES	18,451	46,494
OTHER (EXPENSES) REVENUES		
Interest expense	(46,063)	(31,555)
Interest income	1,940	2,274
Capitalized interest	15,637	461
Amortization of deferred charges	(464)	(1,451)
Other	1,527	369
TOTAL OTHER EXPENSES	(27,423)	(29,903)
FUTURE RECOVERABLE AMOUNTS	15,426	(5,251)
REFUNDS TO PARTICIPANTS	(12,236)	(9,573)
(DECREASE) INCREASE IN NET ASSETS	(5,782)	1,767
NET ASSETS, Beginning of year	33,781	32,014
NET ASSETS, End of year	$ 27,999	$ 33,781

See notes to combined financial statements

COMBINED STATEMENTS OF CASH FLOW

NORTHERN CALIFORNIA POWER AGENCY AND ASSOCIATED POWER CORPORATIONS

	Years Ended June 30, 2011	2010
	(000's omitted)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Received from participants	$ 264,747	$ 304,237
Received from others	28,216	5,648
Payments for employee services	(29,894)	(28,111)
Payments to suppliers for goods & services	(181,245)	(183,884)
NET CASH FROM OPERATING ACTIVITIES	81,824	97,890
CASH FLOWS FROM INVESTING ACTIVITIES		
Proceeds from maturities and sales of investments	256,782	255,325
Interest received on cash and investments	3,282	1,710
Purchase of investments	(283,692)	(228,481)
NET CASH FROM INVESTING ACTIVITIES	(23,628)	28,554
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES		
Expenditures for debt issuance costs	(197)	(7,125)
Acquisition and construction of electric plant	(184,583)	(75,838)
Interest paid on long-term debt	(42,114)	(39,910)
Principal repayment on long-term debt	(41,475)	(31,511)
Proceeds from bond issues	-	578,522
Payments to refund debt	-	(171,387)
NET CASH FROM CAPITAL AND RELATED FINANCING ACTIVITIES	(268,369)	252,751
CASH FLOWS FROM NON-CAPITAL AND RELATED FINANCING ACTIVITIES		
Advances from members	(154)	(40,121)
Other proceeds	1,527	368
Preliminary survey and investigation costs	(73)	(159)
Refunds to participants	(12,236)	(9,573)
NET CASH FROM NON-CAPITAL AND RELATED FINANCING ACTIVITIES	(10,936)	(49,485)
INCREASE IN CASH AND CASH EQUIVALENTS	(221,109)	329,710
CASH AND CASH EQUIVALENTS		
Beginning of year	439,979	110,269
End of year	$ 218,870	$ 439,979

COMBINED STATEMENTS OF CASH FLOW-Continued

NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS

	Years Ended June 30, 2011	2010
	(000's omitted)	
RECONCILIATION OF NET OPERATING REVENUES TO NET CASH FROM OPERATING ACTIVITIES		
Net operating revenues	$ 18,451	$ 46,494
Adjustments to reconcile net operating revenues to net cash from operating activities:		
Depreciation	25,595	33,897
	44,046	80,391
CASH FLOWS IMPACTED BY CHANGES IN		
Accounts receivable	1,552	(569)
Inventory and prepaid	(312)	(102)
Operating reserves	(5,960)	16,709
Deferred revenues	20,777	9,907
Accounts payable	21,721	(8,446)
NET CASH FROM OPERATING ACTIVITIES	$ 81,824	$ 97,890
CASH AND CASH EQUIVALENTS AS STATED IN THE COMBINED BALANCE SHEETS		
Cash and cash equivalents - current assets	$ 57,518	$ 43,342
Cash and cash equivalents - restricted assets	161,352	396,637
End of year	$ 218,870	$ 439,979

See notes to combined financial statements

NOTE A -- ORGANIZATION

The Agency Northern California Power Agency (Agency) was formed in 1968 as a joint powers agency of the State of California. The membership consists of eleven cities with publicly-owned electric utility distribution systems, one port authority, a transit authority, and two other associate member entities. The Agency is generally empowered to purchase, generate, transmit, distribute, and sell electrical energy. Members participate in the projects of the Agency on an elective basis.

Various legal and tax considerations caused the Agency to provide that separate not-for-profit corporations should be delegated by the Agency to own the geothermal electrical generating projects undertaken by the Agency ("the Associated Power Corporations"). The Associated Power Corporations, Northern California Municipal Power Corporations Nos. Two and Three, have delegated to the Agency the authority to construct, operate and manage their respective geothermal plants and related assets. The Agency, in return for financing the costs of acquisition and construction, acquires all the capacity and energy generated by the plants. See Note D – Projects and Related Financing.

The Agency is governed by a Commission comprised of one representative for each member. The Commission is responsible for the general management of the affairs, property, and business of the Agency. Under the direction of the General Manager, the staff of the Agency is responsible for providing various administrative, operating and planning services for the Agency.

NOTE B -- SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting and Principles of Combination For accounting purposes, the Agency is a special-purpose governmental entity that is engaged in a business-type activity, principally as a supplier of wholesale electricity and transmission to its member participants. As such, the Agency's financial statements are presented as an enterprise type fund.

The records of the Agency and its Associated Power Corporations are maintained substantially in accordance with the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts. Accounting principles generally accepted in the United States of America are applied by the Agency in conformance with pronouncements of the Governmental Accounting Standards Board (GASB) and, where not in conflict with GASB pronouncements, the Financial Accounting Standards Board (FASB) pronouncements issued on or before November 30, 1989. The combined financial statements encompass the Agency and Associated Power Corporations on an accrual accounting basis. All significant intercompany balances and transactions have been eliminated from the combined amounts reported.

Cash Operating cash is maintained in interest-bearing depository accounts, which are fully collateralized, in accordance with state law. Cash balances are invested in either overnight repurchase agreements, which are fully collateralized by U.S. Government Securities, or in money market funds invested in short-term U.S. Treasury Securities. The Agency commingles operating cash for investment purposes only. Separate detailed accounting records are maintained for each account's related investments. All cash of the Agency is held by either the Agency's custodian or its primary bank and revenue bond trustee.

Cash Equivalents Cash equivalents are short-term investments purchased with original maturities of 90 days or less. Cash equivalents consist primarily of portions of guaranteed investment contracts, U.S. Treasury and Agency Securities, California State Treasurer's pooled Local Agency Investment Fund (LAIF), and money market mutual funds.

Restricted Cash and Investments Long-term debt and other agreements require the maintenance of certain restricted asset accounts. Cash and investments held in these accounts are restricted for specific uses, including project construction, operations, debt service, and special reserve requirements. Investments are stated at cost adjusted for amortization of premiums and accretion of discounts, which approximates market.

Inventory and Supplies Inventory and supplies consist primarily of spare parts for the maintenance of plant assets and are stated at average cost.

Restricted Assets Cash and cash equivalents, investments and related accrued interest which are restricted under terms of certain agreements, trust indentures or Commission actions limiting the use of such funds, are included in restricted assets.

Electric Plant Electric plant in service is recorded at historical cost. The cost of additions, renewals and betterments is capitalized; repairs and minor replacements are charged to operating expenses as incurred. The original cost of property retired, net of removal and salvage costs, is charged to accumulated depreciation. Depreciation expense is computed using the straight-line method over the estimated useful lives of the related assets. The provision for depreciation was approximately 2% and 3% of the average electric plant in service for the Agency during 2010 and 2009, respectively. Depreciation is calculated using the following estimated lives:

Generation and Transmission	25 to 42 years
General Plant	5 to 25 years
Transportation Equipment	5 years

A summary of changes in electric plant for the year ended June 30, 2011 is as follows:

	Balance June 30, 2010	Additions	Deletions	Balance June 30, 2011
		(000's omitted)		
Land and Land Rights	$ 172,041	$ -	$ (96)	$ 171,945
Structures and Leasehold Improvements	292,661	4,011	(3,728)	292,944
Reservoirs, Dams and Waterways	249,436	13	-	249,449
Equipment	352,850	15,672	(13,317)	355,205
Furniture and Fixtures	1,853	1,701	(76)	3,478
Total	1,068,841	21,397	(17,217)	1,073,021
Construction Work-In-Progress	114,933	199,362	(20,540)	293,755
Accumulated Depreciation	(773,470)	(25,596)	17,218	(781,848)
Electric Plant, Net	$ 410,304	$ 195,163	$ (20,539)	$ 584,928

A summary of changes in electric plant for the year ended June 30, 2010 is as follows:

	Balance June 30, 2009	Additions	Deletions	Balance June 30, 2010
		(000's omitted)		
Land and Land Rights	$ 172,041	$ -	$ -	$ 172,041
Structures and Leasehold Improvements	292,129	447	(4)	292,661
Reservoirs, Dams and Waterways	249,325	111	-	249,436
Equipment	343,016	10,011	(88)	352,850
Furniture and Fixtures	1,708	145	-	1,853
Total	1,058,219	10,714	(92)	1,068,841
Construction Work-In-Progress	16,928	106,695	(8,690)	114,933
Accumulated Depreciation	(739,666)	(33,897)	93	(773,470)
Electric Plant, Net	$ 335,481	$ 83,512	$ (8,689)	$ 410,304

Construction Work-In-Progress Construction work-in-progress (CWIP) includes the capitalized cost of land, material, equipment, labor, interest (net of interest income), certain other financing costs incurred to facilitate the projects and an allocated portion of general and administrative expenses related to the development of electric plant. In addition, CWIP ultimately includes costs incurred during the test and start-up phase of projects prior to commencement of commercial operations.

Preliminary Surveys and Investigations Expenditures for preliminary surveys, plans and investigations (PS&I) are deferred until the ultimate feasibility of the contemplated project is determined. When a project is continued, these expenditures are capitalized as part of construction work-in-progress and the related advances provided by members to fund such expenditures are repaid out of the permanent financing of the project. If a project is abandoned, such expenditures and related advances are included in operations when such determination is made.

Deferred Expenses/Revenues to be Recovered/Refunded in Future Years In accordance with FASB Accounting Standards Codification (ASC) 980, Regulated Operations, the Agency has deferred the net of certain items of expense and revenue that otherwise would have been charged to operations because it is probable that such items will be recovered in the future years' operations. The Agency expects to recover these items in rates over the term of the related debt obligations it has issued. On an ongoing basis, the Agency reviews its operations to determine the continued applicability of these deferrals under ASC 980.

The items of expense that have been deferred are those originally paid from bond proceeds, including depreciation, certain bond amortizations and interest paid from bond proceeds. Revenues used to acquire electric plant have also been deferred to future years. As of June 30, 2011 and 2010, the Agency had accumulated deferred expenses (net of deferred revenues) to be recovered in future years of approximately $110,545,000 and $120,639,000, respectively.

Unamortized Debt Issuance Expenses Debt issuance expenses are amortized over the term of the related issue. Amortization is computed using the effective interest method.

Unamortized Excess Cost on Advance Refunding of Debt Gains and losses on refunding of debt are included as a component of long-term debt and are amortized to interest expense using the effective interest method over the shorter of the term of the original debt refunded or the term of the refunding debt obligation.

Long-Term Debt Long-term debt is stated net of unamortized discounts and premiums and excess cost on advance refunding of debt. Discounts and premiums are amortized over the term of the related obligation using the effective interest method. Amortization of debt discounts and premiums is included in total interest expense for the period. See Note D - Projects and Related Financing.

Operating Reserves The Agency has established various funded operating reserves for anticipated periodic operating costs and related liabilities including, but not limited to, scheduled maintenance other than ordinary repairs and replacements. Certain amounts funded each year are charged to operating expense because the rates established by the Agency for power sales to its members include these costs on a prospective basis. Changes to operating reserve levels are periodically authorized by the Agency's Commission during its annual budgeting process. A non-project specific, individual participant controlled, general operating reserve is also maintained for participating Agency members.

Rates Power sales to participants for their resale include both power generated by operating plants and power purchased from outside sources. Rates for power sales are designed to recover costs that include budgeted annual operating costs and debt service. Additional amounts for operating reserves or rate stabilization may be included in rates under the terms of bond indentures. During fiscal years 2011 and 2010, no amounts were specifically collected for rate stabilization.

The Agency's rates for electric service are not subject to the regulatory jurisdiction of the California Public Utilities Commission (CPUC) or FERC. Rather, the Agency's rates are established annually in connection with its budget, which is approved by its governing Commission.

Power, Transmission and Fuel Forward Transactions In the normal course of its business, the Agency is required to manage loads, resources, and energy price risk on behalf of its members. Consequently, the Agency buys and sells power, transmission, and fuel in wholesale markets as required. The Agency does not enter into such agreements solely for trading purposes. All such transactions are normal purchases and sales subject to settlement at the agreed to contract prices for quantities delivered. While authorized to transact forward purchase contracts for terms of up to five years, forward contract purchases at fiscal year ended June 30, 2011 were for periods not greater than two years duration beyond the current fiscal year. In the event of default, undelivered transactions are required to be marked-to-market subject to the following limitations. If the Agency, as buyer, is the defaulting entity, the Agency's termination settlement amount is capped at the agreed to contract cost for all future undelivered commodities. If the selling counterparty is the defaulting entity, the seller's termination settlement is not capped for all future undelivered commodities. The defaulting entity is also subject to resultant transmission charges, brokerage fees, attorney fees, and all other reasonable expenses. See Note G - Commitments and Contingencies, Power Purchase Contracts.

Fair Values of Financial Instruments The following methods and assumptions were used by the Agency in estimating its fair value disclosures for financial instruments:

Cash and Cash Equivalents - The carrying amount reported in the balance sheets for cash and cash equivalents approximates its fair value.

Investments - The fair values for investments are based on quoted market prices. See Note C.

Swaps - The fair values take into consideration the prevailing interest rate environment, the specific terms and conditions of a given transaction and any upfront payments that were received. All fair values were estimated using the zero-coupon discounting method. This method calculates the future payments required by the swap, assuming that the current forward rates implied by the yield curve are the market's best estimate of future spot interest rates. These payments are then discounted using the spot rates implied by the current yield curve for a hypothetical zero-coupon rate bond due on the date of each future net settlement on the swaps. While the current net mark to market values are negative, this valuation would be realized only if the swaps were terminated at the valuation date.

Net Assets The Agency classifies its net assets into three components; invested in capital assets net of related debt, restricted and unrestricted. These classifications are defined as follows:

Invested in Capital Assets, Net of Related Debt – This component of net assets consists of capital assets, net of accumulated depreciation reduced by outstanding debt balances, net of unamortized debt expenses and unspent bond proceeds.

Restricted – This component consists of net assets with constraints placed on their use. Constraints include those imposed by debt indentures and other agreements; grants, laws and regulations of other governments; or, by the Agency's governing Board of Commissioners.

Unrestricted – This component of net assets consists of net assets that do not meet the definition of "invested in capital assets, net of related debt" or "restricted".

The Agency and the Associated Power Corporations are intended to operate on a not-for-profit basis. Therefore, any balance of net assets represents differences between total revenues collected, using rates based on estimated operating expenses and debt service, and the total actual expenses incurred. In subsequent periods of operation, excess collections (net of encumbrances) that the participating members do not direct be held by or released to the Agency for expenditure by the Agency are refunded to the participating members. Estimated encumbrances at June 30, 2011 and 2010 were $4,495,000 and $6,602,000, respectively. In the event the Agency incurs a negative net assets balance, the balance would be subject to recovery in rates under the terms of the related take-or-pay member agreements. See Note D.

Use of Estimates in the Preparation of Financial Statements The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassifications Interest expense and income totaling $461 thousand in the prior year was reclassified to capitalized interest to conform to the 2011 presentation. Additionally, certain accounts payable totaling $3.5 million were reclassified to accounts and retentions payable – restricted. There was no effect of these reclassifications on total current liabilities in the 2010 Combined Balance Sheets or in total other expenses in the Combined Statements of Revenues, Expenses and Changes in Net Assets.

NOTE C -- INVESTMENTS

The Agency is authorized to invest in obligations of the U.S. Government and its agencies and instrumentalities, in certificates of deposit, commercial paper, banker's acceptances, repurchase and reverse repurchase agreements, passbook savings account demand deposits, municipal bonds, the State Treasurer's LAIF pool, and in other instruments authorized by applicable sections of the Government Code of the State of California. The Agency's investments are stated at cost adjusted for amortization of premiums and accretion of discounts, which approximates market.

Investments at June 30, 2011

Description	Carrying Value	Market Value	Wtd. Avg Maturity (In years)
	(000's omitted)		
U.S. Agencies	$ 149,431	$ 149,646	1.46
U.S. Treasury	1,036	1,036	.16
TOTAL INVESTMENTS	$ 150,467	$ 150,682	

Investments at June 30, 2010

Description	Carrying Value	Market Value	Wtd. Avg Maturity (In years)
	(000's omitted)		
U.S. Agencies	$ 85,769	$ 85,847	.81
Guaranteed Investment Contracts	21,073	21,073	.00
U.S. Treasury	17,241	17,244	.16
TOTAL INVESTMENTS	$ 124,083	$ 124,164	

The Agency's investment policy requires investments that assure safety of the principal, liquidity to meet specific obligations of the Agency when due, and investment quality all in compliance with California State law and the Agency's revenue bond indentures. Generally, operating investment maturities are limited to one year and reserve funds to five year maturities, except for debt service reserve funds, which are allowed maturities up to fifteen years. All U.S. Government and U.S. Government Agency securities held by the Agency are either in effect or actually AA rated.

All securities owned by or held on behalf of the Agency are held by either the Agency's custodian, Union Bank of California, N.A., or its revenue bond trustee, U.S. Bank Trust, N.A.

NOTE D -- PROJECTS AND RELATED FINANCING

Financing Programs The Agency's project construction and development programs have been individually financed by project revenue bonds that are collateralized by the Agency's assignment of all payments, revenues, and proceeds associated with its interest in each project. Each project participant has agreed to pay its proportionate share of debt service and other costs of the related project, notwithstanding the suspension, interruption, interference, reduction or curtailment of output from the project for any reason (that is, the take-or-pay member agreements).

Certain of the revenue bonds are additionally supported by municipal bond insurance credit enhancements.

Long-term debt and stated rates at June 30:	2011	2010
	(000's omitted)	
Geothermal Project		
1993 Refunding Series A and Series B (relating to a like amount of Special Revenue Bonds) Serial, 5.80-5.85% due 2011	$ -	$ 27,560
2009 Series A Serial, 4.00-5.25% due 2012-2025	35,610	35,610
Total Geothermal Project	35,610	63,170
Hydroelectric Project		
1992 Refunding Series A Term, 6.30% due 2019	36,770	36,770
1998 Refunding Series A Term, 5.00-5.20% due 2024-2033	88,355	88,355
2008 Refunding Series A Term, adjustable rate, Initially 1.51% due 2033	85,160	85,160
2008 Refunding Series B (Taxable) Term, adjustable rate, Initially 2.87% due 2021	2,965	3,065
2008 Refunding Series C Serial, 4.00-5.00% due 2011-2025	126,980	128,005
2008 Refunding Series D (Taxable) Serial, 4.05% due 2011	-	7,855
2010 Refunding Series A Serial, 4.00-5.00% due 2014-2024	101,260	101,260
2010 Refunding Series B Serial, 2.75-3.25% due 2013-2014	8,025	8,025
Total Hydroelectric Project	449,515	458,495

NORTHERN CALIFORNIA POWER AGENCY AND ASSOCIATED POWER CORPORATIONS

Long-term debt and stated rates at June 30:	2011	2010
	(000's omitted)	
Capital Facilities Project		
2010 Refunding Series A		
Serial, 2.00-5.25% due 2011-2025	55,120	55,120
Total Capital Facilities Project	55,120	55,120
Lodi Energy Center, Issue One		
2010 Series A		
Serial, 3.00-5.00% due 2013-2020	42,310	42,310
Term, 5.00% due 2025	36,020	36,020
2010 Series B		
Term, 7.311% due 2040 (Federally Taxable-Build America Bonds)	176,625	176,625
Lodi Energy Center, Issue Two		
2010 Series A		
Serial, 3.00-5.00% due 2013-2019	30,540	30,540
2010 Series B		
Term, 4.63% due 2035 (Federally Taxable-Build America Bonds)	110,225	110,225
Total Lodi Energy Center	395,720	395,720
Combustion Turbine Project		
1998 Refunding Series A		
Serial, 5.00% due 2011	-	4,060
Transmission Project		
1998 Refunding Series A		
Serial, 4.125-4.25% due 2011	-	875
Total Long-Term Debt Outstanding	935,965	977,440
Less: Unamortized net cost on advance refunding	(86,927)	(92,326)
Unamortized net (discount) and premium	19,780	23,235
Current portion	(11,175)	(41,475)
Total Long-Term Debt, Net	$ 857,643	$ 866,874

The Agency had the following long-term debt activity during FY 2011:

	Balance June 30, 2010	Additions	Payments, Refundings & Amortizations	Balance June 30, 2011
	(000's omitted)			
Revenue Bonds	$ 977,440	$ -	$ (41,475)	$ 935,965
Unamortized premiums and discounts	23,235	-	(2,257)	20,978
Unamortized cost on advance refund of debt	(92,326)	-	5,399	(86,927)
TOTAL	$ 908,349	$ -	$ (38,333)	$ 870,016

The Agency had the following long-term debt activity during FY 2010:

	Balance June 30, 2009	Additions	Payments, Refundings & Amortizations	Balance June 30, 2010
	(000's omitted)			
Revenue Bonds	$ 628,895	$ 560,125	$ (211,580)	$ 977,440
Unamortized premiums and discounts	5,866	18,397	(1,028)	23,235
Unamortized cost on advance refund of debt	(91,821)	(5,418)	4,913	(92,326)
TOTAL	$ 542,940	$ 573,104	$ (207,695)	$ 908,349

Debt service requirements for each of the next five years and in five-year cumulative increments thereafter as of June 30, 2011:

	Principal	Interest	Total
	(000's omitted)		
2012	$ 11,175	$ 54,879	$ 66,054
2013	28,950	50,064	79,014
2014	33,285	48,960	82,245
2015	32,775	47,375	80,150
2016	34,360	45,829	80,189
2017-2021	196,865	202,150	399,015
2022-2026	217,260	147,632	364,892
2027-2031	179,630	96,089	275,719
2032-2036	141,990	44,261	186,251
2037-2041	59,675	11,161	70,836
	$ 935,965	$ 748,400	$ 1,684,365

Interest includes interest requirements for fixed rate debt at their stated rate and variable rate debt covered by interest rate swaps at their fixed swap rate.

Redemption Provisions As set forth in the bond indentures, the term bonds are subject to redemption prior to maturity in varying amounts at specific dates. At the option of the Agency, the bonds are also subject to early redemption at specific redemption prices and dates.

Defeased Debt Various bond refundings were undertaken to defease debt and realize future debt service savings. Debt was defeased by using the proceeds of the refunding issues and other available monies to irrevocably place in trust cash and U.S. Government Securities, which together with interest earned thereon, will be sufficient to pay both the interest and the appropriate maturity or redemption value of the refunded bonds as required.

Accordingly, these defeased debt issues have been considered extinguished for financial reporting purposes. At year-end, the following defeased debt remained outstanding:

		2011	2010
		(000's omitted)	
Geothermal:	Project No. Three, 1993 Series A	$ -	$ 27,210
Hydroelectric:	Project No. One, 1985 Series A	12,150	12,150
	Project No. One, 1986 Series A	36,960	36,960
	Project No. One, 1998 Series A	-	109,145
		49,110	158,255
	Total Defeased Debt Outstanding	$ 49,110	$ 185,465

Geothermal Project In addition to a federal geothermal leasehold, steam wells, gathering system and related facilities, the project consists of two electric generating stations (Plant 1 and Plant 2). Each plant has two 55 MW (nameplate rating) turbine generator units utilizing low temperature geothermal steam; associated electrical, mechanical and control facilities; a heat dissipation system; a steam gathering system; a transmission tap-line; and, other related facilities. Geothermal steam for the project is derived from the geothermal property, which includes well pads, access roads, steam wells and re-injection wells.

Recent capital improvements include: MW photovoltaic solar array at the Middletown Treatment Plant; and, a 1 MW photovoltaic solar array located at the Clearlake Southeast Treatment Plant, both in Lake County, California. These improvements reduce the power needs for the existing pump stations, which are part of the Southeast Geysers Effluent Pipeline that delivers approximately 9 million gallons of treated wastewater daily to the Geysers Geothermal Project for injection into the steam field.

Hydroelectric Project The Agency contracted to finance, manage, construct, and operate Hydroelectric Project Number One for the licensed owner, Calaveras County Water District. In exchange, the Agency has the right to the electric output of the project for 50 years from February 1982. The Agency also has an option to purchase power from the project in excess of the District's requirements for the subsequent 50 years, subject to regulatory approval.

In April 2010, the Agency refunded $109,145,000 principal amount of 1998 Hydroelectric Refunding Revenue Bonds Series A maturing on July 1 in each of the years 2011 through 2018 and in the year 2023. The refunding was completed through the issuance of $101,260,000 fixed rate tax exempt debt (2010 Series A) and $8,025,000 fixed rate taxable debt (2010 Series B) with yields of 1.62% to 4.31% with varying principal maturities ranging from $1,755,000 to $15,230,000 through July 1, 2023. The refunding is estimated to have decreased project debt service by an estimated $6.8 million over the next 14 years, which results in an estimated economic gain to the Agency of approximately $6.5 million.

NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS

As part of a refinancing plan in November 2004, the Agency entered into two forward starting interest rate swaps in an initial notional amount of $85,160,000 and $1,574,000. Payments under the swap agreements with Citigroup Financial Products, Inc. began on April 2, 2008. To complete the refinancing transaction and realize the debt service savings under the 2004 swap agreement, on April 2, 2008 the Agency completed a bond refunding of certain maturities of the 1998 Hydroelectric Refunding Series A bonds totaling $85,870,000 maturing in 2023 to 2032. These fixed rate bonds were refinanced through the issuance of tax-exempt 2008 Hydroelectric Refunding Series A ($85,160,000) bonds and taxable 2008 Hydroelectric Refunding Series B ($3,165,000) bonds. Both issues are variable interest rate bonds bearing interest at weekly interest rates, payable semi-annually on July 1 and January 1 each year. To support this financing, the Agency entered into two irrevocable direct pay letter of credit agreements with Dexia Credit Local, which expire on April 2, 2013. The payment of principal and interest on these issues are not covered by any financial guaranty insurance policies. This 2008 Hydroelectric Refunding and the associated interest rate swaps are estimated to have reduced project debt service by $11.8 million over the next 24 years providing the Agency with an estimated economic gain (difference between the present values of the old and new debt service payments) of approximately $5.9 million.

The Agency has entered into two separate pay-fixed, receive-variable interest rate swaps to produce savings or to result in lower costs over the life of each transaction than what the Agency would have paid using fixed-rate debt. While these derivative instruments carry additional risks, the Agency's swap policy and favorable negotiations have helped to reduce such risks.

	2008 Hydroelectric Refunding Revenue Bonds Forward Starting Swaps			
Associated Interest Rate Swaps starting April 2, 2008	Series A		Series B (Taxable)	
Counterparty to Interest Rate Swap	Citigroup Financial Products Inc.		Citigroup Financial Products Inc.	
Notional Value of Interest Rate Swap	$85,160,000		$1,465,863	
Fair Value--Due from (to) Counterparty	($12,979,775)		$285,269	
Credit Downgrade Required Collateral Posting:				
For Counterparty, Fair Value Above	$10 million		$10 million	
If S&P or Moody's Credit Rating falls to	A+/A1		A+/A1	
For Agency (Credit of Agency's Insurer National Public Finance Guarantee formerly MBIA), Fair Value Above	$10 million		$10 million	
If S&P or Moody's Credit Rating falls to	A+/A1		A+/A1	
Termination Date	July 1, 2032		July 1, 2032	
	Terms	Rates	Terms	Rates
Payments to (from) Counterparty	Fixed	3.819%	Fixed	-5.330%
Variable Payments (from) to Counterparty	54% LIBOR+.54%*	-0.690%	100% of LIBOR*	0.265%
Net Interest Rate Swap Payments		3.129%		-5.064%
Variable-Rate Bond Payments	SIFMA **	0.448%	SIFMA **	0.948%
Effective Interest Rate on Bonds		3.578%		-4.117%

Average to Date: * 1-Month London Inter-Bank Offered Rate ** Securities Industry and Financial Market Association Municipal Swap Index (formerly the Bond Market Association Municipal Swap Index)

The total fair value of outstanding swap instruments was a net liability of $12,694,000 and $17,379,000 at June 30, 2011 and June 30, 2010, respectively. These amounts are reported as a non-current liability. Consistent with hedge accounting treatment required for derivative instruments, fair value is reported as a component of deferred expenses to be recovered in future years on the balance sheets. For the swaps that were deemed investment instruments under GASB 53, the changes are reported in the statement of revenues, expenses and changes in net assets. The value of the swaps noted above reflects the estimated fair value of the swaps at June 30, 2011 as determined by the Agency's financial advisor. The fair value of the swaps will change due to notional amount, amortizations, and interest rate changes.

The following swap agreement risks are common to all the interest rate swaps. The interest rate swaps expose the Agency to basis risk should the relationship between LIBOR and SIFMA converge, changing the synthetic rate on the bonds. If a change occurs that results in the rates moving to convergence, the expected cost savings of the swap may not be realized. The Agency is exposed to interest rate risk on its pay-fixed, receive variable interest rate swaps. Interest rate risk is the risk that changes in interest rates will adversely affect the fair values of the Agency's financial instruments or cash flows. As the LIBOR or SIFMA swap index decreases, the Agency's net payment on swaps increases. In addition, the Agency is exposed to interest rate risk if the counterparty to the swap defaults or if the swap is terminated. The Agency is also exposed to market access risk, the risk that it will not be able to enter credit markets or that credit will become more costly. The Agency's financial rating is tied to the credit strength of the major participants of the specific project for which each financial instrument is issued. The Agency is also exposed to market access risks caused by disruptions in the municipal bond market.

To mitigate the potential for credit risk, the swap counterparties are required by the agreement to post collateral should the fair value exceed certain thresholds as shown above. At June 30, 2011, credit ratings of the counterparties to the swaps were as follows:

Swap Counterparty & Agency's Insurer	Standard & Poor's	Moody's
Citigroup Financial Products Inc.	A+	A1
National Public Finance Guarantee formerly MBIA (the Agency's insurer)	BBB	Baa1

The swaps utilized the International Swap Dealers Association (ISDA) Master Agreement, which includes standard termination events, such as failure to pay and bankruptcy. However, an additional provision under the Schedule to the ISDA Master Agreement allows the swap to be terminated by the Agency if the counterparty's credit rating falls below A- by Standard & Poor's or A3 by Moody's. If a swap is terminated, the applicable bonds would no longer carry a synthetic fixed interest rate. In addition, if a swap has a negative fair value at the time of an early termination, the Agency would be liable to the counterparty for a payment equal to the swap's fair value.

Combustion Turbine Project The original project consisted of five combustion turbine units, each nominally rated at approximately 25 megawatts. Concurrent with the final project bond maturity, two units located in Roseville were acquired by an Agency member. The remaining project consists of two units in Alameda and one in Lodi. The project provides capacity during peak load periods and emergency capacity reserves. Excess capacity and energy from the project are also sold to other entities from time to time.

Transmission Project The project was undertaken to meet certain obligations of the Agency under the Agency/PG&E Interconnection Agreement. The project includes an ownership interest in PG&E's 230 kV Castle Rock to Lakeville Substation Transmission Line in Sonoma County, additional firm transmission rights in that Transmission Line, and a central scheduling and dispatch facility in service at the Agency's headquarters in Roseville, California.

Capital Facilities Project The project consists of one 49.9 megawatt natural gas-fired steam injected combustion turbine generator unit located in Lodi, California. Wastewater is reclaimed from the City of Lodi's White Slough water pollution control facility, processed to eliminate contaminants, and used in the turbine to produce steam for power enhancement and emissions control.

In January 2010, the Agency refunded $62,525,000 principal amount of 1999 Capital Facilities Refunding Revenue Bonds Series A maturing on August 1 in each of the years 2010 through 2016 and in the year 2025. The refunding was completed through the issuance of $3,640,000 fixed rate tax exempt debt (2010 Series A) and $51,480,000 fixed rate debt (2010 Series B) with yields of 0.95% to 4.70% with varying principal maturities ranging from $600,000 to $5,390,000 through August 1, 2025. The refunding is estimated to have decreased project debt service by an estimated $3.9 million over the next 15 years, which results in an estimated economic gain (difference between the present values of the old and new debt service payments) to the Agency of approximately $3.8 million.

Lodi Energy Center The Agency is currently constructing a new base load, combined cycle, natural gas-fired, combustion turbine generating station (one gas turbine and one steam turbine) to be located in Lodi, California, next to the Capital Facilities Project discussed above. Although the LEC will be capable of operating at 296 MW, it is expected by the terms of the transmission interconnection agreement to operate at 280 MW. Construction began in August 2010. Commercial operation is expected by summer 2012. Pursuant to the Lodi Energy Center Power Sales Agreement, the Agency has agreed to construct and operate the LEC and has sold all of the capacity and energy of the LEC to thirteen participants (including four non-members) in accordance with their respective Generation Entitlement Shares (GES). Each participant has agreed to unconditionally provide for its share of the costs of construction of the LEC and all capital improvements and to pay its share of the operation and maintenance expenses based on its GES. Estimated cost of construction for the project is approximately $375 million. The LEC will be operated and maintained by the Agency under the direction of the LEC Project Management and Operations Agreement among the Agency and the LEC Project Participants.

In June 2010, the Agency issued four series of bonds for the purpose of providing funds to finance the costs of acquisition and construction of the LEC project for all participants, except Modesto Irrigation District. In addition to the costs of construction, financing included interest costs during the construction period, as well as contributions to the Debt Service Reserve Fund, Operating and Maintenance Reserve Account and to pay the costs of issuance of the bonds.

Lodi Energy Center Revenue Bonds, Issue One provided financing for 11 project participants with 55.7857% GES. This financing consisted of $78,330,000 of fixed rate tax-exempt bonds (Series A) and $176,625,000 of fixed rate federally taxable direct payment Build America Bonds (Series B). The bonds are of varying principal amounts ranging from $4,540,000 to $15,975,000 through June 1, 2040. The tax-exempt bonds yield interest at rates from 1.95% to 4.75% through 2025. The Build America Bonds bear interest at 7.311%, with 35% interest subsidy payments due from the Federal Government semiannually, providing for net interest costs of 4.7522%, maturing on June 1, 2040.

Lodi Energy Center Revenue Bonds, Issue Two provided financing for the California Department of Water Resources' 33.5% GES. This financing consisted of $30,540,000 of fixed rate tax-exempt bonds (Series A) and $110,225,000 of fixed rate federally taxable direct payment Build America Bonds (Series B). The bonds are of varying principal amounts ranging from $3,775,000 to $8,915,000 through June 1, 2035. The tax-exempt bonds yield interest at rates from 0.96% to 2.86% through 2019. The Build America Bonds bear interest at rates of 4.63% to 5.679%, with 35% interest subsidy payments due from the Federal Government semiannually, providing for net interest costs of 3.671%, maturing on June 1, 2035.

The Modesto Irrigation District elected to provide its own financing for its 10.7143% GES of the current estimate of the costs of construction of the project. Modesto Irrigation District is not liable for any Agency debt service obligations for the project.

NOTE E -- RETIREMENT PLAN

The Agency was a participating public employer in the California Public Employees Retirement System (CalPERS) Local Miscellaneous 2% at Age 60 Employees' Retirement Plan, which is an agent multiple-employer public employee defined benefit pension plan. However, in December 2009 the Agency changed to the CalPERS 2.5% at Age 55 Employees' Retirement Plan. CalPERS provides retirement and disability benefits, annual cost-of-living adjustments, and death benefits to plan members and beneficiaries. CalPERS acts as a common investment and administrative agent for participating public entities within the State of California. Benefit provisions and all other requirements are established by state statute and Agency resolution. CalPERS issues a separate comprehensive annual financial report, which is available from the CalPERS' Executive Office, 400 P Street, Sacramento, California 95814.

The Agency makes the plan contributions required of its employees on their behalf and for their account. The Agency is required to contribute at an actuarially determined rate of annual covered payroll. The contribution requirements of plan members and the Agency are established and may be amended by CalPERS.

Summary of certain plan provisions and benefits in effect for fiscal year ended June 30, 2011:

Required service for eligibility	5 full-time years
Benefit payments (% of highest 36 consecutive months' annual salary)	Monthly for life
Minimum retirement age	50
Monthly benefit	2.00% @ age 50 to 2.50% @ age 55 & up
Required employee contribution rate (w/o employer pickup)	8.000%
Required employer contribution rates	10.063% normal service 12.986% amortization bases
Actuarial annual required contribution (based on estimated payroll)	$3,842,787

Prior to joining the CalPERS retirement system, the Agency agreed to pay (pick up) 50% of prior service cost for the then existing employees. In separate agreements, the Agency has also agreed to pay (pickup) a portion of the various employee groups' required annual contribution. Actual employer portion contributions to the plan totaled $738,085 and $927,538 for fiscal years 2011 and 2010, respectively. The Agency's annual required contribution (based on actuarially established rates) was determined as part of a June 30, 2009, actuarial valuation using the entry age normal actuarial cost method. The primary actuarial assumptions included a 7.75% annual investment rate of return (net of administrative expenses); forecasted annual salary increases that vary by age, service and type of employment ranging from 3.55% to 14.45%; a 3.25% overall annual payroll growth; an individual salary growth of 3.00%; an annual production growth of .25%; and, an inflation component of 3.00%. A 15-year rate smoothed market approach is used to spread investment returns. At fiscal year end June 30, 2011, the Agency had 162 eligible active employees and 77 retirees drawing benefits under this program.

NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS

Trend Information for Agency CalPERS Retirement Plan

Fiscal Year Ending	Annual Pension Cost (APC)	Percentage of APC Contributed	Net Pension Obligation
June 30, 2007	$ 2,539,145	100.0%	-
June 30, 2008	$ 2,692,579	100.0%	-
June 30, 2009	$ 2,890,336	100.0%	-
June 30, 2010	$ 3,320,661	100.0%	-
June 30, 2011	$ 3,842,787	100.0%	-

Funded Status of the Agency CalPERS Retirement Plan

Actuarial Valuation Date	Actuarial Accrued Liability (a)	Actuarial Value of Assets (b)	Actuarial Accrued Unfunded Liability (a) - (b)	Funded Ratio (b) / (a)	Annual Covered Payroll (c)	Unfunded Actuarial Accrued Liability as % of Payroll [(a) – (b)] / (c)
June 30, 2005	$44,110,675	$17,734,386	$26,376,289	40.2%	$14,101,610	187.0%
June 30, 2006	49,211,093	23,829,467	25,381,626	48.4%	14,326,365	177.2%
June 30, 2007	54,443,624	28,955,468	25,488,156	53.2%	15,378,571	165.7%
June 30, 2008	66,571,897	34,498,660	32,073,237	51.8%	15,930,785	201.3%
June 30, 2009	80,909,833	39,535,328	41,374,505	48.9%	16,871,454	245.2%

Initial unfunded liabilities are amortized over a closed period that depends on the plan's date of entry into CalPERS. The unfunded actuarial accrued liability is being amortized as a level percentage of projected payroll on a closed basis. All changes in liability due to plan amendments, changes in actuarial assumptions, or changes in actuarial methodology are amortized separately over a 20-year period. The average remaining amortization period at the June 30, 2009 valuation date was approximately 25 years. Operating gains and losses of the plan are amortized over a 30-year rolling period, which results in an amortization of about 6% of unamortized gains and losses each year. If the plan's accrued liability exceeds the actuarial value of plan assets, then the amortization payment on the total unfunded liability may not be lower than the payment calculated over a 30-year amortization period. CalPERS actuarial valuations become available approximately two years after the Agency's fiscal year-end.

NOTE F -- OTHER POST EMPLOYMENT BENEFITS (OPEB)

The Agency contracts with the CalPERS under the Public Employees' Medical and Hospital Care Act (PEMHCA) for employee medical insurance. In connection with this plan, the Agency provides medical insurance to all active employees and their families, as well as all qualified retirees (and spouses), subject to certain limitations. The Agency has maintained an actuarially based restricted fund for the sole purpose of paying medical insurance premiums for qualified retired employees (and spouses) participating in the CalPERS medical plan. In 2007, the Agency became a participant in the CalPERS California Employers' Retiree Benefit Trust (CERBT), a pre-funding OPEB plan, which is an irrevocable multi-employer trust and plan consisting of an aggregation of single-employer plans, with pooled administrative and investment functions. The Agency makes actuarially determined Annual Required Contributions (ARC) to this OPEB plan. The ARC represents the forecast funding level to cover normal cost each year and amortize any unfunded actuarial liabilities (or funding excess) over a period not to exceed 30 years. Actuarial valuations of the fund are obtained every two years, as required by CalPERS.

Summary of certain plan provisions and benefits in effect during fiscal year ended June 30, 2011:

Required service for eligibility	10 full-time years
Minimum retirement age	50
Benefit payments	Monthly for life
Vesting for eligible employees	50% at 10 years; 5%/year after
Maximum monthly benefit	PERS Choice Premium

The annual required contribution and funded status of the OPEB plan were determined based on current cost trends of the CalPERS health plans in which the employees currently participate at the time of the actuarial valuation. The June 30, 2011 actuarial valuation was prepared on the basis of the OPEB assumption model, as prescribed by the CalPERS, in effect at the time of the valuation. At fiscal year end June 30, 2011, the Agency had 161 active eligible employees and 88 retirees drawing benefits under this program.

Trend Information for the OPEB Plan

Fiscal Year Ending	Annual OPEB Cost	Percentage of OPEB Cost Contributed	Net OPEB Obligation
June 30, 2007	$ 979,797	100.0%	-
June 30, 2008	900,135	100.0%	-
June 30, 2009	718,982	100.0%	-
June 30, 2010	770,469	100.0%	-
June 30, 2011*	960,896	100.0%	-

Funded Status of the OPEB Fund

Actuarial Valuation Date	Actuarial Accrued Liability (a)	Actuarial Value of Assets (b)	Actuarial Accrued Unfunded Liability (a) - (b)	Funded Ratio (b) / (a)	Annual Covered Payroll (c)	Unfunded Actuarial Accrued Liability as % of Payroll [(a) – (b)] / (c)
June 30, 2007	$ 17,232,609	$ 11,400,322	$ 5,832,287	66.16%	$ 14,740,187	39.6%
June 30, 2008	16,114,250	12,213,980	3,900,270	75.80%	15,491,511	25.2%
June 30, 2010	18,936,156	13,975,353	4,960,803	73.80%	16,355,901	30.3%
June 30, 2011*	21,599,763	14,464,987	7,134,776	66.97%	18,373,660	38.83%

The funded status of the plan and the annual required contributions are subject to periodic revision based on actual results, changes in assumptions or plan provisions, and new estimates of expected future circumstances. Future actuarial valuations will be performed every two years, as prescribed by CalPERS.

The Agency's annual required contribution (based on actuarially established rates) was determined as part of a June 30, 2011, actuarial valuation using the entry age normal actuarial cost method. The primary actuarial assumptions included: valuation using the Entry Age Normal Cost Method; 7.61% annual discount rate; overall payroll growth of 3.25%; 3.00% inflation; and 4.25% maximum employer contribution increase.

* The discount rate was changed from 7.75%, which was used in all prior year's actuarial valuations, to 7.61% for the June 30, 2011 actuarial valuation, as prescribed by CalPERS.

NOTE G -- COMMITMENTS AND CONTINGENCIES

Power Exchange Agreement On behalf of certain of its members, the Agency has a seasonal exchange agreement with Seattle City Light for 60 megawatts of summer capacity and 90,580 megawatt hours of energy in exchange for a return of 46 megawatts of capacity and 108,696 megawatt hours of energy in the winter. The agreement terminates in May 2014.

Power Purchase Contracts The Agency had commitments of approximately $95.1 million in connection with various power purchase contracts as of June 30, 2011. The contracts, extending through June 2014, are normal purchases at agreed to contract prices for fixed quantities of energy. Certain of the Agency's members have individually entered into certain other long-term contracts, which the Agency dispatches and schedules for them. See Note B - Summary of Significant Accounting Policies.

Combustion Turbine Fuel Supply Agreements The Agency has entered into the following agreements to provide natural gas fuel supply for use in combustion turbines:

- A 30-year agreement terminating in November 2023 with the Pacific Gas Transmission Company and its partners in a gas pipeline between Alberta, Canada and northern California. The estimated minimum annual gas transmission commitment is approximately $1.5 million.
- An agreement with Constellation New Energy Gas Division to provide natural gas and act as the Agency's natural gas operating agent. The contract automatically renews each January 1, unless terminated earlier by six months written notice by either party. On June 30, 2011, Constellation provided NCPA with a six-month notice of termination, as a result of which the Constellation Natural Gas Agreement will terminate on December 31, 2011. NCPA expects to negotiate a replacement agreement with another party to provide gas supply and management services prior to the termination of the Agreement. The Agency had approximately $2.2 million of gas purchase commitments at June 30, 2011. The commitments, extending through September 2012, are normal purchases at agreed to prices for fixed quantities of gas.

Western Area Power Administration Base Resource A number of the Agency's members, who have an aggregate 17.53465% share of the Base Resource Contract with the Western Area Power Administration to receive electric power from the Central Valley Project in California, have assigned their shares to the Agency in order to create a power resource portfolio for the mutual benefit of participating Agency members. The assignments terminate the earlier of December 31, 2024 or 60 days after Western approves a reassignment.

Geothermal Royalties Under terms of federal geothermal leasehold agreements, the Agency is required to pay royalties to the United States (U.S.) on the value of geothermal steam produced. Currently, the effective rate of such royalties is 3.6% of an amount based on the Agency's monthly weighted average cost of third-party wholesale electricity purchases made by Agency members participating in the Geothermal Project. The U.S. Department of the Interior, Minerals Management Service maintains the right to periodically review and withdraw their approval or to change this methodology should operations, market conditions, or Federal regulations change.

<u>**Geothermal Steam Production & Decommissioning**</u> Steam for the Agency's geothermal plants comes from lands in the Geysers area, which, are leased by the Agency from the federal government. The Agency operates these steam-supply areas. Operation of the geothermal plants at high generation levels, together with high steam usage by others in the same area, resulted in a decline in the steam production from the steam wells at a rate greater than expected. As a result, by April 1988, for the purpose of slowing the decline in the steam field capability, the Agency changed its steam field production from base-load to load-following and reduced average annual generation. These changes were effective in reducing the decline in steam production.

Beginning in 1991, along with other steam field operators in the area, the Agency began implementing various operating strategies to further reduce the rate of decline in steam production. The Agency has modified both steam turbine units at Plant 1 and the associated steam collection system to enable generation with lower pressure steam at higher mass-flow rates to optimize the utilization of the available steam resource.

The Agency also entered into agreements with other producers in the Geysers area to finance and construct the Southeast Geysers Effluent Pipeline Project, which was completed in September 1997 and began operating soon thereafter. The 26-mile pipeline collects wastewater from Lake County Sanitation District treatment plants at Clearlake and Middletown and delivers the wastewater to the Agency and the other Geysers steam field operator for injection into the steam field. A second pipeline enhancement project to further augment the wastewater injection program was completed in 2004.

Based on current operating protocols and forecasted operations, the Agency expects both the average and peak capacity to continue to decrease, reaching approximately 62 MWG (megawatts gross) by calendar year 2035.

Under terms of the federal geothermal leasehold agreements, which became effective August 1, 1974, the leasehold had a 10-year primary term with provision for renewal as long thereafter as geothermal steam is produced or utilized, but not longer than 40 years. At the expiration of that period, if geothermal steam is still being produced, the Agency has preferential right to renew the leasehold for a second term. The leasehold also requires the Agency to remove its leasehold improvements including the geothermal plants and steam gathering system when and if the Agency abandons the leasehold. These decommissioning costs are currently estimated to total approximately $24.1 million. The Agency has been collecting monies to pay the expected decommissioning costs since 2007 and currently holds approximately $4 million in a reserve for such purpose as of June 30, 2011.

CLAIMS AND LITIGATION

California Energy Crisis During 2000 and 2001, California experienced extreme fluctuations in the prices and supplies of natural gas and electricity in much of the State. While there has been progress in addressing these issues, uncertainty remains. As a result, no assurance can be given that measures undertaken, together with measures to be taken in the future, will prevent the recurrence of shortages, price volatility or other energy problems that have adversely affected California electric utilities in the past. The Agency has settled with the plaintiffs in related litigation, and that settlement has been approved by FERC, there are still some claims by others that remain ongoing. Although the Agency considers these claims to be lacking in merit, no assurance thereof can be given until all proceedings are finally concluded.

Other Factors Affecting the Electric Utility Industry Electric industry market participants, such as the Agency and its members, continue to face numerous potential risks and uncertainties including, but not limited to, significant volatility in energy prices and increased transmission and ancillary services costs; new federal and state renewable energy, operating efficiency, and environmental standards; and, global pressures on economic and financial market conditions. The Agency and its members continue to study and to take various actions in an effort to mitigate and manage these risk and uncertainties. However, the Agency cannot predict either the ultimate outcome of these ongoing changes or whether such outcome will have a material adverse effect on its financial position or results of operations.

Other Legal Matters The Agency is engaged in various legal proceedings before federal and state courts and various administrative tribunals incidental to the Agency's operations.

Based on its review of the aforementioned proceedings with outside legal counsel, the Agency believes that the ultimate aggregate liability, if any, resulting from these proceedings will not have a materially adverse effect on the combined financial position or results of operations of the Agency.

NOTE H – SUBSEQUENT EVENTS

On September 27, 2011, the irrevocable direct pay letter of credit agreements with Dexia Credit Local related to the 2008 Hydroelectric Refunding Series A and B bonds discussed in Note D were terminated. Replacement Letters of Credit with Citibank N.A. were issued on the same day. The Citibank letters of credit are for a period of three years and expire on September 27, 2014.

This page intentionally left blank.

INDEPENDENT AUDITOR'S REPORT ON SUPPLEMENTARY INFORMATION

The Board of Commissioners
Northern California Power Agency and Associated Power Corporations

Our report on our audit of the combined financial statements of Northern California Power Agency and Associated Power Corporations for the year ended June 30, 2011 appears on page 1. The audit was conducted for the purpose of forming an opinion on the basic combined financial statements taken as a whole. The supplementary information as of and for the year ended June 30, 2011 starting on page 39 is presented for purposes of additional analysis and is not a required part of the basic combined financial statements. Such information has been subjected to the audit procedures applied in the audit of the basic combined financial statements and, in our opinion, is fairly stated, in all material respects, in relation to the basic combined financial statements taken as a whole.

Moss Adams LLP

Portland, Oregon
October 27, 2011

OTHER FINANCIAL INFORMATION

COMBINING BALANCE SHEETS

NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS

(000's omitted)

June 30, 2011

	GENERATING & TRANSMISSION RESOURCES									
ASSETS	**Geothermal**	**Hydroelectric**	**Capital Facilities**	**CT No. One**	**Lodi Energy Center**	**Transmission**	**Purchased Power & Transmission**	**Associated Member Services**	**Other Agency**	**Combined**
CURRENT ASSETS										
Cash and cash equivalents	$ 1	$ -	$ 1	$ 1	$ -	$ -	$ -	$ -	$ 57,515	$ 57,518
Investments	-	-	-	-	-	-	-	-	-	-
Accounts receivable										
Participants	-	-	-	-	-	-	-	-	52	52
Other	2	29	-	4	-	-	612	1	476	1,124
Interest receivable			-	-	-	-	3	-	26	29
Inventory and supplies - at average cost	2,725	1,038	642	1,402	-	-	-	-	-	5,807
Prepaid expenses	421	265	30	38	-	-	-	103	165	1,022
Due from Agency and other programs*	13,623	10,369	2,650	(103)	(1,143)	126	21,514	3,429	(50,465)	-
TOTAL CURRENT ASSETS	16,772	11,701	3,323	1,342	(1,143)	126	22,129	3,533	7,769	65,552
RESTRICTED ASSETS										
Cash and cash equivalents	5,614	18,622	580	-	115,070	-	1,073	2	20,391	161,352
Investments	6,185	18,471	2,470	-	46,348	-	12,348	-	64,645	150,467
Interest receivable	11	20	8	-	209	-	-	-	81	329
TOTAL RESTRICTED ASSETS	11,810	37,113	3,058	-	161,627	-	13,421	2	85,117	312,148
ELECTRIC PLANT										
Electric plant in service	566,990	393,198	64,827	36,014	-	7,736	-	305	3,951	1,073,021
Less: accumulated depreciation	(510,720)	(196,266)	(32,851)	(32,747)	-	(7,557)	-	(70)	(1,637)	(781,848)
	56,270	196,932	31,976	3,267	-	179	-	235	2,314	291,173
Construction work-in-progress	884	656	-	-	292,111	-	-	-	104	293,755
TOTAL ELECTRIC PLANT	57,154	197,588	31,976	3,267	292,111	179	-	235	2,418	584,928
OTHER ASSETS AND DEFERRED CHARGES										
Deferred expenses to be recovered in future years	3,909	163,015	19,136	(2,069)	-	(305)	-	-	-	183,686
Unamortized debt issuance expenses	440	7,951	499	-	3,602	-	-	-	-	12,492
Preliminary survey and investigation costs	-	114	-	-	-	-	-	1,036	-	1,150
TOTAL OTHER ASSETS AND DEFERRED CHARGES	4,349	171,080	19,635	(2,069)	3,602	(305)	-	1,036	-	197,328
TOTAL ASSETS	$ 90,085	$ 417,482	$ 57,992	$ 2,540	$ 456,197	$ -	$ 35,550	$ 4,806	$ 95,304	$ 1,159,956

* Eliminated in Combination

OTHER FINANCIAL INFORMATION

COMBINING BALANCE SHEETS

NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS

(000's omitted)

June 30, 2011

	GENERATING & TRANSMISSION RESOURCES									
LIABILITIES	**Geothermal**	**Hydroelectric**	**Capital Facilities**	**CT No. One**	**Lodi Energy Center**	**Transmission**	**Purchased Power & Transmission**	**Associated Member Services**	**Other Agency**	**Combined**
CURRENT LIABILITIES										
Accounts payable	$ 554	$ 482	$ 149	$ 4	$ -	$ -	$ 13,371	$ 217	$ 7,284	$ 22,061
Accounts and retentions payable - restricted for construction	-	-	-	-	24,996	-	-	-	-	24,996
Member advances	791	-	-	-	-	-	-	1,163	-	1,954
Operating reserves	2,267	250	533	75	-	-	-	-	-	3,125
Current portion of long-term debt	1,820	8,755	600	-	-	-	-	-	-	11,175
Accrued interest payable	895	10,825	1,011	-	2,028	-	-	-	-	14,759
TOTAL CURRENT LIABILITIES	6,327	20,312	2,293	79	27,024	-	13,371	1,380	7,284	78,070
NON-CURRENT LIABILITIES AND DEFERRED CREDITS										
Operating reserves & other deposits	3,995	7,830	-	-	-	-	13,436	1	85,147	110,409
Deferred revenues	34,700	4,251	1,501	2,795	26,796	-	-	236	2,862	73,141
Deferred interest rate swap liability	-	12,694	-	-	-	-	-	-	-	12,694
Long-term debt, net	34,357	367,324	53,585	-	402,377	-	-	-	-	857,643
TOTAL NON-CURRENT LIABILITIES AND DEFERRED CREDITS	73,052	392,099	55,086	2,795	429,173	-	13,436	237	88,009	1,053,887
TOTAL LIABILITIES	79,379	412,411	57,379	2,874	456,197	-	26,807	1,617	95,293	1,131,957
NET ASSETS										
Invested in capital assets, net of related debt	(6,229)	(18,484)	(4,025)	(1,432)	(19,242)	(126)	-	4	105	(49,429)
Restricted	6,921	22,451	2,047	-	19,242	-	(15)	36	(30)	50,652
Unrestricted	10,014	1,104	2,591	1,098	-	126	8,758	3,149	(64)	26,776
TOTAL NET ASSETS	10,706	5,071	613	(334)	-	-	8,743	3,189	11	27,999
TOTAL LIABILITIES AND NET ASSETS	$ 90,085	$ 417,482	$ 57,992	$ 2,540	$ 456,197	$ -	$ 35,550	$ 4,806	$ 95,304	$ 1,159,956

* Eliminated in Combination

OTHER FINANCIAL INFORMATION

COMBINING STATEMENTS OF REVENUES, EXPENSES AND CHANGES IN NET ASSETS

NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS

(000's omitted)

	For the Year Ended June 30, 2011									
	GENERATING & TRANSMISSION RESOURCES									
	Geothermal	Hydroelectric	Capital Facilities	CT No. One	Lodi Energy Center	Transmission	Purchased Power & Transmission	Associated Member Services	Other Agency	Combined
SALES FOR RESALE										
Participants	$ 29,908	$ 43,709	$ 7,688	$ 2,951	$ -	$ -	$ 141,271	$ 17,836	$ 100	$ 243,463
Other Third-Party	2,792	-	-	-	-	-	22,171	43	-	25,006
TOTAL SALES FOR RESALE	32,700	43,709	7,688	2,951	-	-	163,442	17,879	100	268,469
OPERATING EXPENSES										
Purchased power	-	-	-	-	-	-	113,360	1,068	-	114,428
Transmission	-	-	-	-	-	-	49,366	-	-	49,366
Operations	18,706	2,756	1,611	365	-	(73)	23	8,480	-	31,868
Depreciation	11,575	9,414	2,224	2,026	-	168	-	45	143	25,595
Administrative and general	4,201	3,570	509	459	-	-	772	6,265	225	16,001
Maintenance	4,839	4,555	2,156	1,210	-	-	-	-	-	12,760
Intercompany (sales) purchases, net *	(748)	249	290	252	-	-	-	(43)	-	-
TOTAL OPERATING EXPENSES	38,573	20,544	6,790	4,312	-	95	163,521	15,815	368	250,018
NET OPERATING REVENUES	(5,873)	23,165	898	(1,361)	-	(95)	(79)	2,064	(268)	18,451
OTHER (EXPENSES) REVENUES										
Interest expense	(1,645)	(25,195)	(2,292)	(48)	(16,871)	-	(3)	(9)	-	(46,063)
Interest income	96	128	30	3	1,234	-	100	9	340	1,940
Capitalized interest	-	-	-	-	15,637	-	-	-	-	15,637
Amortization of deferred charges	(24)	(344)	(31)	(55)	-	(10)	-	-	-	(464)
Other	378	803	3	1	-	-	-	134	208	1,527
TOTAL OTHER EXPENSES	(1,195)	(24,608)	(2,290)	(99)	-	(10)	97	134	548	(27,423)
FUTURE RECOVERABLE AMOUNTS	7,756	4,232	1,482	1,851	-	105	-	-	-	15,426
REFUNDS TO PARTICIPANTS	(1,000)	(3,624)	(1,911)	(1,222)	-	-	(34)	(4,105)	(340)	(12,236)
(DECREASE) INCREASE IN NET ASSETS	(312)	(835)	(1,821)	(831)	-	-	(16)	(1,907)	(60)	(5,782)
NET ASSETS, Beginning of year	11,018	5,906	2,434	497	-	-	8,759	5,096	71	33,781
NET ASSETS, End of year	$ 10,706	$ 5,071	$ 613	$ (334)	$ -	$ -	$ 8,743	$ 3,189	$ 11	$ 27,999

* Eliminated in Combination

OTHER FINANCIAL INFORMATION

COMBINING STATEMENTS OF CASH FLOW

NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS
(000's omitted)

For the Year Ended June 30, 2011

	GENERATING & TRANSMISSION RESOURCES									
	Geothermal	Hydroelectric	Capital Facilities	CT No. One	Lodi Energy Center	Transmission	Purchased Power & Transmission	Associated Member Services	Other Agency	Combined Total
CASH FLOWS FROM OPERATING ACTIVITIES										
Received from participants	$ 33,953	$ 43,608	$ 7,682	$ 2,750	$ 16,624	$ -	$ 141,271	$ 17,971	$ 888	$ 264,747
Received from others	2,792	-	-	(1)	-	-	25,145	43	237	28,216
Payments for employee services	(8,190)	(3,550)	(1,464)	(962)	(1,983)	-	-	(8,306)	(5,439)	(29,894)
Payments to suppliers for goods & services	(17,264)	(6,014)	(2,741)	(1,315)	23,432	73	(163,390)	(7,455)	(6,571)	(181,245)
Payments from (to) other programs *	748	(249)	(290)	(252)	-	-	-	43	-	-
NET CASH FROM OPERATING ACTIVITIES	12,039	33,795	3,187	220	38,073	73	3,026	2,296	(10,885)	81,824
CASH FLOWS FROM INVESTING ACTIVITIES										
Proceeds from maturities and sales of investments	35,520	36,073	3,013	3,606	27,897	666	20,752	-	129,255	256,782
Interest received on cash and investments	1,048	96	21	87	1,544	-	79	9	398	3,282
Purchase of investments	(16,825)	(37,568)	(3,213)	-	(74,749)	-	(22,470)	-	(128,867)	(283,692)
Payments from (to) other programs *	-	-	-	-	-	-	-	-	-	-
NET CASH FROM INVESTING ACTIVITIES	19,743	(1,399)	(179)	3,693	(45,308)	666	(1,639)	9	786	(23,628)
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES										
Expenditures for debt issuance costs	-	(8)	-	-	(189)	-	-	-	-	(197)
Acquisition and construction of electric plant	(5,146)	(138)	(79)	(4)	(178,821)	-	-	(223)	(172)	(184,583)
Interest paid on long-term debt	(2,595)	(20,438)	(2,440)	(102)	(16,513)	(19)	-	(7)	-	(42,114)
Principal repayment on long-term debt	(27,560)	(8,980)	-	(4,060)	-	(875)	-	-	-	(41,475)
Payments from (to) other programs *	(4)	-	-	-	-	9	(3)	(2)	-	-
NET CASH FROM CAPITAL AND RELATED FINANCING ACTIVITIES	(35,305)	(29,564)	(2,519)	(4,166)	(195,523)	(885)	(3)	(232)	(172)	(268,369)
CASH FLOWS FROM NON-CAPITAL AND RELATED FINANCING ACTIVITIES										
Advances from members	-	-	-	-	-	-	-	(154)	-	(154)
Other proceeds	378	802	4	1	-	-	-	134	208	1,527
Preliminary survey and investigation costs	-	-	-	-	-	-	-	(73)	-	(73)
Refunds to participants	(1,000)	(3,624)	(1,911)	(1,222)	-	-	(34)	(4,105)	(340)	(12,236)
Payments from (to) other programs *	(4,545)	867	1,464	1,118	256	(7)	(928)	2,125	(350)	-
NET CASH FROM NON-CAPITAL AND RELATED FINANCING ACTIVITIES	(5,167)	(1,955)	(443)	(103)	256	(7)	(962)	(2,073)	(482)	(10,936)
INCREASE IN CASH AND CASH EQUIVALENTS	(8,690)	877	46	(356)	(202,502)	(153)	422	-	(10,753)	(221,109)
CASH AND CASH EQUIVALENTS										
Beginning of year	14,305	17,745	535	357	317,572	153	651	2	88,659	439,979
End of year	$ 5,615	$ 18,622	$ 581	$ 1	$ 115,070	$ -	$ 1,073	$ 2	$ 77,906	$ 218,870

* Eliminated in Combination

OTHER FINANCIAL INFORMATION

COMBINING STATEMENTS OF CASH FLOW

NORTHERN CALIFORNIA POWER AGENCY
AND ASSOCIATED POWER CORPORATIONS
(000's omitted)

For the Year Ended June 30, 2011

	GENERATING & TRANSMISSION RESOURCES									
	Geothermal	Hydroelectric	Capital Facilities	CT No. One	Lodi Energy Center	Transmission	Purchased Power & Transmission	Associated Member Services	Other Agency	Combined
RECONCILIATION OF NET OPERATING REVENUES TO NET CASH FROM OPERATING ACTIVITIES										
Net operating revenues	$ (5,873)	$ 23,165	$ 898	$ (1,361)	$ -	$ (95)	$ (79)	$ 2,064	$ (268)	$ 18,451
Adjustments to reconcile net operating revenues to net cash from operating activities:										
Depreciation	11,575	9,414	2,224	2,026	-	168	-	45	143	25,595
	5,702	32,579	3,122	665	-	73	(79)	2,109	(125)	44,046
CASH FLOWS IMPACTED BY CHANGES IN										
Accounts receivable	-	-	-	(1)	-	-	808	(1)	746	1,552
Inventory and prepaid	(256)	18	(4)	14	-	-	-	(103)	19	(312)
Operating reserves	2,477	1,576	-	(209)	-	-	2,165	1	(11,970)	(5,960)
Deferred revenues	4,045	(101)	(6)	(201)	16,624	-	-	135	281	20,777
Accounts payable	71	(277)	75	(48)	21,449	-	132	155	164	21,721
NET CASH FROM OPERATING ACTIVITIES	$ 12,039	$ 33,795	$ 3,187	$ 220	$ 38,073	$ 73	$ 3,026	$ 2,296	$ (10,885)	$ 81,824
CASH AND CASH EQUIVALENTS AS STATED IN THE COMBINED BALANCE SHEETS										
Cash and cash equivalents - current assets	$ 1	$ -	$ 1	$ 1	$ -	$ -	$ -	$ -	$ 57,515	$ 57,518
Cash and cash equivalents - restricted assets	5,614	18,622	580	-	115,070	-	1,073	2	20,391	161,352
End of year	$ 5,615	$ 18,622	$ 581	$ 1	$ 115,070	$ -	$ 1,073	$ 2	$ 77,906	$ 218,870

APPENDIX C

BOOK-ENTRY ONLY SYSTEM

General

The Depository Trust Company ("DTC"), Net York, New York will act as securities depository for the 2012 Bonds. The 2012 Bonds will be issued as fully-registered securities registered in the name of Cede & Co. (DTC's partnership nominee) or such other name as may be requested by an authorized representative of DTC. One fully-registered security certificate will be issued for each maturity of the 2012 Bonds of each Series, each in the aggregate principal amount of such maturity, and will be deposited with DTC.

DTC, the world's largest securities depository, is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934. DTC holds and provides asset servicing for over 3.5 million issues of U.S. and non-U.S. equity issues, corporate and municipal debt issues, and money market instrument from over 100 countries that DTC's participants ("Direct Participants") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC is the holding company for DTC, National Securities Clearing Corporation, and Fixed Income Clearing Corporation, all of which are registered clearing agencies. DTCC is owned by the users of its regulated subsidiaries. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants"). DTC has a Standard & Poor's rating of AA+. The DTC Rules applicable to its Participants are on file with the Securities and Exchange Commission. More information about DTC can be found at www.dtcc.com. The information on this website is not incorporated herein by reference.

Purchases of the 2012 Bonds under the DTC system must be made by or through Direct Participants, which will receive a credit for the 2012 Bonds on DTC's records. The ownership interest of each actual purchaser of each 2012 Bond ("Beneficial Owner") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchase. Beneficial Owners are, however, expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the 2012 Bonds are to be accomplished by entries made on the books of Direct and Indirect Participants acting on behalf of Beneficial Owners. Beneficial Owners will not receive certificates representing their ownership interests in the 2012 Bonds, except in the event that use of the book-entry system for the 2012 Bonds is discontinued.

To facilitate subsequent transfers, all 2012 Bonds deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co. or such other name as may be requested by an authorized representative of DTC. The deposit of the 2012 Bonds with DTC and their registration in the name of Cede & Co. or such other DTC nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the 2012 Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such 2012 Bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time. Beneficial Owners of 2012 Bonds may wish to take certain steps to augment transmission to them of notices of significant events with respect to the 2012 Bonds, such as redemptions, tenders, defaults, and proposed amendments to the bond documents. For example, Beneficial Owners of 2012 Bonds may wish to ascertain that the nominee holding the 2012 Bonds for their benefit has agreed to obtain and transmit notices to Beneficial Owners, in the alternative, Beneficial Owners may wish to provide their names and addresses to the registrar and request that copies of the notices be provided directly to them.

Redemption notices shall be sent to DTC. If less than all of the 2012 Bonds are being redeemed, DTC's practice is to determine by lot the amount of the interest of each Direct Participant in such maturity to be redeemed.

Neither DTC nor Cede & Co. (nor such other DTC nominee) will consent or vote with respect to 2012 Bonds unless authorized by a Direct Participant in accordance with DTC's MMI Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to the Authority as soon as possible after the record date. The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts 2012 Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Payments of principal of, premium, if any, and interest on the 2012 Bonds will be made to Cede & Co., or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts, upon DTC's receipt of funds and corresponding detail information from NCPA or the Trustee on payable date in accordance with their respective holdings shown on DTC's records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of such Participant and not of DTC, the Trustee, or the Corporation, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of principal of, premium, if any, and interest evidenced by the 2012 Bonds to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is the responsibility of the Corporation or Trustee, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners will be the responsibility of Direct and Indirect Participants.

DTC may discontinue providing its services as securities depository with respect to the 2012 Bonds at any time by giving reasonable notice to NCPA or the Trustee. Under such circumstances, in the event that a successor securities depository is not obtained, Bond certificates are required to be printed and delivered.

NCPA may decide to discontinue use of the system of book-entry-only transfers through DTC (or a successor securities depository). In that event, 2012 Bond certificates will be printed and delivered to DTC.

NCPA and the Trustee will not have any responsibility or obligation to any DTC Participant, any Beneficial Owner or any other person claiming a beneficial ownership interest in the 2012 Bonds under or through DTC or any DTC Participant, or any other person which is not shown on the registration books of the Trustee as being a Holder with respect to the accuracy of any records maintained by DTC or any DTC Participant; the payment by DTC or any DTC Participant of any amount in respect of the principal of, redemption premium, if any, or interest on the 2012 Bonds; any notice which is permitted or required to be given to Holders; any consent given or other action taken by DTC as a Holder; or any other procedures or obligations of DTC under the book-entry system.

So long as Cede & Co. is the registered owner of the 2012 Bonds, as nominee of DTC, references herein to the Holders or registered owners of the 2012 Bonds will mean Cede & Co., as aforesaid, and will not mean the Beneficial Owners of the 2012 Bonds.

The foregoing description of the procedures and record-keeping with respect to beneficial ownership interest in the 2012 Bonds, payment of principal, premium, if any, interest and other payments on the 2012 Bonds to DTC Participants or Beneficial Owners, confirmation and transfer of beneficial ownership interests in such 2012 Bonds and other related transactions by and between DTC, the DTC Participants and the Beneficial Owners is based solely on information provided by DTC. Accordingly, no representations can be made concerning these matters and neither the DTC Participants nor the Beneficial Owners should rely on the foregoing information with respect to such matters, but should instead confirm the same with DTC or the DTC Participants, as the case may be.

[THIS PAGE INTENTIONALLY LEFT BLANK]

APPENDIX D

SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE

The following is a summary of certain provisions of the Indenture. This summary is not to be considered a full statement of the terms of the Indenture and accordingly is qualified by reference thereto and is subject to the full text thereof. Capitalized terms not defined in this summary or elsewhere in the Official Statement have the respective meanings set forth in the Indenture.

Certain Definitions

"Act" means the provisions relating to the joint exercise of powers found in Chapter 5 of Division 7 of Title 1 of the Government Code of California, as amended and supplemented and shall also include the provisions of any other law applicable to NCPA by virtue of being a public entity pursuant to said Chapter 5 of Division 7 of Title 1 including, without limitation, Article 10 and Articles 11 of Chapter 3 of Division 2 of Title 5 of said Government Code, as each thereof may be amended and supplemented.

"Additional Bonds" means all Bonds, whether issued in one or more Series, authenticated and delivered on original issuance pursuant to Section 203 of the Original Indenture and any Bonds thereafter authenticated and delivered in lieu of or in substitution for such Bonds.

"Adjustable Rate Bond" means, as of any date of determination, any Bond not bearing interest from such date to the maturity thereof at a specified, fixed rate; provided, however, that each Adjustable Rate Bond shall also be an Option Bond with a Purchase Date on the Business Day next succeeding the termination of each Adjustment Period for such Bond.

"Adjusted Aggregate Debt Service" means, as of any date of calculation and with respect to any period, the sum of the amounts of Adjusted Debt Service during such period for all Series of Bonds, other than Lender Bonds; provided, however, that in computing such Adjusted Aggregate Debt Service, each Series of Adjustable Rate Bonds shall be deemed to bear the Assumed Interest Rate applicable thereto.

"Adjusted Debt Service" means, with respect to any Series of Bonds, as of any date of calculation and with respect to any period, the Debt Service for such Series of Bonds for such period which would result if the Principal Installment for such Series due on the final maturity date of such Series were adjusted over the period specified pursuant to the next sentence so that the Bonds of such Series would have Substantially Equal Debt Service for each Fiscal Year of such period and that such Principal Installment would be fully paid at the end of such period, assuming timely payment of all principal or Redemption Price, if any, of and interest on the Bonds of such Series in accordance with such adjustments and computing the interest component of Debt Service on the basis of the true interest cost actually incurred on such Series of Bonds (determined by the true, actuarial method of calculation which consists of calculating true interest cost from the actual delivery date of such Series of Bonds as opposed to calculating it from the date of such Series of Bonds). Such adjustment shall be made over a period which shall begin with the final maturity date of such Series and end on such date or a date which shall be specified in the Supplemental Indenture authorizing such Series of Bonds, which date shall be not later than the earlier to occur of (i) 40 years after the date of such Bonds or (ii) the termination date of the Third Phase Agreement. For purposes of computing such true interest cost for any Series of Bonds containing Adjustable Rate Bonds each such Adjustable Rate Bond shall be deemed to bear the Assumed Interest Rate applicable thereto.

"Agreement of Attornment" means the Agreement of Attornment, dated March 22, 1985, by and among NCPA, the Calaveras County Water District and Sierra Constructors, as the same may be amended and supplemented from time to time in accordance with its terms and terms of the Indenture.

"Beneficial Owner" means, with respect to the 2012 Bonds, any person which has or shares the power, directly or indirectly, to make investment decisions concerning ownership of any of the 2012 Bonds.

"Business Day" means, with respect to the 2012 Bonds, any day of the year on which banks in New York, New York are not required or authorized to remain closed and on which the Trustee, the Paying Agent and the New York Stock Exchange are open.

"Capital Improvements" shall mean all renewals or replacements of or repairs, additions, improvements, modifications or betterments chargeable to the capital account of the Project, which are (i) consistent with Prudent Utility Practice and determined necessary by the Commission to keep the Project in good operating condition or to prevent a loss of revenue therefrom, (ii) required by any governmental agency having jurisdiction over the Project, or (iii) required by the Indenture; provided, however, that Capital Improvements shall not include any additional generating units in addition to the number of generating units presently included in the Project.

"Debt Service Reserve Requirement" means, as of any date of calculation, and with respect to the Debt Service Reserve Account (which does not secure the 2012 Bonds), an amount equal to the greatest amount of Adjusted Aggregate Debt Service for the Participating Bonds for the then current or any future Fiscal Year and, with respect to a Series Debt Service Reserve Account, the amount, if any, specified as such with respect to such Series Debt Service Reserve Account pursuant to the Indenture.

"Favorable Opinion of Bond Counsel" means an opinion of Bond Counsel acceptable to the Insurer to the effect that the action proposed to be taken is authorized or permitted by the Indenture and will not result in the inclusion of interest on any Bonds in gross income for federal income tax purposes.

"Future Bonds" means all Bonds issued when the Eleventh Supplemental Indenture of Trust became effective, i.e., July 1, 1998.

"Initial Facilities" means those facilities included in or required by the FERC License and all associated facilities, rights, land and interest in land, properties, studies, reports, equipment, transmission facilities and improvements appurtenant thereto and necessary or convenient therewith including without limitation any payments to other parties such as contributions in and of construction in connection with the transmission of the output of the facilities included in the definition of the "Project" under the Power Purchase Contract.

"Interest Payment Date" means, with respect to each Series of Bonds, the dates during each year on which interest on such Series of Bonds is scheduled to be paid as specified in, or determined in accordance with, the Indenture or Supplemental Indenture authorizing such Series of Bonds.

"Investment Securities" means and includes any of the following securities, if and to the extent the same are at the time legal for investment of NCPA's funds:

(i) Direct obligations of, or obligations the principal of and interest on which are unconditionally guaranteed by, the United States of America, including obligations issued or held in book entry form on the books of the Department of the Treasury of the United States and including a receipt, certificate or any other evidence of an ownership interest in the aforementioned obligations, or in specified portions thereof (which may consist of specified portions of interest thereon) and also including advance refunded tax-exempt bonds secured by the aforementioned obligations;

(ii) Bonds, debentures, notes, participation certificates or other evidences of indebtedness issued, or the principal of and interest on which are unconditionally guaranteed, by the Bank for Cooperatives, the Federal Intermediate Credit Bank, the Federal Home Loan Bank System, the Export-Import Bank of the United States, the Government National Mortgage Association, the Federal National Mortgage Association, the United States Postal Service or any other agency or instrumentality of or corporation wholly owned by the United States of America;

(iii) New Housing Authority Bonds or Project Notes issued by public agencies or municipalities and fully secured as to the payment of both principal and interest by a pledge of annual contributions to be paid by the United States of America or any agency thereof;

(iv) Direct and general obligations, to the payment of which the full faith and credit of the issuer is pledged, of any State of the United States or any political subdivision thereof which at the time of investment is rated by any nationally recognized bond rating agency and assigned by such agency a rating which denotes a security with investment characteristics at least equal to the investment characteristics of a security presently rated by Moody's Investors Service, Inc. or Standard & Poor's Corporation as "A" or better;

(v) Bank time deposits evidenced by certificates of deposit, and banker's acceptances, issued by any bank, trust company or national banking association insured by the Federal Deposit Insurance Corporation; provided either that the aggregate of such bank time deposits and bankers' acceptances issued by any bank, trust company or banking association does not exceed at any one time ten per centum (10%) of the aggregate of the capital stock, surplus and undivided profits of such bank, trust company or banking association and that such capital stock, surplus and undivided profits shall not be less than Twenty-Five Million Dollars ($25,000,000), or that such deposits are fully and continuously secured by a valid and perfected security interest in obligations described in paragraph (i), (ii) or (iii) of this definition; and

(vi) Repurchase agreements with any bank, trust company or national banking association insured by the Federal Deposit Insurance Corporation, or with any government bond dealer recognized as a primary dealer by the Federal Reserve Bank of New York, which agreements are fully and continuously secured by a valid and perfected security interest in obligations described in paragraph (i), (ii) or (iii) of this definition.

"Moody's" means Moody's Investors Service, a corporation organized and existing under the laws of the State of Delaware, its successors and their assigns, or, if such corporation shall be dissolved or liquidated or shall no longer perform the functions of a securities rating agency, any other nationally recognized securities rating agency designated by NCPA by notice in writing to the Trustee and acceptable to the Insurer.

"NCPA Operating Expenses" means (i) costs incurred by NCPA pursuant to the Third Phase Agreement, (ii) any other current expenses or obligations required to be paid by NCPA under the provisions of the Project Agreements or by law, all to the extent properly allocable to the Project, or required to be incurred under or in connection with the performance of the Third Phase Agreement, (iii) the fees and expenses of the Fiduciaries, (iv) fees incurred pursuant to any lending or credit facility or agreement, including, without limitation, the Reimbursement Agreements, and (v) all other costs (including overhead) properly allocable to the Project. NCPA Operating Expenses shall not include any costs or expenses for new construction or any allowance for depreciation of the Project.

"NCPA Revenues" means (i) all revenues, income, rents and receipts derived or to be derived by NCPA from or attributable to the Project or the Power Purchase Contract or to the payment of the costs of the Project received or to be received by NCPA under the Third Phase Agreement or the Power Purchase Contract or under any other contract for the sale by NCPA of the Project or any part thereof or any contractual arrangement with respect to the use of the Project or any portion thereof or the services or capacity thereof, (ii) the proceeds of any insurance, including the proceeds of any self-insurance fund, covering business interruption loss relating to the Project, (iii) any receipts under the Construction Contract or the Agreement of Attornment, other than insurance proceeds required to be deposited in the Construction Fund in accordance with the provisions of the Indenture, and (iv) interest received or to be received on any moneys or securities (other than in the Construction Fund) held pursuant to the Indenture and required to be paid into the Revenue Fund.

"Participating Bonds" means all Bonds Outstanding prior to the Eleventh Supplemental Indenture of Trust becoming effective (July 1, 1998) and all Future Bonds other than Future Bonds which are specified in the Supplemental Indenture authorizing such Future Bonds not to be Participating Bonds in accordance with the provisions of the Indenture.

"Power Purchase Contract" means the Revised Power Purchase Contract, dated as of March 1, 1985, by and between NCPA and CCWD as the same may be amended and supplemented from time to time in accordance with its terms and the terms of the Indenture.

“Project” means the Initial Facilities and all Capital Improvements.

“Project Agreements” means, prior to the respective termination dates thereof, the Indenture, the Third Phase Agreement, the Power Purchase Contract, the Construction Contract, the Agreement of Attornment and any other contract designated a Project Agreement by the Commission of NCPA.

“Prudent Utility Practice” means any of the practices, methods and acts, which, in the exercise of reasonable judgment in the light of the facts (including but not limited to the practices, methods and acts engaged in or approved by a significant portion of the electrical utility industry prior thereto) known at the time the decision was made, would have been expected to accomplish the desired result at the lowest reasonable cost consistent with good business practices, reliability, safety and expedition, taking into account the fact that Prudent Utility Practice is not intended to be limited to the optimum practice, methods or act to the exclusion of all others, but rather to be a spectrum of possible practices, methods or acts which could have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety and expedition. Prudent Utility Practice includes due regard for manufacturers’ warranties and requirements of governmental agencies of competent jurisdiction and shall apply not only to functional parts of the Project, but also to appropriate structures, landscaping, paining, signs, lighting, other facilities and public relations programs reasonably designed to promote public enjoyment, understanding and acceptance of the Project.

“Securities Depository” means, with respect to a Series of the 2012 Bonds, the securities depository designated in the Supplemental Indenture with respect to such Series and its successors and assigns or if (a) the then incumbent Securities Depository resigns from its functions as depository for such Series of the 2012 Bonds, or (b) NCPA discontinues use of the then incumbent Securities Depository for such Series of the 2012 Bonds pursuant to such Supplemental Indenture, any other securities depository which agrees to follow the procedures required to be followed by a securities depository for such Series of the 2012 Bonds.

“Series Debt Service Reserve Account” means each Account within the Debt Service Fund established with respect to a Series of Future Bonds which are not Participating Bonds, including the 2012 Bonds, pursuant to the Indenture.

“Sinking Fund Installment” means with respect to a Series of the 2012 Bonds, the amount required by the Supplemental Indenture with respect to such Series to be paid by NCPA on any single date for the retirement of 2012 Bonds of such Series.

“Substantially Equal Adjusted Aggregate Debt Service” means, with respect to any period of similar Fiscal Years for all Outstanding Bonds, other than Lender Bonds, that the greatest Adjusted Aggregate Debt Service for any Fiscal Year in such period is not in excess of one hundred and twenty-five percent of the Adjusted Aggregate Debt Service for any preceding Fiscal Year in such period.

“Substantially Equal Debt Service” means, with respect to any period of Fiscal Years for any Series of Bonds, other than Lender Bonds, that the greatest Debt Service for such Bonds for any Fiscal Year in such period is not in excess of one hundred and twenty-five percent of the smallest Debt Service for such Bonds for any Fiscal Year in such period.

“Supplemental Indenture” shall mean any indenture supplemental to or amendatory of the Indenture, entered into by NCPA and the Trustee in accordance with the Indenture.

“S&P” means Standard & Poor’s Ratings Services, a division of The McGraw-Hill Companies, Inc., a corporation organized and existing under the laws of the State of New York, its successors and their assigns, or, if such corporation shall be dissolved or liquidated or shall no longer perform the functions of a securities rating agency, any other nationally recognized securities rating agency designated by NCPA by notice in writing to the Trustee and acceptable to the Insurer.

“Trust Estate” means (A) subject only to the provisions of the Indenture permitting the application thereof for the purposes and on the terms and conditions set forth in the Indenture, (i) the proceeds of the sale of the Bonds, other than Lender Bonds, (ii) the NCPA Revenues and (iii) all amounts on deposit in the Funds established by the Indenture, including the investments, if any, thereof, to the extent held by the Trustee; (B) all right, title and interest of NCPA in, to and under the Third Phase Agreement; (C) all right, title and interest of NCPA in, to and under the Power Purchase Contract; and (D) all right, title and interest of NCPA in, to and under the Construction Contract and the Agreement of Attornment.

"2012 Bonds" means collectively, the 2012 Series A Bonds and the 2012 Series B Bonds.

"2012 Series A Bonds" means the Northern California Power Agency Hydroelectric Project Number One Revenue Bonds, 2012 Refunding Series A.

"2012 Series B Bonds" means the Northern California Power Agency Hydroelectric Project Number One Revenue Bonds, 2012 Taxable Refunding Series B.

Pledge Effected by the Indenture

NCPA has pledged and assigned the Trust Estate to the Trustee for the benefit of the Bondholders.

Nature of Obligation

The Indenture provides that the principal, Redemption Price, if any, and Purchase Price thereof, and interest on the Bonds shall be payable solely from the NCPA Revenues and other funds pledged by NCPA under the Indenture and shall not constitute a charge against the general credit of NCPA. Neither the faith and credit nor the taxing power of the State of California or any public agency thereof or any member of NCPA or any Project Participant is pledged to the payment of the principal, Redemption Price, if any, and Purchase Price of, or interest on the Bonds. NCPA has no taxing power. The Bonds do not constitute a debt, liability or obligation of the State of California or any public agency (other than NCPA) or any member of NCPA or any Project Participant. Neither the members of the Commission of NCPA nor any officer or employee of NCPA shall be individually liable for the Bonds or in respect of any undertakings by NCPA under the Indenture.

Application of NCPA Revenues

NCPA Revenues are pledged by the Indenture to payment of the principal, Redemption Price, if any, and Purchase Price of, and interest on the Bonds, subject to the provisions of the Indenture permitting application for other purposes. The Indenture establishes the following Funds and Accounts for the application of Bond proceeds and NCPA Revenues:

FUNDS	HELD BY
Revenue Fund	NCPA
Operating Reserve Fund	Trustee
Operating Fund	NCPA
Debt Service Fund[*]	Trustee
Debt Service Account	
Debt Service Reserve Account	
Subordinated Indebtedness Fund	Trustee
Note Fund	Trustee
Reserve and Contingency Fund	NCPA
Renewal and Replacement Account	
Reserve Account	
General Reserve Fund	NCPA
Rate Stabilization Account	
General Account	

All NCPA Revenues received are to be deposited promptly in the Revenue Fund upon receipt thereof. Amounts in the Revenue Fund are to be paid monthly in the following order of priority for application therefrom as follows:

(1) To the Operating Reserve Fund, the amount, if any, required so that the balance in said Fund shall equal $100,000 or such greater or lesser amount as shall be recommended by the Consulting Engineer to be on deposit in said Fund .

(2) To the Operating Fund, a sum which, together with any amount in the Operating Fund not set aside as a general reserve for NCPA Operating Expenses or as a reserve for working capital, is equal to the total moneys appropriated for NCPA Operating Expenses in the Annual Budget for the then current month. In addition, if the Supplemental Indenture authorizing a Series of Bonds so provides, amounts from the proceeds of such Bonds may be deposited in the Operating Fund and set aside as a reserve for working capital. Amounts in the Operating Fund shall be paid out from time to time by NCPA for reasonable and necessary NCPA Operating Expenses. The Indenture provides for the application of excess amounts in the Operating Fund to make up any deficiencies in certain other funds established under the Indenture with any balance to be deposited in the General Account of the General Reserve Fund.

(3) To the Debt Service Fund (i) for credit to the General Debt Service Subaccount, the amount, if any, required so that the balance in said subaccount, plus the amounts on deposit in all the other subaccounts in the Debt Service Account to the extent available to pay Accrued Aggregate Debt Service, as of the last day of the then current month, shall equal the Accrued Aggregate Debt Service as of the last day of the then current month; (ii) for credit to the Debt Service Reserve Account, the amount, if any, required for such Account to equal the Debt Service Reserve Requirement for the Debt Service Reserve Account as of the last day of the then current month; and (iii) for credit to each Series Debt Service Reserve Account established for Future Bonds, the amount, if any, required for each such Account to equal the applicable Debt Service Reserve Requirement for such Series Debt Service Reserve Account as of the last day of the then current month; provided that the transfers to the Debt Service Reserve Account and each Series Debt Service Reserve Account shall be made to the Debt Service Reserve Account and each Series Debt Service Reserve Account without preference or priority between such transfers made in accordance with clauses (ii) and (iii) of this subsection (a), and in the event of any insufficiency of such moneys ratably based on the amount required to be deposited in each such Account, without any discrimination or preference. The Trustee will apply amounts in the General Debt Service Subaccount in the Debt Service Account to the payment of principal of and interest on the Bonds. In addition, the Trustee may, and if directed by NCPA

[*] If provided in a Supplemental Indenture authorizing a Series of Future Bonds which are not Participating Bonds, the Debt Service Fund shall include a Series Debt Service Reserve Account for each such Series of Future Bonds as to which a debt service reserve is to be established.

must, apply certain amounts in the Debt Service Account to the purchase or redemption of Bonds to satisfy sinking fund requirements prior to the due date of any Sinking Fund Installment. The Trustee must pay out of the Debt Service Account the amount required for the redemption of Bonds called for redemption pursuant to sinking fund requirements on any redemption date.

Amounts in the Debt Service Reserve Account are to be applied on the last business day of each month to make up any deficiency in the Debt Service Account with respect to Participating Bonds. Whenever the amount in the Debt Service Reserve Account, together with the amount in the Debt Service Account with respect to Participating Bonds, is sufficient to pay in full all Outstanding Participating Bonds in accordance with their terms, the funds on deposit in the Debt Service Reserve Account will be transferred to the Debt Service Account. So long as the amount in the Debt Service Fund available for such purpose is sufficient to pay all then Outstanding Participating Bonds in full (including principal or applicable sinking fund Redemption Price and interest thereon), no deposits shall be required to be made in the Debt Service Reserve Account. Whenever moneys on deposit in the Debt Service Reserve Account exceed the Debt Service Reserve Requirement with respect to such Account, the excess will be deposited in the Revenue Fund.

In the event of the refunding of Participating Bonds, the Trustee shall, upon the direction of NCPA with the advice of Bond Counsel, withdraw from the Debt Service Reserve Account any and all of the amounts on deposit therein and hold such amounts for the payment of the principal or Redemption Price, if applicable, and interest on such Participating Bonds; provided that such withdrawal shall not be made unless (a) immediately thereafter the Participating Bonds being refunded shall be deemed to have been paid pursuant to the Indenture, and (b) the amount remaining in the Debt Service Reserve Account after such withdrawal shall not be less than the Debt Service Reserve Requirement for the Debt Service Reserve Account.

Amounts in each Series Debt Service Reserve Account are to be applied on the last business day of each month to make up any deficiency in the Debt Service Account with respect to the Future Bonds secured by such Series Debt Service Reserve Account. Whenever the amount in a Series Debt Service Reserve Account, together with the amount in the Debt Service Account with respect to the Future Bonds secured by such Series Debt Service Reserve Account, is sufficient to pay in full all Future Bonds secured by such Series Debt Service Reserve Account then Outstanding in accordance with their terms, the funds on deposit in such Series Debt Service Reserve Account will be transferred to the Debt Service Account and applied to the payment or redemption of the Series of Future Bonds secured by such Series Debt Service Reserve Account. So long as the amount in the Debt Service Fund with respect to a Series of Future Bonds secured by a Series Debt Service Reserve Account is sufficient to pay all such Future Bonds then Outstanding in full (including principal or applicable sinking fund Redemption Price and interest thereon), no deposits shall be required to be made in such Series Debt Service Reserve Account. Whenever moneys on deposit in a Series Debt Service Reserve Account exceed the Debt Service Reserve Requirement with respect to such Account, the excess will be deposited in the Revenue Fund.

In the event of the refunding of Future Bonds secured by a Series Debt Service Reserve Account, the Trustee shall, upon the direction of NCPA with the advice of Bond Counsel, withdraw from the Series Debt Service Reserve Account securing such Future Bonds any and all of the amounts on deposit therein and hold such amounts for the payment of the principal or Redemption Price, if applicable, and interest on such Future Bonds; provided that such withdrawal shall not be made unless immediately thereafter the Future Bonds being refunded shall be deemed to have been paid pursuant to the Indenture,.

(4) To the Subordinated Indebtedness Fund, the amount, if any, required so that the balance in said Fund shall equal all principal and interest on outstanding Subordinated Indebtedness accrued and unpaid and to accrue to the end of the then current calendar month. The Trustee will apply amounts in the Subordinated Indebtedness Fund to the payment of interest and reserves on Subordinated Indebtedness in accordance with the provisions of the resolution, agreement or contract relating to the issuance of such Subordinated Indebtedness. However, if at any time the amounts in the Debt Service Fund are less then the amounts required by the Indenture, and there is not on deposit in the General Reserve Fund or in the Reserve and Contingency Fund or in the Note Fund available moneys sufficient to cure such deficiency, the

Trustee will transfer from the Subordinated Indebtedness Fund the amount necessary to make up such deficiency.

(5) To the Note Fund, the amount, if any, required so that the balance in said Fund shall equal all interest on outstanding Notes accrued and unpaid and to accrue to the end of the then current calendar month. The Trustee will apply amounts in the Note Fund to the payment of interest on Notes in accordance with the provisions of the resolution, agreement or contract relating to the issuance of such Notes. However, if at any time the amounts in the Debt Service Fund are less than the amounts required by the Indenture, and there is not on deposit in the General Reserve Fund or in the Reserve and Contingency Fund available moneys sufficient to cure such deficiency, the Trustee will transfer from the Note Fund the amount necessary to make up such deficiency.

(6) To the Reserve and Contingency Fund, for credit to (a) the Renewal and Replacement Account, the amount, if any, provided for deposit therein during the then current month in the current Annual Budget; and (b) the Reserve Account, the amount, if any, required to that the balance in said Account shall equal $3,000,000 or such greater or lesser amount as shall be recommended by the Consulting Engineer to be on deposit in said Account.

Amounts in the Renewal and Replacement Account will be applied to the cost of Capital Improvements. To the extent not provided for in the then current Annual Budget or by reserves in the Operating Fund or from the proceeds of Bonds, amounts in the Reserve Account will be applied to the costs of Capital Improvements to the extent amounts in the Renewal and Replacement Account are not sufficient therefor, and to the payment of extraordinary operating and maintenance costs of the Project and contingencies.

If at any time the amounts in the Debt Service Fund are less than the amounts required by the Indenture, and there are not on deposit in the General Reserve Fund available moneys sufficient to cure such deficiency, then the Trustee will transfer from the Reserve Account and the Renewal and Replacement Account, in that order, the amount necessary to make up such deficiency.

Amounts in the Renewal and Replacement Account or the Reserve Account not required to meet any deficiencies in the Debt Service Fund or for any of the purposes for which such Accounts were established shall be transferred to the Operating Fund to the extent, if any, deemed necessary by NCPA, to make up any deficiencies therein. Any remaining excess shall be deposited into the General Account of the General Reserve Fund.

(7) To the Rate Stabilization Account of the General Reserve Fund, the amount, if any, provided for deposit therein during the then current month in the Annual Budget and, to the General Account of the General Reserve Fund, the balance, if any, in the Revenue Fund. NCPA must transfer from the General Reserve Fund: (a) to the Debt Service Fund amounts necessary to make up any deficiencies in required payments to the Debt Service Fund; and (b) to the Renewal and Replacement Account and the Reserve Account in the Reserve and Contingency Fund the amount necessary to make up any deficiencies in payments to said Accounts.

Amounts in the General Reserve Fund not required to meet any of the deficiencies described above will, upon determination of NCPA, be applied to or set aside for any one or more of the following: (a) transfer to the Revenue Fund; (b) the purchase or redemption of any Bonds, and expenses and reserves in connection therewith; (c) NCPA Operating Expenses or reserves therefor; (d) payments into any separate account or accounts established in the Construction Fund; (e) Capital Improvements or reserves therefor; (f) payment of principal of and interest on Subordinated Indebtedness or purchase or redemption of Subordinated Indebtedness; (g) payment of principal of and interest on Notes; and (h) any other lawful purpose of NCPA related to the Project. Bonds purchased or redeemed with amounts in the General Reserve Fund may be credited to Sinking Fund Installments thereafter to become due (other than the next due).

Deposits from the Revenue Fund into the Debt Service Fund, the Subordinated Indebtedness Fund, the Note Fund, the Reserve and Contingency Fund and the General Reserve Fund are to be made as soon as practicable in each month after the deposit of NCPA Revenues into the Revenue Fund, the Operating Reserve Fund and the Operating Fund have been made for such month, but not later than the last business day of such month.

Certain Requirements of and Conditions to Issuance of Bonds

Bonds shall be authenticated by the Trustee pursuant to the Indenture upon compliance with certain requirements and conditions, including the following:

(a) The Trustee shall have received an Opinion of Bond Counsel to the effect that the Bonds of the Series being issued have been duly and validly authorized, issued and are valid and binding obligations of NCPA and as to certain other matters concerning the Indenture.

(b) The Trustee shall have received the amount, if any, necessary for deposit: (A) in the Debt Service Reserve Account so that the amount in such Account shall equal the Debt Service Reserve Requirement with respect to such Account calculated immediately after the authentication and delivery of each Series of Participating Bonds and (B) in the Series Debt Service Reserve Account, if any, established with respect to each Series of Future Bonds, so that the amount in such Account shall equal the Debt Service Reserve Requirement, if any, with respect to such Account calculated immediately after the authentication and delivery of such Series of Future Bonds;

(c) Except in the case of Lender Bonds and Refunding Bonds, NCPA shall have certified that it is not in default in the performance of its agreements under the Indenture. In the case of Refunding Bonds such certificate may state that upon the application of the proceeds of the Refunding Bonds, NCPA will not be in default in the performance of its agreements under the Indenture.

The Indenture also provides that Principal Installments will be established at the time of issuance for each Series of Bonds so as to comply with the following:

(a) Principal Installments shall commence not later than the later of (A) the first day of the eighth Fiscal Year following the end of the Fiscal Year of authentication and delivery of such Series of Bonds or (B) the first day of the fifth Fiscal Year following the end of the Fiscal Year in which NCPA estimates that the Project will reach its Date of Firm Operation, and shall terminate not later than the date on which the Third Phase Agreement terminates.

(b) Such Principal Installments shall result in either (A) Substantially Equal Debt Service for the Bonds of such Series for the Fiscal Year immediately preceding the due date of the first such Principal Installment to occur subsequent to the Date of Firm Operation of the Project and for each Fiscal Year thereafter to and including the final maturity date of such Series or (B) Substantially Equal Adjusted Aggregate Debt Service for all Outstanding Bonds, including such Series being issued, for the first Fiscal Year in which Principal Installments become due on all Series of Bonds then Outstanding, including such Series being issued, beginning however no earlier than the Fiscal Year immediately preceding the due date of the first Principal Installment to occur subsequent to the Date of Firm Operation of the Project, and for each Fiscal Year thereafter to and including the Fiscal Year immediately preceding the latest maturity of any Series of Bonds Outstanding immediately prior to the issuance of such Series being issued or the Fiscal Year immediately preceding the latest maturity of such Series being issued, whichever is earlier (using in the case of any Series of Bonds sold by competitive bidding a net effective interest rate for the Bonds of such Series as estimated by NCPA); provided that, if the first Principal Installment of any Series of Bonds shall be less than 12 months after the date of issuance thereof, it shall be assumed, for purposes of this calculation, that interest accrued on such Series for the entire 12-month period preceding the first Principal Installment at the same rate as interest accrued for the actual portion of such period during which such Series of Bond was Outstanding.

Additional Bonds

NCPA may issue one or more series of Additional Bonds for the purpose of paying all or a portion of the Cost of Acquisition and Construction of the Project including paying the principal of and interest on any Subordinated Indebtedness or Notes issued for the purpose of paying all or a portion of the Cost of Acquisition and Construction of the Project upon compliance with the conditions to issuance described above.

Refunding Bonds

One or more Series of Refunding Bonds may be issued to refund any Outstanding Bonds of one or more Series or one or more maturities within a Series. Refunding Bonds shall be authenticated and delivered by the Trustee pursuant to the Indenture upon compliance with certain requirements and conditions, including the receipt by the Trustee of either (i) moneys sufficient to pay the applicable Redemption Price of the refunded Bonds to be redeemed plus the amount required to pay principal of refunded Bonds not to be redeemed together with accrued interest on such Bonds to the redemption date or maturity date, as the case may be, or (ii) Investment Securities in such amounts and having such terms as required by the Indenture to pay the principal or Redemption Price, if applicable, and interest due on and before the redemption date or maturity date, as the case may be.

Debt Service Reserves for Future Bonds

Each Series of Future Bonds shall constitute Participating Bonds unless the Supplemental Indenture authorizing such Series of Future Bonds provides that such Series of Future Bonds shall not be Participating Bonds and, if such Series of Future Bonds is to be secured by a Series Debt Service Reserve Account, provides for the establishment of such Series Debt Service Reserve Account and establishes the Debt Service Reserve Requirement for such Account; provided, however, that each Series of Future Bonds shall constitute Participating Bonds unless at or prior to the issuance of such Series of Future Bonds the Trustee shall have received written confirmation from each rating agency then rating the Outstanding Bonds that the issuance of such Series of Future Bonds as other than Participating Bonds, in and of itself, will not result in the withdrawal or reduction in the rating of any Bonds, other than such Series of Future Bonds, to be Outstanding upon the issuance of such Series of Future Bonds.

Notice of Redemption

The Trustee shall give notice of the redemption of any Bonds to be redeemed, which notice shall specify the redemption date and the place or places where amounts due upon redemption will be payable, and, if less than all of the Bonds of any like Series and maturity are to be redeemed, the letters and numbers or other distinguishing marks of such Bonds so to be redeemed, and, in the case of Bonds to be redeemed in part only, such notice shall also specify the respective portions of the principal amount thereof to be redeemed. Such notice shall further state that on such date there shall become due and payable upon each Bond to be redeemed the Redemption Price thereof, or the Redemption Price of the specified portions of the principal thereof in the case of Bonds to be redeemed in part only, together with interest accrued to the redemption date, and that from and after such date interest thereon shall cease to accrue and be payable.

With respect to the redemption of any Bonds, the Trustee will mail a copy of such notice, not less than thirty (30) days before the redemption date, to the registered owners of any Bonds or portions of Bonds which are to be redeemed, a their last addresses, if any, appearing upon the registry books.

Receipt of such notice shall not be a condition precedent to such redemption of the Bonds and failure to receive any such notice shall not affect the validity of the proceedings for the redemption of Bonds. Upon the request of NCPA, the Trustee shall also give notice of redemption to certain securities depositories and bond services as specified in the Indenture.

Interchangeability and Transfer

Bonds, other than Lender Bonds, upon surrender thereof at the principal corporate trust office of the Bond Registrar with a written instrument of transfer satisfactory to the Bond Registrar, duly executed by the Holder or his duly authorized attorney, may be exchanged for an equal aggregate principal amount of Bonds of the same maturity and of other authorized denominations.

Except for Option Bonds deemed tendered but not actually tendered, Bonds shall be transferable only upon the books of NCPA, which shall be kept for such purposes at the principal corporate trust office of the Bond Registrar, by the Holder thereof in person or by his attorney duly authorized in writing, upon surrender thereof together with a written instrument of transfer satisfactory to the Bond Register duly executed by the Holder or his duly authorized attorney. Upon the transfer of any such Bond, other than a Lender Bond, NCPA shall issue in the name of the transferee a new Bond or Bonds of the same aggregate principal amount and Series and maturity as the surrendered Bond.

In all cases in which the privilege of exchanging Bonds or transferring Bonds is exercised, NCPA shall execute and the Trustee shall authenticate and deliver Bonds in accordance with the provisions of the Indenture. For every such exchange or transfer of Bonds, NCPA or the Bond Registrar may make a charge sufficient to reimburse it for any tax, fee or other governmental charge required to be paid with respect to such exchange or transfer.

Investment of Certain Funds and Accounts

The Indenture provides that certain Funds and Accounts held thereunder may, and in the case of the Debt Service Account and the Debt Service Reserve Account in the Debt Service Fund, the Subordinated Indebtedness Fund, and the Note Fund, subject to the terms of agreements relating to the issuance of the Subordinated Indebtedness and Notes, must, be invested to the fullest extent practicable in Investment Securities; provided that certain of such Funds and Accounts can only be invested in certain types of Investment Securities. The Indenture provides that such investments will mature no later than such times as necessary to provide moneys when reasonably expected to be needed for payments from such Funds and Accounts and provides specific limitations on the terms of investments for moneys in certain Funds and Accounts.

Prior to the completion of the Initial Facilities, interest and investment earnings (net of which (a) represents a return of accrued interest paid in connection with the purchase of any investment or (b) is required to effect the amortization of any premium paid in connection with the purchase of any investment) earned on any moneys or investments in such Funds and Accounts will be paid into the Construction Fund and after such date all such interest shall be paid into the Revenue Fund; except that to the extent provided in the Supplemental Indenture authorizing a Series of Additional Bonds to pay the Cost of Acquisition and Construction of Capital Improvements, all such interest earned on any moneys or investments in the account established in the Construction Fund for such Capital Improvements shall be retained in said account.

The Trustee may deposit moneys in all Funds and Accounts held by it under the Indenture in banks or trust companies organized under the laws of any state of the United States or national banking associations ("Depositaries"). All moneys held under the Indenture by the Trustee or any Depositary must be (1) either (a) continuously and fully insured by the Federal Deposit Insurance Corporation, or (b) continuously and fully secured by lodging with the Trustee or any Federal Reserve Bank, as custodian, as collateral security, such securities as are described in clauses (i) through (iv), inclusive, of the definition of "Investment Security" having a market value (exclusive of accrued interest) not less than the amount of such moneys, or (2) held in such other manner as may then be required by applicable Federal or State of California laws and regulations and applicable state laws and regulations of the state in which the Trustee or such Depositary is located, regarding security for the deposit of trust funds; provided, however, that it shall not be necessary for the Trustee, the Depositaries or any Paying Agent to give security for the deposit of any moneys held in trust by it and set aside for the payment of principal or Redemption Price or Purchase Price of, or interest on, any Bonds or to give security for any moneys which are represented by obligations or certificates of deposit purchased as an investment of such moneys.

In computing the amount in any Fund created under the Indenture, obligations purchased as an investment of moneys therein shall be valued at the amortized costs of such obligations or the market value thereof, whichever is lower, exclusive of accrued interest except that obligations purchased as an investment of moneys in the Debt Service Reserve Account are to be valued at the amortized cost thereof.

Covenants

Encumbrances: Disposition of Properties

NCPA will not issue bonds, notes, debentures or other evidences of indebtedness, other than the Bonds, payable out of or secured by a pledge or assignment of the NCPA Revenues or other moneys, securities or funds held or set aside by NCPA, or the Fiduciaries under the Indenture, nor will it create, or cause to be created, any lien or charge thereon; provided, however, that nothing contained in the Indenture shall prevent NCPA from issuing, if and to the extent permitted by law, (1) evidences of indebtedness (a) payable out of moneys in the Construction Fund as part of the Cost of Acquisition and Construction of the Project or (b) payable out of, or secured by a pledge and assignment of, NCPA Revenues to be derived on and after the discharge of the pledge of NCPA Revenues provided in the Indenture or (2) Subordinated Indebtedness or Notes issued in accordance with the provisions of the Indenture.

NCPA may, however, acquire, construct or finance through the issuance of its bonds, notes or other evidences of indebtedness any facilities which do not constitute a part of the Project for the purposes of the Indenture and may secure such bonds, notes or other evidences of indebtedness by a mortgage of the facilities so financed or by a pledge of, or lien on, the revenues therefrom or any lease or other agreement with respect thereto or any revenues derived from such lease or other agreement; provided that such bonds, notes or other evidences of indebtedness shall not be payable out of or secured by the NCPA Revenues or any Fund or Account held under the Indenture and neither the cost of such facilities nor any expenditure in connection therewith or with the financing thereof shall be payable from the NCPA Revenues or from any such Fund or Account.

NCPA will not sell, lease, mortgage or otherwise dispose of the Project or consent to the sale, lease, mortgage or other disposal of the Project other than in accordance with the Third Phase Agreement.

Rate Covenant

NCPA covenants in the Indenture that so long as any Bonds are Outstanding it will have good right and lawful power to establish charges and cause to be collected amounts with respect to the use of the Project, subject to the terms of the Third Phase Agreement. NCPA covenants in the Indenture that it will at all times establish charges and cause to be collected amounts with respect to the use of the Project, as shall be required to provide NCPA Revenues at least sufficient in each Fiscal Year, together with other available funds, for the payment of all the following:

(a) NCPA Operating Expenses during such Fiscal Year;

(b) An amount equal to the Aggregate Debt Service for such Fiscal Year;

(c) The amount, if any to be paid during such Fiscal Year into the Debt Service Reserve Account and each Series Debt Service Reserve Account in the Debt Service Fund;

(d) The amount, if any, to be paid during such Fiscal Year into the Subordinated Indebtedness Fund;

(e) The amount, if any, to be paid during such Fiscal Year into the Note Fund;

(f) The amount to be paid during such Fiscal Year into the Reserve and Contingency Fund for credit to the Renewal and Replacement Account and the Reserve Account therein; and

(g) All other charges or liens whatsoever payable out of NCPA Revenues during such Fiscal Year.

In estimating Aggregate Debt Service on any Adjustable Rate Bonds for purposes of the preceding paragraph, NCPA shall be entitled to assume that such Adjustable Rate Bonds will bear such interest rate or rates as

NCPA shall determine; provided, however, that the interest rate or rates assumed shall not be less than the interest rate borne by such Adjustable Rate Bonds at the time of determination of Aggregate Debt Service.

NCPA will not furnish or supply or cause to be furnished or supplied any use or service of the Project free of charge to any person, firm or corporation, public or private, and NCPA will, consistent with the Project Agreements and upon the direction of the Trustee, enforce the payment of any and all accounts owing to NCPA by reason of the Project by discontinuing such use or service, or by filing suit therefor, as soon as practicable 30 days after any such accounts are due, or by both such discontinuance and by filing suit.

Covenants with Respect to Third Phase Agreement and Project Agreements

NCPA covenants that it will receive and deposit in the Revenue Fund all amounts payable to it under the Third Phase Agreement or otherwise payable to it pursuant to any contract for use of the Project or any part thereof. NCPA will enforce the provisions of the Third Phase Agreement and duly perform its covenants and agreements thereunder, and will not agree to or permit any rescission of or amendment to, or otherwise take any action under or in connection with, the Third Phase Agreement which would reduce the payments required thereunder or which would in any manner materially impair or materially adversely affect the rights or security of Bondholders under the Indenture; provided, however, NCPA is specifically authorized to make certain amendments relating to billing procedures and the sale price of surplus power and energy under the Third Phase Agreement and is also not prohibited from making any other amendments to the Third Phase Agreement.

Subject to the terms of the Indenture, NCPA will enforce or cause to be enforced the provisions of the Project Agreements to which it is a party and duly perform its covenants and agreements thereunder. NCPA will not consent or agree to or permit any rescission of or amendment to or otherwise take any action under or in connection with the Project Agreements which will in any manner materially impair or materially adversely affect the rights of NCPA thereunder or the rights or security of the Bondholders under the Indenture.

Annual Budget

NCPA will file with the Trustee an Annual Budget prepared in accordance with the Third Phase Agreement for each Fiscal Year commencing with the first Power Supply Year. The Annual Budget will set forth the estimated NCPA Revenues and NCPA Operating Expenses of the Project by month for such Fiscal Year and shall include monthly appropriations for the estimated amount to be deposited in each month of such Fiscal Year in the Revenue Fund, including provision for any general reserve for NCPA Operating Expenses and the amount to be deposited in the Renewal and Replacement Account, the Reserve Account in the Reserve and Contingency Fund, the Rate Stabilization Account in the General Reserve Fund and the requirements, if any, for the amounts estimated to be expended from each Fund and Account. NCPA shall review quarterly its estimates set forth in the Annual Budget and in the event such estimates do not substantially correspond with the actual NCPA Revenues, NCPA Operating Expenses or other requirements, NCPA shall adopt an amended Annual Budget for the remainder of such Fiscal Year. NCPA is also required to adopt such an amended Annual Budget if there are at any time during the year extraordinary receipts or payments of unusual costs. NCPA may also at any time in accordance with the provisions of the Third Phase Agreement, adopt an amended Annual Budget for the remainder of the then current Fiscal Year.

Insurance

NCPA will at all times after commencement of construction of the Project, insure the Project or cause the Project to be insured against such causes customarily insured against and in such amounts as are usually obtained. NCPA will also use its best efforts to maintain or cause to be maintained any additional or other insurance which NCPA deems necessary or advisable to protect its interests and those of the Bondholders. If any useful portion of the Project is damaged or destroyed, NCPA shall, as expeditiously as possible, continuously and diligently enforce its right to cause to be prosecuted the reconstruction or replacement thereof. The proceeds of any insurance, including the proceeds of any self-insurance fund, paid on account of damage or destruction (other than any business interruption loss insurance) shall be held by the Trustee and applied, to the extent necessary, to pay the costs of reconstruction or replacement. The proceeds of any business interruption loss insurance shall be paid into the Revenue Fund unless otherwise required by the Third Phase Agreement.

Accounts and Reports

NCPA will keep or cause to be kept proper and separate books of records and accounts relating to the Project and each Fund and Account established by the Indenture and relating to the costs and charges under the Third Phase Agreement. Such books, together with the Third Phase Agreement and all other books and papers of NCPA relating to the Project, will at all times be subject to the inspection of the Trustee and the Holders of an aggregate of not less than 5% in principal amount of Bonds then Outstanding.

NCPA will file annually with the Trustee an annual report for each Fiscal Year, accompanied by an Accountant's Certificate, relating to the Project, including a statement of assets and liabilities as of the end of such Fiscal Year, a statement of NCPA Revenues and NCPA Operating Expenses and a statement as to the existence of any default under the provisions of the Indenture.

NCPA will notify the Trustee forthwith of any Event of Default or default in the performance by NCPA of a provision of the Indenture. NCPA will file annually with the Trustee a certificate of an Authorized NCPA Representative stating whether, to the best of the signer's knowledge and belief, NCPA has complied with its covenants and obligations in the Indenture and whether there is then existing an Event of Default or other event which would become an Event of Default upon the lapse of time or the giving of notice, or both, and if any such default or Event of Default so exists, specifying the same and the nature and the status thereof.

The reports, statements and other documents required to be furnished to the Trustee pursuant to any provisions of the Indenture will be available for inspection of Bondholders at the office of the Trustee and will be mailed to each Bondholder who files a written request therefor with the Trustee. The Trustee may charge each Bondholder requesting such reports, statements or other documents a reasonable fee to cover reproduction, handling and postage.

Extension of Payment of Bonds

NCPA covenants in the Indenture that it will not extend or assent to the extension of the maturity of any of the Bonds, other than Lender Bonds, or claims for interest. If the maturity of any of the Bonds, other than Lender Bonds, or claims for interest is extended, such Bonds or claims for interest shall not be entitled, in the case of any default under the Indenture, to the benefit of the Indenture or any payment out of NCPA Revenues, Funds or the moneys held by the Trustee or by any Paying Agent or any Depositary, except moneys held in trust for payment of (i) the principal of all Bonds Outstanding the maturity of which has not been extended, (ii) the portion of accrued interest on the Bonds which is not represented by such extended claims for interest and (iii) the accrued interest on the Lender Bonds. Nothing herein shall be deemed to limit the right of NCPA to issue Option Bonds or Refunding Bonds and neither such issuance nor the exercise by the Holder of any Option Bond of any of the rights appertaining to such Option Bond shall be deemed to constitute an extension of maturity of Bonds.

Amendments and Supplemental Indentures

Any of the provisions of the Indenture may be amended by NCPA, with the written consent of the Banks, by a Supplemental Indenture upon the consent of the Holders of at least sixty percent in principal amount in each case of (1) all Bonds then Outstanding and (2) if less than all of the several Series of Outstanding Bonds are affected, the Bonds of each affected Series; excluding, in each case, from such consent, and from the Outstanding Bonds, the Bonds of any specified Series and maturity if such amendment by its terms will not take effect so long as any of such Bonds remain Outstanding. Any such amendment may not permit a change in the terms of any Sinking Fund Installment or the terms of redemption or maturity of the principal of or interest on any Outstanding Bond or make any reduction in principal, Redemption Price, Purchase Price or interest rate without the consent of each affected Holder, or reduce the percentages of consents required for a further amendment.

NCPA may enter into, with the written consent of the Banks (without the consent of any Holders of the Bonds or the Trustee), a Supplemental Indenture to close the Indenture against, or impose additional limitations upon, the issuance of Bonds or other evidences of indebtedness; to authorize Bonds of a Series; to add to the restrictions to be observed by NCPA contained in the Indenture; to add to the covenants of NCPA contained in the

Indenture; to confirm any lien or pledge under the Indenture; to authorize the establishment of a fund or funds for self-insurance; to authorize Subordinated Indebtedness or Notes; and to modify any of the provisions of the Indenture in any other respect if (i) no Bonds will be Outstanding at such time or (ii) such modification shall be, and be expressed to be, effective only after all Bonds then Outstanding cease to be Outstanding and all Bonds authenticated and delivered after the adoption of such Supplemental Indenture specifically refer to such Supplemental Indenture in the text of such Bonds. NCPA may enter into, with the written consent of the Banks, a Supplemental Indenture which shall be effective upon the consent of the Trustee (without the consent of any Holders of the Bonds) to cure any ambiguity, supply any omission or correct any defect or inconsistent provision in the Indenture; or to clarify matters or questions arising under the Indenture and not contrary to or inconsistent with the Indenture.

Trustee; Payment Agents

The Trustee may at any time resign on 60 days' notice to NCPA and the Banks. Such resignation will take effect on the date specified in such notice, or, if a successor Trustee has been appointed, such resignation will take effect immediately upon the appointment of such successor. The Trustee may at any time be removed by the Holders of a majority in principal amount of the Bonds then Outstanding. Successor Trustees may be appointed by the Banks and the Holders of a majority in principal amount of Bonds then Outstanding, and failing such an appointment NCPA shall appoint a successor to hold office until the Banks and the Bondholders act. The Trustee and each successor Trustee, if any, must be a bank, trust company, or national banking association doing business and having its principal office in New York, New York or Chicago, Illinois or Los Angeles, California or San Francisco, California and having capital stock and surplus aggregating at least $50,000,000, if there be such an entity willing and able to accept the appointment. The Indenture requires the appointment by NCPA of one or more Paying Agents (which may include the Trustee).

Pursuant to the Indenture, the Trustee, prior to the occurrence of an Event of Default and after the curing of all Events of Default which may have occurred, undertakes to perform only such duties as are specifically set forth in the Indenture. If an Event of Default has occurred and has not been cured, the Trustee shall exercise such of the rights and powers vested in it by the Indenture, and use the same degree of care and skill in their exercise, as a prudent man would exercise or use under the circumstances in the conduct of his own affairs. Subject to the above, neither the Trustee nor any Paying Agent shall be liable in connection with the performance of its duties under the Indenture except for its own negligence, misconduct or default.

NCPA will cause to be paid to the Trustee and any Paying Agent or Depositary reasonable compensation for all services rendered under the Indenture and all reasonable expenses, charges, counsel fees and other disbursements, incurred in the performance of its duties under the Indenture. Each Trustee, Paying Agent or Depositary has a lien on any and all funds held by it under the Indenture securing its rights to compensation except that the proceeds of Drawings under the Letters of Credit or any funds taken into account in calculating the amount drawn under a Letter of Credit are not available for such purpose. NCPA also agrees to indemnify and save each Trustee, Paying Agent or Depositary harmless against any liabilities which it may incur in the exercise and performance of its powers and duties under the Indenture and which are not due to its negligence, misconduct or default.

Defeasance

The pledge of the Trust Estate under the Indenture and all covenants, agreements and other obligations of NCPA to the Bondholders under the Indenture will cease, terminate and become void and be discharged and satisfied whenever all Bonds have been paid in full. Bonds or interest installments will be deemed to have been paid for the purpose of the defeasance referred to above in this paragraph if on the maturity or redemption date thereof Eligible Moneys have been set aside and held in trust by the Paying Agents for such payment. Bonds, other than Lender Bonds, will be deemed to have been so paid prior to the maturity or redemption date thereof whenever the following conditions are met: (1) there have been deposited with the Trustee either Eligible Moneys in an amount which will be sufficient, or Investment Securities purchased with Eligible Moneys the principal of and the interest on which when due, will provide moneys which, together with the Eligible Moneys deposited, will be sufficient, to pay when due principal or Redemption Price, if applicable, and interest due and to become due on such Bonds, (2) in the case of Bonds to be redeemed prior to maturity, NCPA has given to the Trustee irrevocable instructions to mail the notice of redemption therefor, and (3) NCPA has given to the Trustee irrevocable instructions to (i) mail, as soon as practicable, notice to the Holders of such Bonds that the above deposit has been made with the Trustee and that such Bonds are deemed to be paid and stating the maturity or redemption date upon which moneys are to be available to pay principal or Redemption Price, if applicable, on such Bonds and (ii) publish a similar notice.

For purposes of determining whether Adjustable Rate Bonds shall be deemed to have been paid prior to the maturity or redemption date thereof, as the case may be, by the deposit of moneys, or Investment Securities and moneys, if any, in accordance with the preceding paragraph, the interest to come due on such Adjustable Rate Bonds on or prior to the maturity date or redemption date thereof, as the case may be, shall be calculated at the Assumed Interest Rate; provided, however, that if on any date, as a result of such Adjustable Rate Bonds having borne interest at less than the Assumed Interest Rate for any period, the total amount of moneys and Investment Securities on deposit with the Trustee for the payment of interest on such Adjustable Rate Bonds is in excess of the total amount which would have been required to be deposited with the Trustee on such date in respect of such Adjustable Rate Bonds in order to satisfy the preceding paragraph, the Trustee shall, if requested by NCPA, pay the amount of such excess to NCPA free and clear of any trust, lien, pledge or assignment securing the Bonds or otherwise existing under the Indenture.

Option Bonds shall be deemed to have been paid in accordance with the first paragraph of this heading only if there shall have been deposited with the Trustee moneys in an amount which shall be sufficient to pay when due the maximum amount of principal or Redemption Price, if any, and interest on such Bonds which could become payable to the Holders of such Bonds upon the exercise of any options provided to the Holders of such Bonds; provided, however, that if, at the time a deposit is made with the Trustee pursuant to the first paragraph of this heading, the options originally exercisable by the Holder of an Option Bond are no longer exercisable, such Bond shall not be considered an Option Bond for purposes of this paragraph. If any portion of the moneys deposited with the Trustee for the payment of the principal of and Redemption Price, if any, and interest on Option Bonds is not required for such purpose the Trustee shall, if requested by NCPA, pay the amount of such excess to NCPA free and clear of any trust, lien, pledge or assignment securing said Bonds or otherwise existing under the Indenture.

Events of Default and Remedies

Events of Default specified in the Indenture include (i) failure to pay principal or Redemption Price of any Bond when due; (ii) failure to pay any interest installment on any Bond or the unsatisfied balance of any Sinking Fund Installment thereon when due; (iii) failure to pay the Purchase Price of any Option Bond at the time required by the Indenture and such default shall continue for 10 days; (iv) as specified under any Reimbursement Agreement (none of which is in effect); (v) if there is default by NCPA for 120 days after written notice thereof from the Trustee or the Holders of not less than 10% in principal amount of the Bonds then Outstanding in the observance or performance of any other covenants, agreements or conditions contained in the Indenture or in the Bonds; (vi) NCPA shall apply for or consent to the appointment of a receiver or admit in writing its inability to pay its debts generally as they become due; and (vii) a proceeding shall be instituted in any court of competent jurisdiction under any law relating to bankruptcy, insolvency, reorganization or relief of debtors and the same shall result in an entry of an order for relief or continue undismissed or pending unstayed for a period of 60 days. Upon the happening of any such Event of Default described in clause (i), (ii), (iii), (v), (vi) or (vii) above, the Trustee or the Holders of not less than 25% in principal amount of the Bonds then Outstanding may declare the principal of and accrued interest on all Bonds then Outstanding due and payable (subject to a rescission of such declaration upon the curing of such default before the Bonds have matured).

Upon the occurrence of any Event of Default which has not been remedied, NCPA will, if demanded by the Trustee, (1) account, as a trustee of an express trust, for all NCPA Revenues and other moneys, securities and funds pledged or held under the Indenture and (2) cause to be paid over to the Trustee (a) forthwith, all moneys, securities and fund then held by NCPA in any Fund under the Indenture and (b) as received, all NCPA Revenues. The Trustee will apply all moneys, securities, funds and NCPA Revenues received during the continuance of any Event of Default in the following order: (1) to payment of the reasonable and proper charges, expenses and liabilities of the Trustee, the Depositaries and Paying Agents, (2) to the payment of NCPA Operating Expenses, and (3) to the payment of interest on and principal or Redemption Price of the Bonds without preference or priority of interest over principal or Redemption Price or of principal or Redemption Price over interest, unless the principal of all Bonds has not been declared due and payable, in which case first to the payment of interest on and second to the payment of principal or Redemption Price of those Bonds which have become due and payable in order of their due dates, and in the amount available for such payment thereof, ratably, according to the amounts of interest or principal or Redemption Price, respectively, due on such date. In addition, the Trustee will have the right to apply in an appropriate proceeding for appointment of a receiver of the Project.

If an Event of Default has occurred and has not been remedied, the Trustee may, and on request of the Holders of not less than 25% in principal amount of Bonds Outstanding must, proceed to protect and enforce its rights and the rights of the Bondholders under the Indenture forthwith by a suit or suits in equity or at law, whether for the specific performance of any covenant in the Indenture or in aid of the execution of any power granted in the Indenture or any remedy granted under the Act, or for an accounting against NCPA as if NCPA were the trustee of an express trust, or in the enforcement of any other legal or equitable right as the Trustee deems most effectual to enforce any of its rights or to perform any of its duties under the Indenture. The Trustee may, and upon the request of the Holders of a majority in principal amount of the Bonds then Outstanding and upon being furnished with reasonable security and indemnity must, institute and prosecute proper actions to prevent any impairment of the security under the Indenture or to preserve or protect the interests of the Trustee and of the Bondholders.

Upon the occurrence of an Event of Default, NCPA shall give notice to each Project Participant that such Project Participant shall make the payments due by it under the Third Phase Agreement directly to the Trustee.

Except as otherwise provided in the last sentence of this paragraph and except for the rights specifically conferred on the Banks and the Banks' Agent pursuant to the Indenture, no Bondholder will have any right to institute any suit, action or proceeding for the enforcement of any provision of the Indenture or the execution of any trust under the Indenture or for any remedy under the Indenture, unless (1) such Bondholder previously has given the Trustee written notice of an Event of Default, (2) the Holders of at least 25% in principal amount of the Bonds then Outstanding have filed a written request with the Trustee and have afforded the Trustee a reasonable opportunity to exercise its powers and institute such suit, action or proceeding, (3) there has been offered to the Trustee adequate security and indemnity against its costs, expenses and liabilities to be incurred and (4) the Trustee has refused to comply with such request within 60 days after receipt by it of such notice, request and offer of indemnity. The Indenture provides that nothing therein or in the Bonds affects or impairs NCPA's obligation to pay the Bonds and interest thereon due or the right of any Bondholder to enforce such payment of his Bonds.

The Banks' Agent or the Holders of not less than a majority in principal amount of Bonds then Outstanding may direct the time, method and place of conducting any proceeding for any remedy available to the Trustee, or exercising any trust or power conferred upon the Trustee, subject to the Trustee's right to decline to follow such direction upon advice of counsel as to the unlawfulness thereof or upon its good faith determination that such action would involve the Trustee in personal liability or would be unjustly prejudicial to Bondholders not parties to such direction.

Notice of Default

The Trustee shall promptly mail written notice of the occurrence of any Event of Default to each Holder of Bonds at his address, if any, appearing on the registry books of NCPA.

Unclaimed Moneys

Any moneys held by the Trustee, a Paying Agent or Depositary in trust for the payment and discharge of any of the Bonds which remain unclaimed for six years after the date when such Bonds have become due and payable, either at maturity or by call for redemption (unless such moneys were not held at the time of such maturity or call for redemption, and then which remain unclaimed for six years after the date of deposit of such moneys with the Trustee, Paying Agent or Depositary), shall, at the written request of NCPA and after meeting certain publication requirements, be repaid to NCPA, and such Trustee, Paying Agent or Depositary shall thereupon be released and discharged with respect thereto and the Bondholders shall look only to NCPA for the payment of such Bonds.

[THIS PAGE INTENTIONALLY LEFT BLANK]

APPENDIX E

PROPOSED FORMS OF CONTINUING DISCLOSURE AGREEMENTS

CONTINUING DISCLOSURE AGREEMENT BY AND BETWEEN THE NORTHERN CALIFORNIA POWER AGENCY AND U. S. BANK NATIONAL ASSOCIATION

This Continuing Disclosure Agreement (the "Disclosure Agreement"), dated February 7, 2012, is executed and delivered by the Northern California Power Agency and U.S. Bank National Association, as successor trustee (the "Trustee") in connection with the issuance by Northern California Power Agency ("NCPA") of $76,665,000 aggregate principal amount of Northern California Power Agency Hydroelectric Project Number One Revenue Bonds, 2012 Refunding Series A and $7,120,000 aggregate principal amount of Northern California Power Agency Hydroelectric Project Number One Revenue Bonds, 2012 Taxable Refunding Series B (collectively, the "2012 Bonds"). The 2012 Bonds were issued pursuant to an Indenture of Trust, dated as of March 1, 1985, as amended and supplemented, including as supplemented by the Twenty-Second Supplemental indenture of Trust, dated as of February 1, 2012, and by the Twenty-Third Supplemental Indenture of Trust, dated as of February 1, 2012 (collectively, the "Indenture"), by and between NCPA and the Trustee. NCPA and the Trustee covenant and agree as follows:

SECTION 1. **__Purpose of the Disclosure Agreement__.** This Disclosure Agreement is being executed and delivered by NCPA and the Trustee for the benefit of the Bondholders and Beneficial Owners of the 2012 Bonds and in order to assist the Participating Underwriters in complying with the Rule.

SECTION 2. **__Definitions__.** In addition to the definitions set forth in the Indenture, which apply to any capitalized term used in this Disclosure Agreement unless otherwise defined in this Section 2, the following capitalized terms shall have the following meanings:

"Annual Report" shall mean any Annual Report with respect to the 2012 Bonds provided by NCPA pursuant to, and as described in, Sections 3 and 4 of this Disclosure Agreement.

"Beneficial Owner" shall mean any person who has or shares the power, directly or indirectly, to make investment decisions regarding ownership of any 2012 Bonds (including without limitation persons holding 2012 Bonds through nominees, depositories or other intermediaries).

"Disclosure Representative" shall mean the Chairman, General Manager, Interim General Manager, or the Assistant General Manager of NCPA or his or her designee, or such other officer or employee as NCPA shall designate in writing to the Trustee from time to time.

"Dissemination Agent" shall mean the Trustee, acting in its capacity as Dissemination Agent hereunder, or any successor Dissemination Agent designated in writing by NCPA and which has filed with the Trustee a written acceptance of such designation.

"EMMA System" means the MSRB's Electronic Municipal Market Access System or such other electric system designated by the MSRB.

"Listed Event" means any of the events listed in Section 5(a) or (b) of this Disclosure Agreement.

"MSRB" means the Municipal Securities Rulemaking Board, or any successor thereto.

"Participating Underwriter" shall mean the original underwriter of the 2012 Bonds required to comply with the Rule in connection with the offering of the 2012 Bonds.

"Rule" shall mean Rule 15c2-12(b)(5) adopted by the Securities and Exchange Commission under the Securities Exchange Act of 1934, as the same may be amended from time to time.

SECTION 3. Provision of Annual Reports.

(a) With respect to the 2012 Bonds, NCPA shall, or shall cause the Dissemination Agent to, not later than 180 days after the end of each fiscal year of NCPA (which presently ends on June 30), commencing with the report for the Fiscal Year ending June 30, 2012, provide to the MSRB through the EMMA System, in an electronic format and accompanied by identifying information all as prescribed by the MSRB, an Annual Report which is consistent with the requirements of Section 4 of this Disclosure Agreement. The Annual Report may be submitted as a single document or as separate documents comprising a package, and may include by reference other information as provided in Section 4 of this Disclosure Agreement; provided, that the audited financial statements of NCPA may be submitted separately from the balance of the Annual Report and later than the date required above for the filing of the Annual Report if they are not available by that date. If the fiscal year changes for NCPA, NCPA shall give notice of such change in the manner provided under Section 5 hereof.

(b) Not later than fifteen (15) Business Days prior to the date specified in subsection (a) for providing the Annual Report to the MSRB, NCPA shall provide its Annual Report to the Dissemination Agent and the Trustee (if the Trustee is not the Dissemination Agent). If by such date, the Trustee has not received a copy of the Annual Report from NCPA, the Trustee shall contact NCPA and the Dissemination Agent to determine if NCPA is in compliance with this subsection (b).

(c) If the Trustee is unable to verify that an Annual Report has been provided to the MSRB by the date required in subsection (a) of this Section, the Trustee shall send a notice to the MSRB through the EMMA System in substantially the form attached hereto as Exhibit A.

(d) The Dissemination Agent shall file a report with NCPA and the Trustee (if the Dissemination Agent is not the Trustee) certifying that the Annual Report has been provided pursuant to this Disclosure Agreement, stating the date it was provided.

SECTION 4. Content of Annual Reports. NCPA's Annual Report shall contain or include by reference the following:

(i) A summary of the peak generating capability of the Project for the prior Fiscal Year;

(ii) A summary of the average generating capability of the Project for the prior Fiscal Year;

(iii) A summary of total energy generated with respect to the Project for the prior Fiscal Year; and

(iv) The audited financial statements of NCPA for the prior Fiscal Year, prepared in accordance with generally accepted accounting principles for governmental enterprises as prescribed from time to time by any regulatory body with jurisdiction over NCPA and by the Governmental Accounting Standards Board. If NCPA's audited financial statements are not available by the time the Annual Report is required to be filed pursuant to Section 3(a), the Annual Report shall contain unaudited financial statements in a format similar to the audited financial statements, and the audited financial statements shall be filed in the same manner as the Annual Report when they become available.

Any or all of the items listed above may be included by specific reference to other documents, including official statements of debt issues of NCPA or public entities related thereto, which have been submitted to the MSRB through the EMMA System. If the document included by reference is a final official statement, it must be available from the MSRB. NCPA shall clearly identify each such other document so included by reference.

SECTION 5. Reporting of Significant Events.

(a) Pursuant to the provisions of this Section 5, NCPA shall give, or cause to be give, notice of occurrence of any of the following events with respect to the 2012 Bonds not later than ten business days after the occurrence of the event:

(i) principal and interest payment delinquencies;

(ii) unscheduled draws on debt service reserves reflecting financial difficulties;

(iii) unscheduled draws on credit enhancements reflecting financial difficulties;

(iv) substitution of credit or liquidity providers, or their failure to perform;

(v) issuance by the Internal Revenue Service of proposed or final determination of taxability or of a Notice of Proposed Issue (IRS Form 5701 TEB);

(vi) tender offers;

(vii) defeasances;

(viii) rating changes; or

(ix) bankruptcy, insolvency, receivership or similar event of the obligated person;

Note: for the purposes of the event identified in subparagraph (iv), the event is considered to occur when any of the following occur: the appointment of a receiver, fiscal agent or similar officer for an obligated person in a proceeding under the U.S. Bankruptcy Code or in any other proceeding under state or federal law in which a court or governmental authority has assumed jurisdiction over substantially all of the assets or business of the obligated person, or if such jurisdiction has been assumed by leaving the existing governmental body and officials or officers in possession but subject to the supervision and orders of a court or governmental authority, or the entry of an order confirming a plan of reorganization, arrangement or liquidation by a court or governmental authority having supervision or jurisdiction over substantially all of the assets or business of the obligated person.

(b) Pursuant to the provisions of this Section 5, NCPA shall give, or cause to be given, notice of the occurrence of any of the following events with respect to the 2012 Bonds, if material, not later than ten business days after the occurrence of the event:

(i) unless described in paragraph 5(a)(v), adverse tax opinions or other material notices or determinations by the Internal Revenue Service with respect to the tax status of the 2012 Bonds or other material events affecting the tax status of the 2012 Bonds;

(ii) modifications to rights of the Owners of the 2012 Bonds;

(iii) optional, unscheduled or contingent 2012 Bond calls;

(iv) release, substitution or sale of property securing repayment of the 2012 Bonds;

(v) non-payment related defaults;

(vi) the consummation of a merger, consolidation, or acquisition involving an obligated person or the sale of all or substantially all of the assets of the obligated person, other than in the ordinary course of business, the entry into a definitive agreement to undertake such an action or the termination of a definitive agreement relating to any such actions, other than pursuant to its terms; or

(vii) appointment of a successor or additional trustee or the change of name of a trustee;

(c) The Trustee shall, with one (1) Business Day of an officer in the corporate trust department obtaining actual knowledge of the occurrence of any of the Listed Events, contact the Disclosure Representative, inform such person of the event, and request that NCPA promptly notify the Trustee in writing whether or not to report the event pursuant to subsection (g).

(d) Whenever NCPA obtains knowledge of the occurrence of a Listed Event described in Section 5(b), whether because of a notice from the Trustee pursuant to subsection (c) or otherwise, NCPA shall as soon as possible determine if such event would be material under applicable federal securities laws.

(e) If NCPA obtains knowledge of the occurrence of a List Event described in Section 5(a), whether because of a notice from the Trustee pursuant to subsection (c) or otherwise, or if NCPA has determined that knowledge of the occurrence of a Listed Event would be material under applicable federal securities laws, NCPA shall promptly notify the Trustee in writing. Such notice shall instruct the Trustee to report the occurrence pursuant to subsection (g) or shall state that NCPA shall itself report such occurrence.

(f) If in response to a request under subsection (c), NCPA determines that the Listed Event described in Section 5(b) would not be material under applicable federal securities laws, NCPA shall so notify the Trustee in writing and instruct the Trustee not to report the occurrence pursuant to subsection (g).

(g) If the Trustee has been instructed by NCPA to report the occurrence of a Listed Event, the Trustee shall file a notice of such occurrence with the MSRB through the EMMA System. Notwithstanding the foregoing, notice of Listed Events described in subsections (a)(vii) and (b)(iii) need not be given under this subsection any earlier than the notice (if any) of the underlying event is given to Bondholders of affected 2012 Bonds pursuant to the Indenture.

SECTION 6. Termination of Reporting Obligation. The obligations of NCPA under this Disclosure Agreement shall terminate upon the legal defeasance, prior redemption or payment in full of all of the 2012 Bonds. If such termination occurs prior to the final maturity of the 2012 Bonds, NCPA shall give notice of such termination in the same manner as for a Listed Event under Section 5(f).

SECTION 7. Dissemination Agent. NCPA may, from time to time, appoint or engage a Dissemination Agent to assist it in carrying out its obligations under this Disclosure Agreement, and may discharge any such Dissemination Agent, with or without appointing a successor Dissemination Agent. The Dissemination Agent shall not be responsible in any manner for the content of any notice or report prepared by NCPA pursuant to this Disclosure Agreement. The initial Dissemination Agent shall be U. S. Bank National Association.

SECTION 8. Amendment; Waiver. Notwithstanding any other provision of this Disclosure Agreement, NCPA and the Trustee may amend this Disclosure Agreement (and the Trustee shall agree to any amendment so requested by NCPA which does not adversely affect the Trustee's rights or obligations), and any provision of this Disclosure Agreement may be waived; provided that such amendment or waiver, in the opinion of nationally recognized bond counsel satisfactory to the Trustee, such amendment or waiver is permitted by the Rule.

In the event of any amendment or waiver of a provision of this Disclosure Agreement, NCPA shall describe such amendment in its next Annual Report, and shall include, as applicable, a narrative explanation of the reason for the amendment or waiver and its impact on the type (or in the case of a change of accounting principles, on the presentation) of financial information or operating data being presented by NCPA. In addition, if the amendment relates to the accounting principles to be followed in preparing financial statements, (i) notice of such change shall be given in the manner as provided under Section 5, and (ii) the Annual Report for the year in which the change is made should present a comparison (in narrative form and also, if feasible, in quantitative form) between the financial statements as prepared on the basis of the new accounting principles and those prepared on the basis of the former accounting principles.

SECTION 9. Additional Information. Nothing in this Disclosure Agreement shall be deemed to prevent NCPA from disseminating any other information, using the means of dissemination set forth in this Disclosure Agreement or any other means of communication, or including any other information in any Annual Report or notice of occurrence of a Listed Event, in addition to that which is required by this Disclosure Agreement. If NCPA chooses to include any information in any Annual Report or notice of occurrence of a Listed Event in addition to that which is specifically required by this Disclosure Agreement, NCPA shall have no obligation under this Agreement to update such information or include it in any future Annual Report or notice of occurrence of a Listed Event.

SECTION 10. **Default**. In the event of a failure of NCPA or the Trustee to comply with any provision of this Disclosure Agreement, the Trustee may (and, at the request of the Bondholders of at least 25% aggregate principal amount of Outstanding 2012 Bonds and furnishing indemnity satisfactory to the Trustee against its costs and expenses, shall), or any Bondholder or Beneficial Owner of the 2012 Bonds may, take such actions as may be necessary and appropriate, including seeking mandate or specific performance by court order, to cause NCPA or the Trustee, as the case may be, to comply with its obligations under this Disclosure Agreement. A default under this Disclosure Agreement shall not be deemed an Event of Default under the Indenture, and the sole remedy under this Disclosure Agreement in the event of any failure of NCPA or the Trustee to comply with this Disclosure Agreement shall be an action to compel performance.

No Bondholder or Beneficial Owner may institute any such action, suit or proceeding to compel performance unless they shall have first filed with the Trustee and NCPA satisfactory written evidence of their status as such, and a written notice of and request to cure such failure, and NCPA shall have refused to comply therewith within a reasonable time. Any such action, suit or proceeding shall be brought in Federal or State Courts located in the County of Sacramento, California for the benefit of all Bondholders and Beneficial Owners of the 2012 Bonds.

SECTION 11. **Duties, Immunities and Liabilities of Trustee and Dissemination Agent**. Article IX of the Indenture is hereby made applicable to this Disclosure Agreement as if this Disclosure Agreement were (solely for this purpose) contained in the Indenture, and the Dissemination Agent were a Fiduciary thereunder. The Dissemination Agent (if other than the Trustee or the Trustee in its capacity as Dissemination Agent) shall have only such duties as are specifically set forth in this Disclosure Agreement, and NCPA agrees to indemnify and save the Dissemination Agent, its officers, directors, employees and agents, harmless against any loss, expense and liabilities which it may incur arising out of or in the exercise or performance of its powers and duties hereunder, including the costs and expenses (including attorneys fees) of defending against any claim of liability, but excluding liabilities due to the Dissemination Agent's negligence or willful misconduct. The obligations of NCPA under this Section shall survive resignation or removal of the Dissemination Agent and payment of the 2012 Bonds.

SECTION 12. **Beneficiaries**. This Disclosure Agreement shall inure solely to the benefit of NCPA, the Trustee, the Dissemination Agent, the Participating Underwriters and the Bondholders and Beneficial Owners from time to time of the 2012 Bonds, and shall create no rights in any other person or entity.

SECTION 13. **California Law**. This Disclosure Agreement shall be construed and governed in accordance with the laws of the State of California.

SECTION 14. **Notices**. All written notices to be given hereunder shall be given in person or by mail to the party entitled thereto at its address set forth below, or at such other address as such party may provide to the other parties in writing from time to time, namely:

To NCPA:

Northern California Power Agency
651 Commerce Drive
Roseville, California 95678
Attention: General Manager
Telephone: (916) 781-3636
Fax: (916) 783-7693

To the Trustee: U. S. Bank National Association
100 Wall Street, Suite 1600
New York, New York 10005
Attention: Corporate Trust Department
Telephone: (212) 361-4385
Fax: (212) 514-6841

NCPA and the Trustee may, by notice given hereunder, designate any further or different addresses to which subsequent notices, certificates or other communications shall be sent.

SECTION 15. **Counterparts**. This Disclosure Agreement may be executed in several counterparts, each of which shall be an original and all of which shall constitute but one and the same instrument.

Date: February 7, 2012

NORTHERN CALIFORNIA POWER AGENCY

By: _______________________________________
Its:

U. S. BANK NATIONAL ASSOCIATION, as Trustee

By: _______________________________________
Authorized Signatory

EXHIBIT A

NOTICE TO REPOSITORIES OF FAILURE TO FILE ANNUAL REPORT

Name of Issuer:	Northern California Power Agency ("NCPA")
Name of Bond Issue:	$76,665,000 aggregate principal amount of Northern California Power Agency Hydroelectric Project Number One Revenue Bonds, 2012 Refunding Series A and $7,120,000 aggregate principal amount of Northern California Power Agency Hydroelectric Project Number One Revenue Bonds, 2012 Taxable Refunding Series B (collectively, the "2012 Bonds")
Date of Issuance:	February 7, 2012

NOTICE IS HEREBY GIVEN that NCPA has not provided an Annual Report with respect to the 2012 Bonds as required by Section 3 of the Continuing Disclosure Agreement with respect to the 2012 Bonds, dated February 7, 2012, by and between NCPA and U. S. Bank National Association, as trustee. [NCPA anticipates that the Annual Report will be filed by _____________.]

Dated: _______________

U. S. BANK NATIONAL ASSOCIATION, as Trustee on behalf of the Northern California Power Agency

cc: NCPA

CONTINUING DISCLOSURE AGREEMENT
BY AND BETWEEN THE
[SIGNIFICANT SHARE PROJECT PARTICIPANT]
AND
U. S. BANK NATIONAL ASSOCIATION

This Continuing Disclosure Agreement (the “Disclosure Agreement”), dated February 7, 2012, is executed and delivered by the [SIGNIFICANT SHARE PROJECT PARTICIPANT] (the “Project Participant”) and U.S. Bank National Association, as successor trustee (the “Trustee”) in connection with the issuance by Northern California Power Agency (“NCPA”) of $76,665,000 aggregate principal amount of Northern California Power Agency Hydroelectric Project Number One Revenue Bonds, 2012 Refunding Series A and $7,120,000 aggregate principal amount of Northern California Power Agency Hydroelectric Project Number One Revenue Bonds, 2012 Taxable Refunding Series B (collectively, the “2012 Bonds”). The 2012 Bonds were issued pursuant to an Indenture of Trust, dated as of March 1, 1985, as amended and supplemented, including as supplemented by the Twenty-Second Supplemental Indenture of Trust, dated as of February 1, 2012, and by the Twenty-Third Supplemental Indenture of Trust, dated as of February 1, 2012 (collectively, the “Indenture”), by and between NCPA and the Trustee. The Project Participant and the Trustee covenant and agree as follows:

SECTION 1. Purpose of the Disclosure Agreement. This Disclosure Agreement is being executed and delivered by the Project Participant and the Trustee for the benefit of the Bondholders and Beneficial Owners of the 2012 Bonds and in order to assist the Participating Underwriters in complying with the Rule.

SECTION 2. Definitions. In addition to the definitions set forth in the Indenture, which apply to any capitalized term used in this Disclosure Agreement unless otherwise defined in this Section 2, the following capitalized terms shall have the following meanings:

“Annual Report” shall mean any Annual Report with respect to the 2012 Bonds provided by the Project Participant pursuant to, and as described in, Sections 3 and 4 of this Disclosure Agreement.

“Beneficial Owner” shall mean any person who has or shares the power, directly or indirectly, to make investment decisions regarding ownership of any 2012 Bonds (including without limitation persons holding 2012 Bonds through nominees, depositories or other intermediaries).

“Disclosure Representative” shall mean the General Manager of the Project Participant, or his or her designee, or such other officer or employee as the Project Participant shall designate in writing to the Trustee from time to time.

“Dissemination Agent” shall mean the Trustee, acting in its capacity as Dissemination Agent hereunder, or any successor Dissemination Agent designated in writing by the Project Participant and which has filed with the Trustee a written acceptance of such designation.

“EMMA System” means the MSRB’s Electronic Municipal Market Access System or such other electric system designated by the MSRB.

“MSRB” means the Municipal Securities Rulemaking Board, or any successor thereto.

“Participating Underwriter” shall mean the original underwriter of the 2012 Bonds required to comply with the Rule in connection with the offering of the 2012 Bonds.

"Rule" shall mean Rule 15c2-12(b)(5) adopted by the Securities and Exchange Commission under the Securities Exchange Act of 1934, as the same may be amended from time to time.

SECTION 3. Provision of Annual Reports.

(a) The Project Participant shall, or shall cause the Dissemination Agent to, not later than 210 days after the end of each fiscal year of the Project Participant (which presently ends on June 30), commencing with the report for the Fiscal Year ending June 30, 2012, provide to the MSRB through the EMMA System, in an electronic format and accompanied by identifying information all as prescribed by the MSRB, an Annual Report which is consistent with the requirements of Section 4 of this Disclosure Agreement. The Annual Report may be submitted as a single document or as separate documents comprising a package, and may include by reference other information as provided in Section 4 of this Disclosure Agreement; provided, that the audited financial statements of the Project Participant may be submitted separately from the balance of the Annual Report and later than the date required above for the filing of the Annual Report if they are not available by that date. If the fiscal year changes for the Project Participant, the Project Participant shall give notice of such change in the manner provided under Section 5 hereof.

(b) Not later than fifteen (15) Business Days prior to the date specified in subsection (a) for providing the Annual Report to the MSRB, the Project Participant shall provide its Annual Report to the Dissemination Agent and the Trustee (if the Trustee is not the Dissemination Agent). If by such date, the Trustee has not received a copy of the Annual Report from the Project Participant, the Trustee shall contact the Project Participant and the Dissemination Agent to determine if the Project Participant is in compliance with this subsection (b).

(c) If the Trustee is unable to verify that an Annual Report has been provided to the MSRB by the date required in subsection (a) of this Section, the Trustee shall send a notice to the MSRB through the EMMA System in substantially the form attached hereto as Exhibit A.

(d) The Dissemination Agent shall file a report with the Project Participant and the Trustee (if the Dissemination Agent is not the Trustee) certifying that the Annual Report has been provided to the MSRB through the EMMA System pursuant to this Disclosure Agreement, stating the date it was provided.

SECTION 4. Content of Annual Reports. The Project Participant's Annual Report shall contain or include by reference the following:

(i) A summary of the of operations and balance sheet for the Project Participant's electric system for the most recently completed fiscal year;

(ii) A summary of power supply resources of the Project Participant's electric system in tabular form for the most recently completed fiscal year;

(iii) A summary of customers, energy sales, revenues and peak demand of the Project Participant's electric system in tabular form for the most recently completed fiscal year; and

(iv) The audited financial statements of the Project Participant's electric system for the most recently completed fiscal year, prepared in accordance with generally accepted accounting principles for governmental enterprises as prescribed from time to time by any regulatory body with jurisdiction over the Project Participant and by the Governmental Accounting Standards Board. If the Project Participant's electric system audited financial statements are not available by the time the Annual Report is required to be filed pursuant to Section 3(a), the Annual Report shall contain unaudited financial statements in a format similar to the audited financial statements, and the audited financial statements shall be filed in the same manner as the Annual Report when they become available.

Any or all of the items listed above may be included by specific reference to other documents, including official statements of debt issues of the Project Participant or public entities related thereto, which have been submitted to the MSRB through the EMMA System. If the document included by reference is a final official statement, it must be available from the MSRB. The Project Participant shall clearly identify each such other document so included by reference.

SECTION 5. Reporting. Notices required by Section 3(a) or Section 8 of this Disclosure Agreement shall be filed with the MSRB.

SECTION 6. Termination of Reporting Obligation. The obligations of the Project Participant under this Disclosure Agreement shall terminate upon the legal defeasance, prior redemption or payment in full of all of the 2012 Bonds.

SECTION 7. Dissemination Agent. The Project Participant may, from time to time, appoint or engage a Dissemination Agent to assist it in carrying out its obligations under this Disclosure Agreement, and may discharge any such Dissemination Agent, with or without appointing a successor Dissemination Agent. The Dissemination Agent shall not be responsible in any manner for the content of any notice or report prepared by the Project Participant pursuant to this Disclosure Agreement. The initial Dissemination Agent shall be U. S. Bank National Association.

SECTION 8. Amendment; Waiver. Notwithstanding any other provision of this Disclosure Agreement, the Project Participant and the Trustee may amend this Disclosure Agreement (and the Trustee shall agree to any amendment so requested by the Project Participant which does not adversely affect the Trustee's rights or obligations), and any provision of this Disclosure Agreement may be waived; provided that such amendment or waiver, in the opinion of nationally recognized bond counsel satisfactory to the Trustee, such amendment or waiver is permitted by the Rule.

In the event of any amendment or waiver of a provision of this Disclosure Agreement, the Project Participant shall describe such amendment in its next Annual Report, and shall include, as applicable, a narrative explanation of the reason for the amendment or waiver and its impact on the type (or in the case of a change of accounting principles, on the presentation) of financial information or operating data being presented by the Project Participant. In addition, if the amendment relates to the accounting principles to be followed in preparing financial statements, (i) notice of such change shall be given in the manner as provided under Section 5, and (ii) the Annual Report for the year in which the change is made should present a comparison (in narrative form and also, if feasible, in quantitative form) between the financial statements as prepared on the basis of the new accounting principles and those prepared on the basis of the former accounting principles.

SECTION 9. Additional Information. Nothing in this Disclosure Agreement shall be deemed to prevent the Project Participant from disseminating any other information, using the means of dissemination set forth in this Disclosure Agreement or any other means of communication, or including any other information in any Annual Report, in addition to that which is required by this Disclosure Agreement. If the Project Participant chooses to include any information in any Annual Report in addition to that which is specifically required by this Disclosure Agreement, the Project Participant shall have no obligation under this Agreement to update such information or include it in any future Annual Report.

SECTION 10. Default. In the event of a failure of the Project Participant or the Trustee to comply with any provision of this Disclosure Agreement, the Trustee may (and, at the request of the Bondholders of at least 25% aggregate principal amount of Outstanding 2012 Bonds, shall), or any Bondholder or Beneficial Owner of the 2012 Bonds may, take such actions as may be necessary and appropriate, including seeking mandate or specific performance by court order, to cause the Project Participant or the Trustee, as the case may be, to comply with its obligations under this Disclosure Agreement. A default under this Disclosure Agreement shall not be deemed an Event of Default under the Indenture, and the sole remedy under this Disclosure Agreement in the event of any failure of the Project Participant or the Trustee to comply with this Disclosure Agreement shall be an action to compel performance.

No Bondholder or Beneficial Owner may institute any such action, suit or proceeding to compel performance unless they shall have first filed with the Trustee and the Project Participant satisfactory written evidence of their status as such, and a written notice of and request to cure such failure, and the Project Participant shall have refused to comply therewith within a reasonable time. Any such action, suit or proceeding shall be brought in Federal or State Courts located in the County of Sacramento, California for the benefit of all Bondholders and Beneficial Owners of the 2012 Bonds.

SECTION 11. Duties, Immunities and Liabilities of Trustee and Dissemination Agent. Article IX of the Indenture is hereby made applicable to this Disclosure Agreement as if this Disclosure Agreement were (solely for this purpose) contained in the Indenture, and the Dissemination Agent were a Fiduciary thereunder. The Dissemination Agent (if other than the Trustee or the Trustee in its capacity as Dissemination Agent) shall have only such duties as are specifically set forth in this Disclosure Agreement, and the Project Participant agrees to indemnify and save the Dissemination Agent, its officers, directors, employees and agents, harmless against any loss, expense and liabilities which it may incur arising out of or in the exercise or performance of its powers and duties hereunder, including the costs and expenses (including attorneys fees) of defending against any claim of liability, but excluding liabilities due to the Dissemination Agent's negligence or willful misconduct. The obligations of the Project Participant under this Section shall survive resignation or removal of the Dissemination Agent and payment of the 2012 Bonds.

SECTION 12. Beneficiaries. This Disclosure Agreement shall inure solely to the benefit of NCPA, the Project Participant, the Trustee, the Dissemination Agent, the Participating Underwriters and the Bondholders and Beneficial Owners from time to time of the 2012 Bonds, and shall create no rights in any other person or entity.

SECTION 13. California Law. This Disclosure Agreement shall be construed and governed in accordance with the laws of the State of California.

SECTION 14. Notices. All written notices to be given hereunder shall be given in person or by mail to the party entitled thereto at its address set forth below, or at such other address as such party may provide to the other parties in writing from time to time, namely:

To the Significant Share Project Participant: ____________________
____
____
____

To the Trustee: U. S. Bank National Association
100 Wall Street, Suite 1600
New York, New York 10005
Attention: Corporate Trust Department
Telephone: (212) 361-4385
Fax: (212) 514-6841

The Project Participant and the Trustee may, by notice given hereunder, designate any further or different addresses to which subsequent notices, certificates or other communications shall be sent.

SECTION 15. Counterparts. This Disclosure Agreement may be executed in several counterparts, each of which shall be an original and all of which shall constitute but one and the same instrument.

Date: February 7, 2012

[SIGNIFICANT SHARE PROJECT PARTICIPANT]

By: ___________________________________
Name: _________________________________
Title: __________________________________

U. S. BANK NATIONAL ASSOCIATION, as Trustee

By: ____________________________________
Authorized Signatory

EXHIBIT A

NOTICE TO MSRB OF FAILURE TO FILE ANNUAL REPORT

Name of Issuer:	Northern California Power Agency ("NCPA")
Name of Bond Issue:	$76,665,000 aggregate principal amount of Northern California Power Agency Hydroelectric Project Number One Revenue Bonds, 2012 Refunding Series A and $7,120,000 aggregate principal amount of Northern California Power Agency Hydroelectric Project Number One Revenue Bonds, 2012 Taxable Refunding Series B (collectively, the "2012 Bonds")
Name of Obligated Party	[SIGNIFICANT SHARE PROJECT PARTICIPANT] (the "Significant Share Project Participant")
Date of Issuance:	February 7, 2012

NOTICE IS HEREBY GIVEN that the Significant Share Project Participant has not provided an Annual Report with respect to the 2012 Bonds as required by Section 3 of the Continuing Disclosure Agreement with respect to the 2012 Bonds, dated February 7, 2012, by and between the Project Participant and U. S. Bank National Association, as trustee. [the Significant Share Project Participant anticipates that the Annual Report will be filed by _____________.]

Dated: _______________

U. S. BANK NATIONAL ASSOCIATION, as
Trustee on behalf of the Northern California
Power Agency

cc: the Project Participant

APPENDIX F

PROPOSED FORM OF BOND COUNSEL OPINION

Upon delivery of the 2012 Bonds in definitive form, Orrick, Herrington & Sutcliffe LLP, bond counsel to the Agency, proposes to render its approving opinion with respect thereto in substantially the following form:

[Delivery Date]

Commission
Northern California Power Agency
651 Commerce Drive
Roseville, California 95678

Northern California Power Agency
Hydroelectric Project Number One Revenue Bonds,
2012 Refunding Series A and 2012 Taxable Refunding Series B
(Final Opinion)

Ladies and Gentlemen:

We have acted as bond counsel to the Northern California Power Agency (the "Agency") in connection with the issuance of $76,665,000 aggregate principal amount of its Hydroelectric Project Number One Revenue Bonds, 2012 Refunding Series A (the "2012 Series A Bonds"), and $7,120,000 aggregate principal amount of its Hydroelectric Project Number One Revenue Bonds, 2012 Taxable Refunding Series B (the "2012 Series B Bonds" and, together with the 2012 Series A Bonds, the "2012 Bonds"). The 2012 Bonds have been issued pursuant to the provisions of Article 4 of Chapter 5 of Division 7 of Title 1, and Articles 10 and 11 of Chapter 3 of Part 1 of Division 2 of Title 5, of the Government Code of the State of California and Articles 10 and 11 of Chapter 3 of Division 2 of Title 5 of the Government Code of the State of California and the Indenture of Trust, dated as of March 1, 1985 by and between the Agency and U.S. Bank National Association, as successor trustee, as amended and supplemented (the "Indenture"). Capitalized terms not otherwise defined herein shall have the meanings ascribed thereto in the Indenture.

The 2012 Bonds have been issued to provide the funds necessary to refund the Agency's outstanding Hydroelectric Project Number One Revenue Bonds, 1998 Refunding Series A and related purposes.

In such connection, we have reviewed the Indenture, the Hydroelectric Project Member Agreement, the Tax Certificate of the Agency relating to the 2012 Series A Bonds (the "Tax Certificate"), certificates of the Agency, the Trustee, the Project Participants and others, opinions of counsel to the Agency and to each Project Participant, and such other documents, opinions and matters to the extent we deemed necessary to render the opinions set forth herein.

The opinions expressed herein are based on an analysis of existing laws, regulations, rulings and court decisions and cover certain matters not directly addressed by such authorities. Such opinions may be affected by actions taken or omitted or events occurring after the date hereof. We have not undertaken to determine, or to inform any person, whether any such actions are taken or omitted or events do occur or any other matters come to our attention after the date hereof. Accordingly, this letter speaks only as of its date and is not intended to, and may not, be relied upon or otherwise used in connection with any such actions, events or matters. Our engagement with respect to the 2012 Bonds has concluded with their issuance and we disclaim any obligation to update this letter. We have assumed the genuineness of all documents and signatures presented to us (whether as originals or copies) and the due and legal execution and delivery thereof by, and validity against, any parties other than the Agency, and, with respect to the Hydroelectric Project Member Agreement, the Project Participants. We have assumed without undertaking to verify the accuracy of the factual matters represented, warranted or certified in the documents, and of the legal conclusions contained in the opinions, referred to in the third paragraph hereof. Furthermore, we have assumed compliance with all covenants and agreements contained in the Indenture, the Hydroelectric Project Member Agreement and the Tax Certificate, including (without limitation) covenants and agreements compliance which is necessary to assure that future actions, omissions or events will not cause interest on the 2012 Series A Bonds to be included in gross income for federal income tax purposes. We call attention to the fact that the rights and obligations under the 2012 Bonds, the Indenture, the Hydroelectric Project Member Agreement and the Tax Certificate, and their enforceability, may be subject to bankruptcy, insolvency, reorganization, arrangement, fraudulent conveyance, moratorium and other laws relating to or affecting creditors' rights, to the application of equitable principles, to the exercise of judicial discretion in appropriate cases, and to the limitations on legal remedies against public entities in the State of California. We express no opinion with respect to any indemnification, contribution, penalty, arbitration, judicial reference, choice of law, choice of forum, choice of venue, waiver or severability provisions contained in the foregoing documents, nor do we express any opinion with respect to the state or quality of title to or interest in any of the assets described in or as subject to the lien of the Indenture or the accuracy or sufficiency of the description contained therein of, or the remedies available to enforce liens on, any such assets. Our services did not include financial or other non-legal advice. Finally, we undertake no responsibility for the accuracy, completeness or fairness of the Official Statement or other offering material related to the 2012 Bonds and express no opinion with respect thereto.

Based on and subject to the foregoing, and in reliance thereon, as of the date hereof, we are of the following opinions:

1. The 2012 Bonds constitute the valid and binding special, limited obligations of the Agency payable solely from, and secured solely by, the Trust Estate.

2. The Indenture has been duly executed and delivered by, and constitutes the valid and binding obligation of, the Agency. The Indenture creates a valid pledge of the Trust Estate to secure the payment of the principal and redemption price of, and the interest on, the Bonds, including the 2012 Bonds, to the extent set forth in the Indenture, subject to the provisions of the Indenture permitting the application thereof for the purposes and on the terms and conditions set forth therein.

3. The 2012 Bonds are payable solely from the funds provided in the Indenture and shall not constitute a charge against the general credit of the Agency. The 2012 Bonds are not secured by a legal or equitable pledge of, or charge or lien upon, any property of the Agency or any of its income or receipts except the Trust Estate. Neither the faith and credit nor the taxing power of the State of California or any public agency thereof, any member of the Agency or any Project Participant is pledged to the payment of the principal or redemption price of, or interest on, the 2012 Bonds. The 2012 Bonds do not constitute a debt, liability or obligation of the State of California or any public agency thereof (other than the Agency), any member of the Agency or any Project Participant.

4. The Hydroelectric Project Member Agreement has been duly executed and delivered by the Agency and the Project Participants and constitutes a valid and binding agreement of the parties thereto.

5. Interest on the 2012 Series A Bonds is excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986 and is exempt from State of California personal income taxes. Interest on the 2012 Series A Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes, although we observe that it is included in adjusted current earnings when calculating federal corporate alternative minimum taxable income. We express no opinion regarding other tax consequences related to the ownership or disposition of, or the accrual or receipt of interest on, the 2012 Series A Bonds.

6. Interest on the 2012 Series B Bonds is not excluded from gross income for federal income tax purposes and is exempt from State of California personal income taxes. We express no opinion regarding other tax consequences related to the ownership or disposition of, or the accrual or receipt of interest on, the 2012 Series B Bonds.

Faithfully yours,

ORRICK, HERRINGTON & SUTCLIFFE LLP

[THIS PAGE INTENTIONALLY LEFT BLANK]

APPENDIX G

DEBT SERVICE REQUIREMENTS ON THE HYDROELECTRIC PROJECT BONDS

The following table shows the combined annual debt service requirements for the Hydroelectric Project Bonds to be Outstanding upon the delivery of the 2012 Bonds. Principal amounts set forth in the table below include sinking fund redemptions.

		2012 Bonds				
		2012 Series A Bonds		2012 Series B Bonds		
Year Ended (July 1)	Outstanding Hydroelectric Project Bonds Debt Service[1]	Principal	Interest	Principal	Interest	Aggregate Annual Debt Service[2]
2012	$ 32,276,383	--	$ 1,533,300	--	$ 123,034	$ 33,932,717
2013	35,414,808	--	3,833,250	--	307,584	39,555,642
2014	33,275,955	--	3,833,250	--	307,584	37,416,789
2015	33,296,255	--	3,833,250	--	307,584	37,437,089
2016	33,350,390	--	3,833,250	--	307,584	37,491,224
2017	33,672,595	--	3,833,250	--	307,584	37,813,429
2018	33,682,675	--	3,833,250	--	307,584	37,823,509
2019	31,952,410	--	3,833,250	--	307,584	36,093,244
2020	32,009,362	--	3,833,250	--	307,584	36,150,196
2021	31,866,530	--	3,833,250	--	307,584	36,007,364
2022	31,918,162	--	3,833,250	--	307,584	36,058,996
2023	36,054,033	--	3,833,250	--	307,584	40,194,867
2024	22,703,489	$ 4,475,000	3,833,250	$7,120,000	307,584	38,439,323
2025	6,150,797	11,265,000	3,609,500	--	--	21,025,297
2026	6,154,041	11,830,000	3,046,250	--	--	21,030,291
2027	6,162,130	12,425,000	2,454,750	--	--	21,041,880
2028	6,179,681	13,040,000	1,833,500	--	--	21,053,181
2029	15,316,122	4,570,000	1,181,500	--	--	21,067,622
2030	15,362,969	4,800,000	953,000	--	--	21,115,969
2031	15,398,811	5,040,000	713,000	--	--	21,151,811
2032	15,448,267	9,220,000	461,000	--	--	25,129,267
Total[2]	$507,645,869	$76,665,000	$61,784,800	$7,120,000	$3,814,042	$657,029,707

(1) Excludes the Refunded 1998 Bonds which are being refunded with the proceeds of the 2012 Bonds. Interest rate on the 2008 Series A Bonds is assumed to be the swap rate. Interest rate on the outstanding unhedged variable rate Hydroelectric Project Bonds is assumed to bear interest at 4.00% per annum.

(2) Totals may not add due to rounding.

[THIS PAGE INTENTIONALLY LEFT BLANK]

[THIS PAGE INTENTIONALLY LEFT BLANK]

[THIS PAGE INTENTIONALLY LEFT BLANK]

NORTHERN CALIFORNIA POWER AGENCY • Hydroelectric Project Number One Revenue Bonds, 2012 Refunding Series A and 2012 Taxable Refunding Series B

FSC
www.fsc.org
MIX
From responsible sources
FSC™ C017146

Printed by: ImageMaster
www.ImageMaster.com