NEW ISSUE **BOOK-ENTRY ONLY**

In the opinion of Hawkins, Delafield & Wood, Bond Counsel, under existing statutes and court decisions and assuming continuing compliance with certain tax covenants described herein, interest on the Series 2002A Bonds is excluded from gross income for federal income tax purposes pursuant to Section 103 of the Internal Revenue Code of 1986, as amended (the "Code"). Interest on the Series 2002A Bonds is not treated as a preference item in calculating the alternative minimum tax imposed on individuals and corporations under the Code; such interest, however, is included in the adjusted current earnings of certain corporations for purposes of calculating the alternative minimum tax imposed on such corporations. In addition, in the opinion of Bond Counsel, under existing statutes, interest on the Series 2002A Bonds is exempt from State of California personal income taxes. See "Tax Matters" herein.

$6,313,500,000

State of California Department of Water Resources
Power Supply Revenue Bonds, Series 2002A

Dated: November 1, 2002 **Due: as shown on the inside cover**

Interest on the Series 2002A Bonds is payable on May 1 and November 1 of each year, commencing May 1, 2003. Series 2002A Bonds may be purchased in book-entry form only, in principal amounts of $5,000 or any integral multiple thereof. See APPENDIX B—"BOOK-ENTRY SYSTEM."

Series 2002A Bonds maturing on or after May 1, 2013 are subject to redemption prior to maturity. See "THE SERIES 2002A BONDS."

The Department of Water Resources ("DWR") of the State of California (the "State") has issued or plans to issue Power Supply Revenue Bonds ("Bonds") in 2002 in several series in the aggregate principal amount of $11,263,500,000 (the "Series 2002 Bonds"), including the $6,313,500,000 Series 2002A Bonds offered hereby. Net proceeds of the Series 2002 Bonds have been and will be used by DWR to repay outstanding loans and to make a deposit to the Operating Account. See "PLAN OF FINANCE." The Bonds are being issued under a Trust Indenture, as amended and supplemented (the "Indenture"), among DWR and two co-trustees, the Treasurer of the State and U.S. Bank, N.A.

The Bonds are payable primarily from charges ("Bond Charges") to be imposed by the California Public Utilities Commission ("CPUC") upon customers in the service areas of the three major investor-owned electric utilities in California, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company. The CPUC covenants in a rate agreement with DWR ("Rate Agreement") to calculate, revise and impose Bond Charges sufficient to pay debt service on the Bonds and other Bond Related Costs (as defined in the Rate Agreement) when due, as explained under "SECURITY FOR THE BONDS—Bond Related Costs," "SOURCES OF FUNDS TO PAY DEBT SERVICE—Rate Agreement," and "RATE COVENANTS."

In the Indenture, DWR pledges and assigns its revenues from Bond Charges for the payment of debt service on the Bonds and Parity Obligations when due, subject to the possible prior use of revenues from Bond Charges to pay amounts due under Priority Long-Term Power Contracts (as defined in the Indenture), as explained under "SECURITY FOR THE BONDS."

The scheduled payment of the principal of and interest on certain Series 2002A Bonds when due will be insured by financial guaranty insurance policies to be issued by the bond insurers identified on the inside cover of this Official Statement simultaneously with the issuance of the Series 2002A Bonds. See also "SECURITY FOR THE BONDS—Bond Insurance."

This cover page contains certain information for general reference only. It is not a summary. Investors must read the entire Official Statement to obtain information essential to making an informed investment decision.

See "RISK FACTORS" for certain risks that should be considered by investors in deciding whether to purchase Series 2002A Bonds.

THE BONDS SHALL NOT BE OR BE DEEMED TO CONSTITUTE A DEBT OR LIABILITY OF THE STATE OR OF ANY POLITICAL SUBDIVISION THEREOF OR A PLEDGE OF THE FAITH AND CREDIT OF THE STATE OR OF ANY SUCH POLITICAL SUBDIVISION, OTHER THAN DWR TO THE EXTENT PROVIDED IN THE INDENTURE. THE BONDS SHALL BE PAYABLE SOLELY FROM THE FUNDS PLEDGED THEREFOR PURSUANT TO THE INDENTURE. THE BONDS SHALL NOT DIRECTLY OR INDIRECTLY OR CONTINGENTLY OBLIGATE THE STATE OR ANY POLITICAL SUBDIVISION THEREOF TO LEVY OR TO PLEDGE ANY FORM OF TAXATION WHATEVER THEREFOR OR TO MAKE ANY APPROPRIATION FOR THEIR PAYMENT.

MATURITIES, PRINCIPAL AMOUNTS, INTEREST RATES, PRICES AND YIELDS
(see inside cover)

Certain legal matters incident to the authorization, sale and issuance of the Series 2002A Bonds are subject to the approval of The Honorable Bill Lockyer, Attorney General of the State of California, and of Hawkins, Delafield & Wood, Bond Counsel. Certain legal matters will be passed upon for DWR by Peggy Bernardy, Chief Counsel to DWR, and Orrick, Herrington & Sutcliffe LLP, Disclosure and Special Counsel to DWR. Certain legal matters will be passed upon for the CPUC by Gary M. Cohen, General Counsel to the CPUC, and Paul, Weiss, Rifkind, Wharton & Garrison, Special Counsel to the CPUC. Certain legal matters will be passed upon for the Treasurer of the State of California by Sidley Austin Brown & Wood LLP. Certain legal matters will be passed upon for the Underwriters by O'Melveny & Myers LLP and Leslie M. Lava, Esq., co-counsel to the Underwriters. It is expected that the Series 2002A Bonds will be available for delivery on or about November 14, 2002.

Honorable Philip Angelides
Treasurer of the State of California

JPMorgan **Lehman Brothers**

Bear, Stearns & Co. Inc. **E. J. De La Rosa & Co., Inc.** **Salomon Smith Barney**

Morgan Stanley & Co. Incorporated **UBS Paine Webber Inc.**

Banc of America Securities LLC BNY Capital Markets, Inc. CIBC World Markets E*BondTrade, LLC Fidelity Capital Markets First Albany Corporation Goldman, Sachs & Co. Jackson Securities Loop Capital Markets, LLC M.R. Beal & Company Merrill Lynch & Co., Inc. Pacific American Securities, LLC Prager, McCarthy & Sealy, LLC Prudential Securities Incorporated Quick & Reilly, Inc. Ramirez & Co., Inc. RBC Dain Rauscher Redwood Securities Group, Inc. Siebert Brandford Shank & Co. LLC Stone & Youngberg LLC Sutter Securities Inc. The Chapman Company U.S. Bancorp Piper Jaffray Wells Fargo Institutional Securities, LLC

Dated: November 7, 2002

$2,707,500,000 Uninsured 2002A Bonds

Maturity (May 1)	Principal Amount	CUSIP (13066Y)	Coupon	Yield	Price[1]
2005	$ 33,250,000	BJ7	3.000%	2.820%	100.424%
2005	84,625,000	BK4	5.500	2.820	106.334
2006	36,595,000	BL2	3.000	3.190	99.380
2006	26,150,000	BM0	5.500	3.190	107.517
2007	20,975,000	BN8	3.400	3.580	99.262
2007	93,100,000	BP3	5.500	3.580	107.854
2008	23,080,000	BQ1	3.750	3.900	99.267
2008	239,900,000	BR9	5.500	3.900	107.803
2009	26,115,000	BS7	4.000	4.120	99.323
2009	80,225,000	BT5	5.500	4.120	107.759
2010	18,435,000	BU2	4.200	4.360	98.988
2010	130,300,000	BV0	5.500	4.360	107.194
2011	5,840,000	BW8	4.300	4.480	98.741
2011	77,050,000	BX6	5.500	4.480	107.117
2012	14,750,000	BY4	4.400	4.570	98.704
2012	77,825,000	BZ1	5.500	4.570	107.078
2013	9,365,000	CA5	4.600	4.730	98.934
2013	189,950,000	CB3	6.000	4.730[2]	110.239
2014	5,620,000	CC1	4.750	4.830	99.300
2014	90,025,000	CD9	6.000	4.830[2]	109.437
2015	2,910,000	CE7	4.850	4.890	99.628
2015	14,960,000	CF4	5.250	4.890[3]	102.919
2015	115,000,000	CG2	6.000	4.890[2]	108.960
2016	5,720,000	CH0	4.900	4.990	99.123
2016	139,950,000	CJ6	5.875	4.990[3]	107.143
2017	20,285,000	CK3	5.000	5.070	99.286
2017	163,550,000	CL1	5.750	5.070[3]	105.467
2018	170,575,000	CN7	5.125	5.200	99.207
2019	170,000,000	CP2	5.125	5.270	98.414
2020	146,000,000	CQ0	5.250	5.340	98.983
2021	163,000,000	CR8	5.375	5.410	99.592
2022	312,375,000	CS6	5.375	5.480	98.750

[1] Plus accrued interest.
[2] Priced to a May 1, 2012 redemption date at a redemption price of 101.0%.
[2] Priced to a May 1, 2013 redemption date at a redemption price of 100.0%.

$3,606,000,000 Insured 2002A Bonds

Maturity (May 1)	Principal Amount	CUSIP (13066Y)	Coupon	Yield	Price[1]	Bond Insurer
2006	$ 46,840,000	CT4	3.000%	2.480%	101.715%	MBIA
2006	49,810,000	CU1	5.000	2.480	108.314	MBIA
2007	102,900,000	CV9	3.500	2.840	102.747	MBIA
2007	43,015,000	CW7	5.000	2.840	108.994	MBIA
2007	150,000,000	CX5	5.250	2.840	110.036	MBIA
2008	78,700,000	CY3	3.125	3.200	99.625	FSA
2008	107,060,000	CZ0	5.000	3.200	108.956	MBIA
2009	42,925,000	DA4	3.375	3.450	99.567	MBIA
2009	17,595,000	DB2	5.000	3.450	108.910	MBIA
2009	200,000,000	DC0	5.250	3.450	110.348	MBIA
2010	25,675,000	DD8	3.600	3.700	99.351	Ambac
2010	63,840,000	DE6	5.000	3.700	108.409	MBIA
2010	200,000,000	DF3	5.250	3.700	110.027	MBIA
2011	16,235,000	DG1	3.700	3.830	99.066	MBIA
2011	4,815,000	DH9	5.000	3.830	108.388	MBIA
2011	200,000,000	DJ5	5.250	3.830	110.181	FSA
2012	10,820,000	DK2	3.800	3.930	98.979	FSA
2012	10,965,000	DL0	5.000	3.930	108.387	MBIA
2012	115,000,000	DM8	5.250	3.930	110.346	MBIA
2012	85,000,000	DN6	5.250	3.930	110.346	FSA
2013	24,055,000	DP1	4.000	4.200	98.319	XLCA
2013	25,180,000	DQ9	5.000	4.100	107.593	FSA
2013	300,000,000	DR7	5.500	4.100[2]	111.569	Ambac
2014	15,630,000	DS5	4.125	4.250	98.873	Ambac
2014	3,350,000	DT3	5.000	4.250[3]	106.280	Ambac
2014	300,000,000	DU0	5.500	4.250[2]	110.326	Ambac
2015	5,600,000	DV8	4.250	4.450	98.100	XLCA
2015	4,930,000	DW6	5.000	4.350[3]	105.415	Ambac
2015	325,000,000	DX4	5.500	4.350[2]	109.507	Ambac
2016	1,870,000	DY2	4.375	4.450	99.244	Ambac
2016	2,930,000	DZ9	5.000	4.450[3]	104.559	Ambac
2016	325,000,000	EA3	5.500	4.450[2]	108.695	Ambac
2017	4,950,000	EB1	4.400	4.540	98.525	Ambac
2017	3,395,000	EC9	5.000	4.540[3]	103.796	Ambac
2017	305,345,000	ED7	5.375	4.640[3]	106.036	XLCA
2018	29,730,000	EE5	4.500	4.620	98.682	Ambac
2018	16,425,000	EF2	5.000	4.620[3]	103.123	Ambac
2018	341,415,000	EG0	5.375	4.620[3]	106.206	Ambac

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Copies of this Official Statement may be obtained from:

HONORABLE PHILIP ANGELIDES
Treasurer of the State of California
Agent for Sale
P.O. Box 942809
Sacramento, California 94209-0001
1-800-900-3873

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GENERAL INFORMATION

All capitalized terms used in this Official Statement that are not defined in this Official Statement but that are defined in the Indenture have the meanings in this Official Statement given to such terms in the Indenture. For definitions of certain terms used in the Indenture, see APPENDIX C – "SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE." For an index of principal definitions used in this Official Statement, see APPENDIX H – "INDEX OF PRINCIPAL DEFINITIONS."

Descriptions and summaries of CPUC orders, the Rate Agreement, the Indenture, the Series 2002A Bonds, DWR's servicing arrangements, DWR's power supply contracts (including the Priority Long-Term Power Contracts), Division 27 (commencing with Section 80000) of the California Water Code, as amended from time to time (the "Act"), and other documents, regulations and laws referred to in this Official Statement do not purport to be complete and reference is made to each of them for a complete statement of their provisions. A copy of the Rate Agreement is attached as Appendix D to this Official Statement. Copies of DWR's power supply contracts are posted on DWR's Internet site at www.cers.water.ca.gov. Copies of other DWR documents may be obtained by request to DWR at cersforum@water.ca.gov or 3310 El Camino Avenue, Suite 120, Sacramento, California 95821, upon payment of a reproduction fee.

So far as any statements made in this Official Statement involve matters of opinion, assumptions, projections, anticipated events or estimates, whether or not expressly stated, they are set forth as such and not as representations of fact, and actual results may differ substantially from those set forth herein. Neither this Official Statement nor any statement which may have been made verbally or in writing is to be construed as a contract with the owners of the Series 2002A Bonds.

No person has been authorized to give information or to make any representations other than those contained in this Official Statement; and, if given or made, such other information or representations must not be relied upon as having been authorized by DWR or the State. This Official Statement does not constitute an offer to sell or a solicitation of an offer to buy, nor shall there be any sale of the Series 2002A Bonds offered hereby by any person in any jurisdiction in which it is unlawful for such person to make such offer, solicitation or sale. This Official Statement speaks only as of its date and any information, estimates and/or 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 material change in the affairs of DWR or the CPUC since the date hereof.

The information set forth herein has been obtained from official sources that are believed to be reliable, but it is not guaranteed as to accuracy or completeness. The presentation of information is intended to show recent historic information and is not intended to indicate future or continuing trends in the financial position or other affairs of DWR or the CPUC. No representation is made that past experience, as it might be shown by such financial and other information, will necessarily continue or be repeated in the future.

This Official Statement includes forward-looking statements that are based on DWR's current expectations and projections about future events. These forward-looking statements are subject to risks and uncertainties, including risks and uncertainties outside the control of DWR. Such statements generally are identifiable by the terminology used, such as "plan," "expect," "estimate," "budget," "believes" or other similar words. Such forward-looking statements include but are not limited to certain statements contained in the description of the DWR Power Supply Program, the Consultant's Report attached as Appendix A, and under the captions "SUMMARY," "POWER SUPPLY PROGRAM," "PLAN OF FINANCE," "PRIORITY LONG-TERM POWER CONTRACTS," "SOURCES OF FUNDS TO PAY DEBT SERVICE," "RATEMAKING AND RELATED ACTIONS," and "RISK FACTORS" in this Official Statement.

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 described to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Neither DWR nor the Consultant plans to issue any updates or revisions to these forward-looking statements if or when expectations or events, conditions or circumstances on which such statements are based occur.

A wide variety of other information, including financial information, concerning DWR and the State is available from DWR, the State Treasurer, the State and publications and websites of DWR, the State Treasurer, the State and various State agencies and officials, including the CPUC. No such information is a part of or incorporated into this Official Statement.

The CPUC makes no representation as to the accuracy or completeness of any forward-looking statements or projections contained in this Official Statement, including, without limitation, any assumptions or conclusions contained in the Consultant's Report attached as Appendix A. The CPUC makes no representation as to the accuracy or completeness of this Official Statement, including any description in this Official Statement of litigation involving or affecting the CPUC, and any statements regarding such litigation do not necessarily represent the CPUC's view of such litigation or any position in such litigation. In addition, while CPUC staff have assisted in the preparation of certain sections of this Official Statement, the CPUC can only take positions through formal action and has not taken any such action or approved this Official Statement. The CPUC is an independent five-member body that must act by an affirmative vote of a majority of its members and, as a result, the CPUC can only indicate its views in formal decisions or other formal actions. In addition, the CPUC is not subject to the control of DWR and may take positions in the future different from DWR in litigation, or other matters described in this Official Statement. As a result, statements in this Official Statement regarding electricity markets and regulation, and DWR's views of the CPUC's role or DWR's role in such markets and regulation, do not necessarily represent the views, opinions or beliefs of the CPUC and should not be construed as such by any recipient of this Official Statement.

Information about the IOUs in this Official Statement has been obtained from publicly available documents. Each of the IOUs and the parent companies of each of the IOUs named under "SERVICING ARRANGEMENTS" file annual, quarterly and certain other reports with the Securities and Exchange Commission ("SEC"). Such reports are available on the SEC's website (www.sec.gov) and upon request from the Office of Public Reference of the SEC, 450 5th Street, NW, Room 1300, Washington, D.C. 20549-0102 (phone: (202) 942-8090; fax: (202) 628-9001; e-mail: publicinfo@sec.gov). No such report is a part of or incorporated into this Official Statement. Filings by each of the IOUs with the Federal Energy Regulatory Commission ("FERC") may be found on FERC's website (www.ferc.gov). No such report on the SEC's website or report on the FERC website is a part of or incorporated into this Official Statement. The information referred to in this paragraph has not been independently verified and DWR, the Consultant and the Underwriters do not warrant that this information is accurate or complete.

Information about bond insurers in this Official Statement has been obtained from such insurers. Additional information concerning such insurers may be found in other documents referenced in Appendix K. No such additional information or other document is a part of or incorporated into this Official Statement unless expressly stated otherwise. The information referred to in this paragraph has not been independently verified and DWR, the Consultant, the CPUC and the Underwriters do not warrant that such information is accurate or complete.

The following sentence has been provided by Financial Security Assurance Inc. ("Financial Security") for inclusion in this Official Statement. Other than with respect to information concerning Financial Security contained under the caption "FINANCIAL SECURITY ASSURANCE INC." of Appendix K, including the specimen "Municipal Bond Insurance Policy" therein, none of the information in this Official Statement has been supplied or verified by Financial Security and Financial Security makes no representation or warranty, express or implied, as to (i) the accuracy or completeness of such information; (ii) the validity of the Series 2002A Bonds; or (iii) the tax exempt status of the interest on the Series 2002A Bonds.

In connection with this offering the Underwriters may over-allot or effect transactions which stabilize or maintain the market prices of the Series 2002A Bonds offered hereby at levels above that which might otherwise prevail in the open market. Such stabilizing, if commenced, may be discontinued at any time.

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 a part of, their 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.

OFFICIAL STATEMENT

$6,313,500,000
State of California Department of Water Resources
Power Supply Revenue Bonds, Series 2002A

SUMMARY

This summary is a brief description of the Series 2002A Bonds and this Official Statement. A full review should be made of the entire Official Statement, including the Appendices. The Index of Principal Definitions in Appendix H lists the pages on which the definitions of principal terms used in this Official Statement appear.

General..... This Official Statement describes the Department of Water Resources ("DWR") of the State of California (the "State"), DWR's Power Supply Program and DWR's Power Supply Revenue Bonds (the "Bonds"). In 2002, DWR has issued or will issue $11,263,500,000 principal amount of Bonds (collectively, the "Series 2002 Bonds"). The Series 2002 Bonds consist of DWR's Power Supply Revenue Bonds, Series 2002B, Series 2002C and Series 2002D, issued on October 30, 2002 in the aggregate principal amount of $4,250,000,000; its Power Supply Revenue Bonds, Series 2002A offered hereby in the principal amount of $6,313,500,000 (the "Series 2002A Bonds"); and its Power Supply Revenue Bonds, Series 2002E, to be issued on the same date as the Series 2002A Bonds in the principal amount of $700,000,000. See "PLAN OF FINANCE."

Department of Water Resources.....DWR was established in 1956 under California law as a department of the State. The Director and Chief Deputy Director of DWR are appointed by the Governor and, as a part of the Executive Branch, report to the Governor through the Secretary of the Resources Agency. DWR has been operating the Power Supply Program since early 2001. See "POWER SUPPLY PROGRAM." Under the Power Supply Program, DWR has been purchasing power for sale to end use customers in the service areas of the three major investor-owned electric utilities in the State, Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE"), and San Diego Gas & Electric Company ("SDG&E") (collectively, the "IOUs").

Power Supply Program.....In January 2001, Governor Davis determined that the electricity available through the IOUs was insufficient to prevent widespread and prolonged disruption of electric service in California, proclaimed a state of emergency to exist under California law, and directed DWR to enter into contracts and arrangements for the purchase and sale of electric power as necessary to assist in mitigating the effects of the emergency. The Power Supply Program has been implemented under the authority of the Governor's proclamation, related executive orders of the Governor, and legislation enacted in 2001, and pursuant to orders issued by the California Public Utilities Commission (the "CPUC") in response to the legislation. The general purpose of the Power Supply Program has been to provide to the customers of the IOUs the portion of their power not provided by the IOUs (the "net short"). DWR plans to end its purchases and sales of electricity before the Series 2002 Bonds are retired. See "POWER SUPPLY PROGRAM – Transition of Procurement Responsibility After 2002" and APPENDIX A – "CONSULTANT'S REPORT – Plan to Transition DWR

Net Short Responsibilities." Bond Charges (described below) are to be the primary source of money to pay debt service on the Bonds, and must be imposed by the CPUC whether or not DWR continues to purchase or sell electricity under the Power Supply Program. See "RATE COVENANTS."

California Public Utilities Commission.....The CPUC was established in 1911 under the California Constitution and the California Public Utilities Act enacted in 1912. The CPUC is an independent regulatory agency and is not controlled by DWR. The CPUC regulates the IOUs and other California entities, mostly investor-owned electric, telecommunications, natural gas, water, railroad companies, and rail transit and passenger transportation companies. See "CALIFORNIA PUBLIC UTILITIES COMMISSION."

Under California law, the CPUC sets charges to recover DWR's statutorily defined revenue requirements and establishes the procedures that it will use to set charges and to allocate charges among service areas and electric customers. The CPUC has adopted a number of decisions that implement recent legislation that facilitated DWR's provision of the net short. See "RATEMAKING AND RELATED ACTIONS" and "RATE COVENANTS."

The CPUC makes no representation as to the accuracy or completeness of any forward-looking statements or projections contained in this Official Statement, including, without limitation, any assumptions or conclusions contained in the Consultant's Report attached as Appendix A. The CPUC makes no representation as to the accuracy or completeness of this Official Statement, including any description in this Official Statement of litigation involving or affecting the CPUC, and any statements regarding such litigation do not necessarily represent the CPUC's view of such litigation or any position in such litigation. In addition, while CPUC staff have assisted in the preparation of certain sections of this Official Statement, the CPUC can only take positions through formal action and has not taken any such action or approved this Official Statement. The CPUC is an independent five-member body that must act by an affirmative vote of a majority of its members and, as a result, the CPUC can only indicate its views in formal decisions or other formal actions. In addition, the CPUC is not subject to the control of DWR and may take positions in the future different from DWR in litigation, or other matters described in this Official Statement. As a result, statements in this Official Statement regarding electricity markets and regulation, and DWR's views of the CPUC's role or DWR's role in such markets and regulation, do not necessarily represent the views, opinions or beliefs of the CPUC and should not be construed as such by any recipient of this Official Statement.

Bond Authorization.....The Series 2002 Bonds are being issued under Division 27 (commencing with Section 80000) of the California Water Code, as amended from time to time (the "Act") and a Trust Indenture, as amended and supplemented (the "Indenture"), including, with respect to the Series 2002A Bonds, a Second Supplemental Trust Indenture (the "Second Supplemental Indenture") among DWR, the Treasurer of the State as Trustee, and U.S. Bank, N.A., as Co-Trustee (collectively, the "Trustees").

Purpose of the Series 2002 Bonds.....Proceeds of the Series 2002 Bonds (net of costs of issuance, costs of credit enhancement, and deposits to certain accounts under the Indenture) have been and will be used by DWR first, to repay outstanding loans from certain underwriters of the Series 2002 Bonds (or affiliated lenders) and commercial banks in the amount of approximately $3.5 billion, and second, to repay the principal of outstanding loans from the State's General Fund in the amount of approximately $6.1 billion. The loans financed Power Supply Program costs during 2001 that exceeded DWR's revenues from the sale of electricity. See "POWER SUPPLY PROGRAM" and "PLAN OF FINANCE."

The Series 2002A Bonds ..... The Series 2002A Bonds will be dated and will mature on the dates and in the amounts shown on the inside cover of this Official Statement. Interest on the Series 2002A Bonds is payable on May 1 and November 1 of each year, commencing May 1, 2003. Series 2002A Bonds may be purchased in book-entry form only, in the principal amount of $5,000 or any integral multiple thereof. The Series 2002A Bonds maturing on or after May 1, 2013 will be subject to redemption before their stated maturities, at the option of DWR. See "THE SERIES 2002A BONDS."

Rate Covenants and Bond Charges ...The Bonds are payable primarily from charges ("Bond Charges") to be imposed by the CPUC upon customers (currently estimated by DWR to be approximately 10 million accounts) in the service areas of the IOUs. See "PLAN OF FINANCE – Sources of Revenues During Calendar Years 2001 and 2002; DWR Charges for 2003."

In the Rate Agreement with DWR ("Rate Agreement"), the CPUC covenants to calculate, revise and impose from time to time, Bond Charges sufficient to provide moneys so that amounts available for deposit in the Bond Charge Payment Account under the Indenture from time to time, together with amounts on deposit in the Bond Charge Payment Account, are at all times sufficient to pay or provide for the payment of debt service on the Bonds and other Bond Related Costs (as defined in the Rate Agreement) when due in accordance with the Indenture and other financing documents. See "SECURITY FOR THE BONDS – Bond Related Costs," "SOURCES OF FUNDS TO PAY DEBT SERVICE – Rate Agreement," and "RATE COVENANTS."

Under the Rate Agreement, DWR is responsible for notifying the CPUC of the amounts required to pay Bond Related Costs that are to be recovered from Bond Charges. See "RATE COVENANTS." Under the Rate Agreement, DWR is also responsible for notifying the CPUC of DWR's "Retail Revenue Requirements" (defined in the Rate Agreement as the amounts required to pay DWR costs that are to be recovered from Power Charges imposed by the CPUC from time to time). Retail Revenue Requirements do not include Bond Related Costs recovered from Bond Charges.

In the Indenture, DWR covenants to cause to be established, fixed and revised from time to time, charges sufficient, together with any other available moneys and securities on deposit in DWR's Electric Power Fund, to satisfy all of DWR's "Revenue Requirements" at the times and in the amounts needed. "Revenue Requirements" is defined in the Indenture to

mean the amounts needed from time to time by DWR to satisfy its obligations under the Act and under proclamations and orders issued pursuant to the California Emergency Services Act that are identified in the Indenture. These obligations include, but are not limited to, making deposits to the Bond Charge Payment Account and Debt Service Reserve Account in the amounts and at the times required by the Indenture.

In February 2002, the CPUC adopted a final order establishing charges to recover DWR's Retail Revenue Requirements for 2001 and 2002. The revenues from those charges, together with other DWR funds (including Bond proceeds), are projected by DWR to be sufficient to satisfy DWR's rate covenant for 2002, including amounts needed for deposit in the Bond Charge Payment Account to pay debt service on the Bonds prior to the receipt of sufficient Bond Charge Revenues.

The receipt of sufficient Revenues for calendar year 2003 depends upon action by the CPUC to impose Power Charges and Bond Charges for 2003. DWR submitted its Retail Revenue Requirements for the calendar year 2003 to the CPUC on August 19, 2002, and expects that the CPUC will impose Power Charges that will begin to accrue on and after January 1, 2003. On October 24, 2002, the CPUC adopted a decision establishing the methodology by which Bond Charges will be imposed. On November 4, 2002, TURN, SCE and PG&E each filed an application for rehearing of that decision. The TURN and SCE applications contend that the allocation methodology adopted by the CPUC was unlawful and discriminatory in that it exempted from Bond Charges certain residential usage only in the SDG&E service area. The PG&E application made the same complaint and also contended that there were defects in the procedure by which the CPUC consented to an increase in the amount of Bonds. The PG&E application further contended that these alleged defects affected the adoption of the CPUC's October 24, 2002 decision. TURN also contends that the CPUC is required to exempt certain electricity usage from Bond Charges under an interpretation of State law. November 4, 2002 was the last day that an interested party could request a rehearing on the October 24, 2002 CPUC decision. Although the implementation of Bond Charges is subject to a possible rehearing or revision of, and potential legal challenges to, that decision, and to additional actions yet to be taken, all of which could result in modification of such decision or delay in implementation, DWR expects that the CPUC will impose Bond Charges that will begin to accrue on or about November 15, 2002. See "PLAN OF FINANCE – Sources of Revenues During Calendar Years 2001 and 2002; DWR Charges for 2003." See also "RATEMAKING AND RELATED ACTIONS – DWR Actions to Establish Revenue Requirements – *Proceedings Under Revenue Requirement Regulations*." See also "RISK FACTORS – Determination of Power Charges and Bond Charges; Possible Uses of Amounts in the Bond Charge Collection Account to Pay Priority Contract Costs" and other sections of this Official Statement referred to therein.

Bond Related Costs .....Bond Related Costs that are payable from Bond Charges imposed by the CPUC under the Rate Agreement include, among other costs, debt service on the Bonds and payments required to be made: (i) under agreements with issuers of credit and liquidity facilities, including letters of credit, bond insurance, guarantees, debt service reserve fund surety bonds, lines of

credit, reimbursement agreements, and standby bond purchase agreements, (ii) under agreements relating to other financial instruments entered into in connection with the Bonds, including but not limited to investment agreements, hedges, interest rate swaps, caps, options and forward purchase agreements, and (iii) under agreements relating to the remarketing of Bonds, including but not limited to remarketing agreements, dealer agreements and auction agent agreements. Such payments may cover fees, expenses, indemnification, or other obligations due the providers of any such facilities, and such agreements may be entered into at any time concurrently with or after the issuance of Bonds. See "SECURITY FOR THE BONDS – Bond Related Costs."

In connection with variable interest rate Series 2002 Bonds, DWR has entered or expects to enter into agreements, such as agreements with issuers of credit and liquidity facilities and agreements with interest rate swap providers, requiring the payment of certain Bond Related Costs on a parity with payment of debt service on the Bonds. See "PLAN OF FINANCE" and "SECURITY FOR THE BONDS – Bond Related Costs."

Security for the Bonds; Bond Charge Revenues ..... The primary source of moneys for the payment of debt service on the Bonds and other Bond Related Costs will be Bond Charge Revenues, which constitute part of the Trust Estate securing the Bonds, as described below.

The "Trust Estate" is assigned and pledged to the Trustees under the Indenture for the benefit of the Bonds and Parity Obligations, subject to the use of the Trust Estate in accordance with the Indenture. The "Trust Estate" is defined in the Indenture to include, among other things, "Revenues." "Revenues" includes both "Bond Charge Revenues" and "Power Charge Revenues." "Revenues" also includes revenues from possible future sources as described under "RATEMAKING AND RELATED ACTIONS – CPUC Actions Limiting Customer Access to Other Energy Providers" and "-Proposed CPUC Action Imposing Bond Charges on Customers of Electric Service Providers."

- "Bond Charge Revenues" are Revenues received by DWR arising from Bond Charges imposed by the CPUC upon customers in the service areas of the IOUs as described under "RATE COVENANTS."

- "Power Charge Revenues" are Revenues received by DWR arising from Power Charges imposed by the CPUC upon customers for electric power deemed sold to customers by DWR as described under "POWER SUPPLY PROGRAM."

The use of amounts on deposit in the Bond Charge Collection Account (including Bond Charge Revenues) for the payment of debt service on the Bonds and other Bond Related Costs when due is subject to the possible prior use of such amounts to pay amounts due under Priority Long-Term Power Contracts ("Priority Contract Costs"). See "SECURITY FOR THE BONDS" and "PRIORITY LONG-TERM POWER CONTRACTS." See also "RISK FACTORS – Determination of Power Charges and Bond Charges; Possible Use of Amounts in the Bond Charge Collection Account to Pay Priority Contract Costs."

Sources of Payment of Operating Expenses; Priority Long-Term Power Contracts .....Power Supply Program operating expenses, including Priority Contract Costs, are expected to be paid from Power Charge Revenues and other Revenues (other than Bond Charge Revenues). Each Priority Long-Term Power Contract (see "PRIORITY LONG-TERM POWER CONTRACTS") contains a provision requiring that payments by DWR under the contract are to be paid or payable prior to payment of debt service or other payments on indebtedness of DWR secured by a pledge of revenues under the Act and other amounts in the Electric Power Fund established by the Act. DWR expects that after 2002 most of the power purchased by DWR under the Act will be purchased under Priority Long-Term Power Contracts and most operating expenses will be Priority Contract Costs. See APPENDIX A – "CONSULTANT'S REPORT – Power Supply Resources." The CPUC covenants to calculate, revise and impose Power Charges sufficient to satisfy the Retail Revenue Requirements as specified by DWR. See "Rate Covenants and Bond Charges" above. See also "RISK FACTORS – Determination of Power Charges and Bond Charges; Possible Use of Amounts in the Bond Charge Collection Account to Pay Priority Contract Costs."

Accounts and Flow of Funds under the Indenture.....The Indenture establishes within the Electric Power Fund two sets of accounts for Revenues. One set of accounts, the "Bond Charge Accounts," is primarily for the deposit of Bond Charge Revenues and the payment of Bond Related Costs. Another set of accounts, the "Power Charge Accounts," is primarily for the deposit of Power Charge Revenues and the payment of operating expenses (including Priority Contract Costs and other costs of the Power Supply Program). Bond Charge Accounts include the Bond Charge Collection Account, the Bond Charge Payment Account, and the Debt Service Reserve Account. Power Charge Accounts include the Operating Account, the Priority Contract Account and the Operating Reserve Account. See "SECURITY FOR THE BONDS – Accounts and Flow of Funds under the Indenture."

Bond Charge Accounts .....The Indenture requires the following deposits and transfers of Bond Charge Revenues:

- All Bond Charge Revenues are required to be deposited in the Bond Charge Collection Account. DWR is also required to deposit in the Bond Charge Collection Account any payments received from any counterparty to a Qualified Swap relating to Bonds.

- On or before the last Business Day of each month, DWR is required to transfer from the Bond Charge Collection Account to the Bond Charge Payment Account such amount as is necessary to make the amount in the Bond Charge Payment Account sufficient to pay Bond Related Costs (including Debt Service on the Bonds) estimated to accrue or be payable during the next succeeding three calendar months. Each such transfer is subject to the prior transfer of amounts in the Bond Charge Collection Account to the Priority Contract Account if and to the extent amounts in the Priority Contract Account, the Operating Account and

the Operating Reserve Account are insufficient to pay Priority Contract Costs. See "PRIORITY LONG-TERM POWER CONTRACTS."

- Deficiencies in the Bond Charge Payment Account are required to be made up *first*, from the Operating Account and *second*, from the Debt Service Reserve Account (except for the payment of Fiduciary costs).

- The Debt Service Reserve Account is to be funded at the time Bonds are issued so that the Debt Service Reserve Account has a balance in the amount of maximum aggregate annual Debt Service on all outstanding Bonds, calculated in accordance with the Indenture (the "Debt Service Reserve Requirement"). Each month after the Bond Charge Payment Account is funded as described above, Revenues are to be transferred to the Debt Service Reserve Account and to any reserve established for Parity Obligations to the extent necessary to meet the respective requirements (including replenishment requirements) for such reserves. Amounts in the Debt Service Reserve Account may be used for the payment of Bond Related Costs (including debt service on the Bonds) except Fiduciary costs, but only if amounts in the Bond Charge Payment Account and Operating Account are insufficient for that purpose. See "SECURITY FOR THE BONDS – Accounts and Flow of Funds under the Indenture" and " – Debt Service Reserve Account."

Power Charge Accounts.....The Indenture requires the following deposits and transfers of all Revenues other than those required to be deposited in the Bond Charge Collection Account:

- All Revenues (including but not limited to Power Charge Revenues), other than Bond Charge Revenues and payments to DWR under Qualified Swaps relating to Bonds, are required to be deposited in the Operating Account.

- On or before the fifth Business Day of each month, DWR is required to transfer from the Operating Account to the Priority Contract Account such amount as is necessary to make the amount in the Priority Contract Account sufficient to pay Priority Contract Costs estimated to be due during the balance of such month and through the first five Business Days of the next succeeding calendar month. Amounts in the Priority Contract Account may be used solely to pay Priority Contract Costs. See "SECURITY FOR THE BONDS – Accounts and Flow of Funds under the Indenture." See "RISK FACTORS – Determination of Power Charges and Bond Charges; Possible Use of Amounts in the Bond Charge Collection Account to Pay Priority Contract Costs."

- Amounts in the Operating Account after the monthly transfer to the Priority Contract Account are to be used for the following purposes in the following order of priority: (i) for transfer to the Priority Contract Account if the estimated amount transferred to that account (as described in the preceding paragraph) is insufficient to pay actual Priority Contract Costs then payable; (ii) for the payment of other operating expenses; (iii) to reimburse the Bond Charge Collection Account for amounts previously transferred from the Bond Charge

Collection Account to the Priority Contract Account to pay Priority Contract Costs; (iv) to pay debt service on the Bonds and other Bond Related Costs (if amounts in the Bond Charge Payment Account are not sufficient for those purposes) and, in addition, prior to the time Bond Charge Revenues are received in amounts sufficient to make the transfers described in the second bullet point under "Bond Charge Accounts" above, to make those transfers as required; (v) for transfer to the Debt Service Reserve Account to the extent required by the Indenture as a result of the use of Bond Charge Revenues to pay Priority Contract Costs or a change in value of investments in such Account; (vi) to reimburse the General Fund to the extent provided by the Indenture for amounts advanced by the General Fund to the Electric Power Fund; (vii) to replenish the Operating Reserve Account to its requirement as provided by the Indenture; (viii) to pay any subordinated indebtedness and subordinated obligations and certain other amounts relating thereto; and (ix) for any other lawful purpose of the Power Supply Program. See "SECURITY FOR THE BONDS – Accounts and Flow of Funds under the Indenture," "– Debt Service Reserve Account" and " – Operating Reserve Account."

- The Operating Reserve Account was funded in an amount equal to the Operating Reserve Account Requirement at the time of issuance of the first series of Bonds on October 30, 2002 (see "PLAN OF FINANCE"). Amounts in the Operating Reserve Account are to be transferred to the Operating Account if and to the extent that the amount in the Operating Account is insufficient for any of the purposes listed in clauses (i) through (v) of the preceding paragraph, unless the amount in the Operating Reserve Account is equal to or less than the "Priority Contract Contingency Reserve Amount" (an amount equal to the maximum amount projected by DWR to be payable under Priority Long-Term Power Contracts in any calendar month during the then-current revenue requirement period), in which event amounts in the Operating Reserve Account may only be used to make up any deficiency in the Priority Contract Account. See "SECURITY FOR THE BONDS – Accounts and Flow of Funds under the Indenture" and " – Operating Reserve Account."

Bond Insurance ..... The scheduled payment when due of the principal of and interest on certain Series 2002A Bonds will be insured by financial guaranty insurance policies to be issued by the bond insurers identified on the inside cover of this Official Statement. See also "SECURITY FOR THE BONDS – Bond Insurance" and APPENDIX K – "INFORMATION CONCERNING THE BOND INSURERS AND FORMS OF FINANCIAL GUARANTY INSURANCE POLICIES."

Collection of Revenues; Servicing Arrangements ..... DWR has entered into Servicing Agreements with SCE and SDG&E that have been approved by CPUC orders, and the CPUC has adopted a Servicing Order for PG&E (collectively, the "Servicing Arrangements") under which DWR's Bond Charges and Power Charges are to be collected from customers for DWR by the IOUs solely as the agents of DWR. The CPUC orders relating to the current servicing arrangements are final and unappealable under California law; however PG&E may challenge the

Servicing Order at any time in its bankruptcy proceeding. See "LITIGATION AND ADMINISTRATIVE PROCEEDINGS – Litigation Pending or Threatened in State and Federal Courts – *Pacific Gas and Electric Bankruptcy*." See also "SERVICING ARRANGEMENTS."

Consultant's Report ..... DWR has engaged Navigant Consulting, Inc. (the "Consultant") to prepare a report (the "Consultant's Report") for the purpose of this Official Statement. See "THE CONSULTANT." The Consultant's Report is attached as Appendix A and should be read in its entirety.

Although DWR believes that the conclusions contained in the Consultant's Report and the assumptions and projections upon which the conclusions are based are reasonable, no assurance can be given that any such projections will be realized or that the assumptions will prove to be correct. DWR has not undertaken an independent investigation of all of the assumptions, projections, conclusions and other matters stated in the Consultant's Report. DWR has relied on the Consultant's expertise in the matters covered in the Consultant's Report. The Underwriters of the Bonds and the financial advisors and counsel named in this Official Statement have also relied on the Consultant's expertise in the matters covered in the Consultant's Report.

The CPUC makes no representation as to the accuracy or completeness of any forward-looking statements or projections contained in this Official Statement, including, without limitation, any assumptions or conclusions contained in the Consultant's Report. See "California Public Utilities Commission" above in this Summary.

Litigation and Administrative Proceedings ..... Litigation and administrative proceedings involving DWR or affecting DWR's Power Supply Program are summarized under "LITIGATION AND ADMINISTRATIVE PROCEEDINGS."

Risks..... Investment in the Series 2002A Bonds is subject to certain risks, including the events and circumstances identified under "RISK FACTORS" beginning at page 59 of this Official Statement (cross references below are to subsections of that section).

There can be no assurance that the occurrence of one or more of such events or circumstances will not materially and adversely affect the ability of DWR to pay debt service on the Bonds.

Such risks relate to the following events or circumstances, among others:

- Administrative challenges or legal proceedings pertaining to DWR's proceedings for establishing its Revenue Requirements or the CPUC's proceedings for calculating, revising and imposing Bond Charges and Power Charges, and the possible use of amounts on deposit in the Bond Charge Collection Account to pay Priority Contract Costs (see "Determination of Power Charges and Bond Charges; Possible Use of Amounts in the Bond Charge Collection Account to Pay Priority Contract Costs");

- Receipt by DWR, under the Servicing Arrangements, of less than all of the money due from customers for Bond Charges and Power Charges (see "Collection of Bond Charges and Power Charges");

- Action or inaction by a bankrupt IOU resulting in a reduction of DWR's revenues or otherwise disrupting the Servicing Arrangements (see "Bankruptcy Risks");

- Uncertainties concerning the future of the Power Supply Program (see "Certain Risks Associated With DWR's Power Supply Program");

- Increases in overall electric rates (see "Potential Increases in Electric Rates");

- Reduction of the customer base providing revenues to DWR (see "Potential Decrease in DWR Customer Base");

- Changes in the electric industry or in state or federal law or policy that affect DWR (see "Uncertainties Relating to Electric Industry and Markets" and "Uncertainties Relating to Government Action"); and

- Actual results materially differing from the projections and assumptions contained in this Official Statement and the Appendices, including the Consultant's Report, or contained in DWR's Revenue Requirements (see "Uncertainty of Projections and Assumptions").

AUTHORIZATION FOR THE BONDS AND BOND CHARGES

The Bonds are being issued under Division 27 (commencing with Section 80000) of the California Water Code, as amended from time to time (defined above as the "Act") and a Trust Indenture, as amended and supplemented (defined above as the "Indenture") among DWR, the Treasurer of the State as Trustee, and U.S. Bank, N.A., as Co-Trustee (defined above collectively as the "Trustees").

The Act provides that DWR is entitled to recover its costs, including power purchase costs and debt service on the Bonds (collectively, under the Act, its "Revenue Requirements"), in the amounts and at the times necessary to satisfy its contractual obligations, and is to advise the CPUC of its Revenue Requirements so that its Revenue Requirements can be recovered through charges imposed upon customers by the CPUC. The Act also authorizes the CPUC and DWR to enter into agreements with respect to such charges. Under California law, the CPUC sets charges to recover DWR's statutorily defined revenue requirements, establishes the procedures that it will use to set charges and to allocate charges among service areas and electric customers, and has the authority to require the IOUs to collect charges for DWR. See "RATEMAKING AND RELATED ACTIONS."

Legal, regulatory and other administrative proceedings pertaining to actions by DWR and the CPUC pursuant to the Act and other State laws are pending or threatened (see "LITIGATION AND ADMINISTRATIVE PROCEEDINGS"). Uncertainty as to the outcome of those proceedings poses risks that should be considered by investors in deciding whether to purchase Series 2002A Bonds. See "RISK FACTORS."

No action or approval by the Federal Energy Regulatory Commission ("FERC") or any other federal agency is required for the issuance of the Bonds or the calculation, revision, imposition or collection of Bond Charges or Power Charges.

THE SERIES 2002A BONDS

General

The Series 2002A Bonds will mature on the dates and in the amounts shown on the inside cover of this Official Statement. The Series 2002A Bonds will accrue interest from November 1, 2002 at the per annum interest rates set forth on the inside cover of this Official Statement. Interest on the Series 2002A Bonds is payable on May 1 and November 1 of each year, commencing May 1, 2003, to the owners of record at the close of business on the 15th day (whether or not a business day) of the preceding calendar month. Series 2002A Bonds may be purchased in book-entry form only, in the principal amount of $5,000 or any integral multiple thereof. See APPENDIX B – "BOOK-ENTRY SYSTEM."

The Treasurer of the State is the Trustee and U.S. Bank, N.A., is the Co-Trustee under the Indenture. The Treasurer of the State is also the Registrar and Paying Agent for the Series 2002A Bonds.

So long as any Series 2002A Bond is registered in the name of Cede & Co., as nominee of DTC, procedures with respect to the transfer of ownership, redemption, and the payment of principal, Redemption Price, premium, if any, and interest on such Bond shall be in accordance with arrangements among DWR, the Paying Agent and DTC.

Redemption

Optional Redemption

Series 2002A Bonds maturing on or before May 1, 2012 are not subject to optional redemption prior to their respective stated maturities. Series 2002A Bonds maturing on and after May 1, 2013 are subject to optional redemption prior to their respective stated maturity dates, in whole or in part, in such order of maturity and

interest rate and, within any maturity supported by more than one Enhancement Facility, selected among the Series 2002A Bonds supported by such Enhancement Facilities, all as may be designated by DWR, on any date on and after May 1, 2012 at the redemption prices set forth below, plus accrued interest to the date fixed for redemption.

Redemption Periods	Redemption Prices
May 1, 2012 through October 31, 2012	101.0%
November 1, 2012 through April 30, 2013	100.5
May 1, 2013 and thereafter	100.0

Selection of Bonds for Redemption

If less than an entire maturity of Series 2002A Bonds bearing interest at the same rate and, if applicable, supported by the same Enhancement Facility, is to be redeemed, the Registrar shall select the particular bonds or portions thereof to be redeemed in such manner in its discretion as it shall deem appropriate and fair.

Notice of Redemption

The Registrar is to give notice of redemption by mailing copies of such notice (only to The Depository Trust Company ("DTC") rather than the beneficial owners of the Series 2002A Bonds so long as DTC is the securities depository for the Series 2002A Bonds) not less than 30 nor more than 60 days prior to the date fixed for redemption. Notices of redemption given as described above are effective whether the notice is actually received, and whether any DTC procedures for giving notice are complied with. See APPENDIX B – "BOOK-ENTRY SYSTEM."

Any notice of optional redemption may be made conditional upon the availability of moneys sufficient to pay the redemption price or the satisfaction of any other condition, including the receipt by the Paying Agent of moneys sufficient to pay the redemption price, and it may be rescinded at any time before the payment of the redemption price if any such condition is not satisfied or if any other specified event occurs. Notice of rescission of any conditional redemption will be given in the same manner as the notice of redemption, as promptly as practicable upon the failure of such condition or the occurrence of such event.

Effect of Redemption

If, on the redemption date, moneys for the redemption of all Series 2002A Bonds to be redeemed, together with interest to the redemption date, shall be held by the Paying Agent and available therefor, and if notice of redemption shall have been mailed as described above, then, from and after the redemption date, interest on the Series 2002A Bonds called for redemption shall cease to accrue. If such moneys shall not be so available on the redemption date, unless, in the case of any conditional notice, the conditions thereof are not satisfied or such notice is rescinded, the Series 2002A Bonds shall continue to bear interest until paid at the same rate as they would have borne had they not been called for redemption.

DEPARTMENT OF WATER RESOURCES

DWR is a department within the Resources Agency of the Executive Branch of the State. DWR was established in 1956 under California law for the purpose of planning and guiding the development of California's water resources. In addition to responsibility for the Power Supply Program, DWR is separately responsible for the planning, construction, operation and maintenance of the State Water Project, a statewide system of dams, reservoirs, pumping plants, power plants and aqueducts. DWR is the largest purchaser of power for its own use within California because of the power requirements of the State Water Project, and DWR was designated by Governor Davis to undertake the Power Supply Program because of DWR's experience in purchasing and selling power. The Power Supply Program is not part of the State Water Project, the revenues of the State Water Project

are not available for the payment of the Bonds, and the Trust Estate pledged for the payment of the Bonds is not available for the payment of indebtedness incurred for the State Water Project.

The Director of Water Resources oversees DWR's activities, with the assistance of a Chief Deputy Director and four Deputy Directors. The Director and Chief Deputy Director are appointed by the Governor and report to the Governor through the Secretary of the Resources Agency. Biographical information for the DWR management officials currently responsible for the Power Supply Program is as follows.

Thomas M. Hannigan has been the Director of Water Resources since March 1999. He was an elected member of the California Legislature from 1978 to 1996. He served on various State Assembly committees, including Business and Finance, Insurance, Budget, and Revenue and Taxation. Prior to his appointment as Director of DWR he was employed as a commercial real estate broker.

Peggy Bernardy is the Chief Counsel to DWR. She served as Senior Staff Counsel to DWR from 1992 to November 2001, when she was appointed Chief Counsel. She has had a broad range of duties covering most aspects of DWR activities. From 1990 to 1992, Ms. Bernardy served on the legal staff of the California Fair Political Practices Commission, where she specialized in conflict of interest laws, financial disclosure requirements, and campaign finance issues.

Perla Netto-Brown is the Chief Financial Officer of DWR. Prior to joining DWR, Ms. Netto-Brown was employed by the California Auditor General. She joined DWR in 1986, has served in various capacities in the Division of Fiscal Services and was named Chief of the Division of Fiscal Services in 2000.

Peter Garris is the Deputy Director of DWR responsible for the Power Supply Program. From October 1997 to January 2001, Mr. Garris served in senior management positions with the California Independent System Operator. Prior to 1997 he worked on power operations for DWR and several electric utilities. He rejoined DWR in January 2001.

Viju Patel is the Energy Advisor to the Deputy Director of the Power Supply Program. He develops, recommends and implements energy policy. Since joining DWR in 1982, Mr. Patel has served as a division chief and in other positions for the power operations of DWR's State Water Project. Prior to joining DWR in 1982, Mr. Patel worked for the California Energy Commission and a power company.

Veronica Hicks is the Chief of the Risk Management and Fiscal Office for the Power Supply Program and served as project manager for the implementation of energy transaction and risk management system implementation. Ms. Hicks has been with DWR for 23 years, and most recently served as the executive assistant to the Deputy Director in charge of the Power Supply Program before assuming her current position.

James E. Olson is the Chief of Financial Operations for the Power Supply Program. He was an audit partner with a national accounting firm prior to joining DWR as Deputy Controller in 1993 with responsibility for management of general accounting and financial reporting for DWR. He was assigned responsibility for the financial operations of the Power Supply Program in January 2001.

CALIFORNIA PUBLIC UTILITIES COMMISSION

The modern CPUC was established in 1911 under the California Constitution as the Railroad Commission. In 1912, the State Legislature passed the Public Utilities Act, expanding the Railroad Commission's regulatory authority to include natural gas, electric, telephone, and water companies as well as railroads and marine transportation companies. In 1946, the Railroad Commission was renamed the California Public Utilities Commission.

The CPUC consists of five members appointed by the Governor and confirmed by the Senate. Members serve for six-year, staggered terms. The Governor appoints one of the five to serve as President. The CPUC is an

independent regulatory agency. It regulates the IOUs and other California entities, mostly investor-owned electric, telecommunications, natural gas, water, railroad, rail transit and passenger transportation companies. Some of the entities regulated by the CPUC are not investor-owned. The CPUC's headquarters are in San Francisco.

Brief biographies of the five CPUC Commissioners follow.

Loretta Lynch, President. Ms. Lynch was appointed by Governor Davis as President of the CPUC in March 2000. Her term expires on January 1, 2005. Prior to her appointment to the Commission, Ms. Lynch was the director of Governor Davis' Office of Planning and Research. She practiced law before joining the Office of Planning and Research.

Henry M. Duque, Commissioner. Mr. Duque was appointed to an expired term at the CPUC by Governor Wilson in 1995. Governor Wilson reappointed him to a six-year term that expires on January 1, 2003. Prior to his appointment to the CPUC, Mr. Duque held various positions with banking and financial institutions.

Carl Wood, Commissioner. Mr. Wood was appointed by Governor Davis to a six-year term expiring on January 1, 2005. Prior to his appointment he held various positions with unions and other labor organizations involved in the electricity and natural gas industries.

Geoffrey F. Brown, Commissioner. Mr. Brown was appointed to the CPUC by Governor Davis in January 2001. His term expires on January 1, 2007. Mr. Brown practiced law and served as Public Defender of San Francisco prior to his appointment to the CPUC.

Michael R. Peevey, Commissioner. Mr. Peevey was appointed to the CPUC by Governor Davis in March 2002. His term expires on January 1, 2003. Prior to his appointment he held various positions with energy companies, including serving as president of SCE (one of the IOUs) from August 1990 to March 1993.

Since January 1, 2001, the CPUC has adopted a number of decisions that relate to DWR's Power Supply Program. Additional CPUC decisions relating to the Power Supply Program and the Bonds are expected by DWR.

- The CPUC adopted decisions in 2001 and 2002 pertaining to the revenues collected relating to DWR power purchases and other servicing matters. See "RATEMAKING AND RELATED ACTIONS – CPUC Actions to Approve and Impose Servicing Arrangements."

- The CPUC adopted a decision in February 2002, authorizing the Rate Agreement described under "SOURCES OF FUNDS TO PAY DEBT SERVICE – Rate Agreement."

- The CPUC adopted decisions in March and May of 2001, which had the effect of allowing DWR to recover certain costs from charges. The CPUC adopted a decision in February 2002 establishing charges to provide revenue to recover DWR's 2001 and 2002 Revenue Requirements, including amounts for debt service on the Bonds through the end of 2002. DWR expects that the CPUC will impose Power Charges for 2003 that will begin to accrue on and after January 1, 2003. On October 24, 2002, the CPUC adopted a decision establishing the methodology by which Bond Charges will be imposed. On November 4, 2002, TURN, SCE and PG&E each filed an application for rehearing of that decision. The TURN and SCE applications contend that the allocation methodology adopted by the CPUC was unlawful and discriminatory in that it exempted from Bond Charges certain residential usage only in the SDG&E service area. The PG&E application made the same complaint and also contended that there were defects in the procedure by which the CPUC consented to an increase in the amount of Bonds. The PG&E application further contended that these alleged defects affected the adoption of the CPUC's October 24, 2002 decision. TURN also contends that the CPUC is required to exempt certain electricity usage from Bond Charges under an interpretation of State law. November 4, 2002 was the last day that an interested party could request a rehearing on the October 24, 2002 CPUC decision. Although the implementation of Bond Charges is subject to a possible rehearing or revision of, and potential legal challenges to, that

decision, and to additional actions yet to be taken, all of which could result in modification of such decision or delay in implementation, DWR expects that the CPUC will impose Bond Charges that will begin to accrue on or about November 15, 2002. See "PLAN OF FINANCE – Sources of Revenues During Calendar Years 2001 and 2002; DWR Charges for 2003." See also "RATEMAKING AND RELATED ACTIONS – DWR Actions to Establish Revenue Requirements – *Proceedings Under Revenue Requirement Regulations*." See also "RISK FACTORS – Determination of Power Charges and Bond Charges; Possible Uses of Amounts in the Bond Charge Collection Account to Pay Priority Contract Costs" and other sections of this Official Statement referred to therein.

- In March 2002, the CPUC voted to maintain the suspension date adopted in an earlier decision which suspended the right of customers of the IOUs to acquire "direct access" after September 20, 2001 and is considering in a current proceeding the imposition of cost responsibilities surcharges (i.e., "direct access surcharges" or "exit fees") on direct access customers. This decision was taken pursuant to requirements of the Act. However, recent state legislation known as "AB 117" authorizes local government "community aggregation" programs under certain circumstances. See "RATEMAKING AND RELATED ACTIONS – CPUC Actions Limiting Customer Access to Other Energy Providers" and "RISK FACTORS – Potential Decrease in DWR Customer Base" and " – Uncertainties Relating to Government Action – Recent State Legislation." On November 7, 2002, the CPUC adopted a decision that established a direct access cost responsibility surcharge mechanism whereby designated direct access customers are made responsible for paying costs incurred by the Department that are being recovered through Bond Charges and Power Charges, and for paying certain above-market costs incurred by each of the IOUs through their own resources and contracts. The decision excluded continuous direct access customers, defined as those taking direct access continuously both before and since January 17, 2001 (in the PG&E and SCE service territories) or February 7, 2001 (in the SDG&E service territory), from paying Bond Charges. Pursuant to the Rate Agreement, Bond Charges will be imposed on direct access customers when the surcharges and this decision become final and unappealable. The decision also determined that pursuant to the Act and AB 117, any direct access customer who took bundled service from an electrical corporation on or after February 1, 2001, is responsible for paying a share of the DWR revenue requirements, including both previously incurred costs as well as an ongoing cost component, which is recovered through Power Charges. Imposition of the surcharges was to ensure bundled customer indifference (e.g., to prevent cost shifting between bundled customers and direct access customers). The decision also adopted an initial interim cap of 2.7 cents/kWh, in response to concerns that the surcharges might cause direct access to become uneconomic. Bundled customers will finance any undercollection resulting from the cap, and they will be repaid with interest over a reasonable period. The cap is subject to adjustment as determined in further proceedings ordered in the decision.

The CPUC makes no representation as to the accuracy or completeness of any forward-looking statements or projections contained in this Official Statement, including, without limitation, any assumptions or conclusions contained in the Consultant's Report attached as Appendix A. The CPUC makes no representation as to the accuracy or completeness of this Official Statement, including any description in this Official Statement of litigation involving or affecting the CPUC, and any statements regarding such litigation do not necessarily represent the CPUC's view of such litigation or any position in such litigation. In addition, while CPUC staff have assisted in the preparation of certain sections of this Official Statement, the CPUC can only take positions through formal action and has not taken any such action or approved this Official Statement. The CPUC is an independent five-member body that must act by an affirmative vote of a majority of its members and, as a result, the CPUC can only indicate its views in formal decisions or other formal actions. In addition, the CPUC is not subject to the control of DWR and may take positions in the future different from DWR in litigation, or other matters described in this Official Statement. As a result, statements in this Official Statement regarding electricity markets and regulation, and DWR's views of the CPUC's role or DWR's role in such markets and regulation, do not necessarily represent the views, opinions or beliefs of the CPUC and should not be construed as such by any recipient of this Official Statement.

POWER SUPPLY PROGRAM

General

In January 2001, Governor Davis determined that the electricity available through the IOUs was insufficient to prevent widespread and prolonged disruption of electric service in California, proclaimed a state of emergency to exist under California law, and directed DWR to enter into contracts and arrangements for the purchase and sale of electric power as necessary to assist in mitigating the effects of the emergency. The Power Supply Program has been implemented under the authority of the Governor's proclamation, related executive orders of the Governor, and legislation enacted in 2001, and pursuant to CPUC orders issued in response to the legislation. The general purpose of the Power Supply Program has been to provide to the customers of the IOUs the portion of their electric power not provided by the IOUs (the "net short").

Under the Power Supply Program, DWR sells electricity to the customers in California that are also served by the IOUs. DWR purchases power from wholesale suppliers under long-term contracts and in short-term and spot market transactions. DWR electricity is delivered to customers through the transmission and distribution systems of the IOUs and payments from customers are collected by the IOUs pursuant to servicing arrangements approved or ordered by the CPUC (see "SERVICING ARRANGEMENTS").

DWR, CPUC staff and other State agencies are cooperating to return to the IOUs the function of providing all of their customers' electric power load. See "Transition of Procurement Responsibility After 2002" and "APPENDIX A – CONSULTANT'S REPORT – Plan to Transition DWR's Net Short Responsibilities." Beginning in 2003, Bond Charges are to be the primary source of moneys to pay debt service on the Bonds, and, pursuant to the Rate Agreement, must be imposed by the CPUC whether or not DWR continues to purchase or sell electricity under the Power Supply Program. See "RATE COVENANTS."

Background and History

In September 1996, State legislation ("AB 1890") became effective which facilitated the restructuring of the California electric energy market and placed a number of requirements on the CPUC. Following the passage of AB 1890, the IOUs were required to rely on purchases through the California Power Exchange (the "PX") and the California Independent System Operator Corporation ("CAISO") to meet the power supply needs not otherwise provided by their retained generation and other sources available to them. By the summer of 2000, prices for power procured through the PX began to rise, swiftly and dramatically. In addition, insufficient power supply was being bid into the PX and CAISO to satisfy all required load at prices within historic ranges.

While wholesale prices for electricity increased precipitously during 2000, the retail rates of PG&E and SCE remained frozen as mandated in AB 1890. In the SDG&E service area, where rates had been unfrozen, retail rates escalated sharply, resulting in the California Legislature enacting a statutory cap on retail rates in the San Diego area and delaying the recovery of SDG&E's unrecovered costs. By December 2000, PG&E and SCE had incurred several billion dollars of electricity purchase obligations in excess of concurrent retail rate revenues received from their customers, adversely affecting the creditworthiness of those IOUs and their ability to pay for power purchases from the PX, the CAISO and other suppliers. Due to PG&E and SCE's defaults on power payments, the PX became insolvent and ceased operations in January 2001.

The credit difficulties experienced by PG&E and SCE also contributed to a shortage of power supply resources bid into the California market, creating an immediate need for a creditworthy party to assume the obligation of purchasing the electricity needed to meet the needs of customers of the IOUs. On January 17, 2001, the Governor declared a state of emergency and authorized DWR to begin purchasing the customers' electric requirements not otherwise met by the IOUs' retained generation and other sources. On January 19, 2001, Senate Bill 7 was passed during the First Extraordinary Session of 2001 and signed into law ("SB 7X"). SB 7X confirmed DWR's responsibilities in the emergency and appropriated $400 million to DWR for power purchases and administrative costs.

SCE sued the CPUC in federal district court in November 2000 seeking declaratory and injunctive relief compelling the CPUC to permit SCE to recover in retail rates all of its wholesale electricity procurement costs. In October 2001, SCE and the CPUC entered into a settlement of the case to permit SCE to recover an agreed-upon amount of certain defined "procurement related obligations" from the amounts by which charges paid to SCE by its customers exceed SCE's current power costs. The district court approved the settlement over the objections of The Utility Reform Network ("TURN"), a nonprofit consumer organization. TURN appealed the stipulated judgment resulting from the settlement. On September 23, 2002, the Ninth Circuit Court of Appeals affirmed the decisions of the district court as to certain questions arising under federal law, but certified to the California Supreme Court certain questions relating to the validity of the settlement agreement under California law. The potential impacts of further proceedings relating to this suit on the creditworthiness of SCE are uncertain. See "Transition of Procurement Responsibility After 2002" below, "LITIGATION AND ADMINISTRATIVE PROCEEDINGS – Litigation Pending or Threatened in State and Federal Courts – *Actions Affecting IOU Rates*," and "RISK FACTORS – Bankruptcy Risks."

In April 2001, PG&E filed for voluntary bankruptcy. See "LITIGATION AND ADMINISTRATIVE PROCEEDINGS – Litigation Pending or Threatened in State and Federal Courts – *Pacific Gas and Electric Bankruptcy*." PG&E and its parent, PG&E Corp., have filed a joint plan of reorganization (the "PG&E Plan"). In addition, the CPUC, with the Official Committee of the Unsecured Creditors, has filed an alternative plan of reorganization (the "CPUC Plan"). The bankruptcy court is expected to consider confirmation of a plan at the end of 2002. The bankruptcy court can confirm only one plan, and could decline to confirm both of the plans. If the bankruptcy court declines to confirm both of the plans, PG&E, the CPUC, another party in interest, or any combination of the foregoing, could file another proposed plan of reorganization.

The Act

In early 2001, the State Legislature passed and the Governor signed the Act, which established a framework under which DWR would purchase the electric requirements of the customers not otherwise met by the IOUs and would recover the costs of the Power Supply Program. The Act authorized DWR to contract for power under such terms and conditions as it deemed appropriate, taking into account a number of factors, including a desire to secure as much low-cost power as possible under contract. Although the Act does not authorize DWR to enter into new power contracts after December 31, 2002, the Act does not prevent DWR from administering its contract portfolio after that date. Under the Act, power acquired by DWR is sold directly to customers in the service areas of the IOUs, and payment for such power is a direct obligation of the customers. The Act authorized DWR to contract with the IOUs for the transmission and distribution of its power, and for billing, collection and related services, all as agents of DWR. The Act also directed the CPUC, at the request of DWR, to order the IOUs to provide such services. The Act provided for the suspension of the right of customers to purchase their power from energy providers other than the IOUs and DWR, after the passage of such period of time as determined by the Commission, and so long as DWR continues to provide power.

The State Legislature provided for appropriations from the State's General Fund, on an interim basis pending issuance of bonds, to enable DWR to make power purchases (together with the $400 million appropriated under SB 7X, the "State Loans"). To provide permanent financing for costs incurred in connection with the Power Supply Program, the Act authorized DWR to issue up to $13.423 billion in bonds (excluding bond anticipation notes and refunding bonds issued to achieve interest rate savings). The Series 2002 Bonds are being issued pursuant to this authorization. Taking into account the amortization of a portion of the Interim Loan before the retirement of the remaining balance on October 30, 2002, and following the issuance of all of the Series 2002 Bonds, $1.32 billion of the original statutory authorization will remain.

Implementation

DWR and the CPUC have taken a number of actions, the most important of which are described below, to implement the Act. The Consultant has played an integral role in assisting DWR in implementing the Act and

creating the Power Supply Program. See "RELATIONSHIPS" and the Introduction to the Consultant's Report attached as Appendix A under the heading "Purpose of the Report and Role of NCI."

In addition to purchasing substantial amounts of power on the spot market and under other short-term contracts, DWR solicited proposals for, negotiated and entered into, and in some instances, renegotiated, long-term power contracts, including the Priority Long-Term Power Contracts described under "PRIORITY LONG-TERM POWER CONTRACTS."

DWR submitted its Revenue Requirements for the calendar years 2001 and 2002 to the CPUC, made several revisions, and filed the last such revision on November 5, 2001. See "RATEMAKING AND RELATED ACTIONS – DWR Actions to Establish Revenue Requirements" for further information concerning the determination of DWR's Revenue Requirements and a suit brought by PG&E pertaining thereto. The CPUC considered DWR's 2001 and 2002 Revenue Requirements, conducted proceedings to determine the allocation of DWR's costs among the IOU service areas, and on February 21, 2002, issued an order adopting specific DWR charges for each of the IOU service areas for 2001 and 2002. The IOUs are including those DWR charges in billings to customers. See "RATEMAKING AND RELATED ACTIONS – CPUC Actions to Calculate, Revise and Impose Bond Charges and Power Charges" for information concerning CPUC action to recover DWR's Bond Charges and Retail Revenue Requirements for 2003.

DWR has entered into a Servicing Agreement, as amended, with SCE and a Servicing Agreement, as amended, with SDG&E (collectively "Servicing Agreements"), which the CPUC approved in orders issued in April 2002 and amended in July 2002. Under the Servicing Agreements, SCE and SDG&E are each required to collect Bond Charges and Power Charges from customers and remit collections to DWR.

PG&E and DWR did not reach agreement on the terms and conditions of a servicing agreement, and as a result and as provided by the Act, DWR requested the CPUC to order PG&E to provide services to DWR on terms comparable to the terms of the Servicing Agreements with SCE and SDG&E. On May 16, 2002, the CPUC issued an order (the "PG&E Servicing Order") requiring PG&E to collect Bond Charges and Power Charges from customers and remit collections to DWR and provide other services as provided by the order. The PG&E Servicing Order is now final and unappealable under California law (See "SERVICING ARRANGEMENTS" and "RATEMAKING AND RELATED ACTIONS – CPUC Actions to Approve and Impose Servicing Arrangements").

Representatives of DWR and the CPUC negotiated an initial proposed rate agreement, which was rejected by the CPUC Commissioners by vote on October 2, 2001. After further negotiations, on February 21, 2002, the CPUC issued a decision, which is final and unappealable under California law, adopting the Rate Agreement attached as Appendix D, which was thereafter executed by the CPUC and DWR as of March 8, 2002. See "SOURCES OF FUNDS TO PAY DEBT SERVICE – Rate Agreement."

In March 2002, the CPUC reaffirmed an earlier decision to suspend the right of customers of the IOUs to acquire service from other suppliers of electricity after September 20, 2001 for so long as DWR is providing power to customers. However, recent state legislation known as "AB 117" permits a limited exception which authorizes local government entities to become "community choice aggregators" and to develop programs to provide electricity to interested customers within the boundaries of such entities. Under the legislation, community choice aggregation shall not be authorized until the CPUC, among other things, imposes a cost-recovery mechanism that would require customers purchasing power from a community choice aggregator to pay specified amounts for recovery of DWR costs (including bond related costs) and certain costs of the IOUs. See "RATEMAKING AND RELATED ACTIONS – CPUC Actions Limiting Customer Access to Other Energy Providers."

Transition of Procurement Responsibility After 2002

The Act does not authorize DWR to enter into new power contracts after December 31, 2002. As a result, DWR is not authorized to provide to customers after December 31, 2002, the portion of the net short not provided by DWR's existing power contracts (the "residual net short"), including the long-term power contracts and any other power contracts executed by DWR prior to the end of 2002.

In order for an IOU to resume the procurement of the residual net short, it must, among other things, establish a sufficient level of creditworthiness. SDG&E is currently sufficiently creditworthy to purchase the residual net short for its service area, but SCE and PG&E may not be sufficiently creditworthy by the end of 2002 to purchase the residual net short for their respective service areas.

No assurance can be given that the conditions for resumption by the IOUs of the purchase of the residual net short for their customers will be met by the end of 2002. If DWR's responsibility for purchasing the residual net short is not extended and no other transition plan is implemented to enable another party or parties to purchase the residual net short for the customers of the IOUs, involuntary load curtailments and other disruptions to electric service may occur within the State.

DWR is engaged in contingency planning for the possibility that DWR's authorization to provide the residual net short (i.e., to enter into additional short-term purchase contracts that would not constitute Priority Long-Term Power Contracts) will be extended by legislation or executive order. The Indenture provides that Power Charge Revenues from the sale of residual net short power under such legislation or executive order are, like other Power Charge Revenues, to be deposited in the Operating Account, and that the costs of such power are to be paid from the Operating Account. See APPENDIX C — "SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE – Application and Flow of Funds."

The Retail Revenue Requirement for 2003 that DWR submitted to the CPUC on August 19, 2002 assumed that DWR would not provide the residual net short after 2002. The Consultant's Report attached as Appendix A analyzes certain scenarios that assume that DWR continues to provide the residual net short after 2002. Under these "sensitivity analyses," the Consultant has concluded that the provision by DWR of the residual net short after 2002 is not reasonably expected to result in the use of funds in the Bond Charge Collection Account to pay DWR's Retail Revenue Requirements, assuming that any necessary increases in Bond Charges and Power Charges are timely implemented. See APPENDIX A – "CONSULTANT'S REPORT - Conclusions– *DWR Revenue Recovery*" and "Sensitivity Analyses." Transition is discussed in the Consultant's Report under the heading "Plan to Transition DWR Net Short Responsibilities."

DWR, CPUC staff and several other State agencies are coordinating efforts to return to the IOUs the function of providing not just the residual net short, but the entire net short. Plans to do so include three components: operational management of DWR's long-term contracts, procurement of the residual net short, and full assignment of DWR's long-term contracts and release of DWR from any liability under those contracts. Recent legislation known as "AB 57" requires the CPUC to review and adopt a procurement plan for each electrical corporation in accordance with elements, incentive mechanisms and objectives set forth in AB 57, for the procurement of electricity needs not being met by DWR. AB 57 has no direct effect on Bond Charges.

On September 19, 2002, the CPUC adopted an order allocating DWR's long-term power contracts among PG&E, SDG&E and SCE for the purposes, among others, of operational management of the contracts and allocation of power supply from the contracts as of January 1, 2003. Under such order, each IOU would be responsible for scheduling the electricity produced or delivered under the contracts allocated to such IOU. Generally, the contracts allocated to each IOU are the contracts with delivery points in that IOU's service area. In addition, the order specifies rules which would determine the order of dispatch of power from the contracts and from the IOU's retained generation and other sources and a rule for the allocation of revenues from the sale of surplus DWR and IOU power. DWR has submitted to the CPUC proposed forms of detailed operating agreements

pursuant to which DWR and each IOU would coordinate, among other things, the scheduling of electricity by the IOU and the payment for such electricity by DWR.

On October 24, 2002, the Commission adopted an order setting out the regulatory framework under which SCE, PG&E and SDG&E would resume full procurement responsibility on January 1, 2003. This framework contains, among other things, requirements for updating utility procurement plans, procedures for expedited review, and cost recovery mechanisms designed to conform to AB 57's requirements. This order may be subject to administrative and subsequent legal challenge. See "RATEMAKING AND RELATED ACTIONS - CPUC Actions to Calculate, Revise and Impose Bond Charges and Power Charges."

DWR and the CPUC have also been considering arrangements whereby DWR and an IOU would enter into one or more contracts during 2002 for the purchase from third parties of capacity and energy for the purpose of satisfying a portion of the residual net short after 2002. Each such contract would provide for the ultimate transfer to the IOU of all of DWR's responsibilities under such contract upon satisfaction of specified conditions, including establishing that the IOU is creditworthy. Pending the IOU becoming creditworthy, the costs associated with such contracts would be included in DWR's Retail Revenue Requirement and may result in the determination and filing of an adjusted Retail Revenue Requirement, if required. See "RATEMAKING AND RELATED ACTIONS." In August 2002, the CPUC adopted an order allowing the IOUs, in conjunction with DWR and subject to certain conditions, to enter into such contracts for power in amounts up to amounts sufficient to provide the residual net short for their respective service areas. PG&E and SCE have filed applications for rehearing of that order.

DWR plans to transfer to the IOUs full responsibility for all of DWR's existing long-term power contracts as soon as practicable. However, many of DWR's long-term power contracts currently require counterparty approval of any assignment of financial responsibility to third parties, including the IOUs, or only permit assignment to a creditworthy counterparty. Moreover, the IOUs have indicated to DWR that they do not wish to assume DWR's long-term power contracts. In particular, the proposed plans of reorganization for PG&E currently under consideration by the bankruptcy court indicate that it may be difficult to assign DWR's long-term power contracts to PG&E. The PG&E Plan provides that PG&E, as reorganized, should not accept an assignment of the contracts, while the CPUC's alternative plan neither prohibits nor requires such an assignment. Accordingly, DWR's plans to transfer to the IOUs the responsibility for DWR's long-term power contracts may not be realized.

PLAN OF FINANCE

Sources and Uses of Funds

Proceeds of the Series 2002 Bonds (net of costs of issuance, costs of credit enhancement and amounts deposited in the Debt Service Reserve Account, the Bond Charge Payment Account and the Bond Charge Collection Account) have been and will be used first, to repay an outstanding interim loan to DWR from certain underwriters of such Bonds (or affiliated lenders) and commercial banks in the amount of approximately $3.5 billion, second, to repay the principal of outstanding loans to DWR from the State's General Fund in the amount of approximately $6.1 billion, and third, to deposit amounts in the Operating Account. The loans financed Power Supply Program costs during 2001 that exceeded DWR's revenues from the sale of electricity. See "POWER SUPPLY PROGRAM."

Interim Loan

DWR borrowed money for the Power Supply Program in the principal amounts listed below (collectively, the "Interim Loan") from the following lenders:

Lender	Principal Amount
JPMorgan Chase Bank	$1,500,000,000
J.P. Morgan Chase & Co.	1,000,000,000
Lehman Commercial Paper Inc.	1,000,000,000
Commerzbank AG	500,000,000
Bayerische Landesbank	300,000,000
Total	$4,300,000,000

JPMorgan Chase Bank, J.P. Morgan Chase & Co. and Lehman Commercial Paper Inc. are underwriters of the Series 2002 Bonds or are affiliates of underwriters of such Bonds. JPMorgan Chase Bank is also a letter of credit provider or a liquidity facility provider with respect to certain subseries of the Series 2002C Bonds. Commerzbank AG is an affiliate of an underwriter of the Series 2002E Bonds. Bayerische Landesbank is a letter of credit provider for certain subseries of Series 2002B and Series 2002C Bonds.

On October 30, 2002, the remaining principal balance of the Interim Loan was repaid in full from proceeds of the Series 2002B, Series 2002C and Series 2002D Bonds.

State Loans

Between January 2001 and June 2001, DWR borrowed approximately $6.1 billion from the General Fund of the State for the Power Supply Program. On November 14, 2002, proceeds of the Series 2002A and Series 2002E Bonds in the approximate amount of $5.9 billion, together with amounts on deposit in the Electric Power Fund, will be used to repay the General Fund in full.

Other Series 2002 Bonds

DWR has issued and plans to issue other Series 2002 Bonds to complete its plan of finance. On October 30, 2002, DWR issued its variable rate Series 2002B, 2002C and 2002D Bonds in an aggregate principal amount of $4,250,000,000. Simultaneously with the issuance of the Series 2002A Bonds, DWR will issue its federally taxable Series 2002E Bonds in an aggregate principal amount of $700,000,000.

Interest Rate Hedging

DWR has entered into interest rate swap agreements (the "Series 2002 Swaps") with respect to approximately $1.43 billion of the $4.25 billion original principal amount of variable rate Series 2002 Bonds. Under the Series 2002 Swaps, DWR is obligated to pay fixed rate payments as consideration for receiving floating rate payments that are designed to closely approximate DWR's interest costs on the hedged variable rate Bonds. The floating rate payments to be received by DWR on approximately $1.1 billion initial notional amount of Series 2002 Swaps will be based on percentages of LIBOR and the floating rate payments to be received by DWR on approximately $330 million initial notional amount will be based on the BMA Municipal Swap Index.

Estimated Sources and Uses of Funds

The estimated combined sources and uses of the proceeds of the Series 2002A Bonds and the other Series 2002 Bonds and the uses of certain amounts available in the Electric Power Fund are as follows:

SOURCES OF FUNDS	Forecasted Electric Power Fund as of November 14, 2002	Series 2002A	Series 2002E	Total
Revenue Bonds				
Principal Amount of Bonds	-	$6,313,500,000.00	$700,000,000.00	$7,013,500,000.00
Net Premium (Discount)	-	397,979,894.75	(49,700.00)	397,930,194.75
Accrued Interest	-	11,959,970.44	1,011,490.28	12,971,460.72
Total Revenue Bonds	-	$6,723,439,865.19	$700,961,790.28	$7,424,401,655.47
DWR Accounts				
Operating Account	$1,016,711,105.74	-	-	$1,016,711,105.74
Priority Contract Account	308,390,382.57	-	-	308,390,382.57
Operating Reserve Account	777,376,200.46	-	-	777,376,200.46
Bond Charge Collection Account	16,634,999.99	-	-	16,634,999.99
Bond Charge Payment Account	67,771,046.02	-	-	67,771,046.02
Debt Service Reserve Account	425,000,000.00	-	-	425,000,000.00
Total DWR Accounts	$2,611,883,734.78	-	-	$2,611,883,734.78
Total Sources of Funds	$2,611,883,734.78	$6,723,439,865.19	$700,961,790.28	$10,036,285,390.25
USES OF FUNDS				
Repayment of State Loans[1]	$522,362,731.14	$5,926,651,141.08	$3,590,451.96	$6,452,604,324.18
Costs of Issuance	-	26,006,739.96	4,037,180.65	30,043,920.61
Underwriter's Discount	-	43,869,516.30	4,320,004.60	48,189,520.90
Bond Insurance Premium	-	110,785,933.42	-	110,785,933.42
Deposit to Debt Service Reserve Account[2]	425,000,000.00	451,943,758.32	50,108,597.58	927,052,355.90
Deposit to Bond Charge Collection Account[3]	16,634,999.99	27,599,931.78	2,334,208.33	46,569,140.10
Deposit to Bond Charge Payment Account[4]	67,771,046.02	136,582,844.33	11,671,041.67	216,024,932.02
Deposit to Operating Account[5]	494,348,374.60	-	624,900,305.49	1,119,248,680.09
Deposit to Priority Contract Account[6]	308,390,382.57	-	-	308,390,382.57
Deposit to Operating Reserve Account[7]	777,376,200.46	-	-	777,376,200.46
Total Uses of Funds	$2,611,883,734.78	$6,723,439,865.19	$700,961,790.28	$10,036,285,390.25

[1] Represents a final repayment of principal and interest on State General Fund loans made to DWR in the aggregate amount of $6,094,066,909.00. The Series 2002D Bonds, issued on October 30, 2002, repaid $163,825,315.96 of the State General Fund loans. Repayment of interest in the amount of $522,362,731.14 is funded from amounts in the Operating Account at closing.

[2] The Debt Service Reserve Requirement. See "SECURITY FOR THE BONDS - Debt Service Reserve Account."

[3] One month's estimated Bond Related Costs.

[4] Capitalized interest through and including December 31, 2002, and three months' estimated Bond Related Costs.

[5] An amount determined so that the amount in the Operating Account is projected to be at least the Minimum Operating Expense Available Balance through the end of 2003.

[6] The projected amount due on Priority Long-Term Power Contracts through the fifth day of the next calendar month.

[7] The Operating Reserve Account Requirement. See "SECURITY FOR THE BONDS - Operating Reserve Account."

Bond Debt Service

The following table depicts estimated debt service on the Series 2002 Bonds. The tax-exempt floating rate Series 2002B, Series 2002C and Series 2002D Bonds are assumed to bear a fixed interest rate of four percent per annum for the purposes of this table.

	SERIES 2002A BONDS			OTHER SERIES	TOTAL SERIES 2002 BONDS		
Year	Principal	Interest	Total	Total Debt Service	Principal	Interest	Total
2002	-	-	-	-	-	-	-
2003	-	$331,199,181	$331,199,181	$186,142,981	-	$517,342,162	$517,342,162
2004	-	331,199,181	331,199,181	375,075,838	$180,000,000	526,275,019	706,275,019
2005	$117,875,000	328,373,244	446,248,244	456,343,856	387,875,000	514,717,100	902,592,100
2006	159,395,000	322,331,406	481,726,406	425,634,722	409,395,000	497,966,129	907,361,129
2007	409,990,000	309,385,056	719,375,056	186,823,537	426,990,000	479,208,594	906,198,594
2008	448,740,000	288,718,419	737,458,419	170,000,411	448,740,000	458,718,830	907,458,830
2009	366,860,000	268,639,509	635,499,509	271,229,218	471,060,000	435,668,727	906,728,727
2010	438,250,000	248,218,253	686,468,253	220,842,146	495,050,000	412,260,398	907,310,398
2011	303,940,000	229,024,560	532,964,560	375,403,746	521,340,000	387,028,306	908,368,306
2012	314,360,000	212,915,010	527,275,010	382,702,727	548,060,000	361,917,737	909,977,737
2013	548,550,000	189,446,123	737,996,123	172,441,282	576,650,000	333,787,405	910,437,405
2014	414,625,000	162,681,284	577,306,284	334,164,032	609,025,000	302,445,315	911,470,315
2015	468,400,000	138,097,923	606,497,923	306,272,874	642,600,000	270,170,797	912,770,797
2016	475,470,000	111,702,078	587,172,078	326,809,407	677,770,000	236,211,485	913,981,485
2017	497,525,000	84,790,141	582,315,141	333,157,619	714,725,000	200,747,759	915,472,759
2018	558,145,000	56,554,969	614,699,969	302,153,488	752,445,000	164,408,457	916,853,457
2019	170,000,000	37,572,656	207,572,656	712,539,318	792,500,000	127,611,974	920,111,974
2020	146,000,000	29,383,906	175,383,906	748,645,662	830,500,000	93,529,568	924,029,568
2021	163,000,000	21,170,781	184,170,781	741,983,832	869,550,000	56,604,613	926,154,613
2022	312,375,000	8,395,078	320,770,078	606,234,789	909,225,000	17,779,867	927,004,867
	$6,313,500,000	$3,709,798,757	$10,023,298,757	$7,634,601,487	$11,263,500,000	$6,394,400,244	$17,657,900,244

Sources of Revenues During Calendar Years 2001 and 2002; DWR Charges For 2003

Pursuant to CPUC orders issued in March, May, and September of 2001, the IOUs were required to remit to DWR on an interim basis revenues based on the amount of DWR power being delivered to IOU customers multiplied by an amount derived from the generation component of each IOU's rate then applicable for power being delivered to the same customers. On February 21, 2002, the CPUC adopted an order allocating DWR's 2001-2002 Revenue Requirements among the service areas of the IOUs and establishing a per-kilowatt charge to be collected from customers for power provided by DWR within each IOU service area. The February 21, 2002 CPUC order did not modify overall customer charges. Applications for rehearing of the decision were denied by the CPUC on March 21, 2002, and the order is final and unappealable under California law.

Revenues for the remainder of calendar year 2002 from charges authorized by the February 21, 2002 CPUC order for the sale of electricity by DWR to customers of the IOUs under the Power Supply Program, together with other available funds are projected by DWR to be sufficient to satisfy DWR's rate covenant (described under "RATE COVENANTS") and to meet DWR's Revenue Requirements for the balance of 2002, including the amounts needed to make the deposits required to the accounts held under the Indenture for debt

service on the Bonds (and all other Bond Related Costs), all operating expenses and all other obligations permitted or required by the Act and the Indenture to be paid by DWR, and to maintain required balances in the reserves and other accounts held under the Indenture.

DWR submitted its Retail Revenue Requirements for the calendar year 2003 to the CPUC on August 19, 2002 (see "RATEMAKING AND RELATED ACTIONS – DWR Actions to Establish Revenue Requirements"). DWR expects that the CPUC will impose Power Charges that will begin to accrue on and after January 1, 2003. On October 24, 2002, the CPUC adopted a decision establishing the methodology by which Bond Charges will be imposed. On November 4, 2002, TURN, SCE and PG&E each filed an application for rehearing of that decision. The TURN and SCE applications contend that the allocation methodology adopted by the CPUC was unlawful and discriminatory in that it exempted from Bond Charges certain residential usage only in the SDG&E service area. The PG&E application made the same complaint and also contended that there were defects in the procedure by which the CPUC consented to an increase in the amount of Bonds. The PG&E application further contended that these alleged defects affected the adoption of the CPUC's October 24, 2002 decision. TURN also contends that the CPUC is required to exempt certain electricity usage from Bond Charges under an interpretation of State law. November 4, 2002 was the last day that an interested party could request a rehearing on the October 24, 2002 CPUC decision. Although the implementation of Bond Charges is subject to a possible rehearing or revision of, and potential legal challenges to, that decision, and to additional actions yet to be taken, all of which could result in modification of such decision or delay in implementation, DWR expects that the CPUC will impose Bond Charges that will begin to accrue on or about November 15, 2002. See "RATEMAKING AND RELATED ACTIONS – DWR Actions to Establish Revenue Requirements – *Proceedings Under Revenue Requirement Regulations*." See also "RISK FACTORS – Determination of Power Charges and Bond Charges; Possible Uses of Amounts in the Bond Charge Collection Account to Pay Priority Contract Costs" and other sections of this Official Statement referred to therein.

On September 19, 2002, the CPUC adopted an order to the effect that the charges authorized by the February 21, 2002 CPUC order for calendar year 2002 will continue in effect until further action by the CPUC (expected to be taken in connection with the imposition of Power Charges to recover DWR's Retail Revenue Requirement for the calendar year 2003). PG&E filed an application for rehearing of the decision adopting such order, which was denied by the CPUC on October 21, 2002. See "RATEMAKING AND RELATED ACTIONS – CPUC Actions to Calculate, Revise and Impose Bond Charges and Power Charges." Projected Revenues based on the continuation of charges authorized for calendar year 2002 would be less than projected Revenues based on the Bond Charges and Power Charges that would be required to be imposed to cover the Revenue Requirements that DWR has submitted to the CPUC for calendar year 2003.

Summary of Historical and Projected Financial Results

The following table provides a summary of actual and projected revenues, expenditures and fund balances of the Power Supply Program from its inception in January 2001 through calendar year 2005. This table was prepared by DWR primarily based upon audited financial results for the period ending June 30, 2001, unaudited results for the period beginning July 1, 2001 and ending June 30, 2002, and projections that correspond with Exhibit 19 from the Consultant's Report in Appendix A. All figures are in millions of dollars.

	Calendar Year				
POWER CHARGE ACCOUNTS	2001[1]	2002	2003	2004	2005
BEGINNING BALANCE					
Operating Account	-	$ 2,574	$ 1,228	$ 1,745	$ 1,674
Operating Reserve Account	-	-	777	777	777
Total Beginning Balance	-	2,574	2,005	2,522	2,451
OPERATING REVENUES AND EXPENSES					
Operating Revenues[2]	$ 3,709	4,803	4,836	4,537	4,523
Power Costs[3]	(11,336)	(4,446)	(4,120)	(4,422)	(4,129)
Other Operating Expenses[4]	-	(192)	(199)	(187)	(280)
Net Operating Revenues	(7,627)	165	517	(71)	113
OTHER FINANCIAL RESOURCES (DEBT)					
Net State General Fund and Interim Loan Proceeds	10,317	-	-	-	-
Interim Loan Debt Service Payments	(116)	(945)	-	-	-
Net Revenue Bond Proceeds attributable to Power Charge Accounts	-	10,453	-	-	-
Interim Loan and State General Fund Loans Repayment	-	(10,087)	-	-	-
Transfers to Bond Charge Accounts for payment of Bond Related Costs	-	(155)	-	-	-
Net Other Financial Resources	10,201	(734)	-	-	-
NET CHANGE IN ACCOUNT BALANCES	2,574	(568)	517	(71)	113
ENDING AGGREGATE BALANCE	$ 2,574	$ 2,005	$ 2,522	$ 2,451	$ 2,565

BOND CHARGE ACCOUNTS	Calendar Year 2001[1]	2002	2003	2004	2005
BEGINNING BALANCE					
Bond Charge Collection Account	-	-	$ 56	$ 238	$ 246
Bond Charge Payment Account	-	-	269	622	633
Debt Service Reserve Account	-	-	974	974	974
Total Beginning Balance	-	-	1,298	1,834	1,852
REVENUES, TRANSFERS AND EXPENSES					
Total Revenues[5]	-	$ 6	1,167	994	975
Transfers from Power Charge Accounts for payment of Bond Related Costs	-	155	-	-	-
Total Expenses - Bond Related Costs[6]	-	(47)	(632)	(976)	(976)
Net Revenues	-	114	535	18	(1)
OTHER FINANCIAL RESOURCES (DEBT)					
Net Revenue Bond Proceeds attributable to Bond Charge Accounts	-	1,184	-	-	-
NET CHANGE IN ACCOUNT BALANCES	-	1,298	535	18	(1)
ENDING AGGREGATE BALANCE	-	$ 1,298	$ 1,834	$ 1,852	$ 1,851

Source: Results from January 17, 2001 through June 30, 2001 are derived from DWR audited financial statements. Results from July 1, 2001 through June 30, 2002 are derived from DWR unaudited financial reports. Results from July 1, 2002 through December 31, 2005 are derived by DWR from the Consultant's projections shown in Exhibit 19 of Appendix A to this Official Statement. All figures are in millions of dollars. Numbers may not add, due to rounding. These projections are the responsibility of DWR. PricewaterhouseCoopers LLP (PwC), independent accountant for DWR, has neither examined nor compiled such projections and, accordingly, PwC does not express an opinion or any other form of assurance with respect thereto. The PwC report included in Appendix J relates to historical financial information of the Department of Water Resources Electric Power Fund. The PwC report does not extend to the projections set forth above and should not be read to do so. These projections were not prepared with a view toward compliance with the guidelines established by the American Institute of Certified Public Accountants for preparation and presentation of prospective financial information.

[1] Figures for calendar year 2001 commence on January 17, 2001.
[2] Total Operating Revenues include Power Charge Revenues, surcharge revenues, other power sales revenues and interest income.
[3] Assumes that DWR does not procure the residual net short after December 31, 2002. After 2002, substantially all power costs are Priority Contract Costs.
[4] Other Operating Expenses include administrative and general costs, ancillary services, and other operating expenses.
[5] Total Revenues include Bond Charge Revenues from retail customers and interest income.
[6] Bond Related Costs include debt service on Bonds and all other Bond Related Costs. See "SECURITY FOR THE BONDS – Bond Related Costs."

SECURITY FOR THE BONDS

Introduction

The primary source of moneys for the payment of the Bonds and Bond Related Costs is Bond Charge Revenues, which constitutes part of the Trust Estate securing the Bonds, as described below.

The "Trust Estate" is assigned and pledged to the Trustees under the Indenture for the benefit of the Bonds and Parity Obligations, subject to the use of the Trust Estate in accordance with the Indenture. The "Trust Estate" is defined in the Indenture to include, among other things, "Revenues." "Revenues" includes both "Bond Charge Revenues" and "Power Charge Revenues." "Revenues" also includes possible future revenues received by DWR from any charges on customers of electric service providers. The adoption of such charges is being considered by the CPUC, as described in "RATEMAKING AND RELATED ACTIONS – CPUC Actions Limiting Customer Access to Other Energy Providers" and "– Proposed CPUC Action Imposing Bond Charges on Customers of Electric Service Providers." See also APPENDIX C – "SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE – Definitions."

- "Bond Charge Revenues" are Revenues received by DWR arising from Bond Charges imposed by the CPUC upon customers in the service areas of the IOUs as described under "RATE COVENANTS."

- "Power Charge Revenues" are Revenues received by DWR arising from Power Charges imposed by the CPUC upon customers for electric power deemed sold to customers by DWR as described under "POWER SUPPLY PROGRAM."

The use of amounts on deposit in the Bond Charge Collection Account (including Bond Charge Revenues) for the payment of debt service on the Bonds and other Bond Related Costs when due is subject to the possible prior use of such amounts to pay "Priority Contract Costs" (defined to include costs and expenses under the Priority Long-Term Power Contracts described under "PRIORITY LONG-TERM POWER CONTRACTS") and under certain circumstances, expenses of the Trustees (see APPENDIX C – SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE – Events of Default and Remedies). See also "SECURITY FOR THE BONDS – Accounts and Flow of Funds Under the Indenture," "PRIORITY LONG-TERM POWER CONTRACTS," and "RISK FACTORS – Determination of Power Charges and Bond Charges; Possible Use of Amounts in the Bond Charge Collection Account to Pay Priority Contract Costs."

The accounts created under the Indenture and the flow of funds under the Indenture are elements of security for the Bonds and are discussed below. See APPENDIX C – "SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE" for a detailed discussion of security provisions for the Bonds.

THE BONDS SHALL NOT BE OR BE DEEMED TO CONSTITUTE A DEBT OR LIABILITY OF THE STATE OR OF ANY POLITICAL SUBDIVISION THEREOF OR A PLEDGE OF THE FAITH AND CREDIT OF THE STATE OR OF ANY SUCH POLITICAL SUBDIVISION, OTHER THAN DWR TO THE EXTENT PROVIDED IN THE INDENTURE. THE BONDS SHALL BE PAYABLE SOLELY FROM THE FUNDS PLEDGED THEREFOR PURSUANT TO THE INDENTURE. THE BONDS SHALL NOT DIRECTLY OR INDIRECTLY OR CONTINGENTLY OBLIGATE THE STATE OR ANY POLITICAL SUBDIVISION THEREOF TO LEVY OR TO PLEDGE ANY FORM OF TAXATION WHATEVER THEREFOR OR TO MAKE ANY APPROPRIATION FOR THEIR PAYMENT.

Accounts and Flow of Funds under the Indenture

Revenues are held in and accounted for in the Electric Power Fund established under the Act for DWR. The Indenture establishes two sets of accounts for Revenues within the Electric Power Fund.

One set of accounts is primarily for the deposit of Bond Charge Revenues and the payment of Bond Related Costs (collectively, the "Bond Charge Accounts"):

- the Bond Charge Collection Account,
- the Bond Charge Payment Account, and
- the Debt Service Reserve Account.

The other set of accounts is primarily for the deposit of Power Charge Revenues and the payment of operating expenses (including payments of Priority Contract Costs and other power purchase costs and other costs of the Power Supply Program) (collectively, the "Power Charge Accounts"):

- the Operating Account,
- the Priority Contract Account, and
- the Operating Reserve Account.

In addition, an Administrative Cost Account facilitates accounting for certain Department administrative costs that are subject to appropriation, but this account has no effect on the priorities of the uses of revenues.

On the following page is a simplified schematic representation of the flow of funds within the two sets of accounts (taking into account the repayment of all General Fund advances and excluding the Administrative Cost Account).

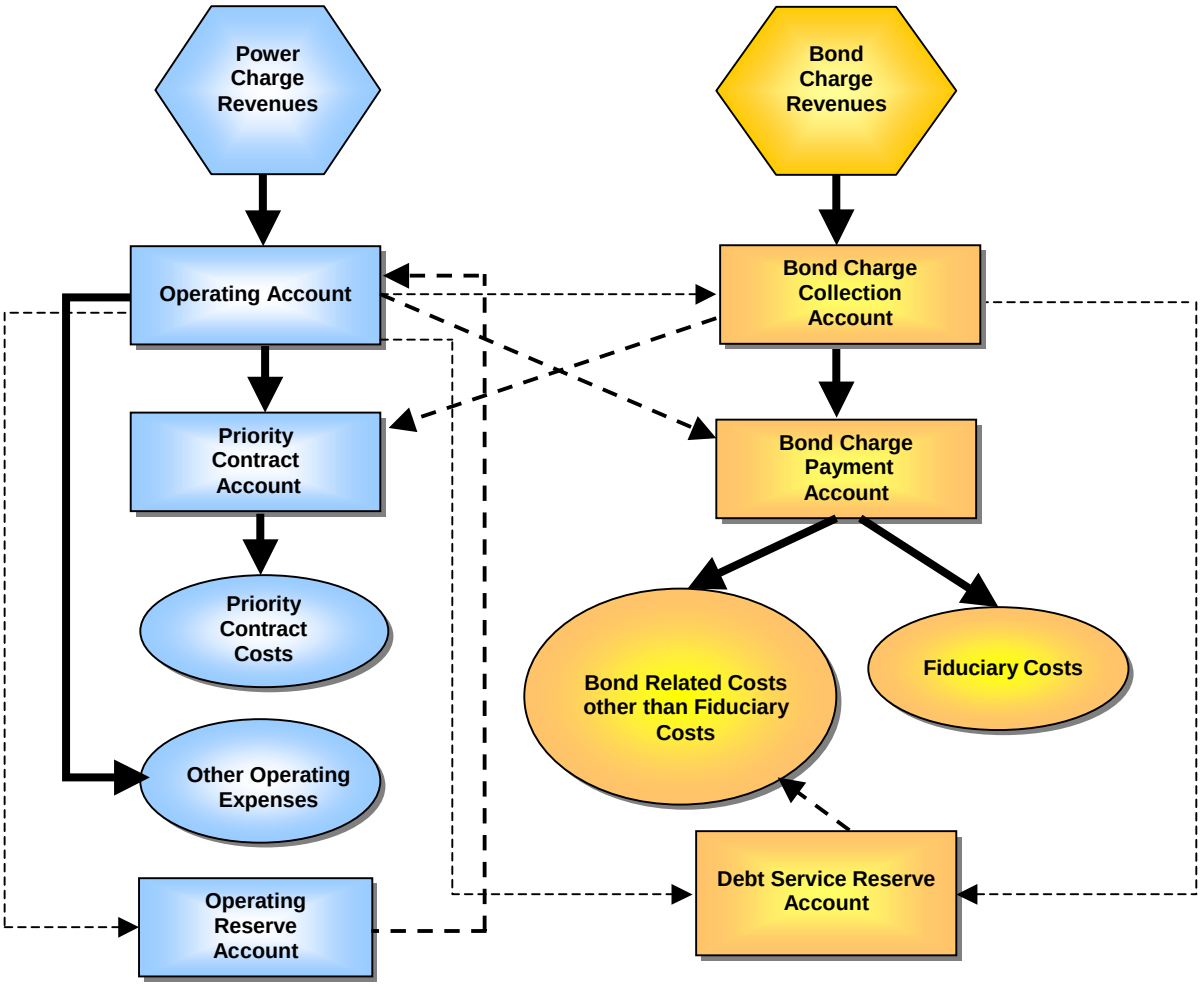
The Indenture requires all Bond Charge Revenues and any payments received from any counterparty to a Qualified Swap relating to Bonds to be deposited in the Bond Charge Collection Account, and all Power Charge Revenues and all other Revenues to be deposited in the Operating Account.

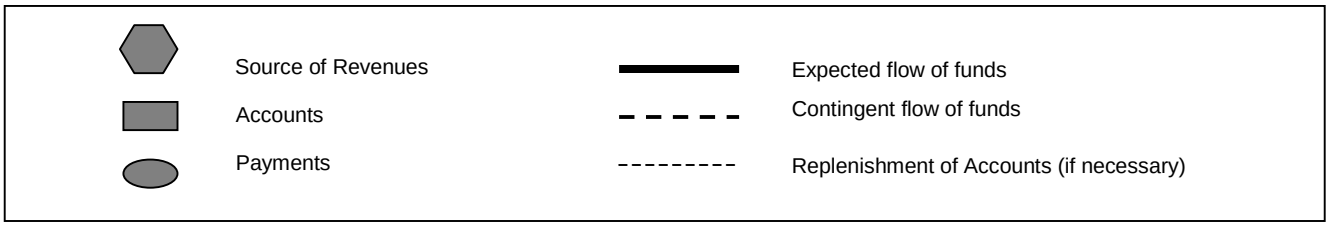
The Indenture requires the following transfers of Revenues to and from the Bond Charge Accounts:

- On or before the last Business Day of each month, DWR is required to transfer from the Bond Charge Collection Account to the Bond Charge Payment Account such amount as is necessary to make the amount in the Bond Charge Payment Account sufficient to pay Bond Related Costs (including "Debt Service" on the Bonds) estimated to accrue or be payable during the next succeeding three calendar months. For the definition of Debt Service, see "APPENDIX C – SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE – Definitions." Each such transfer is subject to the prior transfer of amounts in the Bond Charge Collection Account to the Priority Contract Account if and to the extent amounts in the Priority Contract Account, the Operating Account and the Operating Reserve Account are insufficient to pay Priority Contract Costs then due under Priority Long-Term Power Contracts. See "PRIORITY LONG-TERM POWER CONTRACTS." Amounts in the Bond Charge Payment Account may be used solely to pay debt service on the Bonds and other Bond Related Costs.

- Deficiencies in the Bond Charge Payment Account are required to be made up *first*, from the Operating Account and *second*, from the Debt Service Reserve Account (except for Fiduciary costs).

Flow of Revenues under the Indenture*





*Simplified for graphic presentation purposes.

- Each month after the Bond Charge Payment Account is funded as described above, Revenues are required to be transferred to the Debt Service Reserve Account, on a parity with payments for any reserve established for Parity Obligations, to the extent necessary to meet the respective requirements for such reserves. In the case of the Debt Service Reserve Account: (i) to the extent such transfer is required as a result of the use of Bond Charge Revenues for the payment of Priority Contract Costs or change in investment value, such transfers shall be made *first,* from the Operating Account and *second*, to the extent necessary, from the Bond Charge Collection Account, and (ii) if any other transfer is required, it shall be made from the Bond Charge Collection Account. Deficiencies in the Debt Service Reserve Account may be cured by monthly deposits during the period commencing no later than seven months following the determination of the deficiency, such that the deficiency is cured by no later than 12 months following the determination of the deficiency.

The Indenture requires the following transfers of Revenues to and from the Power Charge Accounts:

- On or before the fifth Business Day of each month, DWR is required to transfer from the Operating Account to the Priority Contract Account such amount as is necessary to make the amount in the Priority Contract Account sufficient to pay Priority Contract Costs estimated to be due during the balance of such month and through the first five Business Days of the next succeeding calendar month. Amounts in the Priority Contract Account may be used solely to pay Priority Contract Costs.

- Amounts in the Operating Account after the above transfer to the Priority Contract Account are to be used for the following purposes in the following order of priority:

  (i) for transfer to the Priority Contract Account if the amount therein is insufficient to pay Priority Contract Costs then due (that is, if the estimated amount previously transferred to that account turns out to be insufficient to pay actual Priority Contract Costs);

  (ii) for the payment of other operating expenses;

  (iii) to reimburse the Bond Charge Collection Account for any amounts previously transferred from the Bond Charge Collection Account to the Priority Contract Account to pay Priority Contract Costs;

  (iv) to pay debt service on the Bonds and other Bond Related Costs (if amounts in the Bond Charge Payment Account are not sufficient for those purposes) and, in addition, prior to the time Bond Charge Revenues are received in amounts sufficient to make the required transfers described above from the Bond Charge Collection Account to the Bond Charge Payment Account with respect to Bond Related Costs, amounts to make those transfers as required;

  (v) for transfer to the Debt Service Reserve Account to the extent required by the Indenture as a result of the use of Bond Charge Revenues to pay Priority Contract Costs or a change in value of investments in the Debt Service Reserve Account;

  (vi) to reimburse the General Fund as and to the extent provided by the Indenture for amounts advanced by the General Fund to the Electric Power Fund;

  (vii) to replenish the Operating Reserve Account to its requirement as provided by the Indenture;

  (viii) to pay Subordinated Indebtedness and Subordinated Obligations and certain other amounts relating thereto; and

  (ix) for any other lawful purpose of the Power Supply Program.

- The Operating Reserve Account may be drawn upon to make up any deficiency in the Operating Account for any of the purposes listed in clauses (i) through (v) of the preceding list, provided, however, that if and to the extent that the amount in the Operating Reserve Account is or would be less than or equal to the Priority Contract Contingency Reserve Amount, amounts in the Operating Reserve Account may be used only to make up any deficiency in the Priority Contract Account. See "Operating Reserve Account" below.

The Indenture prescribes an application of Revenues that may be different than as described above in the event of a default thereunder. See APPENDIX C – "SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE – Events of Defaults and Remedies."

Debt Service Reserve Account

The "Debt Service Reserve Requirement" is an amount equal to maximum aggregate annual Debt Service on all outstanding Bonds, determined in accordance with the Indenture. The Debt Service Reserve Account is required by the Indenture to be funded in the amount of the Debt Service Reserve Requirement and will initially be funded with proceeds from the sale of the Bonds (see "PLAN OF FINANCE"). The Debt Service Reserve Account is required to be replenished, if necessary, from Power Charge Revenues or Bond Charge Revenues in the manner and at the times (which may extend over a period of one year commencing seven months following the determination of the deficiency) described under APPENDIX C – "SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE – Application and Flow of Funds – *Debt Service Reserve Account*."

For an explanation of assumptions to be used in calculating the Debt Service Reserve Requirement for variable rate and hedged bonds and under other circumstances, see the definitions of Debt Service and Debt Service Reserve Account in APPENDIX C – "SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE – Definitions."

Alternate Debt Service Reserve Account Deposits may be made to the Debt Service Reserve Account in lieu of cash and/or securities. Such Deposits may consist of irrevocable surety bonds, insurance policies, letters of credit or similar obligations.

Whenever the amount in the Debt Service Reserve Account exceeds the Debt Service Reserve Requirement, after giving effect to any Alternate Debt Service Reserve Account Deposit, the excess shall, at least annually, be transferred to the Bond Charge Collection Account.

Amounts in the Debt Service Reserve Account may be used for the payment of Bond Related Costs (including debt service on the Bonds, payments under Enhancement Facilities and scheduled and termination payments under Qualified Swaps) except Fiduciary costs, and in each case only if amounts in the Bond Charge Payment Account and Operating Account are insufficient for that purpose. See APPENDIX C – "SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE—Application and Flow of Funds – *Debt Service Reserve Account*."

Operating Account

DWR covenants in the Indenture to include in its Revenue Requirements amounts estimated to be sufficient, among other things, to cause the amount on deposit in the Operating Account (excluding any reserves established for any Subordinated Indebtedness or Subordinated Obligations), at all times during any calendar month, to equal the Minimum Operating Expense Available Balance. "Minimum Operating Expense Available Balance" means, at the time Revenue Requirements are submitted to the CPUC, (i) for so long as DWR is procuring all or a portion of the residual net short, $1 billion, and (ii) thereafter, the maximum amount projected by DWR by which operating expenses exceed Power Charge Revenues during any one calendar month during that revenue requirement period, based on such assumptions as DWR deems to be appropriate after consultation with the CPUC and taking into account a range of possible future outcomes.

While DWR is purchasing the residual net short (as described in "POWER SUPPLY PROGRAM – Transition of Procurement Responsibility After 2002"), if on any date the Operating Account balance falls below $750 million, unless the Operating Account balance has been restored to at least the Minimum Operating Expense Available balance on the 31st day thereafter, then on or prior to the 45th day following the date on which the Operating Account balance fell below $750 million, DWR will submit a new Revenue Requirement to the CPUC providing for Revenues sufficient to restore the Operating Account to the Minimum Operating Expense Available Balance within a period ending no later than 240 days following the date of the submission of such new Revenue Requirement to the CPUC. While DWR is purchasing the residual net short, if on any date the Operating Account balance falls below $500 million and DWR has not yet submitted a Revenue Requirement pursuant to the preceding sentence, then on or prior to the earlier of (a) the 10th business day following the date on which the Operating Account balance falls below $500 million or (b) the date on which a Revenue Requirement is required to be submitted to the CPUC in accordance with the preceding sentence, DWR will submit a new Revenue Requirement to the CPUC providing for Revenues sufficient to restore the Operating Account to the Minimum Operating Expense Available Balance within a period ending no later than 240 days following the date of the submission of such new Revenue Requirement to the CPUC.

Operating Reserve Account

The "Operating Reserve Account Requirement" is an amount, during each revenue requirement period, equal to the greater of (1) the largest aggregate amount, as projected by DWR, by which operating expenses exceed Power Charge Revenues during any seven calendar month period commencing in that revenue requirement period, and (2) either (A) 18 percent of DWR's projected annual operating expenses for any revenue requirement period in which DWR is procuring all or a portion of the residual net short and which commences prior to 2006, or (B) 12 percent of DWR's projected annual operating expenses for any revenue requirement period in which DWR is not procuring all or a portion of the residual net short or which commences after 2005; provided, however, that solely for purposes of (2) above for revenue requirement periods commencing after 2003, the projected amount shall not be less than the applicable percentage of DWR's operating expenses for the most recent 12 calendar month period for which DWR determines that reasonably full and complete operating expense information is available, adjusted for reductions in DWR financial responsibility for power supply contracts. Projections may be based on such assumptions as DWR deems to be appropriate and, in the case of clause (1) above, may take into account a range of possible future outcomes. Whenever the Indenture requires DWR to consult with the CPUC with respect to assumptions made by DWR, DWR is required to involve the CPUC in the development of those assumptions by conferring regularly in a manner consistent with DWR's obligations under Article 4 of the Rate Agreement. The Operating Reserve Account was funded with a deposit from amounts available in the Electric Power Fund at the time of issuance of the first series of Bonds. The Operating Reserve Account is required to be replenished, if necessary, from Power Charge Revenues in the manner and at the times (which may extend over a period of one year commencing seven months following the determination of the deficiency) described in APPENDIX C – "SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE – Application and Flow of Funds – *Operating Reserve Account*."

Amounts in the Operating Reserve Account may be used only for the purpose of funding the Priority Contract Account and the purposes listed in clauses (i) through (v) of the list under "Accounts and Flow of Funds under the Indenture" above, provided, however, that if and to the extent that the amount in the Operating Reserve Account is or would be less than or equal to the Priority Contract Contingency Reserve Amount, amounts in the Operating Reserve Account may only be used to make up any deficiency in the Priority Contract Account. The "Priority Contract Contingency Reserve Amount" is to be calculated at the beginning of each revenue requirement period and is the maximum monthly amount of Priority Contract Costs projected by DWR to be payable under Priority Long-Term Power Contracts during that revenue requirement period, based on such assumptions as DWR deems to be appropriate, taking into account a range of possible future outcomes.

Whenever the Operating Reserve Account Requirement is reduced pursuant to the Indenture, any excess amounts in the Operating Reserve Account ("Excess Amounts") will be used at such time to satisfy any deficiencies existing at such time in the transfers, applications and withdrawals described in clauses (i) through

(vi) of the list under "Accounts and Flow of Funds under the Indenture" above, including repayment in full to the General Fund of the State for all advances made to DWR from amounts appropriated to the Electric Power Fund, including interest thereon. Unless otherwise agreed by both DWR and the CPUC, each acting in its own discretion, any Excess Amounts remaining after application to the uses described in the preceding sentence shall be used, at the direction of the CPUC after consultation with DWR, to (i) adjust DWR charges or (ii) with the agreement of DWR, to reduce debt outstanding under the Indenture, in all instances upon consideration of the interests of the customers of the IOUs and of DWR and, if applicable, Electric Service Provider retail customers. If and when DWR no longer is responsible for the payment of costs under any Power Supply Contract, the balance, if any, in the Operating Reserve Account is required to be applied as described in the preceding two sentences.

Bond Related Costs

Bond Related Costs that are payable from Bond Charges imposed by the CPUC under the Rate Agreement consist of payments or deposits or other provision to be made by DWR under the Indenture or other financing documents or the Act, for the following components of DWR's Revenue Requirements under the Act:

(i) principal of, premium, if any, and interest on Bonds and any additional amount required under the Indenture or other financing documents to be deposited into the Bond Charge Collection Account to provide debt service coverage of the Bonds;

(ii) payments required to be made (A) under agreements with issuers of credit and liquidity facilities and their participants, including letters of credit, bond insurance, guarantees, debt service reserve fund surety bonds, lines of credit, reimbursement agreements, and standby bond purchase agreements, (B) under agreements relating to other financial instruments entered into in connection with the Bonds, including but not limited to investment agreements, hedges, interest rate swaps, caps, options and forward purchase agreements, and (C) under agreements relating to the remarketing of Bonds, including but not limited to remarketing agreements, dealer agreements and auction agent agreements;

(iii) deposits to the Debt Service Reserve Account established under the Indenture to the extent necessary to provide therein an amount equal to the requirement for such account under the Indenture and other financing documents if not otherwise replenished from Power Charges;

(iv) the costs of the Trustees and the Registrars and Paying Agents associated with the issuance and administration of the Bonds; and

(v) when and if DWR no longer sells Power under the Act and Bonds remain outstanding, DWR's Bond Charge servicing costs, costs of preparing and providing the information and reports required under the Indenture and other financing documents, the Rate Agreement and the Act, related audit, legal and consulting costs, related administrative costs, and costs of complying with arbitrage restrictions and rebate requirements.

The amount payable under Parity Obligations is not limited by the Indenture or the Rate Agreement. However, not all costs that constitute Bond Related Costs under the Rate Agreement are payable on a parity with the Bonds. "Parity Obligation" is defined in the Indenture to include only "Reimbursement Obligations" and the amounts payable under "Qualified Swaps." The criteria for determining whether an agreement is a Reimbursement Obligation or a Qualified Swap are explained in APPENDIX C – "SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE – Special Provisions Relating to Enhancement Facilities, Qualified Swaps and Other Similar Arrangements."

In connection with the variable rate Series 2002B and Series 2002C Bonds, DWR has entered and expects to enter into agreements, such as agreements with issuers of credit and liquidity facilities and agreements with interest rate swap providers, which constitute Parity Obligations. See "PLAN OF FINANCE."

Bond Insurance

The scheduled payment when due of the principal of and interest on certain Series 2002A Bonds identified on the inside cover of this Official Statement (the "Insured Bonds") will be insured by financial guaranty insurance policies (each, a "Policy") to be issued by the applicable bond insurers (each, a "Bond Insurer") identified on such inside cover.

For information concerning the Bond Insurers and the forms of their respective Policies, see Appendix K.

It is a condition to the issuance of the Series 2002A Bonds that the Bond Insurers issue the Policies. A specimen of each such Policy is included in Appendix K. Certain other information concerning each Bond Insurer and its Policy, which has been supplied by the Bond Insurer, is also set forth in Appendix K. No representation is made by DWR or the Underwriters as to the accuracy, completeness or adequacy of such information, or as to any additional documents referred to in Appendix K, or as to the absence of material adverse changes in such information subsequent to the date hereof. Neither DWR nor the Underwriters have made any independent investigation of the Bond Insurers or the Policies, and reference should be made to the information set forth below and in Appendix K hereto for a description thereof. Any additional documents referred to in Appendix K are not a part of this Official Statement. Except for payment of the premiums for the Policies, DWR has no responsibility whatsoever with respect to the Policies, including the collection of amounts payable thereunder.

The Indenture provides that so long as a Policy is in full force and effect, and payment on such Policy is not in default, then the applicable Bond Insurer shall be deemed to be the sole Owner of the outstanding Series 2002A Bonds covered by such Policy when the approval, consent or action of the Owners thereof is required or may be exercised under the Indenture, except as provided by the provisions of the Indenture permitting modifications and amendments only with the consent of a particular Owner (see APPENDIX C - "SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE – Supplemental Indentures and Amendments"). With respect to such modifications and amendments, the consent of such Bond Insurer shall be required in addition to the consent of such Owner. Certain Bond Insurers may also have the right to consent to certain amendments to the Indenture or the Rate Agreement, even if the approval of Owners is required, and to give notices of default under the Indenture.

PRIORITY LONG-TERM POWER CONTRACTS

General

Under the Rate Agreement, the term "Priority Long Term Power Contracts" is defined as (i) those long-term electric power contracts identified in the appendix to the Rate Agreement and not including any electric power contracts entered into after August 14, 2001, provided, however, that such term includes any priority long-term electric power contract entered into after such date as an amendment or novation of any Priority Long-Term Power Contract, and (ii) any contracts entered into for the purpose of securing fuel for use at generating facilities being operated pursuant to such Priority Long-Term Power Contracts, if that fuel supply contract contains a provision to the general effect that payments by DWR under the contract are to be paid or payable prior to bonds, notes or other indebtedness of DWR secured by a pledge or assignment of the revenues of DWR under the Act and other amounts in the Electric Power Fund. The Indenture incorporates by reference the Rate Agreement's definition of that term.

The Priority Long-Term Power Contracts each provide, in effect, that payments by DWR under the contracts are to be paid or are payable prior to bonds, notes, or other indebtedness of DWR secured by a pledge or assignment of the revenues of DWR under the Act and other amounts in the Electric Power Fund established by the Act. DWR expects that after 2002 substantially all of the power purchased by DWR under the Act will be purchased under Priority Long-Term Power Contracts and substantially all operating expenses will be Priority Contract Costs. See "PLAN OF FINANCE – Summary of Historical and Projected Financial Results." See also APPENDIX A – "CONSULTANT'S REPORT – Power Supply Resources," and Appendix I thereto.

The Priority Long-Term Power Contracts obligate DWR to purchase power from various suppliers. The Priority Long-Term Power Contracts currently have varying terms up to twelve years. The prices DWR is obligated to pay under the Priority Long-Term Power Contracts are generally higher than prices currently prevailing in the spot market. In some months of some years, the total amount of energy to be purchased by DWR through the Priority Long-Term Power Contracts is expected to be in excess of its customers' needs. In these periods, DWR will seek to sell the excess energy to other users. DWR expects that the price it receives for the excess energy will be less than its cost for that energy.

Most of the Priority Long-Term Power Contracts include a requirement that DWR issue bonds on or before specified dates which have now passed. DWR entered into the Interim Loan prior to the specified dates for issuance of its bonds, and believes that it has therefore satisfied this requirement. Some of the other parties have indicated, however, that they may disagree and may have the right to cease performance under the Priority Long-Term Power Contracts.

In addition, DWR believed that the counterparties to the Priority Long-Term Power Contracts were financially capable of performing their obligations to deliver energy to DWR at the time those contracts were entered into. DWR now believes that one or more of those counterparties may have become financially distressed since the Priority Long-Term Power Contracts were entered into, and it is possible that one or more of them may be unable to deliver energy to DWR for periods during the term of the Priority Long-Term Power Contracts.

If any other counterparty fails to deliver power to DWR, whether such counterparty is contractually permitted to do so under the provisions of its Priority Long-Term Power Contract or financially unable to perform its obligations thereunder or unable to deliver power for any other reason, DWR or one or more IOUs may have to purchase replacement power. Replacement power could be purchased currently at prices below those that DWR is obligated to pay under the Priority Long-Term Power Contracts, but if DWR or an IOU is required to purchase replacement power in the future, such power might not be available or might only be available at prices higher than DWR is obligated to pay under the Priority Long-Term Power Contracts. Although DWR would be able to sue any counterparty that failed to deliver energy to it pursuant to Priority Long-Term Power Contracts, any recovery of damages could be substantially delayed or might never be obtained if the counterparty that failed to deliver energy is or becomes insolvent.

Payment Priority

The use of amounts on deposit in the Bond Charge Collection Account (including Bond Charge Revenues) for the payment of debt service on the Bonds and other Bond Related Costs) when due is subject to the possible prior use of such amounts to pay Priority Contract Costs. See "SECURITY FOR THE BONDS – Accounts and Flow of Funds Under the Indenture." DWR believes it should not be necessary to use Bond Charge Revenues to pay Priority Contract Costs because DWR expects Power Charge Revenues to be adequate to pay all Priority Contract Costs as and when due. See "SOURCES OF FUNDS TO PAY DEBT SERVICE – Recovery of Amounts Used to Pay Priority Contract Costs." See also "RISK FACTORS – Determination of Power Charges and Bond Charges; Possible Use of Amounts in the Bond Charge Collection Account to Pay Priority Contract Costs."

If Bond Charge Revenues and other amounts on deposit in the Bond Charge Collection Account are used to pay Priority Contract Costs, the Rate Agreement provides that DWR shall take such actions as are required

under the Rate Agreement so that the amounts applied from the Bond Charge Collection Account for such purpose shall be replenished from Power Charges. See "SOURCES OF FUNDS TO PAY DEBT SERVICE – Recovery of Amounts Used to Pay Priority Contract Costs."

In the absence of material change in the net per unit cost of energy derived from Priority Long-Term Power Contracts and provided to DWR's retail customers and in the absence of material termination payments on Priority Long-Term Power Contracts, Power Charge Revenues are expected to increase and decrease approximately in proportion to increases and decreases in Priority Contract Costs. Furthermore, the timing of monthly payments of Priority Contract Costs (an average lag of about 35 days from provision of energy) is comparable to the timing of receipt by DWR of Power Charge Revenues (an average lag of about 45 days from consumption of energy).

However, a number of factors affect the variability of net per unit Priority Contract Costs from time to time, and, as a result, the sufficiency of the monthly amount of Power Charge Revenues in relation to the monthly amount of Priority Contract Costs. These factors include, but are not limited to, the cost from time to time of natural gas and other fuel costs, the amount of surplus power from Priority Long-Term Power Contracts (energy DWR is required to take) sold at prices below the price paid for such power, and the amount of power dispatched from time to time under contracts with fixed capacity payments or with adjustment rights on block quantities. The Consultant's Report evaluates several cash flow scenarios that make varying assumptions concerning these factors. See APPENDIX A – "CONSULTANT'S REPORT – Sensitivity Analyses."

Termination Payments

In addition, most of the Priority Long-Term Power Contracts provide for the payment of termination liquidated damages by DWR upon the occurrence of an event of default by DWR and termination of the Priority Long-Term Power Contract by the seller. Such termination liquidated damages are generally equal to the net present value of the difference between the price for power pursuant to the Priority Long-Term Power Contract and the then-current market price for power, for the entire remaining term of the Priority Long-Term Power Contract. The amount of termination liquidated damages that would be payable upon the occurrence of an event of default by DWR and subsequent termination of a Priority Long-Term Power Contract will vary depending on market conditions at the time of termination; however, such damages could be in the hundreds of millions of dollars or greater with respect to certain Priority Long-Term Power Contracts. Under most of the Priority Long-Term Power Contract termination payments are due within 180 days of any termination. Termination liquidated damages, if payable, would constitute Priority Contract Costs.

Operating Reserve Account

The Indenture requires the Operating Reserve Account to be established and maintained by DWR at an amount equal to the Operating Reserve Account Requirement, which may be based on such assumptions as DWR deems to be appropriate, after consultation with the CPUC, and taking into account a range of possible future outcomes. See "SECURITY FOR THE BONDS—Operating Reserve Account." When establishing the Operating Reserve Requirement from time to time, DWR intends to utilize assumptions and take into account possible future outcomes that include a range of variation in the circumstances that affect the factors described in the foregoing paragraph.

Litigation and Administrative Proceedings

Litigation and administrative proceedings are pending concerning DWR's long-term power contracts. See "LITIGATION AND ADMINISTRATIVE PROCEEDINGS – Litigation Pending or Threatened in State and Federal Courts - *Actions Contesting Certain Long-Term Power Contracts*" and "LITIGATION AND ADMINISTRATIVE PROCEEDINGS – FERC Administrative Actions - *Actions Contesting Certain Long-Term Power Contracts."*

SOURCES OF FUNDS TO PAY DEBT SERVICE

The Bonds (and all other Bond Related Costs) are payable primarily from Bond Charges to be imposed by the CPUC upon customers in the service areas of the three IOUs. Approximately 77 percent of all Californians use electricity provided by the IOUs. The IOUs serve approximately 80 percent of the geographic area of the State.

Rate Agreement

The CPUC and DWR have entered into the Rate Agreement pursuant to the Act to facilitate the issuance of Bonds and for the benefit of Bondholders (and all other persons to whom DWR is obligated to pay Bond Related Costs). The obligation of the CPUC to calculate, revise and impose Bond Charges is irrevocable and cannot be changed by DWR and the CPUC. Other provisions of the Rate Agreement may be amended only by an amendment approved by DWR and the CPUC. Under the Indenture, DWR covenants not to amend the Rate Agreement unless DWR has determined that the amendment will not have a material adverse effect on the ability of DWR to comply with the provisions of the Indenture.

In the Rate Agreement, the CPUC covenants and agrees to calculate, revise and impose from time to time, Bond Charges sufficient to provide moneys so that the amounts available for deposit in the Bond Charge Payment Account from time to time, together with amounts on deposit in the Bond Charge Payment Account, are at all times sufficient to pay or provide for the payment of all Bond Related Costs when due in accordance with the "Financing Documents" (defined in the Rate Agreement attached as Appendix D). The Rate Agreement provides that this covenant shall have the force and effect of a "financing order" under the California Public Utilities Code and shall be irrevocable and enforceable in accordance with its terms, including, without limitation, in circumstances in which DWR has breached its obligations under the Rate Agreement or in respect of the Financing Documents. Under the California Public Utilities Code, a "financing order" is binding upon the Commission as it may be constituted from time to time, and the Commission shall have no authority to rescind, alter or amend its obligations thereunder. Under the Act, the rights, powers and duties of the Commission may not be diminished or impaired in a manner which would adversely affect the interests or rights of Bondholders. See, however, "RISK FACTORS – Determination of Power Charges and Bond Charges; Possible Use of Amounts in the Bond Charge Collection Account to Pay Priority Contract Costs – *Application and Enforcement of CPUC's Bond Charge Rate Covenant*."

In the Rate Agreement, the CPUC also covenants and agrees to calculate, revise and impose, from time to time, Power Charges sufficient to provide moneys in the amounts and at the times necessary to satisfy DWR's "Retail Revenue Requirements" (defined in the Rate Agreement attached as Appendix D) as specified by DWR.

In the event of a failure of the CPUC to calculate and impose Bond Charges in accordance with the Rate Agreement, the Rate Agreement is enforceable against the CPUC by the Co-Trustee under the Indenture 30 days after DWR has defaulted and failed to enforce the Rate Agreement. The Rate Agreement imposes certain conditions to the exercise by the Co-Trustee of DWR's rights under the Rate Agreement.

The Rate Agreement specifies the actions to be taken by DWR and the timetable that the CPUC will use to calculate, revise and impose Bond Charges and Power Charges. See "RATEMAKING AND RELATED ACTIONS – CPUC Actions to Calculate, Revise and Impose Bond Charges and Power Charges."

To enable the CPUC to set and adjust Bond Charges and Power Charges, the Rate Agreement requires DWR to periodically determine and submit cost information and projections to the CPUC and to provide reports to the CPUC concerning fund balances under the Indenture. See "RATEMAKING AND RELATED ACTIONS – DWR Actions to Establish Revenue Requirements." The Rate Agreement specifies information that DWR will include with its Retail Revenue Requirements.

If DWR projects that there will be insufficient amounts on deposit in the Bond Charge Payment Account to make timely payment of Bond Related Costs, the Rate Agreement requires DWR to submit to the CPUC a request that the CPUC increase Bond Charges, and the CPUC is required to calculate and impose revised Bond Charges to pay such Bond Related Costs no later than 120 days from the date following DWR's request. The Rate Agreement further provides that, even if DWR does not submit such a request, the CPUC is bound by its covenant to calculate, revise and impose Bond Charges, as described above.

A decision approving the Rate Agreement was adopted by the CPUC on February 21, 2002, and the Rate Agreement was executed by the CPUC and DWR as of March 8, 2002. The decision approving the Rate Agreement is now final and unappealable under California law. The Rate Agreement is attached as Appendix D to this Official Statement.

DWR may not issue additional Bonds under the Indenture in addition to the Series 2002A Bonds and the other Series 2002 Bonds unless DWR and the CPUC have entered into a rate agreement with respect to such additional Bonds.

The Consultant has concluded that the Rate Agreement provides a reasonable mechanism for the establishment and, as needed, timely adjustment and implementation of Bond Charges and Power Charges. See the Consultant's Report attached as Appendix A.

Counsel to the CPUC and Bond Counsel will each deliver an opinion, in connection with the issuance of the Series 2002 Bonds, concerning the Rate Agreement, among other matters. See APPENDIX F – "PROPOSED FORM OF OPINION OF BOND COUNSEL" and APPENDIX G – "PROPOSED FORM OF OPINION OF CPUC COUNSEL", respectively, for copies of the forms of such proposed opinions. Such opinions represent expressions of professional judgment and not guarantees of result. See "RISK FACTORS – Determination of Power Charges and Bond Charges; Possible Use of Amounts in the Bond Charge Collection Account to Pay Priority Contract Costs."

Recovery of Amounts Used to Pay Priority Contract Costs

On or before the fifth Business Day of each month, DWR is required to transfer from the Operating Account to the Priority Contract Account such amount as is necessary to make the amount in the Priority Contract Account sufficient to pay the Priority Contract Costs (costs and expenses under or pursuant to the Priority Long-Term Power Contracts) estimated to be due during the balance of such month and through the first five Business Days of the next succeeding calendar month. Amounts in the Priority Contract Account may be used solely to pay Priority Contract Costs. See "SECURITY FOR THE BONDS – Accounts and Flow of Funds under the Indenture."

On or before the last Business Day of each month, DWR is required to transfer from the Bond Charge Collection Account to the Bond Charge Payment Account such amount as is necessary to make the amount in the Bond Charge Payment Account sufficient to pay Bond Related Costs (including debt service on the Bonds) estimated to accrue or to be payable during the next succeeding three calendar months. Each such transfer is subject to the prior transfer of amounts in the Bond Charge Collection Account to the Priority Contract Account if and to the extent amounts in the Priority Contract Account, the Operating Account and the Operating Reserve Account are insufficient to pay Priority Contract Costs then due and payable under or pursuant to Priority Long-Term Power Contracts. See "PRIORITY LONG-TERM POWER CONTRACTS."

The Indenture and the Rate Agreement thus permit Bond Charge Revenues to be used to pay Priority Contract Costs that are not paid from other funds under the Indenture, such as Power Charge Revenues. The flow of funds required by the Indenture provides that Priority Contract Costs are to be paid each month from Power Charge Revenues before any payment or funding of any other Department Costs. See "SECURITY FOR THE BONDS – Accounts and Flow of Funds under the Indenture." The CPUC covenants in the Rate Agreement to calculate, revise and impose, from time to time, Power Charges sufficient to provide moneys in the amounts and

at the times necessary to satisfy the Retail Revenue Requirements submitted by DWR to the CPUC in accordance with the Rate Agreement. The Rate Agreement provides that in the event Priority Contract Costs are funded out of the Bond Charge Collection Account, DWR shall take such actions as are required under the Rate Agreement so that the amounts applied from the Bond Charge Collection Account for such purpose shall be replenished from Power Charges. See "SOURCES OF FUNDS TO PAY DEBT SERVICE – Rate Agreement" and "RISK FACTORS – Determination of Power Charges and Bond Charges; Possible Use of Amounts in the Bond Charge Collection Account to Pay Priority Contract Costs."

RATE COVENANTS

The CPUC has irrevocably covenanted in the Rate Agreement, for the benefit of Bondholders (and all other persons to whom DWR is obligated to pay Bond Related Costs), to calculate, revise and impose from time to time, Bond Charges sufficient to provide moneys so that amounts available for deposit in the Bond Charge Payment Account under the Indenture from time to time, together with amounts on deposit in the Bond Charge Payment Account, are at all times sufficient to pay or provide for the payment of debt service on the Bonds and all other Bond Related Costs (as defined in the Rate Agreement) when due in accordance with the Indenture and other financing documents. See "SOURCES OF FUNDS TO PAY DEBT SERVICE – Rate Agreement." The Rate Agreement provides that this covenant shall have the force and effect of a "financing order" under the California Public Utilities Code and shall be irrevocable and enforceable in accordance with its terms, including, without limitation, in circumstances in which DWR has breached its obligations under the Rate Agreement or in respect of the Financing Documents. Under the California Public Utilities Code, a "financing order" is binding upon the Commission as it may be constituted from time to time, and the Commission shall have no authority to rescind, alter or amend its obligations thereunder. Under the Act, the rights, powers and duties of the Commission may not be diminished or impaired in a manner which would adversely affect the interests or rights of Bondholders. See "SECURITY FOR THE BONDS – Bond Related Costs." See also, however, "RISK FACTORS – Determination of Power Charges and Bond Charges; Possible Use of Amounts in the Bond Charge Collection Account to Pay Priority Contract Costs."

DWR covenants in the Indenture to cause to be established, fixed and revised from time to time, charges sufficient, together with any other available moneys and securities on deposit in DWR's Electric Power Fund, to satisfy all of DWR's "Revenue Requirements" at the times and in the amounts needed. "Revenue Requirements" is defined in the Indenture to mean the amounts needed from time to time by DWR to satisfy its obligations under the Act and under proclamations and orders issued pursuant to the California Emergency Services Act. These obligations include, but are not limited to, making deposits to the Bond Charge Payment Account and Debt Service Reserve Account in the amounts and at the times required by the Indenture. See APPENDIX C – "SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE."

RATEMAKING AND RELATED ACTIONS

DWR Actions to Establish Revenue Requirements

Overview

To enable the CPUC to set Bond Charges and Power Charges, the Rate Agreement described under "SOURCES OF FUNDS TO PAY DEBT SERVICE – Rate Agreement" requires DWR to periodically determine and submit to the CPUC the amount of DWR's Retail Revenue Requirements and information concerning Bond Related Costs. The Rate Agreement defines Retail Revenue Requirements as the amount of Department Costs that are to be generated from Power Charges imposed by the CPUC from time to time. "Department Costs" means all amounts which DWR is entitled under the Act to recover (other than Bond Related Costs recovered from Bond Charges).

The Rate Agreement requires DWR, at least annually, and more frequently as deemed reasonably necessary or appropriate by DWR or the CPUC, to review, determine and revise its Retail Revenue Requirements. The Rate Agreement requires DWR promptly to notify the CPUC following any determination or revision of DWR's Retail Revenue Requirements. The Rate Agreement also requires DWR to revise and communicate to the CPUC its Retail Revenue Requirements within 20 days of DWR projecting that within 120 days: (i) there will be insufficient funds in the Priority Contract Account to pay Priority Contract Costs; or (ii) there will be less than the Operating Reserve Account Requirement in the Operating Reserve Account; or (iii) shortfalls in the Priority Contract Account, Operating Account and the Operating Reserve Account will require moneys in the Bond Charge Collection Account to pay Priority Contract Costs; or (iv) moneys in the Debt Service Reserve Account will be used to pay Bond Related Costs. DWR is also required by the Rate Agreement to revise and communicate to the CPUC within three business days its Retail Revenue Requirements in the event of a withdrawal from the Bond Charge Collection Account to pay Department Costs or in the event of a withdrawal from the Operating Reserve Account or the Debt Service Reserve Account such that the amount in either such account is less than that required by the Indenture or any other financing document. See "SOURCES OF FUNDS TO PAY DEBT SERVICE – Rate Agreement" concerning the procedures to be followed if DWR projects that there will be insufficient moneys on deposit in the Bond Charge Payment Account to make timely payment of Bond Related Costs.

The Rate Agreement also requires DWR to provide monthly reports to the CPUC concerning DWR's receipts and costs in a form that permits comparison to Retail Revenue Requirement projections, and permits the CPUC to increase Power Charges to prevent any shortfall on an interim basis if it determines that existing Power Charges are not sufficient to pay Department Costs (which for this purpose includes funding or replenishment of the Bond Charge Collection Account, Bond Charge Payment Account or Debt Service Reserve Account at the levels and at the times required by the Indenture or other financing documents) even if DWR does not provide a revised Retail Revenue Requirement to the CPUC in a timely manner.

DWR covenants in the Rate Agreement that, upon the request of the CPUC, DWR will participate in any CPUC proceedings, including providing witnesses, attending public hearings and providing any other materials necessary to facilitate the CPUC's completion of its proceedings in connection with the establishment of Power Charges or Bond Charges by the CPUC.

Just and Reasonable Requirement

DWR has agreed in the Rate Agreement that prior to including any cost in the Retail Revenue Requirements communicated to the CPUC, DWR will conduct whatever procedures are required by law to determine that such cost is just and reasonable within the meaning of Section 451 of the California Public Utilities Code. It is not clear what procedures are required by law. After following certain procedures described below, DWR has made a determination that its Bond Related Costs as well as the costs included in its Retail Revenue Requirements for the calendar years 2001, 2002 and 2003 are just and reasonable.

Section 80110 of the California Water Code provides that any just and reasonable review under Section 451 of the California Public Utilities Code shall be conducted and determined by DWR. Section 451 provides that all charges by a "public utility" shall be just and reasonable but neither defines "just and reasonable" nor specifies the procedures to be followed to make that determination. The regulation by the CPUC of the IOUs and other California entities has resulted in judicial and administrative decisions that have interpreted the meaning of Section 451 for the purpose of regulating utility charges. Whether these decisions govern the determination of whether DWR's costs are just and reasonable has not been reviewed or determined by any court.

In *Pacific Gas and Electric Company v. The California Department of Water Resources, et al*., the Superior Court ruled on the procedures followed and to be followed by DWR in making its determination that costs included in its Revenue Requirements are just and reasonable. The Superior Court issued its judgment to the effect that the California Government Code provisions concerning the adoption of regulations by State agencies (the "APA") apply to DWR's determination. See "LITIGATION AND ADMINISTRATIVE PROCEEDINGS –

Litigation Pending or Threatened in State and Federal Courts – *Actions and Adverse Comments Contesting DWR's Revenue Requirements*." In order to comply with the court's judgment, DWR adopted emergency regulations in early June, 2002, establishing a procedure for public participation in the determination of its Revenue Requirements and establishing a standard for the determination that costs included in its Revenue Requirements are just and reasonable (the "Revenue Requirement Regulations"). By adopting the Revenue Requirement Regulations, DWR did not concede its position that its just and reasonable determination is not subject to the APA, and DWR is appealing the Superior Court decision.

The Revenue Requirement Regulations require DWR to provide to interested parties an opportunity to submit comments on each proposed determination made by DWR. Under the Revenue Requirement Regulations, the time for comment by interested parties on a proposed Revenue Requirements determination and the bases therefor will normally be at least 21 calendar days, but may be shorter in circumstances in which a shorter period is deemed reasonably necessary by DWR, including those circumstances in which the Rate Agreement requires revised Revenue Requirements to be communicated to the CPUC within a shorter period. If DWR adds significant additional material as the basis for the Revenue Requirements, the regulations require DWR to allow a reasonable period of time for public comment on the additional material.

The Revenue Requirement Regulations state that to protect ratepayer interests, the record of the determination must demonstrate by substantial evidence that the Revenue Requirement is just and reasonable, considering the circumstances existing or projected to exist at the respective times of DWR's decisions concerning whether to incur the costs comprising such Revenue Requirement, and the factors which under the Act are relevant to such determination and such decisions, including but not limited to the following express provisions of the Act:

- The development and operation of the Power Supply Program as provided in the Act is in all respects for the welfare and the benefit of the people of the State, to protect the public peace, health, and safety, and constitutes an essential governmental purpose;

- DWR must do those things necessary and authorized under the Act to make power available directly or indirectly to electric consumers in California (provided that except as otherwise stated, nothing in the Act authorizes DWR to take ownership of the transmission, generation, or distribution assets of any electrical corporation in the State of California);

- Upon those terms, limitations, and conditions as it prescribes, DWR may contract with any person, local publicly owned electric utility, or other entity for the purchase of power on such terms and for such periods as DWR determines and at such prices DWR deems appropriate taking into account all of the factors listed in section 80100 of the Act;

- DWR may sell any power acquired by DWR pursuant to the Act to retail end use customers, and to local publicly owned electric utilities, at not more that DWR's acquisition costs, including transmission, scheduling, and other related costs, plus other costs as provided in section 80200 of the Act;

- DWR must, at least annually, and more frequently as required, establish and revise revenue requirements sufficient, together with any moneys on deposit in the Electric Power Fund, to provide for all of the costs listed in section 80134(a) of the Act (including but not limited to the amounts necessary to pay debt service on bonds (including the Interim Loan and the Bonds), the amounts necessary to pay for power purchased by DWR, reserves in such amount as may be determined by DWR to be necessary or desirable, the repayment to the General Fund of appropriations made to the Electric Power Fund for purposes of the Act and DWR's administrative costs); and

- Obligations of DWR authorized by the Act shall be payable solely from the Electric Power Fund.

The Revenue Requirement Regulations are subject to judicial review in State court. The actions taken by DWR under the Revenue Requirement Regulations are also subject to judicial review in State court. Any such proceedings could further delay consideration of DWR's Revenue Requirements or result in a judicial determination that less than all of DWR's costs are just and reasonable. See "RISK FACTORS – Determination of Power Charges and Bond Charges; Possible Use of Amounts in the Bond Charge Collection Account to Pay Priority Contract Costs." The Revenue Requirement Regulations are emergency regulations that DWR expects to renew and ultimately replace with permanent regulations.

Proceedings under Revenue Requirement Regulations

On June 14, 2002, DWR issued its proposed Revenue Requirements for 2003 (and its re-examination and re-determination for 2001 and 2002) and offered interested parties an opportunity to submit comments pursuant to the Revenue Requirement Regulations. Comments were submitted by PG&E, SCE, SDG&E and the California Large Energy Consumers Association ("CLECA"). DWR responded to the comments, revised its proposed Revenue Requirements, determined that its Revenue Requirements, as so revised, are just and reasonable, and submitted its Revenue Requirements to the CPUC on August 19, 2002. The 2003 Revenue Requirements determination (and the re-examination and re-determination for 2001 and 2002) are available on DWR's website or upon request to DWR.

The February 21, 2002 CPUC order set a schedule for the implementation of DWR's Revenue Requirements for 2003 under which DWR was to submit its Retail Revenue Requirements for 2003 to the CPUC on June 1, 2002, and the CPUC would impose Power Charges to take effect on January 1, 2003. The DWR submission was delayed until August 19, 2002 by the PG&E litigation and the proceedings described above. DWR expects that the CPUC will impose Power Charges that will begin to accrue on and after January 1, 2003. On October 24, 2002, the CPUC adopted a decision establishing the methodology by which Bond Charges will be imposed. On November 4, 2002, TURN, SCE and PG&E each filed an application for rehearing of that decision. The TURN and SCE applications contend that the allocation methodology adopted by the CPUC was unlawful and discriminatory in that it exempted from Bond Charges certain residential usage only in the SDG&E service area. The PG&E application made the same complaint and also contended that there were defects in the procedure by which the CPUC consented to an increase in the amount of Bonds. The PG&E application further contended that these alleged defects affected the adoption of the CPUC's October 24, 2002 decision. TURN also contends that the CPUC is required to exempt certain electricity usage from Bond Charges under an interpretation of State law. November 4, 2002 was the last day that an interested party could request a rehearing on the October 24, 2002 CPUC decision. Although the implementation of Bond Charges is subject to a possible rehearing or revision of, and potential legal challenges to, that decision, and to additional actions yet to be taken, all of which could result in modification of such decision or delay in implementation, DWR expects that the CPUC will impose Bond Charges that will begin to accrue on or about November 15, 2002. See "PLAN OF FINANCE – Sources of Revenues During Calendar Years 2001 and 2002; DWR Charges for 2003." See also "RATEMAKING AND RELATED ACTIONS – CPUC Actions to Calculate, Revise and Impose Bond Charges and Power Charges." See also "RISK FACTORS – Determination of Power Charges and Bond Charges; Possible Uses of Amounts in the Bond Charge Collection Account to Pay Priority Contract Costs" and other sections of this Official Statement referred to therein.

DWR determined that its Revenue Requirements are just and reasonable because they comport with DWR's statutory responsibilities, accurately reflect lawfully incurred costs, do not over-collect, and contain costs that are reasonable given the circumstances under which they were incurred. DWR believes, for those and other reasons, that DWR would prevail in legal proceedings, if any, that may be brought to force a judicial review of DWR's determination. DWR also believes that with the availability of the substantial reserves described under "PLAN OF FINANCE," the pendency of any such proceedings will not disrupt the cash flow for the Power Supply Program to an extent that would prevent DWR from paying scheduled debt service on the Bonds. However, if such proceedings resulted in the recovery by DWR of less than all of DWR's actual costs, the ability of DWR to pay debt service on the Bonds could be adversely affected. See "RISK FACTORS – Determination of

Power Charges and Bond Charges; Possible Use of Amounts in the Bond Charge Collection Account to Pay Priority Contract Costs."

The comments filed with DWR in its proceedings under the Revenue Requirement Regulations were extensive. Among other things, commentators stated: (1) that the Revenue Requirement Regulations and DWR's proceedings under the Revenue Requirement Regulations did not comply with the APA or the decision in *Pacific Gas and Electric Company v. The California Department of Water Resources, et al*., described above under "Just and Reasonable Requirement;" (2) that DWR did not follow the Revenue Requirement Regulations in connection with the distribution of additional significant material, (3) that DWR costs are not just and reasonable; and (4) that the evidence and DWR's proceedings do not support DWR's determination that its Revenue Requirements are just and reasonable. In addition, after DWR submitted its 2003 Revenue Requirements to the CPUC as described above, PG&E and SCE each requested that DWR reconsider its determination and submitted comments in support of their requests. DWR denied such requests on October 8, 2002. On October 17, 2002, PG&E filed a new lawsuit in state court concerning the matters cited in its request for reconsideration. See "LITIGATION AND ADMINISTRATIVE PROCEEDINGS – Litigation Pending or Threatened in State and Federal Courts – Actions and Adverse Comments Contesting DWR's Revenue Requirement" for a description of this lawsuit.

CPUC Actions to Calculate, Revise and Impose Bond Charges and Power Charges

The CPUC has authority under the Act to set charges to recover DWR's costs. The CPUC has authority to establish the procedures that it will use to set electric charges, and to allocate charges among service areas and electric customers.

The CPUC has irrevocably covenanted to calculate, revise and impose Bond Charges as described under "RATE COVENANTS." See "SOURCES OF FUNDS TO PAY DEBT SERVICE – Rate Agreement" concerning the procedures for calculating, revising and imposing Bond Charges and Power Charges. Under the Act and the Rate Agreement, the CPUC does not review the reasonableness of DWR's costs, including its Bond Related Costs. See "DWR Actions to Establish Revenue Requirements" above. The calculation, revision and imposition of Bond Charges and Power Charges to recover DWR's costs is the responsibility of the CPUC.

In the event DWR fails to timely submit revised Retail Revenue Requirements, and the CPUC believes that Power Charges are not sufficient to pay Department Costs (which for this purpose includes replenishment of the Bond Charge Collection Account and Bond Charge Payment Account), the CPUC may revise Power Charges on an interim basis to cover the shortfall pending DWR's submittal of revised Retail Revenue Requirements. The CPUC may also require DWR to submit revised Retail Revenue Requirements. The Rate Agreement requires the CPUC to impose revised Bond Charges and Power Charges, as appropriate and necessary, no later than 120 days following the submittal of DWR's request that the CPUC take such action.

See "DWR Actions to Establish Revenue Requirements" concerning CPUC actions in 2001 and 2002 to recover costs incurred by DWR.

Applications for rehearing of any CPUC order can be sought by interested parties. Court challenges to CPUC orders are limited to issues specifically raised in an application for rehearing. According to the California Public Utilities Code, applications for rehearing of CPUC decisions on matters under the Act (such as Bond Charges) and certain related statutes must be filed within 10 days of the mailing of the CPUC decision, the CPUC's decision on rehearing must be made within 20 days of the application for rehearing, and CPUC decisions on rehearing can only be challenged in the California Supreme Court and any challenge must be filed within 30 days of the decision. Review by the California Supreme Court is discretionary and State law provides that judicial review can only result in a prospective effect on rates and charges, including Bond Charges. The California Public Utilities Code provides that orders of the CPUC which have become final and unappealable are conclusive in all collateral actions or proceedings. The California Public Utilities Code prohibits California courts from seeking to review or change a final and unappealable CPUC order.

CPUC Actions to Approve and Impose Servicing Arrangements

Bond Charges and the right to receive Bond Charges (as well as Power Charges and the right to receive Power Charges) are property of DWR under the Act and the Rate Agreement and have been pledged and assigned to the Trustees under the Indenture. DWR has entered into the Servicing Agreements with SCE and SDG&E, which the CPUC has approved pursuant to orders of the CPUC issued in April 2002 and July 2002, and under which SCE and SDG&E are each required to collect Bond Charges and Power Charges from customers and remit collections to DWR.

PG&E has not entered into a servicing agreement with DWR. The CPUC issued an order in 2001 pertaining to PG&E's collection of payments from customers for DWR electricity. PG&E has been collecting payments from customers and making remittances to DWR. After the Rate Agreement between DWR and the CPUC was signed, the CPUC issued another order (in May 2002) pertaining to PG&E (defined above as the "PG&E Servicing Order"), under which PG&E is required to collect Bond Charges and Power Charges from customers and remit collections to DWR on terms comparable to the terms of the Servicing Agreements with SCE and SDG&E. The PG&E Servicing Order is final and unappealable under California law.

Prior to the 2002 PG&E Servicing Order, PG&E had requested that the federal bankruptcy court deny approval of PG&E's entry into and implementation of the previous CPUC servicing order, but PG&E has since withdrawn that request. PG&E may also seek federal bankruptcy court action at any time with respect to the 2002 PG&E Servicing Order. Such review could also result in reversal or modification of the PG&E Servicing Order. See "RISK FACTORS – Bankruptcy Risks – *Potential Impact of PG&E Bankruptcy Proceedings on PG&E Servicing Order."*

The Servicing Agreements and the PG&E Servicing Order are collectively called the "Servicing Arrangements" and are summarized under "SERVICING ARRANGEMENTS."

DWR does not have the personnel, equipment or customer information necessary to provide its own metering, billing and collection services, and so Servicing Arrangements obligating the IOUs to provide such services to DWR are necessary to the timely collection of funds to pay debt service on the Bonds and all other Bond Related Costs as well as the DWR expenses payable from Power Charges. DWR covenants in the Indenture that it will maintain these Servicing Arrangements (or replacements therefor) in effect at all times while the Bonds are outstanding (see APPENDIX C – "SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE – Servicing Arrangements; Collection of Revenues"). See "RISK FACTORS – Collection of Bond Charges and Power Charges."

CPUC Actions Limiting Customer Access to Other Energy Providers

In March 2002, the CPUC voted to maintain the suspension date adopted in an earlier decision which suspended the right of customers of the IOUs to acquire "direct access" after September 20, 2001 and to consider in a future proceeding the imposition of cost responsibility surcharges (i.e., "direct access surcharges" or "exit fees") on direct access customers. This decision (the "Direct Access Decision") was taken pursuant to requirements of the Act.

After further proceedings, the CPUC adopted on November 7, 2002, a decision that established a direct access cost responsibility surcharge mechanism whereby designated direct access customers are made responsible for paying costs incurred by the Department that are being recovered through Bond Charges and Power Charges, and for paying certain above-market costs incurred by each of the IOUs through their own resources and contracts. The decision excluded continuous direct access customers, defined as those taking direct access continuously both before and since January 17, 2001 (in the PG&E and SCE service territories) or February 7, 2001 (in the SDG&E service territory), from paying Bond Charges. Pursuant to the Rate Agreement, Bond Charges will be imposed on direct access customers when the surcharges and this decision become final and unappealable. The decision also determined that pursuant to the Act and AB 117 (recently enacted state

legislation), any direct access customer who took bundled service from an electrical corporation on or after February 1, 2001, is responsible for paying a share of the DWR revenue requirements, including both previously incurred costs as well as an ongoing cost component, which is recovered through Power Charges. Imposition of the surcharges was to ensure bundled customer indifference (e.g., to prevent cost shifting between bundled customers and direct access customers). The decision also adopted an initial interim cap of 2.7 cents/kWh, in response to concerns that the surcharges might cause direct access to become uneconomic. Bundled customers will finance any undercollection resulting from the cap, and they will be repaid with interest over a reasonable period. The cap is subject to adjustment as determined in further proceedings ordered in the decision.

Also, recently enacted AB 117 permits a limited exemption which authorizes local government entities to become "community choice aggregators" and to develop programs to provide electricity to interested customers within the boundaries of such entities. Under the legislation, community choice aggregation shall not be authorized until the CPUC, among other things, imposes a cost-recovery mechanism that would require customers purchasing power from a community choice aggregator to pay specified amounts for recovery of DWR costs (including bond related costs) and certain costs of the IOUs. See "RISK FACTORS – Potential Decrease in DWR Customer Base" and " – Uncertainties Relating to Government Action – Recent State Legislation."

Proposed CPUC Action Imposing Bond Charges on Customers of Electric Service Providers

"Electric Service Provider" is defined in the Rate Agreement as an entity (other than a public agency that serves its own jurisdictional clients) that provides electrical service to retail customers located within the service area of any of the IOUs. The CPUC may impose Bond Charges on power that is sold by Electric Service Providers if the CPUC issues an order that provides for such charges and the order becomes final and unappealable under California law. On November 7, 2002, the CPUC adopted a decision that established a direct access cost responsibility surcharge mechanism whereby designated direct access customers were made responsible for Bond Charges, as well as other costs. The decision excluded continuous direct access customers, defined as those taking direct access continuously both before and since January 17, 2001 (in the PG&E and SCE service territories) or February 7, 2001 (in the SDG&E service territory), from paying these charges.

SERVICING ARRANGEMENTS

The CPUC has approved Servicing Agreements between DWR and SDG&E and between DWR and SCE. The CPUC has adopted the PG&E Servicing Order pertaining to PG&E. The principal terms of these Servicing Arrangements are described below. The Servicing Arrangements are expected to be amended in connection with the proceedings to allocate DWR's long-term power contracts to the IOUs. See "POWER SUPPLY PROGRAM – Transition of Procurement Responsibility After 2002." These amendments are not expected to materially change any of the provisions of the Servicing Arrangements described below. In addition, DWR covenants in the Indenture not to voluntarily consent to or permit any amendment of any Servicing Arrangement unless DWR determines that the amendment will not have a material adverse affect on the ability of DWR to comply with the provisions of the Indenture.

General. The IOUs own the infrastructure, personnel and customer information required to transmit and distribute power, and to bill and collect Bond Charges and Power Charges (collectively, the "IOU Services"). Accordingly, arrangements with the IOUs for IOU Services are necessary to collect Revenues and conduct DWR's Power Supply Program. Under the Act, the CPUC is required to order the IOUs to provide IOU Services upon request of DWR.

Term. The stated termination date of each IOU's Servicing Arrangement is 180 days after the final Bond Charges and Power Charges are imposed in the IOU's service territory. DWR has the right to terminate a Servicing Agreement following an "Event of Default" by the IOU (see "*Events of Default*" below). DWR does not have the right to terminate the PG&E Servicing Order. The PG&E Servicing Order will remain in effect until

the CPUC terminates the order to perform the IOU Services. The IOUs do not have the right to terminate a Servicing Arrangement.

Transmission and Distribution Services. Each IOU is bound by its Servicing Arrangement to transmit and distribute power supplied by DWR in accordance with the Servicing Arrangement, the Act, other applicable laws, CPUC rules and regulations and agreements between the IOU and DWR. The Servicing Arrangements do not obligate the IOUs to construct high voltage transmission improvements.

Exchange of Information. Because the IOUs and DWR each currently supply a portion of the daily electrical demand of the customers, coordination of DWR's power supply resources and the IOUs' resources is necessary. In furtherance of that coordination, each Servicing Arrangement provides for the daily exchange of information between the IOU and DWR.

Metering, Billing and Collection Services. Each of the IOUs is to provide metering services, meter reading services, billing services, and collection services for DWR. Each IOU is to follow its customary standards, policies and procedures in performing these services, which are regulated by the CPUC. DWR charges are included in the IOUs' regular billing statements. The IOUs will not permit customers to direct how partial payments of balances due on consolidated bills will be applied; each IOU will allocate partial payments from customers based upon the same proportion that DWR's charges bear to total charges on the consolidated bills. Each IOU will collect DWR's charges and its own charges from customers using its own collection practices and disconnection policies (all of which are subject to CPUC regulation). Risk of nonpayment is borne by the IOUs and DWR proportionately. DWR does not consider nonpayment by customers to be a material risk to Bondholders because historical levels of uncollectible charges have been and will be accounted for in the calculation of DWR's Revenue Requirements. See "Collection Experience" below.

Calculation and Remittance of Revenues. The IOUs will remit amounts collected for Bond Charges and Power Charges to DWR on a daily basis. The amounts due will generally be calculated as the applicable charge multiplied by the amount of energy upon which such charge is applied, adjusted for or reflecting collection experience. Due to a number of technical limitations, the IOUs will remit revenues to DWR for each day on an estimated basis, and will reconcile the estimated remittances and the actual amounts due approximately 90 days later. The reconciliations could result in refunds to the IOUs of overpaid amounts or in additional remittances to DWR. The technical limitations which necessitate this method of remittance include the unavailability, for up to 90 days, of precise data on the respective quantities of energy delivered by DWR and the IOUs on a particular day; and limitations in the billing and accounting systems of the IOUs, among others.

Charges Payable by DWR to IOUs. Under the Servicing Arrangements, the IOUs are entitled to recover the reasonable costs of providing the IOU Services. DWR pays each IOU for the incremental costs of metering, meter reading, billing, collection and other IOU Services. All of the foregoing costs will be included by DWR in its Revenue Requirements filings with the CPUC and recovery will be sought from customers through DWR charges. Delinquent payments by DWR will bear interest at a variable interest rate equal to three percent plus the prime lending rate of a commercial bank named in each Servicing Arrangement.

Amounts Due DWR Held in Trust. Each Servicing Arrangement provides that all amounts required to be remitted to DWR by the IOU shall be held by the IOU in trust for DWR and shall be remitted to DWR, subject to periodic adjustment, as described above in "*Calculation and Remittance of Revenues.*"

Assignment to Trustees. Each Servicing Arrangement permits DWR to assign or pledge its rights to receive payments from the IOU to the Trustees under the Indenture to secure DWR's obligations thereunder. DWR has irrevocably assigned its rights to customer payments under each Servicing Arrangement under the Indenture. DWR also has the right under each Servicing Arrangement to transfer its rights and obligations to any entity created by the California Legislature to assume the rights and obligations of DWR under the Act.

Events of Default. Each Servicing Agreement lists "Events of Default" by the IOU that include any failure to remit funds to DWR that continues unremedied for three days and certain failures to observe or perform under the Servicing Arrangement. Upon any Event of Default, DWR may, in addition to exercising its remedies under the Servicing Agreement, terminate the Servicing Agreement (see "*Term*" above*),* and apply to the CPUC (and, if necessary, a court) for sequestration and payment to DWR or the Trustees of amounts due DWR under the Servicing Arrangement.

Each Servicing Arrangement also states that DWR will be in default under the Servicing Arrangement if DWR fails to perform any of a number of duties listed in the Servicing Arrangement, including the failure to pay the IOU money when due. Upon any default by DWR, the IOU may not terminate the Servicing Arrangement in whole or in part or any obligation thereunder, but the IOU may exercise any other remedies available under the Servicing Arrangement, the Act, and other applicable laws, rules and regulations.

Force Majeure Clause. Each Servicing Arrangement includes a *force majeure* clause that provides that neither DWR nor the IOU is liable for any delay or failure in performance of any part of the Servicing Arrangement (including the obligation to remit money at the times therein specified) from any cause beyond its reasonable control, including but not limited to: unusually severe weather; flood; fire; lightning; epidemic; quarantine restriction; war; sabotage; act of a public enemy; earthquake; insurrection; riot; civil disturbance; strike; restraint by court order or any nation or government, any state or other political subdivision of a state, and any entity exercising executive, legislative, judicial, regulatory or administrative functions of or pertaining to a government, including the CPUC; or any combination of these causes, which by the exercise of due diligence and foresight DWR or the IOU could not reasonably have been expected to avoid and which by the exercise of due diligence is unable to overcome. Notwithstanding these provisions, each party's obligation to pay money under the Servicing Arrangement continues to the extent such party is able to make such payment and any amounts required to be remitted to DWR by the IOU shall be held by the IOU in trust for DWR and remitted to DWR as soon as reasonably practicable. Amounts so paid to or by DWR pursuant to the *force majeure* clause shall not bear interest. Each Servicing Arrangement states that seeking the protection of or being forced into bankruptcy is not a *force majeure* event that excuses timely IOU performance of its Servicing Arrangement.

Audits. DWR has the right under each Servicing Arrangement to request an audit, conducted by DWR, of each IOU's records and procedures. Each Servicing Arrangement also requires each IOU to employ independent accountants to audit annually the compliance of the IOU with its obligations to DWR under its Servicing Arrangement. A copy of each report of the independent accountants is to be provided to DWR and the CPUC.

Other Important Provisions. Other important provisions are contained in the Servicing Arrangements, which are available as described under "GENERAL INFORMATION."

Descriptions of Servicers. None of the IOUs is obligated to use its own funds to make payments to DWR. See "GENERAL INFORMATION" for sources of information about the IOUs. A brief description identifying each IOU is as follows.

- PG&E is a wholly owned subsidiary of PG&E Corporation and is headquartered in San Francisco. PG&E is the largest investor-owned utility in the nation, providing natural gas and electric service to approximately 4.5 million accounts. Its service area covers approximately 70,000 square miles in northern and central California. See "LITIGATION AND ADMINISTRATIVE PROCEEDINGS – Litigation Pending or Threatened in State and Federal Courts – *Pacific Gas and Electric Bankruptcy*."

- SCE is a wholly owned subsidiary of Edison International and is headquartered in Rosemead. SCE provides natural gas and electric service to approximately 4.3 million accounts. Its service area is approximately 50,000 square miles in central, coastal and southern California.

- SDG&E is a wholly owned subsidiary of Sempra Energy and is headquartered in San Diego. SDG&E provides electric service to approximately 1.3 million accounts. Its service area covers approximately 4,100 square miles in San Diego County and southern Orange County.

Collection Experience. The following table illustrates the collection experience of the IOUs for the last five years as reported on filings made by the IOUs with FERC.

Servicer	1997	1998	1999	2000	2001
PG&E					
Operating revenues	$7,699,953,520	$7,178,147,254	$7,229,071,782	$6,856,562,309	$7,347,247,921
Uncollectible amounts	$22,824,475	$8,006,400	$13,600,782	$14,449,286	$18,383,872
Percent	0.3%	0.1%	0.2%	0.2%	0.3%
SDG&E					
Operating revenues	$1,776,255,221	$1,866,800,599	$1,500,005,478	$2,159,164,231	$1,624,648,749
Uncollectible amounts	$2,687,000	$5,932,795	$2,473,480	$4,983,503	$7,531,102
Percent	0.2%	0.3%	0.2%	0.2%	0.5%
SCE					
Operating revenues	$7,933,448,828	$7,382,750,715	$7,330,584,038	$7,695,586,360	$8,035,505,738
Uncollectible amounts	$20,597,107	$19,808,408	$21,968,749	$24,017,070	$28,926,767
Percent	0.3%	0.3%	0.3%	0.3%	0.4%

LITIGATION AND ADMINISTRATIVE PROCEEDINGS

No litigation is pending against DWR (with service of process on DWR having been accomplished) in any federal or state court or threatened against DWR, nor is DWR a party in any administrative proceeding pending before any administrative body, nor is any administrative proceeding pending before DWR, which (i) seeks to restrain or enjoin the sale or delivery of the Series 2002A Bonds or the performance by DWR of the purchase contract for the Series 2002A Bonds, (ii) challenges the constitutionality, validity or enforceability of the Indenture, the pledge of the Trust Estate, the Rate Agreement or any other document or approval necessary to the issuance of the Series 2002A Bonds, (iii) challenges the existence, organization or powers of DWR to adopt, execute and deliver the Indenture or the Rate Agreement or perform DWR's obligations under the Indenture or, except as described below, under the Rate Agreement, or (iv) challenges the constitutionality or validity of the Act or the powers of DWR thereunder.

There are litigation and administrative proceedings pending or threatened which may affect DWR's ability to perform certain of its obligations under the Rate Agreement. Certain pending legal and administrative proceedings involving DWR or affecting DWR's Power Supply Program are summarized below. See also "RATEMAKING AND RELATED ACTIONS – DWR Actions to Establish Revenue Requirements" and "RISK FACTORS – Determination of Power Charges and Bond Charges; Possible Use of Amounts in the Bond Charge Collection Account to Pay Priority Contract Costs."

Litigation Pending or Threatened in State and Federal Courts

Actions and Adverse Comments Contesting DWR's Revenue Requirement

In *Pacific Gas and Electric Company v. The California Department of Water Resources, et al.*, filed in August 2001 in Sacramento County Superior Court, (Case number 01CS01200), PG&E contended that when DWR determined that its revenue requirement for 2001-2002 was "just and reasonable" (a determination the Act authorizes DWR to make), DWR failed to follow the California Administrative Procedure Act (the "APA"). PG&E also contended, among other things, that DWR's "just and reasonable" determination was arbitrary and capricious because it was based on undisclosed assumptions and projections and was "entirely lacking in evidentiary support." On June 7, 2002, the superior court issued a judgment finding that DWR had failed to

follow the APA in making its "just and reasonable" determination, and ordered DWR to follow the procedures mandated by the APA before making any "just and reasonable" determination. The court's order stated that its ruling does not in any way affect any action taken by the CPUC, including the enforcement and collection of certain existing rates and charges based on a CPUC order implementing cost recovery of DWR's 2001-2002 revenue requirement (CPUC Decision 02-02-052, issued February 22, 2002), and that the court had determined that it did not need to address the remainder of PG&E's contentions at that time. DWR filed a notice of appeal on August 6, 2002, and this matter is now pending before the California Court of Appeal, Third Appellate District, as Case no. C041076.

Among the comments submitted by various parties on DWR's proposed revenue requirement for 2003 (and its re-examination and re-determination for 2001 and 2002) were comments by SCE which included a comment that before submitting a final revenue requirement for 2003 to the CPUC, DWR should comply with the APA and provide a meaningful opportunity for public comment to avoid subjecting its revenue requirement determination to legal challenge. In addition, after DWR submitted its revenue requirement for 2003 to the CPUC, PG&E and SCE each requested that DWR reconsider its determination and submitted comments in support of their requests. DWR denied those reconsideration requests on October 8, 2002.

On October 17, 2002, PG&E filed a lawsuit in Sacramento County Superior Court (Pacific Gas and Electric Company v. The California Department of Water Resources, et al., Case no. 02CS01631) concerning the matters cited in PG&E's request for reconsideration of DWR's determination of its revenue requirements for 2003 (and DWR's re-examination and redetermination of its revenue requirements for 2001 and 2002). In its complaint, PG&E contends that DWR was required to but did not comply with the APA, the Act and the Public Utilities Code in making DWR's "just and reasonable" determination, that the Revenue Requirement Regulations do not comply with the APA or the Superior Court's order in the first PG&E v. DWR lawsuit, that DWR did not follow the Revenue Requirement Regulations in making the "just and reasonable" determination, that DWR's "just and reasonable" determination is arbitrary and capricious, lacking in evidentiary support, and contrary to law because it is based on an incomplete record, and that DWR's revenue requirements are "unjust and unreasonable" because they are largely made up of costs under DWR's long-term power contracts which other agencies representing the State, at FERC and in other contexts, have asserted are "unjust and unreasonable" and because the revenue requirements include "unjust and unreasonable" costs for the Bonds. In its complaint, PG&E seeks a writ of mandate directing DWR to withdraw its determination that DWR's revenue requirements are "just and reasonable", to take no action in furtherance of its August 16, 2002 Revenue Requirements, including requesting or imposing its revenue requirements (including those related to power-related costs and bond-related costs) in charges to retail customers, and to comply with the APA and any other applicable statute prior to requesting or imposing its revenue requirements in charges to retail customers. PG&E also seeks a judicial declaration that DWR's determination that its revenue requirements are "just and reasonable" and all actions pursuant to that determination are invalid and void.

The matters raised by this lawsuit were considered by DWR in connection with DWR's decision to deny PG&E's request for reconsideration of DWR's determination and redetermination of its Revenue Requirements for 2001, 2002 and 2003. In DWR's response to PG&E's request, DWR examined these matters and concluded that PG&E had not stated sufficient grounds for reconsideration. DWR believes that its determination and redetermination of such Revenue Requirements and its decision to deny PG&E's request for reconsideration were procedurally lawful and substantively correct.

For a description of those matters, and the potential impacts of adverse judicial decisions affecting DWR's determinations of its revenue requirements, see the sections of the Official Statement entitled "RATEMAKING AND RELATED ACTIONS - DWR Actions to Establish Revenue Requirements," "RISK FACTORS - Determination of Power Charges and Bond Charges; Possible Use of Amounts in the Bond Charge Collection Account to Pay Priority Contract Costs" and the other sections of the Official Statement referred to in those sections. A copy of DWR's October 8, 2002 Response to Requests for Reconsideration, which includes a discussion of these issues and the reasons for such denial, is available on DWR's website. See "GENERAL INFORMATION" in the Official Statement.

Actions Contesting Certain Long-Term Power Contracts

The plaintiffs in the cases discussed below contest the validity of certain of the long-term power contracts, some of which are Priority Long-Term Power Contracts. For a discussion of the effect of a determination of invalidity, see "RISK FACTORS – Certain Risks Associated with DWR's Power Supply Program – *Priority Long-Term Power Contracts*."

In *Carboneau v. State of California et al.*, filed in November 2001 in Sacramento County Superior Court (Case no. 01AS06848), plaintiffs have stated and plead, among other things, that certain named defendants who participated in the negotiation of certain long-term power contracts on behalf of DWR had conflicts of interest, and that in negotiating these contracts defendants engaged in unfair business practices and violated anti-trust laws. Plaintiffs seek declaratory and injunctive relief as well as damages, with a main objective being to have all of those long-term power contracts entered into by DWR since January 2001, declared void as against public policy. On June 12, 2002, the court issued a judgment dismissing this action as to the State and DWR. On August 7, 2002, plaintiffs filed a notice of appeal, and this matter is now pending before the California Court of Appeal, Third Appellate District, as Case no. C041893.

In *McClintock, et. al. v. Budhraja, DWR, et. al.*, filed in May 2002 in Los Angeles County Superior Court (Case no. GC029447), plaintiffs, including eight members of the California State Legislature, allege a DWR consultant involved in negotiating certain long-term power contracts had a conflict of interest, and as a result certain of the long-term contracts are void. The plaintiffs seek, among other things, to restrain or enjoin DWR's performance under the long-term power contracts, a declaration that the contracts are void, an order of restitution of amounts paid by the State to the consultant, and an order of restitution of amounts paid by the State to power providers with knowledge of the conflict. The complaint in this matter has not been served on DWR, and therefore DWR has taken no action in this matter.

In *Millar v. Allegheny Energy, et. al.*, filed in May 2002 in San Francisco City and County Superior Court and now pending in the U.S. District Court, Northern District of California, San Francisco Division as Case no. C02-2855 EMC), plaintiff alleges that the sellers who entered into certain long-term power contracts engaged in unfair and fraudulent business acts and practices, and seeks to enjoin the enforcement of certain unfair and oppressive terms and conditions of the long-term power contracts and restitution of monies wrongfully obtained by the power providers. DWR is named solely as a "nominal defendant", and restitution is not sought from DWR or the State. Plaintiff has moved the district court to remand the action to San Francisco City and County Superior Court, and the court took that motion under submission on August 9, 2002. DWR's response to this action has not been filed, pending determination of this remand motion.

In *Sempra Energy Resources v. Department of Water Resources*, filed in May 2002 in San Diego County Superior Court (Case no. 789291), plaintiff seeks declaratory relief as to the respective rights and duties of plaintiff and DWR under the long-term energy contract between the parties. In July 2002, DWR cross-complained, alleging that Sempra failed to perform its obligations under the contract to build new power plants to help meet the State's long-term energy needs and to expedite permitting and construction of a particular generating facility known as the Elk Hills project, which was agreed-upon by the parties to provide 300 megawatts of power. DWR seeks damages according to proof and either a declaration that the contract is not binding on DWR or that, if the contract is binding on DWR, a declaration that Sempra must build the projects as promised unless commercially unreasonable and an injunction prohibiting Sempra from freely substituting market energy for energy from new sources of generating capacity.

"Block Forward Contracts" Consolidated Actions

In February 2001, during the state of emergency described under "POWER SUPPLY PROGRAM", the Governor, pursuant to his "commandeering" authority under the California Emergency Services Act, issued executive orders "commandeering" power purchase arrangements held by PG&E and SCE, referred to as "block forward contracts." The issue of whether and to what extent compensation is due is now before the Sacramento

County Superior Court in a declaratory relief action filed by the State in September 2001, *People v. ACN Energy, Inc., et al.* (Case no. 01AS05497), which names as defendants those market participants which have and those which, the State believes, might claim compensation as a result of the Governor's actions. Among the defendants named by the State in the declaratory relief action are 31 market participants that previously filed administrative claims in an amount in excess of $1 billion against the State as a result of the Governor's actions. (The administrative agency with which those claims were filed was divested of jurisdiction over those claims by the Sacramento County Superior Court.) In this action the State seeks a declaration that the Governor's "commandeering" of the "block forward contracts" was a legitimate exercise of police powers and that the State is not liable for damages occurring in the exercise of such powers nor for compensation for inverse condemnation, or, alternatively that any damages suffered by any of the defendants is offset by payments made by DWR for electricity received under the "commandeered" "block forward contracts."

Complaints and cross-complaints for inverse condemnation, recovery under the Emergency Services Act and other causes of action brought by PG&E, Reliant Energy Services, Sempra, the PX, Mirant, Duke Energy Trading and Marketing, and a number of other market participants have been joined with the declaratory relief action in Judicial Council Coordination Proceeding No. 4203. This consolidated action is pending in the Sacramento County Superior Court. Duke Energy Trading and Marketing asserts that language in the United States Court of Appeals decision in Duke Energy Trading and Marketing, L.L.C. v. Davis, et al. (9th Cir. 2001) 267 F.3d 1042, in which the court instructed the trial court to enjoin the Governor's "commandeering" orders, should apply to Duke's cross-complaint.

On September 27, 2002, the court granted the State's motion to stay the consolidated actions for six months, in significant part to await the outcome of matters pending before FERC. The motions of several plaintiffs and cross-complainants to modify or lift the stay were denied on November 1, 2002. In addition, notwithstanding the stay, the court has required that the State respond to Duke's cross-complaint.

See "RISK FACTORS – Potential Increases in Electric Rates – *'Block Forward Contracts' Consolidated Actions*" concerning the impact of these proceedings.

Action Seeking Compensation from the State for Breach of Contract

On September 6, 2002, PG&E filed a complaint for breach of contract against the State in the Sacramento County Superior Court, *Pacific Gas and Electric Company v. The State of California* (Case no. 02A505360). PG&E's complaint alleges that statutes enacted in 1996 as part of the restructuring of the electric power industry in California (Statutes of 1995-1996, Chapter 854; Assem. Bill 1890, "AB 1890") authorized PG&E to sell the output of its retained generation facilities in interstate power markets at prices regulated by FERC and to sell the facilities themselves, and that AB 1890 established a "regulatory contract" between the State and PG&E. PG&E further alleges that, by enacting statutes in 2001 (Statutes of 2001-02, First Extraordinary Session, Chapter 2; Assem. Bill 6 X1) that amended portions of AB 1890, the State deprived PG&E of the right to such sales and thereby breached the "regulatory contract" that PG&E claims was established with PG&E in AB 1890. PG&E's complaint seeks damages in an amount to be proven, but in an administrative procedure that preceded this action, in which PG&E's claims were denied by the California Government Claims Board, PG&E sought damages of at least $4.3 billion to compensate for the losses alleged in this action. PG&E has not sought recovery from the Fund, and should any judgment be awarded to PG&E, DWR believes that the Act does not authorize recovery of such judgment from the Fund.

Actions Affecting IOU Rates

DWR is not a party to the following three matters. However, the outcome of these actions could result in increased retail prices of IOU electricity as described under "RISK FACTORS – Potential Increases in Electric Rates."

Pacific Gas and Electric v. Lynch, filed in August 2001, is pending in the U.S. District Court, Northern District of California (Case no. C 01-3023 VRW). PG&E has asked the court for declaratory and injunctive relief compelling the CPUC to permit PG&E to recover in retail rates the costs which it incurred or incurs in the procurement of wholesale electricity. The CPUC and a consumer group filed motions to dismiss PG&E's complaint. The case was transferred to District Court Judge Walker in the Northern District of California as a related case with PG&E's appeal of the bankruptcy court's denial with prejudice of PG&E's request for injunctive and declaratory relief enjoining implementation and enforcement of an accounting order adopted by the CPUC in March 2001 (see Pacific Gas and Electric Company (PG&E) v. Lynch described in the immediately succeeding paragraph, and "*Pacific Gas and Electric Bankruptcy*" below). On July 25, 2002, Judge Walker denied the motions to dismiss and he denied the cross-motions for summary judgment filed by PG&E, the CPUC and a consumer group. On August 23, 2002, the CPUC filed a notice of appeal in the 9th Circuit Court of Appeal, appealing the District Court's denial of the CPUC's motion to dismiss. A trial in this matter, if necessary, has been scheduled for June 9, 2003. This action would be dismissed with prejudice under the plan of reorganization filed by the CPUC and the Official Committee of Unsecured Creditors in the PG&E Bankruptcy (see "Litigation Pending or Threatened in State and Federal Courts – *Pacific Gas and Electric Bankruptcy*").

In April 2001, PG&E filed an adversary proceeding in its bankruptcy proceeding (see "*Pacific Gas and Electric Bankruptcy*" below) to prevent the CPUC and its individual Commissioners from implementing or enforcing an order that required PG&E to make certain transfers between certain regulatory accounts which track PG&E revenues and costs. PG&E asserted, among other things, that implementation and enforcement of the order would violate the automatic stay in bankruptcy and would have the effect of extending the rate freeze then in effect, thereby delaying the time when PG&E can seek rates sufficient to recover its costs of obtaining power. The bankruptcy court dismissed this complaint with prejudice and denied PG&E's motion for preliminary injunction. An appeal and cross-appeals are pending in the U.S. District Court, in *Pacific Gas and Electric Company (PG&E) v. Lynch*, U.S. District Court, Northern District of California (Case no. C 01-2490 VRW). This matter is before the district court as a case related to *Pacific Gas and Electric Company (PG&E) v. Lynch* (Case no. C 01-3023 VRW) described in the immediately preceding paragraph. All briefing has been submitted, and no date has been set for oral argument. On August 14, 2002, the California Supreme Court denied a petition for writ of review filed by PG&E seeking review of an appellate court's denial on the merits of PG&E's challenge to the same Commission order PG&E sought to enjoin in bankruptcy court, Commission Decision 01-03-082 and subsequent Commission Decision 02-01-001(*Pacific Gas and Electric Company v. Public Utilities Commission of the State of California* (Case no. S107812)).

Southern California Edison v. Lynch, filed in November 2000 (Case no. 00-12056 RSWL (Mex)), is now pending in the United States Court of Appeals for the Ninth Circuit (Case nos. 01-56879, 01-56993 and 01-57020, consolidated). SCE had asked the federal district court for declaratory and injunctive relief compelling the CPUC to permit SCE to recover in retail rates all the costs which it incurred or incurs in the procurement of wholesale electricity. The CPUC and SCE entered into a settlement agreement. The district court approved the settlement over the objections of The Utility Reform Network ("TURN"), a nonprofit consumer organization. TURN appealed the stipulated judgment resulting from the settlement. On September 23, 2002, the Ninth Circuit Court of Appeals affirmed the decisions of the district court as to certain questions arising under federal law, but certified to the California Supreme Court certain questions relating to the validity of the settlement agreement under California law. For further information on this settlement, see "POWER SUPPLY PROGRAM -- Background and History."

Pacific Gas and Electric Bankruptcy

In April 2001, PG&E filed a voluntary Chapter 11 bankruptcy petition in U.S. Bankruptcy Court for the Northern District of California, San Francisco Division (*In re Pacific Gas and Electric*, U.S. Bankruptcy Court, N.D. Cal.). The State has filed numerous claims as a creditor of PG&E, including but not limited to, claims for income and property taxes, regulatory fees, fines and penalties and environmental fees, fines and penalties.

DWR has filed administrative claims for post-petition purchases of electricity, arising from the sale of electric energy or services for the customers of PG&E for the period April 7, 2001, through June 30, 2002, in an estimated amount of approximately $396 million. Claims for amounts due for July 2002 and beyond, if any, may be filed and the filed claims will be amended from time to time to reflect additional charges or payments by PG&E. DWR has also filed claims for pre-petition power-related matters in the estimated amount of approximately $171 million. PG&E has objected to DWR's pre-petition claims on the grounds that these amounts are not part of the PG&E bankruptcy estate, but are funds held by PG&E as a collection agent for DWR and that to the extent the claim is for imbalance energy the claim is being paid to DWR pursuant to statute and CPUC decisions. DWR has filed an opposition to PG&E's objection. This matter has been scheduled for hearing on November 27, 2002.

PG&E's proposed plan of reorganization seeks an extensive restructuring of PG&E's business and the transfer of certain of its assets, including its electric and gas transmission assets, to newly created limited liability companies. PG&E maintains that they may take such action without obtaining CPUC approval or complying with other State laws, on the theory that the Bankruptcy Code preempts California law. PG&E's proposed plan contemplates that PG&E will, after reorganization, continue to transmit and distribute DWR power and to bill and collect DWR charges as agent for DWR. The plan states that PG&E will seek to establish conditions to PG&E's resumption of its responsibility for the power currently being provided its customers by DWR, and a ruling to prohibit it from accepting an assignment of any of DWR's long-term power purchase contracts. The bankruptcy court ruled in February 2002 that PG&E must amend its plan to remove relief that is contrary to the State's sovereign immunity or prove that the State has waived its sovereign immunity, and that PG&E must proceed on an implied preemption theory, rather than on an express preemption theory. PG&E appealed the bankruptcy court's decision to the U.S. District Court (*In re Pacific Gas and Electric Company*, Case no. 3: 02-cv-01550 (VRW)) and the CPUC and State agencies, among others, cross-appealed. On August 30, 2002, the U.S. District Court held that the Bankruptcy Code preempted non-bankruptcy laws otherwise applicable to restructuring transactions necessary to an effective and feasible reorganization of a debtor, and on that basis reversed the bankruptcy court's ruling and remanded the matter to the bankruptcy court for action consistent with the District Court's order. The CPUC and State agencies, among others, filed a notice of appeal of the District Court's order with the Ninth Circuit Court of Appeals and a protective motion for a permissive appeal under 28 U.S.C. §1292(b) with the District Court. PG&E filed a notice of nonopposition to the protective motion. The CPUC and the State agencies, among others, also filed a motion for a stay of the District Court's order, which was heard on October 8, 2002 and taken under submission by the District Court. PG&E has filed a motion with the Ninth Circuit Court of Appeals to expedite the briefing and set oral argument in the appeal. The CPUC and State agencies, among others, agreed to the proposed briefing schedule.

The bankruptcy court approved an amended disclosure statement filed with the bankruptcy court prior to the District Court's decision, and that amended disclosure statement was sent to creditors concurrently with the disclosure statement of an alternative plan of reorganization filed by the CPUC. Confirmation objections to both plans have been filed with the bankruptcy court.

On August 30, 2002, the CPUC and the Official Committee of Unsecured Creditors jointly filed an amended plan of reorganization for PG&E, together with a joint motion seeking, among other things, to resolicit votes on preferences for the amended plan of reorganization. On September 20, 2002, the bankruptcy court approved a limited form of resolicitation. Hearings considering confirmation of a plan will begin no earlier than mid-November 2002. For a discussion of the possible effects of the adoption of the PG&E plan of reorganization on DWR's plans to transition from purchasing power for PG&E, see "POWER SUPPLY PROGRAM – Transition of Procurement Responsibility After 2002."

Action Pertaining to Continuous Appropriations of the State's General Fund and State Special Funds

In June, 1998, plaintiffs in *Howard Jarvis Taxpayers Association et. al. v. Kathleen Connell*, plaintiff filed a complaint in the Los Angeles County Superior Court for certain declaratory and injunctive relief challenging the authority of the State Controller to make payments from the State Treasury in the absence of a

state budget. The complaint did not specifically attack DWR, the validity of its special funds or their continuing appropriation. In July 1998, the trial court issued a preliminary injunction prohibiting the Controller from paying moneys from the State Treasury for fiscal year 1998-99, with certain limited exceptions, in the absence of a state budget. The preliminary injunction, among other things, prohibited the Controller from making any payments pursuant to any continuing appropriations.

As permitted by the State Constitution, the Legislature enacted and the Governor signed an emergency appropriation that allowed the continued payment of various state obligations, including debt service. Also, the State Controller and various employee unions filed appeals and sought stays of the preliminary injunction and the preliminary injunction was stayed pending the Court of Appeal's decision on the merits. On May 29, 2002, the Court of Appeal issued its decision that, in relevant part, reversed the preliminary injunction to the extent that it barred the State Controller from disbursing funds pursuant to continuing appropriations. The Controller and several employee unions have filed petitions for review of the Court of Appeal's decision with the California Supreme Court. The Controller's petition does not seek to affect the Court of Appeal's decision pertaining to continuing appropriations. The unions' petitions address employee pay issues. Plaintiffs have not filed a petition for review, but have answered the petitions filed by the Controller and the unions asserting that the case below is not moot, though the plaintiffs also state that they are satisfied with the injunction as modified by the Court of Appeal. On August 14, 2002, the California Supreme Court granted petition for review (Case no. S108099), and ordered that the stay issued by the Court of Appeal shall remain in effect.

Action Seeking to Revise the CAISO's Governing Board

On August 16, 2002, the FERC filed a complaint for declaratory judgment and injunctive relief in the U.S. District Court for the District of Columbia (Case no. 1:02cv01625) seeking an order mandating the CAISO to comply with orders issued by the FERC that directed the CAISO to take certain steps to reorganize the CAISO Board. The FERC also seeks a judgment declaring that the governance provisions of the CAISO tariff fall within the exclusive jurisdiction of the FERC; that the creation, composition and continued operation of the current CAISO Board under State law is unlawful; and that failure to comply with certain orders of the FERC will constitute violations of federal law and subject the CAISO to penalties.

Action Seeking Termination of State of Emergency

On October 9, 2002, a petition for writ of mandate entitled *The National Tax-Limitation Committee, et al. v. Davis, et al*., was filed in Sacramento County Superior Court (Case number 02CS01567). Petitioners in this matter allege that California is no longer in a state of emergency relative to electric power, and request the court to issue an alternative writ of mandate requiring the Governor "to terminate his declaration of the emergency and the exercise of all powers flowing therefrom, including, but not limited to, the purchase of electricity or the negotiation of contracts therefor."

The Series 2002 Bonds are being issued pursuant to the authority conferred by the Act and not in reliance upon the Governor's declaration of emergency or any executive orders issued thereunder.

FERC Administrative Actions

Actions Contesting Certain Long-Term Power Contracts

The administrative actions described below challenge aspects of certain of the long-term power contracts, some of which are Priority Long-Term Power Contracts. For a discussion of the effect of a determination of invalidity as to one or more of DWR's long-term power contracts, see "RISK FACTORS – Certain Risks Associated with DWR's Power Supply Program – *Priority Long-Term Power Contracts*."

The CPUC and the California Electricity Oversight Board ("CEOB"), a State agency established to protect public interests concerning the restructured electricity industry and authorized to represent the State before

FERC, have filed complaints with FERC challenging the just and reasonable nature of certain of the long-term power contracts (FERC Docket nos. EL02-60 and EL02-62, respectively). The CEOB's complaint seeks an order that the contracts are voidable at the State's option or, alternatively, abrogation of the contracts and the CPUC's complaint seeks abrogation of the contracts. Both complaints alternatively seek reformation of the contracts to provide for just and reasonable pricing and a reduction in duration and reformation of certain non-price terms and conditions. On April 25, 2002, FERC required that the parties first engage in settlement proceedings to attempt to achieve resolution prior to the matter going to hearing. The CPUC and the CEOB have withdrawn their complaints against certain generators with whom settlement negotiations have resulted in renegotiated contracts, and a small number of contracts are proceeding to hearing. Should the remaining contracts be determined by FERC to not be just and reasonable or in the public interest, it could result in a decrease of the rates or other changes to the terms and conditions of those contracts prospectively from April 26, 2002. A trial-type hearing is currently scheduled to commence with respect to non-settling respondents on December 2, 2002.

A consumer group, Californians for Renewable Energy (CARE) has requested that FERC reject certain of DWR's long-term power contracts in FERC Docket no. EL00-95. On November 5, 2001, the FERC administrative law judge rejected CARE's request, ruling that the request was beyond the scope of the proceeding. On January 2, 2002, CARE renewed its request for rejection of DWR's long-term power contracts.

On February 13, 2002, in Docket no. PA02-2, the FERC directed a staff investigation into whether any entity, including Enron Corporation (through any of its affiliates or subsidiaries), manipulated prices in the electric or natural gas markets in the western United States. This inquiry is ongoing. FERC issued a preliminary report commencing additional hearings and investigations on August 13, 2002. Should this investigation lead the FERC to determine that the DWR long-term power contracts are not just and reasonable or in the public interest, it could result in a decrease of the rates or other changes to the terms and conditions of those contracts.

Actions Requiring DWR to Pay for Power Ordered for PG&E and SCE

In November 2001, FERC issued an order (97 FERC ¶61,151 in FERC Docket nos. ER01-3013 and ER01-889), directing the CAISO to require payment of certain amounts from DWR in relation to costs incurred by the CAISO for which DWR was the creditworthy counterparty for PG&E and SCE. DWR has paid the invoices under protest, alleging that certain of the amounts due are incorrectly calculated and that others represent costs DWR should not be required to pay. On rehearing, FERC issued a subsequent order on March 27, 2002 (98 FERC ¶61,355), which determined that the ISO's invoice to DWR was insufficiently explained and required the CAISO to submit a detailed compliance filing, which was made on April 17, 2002, and supplemented by DWR on May 20, 2002. These payment matters are still the subject of this administrative action. Reimbursement to DWR for amounts DWR has paid under dispute has been ordered by the CPUC and a substantial portion of such reimbursement has been received by DWR.

The City of Redding has filed a rehearing request of the March 2002 order, arguing that DWR should pay for energy acquired prior to the existence of DWR's Power Supply Program. FERC action on this request is pending. Two power sellers have contended that the CAISO misallocated DWR payments to portions of January 2001 pre-dating the inception of the Power Supply Program. Those power sellers are seeking additional amounts totaling $58 million to the extent that the CAISO fails to distribute funds to them to correct this misallocation and to address other shortfalls, which may be attributable to other CAISO creditors' nonpayment.

FERC Docket no. ER02-651 relates to the CAISO's allocation of certain interest payments made by DWR. DWR alleged that the CAISO had applied interest payments made by DWR to periods predating the existence of DWR's Power Supply Program. In June 2002, the FERC ordered CAISO to file new tariff language, and in response, CAISO made a compliance filing in July 2002, stating that it would re-distribute default interest. Power sellers have also used this forum to assert the CAISO's misallocation of DWR payments, contending that the CAISO's response in this docket only increases the amounts claimed as described in the paragraph immediately above.

RISK FACTORS

This section of the Official Statement describes certain risk factors that may affect the payment of and security for the Bonds. Potential investors should consider, among other matters, these risk factors in connection with any purchase of the Series 2002A Bonds. The following discussion is not meant to present an exhaustive list of the risks associated with the purchase of any Series 2002A Bonds (and other considerations that may be relevant to particular investors) and does not necessarily reflect the relative importance of the various risks. Potential investors are advised to consider the following factors, along with all other information contained or incorporated by reference in this Official Statement, in evaluating whether to purchase the Series 2002A Bonds.

Determination of Power Charges and Bond Charges; Possible Use of Amounts in the Bond Charge Collection Account to Pay Priority Contract Costs

DWR's Bond Related Costs (including debt service on the Bonds) are payable primarily from Bond Charges, while DWR's Power Supply Program operating expenses (including Priority Contract Costs) are payable primarily from Power Charges. Bond Charges and Power Charges are established through an administrative process and, as part of that process, are subject to administrative and legal challenges by third parties. Several such challenges are currently pending. DWR believes that the possibility is remote that DWR would be prevented, as a result of these challenges and the other circumstances described below, from paying debt service on the Bonds and other Bond Related Costs when due. There can be no guarantee, however, that such circumstances would not materially and adversely affect the ability of DWR to pay debt service on the Bonds and other Bond Related Costs when due.

Unsettled Administrative Process

The administrative process for the calculation, revision and imposition of Bond Charges and Power Charges and the actions taken by DWR and the CPUC to date pursuant to that process (including DWR's determination of its Revenue Requirements for 2003 and its redetermination of its Revenue Requirements for 2001 and 2002) are described under "RATEMAKING AND RELATED ACTIONS."

The Rate Agreement requires DWR, as part of the administrative process, periodically to determine and submit its Retail Revenue Requirements and information concerning its Bond Related Costs (collectively referred to herein as DWR's "Revenue Requirements") to the CPUC. Under the Rate Agreement, DWR agrees that prior to including any cost in its Retail Revenue Requirements, DWR "will conduct whatever procedures are required by law to determine that such cost is just and reasonable within the meaning of Section 451 of the California Public Utilities Code." The Act does not specify what, if any, procedures may be required with respect to any such determination; and neither the Act nor Section 451 of the California Public Utilities Code specifies what "just and reasonable" means in the context of the Power Supply Program. These unsettled issues are the subject of current legal and administrative proceedings (see "Administrative and Legal Challenges to DWR's Revenue Requirements" below) and may be the subject of additional, future legal and administrative challenges as well.

The receipt of Power Charge Revenues for energy sold by DWR after the end of 2002, and the commencement of receipt of Bond Charge Revenues for any period, each depend on CPUC actions yet to be taken. On September 19, 2002, the CPUC adopted an order to the effect that the charges authorized by the February 21, 2002 CPUC order for calendar year 2002 will continue in effect until further action by the CPUC (expected to be taken in connection with the imposition of Power Charges to recover DWR's Retail Revenue Requirement for the calendar year 2003). PG&E filed an application for rehearing of the decision adopting such order. The CPUC denied that request on October 21, 2002. See "RATEMAKING AND RELATED ACTIONS – CPUC Actions to Calculate, Revise and Impose Bond Charges and Power Charges."

DWR covenants in the Indenture to take all legally available action which, in the judgment of DWR, may be necessary or desirable to assure that a regulatory or judicial investigation of, or challenge to, any action taken by DWR in the performance of its obligations under the Act, the Indenture or the Rate Agreement will not result

in the inability of DWR to pay amounts payable under the Bonds and Parity Obligations when due. In accordance with this covenant, DWR intends to defend vigorously its right to recover its Revenue Requirements and the steps taken by it with respect to its Revenue Requirement determinations. As noted elsewhere, however, DWR, the CPUC and other State agencies are already involved in litigation and administrative proceedings that could affect the Power Supply Program, the Bonds and the California energy market generally. See "LITIGATION AND ADMINISTRATIVE PROCEEDINGS." It is possible that the legal positions being taken in such proceedings may limit or otherwise affect the legal positions that might be taken by DWR or on its behalf in defending its right to recover its Revenue Requirements.

Administrative and Legal Challenges to DWR's Revenue Requirements

Certain of the litigation and administrative proceedings that are currently pending concern the administrative processes that DWR has followed to date relating to its Revenue Requirements and its determinations that the costs included in its Revenue Requirements are "just and reasonable." DWR's November 5, 2001 determination of its Revenue Requirements for 2001 and 2002 is the subject of litigation currently on appeal by DWR from a superior court judgment adverse to DWR. See "LITIGATION AND ADMINISTRATIVE PROCEEDINGS - Litigation Pending or Threatened in State and Federal Courts – *Actions and Adverse Comments Contesting DWR's Revenue Requirements*." DWR's August 16, 2002 determination of its Revenue Requirements for 2003 and the redetermination of its Revenue Requirements for 2001 and 2002, submitted to the CPUC on August 19, 2002, have been challenged administratively by PG&E, SCE and other parties. Those parties have asserted, among other things, that DWR's administrative process (including the procedures established by DWR's Revenue Requirement Regulations) did not comply with the requirements of the California Government Code governing such matters, that DWR did not provide adequate support and justification for its determinations that its Revenue Requirements are "just and reasonable", and that certain of DWR's costs included in its Revenue Requirements are not "just and reasonable." PG&E and SCE each requested reconsideration by DWR of DWR's August 16, 2002 determination and redetermination of its Revenue Requirements for 2001, 2002 and 2003. On October 8, 2002, DWR denied those requests for reconsideration. See "RATEMAKING AND RELATED ACTIONS - DWR Actions to Establish Revenue Requirements - Proceedings Under Revenue Requirement Regulations." Additional litigation may be brought to challenge DWR's Revenue Requirements and its "just and reasonable" determinations. DWR believes that DWR would prevail in legal proceedings, if any, that may be brought to force a judicial review of DWR's determination.

On October 17, 2002, PG&E filed a lawsuit in Sacramento County Superior Court (Pacific Gas and Electric Company v. The California Department of Water Resources, et al., Case no. 02CS01631) concerning the matters cited in PG&E's request for reconsideration of DWR's determination of its revenue requirements for 2003 (and DWR's re-examination and redetermination of its revenue requirements for 2001 and 2002). In its complaint, PG&E contends that DWR was required to but did not comply with the APA, the Act and the Public Utilities Code in making DWR's "just and reasonable" determination, that the Revenue Requirement Regulations do not comply with the APA or the Superior Court's order in the first PG&E v. DWR lawsuit, that DWR did not follow the Revenue Requirement Regulations in making the "just and reasonable" determination, that DWR's "just and reasonable" determination is arbitrary and capricious, lacking in evidentiary support, and contrary to law because it is based on an incomplete record, and that DWR's revenue requirements are "unjust and unreasonable" because they are largely made up of costs under DWR's long-term power contracts which other agencies representing the State, at FERC and in other contexts, have asserted are "unjust and unreasonable" and because the revenue requirements include "unjust and unreasonable" costs for the Bonds. In its complaint, PG&E seeks a writ of mandate directing DWR to withdraw its determination that DWR's revenue requirements are "just and reasonable", to take no action in furtherance of its August 16, 2002 Revenue Requirements, including requesting or imposing its revenue requirements (including those related to power-related costs and bond-related costs) in charges to retail customers, and to comply with the APA and any other applicable statute prior to requesting or imposing its revenue requirements in charges to retail customers. PG&E also seeks a judicial declaration that DWR's determination that its revenue requirements are "just and reasonable" and all actions pursuant to that determination are invalid and void.

The matters raised by this lawsuit were considered by DWR in connection with DWR's decision to deny PG&E's request for reconsideration of DWR's determination and redetermination of its Revenue Requirements for 2001, 2002 and 2003. In DWR's response to PG&E's request, DWR examined these matters and concluded that PG&E had not stated sufficient grounds for reconsideration. DWR believes that its determination and redetermination of such Revenue Requirements and its decision to deny PG&E's request for reconsideration were procedurally lawful and substantively correct.

For a description of those matters, and the potential impacts of adverse judicial decisions affecting DWR's determinations of its revenue requirements, see the sections of the Official Statement entitled "RATEMAKING AND RELATED ACTIONS - DWR Actions to Establish Revenue Requirements," "RISK FACTORS - Determination of Power Charges and Bond Charges; Possible Use of Amounts in the Bond Charge Collection Account to Pay Priority Contract Costs" and the other sections of the Official Statement referred to in those sections. A copy of DWR's October 8, 2002 Response to Requests for Reconsideration, which includes a discussion of these issues and the reasons for such denial, is available on DWR's website. See "GENERAL INFORMATION" in the Official Statement.

Litigation may prevent DWR from including Priority Contract Costs in its Retail Revenue Requirement

DWR's Priority Long-Term Power Contracts require that payments by DWR under those contracts (including any termination payments that may be payable by DWR) are payable prior to payment of debt service on the Bonds. See "PRIORITY LONG-TERM POWER CONTRACTS." Accordingly, in the Indenture, DWR's pledge and assignment of its revenues from Bond Charges (and other funds available in the Bond Charge Collection Account) are subject to possible prior use for payment of Priority Contract Costs, as explained under "SECURITY FOR THE BONDS." The use of amounts on deposit in the Bond Charge Collection Account to pay Priority Contract Costs could occur, particularly if current or future judicial review of DWR's determination of its Revenue Requirements were to result in DWR being prevented from including in its Retail Revenue Requirement all of its actual power costs or other operating expenses because any such costs or expenses were held not to be "just and reasonable."

In the Consultant's Report, the Consultant has concluded that Power Charges can reasonably be expected to be collected in amounts that, together with other revenues deposited in the Operating Account and reserve funds in the Operating Reserve Account under the Indenture, will be sufficient to pay the Priority Contract Costs without reliance on transfers from the Bond Charge Collection Account held under the Indenture, and to pay other DWR costs. See APPENDIX A – "CONSULTANT'S REPORT -Conclusions." In reaching this conclusion, however, the Consultant has assumed, among other things, that all costs included in Retail Revenue Requirements submitted to the CPUC by DWR to be recovered through Power Charges and Bond Charges will be "just and reasonable", to the extent required by the Act or the Rate Agreement. See APPENDIX A – "CONSULTANT'S REPORT – Principal Assumptions and Considerations."

In the event that Power Charges imposed by the CPUC based on DWR's Retail Revenue Requirements and other amounts on deposit in the Operating Account are not sufficient to recover all of DWR's Priority Contract Costs, the Indenture requires that amounts be transferred from the Operating Reserve Account to pay Priority Contract Costs. See "SECURITY FOR THE BONDS – Operating Account" and "- Operating Reserve Account."

If a court were to determine that any of DWR's Priority Contract Costs were not "just and reasonable", DWR were prevented from including such Priority Contract Costs in its Retail Revenue Requirements and DWR were nevertheless obligated to pay such Priority Contract Costs, amounts in the Operating Account and Operating Reserve Account may be insufficient to pay such Priority Contract Costs and, as a result, the Indenture would require amounts to be transferred from the Bond Charge Collection Account to pay such Priority Contract Costs. See "SECURITY FOR THE BONDS – Accounts and Flow of Funds under the Indenture."

Application and Enforcement of CPUC's Bond Charge Rate Covenant

Under the Rate Agreement, the CPUC covenants to calculate, revise and impose from time to time, Bond Charges sufficient to provide moneys so that amounts available for deposit in the Bond Charge Payment Account under the Indenture from time to time, together with amounts on deposit in the Bond Charge Payment Account, are at all times sufficient to pay or provide for the payment of debt service on the Bonds and all other Bond Related Costs when due in accordance with the Indenture and other financing documents (the "CPUC's Bond Charge Rate Covenant"). The Rate Agreement provides that this covenant shall have the force and effect of a "financing order" under the California Public Utilities Code and shall be irrevocable and enforceable in accordance with its terms, including, without limitation, in circumstances in which DWR has breached its obligations under the Rate Agreement or in respect of the Financing Documents. The CPUC decision adopting the Rate Agreement is final and unappealable under California law. Under the California Public Utilities Code, a "financing order" is binding upon the Commission as it may be constituted from time to time, and the Commission shall have no authority to rescind, alter or amend its obligations thereunder. Under the Act, the rights, powers and duties of the Commission may not be diminished or impaired in a manner which would adversely affect the interests or rights of Bondholders. See "SECURITY FOR THE BONDS – Bond Related Costs," "SOURCES OF FUNDS TO PAY DEBT SERVICE – Rate Agreement" and "RATE COVENANTS."

Under the Indenture, DWR is obligated to "take such actions as shall be necessary and available to enforce all of the obligations required to be performed under [the] Rate Agreement by the [CPUC]." The Indenture further provides that DWR "shall commence such proceedings and take such other actions as may be necessary to assure compliance by the [CPUC] with the [CPUC's Bond Charge Rate Covenant] in the event that Bond Charge Revenues are applied to the payment of Priority Contract Costs for any reason." See APPENDIX C – "SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE – Protection of Security."

However, any case involving interpretation or enforcement of the Rate Agreement would be the first case considering certain of the relevant legal questions under California law. Despite the terms of the Rate Agreement, it is possible that a court might, if asked to order the CPUC to comply with the CPUC's Bond Charge Rate Covenant, decline to give effect to the Rate Agreement in accordance with its literal terms if the effect of so doing would be to permit the recovery by DWR of power or bond costs that had been determined previously (in a legal challenge against DWR) not to be "just and reasonable." Any such court action could adversely affect the amount of revenues, including Bond Charge Revenues, available for the payment of the Bonds.

Transfer of amounts from the Bond Charge Collection Account to pay Priority Contract Costs could, in the absence of a sufficient increase in Bond Charges, result in a shortage of funds available in the Bond Charge Collection Account for transfer to the Bond Charge Payment Account for payment of debt service on the Bonds. Pursuant to the Indenture, if such a shortage occurred, any amounts available in the Debt Service Reserve Account would be used to pay debt service on the Bonds. There can be no assurance that the amount in the Debt Service Reserve Account would be sufficient in all such events to pay debt service on the Bonds and other Bond Related Costs. See "SECURITY FOR THE BONDS – Debt Service Reserve Account."

DWR's Assessment of these Risks

DWR believes, in light of (i) its determination that the costs included in its Revenue Requirements for 2001, 2002 and 2003 (as submitted to the CPUC on August 19, 2002) are "just and reasonable", (ii) the provisions of the Act to the effect that DWR is entitled to recover, as a revenue requirement, amounts and at the times necessary to enable it to pay the costs listed in the Act, including debt service on bonds, power purchase costs, reserves determined by DWR to be appropriate, repayment of the General Fund and DWR administrative costs, (iii) the Consultant's conclusion described above, (iv) the operating reserves established under the Indenture, (v) the CPUC's Bond Charge Rate Covenant, and (vi) the debt service reserves established under the Indenture, that the possibility is remote that DWR would be prevented, as a result of the circumstances described above, from paying debt service on the Bonds and other Bond Related Costs when due. There can be no guarantee,

however, that such circumstances would not materially and adversely affect the ability of DWR to pay debt service on the Bonds and other Bond Related Costs when due.

Collection of Bond Charges and Power Charges

DWR has entered into Servicing Agreements with SCE and SDG&E under which SCE and SDG&E are each required to collect Bond Charges and Power Charges from customers and remit collections to DWR. PG&E has not entered into a servicing agreement with DWR. On May 16, 2002, the CPUC issued the PG&E Servicing Order, which is now final and unappealable, under which PG&E is required to collect Bond Charges and Power Charges from customers and remit collections to DWR on terms comparable to the terms of the Servicing Agreements with SCE and SDG&E. SCE, SDG&E and PG&E receive compensation for their respective services. See "SERVICING ARRANGEMENTS" and "RATEMAKING AND RELATED ACTIONS – CPUC Actions to Approve and Impose Servicing Arrangements." The PG&E Servicing Order could be challenged by PG&E in its bankruptcy proceedings. See "Bankruptcy Risks – *Potential Impact of PG&E Bankruptcy Proceedings on PG&E Servicing Order*" below and "LITIGATION AND ADMINISTRATIVE PROCEEDINGS – Litigation Pending or Threatened in State and Federal Courts – *Pacific Gas and Electric Bankruptcy*." The PG&E Servicing Order is in full force and effect, and PG&E is obligated by California law to comply with the PG&E Servicing Order unless and until the PG&E Servicing Order is reversed or modified by the CPUC or any similar action is taken by the bankruptcy court in PG&E's bankruptcy proceedings.

DWR does not have the personnel, equipment or customer information necessary to bill and collect Bond Charges and Power Charges from customers or to transmit and distribute power to customers (defined above as the "IOU Services") as described under "SERVICING ARRANGEMENTS" and is dependent upon the IOUs to provide the IOU Services. DWR believes there are no alternate servicers currently available, that alternate servicers may not be available in the future, and that it may not be feasible for any such servicers to perform effectively the IOU Services. Moreover, even if an acceptable alternate servicer is identified, the transfer of responsibilities under a Servicing Arrangement also would require regulatory approval from the CPUC, which might not be granted or which could result in additional delay. Accordingly, if one or more IOUs fails to perform or is excused by a court from performing under the Servicing Arrangements, DWR could experience a substantial delay in obtaining, or be unable to obtain, replacement services from an alternate source. A bankruptcy of SCE or SDG&E could also lead to termination of its Servicing Agreement (see "Bankruptcy Risks – *Potential Rejection of Servicing Agreements or Other Disruption of Servicing Arrangements*" below). Any such problems could adversely affect the cash flow for the Power Supply Program and, ultimately, the ability of DWR to pay debt service on the Bonds. See "PLAN OF FINANCE" and "SECURITY FOR THE BONDS – Accounts and Flow of Funds under the Indenture" for information concerning reserve accounts established and required to be maintained under the Indenture to mitigate the impact of any cash flow shortfalls.

Bankruptcy Risks

Uncertainty as to Outcome of PG&E Bankruptcy

PG&E and its parent, PG&E Corp., have filed a joint plan of reorganization (defined above as the "PG&E Plan"). In addition, the CPUC and the Official Committee of Unsecured Creditors have filed an alternative plan of reorganization (defined above as the "CPUC Plan"). Hearings considering confirmation of the plans are expected to begin no earlier than mid-November 2002. The bankruptcy court can confirm only one plan, and could decline to confirm both plans. See "POWER SUPPLY PROGRAM – Background and History." If the bankruptcy court declines to confirm both plans, either PG&E, the CPUC, another party in interest, or any combination of the foregoing could file another plan of reorganization. Because any plan of reorganization will be confirmed after issuance of the Bonds, DWR cannot accurately predict what the confirmed PG&E plan of reorganization will provide.

Effect of IOU Bankruptcy on Remittance to DWR of Revenues From Bond Charges and Power Charges

DWR believes that all revenues from Bond Charges and Power Charges are the property of DWR and held in trust for DWR by the IOUs for all California law and federal bankruptcy law purposes. The Rate Agreement and the Act provide that Bond Charges and Power Charges are the property of DWR for all purposes under California law. Although PG&E requested rehearing of the CPUC decision adopting the Rate Agreement, the CPUC denied the request for rehearing. PG&E did not challenge this decision in the California Supreme Court, and it is now final and unappealable under California law.

It is possible that a bankrupt IOU could claim that the revenues collected by it for Bond Charges and Power Charges are property of its bankruptcy estate and are not held in trust for the benefit of DWR and could refuse to remit such revenues to DWR. PG&E has not made such a claim in its bankruptcy proceeding. Nonetheless, an IOU could assert an equitable and legal interest in the Power Charges and the Bond Charges and DWR can give no assurance as to whether or how long DWR or its creditors would be prevented from exercising their rights under relevant documents until the validity of such assertions are finally determined. DWR could be subject to a temporary restraining order, preliminary injunction or other interim relief affording delay pending a determination of the merits of an IOU's assertion. DWR revenues that are in possession of the IOU at the time of commencement of a bankruptcy case that have been commingled with property of the IOU could be treated as part of the IOU's bankruptcy estate. Finally, if revenues from Bond Charges and Power Charges were ultimately to be determined by a bankruptcy court to be property of an IOU's bankruptcy estate and not held in trust on behalf of DWR, DWR's efforts to collect such revenues might result in costly and time-consuming litigation.

Potential Rejection of Servicing Agreements or Other Disruption of Servicing Arrangements

As explained above under "Collection of Bond Charges and Power Charges," DWR's ability to collect Bond Charges and Power Charges is dependent on the IOUs acting in their capacities as servicers under the Servicing Arrangements. In the event of bankruptcy proceedings with respect to SDG&E or SCE, the bankrupt IOU could move to reject its Servicing Agreement pursuant to the Bankruptcy Code. This rejection would require the approval of the bankruptcy court, and DWR could raise objections to such rejection. A successful rejection of the IOU's Servicing Agreement could result in DWR being unable to require the IOU to continue to collect and remit Bond Charges and Power Charges to DWR (or to provide any other services) under the Servicing Agreement after the date of rejection. However, the CPUC is required under the Act to order the IOU to provide IOU Services upon request of DWR in the event the IOU's Servicing Agreement is rejected by an IOU in bankruptcy, thus replacing the Servicing Agreement with a servicing order similar to the PG&E Servicing Order. Although a bankrupt IOU subjected to a servicing order in this manner could challenge that order, either in its bankruptcy proceedings or under State law, DWR believes that the possibility is remote that such challenge would be successful or that the billing, collection and remittance of Bond Charges and Power Charges would be materially disrupted by such challenge. See the discussion below under "Potential Impact of PG&E Bankruptcy Proceedings on PG&E Servicing Order."

Potential Impact of PG&E Bankruptcy Proceedings on PG&E Servicing Order

PG&E has been transmitting and distributing DWR power to PG&E's customers since the beginning of the Power Supply Program in January 2001. PG&E has collected and remitted to DWR the revenue from charges relating to such DWR power.

The plan of reorganization that PG&E has submitted to the bankruptcy court in PG&E's bankruptcy proceedings acknowledges that PG&E acts as the billing and collection agent for DWR's power sales to PG&E's retail customers. The plan of reorganization contemplates that PG&E will, after reorganization, continue to transmit and distribute DWR power and to bill and collect DWR charges as agent for DWR. The alternative plan of reorganization proposed by the CPUC also contemplates that PG&E will, after reorganization, provide such services to DWR.

As explained above under "Collection of Bond Charges and Power Charges," in May 2002, the CPUC adopted the PG&E Servicing Order, under which PG&E is expressly required to provide the IOU Services. PG&E's failure to comply with the PG&E Servicing Order, in absence of its being excused from doing so by the bankruptcy court or the CPUC, could result in fines and penalties.

PG&E could seek relief from the PG&E Servicing Order in the bankruptcy court at any time and the bankruptcy court could grant such relief. The bankruptcy court could temporarily or permanently enjoin the CPUC from enforcing the order if the court determined that the order violated the automatic stay or other provisions of the Bankruptcy Code or could void the order altogether if it determined that the order was preempted by or otherwise violated the Bankruptcy Code or other provisions of federal law. If PG&E did seek such relief, DWR believes that the possibility is remote that the billing, collection and remittance of Bond Charges and Power Charges would be materially disrupted or altered by a successful PG&E challenge to the PG&E Servicing Order in bankruptcy court. DWR does not believe that PG&E will be relieved in any material way from substantial compliance with the PG&E Servicing Order, assuming that the PG&E Servicing Order provides for reasonable compensation for such services. The CPUC ruled in its PG&E Servicing Order approval proceedings that the PG&E Servicing Order provides reasonable compensation to PG&E (although such a ruling would not be binding upon the bankruptcy court).

Certain Risks Associated With DWR's Power Supply Program

DWR's purchases and sales of electricity will likely end under the Power Supply Program before the Bonds are retired. See "POWER SUPPLY PROGRAM – Transition of Procurement Responsibility After 2002" and APPENDIX A – "CONSULTANT'S REPORT – Plan to Transition DWR Net Short Responsibilities." Bond Charges are to be the primary source of money to pay debt service on the Bonds, and must be imposed by the CPUC whether or not DWR continues to purchase or sell electricity under the Power Supply Program. See "RATE COVENANTS." Certain risks associated with the Power Supply Program are discussed in the following paragraphs.

Priority Long-Term Power Contracts

As explained above under "Determination of Power Charges and Bond Charges; Possible Use of Amounts in the Bond Charge Collection Account to Pay Priority Contract Costs," the use of amounts in the Bond Charge Collection Account (including Bond Charge Revenues) for the payment of debt service on the Bonds and other Bond Related Costs when due is subject to the possible prior use of such amounts to pay amounts due under DWR's Priority Long-Term Power Contracts (including any termination payments which may be payable by DWR). Exposure to this risk will not end in 2002.

See "PRIORITY LONG-TERM POWER CONTRACTS" for a discussion of the impact on the Power Supply Program of the failure of contractors to deliver power to DWR in accordance with the Priority Long-Term Power Contracts. See "LITIGATION AND ADMINISTRATIVE PROCEEDINGS – Litigation Pending or Threatened in State and Federal Courts – *Actions Contesting Certain Long-Term Power Contracts*" and "LITIGATION AND ADMINISTRATIVE PROCEEDINGS – FERC Administrative Actions – *Actions Contesting Certain Long-Term Power Contracts*" concerning legal actions and administrative proceedings seeking to terminate DWR's long-term power purchase contracts, including DWR's Priority Long-Term Power Contracts. If legal actions or administrative proceedings resulted in termination, replacement power could be purchased currently at prices below prices that DWR is obligated to pay under the Priority Long-Term Power Contracts. However, DWR is not authorized under current law to enter into contracts after 2002 to purchase replacement power. See "POWER SUPPLY PROGRAM – Transition of Procurement Responsibility After 2002."

Transition Risks and Possible Extension of DWR's Responsibilities

So long as DWR continues to bear financial responsibility for the Priority Long-Term Contracts, Bond Charges and other amounts in the Bond Charge Collection Account might be used to pay Priority Contract Costs rather than debt service on the Bonds, as explained above under "Determination of Power Charges and Bond Charges; Possible Use of Amounts in the Bond Charge Collection Account to Pay Priority Contract Costs." As described under "POWER SUPPLY PROGRAM – Transition of Procurement Responsibility After 2002," DWR plans to transfer financial responsibility for the Priority Long-Term Contracts to the IOUs but those plans may not be realized.

Payment of DWR Administrative Expenses Requires Appropriation by State Legislature

DWR does not depend upon appropriations in the State budget to pay debt service on the Bonds or its power costs, including its Priority Contract Costs, because such payments are already authorized by continuing appropriations in the Act. However, DWR depends upon annual State budget appropriations for portions of its operating budget.

Under State law, the Legislature is required to adopt a budget for each fiscal year, which runs from July 1 to June 30, before the start of the fiscal year. On a number of occasions, the Legislature has not adopted the State budget in a timely manner. In a recent decision, a State Court of Appeal held that the Controller of the State is not authorized to make payments without an appropriation, other than to State employees to the extent of federal minimum wage requirements and in certain other limited circumstances not relevant to DWR, in a fiscal year in which a budget has not been adopted by the State Legislature. This decision is being appealed. Budget delays affecting the Controller's legal ability to pay amounts owed by DWR could adversely affect the willingness of vendors and consultants to continue to provide supplies or services to DWR or otherwise adversely affect DWR's operations.

In addition, the Rate Agreement only provides for recovery of amounts DWR is entitled to recover under the Act. If DWR incurs unauthorized expenses, it will need to absorb those costs in its budget or seek legislation authorizing and funding those costs.

Potential Increases in Electric Rates

DWR's Power Supply Program, timely payment of debt service on the Bonds and the financial condition of the IOUs are dependent, in part, upon the payment by customers of the amounts billed to such customers for the energy they receive. There are multiple factors that might result in increased overall rates charged to such customers and, as a result, potentially have an adverse effect on collections. Many of these factors are not under the influence or control of the State or DWR or are factors over which the State and DWR have only limited influence or control. These factors include, but are not limited to, the following factors.

Changes in General Economic Conditions

Significant changes in general economic conditions may be caused by, among other things, fluctuating business cycles, uncharacteristic weather patterns (such as droughts) or the occurrence of natural disasters (such as earthquakes or floods). Such factors could lead to significant reductions in retail energy sales, resulting in increased retail rates for electric energy to offset reduced revenues.

Energy Market-Driven Increases in Wholesale Power Costs

Wholesale power costs are affected by a number of factors, including, but not limited to, weather, fuel supplies and transmission, transmission systems operations and capacity (including import capability), and generation capacity. Natural gas pipeline transmission interruptions (due to seismic or other environmental events, accidents or intentional acts) could result in higher natural gas prices in California and substantial

increases in gas-fired electric generating facility operating costs. Significant increases in the costs of wholesale power could result in the need to increase retail rates for electric energy.

Market Manipulation

The California Independent System Operator ("CAISO") has adopted regulations governing the conduct of energy suppliers and other entities whose activities affect the transmission system. CAISO regulations are intended, among other things, to prevent manipulation of the CAISO's procedures by transmission system participants. The CAISO monitors the activities of transmission system participants, but manipulative behavior could occur, possibly resulting in higher or substantially higher costs.

"Block Forward Contracts" Consolidated Actions

In February 2001, during the state of emergency described under "POWER SUPPLY PROGRAM," the Governor issued executive orders commandeering power purchase arrangements held by PG&E and SCE, referred to as "block forward contracts." The issue of whether and to what extent compensation is due is now before the Sacramento County Superior Court. See "LITIGATION AND ADMINISTRATIVE PROCEEDINGS – Litigation Pending or Threatened in State and Federal Courts – *Block Forward Contracts Consolidated Actions*." See also "POWER SUPPLY RESOURCES – DWR Resources – DWR Contracts – *PX Block Forward Contracts*" in Appendix A hereto.

If any of the claimants prevail, DWR could be required under the Indenture and the Rate Agreement to file a revised Retail Revenue Requirement resulting in an increase in Power Charges to ensure recovery of these costs. The estimated DWR Revenue Requirements discussed in the Consultant's Report are based on the assumption that the claimants will not prevail in their monetary claims against the State in this action.

Action Requiring DWR to Pay for Power Ordered for PG&E and SCE

A FERC order directed the CAISO to require DWR to pay certain amounts for power purchased by DWR on behalf of PG&E and SCE. DWR has paid and continues to pay in full to the CAISO all amounts that the CAISO has invoiced. These amounts have been distributed to market participants through the CAISO settlement system. For January 2001, CAISO distributed monies on a pro-rata basis to all market participants for the entire month although DWR purchased power on behalf of PG&E and SCE beginning in late January. As a result, market participants did not receive payment in full for the amounts owed them for power purchased in the last half of January by DWR on behalf of PG&E and SCE. Two suppliers of energy have petitioned FERC, contending that additional amounts totaling $57.52 million are owed by DWR for this and other shortfalls potentially attributable to others' nonpayment to the extent that the CAISO fails to rectify these matters. This dispute has been submitted to FERC, which has not announced when it will rule on this matter or whether it will require DWR to make additional payments to the CAISO. See "LITIGATION AND ADMINISTRATIVE PROCEEDINGS – FERC Administrative Actions – *Action Requiring DWR to Pay for Power Ordered for PG&E and SCE*." If DWR were required to make additional payments to the CAISO, DWR would be required under the Indenture and the Rate Agreement to file a revised Retail Revenue Requirement resulting in an increase in Power Charges to provide funds to make these payments to the CAISO. The estimated DWR Revenue Requirements discussed in the Consultant's Report are based on the assumption that DWR will not be required to make any additional payments to the CAISO relative to this matter, and no provision has been made for the payment of any of such claims in such estimated DWR Revenue Requirements. See "DWR ESTIMATED OPERATING RESULTS" in Appendix A hereto.

Actions Affecting Retail Rates

PG&E and SCE each filed actions in federal court seeking to have a retail electric rate freeze lifted before the termination of the rate freeze by California law in March 2002. See "LITIGATION AND ADMINISTRATIVE PROCEEDINGS – Litigation Pending or Threatened in State and Federal Courts – *Actions*

Affecting IOU Rates" and "POWER SUPPLY PROGRAM – Background and History." As reported under that heading, the suit brought by SCE has been settled. However, the settlement is currently being challenged in the Ninth Circuit Court of Appeals. If the SCE settlement is determined to be invalid, or if PG&E is successful in its suit, it is possible that customers of such IOUs could be adversely affected over a short period of time in terms of the prices those customers would be required to pay for their electricity.

Impact of These Factors

The factors discussed above (or other factors) might result in increased rates while Bonds remain outstanding. If the rates charged to customers increase (or have other adverse effects on the energy industry or markets, as occurred in California in 2000 and 2001 (see "INTRODUCTION – Overview – *Circumstances Leading to DWR's Role as Power Supplier*" in Appendix A hereto)), additional legislative or other governmental action might follow, the effect of which cannot be predicted. See "Uncertainties Relating to Government Action – *Possible State Legislation or Action*" and "– *Possible Federal Legislation or Action*" below. Moreover, a combination of one or more such factors could lead to increased retail rates for electric energy, which could in turn lead to increased delinquencies and non-payments by customers. Under each Servicing Arrangement, the risk of non-payment or partial payment is borne proportionally by DWR and the IOU. Such results could have an adverse effect on the IOUs' business operations and could adversely affect DWR's ability to pay debt service on the Bonds. See "Calculation, Revision and Imposition of Bond Charges," "Determination of Power Charges and Bond Charges; Possible Use of Amounts in the Bond Charge Collection Account to Pay Priority Contract Costs," and "Bankruptcy Risks" above.

The CPUC has authority under the Act to set charges for customers of the IOUs to recover DWR's costs. The CPUC does so as part of the process of establishing a retail rate structure and setting retail rates for all electricity supplied to customers of the IOUs by the IOUs and by DWR. DWR is not in a position to determine whether any future increases in DWR's costs will be recovered within the existing retail rates or whether additional charges on customers will be imposed by the CPUC in the future to cover all or any part of any future increases in DWR costs. DWR notes that, in any event, the CPUC's covenant to calculate, revise and impose Bond Charges sufficient to pay debt service on the Bonds and other Bond Related Costs when due (explained under "SECURITY FOR THE BONDS – Bond Related Costs," "SOURCES OF FUNDS TO PAY DEBT SERVICE – Rate Agreement," and "RATE COVENANTS") is not limited by or subject to a ceiling or cap on retail rates and must take collection experience into account.

Potential Decrease in DWR Customer Base

Direct Access

In the Direct Access Decision, the CPUC affirmed an earlier decision which suspended the ability of IOU customers to enter into new contracts or arrangements for direct access service after September 20, 2001, and provided certain exceptions based on its interpretation of applicable law. Exceptions include permission for residential and small commercial customers to move from one address to another within the same service area, for a direct access contract to be assigned to a new customer representing approximately the same load at the same location, and for any customer to change its name or corporate identity (but not in order to increase load). The Direct Access Decision is now final and unappealable under California law.

The Direct Access Decision was made pursuant to the Act, which provides that the CPUC shall suspend direct access until DWR is no longer providing power to its customers. In the event that DWR is no longer selling power purchased under the Priority Long-Term Power Contracts (for example, in the event of an assignment of such contracts to the IOUs), the suspension of direct access could be lifted by the CPUC. The suspension of direct access also could be affected by recently enacted legislation, future amendments to the Act or other legislation. See, for example, "Uncertainties Relating to Government Action – *Recent State Legislation*" below).

If DWR's customer base is substantially reduced by the implementation of additional direct access, DWR would be required under the Indenture and the Rate Agreement to file, if necessary, revised Revenue Requirements resulting in revisions to Bond Charges and Power Charges to ensure complete recovery of its costs from DWR's remaining customers and direct access customers who are required to pay Bond Charges or other surcharges.

Filing a revised Revenue Requirement may not be necessary if, in connection with the extension of direct access, charges for the benefit of DWR were to be imposed on direct access customers ("direct access charges"). In the Direct Access Decision, the CPUC ordered that direct access "surcharges" or "exit fees" shall be considered in another CPUC proceeding, so that direct access customers pay their fair share of DWR costs.

Recently, the CPUC completed its consideration of these "direct access charges" and adopted on November 7, 2002, a decision that established a direct access cost responsibility surcharge mechanism whereby designated direct access customers are made responsible for paying costs incurred by the Department that are being recovered through Bond Charges and Power Charges, and for paying certain above-market costs incurred by each of the IOUs through their own resources and contracts. The decision excluded continuous direct access customers, defined as those taking direct access continuously both before and since January 17, 2001 (in the PG&E and SCE service territories) or February 7, 2001 (in the SDG&E service territory), from paying Bond Charges. Pursuant to the Rate Agreement, Bond Charges will be imposed on direct access customers when the surcharges and this decision become final and unappealable. The decision also determined that pursuant to the Act and AB 117, any direct access customer who took bundled service from an electrical corporation on or after February 1, 2001, is responsible for paying a share of the DWR revenue requirements, including both previously incurred costs as well as an ongoing cost component, which is recovered through Power Charges. Imposition of the surcharges was to ensure bundled customer indifference (e.g., to prevent cost shifting between bundled customers and direct access customers). The decision also adopted an initial interim cap of 2.7 cents/kWh, in response to concerns that the surcharges might cause direct access to become uneconomic. Bundled customers will finance any undercollection resulting from the cap, and they will be repaid with interest over a reasonable period. The cap is subject to adjustment as determined in further proceedings ordered in the decision.

The Consultant's Report does not assume participation by DWR's electric customers in direct access beyond that contemplated by the Direct Access Decision, but, as described above, such participation could occur. For additional information regarding direct access, the Direct Access Decision, the direct access charges and recent legislation, see "Uncertainties Relating to Government Action – *Recent State Legislation*" below and "CAPACITY AND ENERGY REQUIREMENTS – Self-Generation and Direct Access – Direct Access" in Appendix A.

Load Departing IOU Service

Participation by the IOU's current customers in self-generation programs and other means of generating their own electricity could also reduce DWR's revenues, as could certain changes that result in the IOUs' current customers migrating to municipal utilities, irrigation districts, and agricultural districts that provide electricity. The State has implemented several programs designed to accelerate the development of self-generation facilities. A substantial reduction of DWR's customer revenues could require DWR to file a revised Revenue Requirement resulting in an increase in Bond Charges and Power Charges to ensure complete recovery of its costs. See "Calculation, Revision and Imposition of Bond Charges" above and "CAPACITY AND ENERGY REQUIREMENTS – Self-Generation and Direct Access – *Self Generation*" in Appendix A hereto. The CPUC is considering imposition of a "surcharge" or "exit fee" on some or all of the customers discussed in this paragraph in the Direct Access Cost Responsibility Proceedings.

Uncertainties Relating to Electric Industry and Markets

The electric industry and markets in the western states region, including the governing laws and regulations, continue to undergo significant changes. Some of the recent changes include restructuring of

regulation of the electric industry, the abandonment or partial abandonment of restructuring changes, attempts to construct substantial amounts of new generation facilities (mostly gas-fired) and PG&E's bankruptcy (see "LITIGATION AND ADMINISTRATIVE PROCEEDINGS – Litigation Pending or Threatened in State and Federal Courts – *Pacific Gas and Electric Bankruptcy*"). In addition, effects of compliance with rapidly changing environmental, safety, licensing, regulatory and legislative requirements for the IOUs, the power production facilities and other entities involved with the Power Supply Program and shifts in the availability of different fuels (including natural gas) may also compound the uncertainties relating to electric industry and markets. There might also be significant volatility in energy prices due to a wide variety of factors that affect both the supply and demand for electric energy in the western United States. Future changes in the electric industry and markets could have an adverse effect on DWR, its Power Supply Program or its ability to pay debt service on the Bonds.

Uncertainties Relating to Government Action

California Emergency Services Act

The Governor has relied in whole or in part on the California Emergency Services Act (California Government Code Section 8550 *et seq*.) for legal authority to authorize, among other things: the commencement of the Power Supply Program in January 2001; loans from the State General Fund to DWR and the Interim Loan to DWR (described under "PLAN OF FINANCE"); the commandeering of block forward power purchase contracts (described under "LITIGATION AND ADMINISTRATIVE PROCEEDINGS – Litigation Pending or Threatened in State and Federal Courts – *Block Forward Contracts Consolidated Actions*"); and the conservation programs described in the Consultant's Report attached as Appendix A under the heading "CAPACITY AND ENERGY REQUIREMENTS – New Conservation and Load Management." It is possible that DWR's authorization to enter into power purchase contracts after 2002 may be extended by an executive order of the Governor under the Emergency Services Act.

Under the Emergency Services Act, the Governor is authorized to proclaim a state of emergency upon finding that conditions of disaster or of extreme peril to the safety of persons and property within the State have been caused by a severe energy shortage (or other specified conditions). The Governor proclaimed such a state of emergency to exist in January 2001. The state of emergency has not been terminated. The Emergency Services Act requires the Governor to proclaim the termination of a state of emergency at the earliest possible date that conditions warrant. All of the powers granted the Governor by the Emergency Services Act with respect to a state of emergency terminate when the state of emergency has been terminated by proclamation of the Governor or by concurrent resolution of the Legislature declaring it at an end. The termination of the current state of emergency would mean that DWR would no longer be able to rely upon executive orders of the Governor under the Emergency Services Act as the legal basis for future DWR actions comparable to those described in the preceding paragraph (unless and until another state of emergency occurs).

Under the Emergency Services Act during a state of emergency, the Governor has the broad powers described below that could enable the Governor to make changes in the Power Supply Program, the Act, the Rate Agreement or with respect to action by DWR or the CPUC, in each case subject to the limitations of the United States and California Constitutions described under "*Possible State Legislation or Action*" below. The Emergency Services Act provides that during a state of emergency the Governor shall, to the extent he deems necessary, have complete authority over all agencies of the State government and the right to exercise within the area designated all police power vested in the State by the Constitution and laws of the State in order to effectuate the purposes of the Emergency Services Act. During a state of emergency the Governor may direct all agencies of State government to utilize and employ State personnel, equipment, and facilities for the performance of any and all activities designed to prevent or alleviate actual and threatened damage due to the emergency; and he may direct such agencies to provide supplemental services and equipment to political subdivisions to restore any services which must be restored in order to provide for the health and safety of the citizens of the affected area. Any agency so directed by the Governor may expend any of the moneys that have been appropriated to it in performing such activities, irrespective of the particular purpose for which the money was appropriated. During a state of emergency the Governor may suspend any regulatory statute, or statute prescribing the procedure for

conduct of State business, or the orders, rules, or regulations of any State agency where the Governor determines and declares that strict compliance with any statute, order, rule, or regulation would in any way prevent, hinder, or delay the mitigation of the effects of the emergency. In the exercise of the Governor's emergency powers, the Governor is authorized to "commandeer" or utilize any private property or personnel deemed by him necessary in carrying out the responsibilities vested in him as Chief Executive of the State and the State shall pay the reasonable value thereof.

Possible State Legislation or Action

The Act states that while any obligations of DWR incurred under the Act remain outstanding and are not fully performed or discharged, the rights, powers, duties, and existence of DWR and the CPUC shall not be diminished or impaired in any manner that will affect adversely the interests and rights of the holders of or parties to such obligations. This provision of the Act affords limited but not complete protection for the owners of Bonds against amendment of the Act and the Rate Agreement by legislation, action by the Governor under the Emergency Services Act, or voter initiative. Under California law, the electorate has the right, through its initiative powers, to propose statutes as well as amendments to the California Constitution. Generally, any matter that is a proper subject of legislation can become the subject of an initiative and be submitted to voters at the next general election.

Bond Counsel will deliver an opinion as to the validity of the Indenture and the Rate Agreement. See APPENDIX F – "PROPOSED FORM OF OPINION OF BOND COUNSEL." In addition, Bond Counsel will deliver an opinion to the effect that the owners of the Bonds are further entitled to the benefit of the prohibitions in Article I, section 10, of the Constitution of the United States (the "Contract Clause") against a state's impairment of the obligation of contracts. The prohibition, although not absolute, is particularly strong when applied to the State's attempt to evade its own obligations. Similar protections are afforded by Article I, Section 9, of the California Constitution.

Based on the U.S. Supreme Court's standard of review for Contract Clause challenges in *Energy Reserves Group, Inc. v. Kansas Power & Light Co.*, the State must justify the exercise of its inherent police power to safeguard the vital interests of its people before the State may alter the Act, the Indenture or the Rate Agreement in a manner that would substantially impair the rights of the Owners of the Bonds. However, to justify the enactment by the State of legislation that substantially impairs the contractual rights of the Bondholders, the State must demonstrate a significant and legitimate public purpose, such as the remedying of a broad and general social or economic problem. In the event that the State demonstrates a significant and legitimate public purpose for such legislation, the State must also show that the impairment of the Bondholders' rights is reasonable and appropriate to the public purpose justifying the legislation's adoption.

There have been cases in which legislative concerns with the burden of taxation or governmental charges have led to adoption of legislation reducing, eliminating or imposing a moratorium on taxes or charges that supported bonds or other contractual obligations entered into by public instrumentalities. Bond Counsel has advised DWR that such concerns have not been considered by the courts to provide sufficient justification for a substantial impairment of the security for such bonds and other contractual obligations and, in several cases, have held such legislation as an unconstitutional impairment of contract.

Nonetheless, a repeal, amendment or suspension of, or moratorium on, certain provisions of the Act, the Indenture or the Rate Agreement could be sought or adopted, even if such repeal, amendment, suspension or moratorium might constitute a violation of the Indenture or the Rate Agreement. Additionally, the State might take, or refuse to take, or cause DWR or the CPUC to take, or refuse to take, action required of DWR under the Indenture or of DWR or the CPUC under the Rate Agreement, even if such action or inaction might constitute a violation of the Indenture or the Rate Agreement. Costly and time-consuming litigation might ensue which might adversely affect the price and liquidity of the Bonds and the timely payment thereof. Moreover, the outcome of such litigation might be adverse to the interests of owners of the Bonds, and accordingly, owners of the Bonds could experience a decline in value of their investment as a result of any such event.

Recent State Legislation

Recent State legislation known as "AB 117" authorizes local government entities to become "community choice aggregators" and to develop programs to provide electricity to interested customers, including current IOU customers, who are within the boundaries of such entities. Under AB 117, community choice aggregation may not be authorized until the CPUC, among other things, imposes a cost-recovery mechanism that would require customers purchasing power from a community choice aggregator to pay specified amounts for recovery of DWR costs and certain costs of the IOUs. Each customer participating in such a plan would be required to pay CPUC-approved charges to enable DWR to recover both (1) charges equivalent to the charges that would otherwise be imposed on the customer by the CPUC to recover debt service on the Bonds and other Bond Related Costs (see "SOURCES OF FUNDS TO PAY DEBT SERVICE – Rate Agreement") and (2) any additional costs of DWR equal to the customer's proportionate share of DWR's estimated net unavoidable electricity purchase contract costs as determined by the CPUC. DWR believes that the charges contemplated by AB 117 would make DWR financially indifferent as to whether community-wide electricity buyers' programs were or were not established by cities and counties. However, if for any reason the charges imposed and collected do not provide DWR with adequate cost recovery, DWR would be required under the Indenture and the Rate Agreement to file a revised Revenue Requirement to cover any shortfall.

There can be no assurance that the Legislature will not adopt additional legislation in the future that would allow current customers of the IOU's to utilize "direct access."

Possible Federal Legislation or Action

Federal legislation could be enacted or federal action taken with respect to the electric industry and markets in the western states region that could adversely affect the payment of debt service on the Bonds. Congress or FERC may choose to change current national energy policies. For example, FERC has issued the first of several orders on California power market redesign, revising price mitigation rules and imposing higher wholesale price caps in California (see "POWER SUPPLY COSTS – FERC Price Mitigation" in Appendix A hereto for additional information on the FERC order on price mitigation). Such a change could lead to an increase in power purchase costs, adversely impacting the cash flow for the Power Supply Program and possibly requiring the temporary use of Bond Charge Revenues to pay amounts due under DWR's Priority Long-Term Power Contracts (as described above under "Determination of Power Charges and Bond Charges; Possible Use of Amounts in the Bond Charge Collection Account to Pay Priority Contract Costs") instead of debt service on the Bonds.

The provisions of the United States Constitution discussed under "*Possible State Legislation or Action*" above, affording protection against contract impairments by State action to the owners of the Bonds, do not apply to the federal government. While the Due Process Clause of the United States Constitution protects against certain contract impairments by the federal government, the Due Process Clause may not protect owners of the Bonds against adverse effects of federal legislation or action.

Uncertainty of Projections and Assumptions

General

This Official Statement and the Appendices hereto include projections and assumptions about, among other things, system transmission operations and capacity, weather trends, generation capacity, fuel costs, spot market prices for energy and energy consumption. In addition, the determination of DWR's Revenue Requirements involves the making of similar projections and assumptions. These projections and assumptions are subject to risks and uncertainties, including risks and uncertainties outside the control of DWR. The accuracy of such projections and assumptions is subject to known and unknown risks, uncertainties and other factors that may cause actual results, performance or achievements to be materially different from such projections and assumptions. Differences in actual results from projections may be difficult to recognize in a timely manner for

purposes such as the adjustment of DWR's Revenue Requirements. Material differences could result in a variety of unpredictable consequences which could adversely affect the Power Supply Program and the ability of DWR to pay debt service on the Bonds.

This Official Statement and the Appendices hereto also assume future approvals and other actions by a number of governmental entities that regulate the energy industry, including the CPUC, FERC and the California Energy Commission. If such approvals or other actions do not occur or do not occur on a timely basis, the ability of DWR to make timely payment of debt service on the Bonds could be materially and adversely affected. In addition, DWR must act in a timely manner to revise its Revenue Requirements in order to conform to the assumptions made in this Official Statement and the Appendices hereto.

Projections and Assumptions in Consultant's Report

Although DWR believes that the projections contained in the Consultant's Report and the assumptions on which they are based are reasonable, such projections may not be realized. The projections contained in the Consultant's Report may not be indicative of actual future performance. Moreover, DWR does not assume any responsibility for the accuracy of such projections or assumptions. No representation is made or intended, nor should any representation be inferred, with respect to the likely existence of any particular future set of facts or circumstances, and prospective purchasers of the Bonds are cautioned not to place undue reliance upon the results projected. If actual results are less favorable than the results projected, the ability of DWR to make timely payment of debt service on the Bonds may be materially and adversely affected.

See APPENDIX A – "CONSULTANT'S REPORT," including "Principal Assumptions and Considerations" therein, for additional discussion of the projections and assumptions contained in the Consultant's Report.

CPUC Disclaimer

The CPUC makes no representation as to the accuracy or completeness of any forward-looking statements or projections contained in this Official Statement, including, without limitation, any assumptions or conclusions contained in the Consultant's Report attached as Appendix A. The CPUC makes no representation as to the accuracy or completeness of this Official Statement, including any description in this Official Statement of litigation involving or affecting the CPUC, and any statements regarding such litigation do not necessarily represent the CPUC's view of such litigation or any position in such litigation. In addition, while CPUC staff have assisted in the preparation of certain sections of this Official Statement, the CPUC can only take positions through formal action and has not taken any such action or approved this Official Statement. The CPUC is an independent five-member body that must act by an affirmative vote of a majority of its members and, as a result, the CPUC can only indicate its views in formal decisions or other formal actions. In addition, the CPUC is not subject to the control of DWR and may take positions in the future different from DWR in litigation, or other matters described in this Official Statement. As a result, statements in this Official Statement regarding electricity markets and regulation, and DWR's views of the CPUC's role or DWR's role in such markets and regulation, do not necessarily represent the views, opinions or beliefs of the CPUC and should not be construed as such by any recipient of this Official Statement.

Limited Obligations

The Bonds shall not be or be deemed to constitute a debt or liability of the State or of any political subdivision thereof or a pledge of the faith and credit of the State or of any such political subdivision, other than DWR to the extent provided in the Indenture. The Bonds shall be payable solely from the funds pledged therefor pursuant to the Indenture. The Bonds shall not directly or indirectly or contingently obligate the State or any political subdivision thereof to levy or to pledge any form of taxation whatever therefor or to make any appropriation for their payment.

FINANCIAL STATEMENTS

The financial statements of the Department of Water Resources Electric Power Fund at June 30, 2001 and for the period from January 19, 2001 (date of inception) to June 30, 2001 appearing in Appendix J to this Official Statement have been audited by PricewaterhouseCoopers LLP (PwC), independent accountants, as set forth in their report appearing in Appendix J. Unaudited financial information for the ten months ended April 30, 2002 is also included in Appendix J.

DWR has engaged the Consultant (Navigant Consulting, Inc.) to prepare the Consultant's Report (included in Appendix A) for the purpose of this Official Statement. The projections in the Consultant's Report are the responsibility of the Consultant and DWR. PwC has neither examined nor compiled such projections and, accordingly, PwC does not express an opinion or any other form of assurance with respect thereto. The PwC report included in Appendix J of this Official Statement relates to historical financial information of the Department of Water Resources Electric Power Fund. The PwC report does not extend to the projections in the Consultant's Report and should not be read to do so. The projections were not prepared with a view toward compliance with the guidelines established by the American Institute of Certified Public Accountants for preparation and presentation of prospective financial information.

RATINGS

Moody's Investors Service ("Moody's"), Standard & Poor's Ratings Group, a division of The McGraw-Hill Companies, Inc. ("Standard & Poor's") and Fitch, Inc., doing business as Fitch Ratings, are expected to assign ratings of Aaa, AAA and AAA, respectively, to the Insured Bonds. Such ratings are conditioned upon the simultaneous issuance of the bond insurance policies described herein. Moody's, Standard & Poor's and Fitch Ratings have also assigned ratings of A3, BBB+, and A-, respectively, to all Series 2002A Bonds other than the Insured Bonds. An explanation of the significance of these ratings may be obtained from Moody's at 99 Church Street, New York, New York 10007, from Standard & Poor's at 55 Water Street, New York, New York 10041 and from Fitch Ratings at One State Street Plaza, New York, New York 10004. Such ratings reflect only the views of the rating agencies.

Generally, rating agencies base their ratings on such information and materials and on investigations, studies and assumptions made by the rating agencies themselves. There is no assurance that the ratings mentioned above will remain in effect for any given period of time or that the ratings might not be lowered or withdrawn entirely by the rating agencies, if in their judgment circumstances so warrant. DWR and the Underwriters have undertaken no responsibility to oppose any such proposed revision or withdrawal. DWR has agreed to notify the Municipal Securities Rulemaking Board or each Nationally Recognized Municipal Securities Information Repository and the State Repository, if any, of any change in the ratings of the Series 2002A Bonds. See "CONTINUING DISCLOSURE" herein. Any such downward change in or withdrawal of the ratings might have an adverse effect on the market price or marketability of the Series 2002A Bonds.

UNDERWRITING

The Series 2002A Bonds will be purchased by an underwriting group represented by J.P. Morgan Securities Inc. (collectively called the "Underwriters") from the State Treasurer, who is authorized pursuant to the laws of the State to sell the Series 2002A Bonds on behalf of DWR. The Underwriters have agreed to purchase the Series 2002A Bonds at a price of $6,667,610,378.45, plus accrued interest. The price represents the principal amount of the Series 2002A Bonds of $6,313,500,000.00, plus net original issue premium of $397,979,894.75, less an Underwriters' discount of $43,869,516.30. The purchase contract pursuant to which the Series 2002A Bonds are being sold provides that the Underwriters will purchase all of the Series 2002A Bonds if any are purchased. The obligation to make such purchase will be subject to certain terms and conditions set forth in such purchase contract, the approval of certain legal matters by counsel and certain other conditions.

FINANCIAL ADVISORS

Montague DeRose and Associates, LLC served as financial advisor to DWR in connection with the Series 2002A Bonds. Public Resources Advisory Group served as financial advisor to the State Treasurer in connection with the Series 2002A Bonds. Arimax Financial Advisors Inc. served as financial advisor to the CPUC in connection with the Series 2002A Bonds.

THE CONSULTANT

DWR has engaged the Consultant (Navigant Consulting, Inc.) to prepare the Consultant's Report for the purpose of this Official Statement. The Consultant's Report is attached as Appendix A and should be read in its entirety. The Consultant has provided and expects to provide other services to DWR, as described in this Official Statement under "RELATIONSHIPS" and in the Introduction to the Consultant's Report attached as Appendix A under the heading "Purpose of the Report and Role of NCI."

Although DWR believes that the conclusions contained in the Consultant's Report and the assumptions upon which they are based are reasonable, no assurance can be given that any such projections will be realized or that the assumptions will prove to be correct. DWR has not undertaken an independent investigation of all of the assumptions, conclusions and other matters stated in the Consultant's Report. DWR has relied on the Consultant's expertise in the matters covered in the Consultant's Report. The Underwriters of the Bonds and the financial advisors and counsel named in this Official Statement have also relied on the Consultant's expertise in the matters covered in the Consultant's Report. See "RISK FACTORS – Uncertainty of Projections and Assumptions."

APPROVAL OF LEGAL MATTERS

The issuance of the Series 2002A Bonds is subject to the approving opinions of the Honorable Bill Lockyer, Attorney General of the State, and Hawkins, Delafield & Wood, Bond Counsel. The proposed forms of such opinions are set forth in Appendix E and Appendix F to this Official Statement. Certain legal matters will be passed upon by: Peggy Bernardy, Chief Counsel to DWR; Orrick, Herrington & Sutcliffe LLP, disclosure and special counsel to DWR; Gary M. Cohen, General Counsel to the CPUC; Paul, Weiss, Rifkind, Wharton & Garrison, special counsel to the CPUC; Sidley Austin Brown & Wood LLP, special counsel to the Treasurer of the State; and O'Melveny & Myers LLP and Leslie M. Lava, Esq., co-counsel to the Underwriters.

RELATIONSHIPS

The Power Supply Program and related activities, including the sale of Bonds, has been made possible, in part, by hiring underwriters, financial advisors, consultants and lawyers to assist and advise DWR. Many of the firms and individuals involved in this effort have prior or ongoing relationships with the IOUs, other investor-owned utilities, public power utilities and other businesses that contract or compete with DWR or contract with the State and other State agencies or that may do so in the future. DWR has required disclosure of, and has taken into account, these relationships and has determined it to be in the best interests of DWR to continue to work with these firms and individuals.

In addition, in the ordinary course of sales, trading, brokerage and financing activities, certain of the Underwriters may at any time hold long or short positions, and may trade or otherwise effect transactions, for their own accounts or the accounts of customers, in debt or equity securities or senior loans, as applicable, of DWR, the State of California, other State agencies, the IOUs, power suppliers, municipal utilities and other participants in the electric power industry. In connection with these activities and the provision of other services, certain of the Underwriters may be or become creditors of such entities. See "PLAN OF FINANCE – Sources and Uses of Funds – Interim Loan." In addition, certain of the Underwriters currently serve as remarketing agents for variable rate obligations issued by DWR, the State of California and other State agencies.

In addition to preparing the Consultant's Report, the Consultant has provided separate services to DWR to assist it in implementing the Act and creating the Power Supply Program. These services include, but are not limited to, evaluation of the net short electric requirements provided to DWR by the IOUs, support in the evaluation and negotiation of power supply contracts, compilation and periodic updating of power supply quantities and costs from contracted power supply sources, estimation of fuel supply costs and requirements for contracted power supplies, estimation of future power purchase costs in the short-term market, evaluation of electric transmission constraints and associated impact on power supply deliveries, review of actions by other power suppliers and state governmental agencies for effect on the availability and cost of power supplies to meet the customers' net short electric requirements, support in the development of future DWR revenue requirements and support to DWR in filings with the CPUC on revenue recovery and related issues. It is anticipated that the Consultant will continue to provide services to DWR related to the Power Supply Program subsequent to the issuance of the Bonds. See the Consultant's Report attached hereto as Appendix A (including, but not limited to, the section entitled "INTRODUCTION - Purpose of the Report and Role of NCI") for additional information regarding the services provided to DWR by the Consultant.

TAX MATTERS

In the opinion of Hawkins, Delafield & Wood, Bond Counsel, under existing statutes and court decisions and assuming continuing compliance with certain tax covenants described herein, interest on the Series 2002A Bonds is excluded from gross income for federal income tax purposes pursuant to Section 103 of the Internal Revenue Code of 1986, as amended (the "Code"). Interest on the Series 2002A Bonds is not treated as a preference item in calculating the alternative minimum tax imposed on individuals and corporations under the Code; such interest, however, is included in the adjusted current earnings of certain corporations for purposes of calculating the alternative minimum tax imposed on such corporations. In rendering its opinion, Bond Counsel has relied on certain representations, certifications of fact, and statements of reasonable expectations made by DWR in connection with the Series 2002A Bonds, and Bond Counsel has assumed compliance by DWR with certain ongoing covenants to comply with applicable requirements of the Code to assure the exclusion of interest on the Series 2002A Bonds from gross income under Section 103 of the Code.

In addition, in the opinion of Bond Counsel, under existing statutes, interest on the Series 2002A Bonds is exempt from State of California personal income taxes.

Bond Counsel expresses no opinion regarding any other federal or state tax consequences with respect to the Series 2002A Bonds. Bond Counsel renders its opinion under existing statutes and court decisions as of the issue date, and assumes no obligation to update its opinion after the issue date to reflect any future action, fact or circumstance, or change in law or interpretation, or otherwise. Bond Counsel expresses no opinion on the effect of any action hereafter taken or not taken in reliance upon an opinion of other counsel on the exclusion from gross income for federal income tax purposes of interest on the Series 2002A Bonds, or under state and local tax law.

Certain Ongoing Federal Tax Requirements and Covenants

The Code establishes certain ongoing requirements that must be met subsequent to the issuance and delivery of the Series 2002A Bonds in order that interest on the Series 2002A Bonds be and remain excluded from gross income under Section 103 of the Code. These requirements include, but are not limited to, requirements relating to use and expenditure of gross proceeds of the Series 2002A Bonds, yield and other restrictions on investments of gross proceeds, and the arbitrage rebate requirement that certain excess earnings on gross proceeds be rebated to the federal government. Noncompliance with such requirements may cause interest on the Series 2002A Bonds to become included in gross income for federal income tax purposes retroactive to their issue date, irrespective of the date on which such noncompliance occurs or is discovered. DWR covenants to comply with certain applicable requirements of the Code to assure the exclusion of interest on the Series 2002A Bonds from gross income under Section 103 of the Code.

Certain Collateral Federal Tax Consequences

The following is a brief discussion of certain collateral federal income tax matters with respect to the Series 2002A Bonds. It does not purport to address all aspects of federal taxation that may be relevant to a particular owner of a Bond. Prospective investors, particularly those who may be subject to special rules, are advised to consult their own tax advisors regarding the federal tax consequences of owning and disposing of the Series 2002A Bonds.

Prospective owners of the Series 2002A Bonds should be aware that the ownership of such obligations may result in collateral federal income tax consequences to various categories of persons, such as corporations (including S corporations and foreign corporations), financial institutions, property and casualty and life insurance companies, individual recipients of Social Security and railroad retirement benefits, individuals otherwise eligible for the earned income tax credit, and taxpayers deemed to have incurred or continued indebtedness to purchase or carry obligations the interest on which is not included in gross income for federal income tax purposes. Interest on the Series 2002A Bonds may be taken into account in determining the tax liability of foreign corporations subject to the branch profits tax imposed by Section 884 of the Code.

Legislation affecting municipal bonds is regularly under consideration by the United States Congress. In addition, the Internal Revenue Services has established an expanded audit program for tax-exempt bonds. There can be no assurance that legislation enacted or proposed or an audit initiated by the Internal Revenue Service after the date of issuance of the Series 2002A Bonds will not have an adverse effect on the tax-exempt status or market price of the Series 2002A Bonds or that an audit initiated by the Internal Revenue Service involving other tax-exempt bonds will not have an adverse affect on the market price of the Series 2002A Bonds.

Original Issue Discount

"Original issue discount" ("OID") is the excess of the sum of all amounts payable at the stated maturity of a Series 2002A Bond (excluding certain "qualified stated interest" that is unconditionally payable at least annually at prescribed rates) over the issue price of that maturity. In general, the "issue price" of a maturity means the first price at which a substantial amount of the Series 2002A Bonds of that maturity was sold (excluding sales to bond houses, brokers, or similar persons acting in the capacity as underwriters, placement agents, or wholesalers). In general, the issue price for each maturity of Series 2002A Bonds is expected to be the initial public offering price set forth on the cover page of this Official Statement. Bond Counsel further is of the opinion that, for any Series 2002A Bonds having OID (a "Discount Bond"), OID that has accrued and is properly allocable to the owners of the Discount Bonds under Section 1288 of the Code is excludable from gross income for federal income tax purposes to the same extent as other interest on the Series 2002A Bonds.

In general, under Section 1288 of the Code, OID on a Discount Bond accrues under a constant yield method, based on periodic compounding of interest over prescribed accrual periods using a compounding rate determined by reference to the yield on that Discount Bond. An owner's adjusted basis in a Discount Bond is increased by accrued OID for purposes of determining gain or loss on sale, exchange, or other disposition of such Bond. Accrued OID may be taken into account as an increase in the amount of tax-exempt income received or deemed to have been received for purposes of determining various other tax consequences of owning a Discount Bond even though there will not be a corresponding cash payment.

Owners of Discount Bonds should consult their own tax advisors with respect to the treatment of original issue discount for federal income tax purposes, including various special rules relating thereto, and the state and local tax consequences of acquiring, holding, and disposing of Discount Bonds.

Bond Premium

In general, if an owner acquires a Series 2002A Bond for a purchase price (excluding accrued interest) or otherwise at a tax basis that reflects a premium over the sum of all amounts payable on the Series 2002A Bond

after the acquisition date (excluding certain "qualified stated interest" that is unconditionally payable at least annually at prescribed rates), that premium constitutes "bond premium" on that Series 2002A Bond (a "Premium Bond"). In general, under Section 171 of the Code, an owner of a Premium Bond must amortize the bond premium over the remaining term of the Premium Bond, based on the owner's yield over the remaining term of the Premium Bond, determined based on constant yield principles. An owner of a Premium Bond must amortize the bond premium by offsetting the qualified stated interest allocable to each interest accrual period under the owner's regular method of accounting against the bond premium allocable to that period. In the case of a tax-exempt Premium Bond, if the bond premium allocable to an accrual period exceeds the qualified stated interest allocable to that accrual period, the excess is a nondeductible loss. Under certain circumstances, the owner of a Premium Bond may realize a taxable gain upon disposition of the Premium Bond even though it is sold or redeemed for an amount less than or equal to the owner's original acquisition cost. Owners of any Premium Bonds should consult their own tax advisors regarding the treatment of bond premium for federal income tax purposes, including various special rules relating thereto, and state and local tax consequences, in connection with the acquisition, ownership, amortization of bond premium on, sale, exchange, or other disposition of Premium Bonds.

CONTINUING DISCLOSURE

DWR will covenant for the benefit of the holders and beneficial owners of the Series 2002A Bonds to provide certain financial information and operating data relating to DWR (the "Annual Report") by not later than 270 days following the end of DWR's fiscal year (which ends June 30) and to provide notices of the occurrence of certain enumerated events, if material. The Annual Report will be filed by DWR with each nationally recognized municipal securities information repository certified by the Securities and Exchange Commission (the "Repositories"). The notices of material events will be filed by DWR with the Municipal Securities Rulemaking Board or the Repositories. The specific nature of the information to be contained in the Annual Report or the notices of material events is included in the form of Continuing Disclosure Certificate attached hereto in APPENDIX I - "FORM OF CONTINUING DISCLOSURE CERTIFICATE."

Under the Indenture, DWR has agreed to post on its website, so long as it maintains a website, or to send to any person requesting the same in writing if it no longer maintains a website, (i) within 45 days after the end of each fiscal year quarter (except the fourth quarter), unaudited financial statements of the Electric Power Fund for such quarter, (ii) within 120 days after the end of each fiscal year, audited financial statements of the Electric Power Fund for such fiscal year and (iii) each Revenue Requirement filed with the CPUC, within 10 Business Days after the filing. The Department also has agreed in the Indenture to file the foregoing unaudited financial statements with each Repository, and provide notices of certain events upon request. See APPENDIX C – "SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE – Continuing Disclosure."

Pursuant to the Indenture, failure of DWR to comply with its continuing disclosure obligations under the Continuing Disclosure Certificate or under the Indenture will not be considered an event of default under the Indenture. However, the Trustees, or any Bondholder or Beneficial Owner (as defined in the Continuing Disclosure Certificate) may seek specific performance by court order, to cause DWR to comply with its continuing disclosure obligations under the Continuing Disclosure Certificate or under the Indenture, as the sole remedy. DWR has complied in all material respects with all previous similar undertakings under continuing disclosure certificates.

AUTHORIZATION

The delivery of this Official Statement, including the Appendices and other information herein, has been duly authorized by DWR.

STATE OF CALIFORNIA
DEPARTMENT OF WATER RESOURCES

By /s/ Thomas M. Hannigan
Director of Water Resources

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APPENDIX A

State of California
Department of Water Resources

Power Supply Revenue Bonds

Consultant's Report

October 1, 2002

Navigant Consulting, Inc.

October 1, 2002

Mr. Thomas Hannigan
Director of Water Resources
State of California
Department of Water Resources
1416 9th Street, 11th Floor
Sacramento, CA 95814

Dear Mr. Hannigan:

Navigant Consulting, Inc. ("NCI") has been retained by the State of California Department of Water Resources ("DWR") in connection with the issuance by DWR of the Power Supply Revenue Bonds (the "Bonds").

NCI submits this report (the "Consultant's Report") stating its findings, assumptions, and conclusions. NCI consents to the inclusion of, and references to, the Consultant's Report in DWR's Official Statement relating to the Bonds.

In the preparation of the Consultant's Report, NCI conducted an evaluation of engineering, economic, planning, operations, regulatory, and related matters supporting an estimate of the annual Operating Results of DWR for the period January 1, 2002 through December 31, 2011. For purposes of this assignment, NCI has made investigations and analyses, including discussions with staff and representatives of DWR, the California Public Utilities Commission, the California Energy Commission, and the major investor-owned electric utilities in California, among others, and examinations of reports and projections prepared by consultants and advisors to DWR and the State of California, which NCI deemed necessary and appropriate to reach its conclusions. The Official Statement and the Consultant's Report attached hereto should be read in their entirety.

Respectfully submitted,

/s/Ronald O. Nichols

Ronald O. Nichols
Senior Managing Director

Encl.

STATE OF CALIFORNIA
DEPARTMENT OF WATER RESOURCES

POWER SUPPLY REVENUE BONDS

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GLOSSARY

20/20 Program	An energy conservation program that rewarded the Customers with a 20 percent rebate on their monthly electric bill if their energy use was 20 percent less than their usage during the same month of 2000. The program was applied to each of the four summer months from June through September 2001. This program has been extended to the summer of 2002 for the months of July through October.
Act	Division 27 (commencing with Section 80000) of the California Water Code, also commonly referred to as "AB 1X".
AB 29X and SB 5X	Assembly Bill 29X (Chapter 8, Statutes of 2001) and Senate Bill 5X (Chapter 7, Statutes of 2001) from the First Extraordinary Session, which provided funding for conservation and peak demand reduction. These bills assist low-income households and foster conservation education and public awareness.
AB 117	Assembly Bill 117 of the 2001-2002 legislative session. An act that, if signed into law, would amend Sections 331 and 366 of, and add Section 381.1 to, the Public Utilities Code, and would permit the aggregation of retail electric load by municipal and private aggregators.
AB 970	Assembly Bill 970 (Chapter 329, Statutes of 2000), which provided funding for conservation programs to reduce peak electricity usage and directs the CPUC and the IOUs to provide incentives for demand responsive systems and distributed generation. The bill also expedites the siting process for new generation.
AB 1890	Assembly Bill 1890 (Chapter 854, Statutes of 1996) approved by the California Legislature in September 1996, which modified, strengthened, and enforced the CPUC's decision to restructure California's electricity markets.
AC	Alternating current.
ancillary services	Services used by the CAISO to ensure reliable operations. Ancillary services are generally the services, other than scheduled energy, which are required to maintain system reliability and meet WECC/NERC operating criteria. Such services consist of spinning, non-spinning, and replacement reserves, regulation, voltage control, and black start capability.
as-available	Power supply agreements that are generator specific, with the seller agreeing to make energy available to DWR to the extent energy is available, based upon generator operating status and lack of a call on output from any pre-existing power sales contract.
base load	The lowest level of power production needs during a season or year. Reflects a constant, around-the-clock level of power production or end-use needs.
Bcf	Billion cubic feet.
bilateral contract	An agreement between a buyer and seller for the purchase and the sale of energy products and services.

GLOSSARY

black start capability	The ability of a generating unit to be brought on-line without the aid of an external power supply (i.e., self-contained). For example, combustion turbines are often designed with black start capabilities.
Bonds	State of California Department of Water Resources Power Supply Revenue Bonds.
Bond Charges	Charges imposed on the Customers, based on the aggregate amount of power sold to each Customer by DWR or an IOU, or as applicable, an ESP, for the purpose of providing funds sufficient to pay Bond-Related Costs.
Bond Charge Collection Account	An account created under the Indenture into which revenues received by DWR from Bond Charges are deposited.
Bond Charge Payment Account	An account created under the Indenture into which amounts are transferred from the Bond Charge Collection Account for payment of Bond-Related Costs.
Bond-Related Costs	Amounts equivalent to debt service on the Bonds, credit enhancement and liquidity facilities charges, and costs relating to other financial instruments, fiduciary costs, administrative costs, and agreements entered into in connection with the Bonds, and, when and if DWR no longer sells power, certain administrative and servicing costs
BPA	Bonneville Power Administration.
Btu	British thermal unit; the standard unit for measuring the heat content of fuel. It is the amount of heat energy needed to raise the temperature of one pound of water one degree Fahrenheit.
CAISO	California Independent System Operator Corporation, an independent, non-profit public benefit corporation created pursuant to AB 1890 to operate the transmission system primarily owned by the IOUs and to provide open and non-discriminatory access to the CAISO-controlled transmission system by scheduling loads and resources.
capacity payment	A fixed monthly or yearly payment for generation capacity. Normally assessed on a dollar per kilowatt-month or dollar per megawatt-month basis.
CEC	California Energy Resources Conservation and Development Commission; also known as the California Energy Commission.
CERS	California Energy Resources Scheduling, a division of DWR. CERS' function is the acquisition, scheduling, trading, and dispatching of energy supplies.
city-gate	The location at which natural gas changes ownership or transportation responsibility from an interstate pipeline company to a local distribution company (gas utility).
COI	California-Oregon Intertie. The COI interconnects with the Pacific Northwest at the California-Oregon border and has been identified by the WECC as "Path 66."

GLOSSARY

coincident peak demand	The sum of two or more peak demands which occur in the same demand interval.
Control area	An electrical region in which generation is regulated in order to balance load and maintain planned interchange schedules with other control areas and to assist in controlling the frequency of the interconnected system in accordance with WECC and NERC.
Contractors	Twenty-nine local public agencies that contract with DWR for the supply of water.
CPA	California Consumer Power and Conservation Financing Authority.
CPA Contract	A contract under which CPA will provide DWR with a minimum of 250 MW of load serving capability by October 2002 and 500 MW per month by June 2003. The CPA Contract will extend from July 2002 through May 2007.
CPUC	California Public Utilities Commission.
Customers	Retail electric end-users served by and within the service areas of the IOUs. The term "Customers," when used with respect to Bond Charges, also includes retail electric end-users served by ESPs to the extent a CPUC decision that is final and non-appealable has imposed Bond Charges on such users.
CVP	Central Valley Project.
day-ahead	Twenty-four hours in advance of the need for, or delivery of, capacity or energy.
day-ahead market	The forward market for the supply of electrical power at least 24 hours before delivery to buyers.
DC	Direct current.
Debt Service Reserve Account	An account created under the Indenture which holds reserves to be used only for the payment of debt service on the Bonds and only in the event that all other funds available for such use are fully depleted.
decommissioning	The dismantling of a power plant involving the disassembly of the equipment and transportation of all materials to a site for final disposal.
Department Costs	All amounts that DWR is entitled to recover under the Act, except Bond-Related Costs recovered through Bond Charges.
Diablo Canyon	Diablo Canyon Nuclear Station owned by PG&E and located on the coast of California, near San Luis Obispo.
direct access	The right of an electric end-user to engage in a bilateral contract with an ESP.
direct access charge	A charge that may be established by the CPUC in the future for the purpose of ensuring that Customer participation in direct access does not result in an increase in Bond Charges and Power Charges paid by the remaining Customers.

GLOSSARY

Director	Director of the Department of Water Resources, who is appointed by the Governor, is a part of the Executive Branch, and reports to the Governor through the Secretary of the Resources Agency.
dispatchable generation	Electric generating facilities, the output of which can be increased or decreased, when and as needed, in response to changes in electric demand.
distribution	The wires and related facilities that connect transmission substations with an electric end-user's premises or place of business.
DSM	Demand-side management. Represents the direct or indirect control of peak demands imposed on the electric system by end-users.
DWR	State of California Department of Water Resources.
EG	Electric generation, as used in the context of gas supply and transportation tables.
EIA	United States Energy Information Administration.
electric capacity	The rated continuous load-serving capability, generally expressed in kW or MW, of generation, transmission, or other electrical equipment.
Electric Power Fund	A fund established by SB 7X for the procurement of power supply resources by DWR.
energy requirement	Electrical energy usage by end-users, plus lost and unaccounted for energy, before reductions due to conservation and load management. Customer energy requirements are met through the URG, conservation and load management programs, DWR's power supply contracts, including the Priority Long Term Power Contracts, and spot market purchases through the CAISO.
ESP	Electric service provider; a third-party power supplier to any retail electric end-user connected to the transmission or distribution system of an IOU.
FERC	Federal Energy Regulatory Commission.
firm capacity	Power-producing capacity intended to be available at all times during the period covered by a commitment.
General Fund Loans	Advances from the State's General Fund to DWR to fund DWR administrative costs and purchases of electric capacity and energy on behalf of the Customers.
generation	The production of electricity at power plants or other facilities.
Governor's Proclamation	The proclamation by the Governor of the State of California issued on January 17, 2001, pursuant to which a state of emergency was declared to exist in the State and DWR was ordered to enter into contracts and arrangements for the purchase and sale of electric power as necessary to assist in mitigating the effects of the emergency.

GRC	General Rate Case. A triennial filing made by the IOUs to the CPUC relative to IOU retail rates.
GWh	Gigawatt-hour or 1,000 MWh.
hard cap	The price barrier for purchases that cannot be exceeded under any circumstances.
Henry Hub	A centralized point for natural gas trading in Louisiana that offers shippers access to pipelines that have markets in the Southwest, Gulf Coast, Midwest, and Northeast regions of the United States. Because of the large volumes of natural gas that move through Henry Hub, it is used as the reference pricing point and physical delivery point by the New York Mercantile Exchange for its gas futures contracts.
hour-ahead	One hour in advance of the need for, or delivery of, capacity or energy.
hour-ahead market	The forward market for the supply of electrical power at least one hour before delivery to buyers.
imbalance energy	The difference between the forecast hourly energy requirement and the actual hourly energy requirement. The difference may be due to factors such as load-forecast error, resource or import/export curtailment during the active hour, and inadvertent interchange caused by unmatched loads and resources.
Indenture	The trust indenture between DWR and two trustees providing for the issuance of the Bonds, as amended and supplemented.
Interim Borrowing	A loan entered into on June 26, 2001, among DWR and several financial institutions, aggregating $4.3 billion, the proceeds of which were used by DWR for purchases of electric capacity and energy on behalf of the Customers.
IOU-Owned Generation	Generating resources retained by the IOUs.
IOUs	The major investor-owned electric utilities in California, consisting of PG&E, SCE, and SDG&E.
KV	Kilovolt or 1,000 volts.
KW	Kilowatt or 1,000 watts.
kWh	Kilowatt-hour or 1,000 watt-hours. A unit of work or energy equal to that expended by one kilowatt in one hour.
load	The amount of power supplied by a utility or the amount of power consumed by an end-user over a specified time period. Electric load is also referred to as demand.
load factor	The ratio of the average demand in kW supplied during a designated period to the peak demand in kW occurring during the same period. Load factor is calculated by dividing the kWh in the period by the product of the peak demand and the number of hours in the period.
Malin	A city in southern Oregon. Prices for gas delivered to the northern border of California are quoted at prices delivered to Malin.

market-clearing price	The price at which the last unit of demand for a particular commodity is sold within a specific market.
Mojave	Mojave Generating Station, partially owned by SCE, located in southern Nevada.
MW	Megawatt. One megawatt equals 1,000 kilowatts.
MWh	Megawatt-hour. One megawatt-hour equals 1,000 kilowatt-hours or one million-watt hours.
NCI	Navigant Consulting, Inc.
NERC	North American Electric Reliability Council.
net generation	The amount of electric energy produced by a generating station less the energy used in the operation of the generating station.
net short	The Customers' total electric requirements minus electric generation available from the URG.
NOB	Nevada-Oregon Border.
non-coincident peak demand	The sum of the individual peak demands of two or more electric end-users, groups of end-users, or utility systems, without regard to the time of occurrence.
non-spinning reserves	The portion of off-line generating capacity, controlled by the CAISO, that is capable of being loaded in 10 minutes, or load that is capable of being interrupted in 10 minutes, and that is capable of running (or being interrupted) for at least two hours.
NP 15	The CAISO congestion zone north of Path 15. See Figure III-2 in Appendix III.
NRC	Nuclear Regulatory Commission.
Official Statement	DWR's disclosure statement to potential purchasers of the Bonds.
Operating Account	An account created under the Indenture into which revenues received by DWR from Power Charges are deposited. Deposits to the Operating Account are used for payment of Department Costs, including transfers to the Priority Contract Account.
Operating Reserve Account	An account created under the Indenture that holds reserves to be used for the payment of Department Costs in the event that all other funds available for such use are fully depleted.
Operating Results	Estimated annual DWR revenues and revenue requirements for the January 1, 2002 through December 31, 2011 period, based on an evaluation of actual and projected economic, resource planning, engineering, regulatory, operations, energy procurement, and related matters.
out-of-market purchases	Purchases of power supply resources that have not been bid into the imbalance energy or ancillary services markets and that are called upon or contracted with by the CAISO to avoid an interruption in market operations or to prevent or relieve a system emergency.

Pacific Northwest-Southwest AC-DC Intertie	The extra-high voltage transmission system interconnecting California with the Pacific Northwest.
Palo Verde	Palo Verde Nuclear Generating Station, partially owned by SCE and located near Phoenix, Arizona.
Path 15	A system of transmission lines comprised of two 500 kV AC lines and four 230 kV AC lines that interconnect the Los Banos, Gates, and Midway Substations. Path 15 has historically created constraints in the delivery of power between northern and southern California. See Figure III-2 in Appendix III.
Path 26	A system of three 500 kV AC transmission lines interconnecting the Midway and Vincent Substations in southern California. See Figure III-2 in Appendix III.
Path 27	A DC line consisting of a single 500 kV transmission line interconnecting the Intermountain Power Project in Utah with the Los Angeles Department of Water and Power's Adelanto Substation. See Figure III-2 in Appendix III.
Path 46	A system of AC transmission lines consisting of seven 500 kV lines, one 287 kV line, and six 230 kV lines. Also known as the West-of-River transmission system. See Figure III-2 in Appendix III.
peak demand	The greatest demand that occurs during a prescribed demand interval (such as an hour, day, month, or year).
PG&E	Pacific Gas and Electric Company, the CPUC-regulated subsidiary of PG&E Corporation.
planned outage	Generating units not in operation because of planned maintenance, scheduled closures, refueling, or other planned occurrences.
Power Charges	Charges imposed on the Customers, based on the aggregate amount of power sold to each Customer by DWR, for the purpose of providing funds sufficient to pay Department Costs, including the costs DWR incurs to procure and deliver power.
price elasticity	A change in usage or consumption levels attributable to a change in the price of a product or service.
Priority Contract Account	An account created under the Indenture for payment of amounts due under the Priority Long Term Power Contracts.
Priority Long Term Power Contracts	Power contracts (and fuel contracts) entered into by DWR in connection with its power supply program that provide, in effect, that payments by DWR under the contracts are to be paid or are payable prior to bonds, notes, or other indebtedness of DWR secured by a pledge or assignment of the revenues of DWR under the Act and other amounts in the Electric Power Fund.
PROSYM	A price forecasting and production simulation tool. "PROSYM" is a registered trademark of Henwood Energy Services, Inc.

GLOSSARY

PX	California Power Exchange. An independent, nonprofit public benefit corporation created pursuant to AB 1890, with responsibility for administering a competitive electricity market. The PX ceased operations on January 31, 2001.
PX Block Forward Contracts	Contracts between the PX and the IOUs entered into during 2000 that, following the insolvency of the PX, were commandeered by the State of California to help assure delivery of supply under the original terms of the contracts.
QFs	Qualifying Facilities. QFs are renewable power production or co-generation facilities not primarily engaged in the generation or sale of electric power and that qualify under Section 201 of Public Utilities Regulatory Policy Act of 1978. The output from these facilities is sold to the IOUs under long-term agreements.
Rate Agreement	An agreement between DWR and the CPUC, dated March 8, 2002, as adopted in CPUC Decision 02-02-051.
Rate Order	CPUC Decision 02-02-052, dated February 21, 2002, Decision 02-03-003, dated March 1, 2002, and Decision 02-03-062, dated March 21, 2002, establishing the allocation of DWR revenue collections among the Customers within each IOU service area and the procedures implementing the collection process.
real-time	Actions taken or events occurring on a moment-to-moment or instantaneous basis.
real-time market	The competitive generation market controlled and coordinated by the CAISO for arranging real-time imbalance power. The CAISO is responsible for balancing loads and resources in real time. The market price is calculated in 10-minute intervals on an ex-post (after the fact) basis. This market is available for both in-state and out-of-state participants where trades are made across the western United States.
replacement reserves	Generation that is available and can begin production of electricity within one hour.
Report	The Consultant's Report dated October 1, 2002, prepared by NCI, including transmittal letter, table of contents, glossary, exhibits, and appendices.
reserve margin	The difference between net system capability and peak load. It is the margin available to provide for scheduled maintenance, emergency outages, and system operating requirements.
residual net short	The net short minus the sum of new conservation and load management program savings and DWR contract purchases. The residual net short is expected to be met through short-term contracts (90 days or less), spot purchases in the CAISO day-ahead and hour-ahead markets, and (as necessary) reliability purchases by the CAISO in the imbalance market.

Retail Revenue Requirements	Department Costs that are to be funded from revenues generated from Power Charges. Retail Revenue Requirements do not include Department Costs to be paid from sources other than Power Charges.
retail sales	The sale of electricity by a utility or an ESP to any end-user of electricity.
RFB	Request for bid.
San Onofre	The San Onofre Nuclear Generating Station, which is partially owned by SCE and SDG&E and located on the Pacific Ocean, near San Clemente, California.
SB 6X	Senate Bill 6 of the First Extraordinary Session of 2001, signed into law on May 16, 2001. SB 6X authorizes the creation of the CPA (Chapter 10, Statutes of 2001), which is charged with ensuring, among other things, a sufficient and reliable supply of electricity and natural gas. SB 6X authorizes the CPA to issue up to $5 billion in revenue bond indebtedness to carry out its responsibilities.
SB 7X	Senate Bill 7 (Chapter 3, Statutes of 2001) was passed during the First Extraordinary Session of 2001 and signed into law on January 19, 2001. This bill appropriated $400 million to DWR for power purchases and administrative costs.
SCE	Southern California Edison Company, the CPUC-regulated subsidiary of Edison International Company.
Scheduling Coordinator	An entity authorized to submit to the CAISO a balanced generation or demand schedule on behalf of one or more generators.
SDG&E	San Diego Gas & Electric Company, a CPUC-regulated subsidiary of Sempra Energy.
Servicing Arrangements	Collectively, the Servicing Agreement by and between DWR and SCE, as amended and restated, dated in July 2002, and the Servicing Agreement by and between DWR and SDG&E, as amended and restated, dated in March 2002, which the CPUC approved in an order issued in April 2002 (together, the "Servicing Agreements"), and the order issued by the CPUC in May 2002 covering PG&E (the "PG&E Servicing Order"), under which each IOU is required to collect Bond Charges and Power Charges from the Customers and remit collections to DWR.
sensitivity cases	Analysis of various alternatives, key assumptions, trends, and events to examine their effect on the estimated Operating Results.
soft cap	A price barrier that, if exceeded, may subject the seller to subsequent regulatory monitoring and reporting requirements, including the potential for having to pay refunds for prices charged above the price barrier.
SoCalGas	Southern California Gas Company, a CPUC-regulated subsidiary of Sempra Energy.
SP 15	The CAISO zone south of Path 15. See Figure III-2 in Appendix III.

spinning reserves	The portion of unloaded synchronized generating capacity, controlled by the CAISO, that is capable of being loaded in 10 minutes and that is capable of running for at least two hours.
spot market	A market in which electric capacity and energy is purchased and sold for periods of less than 30 days in duration.
Stage 1 Emergency	A Stage 1 Emergency is declared when the CAISO determines that actual or anticipated operating reserves will be less than the WECC minimum operating reserve criteria (five percent of hydroelectric resources and seven percent of other resources, or the largest single contingency (a generating unit or intertie)) within the ensuing two hours. A Stage 1 Emergency is less severe than a Stage 2 or Stage 3 Emergency. Stage 1 Emergencies do not require interruption of service to electric end-users.
Stage 2 Emergency	A Stage 2 Emergency is declared when the CAISO determines there will be a serious operating reserve shortfall (less than five percent) within the ensuing two hours. At this stage, interruption of service to selected electric end-users is required. Many end-users have agreed to be interrupted in the event of a Stage 2 Emergency. These end-users receive a reduced rate for their electric service as compensation for their agreement to be interrupted.
Stage 3 Emergency	A Stage 3 Emergency is declared when the CAISO determines there will be a critical operating reserve shortfall (less than 1.5 percent) within the ensuing two hours. Stage 3 Emergencies are the most severe emergencies and indicate that, without significant CAISO intervention, the electrical system is in danger of imminent collapse. Involuntary curtailment of service to electric end-users (rolling blackouts) is required to maintain operating reserve margins above 1.5 percent.
State	State of California.
State Water Project	The State Water Project is a complex of dams, water storage facilities, aqueducts, pumping stations, and electric generation facilities which have been constructed by DWR for the purpose of developing water supply resources, conveying water to areas of need within California, and providing flood control, recreation, fish and wildlife enhancement, hydroelectric power, and other benefits.
Study Period	The period from January 1, 2002 through December 31, 2011.
Tcf	Trillion cubic feet.
Topock	A location near the border crossing from Arizona into California. Prices for natural gas delivered to the southern California border crossing are quoted at prices delivered to Topock.
tolling agreements	Power purchase contracts containing a variable fuel cost that changes as the price of fuel (in the form of natural gas) changes, or provides an opportunity for the purchaser to provide the fuel for the generation facility and convert that fuel to electricity at an agreed-upon conversion rate or formula.

TOU	Time of use. Refers to the pricing of electricity based on usage levels during specific time periods of the day. Employed as an electric conservation program to discourage peak hour use.
transmission	The wires that run from generators to carry power to distribution facilities. Transmission is usually defined as wires operated at voltages of 60,000 volts and higher.
transmission substation	The equipment used to transform high voltage electricity to lower voltage electricity so that it can be delivered to electric end-users on the distribution system.
unit-contingent	Contracts that are generator-specific, with the delivery of energy contingent upon operation of the generator.
URG	Utility Retained Generation, which includes the IOU-Owned Generation, QF contracts, and bilateral contracts held by the IOUs.
USBR	United States Bureau of Reclamation.
Western	Western Area Power Administration.
WECC	Western Electricity Coordinating Council (formerly, the Western Systems Coordinating Council), a non-profit reliability council responsible for planning and coordinating regional transmission development and operations for reliability purposes. The WECC covers the western part of the continental United States, Canada, and Mexico. The WECC region includes Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Washington, Wyoming, and Utah, the Canadian provinces of Alberta and British Columbia, and the northern-most portion of Mexico.
wheeling	The use of transmission facilities owned by a third party to transmit electricity.
ZP 26	The CAISO zone located in central California between SP 15 and NP 15. See Figure III-2 in Appendix III.

INTRODUCTION

Presented herein is the Consultant's Report (the "Report") of Navigant Consulting, Inc. ("NCI") resulting from NCI's analyses and investigations in connection with the proposed issuance by the Department of Water Resources ("DWR") of the State of California ("State") of up to $11.95 billion aggregate principal amount of Power Supply Revenue Bonds (the "Bonds"). DWR intends to issue the Bonds in multiple series, which are being issued pursuant to the Trust Indenture (the "Indenture"), and Division 27 (commencing with Section 80000) of the California Water Code (the "Act").

The Bonds are described in the Official Statement of DWR (the "Official Statement") to which this Report is appended. This Report and the Official Statement should be read in their entirety for an understanding of DWR, the Bonds, DWR's power supply program, and DWR's revenue sources.

OVERVIEW

Since January 17, 2001, DWR has filled a vital role in meeting a portion of the power supply needs of the retail electric end-users served by and within the service areas of the three major investor-owned electric utilities in California (the "Customers"). This overview provides a description of the events leading to DWR's active role as power supplier and the measures it has taken to ensure an adequate and stable supply of electricity for the Customers.

Circumstances Leading to DWR's Role as Power Supplier

Following the passage of California's electric utility industry restructuring legislation in 1996 (Assembly Bill 1890 or "AB 1890"), Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE"), and San Diego Gas & Electric Company ("SDG&E") (collectively, the "IOUs"), sold most of their non-nuclear thermal generation to non-regulated power producers. Following the sale of these assets, the IOUs relied on purchases through the California Power Exchange (the "PX") and the California Independent System Operator Corporation ("CAISO") to meet the power supply needs not otherwise provided by their retained generation and other sources described below. The prices paid for electricity purchased through the PX and CAISO were based on market-clearing prices, and every bidder whose bid was selected received (and the IOUs were obligated to pay) the highest price of the selected bids for that purchase period (for example, the day-ahead market or the hour-ahead market). In theory, as long as there was a reasonable excess of power supply bid into the California market, this mechanism created competition to keep prices in check. By summer 2000, however, insufficient power supply was being bid into the PX and CAISO, and prices began to rise, swiftly and dramatically.

While wholesale prices for electricity increased precipitously during 2000, the retail rates of PG&E and SCE were frozen as part of the industry restructuring created by AB 1890. By December 2000, PG&E and SCE had incurred several billion dollars of electricity purchase obligations in excess of revenues received from the end-users they serve, eventually resulting in their inability to pay power bills due the PX, the CAISO, and other suppliers. In January 2001, the credit ratings of PG&E and SCE were downgraded below investment grade status by the major rating agencies. Due to PG&E and SCE's default on power payments, the PX soon became insolvent and ceased trading in the market in January 2001.

The credit difficulties experienced by PG&E and SCE contributed to a reduction of power supply resources bid into the California market. Those power suppliers still willing to sell into

the market began assessing credit premiums on power sold to the IOUs, further escalating the market price of electricity. These circumstances created an immediate need for a creditworthy party to assume the obligation of purchasing the electricity needed to meet the needs of the Customers. On January 17, 2001, the Governor declared a state of emergency and authorized DWR to begin purchasing the Customers' electric requirements not otherwise met by the IOUs' retained generation and other sources (the "net short"). On January 19, 2001, Senate Bill 7 was passed during the First Extraordinary Session of 2001 and signed into law ("SB 7X"). This bill confirmed DWR's responsibilities in the emergency and appropriated $400 million to DWR for power purchases and administrative costs. The State Legislature passed Assembly Bill 1 from the First Extraordinary Session on February 1, 2001, which authorized DWR to purchase the electric requirements of the Customers not otherwise met by the IOUs, and to issue the Bonds. This legislation further provided for advances from the State's General Fund, on an interim basis pending issuance of the Bonds, to enable DWR to make such purchases (together with the $400 million appropriated under SB 7X, the "General Fund Loans").

Under the Act, DWR is authorized through December 31, 2002, to enter into contracts for power supply. The contracts entered into prior to that date may extend beyond December 31, 2002, and DWR is authorized to continue its management and administration of these contracts through their termination dates. Absent State action to extend DWR's ability to enter into new contracts after December 31, 2002, any net short requirements not met by DWR's contracts or new conservation and load management programs (referred to as the "residual net short") after 2002 must be met by a creditworthy entity other than DWR.

DWR and the California Public Utilities Commission ("CPUC") are developing plans to have the IOUs purchase the residual net short beginning on or before January 1, 2003. In addition, the State has taken and continues to take steps designed to enable the IOUs to eventually take over the provision of the entire net short through assignment of the DWR contracts (or management of the contracts) so that DWR may terminate its role as a power supplier. Please see the section of this Report entitled "PLAN TO TRANSITION DWR NET SHORT RESPONSIBILITIES" for further discussion of DWR and the CPUC's plans to return responsibility for power supply to the IOUs.

What is the "Net Short"?

The Customers' net short electric requirement is the difference between total Customer electric requirements and the amount of electricity the IOUs provide from what is referred to as "Utility Retained Generation" or "URG". URG includes the generating resources the IOUs still own (the "IOU-Owned Generation"), the output from qualifying facilities or "QFs"(as described more fully in this Report), and the power from contracts the IOUs have entered into with various suppliers ("bilateral contracts"). Assuming no change in Customer requirements, the greater the level of production from the URG, the less the net short that needs to be supplied. Conversely, reductions in the level of electricity provided from the URG increase the quantity of the net short.

Actions Undertaken to Gain Control of Demand, Supply, and Cost

During 2001, DWR and other organizations within State government undertook numerous short-term or one-time actions aimed at achieving some level of control over Customer demand, the availability of electrical supply, and the price paid for that supply. These actions included, but were not limited to:

- Increasing IOU retail electric rates by up to 40 percent;
- Funding various voluntary summer peak period load curtailment programs;

- Funding several energy efficiency and other conservation programs;
- Creating a new accelerated 21-day permitting process for new peaking generation facilities brought on-line during the summer of 2001;
- Contracting with developers of peaking facilities willing to accelerate development of new peaking generation; and
- Modifying the energy price formula for QF contractors to better track actual natural gas prices against the costs of gas-fired QFs.

DWR and the State undertook several additional actions during 2001 that continue to be relied on today to gain control over and maintain the California power market. These actions include the following:

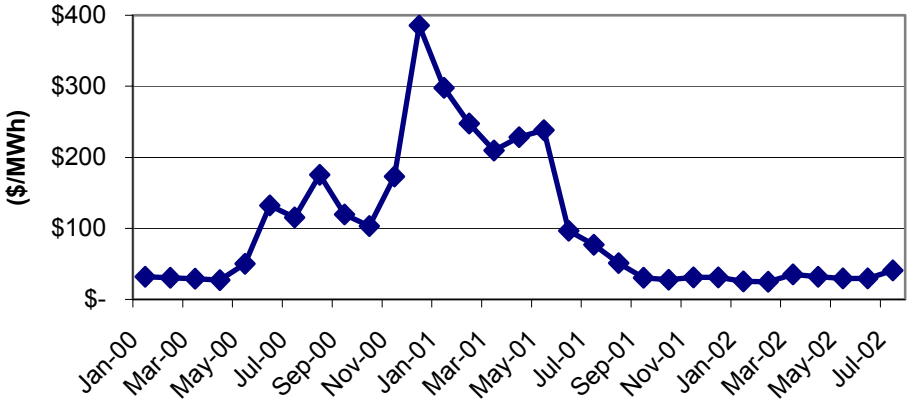
- Eliminating the former PX's pricing mechanism and replacing it with a "pay-as-bid" purchasing method for all transactions except the CAISO's real-time purchases and ancillary market purchases;
- Competitively soliciting long-term, bilateral contracts that provided the ability to lock in gas forward contracts to avoid the volatility of spot market prices; and
- Modifying DWR energy procurement practices to achieve a wider range of short-term purchases.

Since initiation of the above efforts in January 2001, the spot market price of power in California has changed dramatically. As shown in Figure 1, the average prices for spot market purchases dropped from approximately $298 per MWh during January 2001, when DWR began acquiring power on behalf of the Customers, to $77 per MWh and $31 per MWh during July 2001 and December 2001, respectively. During the first seven months of 2002, the average price for spot market purchases averaged slightly more than $30 per MWh. NCI believes this substantial decrease in the cost of spot market power is partially the result of the measures taken to gain control over the wholesale power market in California, including long-term contracts entered into by DWR. The changes in price and availability of wholesale electricity do not mean that volatility has left the marketplace entirely. However, the significant decrease in the volume of energy required to be purchased in the spot market (due to the existence of long-term contracts entered into by DWR) has helped to limit the potential volatility of the total cost of wholesale energy needed to serve the Customers. Figure 4 and Exhibit 14 provide additional information on the effect of the DWR contracts on the residual net short. Summary information on the long-term power supply contracts entered into by DWR and effective as of the date of this Report may be found in Appendix I.

The CPUC has also undertaken actions, and is considering actions, designed to stabilize the California energy market and restore the financial health of the IOUs. These actions include the previously referenced IOU retail rate increases, limitations on the Customers' ability to take delivery from alternative power suppliers, the ability for the IOUs to contract for power supply resources in excess of their URG, establishment of purchasing standards and criteria that would eliminate after-the-fact reasonableness reviews of IOU power purchase transactions, and maintenance of existing IOU retail rate levels to support the financial recovery of the IOUs. Likewise, the CAISO is considering actions that would aid in stabilizing the California energy market, including standards that would require each IOU to have adequate resources to meet the full requirements of the Customers, including reasonable reserve margins. Combined with the Federal Energy Regulatory Commission's ("FERC") June 19, 2001, order establishing market price caps and requiring generators to sell power, these actions will impose increased regulation on the IOUs, while promoting increased stability in the loads served by the IOUs and the resources

available to meet those loads. Additional information on the actions being considered by the CAISO may be found in Appendix III of this Report.

FIGURE 1
CALIFORNIA SPOT MARKET PRICES



Sources: January 2000-December 2001 - California PX Unconstrained Statewide Market Clearing Price (Day-Ahead and Hour-Ahead). February 2001-July 2002 - California Department of Water Resources Day-Ahead and Hour-Ahead Purchases. January 2001 includes costs and volumes from both sources.

PURPOSE OF THE REPORT AND ROLE OF NCI

NCI has been retained by DWR to evaluate the economic, resource planning, engineering, regulatory, operations, energy procurement, and related matters supporting the preparation of an estimate of annual operating results for DWR (the "Operating Results") for the January 1, 2002 through December 31, 2011 period (the "Study Period"). The estimate of Operating Results reflects DWR's activities with respect to its authorization under the Act and does not take into account or represent its management and operation of the State Water Project.

DWR has relied on the General Fund Loans, the proceeds of a $4.3 billion interim loan entered into on June 26, 2001, with several financial institutions (the "Interim Borrowing"), and revenues collected from the Customers to satisfy its revenue requirements associated with the power supply program. The proceeds of the Bonds will be used, in part, to reimburse the State's General Fund for the General Fund Loans and repay the Interim Borrowing. Payment of debt service and related obligations associated with the Bonds after 2002 will be funded through Bond Charges (as hereinafter defined) collected from the Customers, while power supply-related costs will be funded primarily through a separate charge collected from the Customers (the "Power Charges"). This Report evaluates the adequacy of estimated Bond Charge collections, the availability and cost of power supply to meet the needs of the Customers, the Power Charges estimated to be assessed the Customers, and the adequacy of reserve funds established by DWR to support its power supply operations and repayment of the Bonds.

In addition to its role as consultant to DWR in connection with the issuance of the Bonds, NCI provides technical, regulatory, and economic analysis support to the electric procurement process for DWR. These separate services, as an independent advisor to DWR, include, but are not limited to, evaluation of the estimates of net short electric requirements provided to DWR by the IOUs, support in the evaluation and negotiation of power supply contracts, compilation and periodic updating of power supply quantities and costs from contracted power supply sources, estimation of fuel supply costs and requirements for contracted power supplies, estimation of

future power purchase costs in the short-term market, evaluation of electric transmission constraints and associated impact on power supply deliveries, review of actions by other power suppliers and state governmental agencies for effect on the availability and cost of power supplies to meet the Customers' net short electric requirements, assistance to DWR in the development of future estimated DWR revenue requirements, and support to DWR in filings with the CPUC on revenue recovery and related issues.

NCI is a nationally recognized firm of management consultants, engineers, economists, and regulatory specialists headquartered in Chicago, Illinois, with offices throughout the United States and abroad, including a major office in Sacramento, California, that provides in-depth expertise on the power market in California and the western United States. NCI's Energy and Water Practice provides services to energy firms and public agencies, including, but not limited to, electric and gas utilities, power producers, fuel suppliers, and power marketers. Typical services include power marketing analysis, transmission and distribution system planning, generation facilities evaluation, rate and pricing studies, environmental assessments, conservation and demand-side management ("DSM") program development and evaluation, strategic planning, marketing studies, and related services. The role of NCI in the DWR electricity procurement process, as well as its historical and ongoing relationship with other clients, has served to provide information, experience, and expertise useful in preparing this Report, but also could be perceived as potential sources of bias or conflict of interest. Please see the section entitled "RELATIONSHIPS" in the Official Statement for additional information on this subject.

For purposes of the development of DWR's Operating Results and the preparation of this Report, NCI has made investigations and analyses, including, but not limited to, discussions with staff and representatives of and/or review of reports or information prepared by DWR, the CPUC, the California Energy Commission (the "CEC"), FERC, PG&E, SCE, SDG&E, and the CAISO, and examinations of reports and projections prepared by consultants and advisors to DWR, which NCI deemed necessary and appropriate to reach its conclusions. NCI's investigations and analyses were conducted with particular emphasis on consideration of those items of major potential economic, financial, and operational impact on the future operations of DWR in its role as supplier of electric capacity and energy to the Customers, the repayment by the Customers of the power supply services provided by DWR, and the recovery of DWR's Bond-Related Costs from the Customers. This Report summarizes NCI's findings and presents certain technical and economic information concerning DWR, the CAISO, PG&E, SCE, SDG&E, and the Bonds. This Report and the Official Statement should be read in their entirety for information on DWR and the Bonds.

CONCLUSIONS

On the basis of the considerations, assumptions, studies, and analyses described in this Report, NCI presents the following conclusions. This Report and the Official Statement should be read in their entirety before making any decision or judgment whether or not to purchase the Bonds based on the conclusions presented herein.

DWR REVENUE RECOVERY

1. The Rate Agreement between DWR and the CPUC provides a reasonable mechanism for the establishment and, as needed, timely adjustment and implementation of Bond Charges and Power Charges to be recovered from the Customers for the benefit of DWR.
2. Bond Charges can reasonably be expected to be collected in amounts which, together with funds held in the Bond Charge Payment Account, will be sufficient to meet the obligations

payable from the Bond Charge Payment Account when due, including principal and interest payments on the Bonds, parity contract obligations, fiduciary costs, and, under certain circumstances, Bond servicing agreement and administrative costs.

3. Power Charges can reasonably be expected to be collected in amounts which, together with other revenues deposited in the Operating Account and reserve funds in the Operating Reserve Account under the Indenture, will be sufficient to pay the Priority Long Term Power Contract payments when due without reliance on transfers from the Bond Charge Collection Account held under the Indenture, and to pay other Department Costs.

4. Variations in total Customer energy requirements, including residual net short requirements, short-term increases in natural gas prices, and extension of DWR's responsibility for the residual net short, all as measured against the Base Case described in this Report and summarized in the section entitled "SENSITIVITY ANALYSES," are not reasonably expected to result in the use of funds held in the Bond Charge Collection Account under the Indenture to pay DWR's Retail Revenue Requirements if the increases to the Power Charges and Bond Charges identified in Table 21 are made in a timely manner.

5. The Servicing Arrangements between DWR and the IOUs provide a reasonable mechanism for the complete and timely billing, collection, and remittance to DWR of Bond Charges and Power Charges imposed upon the Customers.

POWER SUPPLY RESOURCES

6. DWR can reasonably expect to incur expenditures for net short capacity and energy requirements over the Study Period as reflected in Exhibit 19.

7. Adequate power supply resources are expected to be available to meet the residual net short capacity and energy requirements of the Customers at costs, on average, which are comparable to those set forth in this Report.

8. If a power supplier that has entered into a long-term contract with DWR is unable to fulfill its contractual obligations due to financial or other reasons, replacement power supply resources can be expected to be secured, at costs, in the aggregate, that are not materially higher than the costs that would have been paid the power supplier, so long as the underlying power supply resources no longer under contract are not withdrawn from the market.

DWR MANAGEMENT AND OPERATIONS

9. Through a combination of its own staff and out-sourced professional services, DWR has been and can be expected to continue to be successful in fulfilling its responsibilities in connection with the acquisition and management of net short power supply resources for the Customers.

10. If required to purchase the residual net short requirements of the Customers after December 31, 2002, DWR can be expected to retain the necessary staff and out-sourced professional services to successfully manage and acquire the power supply resources needed to meet the needs of the Customers.

FUEL SUPPLIES

11. Natural gas supplies can reasonably be expected to be available and delivered during the Study Period in the quantities needed to meet the needs of existing and proposed new gas-

fired electric generating facilities serving California, at costs approximating those described in this Report and shown in Tables 14 and 15.

SELF-GENERATION

12. Self-generation, beyond that incorporated in the estimates contained within this Report, is not expected to result in a material reduction in the capacity and energy requirements of the Customers during the Study Period or have a material impact on the net short capacity and energy requirements supplied to the Customers by DWR.

TRANSMISSION SYSTEM

13. The existing high-voltage transmission systems serving California, together with normal and prudent improvements by the IOUs or others during the Study Period, are capable of transmitting the capacity and energy requirements of the Customers set forth in Exhibits 2 and 3 during the Study Period.
14. The IOUs or others can reasonably be expected to construct high-voltage transmission improvements to reduce those transmission constraints that are discussed in Appendix III of this Report.

STUDY ASSUMPTIONS

15. The assumptions upon which this Report is based, which are described beginning on page A-74 of this Report, including the assumptions incorporated in the determination of net short and residual net short capacity and energy requirements and estimated annual DWR revenues and revenue requirements, are reasonable.

The remainder of this Report provides a description of DWR, the Customers' estimated power and energy requirements, the resources estimated to be available to meet those requirements, and the costs estimated to be incurred during the Study Period by DWR for power supply services provided to the Customers. Also included is a description of the mechanisms in place to provide the recovery of costs incurred by DWR from the Customers.

CALIFORNIA DEPARTMENT OF WATER RESOURCES

DWR has created an organization capable of securing and managing the power supply needs of the Customers and has aggressively pursued new power supply resources to meet daily net short requirements in a manner that has assisted in bringing stability to the energy marketplace. At the same time, DWR has created an organization capable of managing and administering the power supply portfolio, with a staff of permanent employees and contract personnel.

OVERVIEW AND DESCRIPTION OF OPERATIONS

DWR is a department of the State of California that, in addition to the power supply program described herein, is responsible for the planning, construction, and operation of the State Water Project. Since the early 1980s, DWR has actively purchased and sold energy to meet a portion of the approximately 2,400 MW of pumping needs of the State Water Project.

DWR was established in 1956 by an act of the California State Legislature. At present, DWR employs approximately 2,600 full-time staff throughout California. The Director of the Department of Water Resources (the "Director"), with the assistance of a Chief Deputy Director

and four Deputy Directors, oversees DWR business. The Director and Chief Deputy Director are appointed by the Governor and, as a part of the Executive Branch, report to the Governor through the Secretary of the Resources Agency.

State Water Project

The State Water Project is a complex of dams, water storage facilities, aqueducts, pumping stations, and electric generation facilities which have been constructed by DWR for the purpose of developing water supply resources, conveying water to areas of need within California, and providing flood control, recreation, fish and wildlife enhancement, hydroelectric power, and other benefits. All 647 miles of the planned conveyance system have been completed. The 444-mile main stem California Aqueduct runs from a point near Stockton southward to a terminus in Riverside County.

DWR has entered into water supply contracts with 29 local public agencies (the "Contractors") for the delivery of water supplies through the State Water Project. Payments received by DWR from the Contractors are pledged to annual operation and maintenance costs, the repayment of State Water Project Bonds, and other expenditures associated with the State Water Project and are not available for repayment of the Bonds.

State Water Project Electric Resources

Since the commencement of the major facilities of the State Water Project in the 1960s, DWR has been an active participant in the power markets of California and the western United States. DWR, on behalf of the State Water Project, is the largest single purchaser and user of power in the State and owns eight hydroelectric generating facilities and a portion of one coal-fired power plant. DWR's share of these hydroelectric and coal-fired generating facilities totals approximately 1,757 MW and 226 MW, respectively. These resources are relied on for operation of the State Water Project and are not included in the contract resources DWR has secured to meet the Customers' net short requirements.

In addition to the power plants it owns in whole or part in connection with the State Water Project, DWR has long-term contracts for the purchase of power from utility and non-utility generators in California and adjacent states. DWR, on behalf of the State Water Project, also participates actively in the spot markets in order to optimize its generating resources and load characteristics and more generally to provide its power needs in connection with the State Water Project.

California Energy Resource Scheduling

To meet its obligations under the Act, DWR has developed a functional unit that operates its California Energy Resource Scheduling ("CERS") division. As of July 30, 2002, CERS' staffing consists of 54 permanent staff and 71 contract employees and consulting advisors. CERS also relies on four employees on loan from other departments within State government. CERS is not actively recruiting additional employees due to a hiring freeze ordered by the Governor for all State departments, but plans to fill seven positions when it is free to do so. CERS is funded and operated separately from the DWR staff that manages the State Water Project. Revenues received by DWR from the Customers are not used to fund any aspect of the State Water Project. Similarly, revenues received by the State Water Project are not used to fund CERS' operations.

CERS performs all of the functions necessary for an organization dealing with large numbers of transactions. CERS performs the day-ahead scheduling to cover the estimated net

short for the next day(s) and enters into transactions in the hour-ahead market to cover the remainder of the net short. CERS reconciles the transactions made during the day with the CAISO and other suppliers. CERS performs a monthly reconciliation with suppliers and receives and processes invoices to effectuate payment by DWR's Division of Fiscal Services.

As described later in this section, CERS also has a risk management function that reviews the creditworthiness of counter parties prior to completing various trading activities. CERS' risk management function also sets trading limits with entities that do business with CERS.

ENERGY SUPPLY OPERATIONS AND RESOURCE SCHEDULING

CERS consists of the Energy Reliability and Trading Office, the Risk Management and Fiscal Office, and the Energy Commodity Office. These offices operate under the direction of a Deputy Director, who has been permanently assigned to CERS. CERS receives legal assistance, as needed, from DWR's legal counsel and accounting assistance from DWR's Division of Fiscal Services.

The Energy Reliability and Trading Office houses the day-ahead and real-time schedulers and traders, and the settlements group. These personnel are responsible for scheduling the dispatch of resources under contract to DWR and acquiring spot market supplies needed to meet the residual net short requirements of the Customers. This group also handles the processing of transactions entered into by DWR.

The Risk Management and Fiscal Office is responsible for CERS' risk management and invoicing functions. Personnel in this office track the energy markets in California and develop forecasting tools and strategies to minimize the cost of purchases for the Customers. This group also performs the billing function and approves invoices, which are subsequently submitted to DWR's Division of Fiscal Services for payment.

The Energy Commodity Office negotiates and develops long- and short-term contracts for the purchase of power. This group periodically performs load forecasting and transmission system studies to analyze existing contracts and to recommend changes in operations to take advantage of various contract provisions.

Coordination with the IOUs

DWR coordinates with the IOUs on a day-ahead basis to determine the amount of energy to purchase for each hour of each day. On a day-ahead basis, the IOUs' schedulers provide an estimated schedule, by hour, of their resource deficiencies to DWR (these deficiencies constitute the net short). DWR uses long-term contracts, monthly contracts, and spot market purchases to supply the net short requirements for the upcoming day. Because there is limited capability to move energy between northern California and southern California, purchases are typically made from resources that, within transmission system limitations, are geographically located in the respective areas where the demand originates; otherwise the transmission system becomes overloaded.

DWR Role in Managing Energy Supply

Pursuant to authorizations under the Act, and as described in this Report, DWR has actively pursued the acquisition and promoted the development of energy resources by others to meet the net short requirements of the Customers. These activities are focused, in part, on maximizing the use and benefit of power supply resources under contract to DWR and

minimizing the costs of the net short requirements, to the extent achievable. Key activities being undertaken by DWR in meeting these needs are described below.

Forecast of Power Needs

Since January 2001, DWR has initiated planning efforts to assess the demand for electricity over a 10-year planning horizon. These estimates of future electric needs are compared to the power supply capability of the URG to determine the projected net short, the expected utilization of DWR contract power, and the quantities of residual net short to be acquired through short-term purchases. Once DWR is no longer responsible for the residual net short, and assuming the long-term power contracts are assigned to or managed by the IOUs (as described later in this Report), DWR is no longer expected to engage in such resource planning efforts.

Contract Negotiations

As of July 30, 2002, DWR had entered into 37 power purchase contracts with 23 sellers of energy, collectively providing an average of more than 9,338 MW of capacity per year over the Study Period. These contracts vary in length, with certain contracts extending beyond the Study Period (the longest of which terminates in 2013). In addition to these contracts, DWR has entered into, and will continue to enter into through December 31, 2002, various quarterly, monthly, and balance-of-the-month contracts to limit its exposure to price volatility in the spot market.

As a result of the significant improvement in market conditions and the corresponding reduction in energy prices during the latter half of 2001 and early 2002, DWR initiated efforts to renegotiate several of its long-term power supply contracts. These renegotiations are aimed at achieving contract price reductions that more closely mirror current market conditions, among other goals, while continuing to ensure a reliable and adequate source of net short power supply for the Customers. Through August 23, 2002, DWR announced it had successfully renegotiated 17 contracts with seven power suppliers resulting in approximately $2.0 billion in nominal net contract savings (after the cost of system impacts and additional dispatchable generation). DWR continues to seek renegotiations with many of the remaining power suppliers, but cannot predict the number of additional contract revisions that will be achieved or the magnitude of the price reductions, if any. The financial projections set forth in this Report do not reflect the renegotiation of any additional DWR power supply contracts. Information on the renegotiated contracts may be found in the section of this Report entitled "POWER SUPPLY RESOURCES—DWR Resources—*Renegotiation of DWR Contracts*." Summary information on all of the long-term power supply contracts entered into by DWR, including those that have been renegotiated, may be found in Appendix I of this Report. The information provided in Appendix I reflects contracts in effect as of August 23, 2002, and does not include information for contracts whose terms have expired.

Economic Scheduling of Resources

DWR has the ability to schedule varying amounts of energy from contracted capacity with nine suppliers representing up to 3,955 MW of generating capacity. With this flexibility, DWR adjusts the generation schedules for these resources upward when needed for power supply reliability, or when spot market prices are higher than costs to operate the generating units under contract. Similarly, DWR adjusts the generation schedules downward whenever spot market prices are more favorable than the contract prices for these resources. Using this flexibility, DWR attempts to minimize its costs to supply the net short, as market conditions and fuel prices allow.

Acquisition of Summer Resources

As of July 30, 2002, DWR had contracted for 8,174 MW of summer 2002 peak capacity and 10,900 MW of summer 2003 peak capacity (excluding renewable and as available resources). These values compare to 3,967 MW under contract during the summer 2001. Under these contracts, DWR makes fixed payments to the owners of the generating resources to assure that the capacity will be available at all times to meet peak loads. DWR also has the option to purchase the energy associated with the capacity during certain hours.

Development of Risk Mitigation Program

DWR, with the assistance of Deloitte & Touche, L.L.C ("Deloitte"), has implemented an energy transaction and risk management software system. This system, in conjunction with other applications, is used to identify, quantify, manage, and monitor the market, administrative, and credit risks associated with the power purchase agreements DWR has executed. The system is used by the risk management, market analysis, operations, forecasting, and trading groups within DWR.

Transaction limits and purchasing strategies for electrical power and natural gas have been established and documented by DWR. A risk management policy has been prepared that documents the roles and responsibilities of various positions within CERS to assure appropriate segregation of duties and the establishment of a risk oversight committee. This committee will review and approve changes to transaction limits and purchasing strategies and will review reports for compliance with these and other policies. As of the date of this Report, the risk management policy is in draft form awaiting final management approval by DWR.

DWR's credit manager, with the assistance of Deloitte, analyzes the financial statements of DWR's counter parties on an on-going basis and recommends credit limits to DWR management. DWR risk management personnel have facilitated DWR's efforts to use financial hedging instruments for natural gas and, in conjunction with the assistance of a third-party advisor, have developed transaction limits and purchasing strategies for power and natural gas.

A number of the long-term power purchase agreements that DWR has entered into allow it to purchase the natural gas needed to generate energy and deliver that natural gas to the generating unit's burner tip or other mutually acceptable location. DWR has purchased natural gas for three of the power purchase agreements that have such provisions and is considering purchasing gas in connection with three additional agreements. For the January through October 2002 period, total gas purchases are estimated to average just over 48 percent of monthly requirements for the three tolling agreements.

DWR has combined its ability to purchase natural gas for power plant operations with financial hedges in order to manage fuel price risk in a cost effective manner. Two agents have been selected for the purchase of financial hedges on behalf of DWR. One margin account has been established in order to facilitate these purchases. Through these accounts, DWR has entered into financial hedges in the form of futures and options associated with a small portion of its gas supply requirements (less than 10 percent) for the months of July through December 2002. These hedges have been taken as an alternative to forward purchases and were established to mitigate the effect of potential gas price increases during the hedge period.

THE RATE AGREEMENT

On February 21, 2002, the CPUC issued a decision approving an agreement establishing the CPUC's obligation and the procedures to be followed to calculate, revise, and impose the charges to the Customers for DWR power for the recovery of DWR's revenue requirements (the "Rate Agreement"). The Rate Agreement provides for two streams of revenue to DWR. One stream of revenue comes from "Bond Charges" imposed on Customers for the purpose of providing sufficient funds to pay "Bond-Related Costs." The term "Customers," when used with respect to Bond Charges, includes retail electric end-users served by electric service providers ("ESPs") to the extent a CPUC decision that is final and non-appealable has imposed Bond Charges on such users. Bond Charges are applied based on the aggregate amount of electric power sold to each Customer by DWR and the applicable IOU, or as applicable, an ESP. Bond-Related Costs include amounts equivalent to Bond debt service, credit enhancement and liquidity facilities charges, and costs relating to other financial instruments, fiduciary costs, administrative costs, and servicing arrangements entered into in connection with the Bonds, and, if and when DWR no longer sells power, certain administrative and servicing costs. The Bond Charges will be imposed upon Customers whether or not DWR is selling power to those customers. The Rate Agreement requires the CPUC to impose Bond Charges that are sufficient to pay all Bond-Related Costs as they come due.

The second stream of revenue comes from "Power Charges" imposed on Customers who buy power from DWR, and is designed to pay for "Department Costs," including the costs that DWR incurs to procure and deliver power, but not including Bond-Related Costs paid through Bond Charges. The Rate Agreement requires the CPUC to impose Power Charges that are sufficient to provide moneys in the amounts and at the times necessary to satisfy the Retail Revenue Requirements (defined below) specified by DWR. Revenues received from Power Charges and Bond Charges, as well as the payment of expenditures and obligations from such revenues, are held in and accounted for in the fund established by SB 7X for the procurement of power supply resources by DWR (the "Electric Power Fund").

To enable the CPUC to set Bond Charges and Power Charges, the Rate Agreement requires DWR to submit its "Retail Revenue Requirements" to the CPUC. The Rate Agreement defines Retail Revenue Requirements as the amount of Department Costs that must be recovered from Power Charges. The Rate Agreement uses DWR's submittal of its Retail Revenue Requirements as a vehicle for DWR to notify the CPUC not only about Department Costs, but also about Bond-Related Costs.

Revenues from Power Charges will be deposited into an "Operating Account." Funds in the Operating Account will be used to pay for Department Costs, and funds also will be transferred to a "Priority Contract Account." The Priority Contract Account will be used to pay for the costs that DWR incurs under its Priority Long Term Power Contracts, which have terms that require DWR to pay for power purchased under these contracts ahead of Bond-Related Costs (such as Bond debt service).

Revenues from Bond Charges will be deposited into a "Bond Charge Collection Account." Funds in the Bond Charge Collection Account will be transferred periodically to a "Bond Charge Payment Account." Funds in the Bond Charge Payment Account may only be used to pay Bond-Related Costs. However, so long as funds remain in the Bond Charge Collection Account, they may be used to pay amounts due under the Priority Long Term Power Contracts to fulfill the priority payment requirements of those contracts, if the amounts in the Operating Account, the Priority Contract Account, and the "Operating Reserve Account" are insufficient for that purpose. If the Bond Charge Collection Account is used to fund amounts due

under the Priority Long Term Power Contracts, then the Bond Charge Collection Account will be replenished from Power Charges.

The flow of funds relating to revenues from Power Charges has been designed to provide that the Priority Long Term Power Contracts will be paid each month from such moneys before any payment or funding of any other Department Costs. This reduces the likelihood that Bond Charges would be used for the Priority Long Term Power Contracts costs. Please see the section entitled "SOURCES OF FUNDS TO PAY DEBT SERVICE" in the Official Statement for more information on the flow of funds under the Rate Agreement.

DWR must submit revised Retail Revenue Requirements if it projects that any of the following will occur within 120 days: (i) there will be insufficient funds in the Priority Contract Account to pay amounts due under the Priority Long Term Power Contracts; (ii) the balance in the Operating Reserve Account will fall below required funding levels; or (iii) it will be necessary to use funds in the Bond Charge Collection Account to pay for costs incurred by DWR under the Priority Long Term Power Contracts.

If DWR has complied with the obligations described in the foregoing paragraph, but nevertheless projects that amounts in the Bond Charge Payment Account will be insufficient to pay Bond-Related Costs, DWR is required to submit its revised requirement for Bond Charges to the CPUC. The Rate Agreement requires the CPUC to calculate and impose revised Bond Charges and/or Power Charges, as appropriate and necessary, no later than 120 days following the submittal of DWR's Retail Revenue Requirements and/or a revised requirement for Bond Charges. DWR will assign to the Bond trustee the right to enforce the CPUC's obligation under the Rate Agreement to impose Bond Charges that are sufficient to pay Bond-Related Costs when due. The trustee may enforce this obligation 30 days after DWR has both defaulted on the requirement it file a request with the CPUC to increase Bond Charges (as described above) and has failed to enforce the CPUC's obligations to revise the Bond Charges in accordance with the Rate Agreement, in the event the CPUC has not acted after 30 days prior written notice.

In the event DWR fails to submit revised Retail Revenue Requirements within the specified time frames, and the CPUC projects that Power Charges are not sufficient to pay Department Costs (which for this purpose includes replenishment of the Bond Charge Collection Account and Bond Charge Payment Account, if necessary), the CPUC may revise Power Charges on an interim basis to cover the shortfall pending DWR's submittal of revised Retail Revenue Requirements.

PLAN TO TRANSITION DWR NET SHORT RESPONSIBILITIES

DWR and the CPUC are jointly developing a plan to transition DWR's responsibilities for the net short, including the residual net short, to the IOUs by January 1, 2003. The objective of this plan is for DWR to transfer all of its net short energy supply responsibilities to the IOUs as soon as practicable, including responsibility for the residual net short purchases and the management of the existing DWR long-term contracts, including the Priority Long Term Power Contracts. The development of this plan is being coordinated with a related proceeding presently before the CPUC, as described later in this section. Under the plan being developed by DWR and the CPUC, the IOUs would begin procuring the residual net short requirements and scheduling energy from the DWR power contracts to meet the hourly energy requirements of the Customers within their respective service territories no later than January 1, 2003. After this date, DWR would continue to administer the Electric Power Fund to meet the Indenture and Bond covenants and monitor its revenue requirements, submitting new revenue requirement requests to the CPUC as required under the Rate Agreement. In the event the IOUs are unable to accept

responsibility for the residual net short on or before January 1, 2003, DWR has identified several alternative contingency measures that could be employed, as discussed later in this section.

Presented below is a description of key elements of the proposed transition plan. The proposed transition plan has been discussed informally with the IOUs by DWR and the CPUC. The IOUs have indicated to DWR and the CPUC that they have concerns with certain aspects of the proposed plan. NCI cannot predict whether the proposed plan will be fully implemented as described below.

KEY COMPONENTS OF THE PRELIMINARY TRANSITION PLAN

The primary objectives of the transition being developed by DWR and the CPUC consist of the following:

- Transition of responsibility for procurement of the residual net short to the IOUs;
- Management of DWR's long-term contracts by the IOUs; and
- Assignment of the financial and legal obligation for the DWR long-term contracts to the IOUs.

These objectives need not be accomplished simultaneously and may occur in phases. DWR and the CPUC intend for the transition to be accomplished in a manner that assures that no disruption of the California energy market occurs.

Procurement of the Residual Net Short

Currently, DWR has the capability to plan, procure, and schedule the residual net short for the IOUs for month-ahead, week-ahead, day-ahead, and hour-ahead dispatch requirements. DWR has the business processes and systems to capture information related to the terms and conditions of all short-term market purchases and long-term contract purchases that are needed to effect payment to the energy sellers and the billing and settlement of purchase costs to the Customers (through the IOUs). This information is also used to monitor revenue requirements and maintain the reporting obligations to the CPUC under the Rate Agreement.

The business processes and information systems (hardware and software) currently used by DWR would continue to be available and utilized until DWR is no longer responsible for the procurement of the residual net short. After the responsibility for the residual net short is transferred to the IOUs, DWR's systems would remain active to complete the billing and settlement cycle for the final short-term contracts procured prior to transfer. Information regarding DWR's procurement, utilization, billing, and settlement for its short-term contracts would be retained and archived to maintain a record to support any future dispute resolution or litigation related to DWR's contracts or past short-term market purchases.

Operating Management of DWR Long-Term Contracts

It is DWR's and the CPUC's objective that DWR's long-term contracts ultimately be assigned to the IOUs. If all DWR power supply contracts cannot be fully assigned for financial, regulatory, legal, or other reasons, DWR could continue to bear financial responsibility for the contracts, while the IOUs manage the output of contracts allocated to them for purposes of scheduling, dispatching, billing, and settlement.

The primary transfer of information systems and database information would occur prior to the transfer of the operating management of DWR's long-term contracts to the IOUs. The terms and conditions for the delivery of energy (and capacity, where applicable) from each contract, the scheduling and dispatching rights, and the information requirements to support billing and settlement reside in key software database systems utilized by DWR. The transfer to the IOUs of the information in these databases and their utilization by the contract management systems will be crucial to the successful transition of operating management of the DWR contracts.

These systems and databases have been inventoried, requirements for transfer to each IOU are being established, and the steps necessary to transition their use to each IOU are being mapped.

To enable a smooth transition, it will be necessary for the IOUs to familiarize themselves with the DWR contracts and DWR's scheduling and dispatch protocols prior to the transfer of responsibilities. As of the date of this Report, DWR and the IOUs are discussing the form and content of operating agreements between each IOU and DWR prescribing the rights and obligations of the IOU and DWR for management, operation, dispatch, disposition of surplus energy, settlement, billing, payment, and related matters.

Financial and Legal Obligation for the DWR Long-Term Contracts

As part of the IOUs' transition to the assumption of responsibility for the operation and management of DWR's contracts (but prior to full assumption of the financial and legal obligations associated with the contracts), the IOUs are expected to provide to DWR all information required for DWR to carry out the daily billing and settlement activities associated with the contracts. DWR is expected to continue to maintain capabilities through its own staff and through outsourcing to regularly audit the IOUs' billing and settlement information. Until such time as the contracts are fully assigned to the IOUs, DWR is expected to continue to perform this review and audit function.

Under the proposed transition plan, upon the transfer of financial and legal obligations associated with DWR's long-term contracts, each IOU would conduct the billing and settlement required under the DWR contracts assigned to them. The billing and settlement business processes and supporting systems used by DWR for this function have been inventoried, and the transfer requirements and steps necessary to transition such processes and systems to the IOUs are being established.

The transition of financial obligations (billing, settlement, and financial reporting) associated with the long-term contracts would be undertaken after the IOUs have become familiar with and demonstrated capability for the operational management of the contracts. This would necessitate an interim period wherein DWR would be informed of the contract scheduling decisions made by the IOUs to provide continuity in billing and settlement.

Many DWR contracts prohibit the assignment of financial responsibility to third parties. In order for this transition to occur, contract counter parties will have to agree to the change.

An objective of DWR in connection with the proposed transition plan is for the IOUs to assume full responsibility for management of the DWR long-term contracts. Given the restrictive terms of the contracts, DWR's ability to accomplish this objective may not be wholly achievable. DWR's ability to transfer its contract obligations will likely fall between two cases: (a) allocation of contract output only; and (b) full assignment of individual contracts to each of the IOUs,

including the transfer of the financial responsibility to pay the cost of energy under those contracts as part of the IOUs' revenue requirement, rather than DWR's separate revenue requirement.

TRANSITION SCHEDULE

DWR expects the transition of the responsibility for the residual net short to begin when the CPUC issues an order to the IOUs directing them to begin procuring the residual net short energy requirements for Customers within their service territories. The CPUC is not expected to issue such an order prior to completing its proceeding entitled "Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development," docket number R01-10-024 (the "Procurement Proceeding"), initiated on October 29, 2001. The purpose of the Procurement Proceeding is to establish ratemaking mechanisms to enable the IOUs to resume purchasing electric energy, capacity, ancillary services, and related products necessary to fulfill their obligations to serve and meet the needs of the Customers within their service territories. The Procurement Proceeding is also considering how renewable resources should be included in the mix of generating resources serving the state.

The proposed transition plan is being developed by DWR and the CPUC independent of the Procurement Proceeding. However, the Procurement Proceeding is addressing mechanisms and issues that will have an important bearing on the implementation of the transition plan and that proceeding will ultimately adopt the protocols and procedures required to implement the transition. The CPUC has acknowledged this relationship and has indicated it will consider the transition plan in conjunction with the Procurement Proceeding. The CPUC has established a schedule for the Procurement Proceeding that provides for the issuance of a final decision in October 2002. This schedule provides that the CPUC will focus on the issues needed to ensure that the IOUs successfully begin purchasing the residual net short by January 1, 2003, and anticipates the development of an interim cost recovery mechanism for costs incurred by the IOUs in connection with such purchases.

On August 22, 2002, as part of the Procurement Proceeding, the CPUC issued a decision (Decision 02-08-071) that permits the IOUs, prior to January 1, 2003, to solicit bids and enter into contracts for a portion of their post-2002 residual net short requirements. Such contracts would be reviewed by and subject to approval of the CPUC prior to their effective dates. The decision provides the power suppliers with a choice of contractual arrangements. Each power supplier may execute a single agreement with the IOU or may execute two separate agreements, one with the IOU and one with DWR. In the case of the latter option, DWR would (i) be a signatory to each such contract entered into by PG&E and SCE; (ii) purchase power under these contracts on behalf of PG&E and SCE; and (iii) recover from the retail end-users of PG&E and SCE the costs attributable to each IOU under these contracts. Contracts entered into by DWR pursuant to this decision will terminate and become the sole responsibility of the respective IOU upon the IOU's receipt of investment grade ratings from Standard & Poors and Moody's Investors Service. Costs incurred by DWR under these contracts (prior to becoming the sole responsibility of the IOUs) will be recovered from the Customers through Power Charges, however payment of such costs will be subordinate to costs incurred under DWR's Priority Long Term Power Contracts.

Although this decision permits SDG&E to enter into similar contracts, subject to the same review and approval process by the CPUC, it does not provide for DWR to be a signatory to the contracts or perform any other role due to the CPUC's finding that SDG&E already possesses an investment grade credit rating. This decision addresses only a portion of the issues being considered by the CPUC under the Procurement Proceeding and it is likely that additional

decisions will be issued prior to the closure of the proceeding. NCI cannot predict the final outcome of the Procurement Proceeding.

On September 19, 2002, the CPUC issued a decision (Decision 02-09-053) as part of the Procurement Proceeding that establishes an allocation of specific DWR power supply contracts among the IOUs. The decision requires the IOUs to assume full responsibility for the operation, dispatch, and administration of these contracts effective January 1, 2003. Legal title, financial reporting, and responsibility for the payment of contract-related bills are to remain with DWR. The decision provides that the IOUs will dispatch the contracts on an economic basis and that variable costs associated with each contract will follow the contract allocation among the IOUs. The determination of the allocation of fixed contract costs among the IOUs is to be determined as part of DWR's revenue requirement filing with the CPUC. NCI cannot predict whether this decision will be appealed by the IOUs or other parties or the changes, if any, that could result from such appeals.

On September 24, 2002, the Governor signed Assembly Bill 57 ("AB 57"). AB 57 establishes a process by which the IOUs may obtain an advance determination from the CPUC that the costs they incur in the procurement of electricity to meet the residual net short will be deemed reasonable and therefore recoverable from the Customers. Among other features, AB 57 (i) establishes a requirement that the CPUC allocate electricity provided by the DWR power supply contracts among the IOUs; (ii) requires that each IOU file, and the CPUC review, modify, or reject, a procurement plan for the acquisition of electric supply resources that will enable the IOUs to serve the Customers at just and reasonable rates; (iii) requires the CPUC to periodically review and modify the procurement plans; and (iv) establishes balancing accounts to track differences between the procurements costs and associated revenues of each IOU.

NCI believes that the completion of full financial and legal assignment of all DWR contracts to the IOUs, such that the IOUs would be responsible for the costs of all contracts as part of each IOU's revenue requirement by January 1, 2003, is unlikely. However, the CPUC's decision of September 19, 2002, establishes a process by which the IOUs will assume responsibility for the management of DWR contract energy scheduling and purchases. Coupled with the CPUC's August 22, 2002 decision, which enables the IOUs to contract for a portion of their residual net short needs, the CPUC has taken steps to transition responsibility for the day-to-day procurement and management of net short resources from DWR to the IOUs.

CONTINGENCY PLANNING

In the event one or more of the IOUs is not able to assume full responsibility for the residual net short on January 1, 2003, the State will need to find a means to ensure the continued acquisition of the residual net short on behalf of the Customers. Options available to the State include, but may not be limited to: (i) one or more of the IOUs purchasing on behalf of the other IOU(s); (ii) action by the legislature that would extend DWR's authority to purchase the residual net short; (iii) a proclamation by the Governor extending DWR's authority to acquire the residual net short; or (iv) a proclamation by the Governor granting another State agency the authority to purchase the residual net short on behalf of the Customers. NCI cannot predict which, if any, of these options would be employed by the State in the event one or more of the IOUs is not capable of acquiring the full residual net short on January 1, 2003. For purposes of this Report, NCI has assumed the responsibility for the residual net short will fully transition to the IOUs on January 1, 2003, while the responsibility for the DWR contracts will remain with DWR through the end of the Study Period.

CAPACITY AND ENERGY REQUIREMENTS

Estimates of the future capacity and energy requirements of the Customers must take into consideration historical and future changes in electric end-user behavior, the addition and availability of end-user self-generation, conservation programs, and other influences that can reasonably be expected to result in a change in electric end-user behavior.

HISTORICAL DEMAND AND ENERGY REQUIREMENTS

The IOUs provide electric service to approximately 77 percent of the total retail electric connections in California. The remainder is served by other investor-owned utilities with small service areas in the State, and a number of municipal utilities, irrigation districts, and other publicly-owned utilities, the largest of which include the Los Angeles Department of Water and Power ("LADWP") and the Sacramento Municipal Utility District ("SMUD").

Prior to implementation of the measures undertaken by DWR and others to stabilize the California power market, annual energy requirements and peak demands of the IOUs generally exhibited relatively steady rates of growth from year to year. From 1996 through 2000, total IOU electric energy sales in California grew at an average compound rate of 2.8 percent per year. During this same period, the non-coincident peak demands of the IOUs increased at an average compound rate of 1.3 percent per year, with annual system load factors ranging from 52 to 55 percent. Consistent with the State's goals, annual energy sales and peak demands declined during 2001, reflecting, in part, the effects of new conservation and load management programs implemented by the State during the year and Customer responses to increases in the retail rates charged by the IOUs, as well as behavioral responses to the energy crisis. Historical annual power and energy requirements for the IOUs for the 1997 through 2001 period are summarized in Exhibit 1 of this Report.

Table 1 provides a summary of the IOUs' historical energy sales and non-coincident peak demands presented in Exhibit 1 for the 1997 through 2001 period. Historical energy sales and peak demands shown in Table 1 are net of the effects of IOU conservation and load management programs and electric end-user loads served by self-generation.

The IOUs operate a number of load management programs under the direction of the CPUC that are designed to reduce electric loads during peak demand periods. In 2001, the IOUs reported having approximately 1,754 MW of load management enrolled in these programs. The IOUs expect similar participation in these load management programs during 2002 and the remainder of the Study Period.

SELF-GENERATION AND DIRECT ACCESS

The installation of self-generation facilities or participation in direct access programs by electric end-users in the IOUs' service areas directly impact the net short requirements to be met by DWR. As described below, NCI has developed estimates of self-generation and direct access for use in calculating the Customers' net short requirements. The State has implemented several initiatives designed to accelerate the development of self-generation facilities. These initiatives include the Self-Generation Incentive Program, a standardized interconnection process, and elimination of standby charges for systems smaller than five MW.

TABLE 1
HISTORICAL IOU ENERGY SALES AND PEAK DEMANDS

	1997	1998	1999	2000	2001
Sales of Electricity (GWh)[1]					
Pacific Gas & Electric Company[2]	76,241	75,676	79,209	81,783	77,218
Southern California Edison[3]	76,057	76,258	78,207	83,435	78,455
San Diego Gas & Electric Company[4]	16,747	17,249	17,930	18,423	17,463
Total Investor-Owned Utilities	**169,045**	**169,183**	**175,346**	**183,641**	**173,136**
Annual Percentage Change	3.6%	0.1%	3.6%	4.7%	-5.7%
Non-Coincident Peak Demand (MW)[5]					
Pacific Gas & Electric Company[2]	17,067	17,168	17,676	18,259	16,981
Southern California Edison[3, 6]	19,118	19,935	19,122	19,757	17,890
San Diego Gas & Electric Company[4, 7]	3,688	3,960	3,606	3,485	3,147
Total Investor-Owned Utilities	**39,873**	**41,063**	**40,404**	**41,501**	**38,018**
Annual Percentage Change	3.9%	3.0%	-1.6%	2.7%	-8.4%

Source: FERC Form 1 filings and data obtained by NCI from the individual utilities.

[1] Total metered sales, excluding sales for resale.

[2] Excludes capacity and energy requirements associated with a contract with the Western Area Power Administration. Data for 1998 reflects reduced agricultural pumping loads resulting from above-average rainfall. For 2000, peak demand reflects reductions of 450 MW of firm and interruptible load curtailments under pre-existing PG&E programs.

[3] For 2000, reflects the effects of above-average temperatures in southern California during the summer months. Peak demands include municipal utility and water pumping loads that receive transmission service from SCE.

[4] For 2000, includes electric end-use load reductions spurred by increases in retail electricity prices beginning in June.

[5] Individual peak demands for each utility. Actual coincident peak demand is lower than the total shown because of load diversity. For SCE, includes peak demands associated with sales for resale.

[6] For 2001, the peak day temperature was six degrees cooler than normal. SCE estimates that under normal temperature conditions, the annual peak demand would have been approximately 1,500 MW higher.

[7] The annual peak demand for 2001 occurred in October. Under normal weather conditions, SDG&E's annual peak demand would be expected to occur in August. SDG&E estimates that under normal summer weather conditions, its annual peak demand during 2001 would have approximated 3,500 MW.

Self-Generation

In March 2001, the CPUC announced a major five-year Self-Generation Incentive Program to encourage installation of efficient and/or renewable generation technologies with a capacity of one MW or less. The incentives range from 30 percent of the systems' cost, up to a maximum of $1,000 per kW for micro-turbines and for internal combustion engines utilizing waste heat recovery, and up to a maximum of $4,500 per kW for photovoltaics, wind turbines, and fuel cells using renewable fuels. The State has committed approximately $125 million per year in incentives through 2005. During 2001, approximately 129 applications representing 43 MW of installed capacity were funded through this program. Applications for the program were not accepted prior to July 2001 and, therefore, program participation is expected to exceed these levels during 2002. These incentives are expected to produce approximately 67 MW of incremental self-generation capacity per year through 2005.

Together with facilities constructed as a result of the Self-Generation Incentive Program, improvements in technology, increased concern over service reliability, and higher electricity prices are expected to result in a total increase in installed self-generation capacity of approximately 1,348 MW by 2011. This estimate was developed based on applications for interconnections made during 2001, installations coming on-line in 2001, and discussions with program mangers, equipment vendors, and the IOUs. Incremental annual additions during 2002

through 2005 are estimated to range from 150 to 170 MW, inclusive of Self-Generation Incentive Program additions. For 2006 through 2011, incremental annual additions in self-generation capacity are estimated to range from 110 to 130 MW. The decrease in capacity additions beyond 2005 takes into account the expiration of the Self-Generation Incentive Program in 2005.

Direct Access

In accordance with the provisions of the Act, the CPUC issued an interim order suspending direct access effective September 20, 2001. A final order affirming the September 20, 2001, suspension date was issued by the CPUC on March 21, 2002 (the "Direct Access Order"). Electric end-users that elected to acquire service from alternative suppliers on or before September 20, 2001 will continue to be eligible for direct access service. The CPUC estimates that approximately 14 percent of total IOU load qualified for direct access service under the Direct Access Order. The Direct Access Order states that direct access will remain suspended until DWR is no longer providing power to the Customers.

The Direct Access Order prohibits the IOUs from accepting any new Direct Access Service Requests not otherwise approved by the CPUC, including requests from existing qualified direct access end-users that wish to add new direct access locations or accounts to their service. However, these customers may renew their direct access service contracts upon their expiration or transfer them to a new service location as long as the load served is of comparable size.

The Direct Access Order contemplates the possible establishment by the CPUC, at a future date, of a charge on direct access Customers ("direct access charge"). As described in the Direct Access Order, the direct access charge will be set at a level that prevents cost shifting as a result of direct access. That is, DWR's charges (Bond Charges and Power Charges) to the remaining Customers would not increase due to Customers participating in direct access. The CPUC has not established an order relative to direct access charges. NCI cannot predict the likelihood that the CPUC will enact direct access charges applicable to Customers that have switched to direct access service nor the level of such fees if authorized by the CPUC. For purposes of this Report, no allowance has been included for revenues that would be recovered by DWR through the application of direct access charges to these Customers.

Assembly Bill 117 ("AB 117"), signed by the Governor on September 24, 2002, authorizes electric end-users, including the Customers, to aggregate their electric loads with private aggregators as individual users, or with community choice aggregators as members of a local community, for the purpose of securing power supply from a party other than the IOUs. AB 117 requires a Customer that purchases power from a community choice aggregator to pay DWR a direct access charge to prevent a shifting of costs to the remaining Customers. The direct access charge will be determined by the CPUC. On September 24, 2002, the CPUC issued a proposed decision providing, among other things, for the calculation of direct access charges.

For purposes of this Report, no incremental participation in direct access, beyond that authorized by the Direct Access Order, is contemplated. This Report has been developed based on the presumption AB 117, together with actions to be taken by the CPUC, will result in the payment of direct access charges by all aggregation participants such that DWR is financially indifferent to their participation. In the event the direct access charges do not provide complete recovery of all DWR revenue requirements attributable to Customers participating in the aggregation programs, DWR is required by the Act and, therefore, can be expected to file revised Retail Revenue Requirements, resulting in a revision of its Bond Charges and Power Charges by the CPUC to ensure complete recovery of its costs from the remaining Customers.

In the event direct access is restored in the future, the CPUC has stated that it will consider assessing direct access charges on Customers switching to direct access service. Moreover, the Rate Agreement stipulates the authority to levy Bond Charges on direct access Customers once an order from the CPUC establishing the charges becomes final and unappealable.

NEW CONSERVATION AND LOAD MANAGEMENT

During 2001, total IOU electric sales declined by approximately 5.7 percent compared to 2000. Analyses completed by the CEC conclude that this reduction was not generally attributable to weather or economic activity. Rather, the load reductions are believed to have resulted primarily from a combination of the following factors:

- Reductions in usage stemming from heightened awareness of California's energy crisis and public appeals to conserve energy and reductions resulting from Customer reactions to significant increases in electricity rates and prices; and
- Impacts of new initiatives and additional funding to promote energy conservation and load management, including rebates, voluntary load reduction programs, revised retail rate designs, and related measures.

The above factors are expected to continue to suppress demand growth within the IOU service areas in the future. The estimated IOU demand and energy requirements discussed later in this section take these factors into account.

Usage Adjustments and Price Elasticity Effects

The CEC estimates that total IOU peak demands during 2001 decreased by approximately 1,300 MW as a result of these factors (excluding 20/20 Program reductions described below). The IOUs have indicated to NCI that they expect these factors to continue to influence electrical usage in the future and have taken them into account when preparing the demand and energy forecasts relied on by NCI for this Report.

Conservation and Load Management Programs

With the onset of electricity shortages and the subsequent rise in prices, a number of new conservation initiatives were undertaken during 2000 and 2001, including new rate designs, funding of new initiatives, and Executive Orders. In total, these initiatives are estimated by the CEC to have substantially reduced IOU peak demands during 2001, and include the programs described below. Estimated peak load reductions identified below were developed by the CEC and have not been verified by NCI.

- The "20/20 Program," established by Executive Order of the Governor on March 13, 2001, provided the Customers with rebates equal to 20 percent of their bills if they reduced consumption by more than 20 percent relative to their consumption for the same period in the previous year. The program applied to the four summer months from June through September during 2001. The CEC estimates the gross program impacts to be 2,200 MW of peak demand savings and 2,743 GWh of energy savings during 2001. Total rebate costs during 2001 were estimated to be $286 million and were funded by DWR;
- Assembly Bill 970 ("AB 970"), signed into law in September 2000, provided $50 million from State funds for conservation and peak demand reduction programs.

Funding was provided for 135 projects. The CEC estimates these programs resulted in peak load reductions of approximately 150 MW;

- Assembly Bill 29X ("AB 29X") and Senate Bill ("SB 5X"), passed in April 2001, provided an aggregate funding of $500 million from State funds for conservation and peak demand reductions. The CEC estimates that these programs produced approximately 275 MW of peak load reduction during 2001;
- The CPUC's Summer Initiative included a $72 million expansion of ongoing IOU energy conservation programs targeting measures to reduce peak demands during the summer of 2001. The CEC estimates this initiative reduced summer peak demands by approximately 124 MW; and
- Conservation and peak load reduction efforts by local and State government that are estimated by the CEC to have reduced their average energy usage by approximately eight percent from comparable 2000 levels during 2001.

On an aggregate basis, the programs described above are estimated to have had a material impact on the electrical requirements of the Customers during 2001. With the exception of the 20/20 Program, new funding for these programs was not continued for 2002. However, the initiatives undertaken during 2001 are expected to provide ongoing load reduction benefits throughout the Study Period. The IOUs have indicated that they have taken these reductions into account in the development of the demand and energy forecasts relied on by NCI for this Report.

New Conservation Program

During 2002, DWR will fund a 20/20 Program similar to the one initiated during 2001. Generally, residential Customers will receive bill credits equal to 20 percent of their electric bills if they reduce consumption by 20 percent or more when compared to the same billing period during 2000 (Customers served by SDG&E must reduce consumption by 15 percent to be eligible for a 15 percent bill credit). This program will be applied to the four summer months from July through October 2002. NCI estimates the program will cost approximately $157 million (of which $149 million is for bill credits), excluding lost sales revenues, and produce peak demand and energy savings of 57 MW (August) and 426 GWh.

The estimates of IOU demand and energy requirements shown in Exhibits 2 and 3 of this Report have been adjusted by NCI to reflect the estimated demand and energy savings associated with the 20/20 Program.

ESTIMATED IOU DEMAND AND ENERGY REQUIREMENTS

For purposes of this Report, NCI has relied on demand and energy forecasts prepared by each IOU. Estimated peak demand and energy requirements for the Study Period are shown in Exhibits 2 and 3, respectively. Total adjusted IOU energy requirements (after self-generation, direct access, and incremental conservation and load management) are estimated to increase at a rate of approximately 2.1 percent per year during the Study Period. Estimated peak demand (after similar adjustment) is also expected to increase at a rate of approximately 2.1 percent per year over the same period.

Estimates of PG&E's peak demand and energy requirements shown in Exhibits 2 and 3 exclude requirements associated with PG&E's integration contract with the Western Area Power Administration ("Western"). Under this contract, PG&E is obligated to supply that portion of Western's load (primarily governmental and municipal sales) that exceeds the output of the hydroelectric generating facilities constructed by the Central Valley Project ("CVP"). PG&E's

obligation varies by year due primarily to hydrological conditions and Western's load levels. PG&E estimates that under average hydrological conditions, its obligations under the Western contract will total 4,819 GWh in 2002 and 5,146 GWh in 2003 and 2004. This contract expires at the end of 2004. Although not included in Exhibits 2 and 3, these requirements have been accounted for in the determination of the Customers' net short requirements discussed later in this Report.

Load Forecasts Used by NCI

As the starting point for its estimates of IOU demand and energy requirements, NCI obtained the most recent load projections available from each IOU. The IOUs typically do not issue new demand and energy projections annually. For PG&E, NCI relied on a projection prepared in April 2002 for PG&E's 2003 General Rate Case ("GRC"). The projection used for SCE was prepared in May 2001 and is being used for its Test Year 2003 GRC. For SDG&E, NCI relied on a forecast prepared in the second half of 2001 for use in proceedings by SDG&E before the CPUC.

Each IOU forecast was generated by econometric models that rely on statistical analysis of historical data to develop regression equations that relate changes in "independent" variables (such as employment growth) to "dependent" variables (such as electricity sales by end-user segment). The resulting equations, together with forecasts of electricity prices, weather conditions, and key economic drivers, are used to predict sales by retail customer class. To improve accuracy, the projections may be modified by the IOUs to account for current trends, judgment, or other events not specifically addressed in the models.

The IOUs' load forecasts and forecasting models have received detailed scrutiny in numerous regulatory proceedings over the years. In addition to scrutiny by the CPUC, FERC, and numerous regulatory interveners, the CPUC's Office of Ratepayer Advocates customarily reviews and critiques the IOUs' forecasts based on its own independent load forecasts using its own econometric models. Typically, the differences between the IOUs' forecasts and those prepared by the Office of Ratepayer Advocates have been small. The high level of scrutiny of these forecasts by regulatory agencies and the acceptance of the projections for revenue allocation and rate-setting purposes provide support for the reasonableness of the IOUs' forecasting efforts.

Model Inputs and Assumptions

Table 2 presents the major assumptions employed in the IOU forecasts utilized by NCI for this Report. PG&E's economic forecast was based on a forecast of economic growth in PG&E's service area prepared by Economy.com. SCE derived its economic assumptions from a national and statewide forecast prepared by Data Resources Inc. ("DRI"), while SDG&E relied on a DRI forecast of economic trends in its service area.

NCI Assessment of the IOU Forecasts

NCI believes that the IOUs' forecasting methodologies and models provide a reasonable starting point for estimating the IOUs' future demand and energy requirements. NCI compared the utility forecasts with actual data for 2001 and examined the underlying assumptions regarding conservation, economic growth, and price responses. NCI believes the forecasts used for this Report adequately capture these factors. In forecasting the net short to be supplied by DWR, NCI adjusted the IOU forecasts for the effects of the estimated direct access loads, self-generation, and incremental conservation and demand side management described above.

TABLE 2
MAJOR ASSUMPTIONS USED IN IOU LOAD FORECASTS

	PG&E	SCE	SDG&E
Growth Assumptions:			
Population Growth[1]	1.0	1.8	1.4[3]
Number of Households[1]	1.3	1.0	1.7[3]
Non-Farm Employment[1,2]	1.0	1.1	2.1[3]
Heating Degree Days	20-Yr. Avg.	30-Yr. Avg.	20 Yr. Avg.
Cooling Degree Days	20-Yr. Avg.	30-Yr. Avg.	20-Yr. Avg.

Source: PG&E data from work papers submitted in PG&E's Notice of Intent for its 2003 GRC. SCE data from Notice of Intent for Test Year 2003 GRC. SDG&E data provided by the IOU.
[1] Percent per year increase during 2002 and 2003, except as noted.
[2] Actual growth during 2001 was 1.2 percent statewide, according to the State Department of Finance.
[3] Annual percent growth from 2000 through 2006.

POWER SUPPLY RESOURCES

Over the Study Period, the capacity and energy requirements of the Customers will be met by a combination of resources, including (i) URG; (ii) new conservation and load management programs (as described previously); (iii) bilateral contracts between DWR and generation providers; (iv) spot purchases in the CAISO day-ahead and hour-ahead markets; and (v) reliability purchases in the CAISO imbalance market. Resources available under the DWR bilateral contracts and through spot and imbalance purchases through the CAISO markets will be provided from existing and new generating facilities owned by municipal utilities and non-utility generators in California and power supply imports from the Pacific Northwest and the remainder of the area encompassed by the Western Electricity Coordinating Council (the "WECC"). The expected availability of these resources, together with the URG, is discussed below.

UTILITY-RETAINED GENERATION

The URG consists of the IOU-Owned Generation (nuclear, hydroelectric, and thermal resources that were retained by the IOUs following the deregulation of the California energy market), contracts with QFs, and bilateral contracts with other power suppliers. Total URG generating capacity available to the IOUs, as of July 30, 2002, is approximately 24,976 MW, as summarized in Table 3. Additional information on the URG may be found in Appendix II of this Report.

IOU-Owned Generation

The IOUs' nuclear resources consist of (i) the Diablo Canyon Nuclear Station ("Diablo Canyon"), which is wholly owned by PG&E (2,160 MW); (ii) the San Onofre Nuclear Generating Station ("San Onofre"), which is operated by SCE and owned in part by SCE and SDG&E (1,614 MW and 430 MW, respectively); and (iii) the Palo Verde Nuclear Generating Station ("Palo Verde"), which is partially owned by SCE (590 MW). The IOUs' nuclear generating stations have been issued operating licenses by the Nuclear Regulatory Commission ("NRC") and are subject to periodic inspection and evaluation by the NRC, including assessments of the adequacy of the decommissioning funds maintained by the IOUs.

TABLE 3
UTILITY-RETAINED GENERATION
(MW)

Fuel Type	PG&E	SCE	SDG&E	Total
IOU-Owned Generation				
Nuclear	2,160	2,204	430	4,794
Hydroelectric	3,890	1,158	-	5,048
Thermal	579	1,604	-	2,183
Subtotal	6,629	4,966	430	12,025
Qualifying Facilities	4,313	4,718	350	9,381
Bilateral Contracts	1,639	1,723	208	3,570
Total	**12,581**	**11,407**	**988**	**24,976**

Source: IOU Form 10-K filings with the U.S. Securities and Exchange Commission, CEC, CPUC, and IOU responses to NCI data requests. Reflects information available to NCI as of May 1, 2002.

PG&E and SCE own a combined total of 147 hydroelectric facilities (5,048 MW) located in the Sierra Nevada Mountains, the San Gabriel Mountains and the San Bernardino Mountains that generally supply energy in proportion to rainfall captured by dams and diversions. PG&E's hydroelectric facilities are located in the DeSabla Watershed, the Drum Watershed, the Helms/Kings Crane Watershed, the Motherlode Watershed, and the Shasta Watershed. SCE's hydroelectric facilities are separated into the Northern Hydro Region (the "Big Creek System") and the Eastern Hydro Region. The Big Creek System consists of projects located in the watershed of the south fork of the San Joaquin River. The Eastern Hydro Region consists of projects located in the watershed basins of the Sierra Nevada Mountains, San Bernardino Mountains, and San Gabriel Mountains. The majority of PG&E's and SCE's hydroelectric facilities are subject to FERC licensing and annual inspections.

SCE owns and operates a 56 percent interest (885 MW) in the coal-fired Mojave Generating Station ("Mojave") in southern Nevada and owns a 48 percent interest (710 MW) in Units 4 and 5 of the coal-fired Four Corners Generating Station ("Four Corners") in northwest New Mexico. SCE also owns and operates a diesel-fueled generating plant located on Santa Catalina Island (9 MW). PG&E retained certain critical gas-fired units (579 MW) that are necessary for areas that are transmission constrained.

Qualifying Facilities

Capacity available to the IOUs through their contracts with the QFs provides approximately 38 percent of total URG. These resources are comprised of thermal co-generation facilities and renewable energy resources. The contracts between the QFs and IOUs have varying expiration dates, with approximately 28 percent of the existing contract capacity expiring by the end of the Study Period. For purposes of this Report, all QF generating capacity is assumed to remain in service through the earlier of the respective QF contract termination dates or December 31, 2011.

Some of the QF facilities under contract to the IOUs are renewable or clean energy resources, such as wind, solar, biomass, and geothermal. Most of these resources cannot be operated by the IOUs in a manner that enables their output to be matched with the capacity and energy requirements of the Customers (e.g., are not dispatchable resources). Consequently, for resource planning purposes, only about three-quarters of the total QF capacity under contract to the IOUs can be counted on to be available to meet peak load requirements.

Bilateral Contracts

The IOUs have historically been net purchasers of energy. Over the years, the IOUs have entered into short- and long-term power purchase agreements with other utilities, primarily in the Pacific Northwest and other areas the WECC outside of California, to meet their needs. Delivery of these purchases is dependent on the operation of the extra-high voltage transmission lines that interconnect California with adjacent states and is assumed to continue through the term of the purchase contracts without interruption. The IOUs also have in-state power purchase agreements with other entities that allow them to provide energy to, and accept energy from, the other party in a way that is beneficial to both parties.

Please see Appendix II of this Report for a more complete discussion of the URG.

EXISTING NON-URG POWER SUPPLY RESOURCES

Within California, non-URG power supply resources include facilities owned by non-utility generators and governmental entities, as well as resources located and owned by parties outside of California and available for import to the State. To the extent these resources are not needed to meet the needs of their owners or contracting parties, they could be available to meet the needs of the Customers during the Study Period.

Non-Utility Power Providers

Non-utility power providers own the large gas-fired steam-boiler plants that were recently divested by the IOUs. Owners of these plants include Duke Energy, Dynegy, Reliant Resources, Mirant, AES, and others. In addition, a number of new generating facilities have been constructed in California by non-utility power providers since January 1, 2002. In general, these resources are used to sell power to large-scale wholesale purchasers, including the IOUs, DWR, and wholesale power marketers.

As of December 31, 2001, total generating capacity owned by non-utility providers, excluding QFs, was estimated by NCI to total approximately 21,794 MW.

Imports and Exports

California has long been a major seasonal importer and exporter of electricity. Power supply resources available for import to California during the Study Period could be relied on to meet a portion of the Customers' net short requirements. As described in more detail in Appendix III of this Report, the high voltage transmission systems in California are interconnected with those of the Pacific Northwest, the Southwest, and Mexico regions, allowing the import of several thousand MW of power. Exports from California occur primarily during nighttime and winter off-peak periods.

The transmission interconnections are used to receive power from out-of-state resources that are owned or controlled by California entities. They are also used to import power purchased from out-of-state generators on a long-term firm or short-term, non-firm basis. Transmission capacity owned by the IOUs, but not used to serve their native load, is available for use by third parties through the scheduling process of the CAISO.

The interconnections are also used to export power to other regions, typically for return of power under exchange agreements during off peak periods. However, exports may also occur during peak periods if spot market prices are higher outside California.

Table 4 contains a listing of non-simultaneous (non-coincident) transfer capabilities of the major regional interconnections with California. Due to various operational variables, including interaction between these paths, the actual transmission capabilities between California and each region may fall below these values at certain times. For example, there is a limit on simultaneous imports into southern California of approximately 14,000 MW.

TABLE 4
CALIFORNIA MAJOR HIGH VOLTAGE INTERCONNECTIONS AND RATINGS

Description	Interconnected Areas	Normal Rating (MW)
Path 66–AC Pacific Intertie.....	Pacific Northwest-Northern California	4,800[1]
Path 65–DC Pacific Intertie.....	Pacific Northwest–Southern California	3,100[2]
Path 27-Intermountain DC.....	Southwest-Southern California	1,920[3]
Path 45-SDG&E-CFE.....	Mexico–Southern California	408[4]
Path 46–West of Colorado River.....	Southwest–Southern California	10,118[5]

Source: WECC 2002 Path Rating Catalog, February 2002.
[1] North to south rating. South to north rating is 3,675 MW.
[2] Bi-directional rating. South to north rating is reduced to 2,200 MW if certain large industrial customers in the Pacific Northwest are not operating.
[3] Northeast to southwest rating. Southwest to northeast rating is 1,400 MW.
[4] North to south rating. South to north rating is 800 MW.
[5] East to west rating.

Pacific Northwest

The Pacific Northwest and California power markets are the largest in the western United States and are highly diverse and complementary in their energy sources and consumption patterns. Winter peaking loads served primarily by hydroelectric and coal-fired resources characterize the Pacific Northwest region. Conversely, summer peaking loads served by a diversified mix of generating resources that include nuclear, hydroelectric, natural gas, and coal characterize California. Therefore, power generally flows on transmission interties from the Pacific Northwest to California during the summer months and from California to the Pacific Northwest during winter months. The interties increase reliability in both regions. They allow economic use of surplus non-firm hydropower from the Pacific Northwest and allow exchanges in which the Pacific Northwest supplies capacity to help meet the peak period needs of California and southwestern purchasers, who in turn supply energy in their off-peak hours or off-peak season to the Pacific Northwest. The extent of this interregional seasonal exchange of energy is impacted by the availability of hydroelectric capability in the Pacific Northwest, and the availability of winter season thermal power generation capability in California.

The largest hydroelectric system in the Pacific Northwest, the Columbia River, has a sustained peaking capacity of approximately 25,000 MW. However, limitations on the storage capacity of the system result in significant variation in the system's energy output from year to year, depending on annual rainfall and snow pack accumulation. In the driest years, the average annual power production is only about 100,000 GWh. Utility planners can expect at least that much energy in any given year, so it is considered guaranteed or "firm" energy. In the wettest years, the system produces approximately 175,000 GWh annually. In average water years, the system produces approximately 145,000 GWh annually.

Generation in excess of what can be guaranteed is commonly referred to as "non-firm" or "secondary" energy. Non-firm energy is sold on the spot market or under short-term contracts at prices that are typically lower than those obtained for firm energy. This energy is used to serve

interruptible loads or to displace more expensive resources both in and out of the Pacific Northwest.

The IOUs and municipal utilities in California purchase a significant amount of energy from the Bonneville Power Administration ("BPA"), a federal power marketing entity, and PacifiCorp in the Pacific Northwest. These purchases range from acquisition of long-term firm energy to spot purchases of non-firm energy. Exports during the winter months also occur. BPA has long-term, firm-power sale and capacity/energy exchange contracts with SCE, the M-S-R Public Power Agency ("M-S-R"), and the cities of Burbank, Glendale, and Pasadena, among other parties in California. Many of these contracts contain provisions for complete or partial termination of energy deliveries if that energy is needed to serve BPA's firm requirements.

Southwest and Mexico

Unlike interconnections with the Pacific Northwest, the interconnections with the Southwest and Mexico are primarily for import of entitlements and firm purchases. There is limited hydroelectric capacity in these regions and little weather and load diversity with California. Therefore, there is less opportunity to take advantage of seasonal exchanges. Many cities in southern California utilize the transmission interconnections with the Southwest to receive their entitlement to power from the Hoover Dam hydroelectric facility, as well as from the San Juan Generating Station ("San Juan") in northwest New Mexico and Palo Verde in Arizona.

Municipal, State, and Federal Resources

There are several municipally owned utilities in California with significant generation and transmission resources. These include, but are not limited to, LADWP, SMUD, the Imperial Irrigation District, the cities of Burbank, Glendale, Pasadena, and Redding, Modesto Irrigation District, Turlock Irrigation District, Silicon Valley Power, and joint powers agencies such as the Southern California Public Power Authority, Northern California Power Agency, and M-S-R. Some of these entities also own major transmission lines linking them with resources in the Pacific Northwest and Southwest. Several of the municipal utilities also own, or have entitlements to energy from, resources located outside California, including the Intermountain Power Project in Utah, San Juan in New Mexico, and Palo Verde in Arizona, as well as entitlements to federal hydroelectric power from Hoover Dam located on the Colorado River between Nevada and Arizona.

There are also several state and federal agencies that own generating and transmission resources in California. These include the State Water Project and the United States Bureau of Reclamation ("USBR"). The USBR resources consist of a network of hydroelectric plants known as the Central Valley Project or "CVP". Power from the CVP is sold by Western to municipal entities throughout California.

Table 5 provides a summary of the generating resources owned by governmental entities. To the extent these resources exceed the power supply needs of the governmental entities, generating capacity could be made available to meet a portion of the net short requirements of the Customers.

TABLE 5
GENERATING RESOURCES OWNED BY GOVERNMENTAL ENTITIES[1]
(MW)

Unit Type	SWP	LADWP	NCPA	SMUD	USBR	Other	Total
Coal	15[2]	1,741	-	-	-	967	2,723
Gas/Oil	-	3,256	144	443	-	1,539	5,382
Geothermal	-	-	67[3]	-	-	95	162
Hydro	1,757	1,943	162	692	2,023	1,373	7,950
Nuclear	-	368	-	-	-	180	548
Wind/Solar	-	-	-	3	-	-	3
Total	**1,772**	**7,308**	**373**	**1,138**	**2,023**	**4,154**	**16,768**

Source: Data obtained by NCI from the individual utilities and from the CEC, FERC, and WECC, as of May 1, 2002.
[1] Includes resources located outside California. Excludes certain generating capacity owned by governmental entities that do not have retail electric service obligations. The generating capacity of such suppliers is included with non-utility generating resources.
[2] Excludes recallable capacity committed to Nevada Power Company.
[3] Maximum achievable capacity, from NCPA.

POTENTIAL NEW RESOURCES AVAILABLE FOR CALIFORNIA

Existing power supply resources owned by or under contract to the IOUs, governmental entities, and non-utility generators are not expected to be sufficient to meet the needs of the Customers and all other electric consumers in California during the Study Period. Consequently, DWR (through December 31, 2002) and other end-use providers will need to rely on new generating facilities constructed within California and the continuation of imported power to satisfy the capacity and energy requirements of electric end-users within the State.

As discussed below, a large number of new resource additions are under development or have been proposed by utility owners and developers within California, the Pacific Northwest, and the remainder of the WECC. These proposed resource additions are shown in Exhibits 4 through 6 of this Report. Due to financial, engineering, environmental, and other reasons, it is highly unlikely that 100 percent of these resources will be constructed or brought on-line within the timeframes or in the quantities proposed by the developers and owners. Consequently, the actual generating capability available in the future to meet the needs of the Customers and other end-users can be expected to differ from the totals discussed below. For analytical purposes, NCI has included only projects under construction and projects in siting review that are under contract to DWR in its assessment of future resource adequacy. These resource additions are supplemented by the addition of certain "generic" new generating units when such are economically viable. For purposes of this Report, no such new generic generating units are assumed to become operational before 2005.

In-State Resources

Based on information obtained from the CEC, WECC, and other sources, approximately 5,326 MW of new generating capacity was constructed and brought on-line in California from January 2001 through July 2002. The WECC and the CEC report that a total of approximately 3,320 MW of additional new generating capacity is under construction in California and scheduled to be in service by summer 2003. These capacity additions are estimated to increase by an additional 1,350 MW by the summer of 2004 and represent new facilities, the output of which would potentially be available to DWR (for contracts entered into before January 1, 2003) and other energy suppliers. Generation additions for 2002 and 2003 referenced in this paragraph (and

the discussions of new generating capacity in the Pacific Northwest and the remainder of the WECC) represent projects scheduled to be on-line no later than July 1 of the year referenced.

The WECC and CEC report that a total of 18,203 MW of new electric generating capacity is in various stages of development within California, including those resources under construction. The majority of these resources (approximately 97 percent) are expected to be natural gas-fired facilities, with small renewable and landfill gas projects making up the balance. Some of the proposed resource additions also represent expansions or re-powering of existing facilities. Table 6 provides a summary of the new resources planned for California through 2006.

TABLE 6
POTENTIAL NEW GENERATING RESOURCES
IN CALIFORNIA BY UNIT TYPE[1]
(MW)

Fuel Type	California
Natural Gas	17,573
Wind	612
Landfill Gas	3
Biomass	15
Total	**18,203**

Source: CEC, WECC, and NCI.
[1] Generation totals consist of projects in the siting, development, feasibility, and planning phases, as well as projects under construction, as of July 30, 2002 (certain project data verified after July 30, 2002). These values exclude 2,588 MW of new generation added during the first seven months of 2002.

The IOUs are not expected to own any of the new resource additions. The majority of new resource additions is expected to be owned by non-utility generators. Many of these power producers are likely to enter into bilateral sales agreements with wholesale purchasers, such that the entities can meet their respective load growth and reserve requirements. It is possible that the generators will contract with entities outside California for the sale of power from these resources, depending upon the price for power in other regions and the availability of transmission capacity. The fuel efficiency, fuel costs, price levels, and terms of power sales contracts available from these projects are unknown at this time. It is highly unlikely that all of these proposed projects will reach commercial operation. Some may be abandoned due to unfavorable market conditions, environmental constraints, inability to obtain financing, or other reasons.

A listing of specific new generating facilities reported to be under construction or in various stages of development in California is provided in Exhibit 4.

Pacific Northwest

Based on information received from the WECC and CEC, approximately 2,168 MW of new generating capacity was constructed and placed in commercial operation in the Pacific Northwest from January 2001 through mid-August 2002. By the summer of 2003, an additional 1,290 MW of projects under construction is expected to come on-line, for a total of 3,458 MW of new generating capacity since January 1, 2001. These figures are expected to increase another 1,440 MW by the summer of 2004 as other projects under construction begin commercial operation.

At present, a total of more than 12,830 MW of new generating capacity in the Pacific Northwest is under construction or is being considered for development. These resources are predominately natural gas-fired facilities. Table 7 provides a summary of potential new resource additions in the Pacific Northwest. A listing of specific projects under construction and being permitted in the Pacific Northwest may be found in Exhibit 5. Factors such as fuel efficiency, fuel costs, price levels, and terms of any power sales contracts that would be available from these projects are not known for all such projects at this time. It is highly unlikely that all of these proposed projects will reach commercial operation and some may be abandoned due to environmental constraints, inability to obtain financing, or other reasons.

TABLE 7
POTENTIAL NEW GENERATING RESOURCES IN THE PACIFIC NORTHWEST[1]
(MW)

Fuel Type	Idaho	Montana	Oregon	Washington	Total
Coal.....	-	100	-	-	100
Natural Gas.....	270	900	4,218	7,065	12,453
Wind.....	-	50	50	180	280
Total.....	**270**	**1,050**	**4,268**	**7,245**	**12,833**

Source: WECC and NCI.
[1] Generation totals consist of projects in the siting, development, feasibility, and planning phases, as well as projects under construction, as of July 30, 2002 (certain project data verified as of August 13, 2002). These values exclude 803 MW of new generation added during approximately the first seven months of 2002.

Remainder of the WECC

Based on information received from the WECC and CEC, approximately 4,425 MW of new generating capacity has been completed and brought on-line in the Southwest and that portion of the WECC located in Mexico from January 2001 through the first of August 2002. Additional new generating capacity of approximately 4,475 MW is under construction and expected to be on-line by the summer of 2003, for a cumulative total of 8,900 MW of new capacity additions since January 1, 2001. By the summer of 2004, an additional 580 MW of project capacity now under construction is expected to be on-line.

Within the southwest United States and that portion of the WECC located in Mexico, approximately 21,331 MW of new generating facilities are under construction or have been proposed through 2011, as shown in Table 8. These facilities are predominately gas-fired facilities (87 percent), with approximately 51 percent of the new gas-fired capacity proposed for Nevada. These resources include projects in various stages of development, including siting review, feasibility assessment, and conceptual development. Exhibit 6 provides information on projects under construction and permitting review in the Southwest and that portion of the WECC in Mexico.

Non-utility generators plan the majority of resource additions in the region. These power producers will likely enter into bilateral sales agreements with wholesale purchasers, including the investor-owned utilities and municipal utilities in the region, as well as federal agencies, state agencies, power marketers and other load-serving entities. It is possible that they will also contract with entities in California, resulting in imports to California. The fuel efficiency, fuel costs, price levels, and terms of the power sales contracts available from these projects are unknown at this time. It is highly unlikely that all of these proposed projects will reach commercial operation. Some may be abandoned due to environmental constraints, inability to obtain financing, or other reasons.

TABLE 8
POTENTIAL NEW GENERATING RESOURCES IN THE SOUTHWEST AND MEXICO[1]
(MW)

Fuel Type	Arizona	Colorado	New Mexico	Nevada	Mexico[2]	Total
Coal	760	-	-	-	-	760
Hydro	1,250	-	-	400	-	1,650
Natural Gas	4,325	1,190	1,940	9,471	1,650	18,576
Wind	-	-	-	345	-	345
Total	**6,335**	**1,190**	**1,940**	**10,216**	**1,650**	**21,331**

Source: WECC and NCI.
[1] Generation totals consist of projects in the siting, development, feasibility, and planning phases, as well as projects under construction, as of July 30, 2002 (certain project data verified as of August 1, 2002). Excludes 2,420 MW of new generation added during approximately the first seven months of 2002.
[2] That portion of the WECC located in Mexico.

Potential Intertie Upgrades

New out-of-state generating resources will only be available to serve load in California to the extent that transmission interconnection capacity is available to import the resources.

In a recent long-term transmission plan developed by SCE, SDG&E, and the CAISO, major new 500 kV lines to Palo Verde, along with upgrading of the existing Palo Verde-Devers and Southwest Power Link 500 kV lines, were identified to meet the long-term reliability needs in the southern California region. These projects, which are in the early planning stages, could increase southern California simultaneous import capability by as much as 2,900 MW by June 2009. The economic viability of these projects, however, is contingent upon the construction of additional generation near Palo Verde. Construction has begun on approximately 3,300 MW of new generation near Palo Verde and plans have been announced by utilities and independent power producers for the interconnection of a total of approximately 5,000 MW in this area. The principal projects encompassed by this plan are summarized below:

- Construction of an additional 500 kV transmission line between Palo Verde and Devers, a second 500/230 kV transformer at Devers, and certain other improvements to the existing Palo Verde to Devers and Palo Verde to Miguel transmission lines. These improvements are estimated to cost $260 million and would add approximately 1,700 MW of import capability to the West-of-River transmission system (Path 46). The estimated completion date is June 2006 for the first 800 MW and June 2009 for the second 900 MW; and
- Construction of an additional 500 kV transmission line from Palo Verde through the Imperial Valley substation and terminating at the Miguel Substation. The estimated completion date of this project is June 2008 at a cost of approximately $450 million. This project would add 1,200 MW of import capability into southern California over the West-of-River transmission system.

At present, the above projects do not have specific project sponsors. Additional information on potential upgrades to the transmission interties serving the California energy market may be found in Appendix III to this Report.

RESOURCES POTENTIALLY AVAILABLE TO MEET CUSTOMER LOADS

Exhibits 4 through 6 identify the new generating resources under construction in California, the Pacific Northwest, and the remainder of the WECC, as well as resources that are still in the permitting and planning stages. The actual generating capability available to meet the electric needs of the Customers and other electric end-users in the future is likely to differ from the totals shown in these exhibits. This difference reflects the adjustments that are commonly and properly made for planning purposes when evaluating the availability of new resource additions. These adjustments are intended to recognize the improbability that 100 percent of planned resources will be constructed or brought on-line and the probability that less than 100 percent of existing generating capacity will be available to be dispatched at any given time.

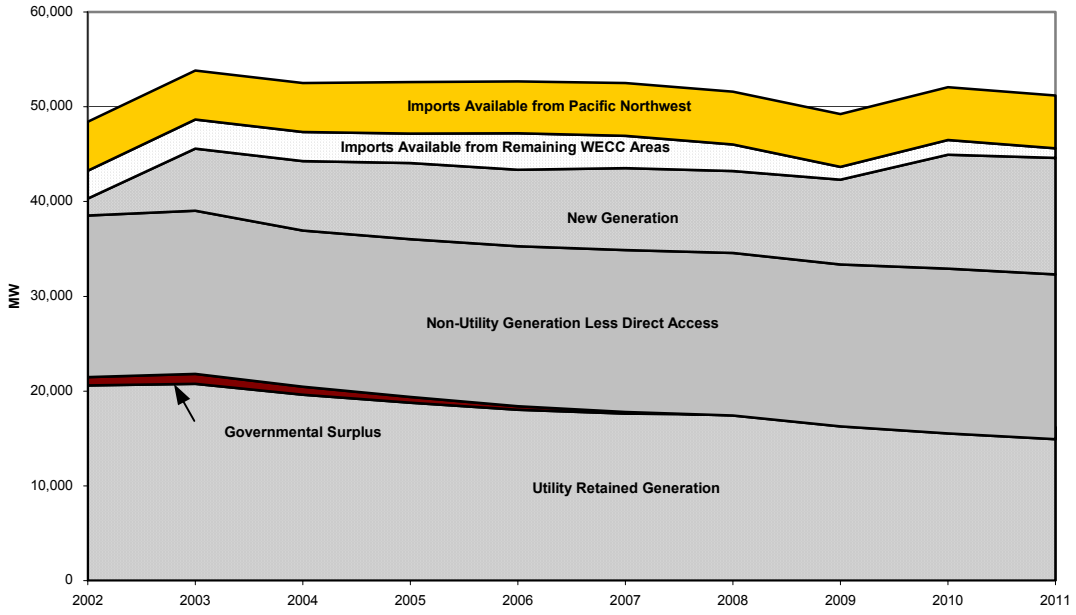
In addition, DWR's ability to acquire output on behalf of the Customers from any resources that are available is dependent on several factors. These include the seller making the output available to DWR, the Customers' need for the output at the time and in the amounts offered, the seller offering the output at a price and under terms that are reasonable in comparison to alternative power supply resources, and DWR's willingness to purchase the output at the price and under the terms offered by the seller.

The following list provides a summary of the principal adjustments made by NCI in the assessment of new resource additions available during the Study Period:

- All new generating facilities currently under construction are assumed to reach commercial operation on the respective dates specified in Exhibits 4 through 6;
- New generating facilities shown in Exhibit 4 that are currently in siting review and under contract to DWR are assumed to reach commercial operation on the dates specified;
- Additional new "generic" resources are assumed to reach commercial operation based on the level of estimated market-clearing prices and certain cost estimates for such generators, as further described in the section of the Report entitled "SIMULATION OF NEW RESOURCE ADDITIONS;"
- All new generating resources, on average, are assumed to be out of service, due to forced or scheduled outages, 5 percent of the time annually;
- Hydroelectric facilities in California were derated by 5 percent during 2002 to account for slightly below normal hydrological conditions. This derating is in addition to the derating normally assigned hydroelectric facilities to account for normal water year conditions and variations in dispatching capabilities. After 2002, hydroelectric generation is assumed to return to historically normal levels. Through April 2002, precipitation levels in California for the current water year (starting October 1, 2001) were 80 percent of normal and reservoir levels were approximately 100 percent of normal; and
- Hydroelectric facilities in the Pacific Northwest were derated by 5 percent during 2002 to account for the effects of the carryover of 2001 dry hydrological conditions. As described above, this derating is in addition to the derating normally assigned hydroelectric facilities to account for normal water year conditions and variations in dispatching capabilities. After 2002, hydroelectric generation is assumed to return to historically normal levels. As of early September 2002, precipitation levels in the Pacific Northwest for the current water year were 97 percent of normal. Reservoir levels were 80 percent of normal as of July 2002.

Exhibit 7 provides a summary of the total generating resources estimated to be available to the Customers during the Study Period. The information presented in Exhibit 7 is summarized in Figure 2 and reflects the existing URG, non-utility generating capacity, new California resource additions being constructed or planned by non-utility generators, surplus generating capacity owned by governmental power producers, and estimated imports available from the Pacific Northwest and the remainder of the WECC. The estimate of new California resources included in Exhibit 7 and reflected in Figure 2 takes into account only those projects currently under consideration by prospective owners and assumes only minor new capacity additions after 2004. The actual amount of new resource additions proposed for California beyond 2004 is likely to exceed the levels assumed herein, depending on future market conditions.

FIGURE 2
ESTIMATED GENERATING RESOURCES AVAILABLE TO THE CUSTOMERS
(MW)



Comparing the total resources estimated to be available to the Customers from Exhibit 7 (as shown in Figure 2 above) and the estimate of Customer peak demands shown in Exhibit 14 (discussed later in this Report), results in a total estimated planning reserve of approximately 37 percent for 2002 and 45 percent for 2003. The estimated planning reserve gradually declines after 2003 to approximately 24 percent by 2011 as the expected amount of new generation additions decrease and older generating units in California are retired from service. Planning reserve margins are relied on for resource planning purposes and represent the excess capacity available to serve loads before reductions for forced and scheduled outages. For purposes of this Report, these reserve margins have been calculated based on the assumption all direct access loads are served from uncommitted power supply resources otherwise available to the Customers. The estimated planning reserve margins described above also assumes the capacity available for import from the Pacific Northwest and the remainder of the WECC can be relied on to serve the Customers' peak demands.

Included in total generating resources available to the Customers is the net generating capacity estimated to be available from governmental power producers in California. In the aggregate, these governmental power producers are estimated to experience a resource deficiency

beginning in 2008. Although new capacity additions by governmental power producers were made during 2001 and have been identified for 2002, these resource additions are not sufficient to offset increases in their electric loads throughout the Study Period. Consequently, absent planned new resource additions not yet announced by governmental power producers, the Customers can expect competition from these entities for new resources constructed in California or imports from other regions of the WECC. Exhibit 8 illustrates the estimated loads and resources used to derive the net generating capacity available from governmental power producers.

The net generating resources estimated to be available to the Customers from the Pacific Northwest and the remainder of the WECC are shown in Exhibits 9 and 10, respectively. DWR's ability to access this generating capability is very dependent on the import capability of the transmission systems between California, the Pacific Northwest, and the remainder of the WECC. Currently, the total rated capacity of interstate transmission lines connecting California and the Pacific Northwest is 6,250 MW and the rated capacity of lines connecting California and the remainder of the WECC is 9,520 MW. However, as a result of constraints on the flow of power between regions during peak periods, together with existing loadings on the transmission facilities, the import capability can be less than the rated capacity of the lines.

Based on analyses performed by NCI, which take into account electric loads within each region, and the availability, type, and location of existing and planned generating facilities, it is expected that the amount of energy imported from the Pacific Northwest and the remainder of the WECC will not reach historical levels during 2002, due primarily to reduced hydroelectric production and increased regional electric loads. After 2002, imports from the Pacific Northwest and the remainder of the WECC are estimated to return to historical levels. Estimated electric loads in the Pacific Northwest and the remainder of the WECC incorporated in this analysis of regional import capability were derived from inputs to NCI's production simulation model discussed later in this Report.

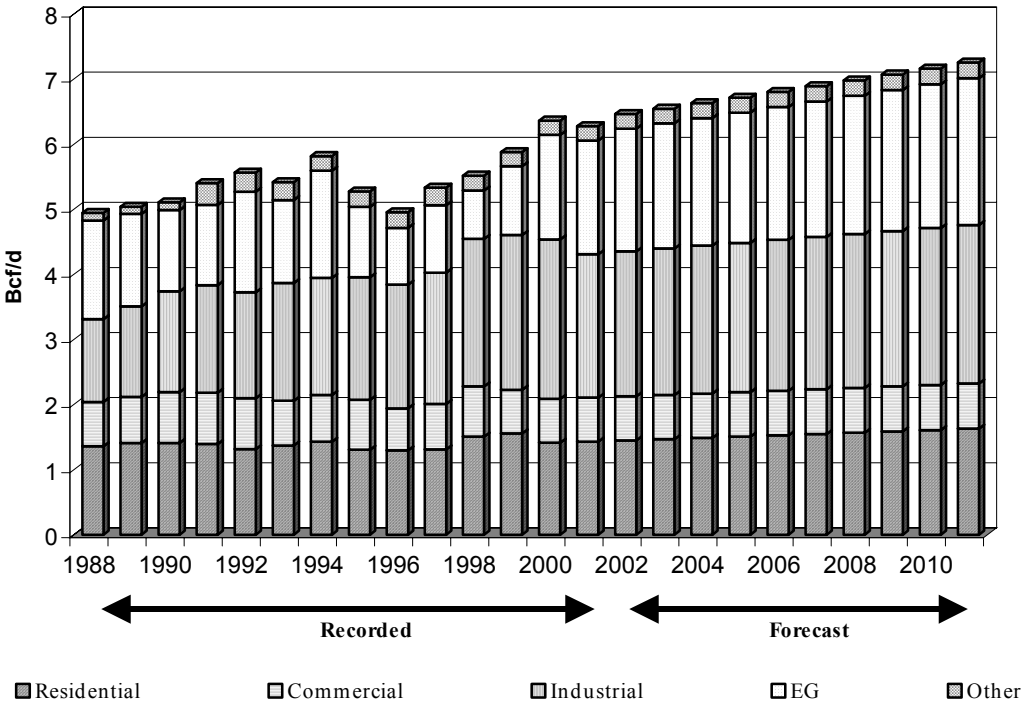
FOSSIL FUEL SUPPLY

The decision to build a new fossil fuel power plant is influenced, in part, by whether and at what price fuel will be available to operate the plant. Likewise, the availability and cost of electric generation from existing resources is partially influenced by the price and adequacy of fuel supplies. Therefore, to assess the amount of generating capacity that may be available in California and the remainder of the WECC in future years, it is necessary to evaluate the future cost and availability of fossil fuels during the Study Period. Presented below is a discussion of these issues relative to natural gas, coal, and oil supplies.

Natural Gas

The United States Energy Information Administration ("EIA") reports that California is the nation's second-largest consumer of natural gas, with current usage of approximately six billion cubic feet ("Bcf") of natural gas on an average day. Approximately one-third of the natural gas consumed in California is used to generate electricity (referred to as "EG" herein). Figure 3 presents recorded and forecast demand for natural gas in California for the 1988 through 2011 period. Recorded data has been obtained from EIA reports and forecast data reflects estimates developed by NCI based on information obtained from EIA, the IOUs, and gas suppliers in California.

FIGURE 3
CALIFORNIA NATURAL GAS DEMAND



Natural Gas Demand

PG&E, Southern California Gas Company ("SoCalGas"), and SDG&E are the principal retail gas suppliers in California. NCI obtained forecasts of long-term gas demand for PG&E and SoCalGas from the 2000 California Gas Report (the "CGR"), the latest year for which the local distribution companies are required by the CPUC to submit forecasts (transportation service from the California border to SDG&E's gas system is provided by SoCalGas and therefore SDG&E's gas demands are included in SoCalGas' forecast). The CGR is the only source of long-term demand forecasts derived for PG&E and SoCalGas. NCI used the forecasts derived from the CGR to estimate usage for end-users other than electric generation.

Estimated gas requirements for electric generation were developed based on the demand and energy forecasts and loads and resources balance discussed previously and NCI's production cost modeling studies for the Study Period. EG demand (excluding QFs, which are included in industrial usage) is forecast to increase from 1.6 Bcf per day during 2000 to 2.3 Bcf per day by 2011 as new generation is added. Average daily demand for natural gas from all end-user categories in California is forecast to approximate 6.5 Bcf per day for 2002, and increase to 7.3 Bcf per day by 2011.

Natural Gas Supply

According to information released by EIA, current annual natural gas production in the United States approximates 19 trillion cubic feet ("Tcf") per year, while annual consumption totals approximately 22 Tcf. The difference between the amounts produced and consumed is made up by imports, primarily from Canada. Total resources in the ground (proven and

probable reserves) for both the United States and Canada were estimated by the National Petroleum Council, in its 1999 report to the United States Secretary of Energy, at 2,300 Tcf.

As shown in Table 9, production of natural gas in the United States has ranged between 18.8 and 19.3 Tcf for the last five years. Beginning in late 1998, oil prices declined sharply, resulting in reductions in new exploration and development and a corresponding decline in total gas production during 1999 and 2000. At the same time new exploration and development was declining, well depletion rates increased, resulting in less production capability. Combining this reduction in supply with a return to normal winter weather patterns in the Midwest and Northeast, as well as significantly expanding natural gas demand due to the addition of new gas-fired generation, created an environment for natural gas prices to increase dramatically. Such increases began in approximately the middle of 2000 and culminated when the New York Mercantile Exchange (the "NYMEX") price for gas futures contracts closed at $9.88 per million British thermal units ("MMBtu") for January 2001. Since that time, natural gas prices have generally declined, dropping as low as $1.86 per MMBtu in October 2001. For the month of April 2002, natural gas prices had increased to more than $3.41 per MMBtu.

TABLE 9
GAS PRODUCTION AND RIG COUNT

Year	Production (Bcf)	Number of Rigs
1997	18,902	566
1998	19,024	560
1999	18,832	426
2000	18,987	720
2001	19,352	939

Source: EIA "Monthly Energy Review," April 2002, and Baker Hughes.

The increase in natural gas prices experienced in 2000 attracted increased investment to bring existing reserves into production and to expand exploration for new resources. The number of rigs drilling for natural gas increased from a low of 362 in April 1999 to a high of 1,068 in July 2001 (an average of 600 rigs is frequently cited by the gas industry as being necessary to maintain production levels). The increase in production levels recorded during 2001 was a reflection of the increased investment in production and exploration activity during the year. During the first quarter 2002, an average of 669 rigs were deployed and in service.

California obtains natural gas from several supply basins: the Western Canadian Sedimentary Basin of Alberta and British Columbia, the Rocky Mountains, the San Juan Basin located in the Four Corners area of New Mexico, Colorado, Arizona, and Utah, and the Permian Basin in west Texas. California is also home to local natural gas production of approximately 0.3 Tcf per year, or five percent of annual usage in the State during 2001. These supply areas, including California, accounted for approximately 59 percent of total production in the United States during 2001.

Natural Gas Pipeline Capacity

Existing interstate pipeline capacity to deliver gas to the California border totals approximately 6.9 Bcf per day. With minor exceptions, PG&E and SoCalGas have adequate in-state capacity to deliver the entire 6.9 Bcf to their load centers. Table 10 identifies the interstate pipelines and delivery capacity relative to the supply basins that serve California.

TABLE 10
INTERSTATE NATURAL GAS PIPELINE
CAPACITY TO CALIFORNIA

Pipeline	Capacity (Bcf per day)
PG&E-GT Northwest (PGT)[1]	1.850
Transwestern[2]	0.950
El Paso Natural Gas[3]	2.890
Kern River Gas Transmission[4]	0.824
Mojave[3]	0.400
Total	**6.914**

Source: FERC filings.
[1] Delivers gas from Western Canadian Sedimentary Basin.
[2] Delivers gas from San Juan and Permian Basins.
[3] Delivers gas from San Juan, Permian, and Anadarko Basins.
[4] Delivers gas from the Rocky Mountains.

During 2001, several pipeline companies announced proposals to build new or additional pipeline capacity to or within California and/or held open seasons to assess feasibility and market interest. Proposed additions announced in 2001 that are being actively developed are shown in Table 11. Several additional proposals were announced during 2001, but are no longer actively being pursued due to stabilization in gas prices.

TABLE 11
INTERSTATE PIPELINE CAPACITY ADDITIONS

Pipeline	Capacity Addition (Bcf per day)	Expected In-Service Date
PG&E-GT Northwest[1]	0.200	September 2002
Kern River Gas Transmission[2]	0.900	May 2003
El Paso Natural Gas[3]	0.230	August 2002
Baja Norte[4]	0.500	January 2003

Source: FERC filings and information released by the respective pipeline companies.
[1] Delivers gas from Western Canadian Sedimentary Basin. Received FERC approval August 6, 2001.
[2] Delivers gas from Rocky Mountains. FERC approval pending. Excludes a .013 Bcf addition placed in service July 2001 as part of a separate project.
[3] Delivers gas from San Juan, Permian, and Andarko Basins. Obtained preliminary approval from FERC on May 9, 2001. This project represents the conversion of an existing oil pipeline from the California border to the SoCalGas system. Total firm delivery capability at the California border would not increase as a result of this project.
[4] Delivers gas from San Juan and Permian Basins. FERC approval pending. Approximately 0.11 Bcf is permitted for delivery from this pipeline into the SDG&E system. This project would redirect existing supply delivered to the California border and would not increase total firm import capability.

To make use of gas supplies brought in by these pipeline additions, PG&E and SoCalGas are expanding portions of their systems from the California border to their respective load centers. PG&E has announced a plan to expand its northern backbone system to match the 0.2 Bcf per day interstate pipeline expansion by PG&E-GT Northwest. SoCalGas reports that it is adding a total of 0.375 Bcf per day of capacity at three different locations on its system. In addition, SoCalGas recently added 0.07 Bcf per day of new intrastate pipeline capacity to deliver gas from its system to the SDG&E system. PG&E and SoCalGas have indicated they expect to complete these expansion efforts by the end of 2002. Table 12 provides a summary of existing pipeline capacity and planned expansions during the Study Period.

As shown in Table 12, existing interstate pipeline capacity to the California border, when combined with in-state gas production capability, is greater than the ability of PG&E, SoCalGas, and bypass customers to take delivery of the gas. This differential will increase when planned interstate pipeline additions by Kern River Gas Transmission and PG&E-GT Northwest are completed prior to the end of 2003. Excess deliverability at the California border could potentially be turned into deliverable supply if the local distribution companies build matching intrastate pipeline capacity to move this gas to their load centers.

TABLE 12
GAS SUPPLY CAPABILITY TO MEET LOADS THROUGH 2004
(BCF PER DAY)

	Existing System	Planned Additions	Total
Capacity Available to Serve California			
Interstate Pipeline Capability – CA Border[1]	6.914	1.100[2]	8.014
In-State Gas Production[3]	1.000	0.040	1.040
Total Capacity to Serve California[4]	**7.914**	**1.140**	**9.054**
Ability to Take Supply[5]			
PG&E/SoCalGas Systems[6]	6.610	0.575[7]	7.185
Existing Bypass[8]	0.994	0.240	1.234
Total Take Capability	**7.604**	**0.815**	**8.419**
Uncommitted Supply Capability[9]	**0.310**	**0.325**	**0.635**

Source: FERC filings, CEC, PG&E, SoCalGas, and NCI.
[1] Aggregate delivery capability of interstate pipelines at the California border and of in-state gas producers.
[2] Additions by Kern River Gas Transmission (0.9 Bcf per day) and PG&E-GT Northwest (0.2 Bcf per day).
[3] Production capability of in-state natural gas producers.
[4] Aggregate capability to meet natural gas demands from interstate pipeline deliveries and in-state gas production. Excludes load-serving capability of storage reserves.
[5] Represents the maximum amount of supply that can be taken from interstate pipelines at the border and from in-state gas producers.
[6] Maximum quantity of natural gas that can be input to the PG&E and SoCalGas systems on a daily basis.
[7] Additions of 0.200 Bcf per day by PG&E and 0.375 Bcf per day by SoCalGas. Amount shown for SoCalGas does not include the 0.07 Bcf per day expansion to the SDG&E system, since this capacity will not increase the amount of gas that can be taken at the California border.
[8] End-use customers taking delivery directly from the interstate pipelines or in–state gas producers.
[9] Capacity available from interstate pipelines at the California border and from in-state gas producers to meet increases in gas requirements. Would require construction of additional system improvements by PG&E or SoCalGas to transport to end-users or bypass customers.

Gas Balance

NCI performed a gas balance analysis that compares natural gas demand with available gas supply and delivery capacity. The results of this analysis indicate whether sufficient pipeline capacity exists to serve projected demands. This analysis also suggests when capacity utilization will reach a level that supports the addition of new pipeline capacity. Such results are frequently used by potential shippers considering commitments for new pipeline capacity, as well as by pipeline companies considering expansion.

NCI's analysis was based on the demand estimates discussed above, which reflect normal seasonal weather conditions. In addition, NCI has taken into account the existing capacity of the interstate and intrastate pipeline systems, planned capacity additions shown in Table 12, and information reported by the CPUC with respect to excess capacity margins within the PG&E and SoCalGas local transmission and distribution systems. Based on this analysis, NCI expects that PG&E will have adequate supply and be able to serve the full demand of its core and non-core

customers throughout the Study Period. SoCalGas is expected to have sufficient capacity and supply to meet the full requirements of its core and non-core customers through 2007, at which time either additional pipeline capacity will need to be constructed or a portion of the non-core gas load will need to be interrupted during periods of highest demand.

In addition to the above factors, this assessment considered the availability of gas supplies in underground storage facilities. PG&E and SoCalGas own facilities providing 36 Bcf and 110 Bcf, respectively, of storage capacity. These facilities are primarily relied on to meet core end-user demands during winter months, but may also be used to enhance system operations during other times of the year. Also considered were the procedures the CPUC has adopted to assess the need for and reasonableness of new intrastate capacity additions. PG&E, SoCalGas, and SDG&E file Biennial Cost Allocation Proceedings that, among other information, contain each utility's resource plans for meeting end-user gas requirements. If the CPUC finds the resource addition to be reasonable and to benefit all end-users, the utility is authorized to proceed with construction of the addition, the cost of which is included in the rates to all end-users. If the resource addition is found to benefit only a few end-users, the CPUC requires that the costs be borne solely by those end-users receiving the benefit. This process helps to ensure that needed capacity additions that benefit all end-users are added, while limiting resource additions that benefit very few end-users to those that are willing to pay for them.

Other Fuel Sources

The IOUs rely on limited amounts of coal- and oil-fired generation to meet a portion of the needs of the Customers. Low sulfur coal in the western United States is produced from large surface mines operating in thick near-surface coal seams. Electric generating facilities are often located at the mines to reduce cost by eliminating some or all of the coal transportation costs. Other facilities must have the coal transported either by truck (short distances) or by rail. For these plants, the cost of transportation is a significant portion of the cost of fuel.

The Mojave and Four Corners coal-fired electric generating facilities constitute the largest sources of thermal generation owned by the IOUs. Coal burned at the Mojave plant is supplied from the Black Mesa Mine ("Black Mesa"), which is operated by Peabody Energy. In 2001, Black Mesa shipped approximately 9.5 million tons of low-sulfur compliance coal to Mojave. Black Mesa has approximately 1.4 billion tons of low-sulfur coal reserves available for production. Mojave's coal contract runs through December 31, 2005. SCE has reported that, over the next several years, it will be considering its options with respect to the coal supply at Mojave.

Low-sulfur coal burned at Four Corners comes from the adjacent Navajo mine operated by BHP-Billiton. The Navajo mine has the capacity to produce approximately eight million tons of low-sulfur coal annually and is the sole supplier of coal to Four Corners. The mine has approximately one billion tons of coal in reserves. In 2001, the coal contract for Four Corners was extended through December 31, 2004, with an interim pricing agreement reached for 2002. The parties' expectation is that additional interim pricing agreements will be developed annually until a long-term agreement is reached.

Oil-burning power plants in California burn distillate fuel, a product of the process of distilling crude oil. Distillate fuel is required to meet environmental restrictions and burns cleaner than residual fuel.

Fuel Costs

Since mid-2000, natural gas prices have fluctuated widely in California, driven by variations in weather patterns, supply availability, pipeline constraints, and storage inventory levels. In recent months, gas prices have moderated and NCI believes the long-term trend will exhibit a flattening of the price curve, with modest increases in price over the Study Period. Presented below is a summary description of recent gas price activity, factors contributing to recent price volatility, and NCI's estimate of gas prices during the Study Period. Also discussed below are NCI's estimates of coal and oil prices over the Study Period and the basis for such estimates.

Recent Natural Gas Price Behavior

Between 1996 and 2000, natural gas prices demonstrated a relatively stable pattern, generally averaging approximately $2.20 per MMBtu at Henry Hub on an annual basis. This price behavior changed in May 2000, when prices failed to decline following the end of the winter heating season, despite excess gas in underground storage. As a result of the relatively high price, many buyers delayed purchasing gas for storage injection, expecting prices to decline as summer progressed. The decision to delay these purchases, together with other factors, contributed significantly to major increases in the cost of natural gas during the latter half of 2000 and early 2001. Over the course of 2001, gas prices began to retreat to lower levels. These reductions were influenced by lower than expected demand for natural gas-fired generation during the summer of 2001, an increase in new gas drilling and production levels (driven by the higher prices experienced during 2000), and the gradual slowing of the national and California economies.

Prior to 2000, the price of gas at the California border traded at approximately the same value as gas tied to Henry Hub delivery, with only minor pricing differentials. The events described above during the latter half of 2000, contributed to the imposition of significant pricing differentials on gas delivered to California relative to Henry Hub. Table 13 illustrates this difference in price during the 1997 through 2001 period. The price increases experienced during the second half of 2000 prompted an increase in exploration and drilling which resulted in an increase in gas production during 2001. These production increases, coupled with lower than expected gas-fired electric generation during the summer 2001 and a return to normal purchasing patterns for storage injection, provided downward pressure on natural gas prices during the second half of 2001. By January 2002, the average price of gas delivered to Topock equaled $2.61 per MMBtu, the same price per MMBtu for gas delivered to Henry Hub.

Enron Bankruptcy

The financial collapse of the Enron Corporation ("Enron") during 2001 has had little impact on the availability and delivery of natural gas supplies. Enron sold its oil and gas production affiliate during 2000 and therefore no production capability was affected by its bankruptcy. The most notable impact Enron's financial difficulties have had on the marketplace is to sharpen the focus of natural gas traders on credit issues, including detailed credit information, collateral, backstop reserves, and the loss limits of their counter parties. At present, however, this focus has not translated into an increase in or a premium on gas prices.

Estimated Natural Gas Costs

NCI estimated forward natural gas prices using a proprietary, in-house forecasting model. The model relates annual natural gas prices to prior period prices, a weather variable

reflecting average heating degree-days, and a variable representing drilling activity (which is driven, in part, by world oil prices) and well completions to produce a forward price at Henry Hub. This derives an econometric equation that is used to estimate future prices. The econometric results exhibit strong and reasonable properties in terms of statistical error measurements and, when data inputs are used that reflect historical conditions, has produced price estimates that are very close to those actually experienced.

TABLE 13
NATURAL GAS PRICES AT HENRY HUB VERSUS SOUTHERN CALIFORNIA BORDER (DOLLARS PER MMBTU)

	1997	1998	1999	2000	2001 Jan.-June[1]	2001 July-Dec.[2]
Topock	$2.49	$2.22	$2.32	$4.91	$13.50	$3.04
Henry Hub	2.58	2.10	2.27	3.88	5.86	2.66
Difference	**$(0.09)**	**$0.12**	**$0.05**	**$1.03**	**$7.64**	**$0.38**

Source: "Gas Daily".
[1] Average monthly contract index prices, January through June 2001.
[2] Average monthly contract index prices, July through December 2001.

The delivered cost of natural gas is typically the cost at the southern California border plus the cost of intrastate transportation. Southern California border prices are derived by adding a "basis" differential to the Henry Hub price. For purposes of this Report, NCI has assumed a basis estimate that reflects a gradual tightening of seasonal supply and delivery capacity and the corresponding pricing signals generated by the market to encourage new capacity additions. The resulting estimated southern California border prices at Topock are shown in Table 14.

TABLE 14
ESTIMATED COST OF NATURAL GAS IN SOUTHERN CALIFORNIA

Year	Dollars per MMBtu	Equivalent Cost per MWh[1]
2002	$3.00	$21.28
2003	3.29	23.35
2004	3.40	24.17
2005	3.51	24.95
2006	3.63	25.75
2007	3.85	27.31
2008	4.06	28.81
2009	4.27	30.31
2010	4.44	31.55
2011	4.60	32.68

Source: NCI March 2002 natural gas price forecast. All values expressed in nominal dollars and exclude transmission and distribution costs within the California border.
[1] Equivalent cost based on a new combined cycle plant operating 8,000 hours per year at a 7,100 Btu per kWh heat rate.

The differentials to other gas price points in the WECC are set so that regional prices reflect levels normally observed in the market. This translates to prices in other regions of the WECC being significantly lower than the price for gas delivered to southern California, which is

the area exhibiting the highest basis differential to Henry Hub. For ease of comparison, Table 15 illustrates these differentials relative to southern California's delivered gas cost.

Estimated Coal and Oil Costs

Over the long term, EIA projects mine mouth coal prices to decline by 1.3 percent per year through 2020, resulting from continued improvements in mine productivity. Coal transportation rates are projected to decline by 1.1 percent per year through 2020. From 2000 to 2001, delivered coal prices declined 2.0 percent nationwide, while in western states prices rose by 1.5 percent, according to EIA (all values estimated by EIA are expressed in real dollars).

TABLE 15
ESTIMATED SOUTHERN CALIFORNIA GAS PRICE DIFFERENTIAL RELATIVE TO OTHER DELIVERY POINTS AND WECC MARKETS (DOLLARS PER MMBTU)

Year	Malin	PG&E City Gate[1]	Pacific Northwest[2]	Rocky Mountains[2]	Arizona & Nevada[2]
2002.....	$0.45	$0.01	$0.34	$0.23	$0.27
2003.....	0.49	0.02	0.35	0.24	0.28
2004.....	0.52	0.03	0.51	0.40	0.44
2005.....	0.52	0.02	0.53	0.41	0.45
2006.....	0.54	0.03	0.61	0.49	0.53
2007.....	0.58	0.04	0.63	0.50	0.55
2008.....	0.61	0.05	0.64	0.51	0.56
2009.....	0.64	0.06	0.66	0.53	0.57
2010.....	0.67	0.07	0.67	0.54	0.59
2011.....	0.69	0.07	0.69	0.55	0.60

Source: NCI March 2002 natural gas price forecast. All values expressed in nominal dollars.
[1] Delivery point to the PG&E natural gas system.
[2] Aggregate price differentials at different delivery points within the regions indicated. Amounts shown in Table 15 are subtracted from the estimated cost of natural gas at the southern California border (Table 14) to derive estimated costs at the above delivery points. Costs associated with the transmission and distribution of natural gas within the California border are not included in Table 15.

NCI has prepared an estimate of the cost of coal for both the Mojave and Four Corners facilities. Four Corners is a mine mouth facility, while Mojave receives its coal supply through a slurry pipeline from the nearby Black Mesa mine. Estimated coal prices for the Study Period reflect a continuation of recent historical prices through the end of the contract period for both facilities (December 31, 2004, for Four Corners and December 31, 2005, for Mojave). Upon expiration of the contracts, the price of coal is expected to increase to a level approximating market value and escalate thereafter, taking into account mine development plans where known. Estimated coal prices are shown in Table 16.

NCI believes it is reasonable to expect that, given the need for energy in California and other markets, Mojave and Four Corners will remain in operation as coal-fired facilities through at least the end of the Study Period.

NCI has relied on EIA's forecast of distillate oil prices for purposes of this Report. Distillate oil pricing depends on a number of factors affecting both supply and demand. Price volatility has been fairly narrow during recent years, which is reflected in the forecast developed by EIA. Estimated distillate oil prices are shown in Table 16.

NET SHORT BEFORE DWR CONTRACTS

The Customers' net short requirements represent the shortfall between their total capacity and energy requirements and the generation available from the IOUs' URG. DWR has implemented a program designed to meet these requirements in a manner that stabilizes electric prices in the California marketplace and encourages the development of new generating resources.

TABLE 16
ESTIMATED COAL AND OIL PRICES
(DOLLARS PER MMBTU)

	Coal		
Year	Mojave	Four Corners	Distillate Oil
2002.....	$1.39	$1.60	$5.55
2003.....	1.43	1.71	5.75
2004.....	1.48	1.77	5.95
2005.....	1.49	1.84	6.16
2006.....	1.50	1.93	6.35
2007.....	1.55	1.93	6.55
2008.....	1.59	1.97	6.76
2009.....	1.64	2.06	6.99
2010.....	1.69	2.10	7.21
2011.....	1.74	2.15	7.44

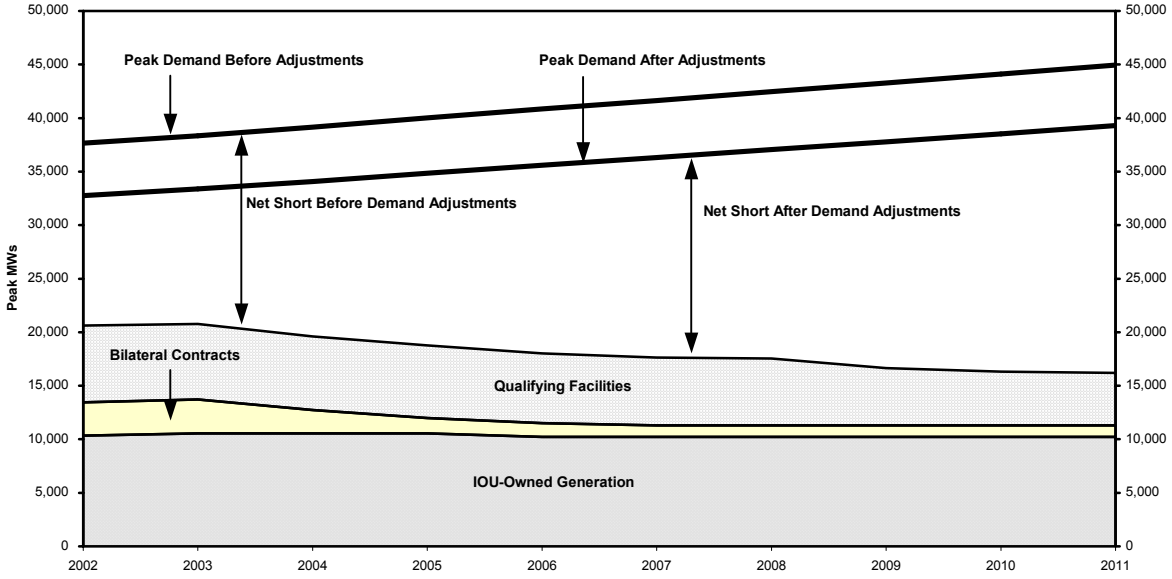
Source: All values expressed in nominal dollars. NCI forecast for coal and EIA forecast for oil. EIA oil forecast escalated by 2.5 percent per year by NCI to account for inflation.

Based on the capacity requirements of the Customers discussed previously in this Report, and the power supply resources expected to be available from the URG, the Customers' combined net short requirements after new conservation and load management are estimated to range from approximately 12,151 MW in 2002 to 23,114 MW in 2011. For comparison, the actual maximum net short during 2001 approximated 18,265 MW on May 23. Factors contributing to the higher relative net short in May 2001 included several QF generators being off-line, two nuclear units being off-line, below average hydroelectric conditions in California, and reduced levels of direct access. Exhibits 11 through 13 of this Report provide a summary of the estimated net short requirements for the Customers within the service area of each IOU. The aggregate combined net short requirements for all Customers are presented in Exhibit 14 of this Report. Figure 4 provides an illustration of the Customers' annual net short over the Study Period.

DWR Resources

Under the Act, DWR is authorized to enter into contracts for power supply until December 31, 2002. After that date, absent action by the State extending DWR's contract procurement authority, the IOUs will be responsible for purchasing the residual net short requirements of the Customers. DWR expects to meet the total net short requirements of the Customers until December 31, 2002, through a combination of long-term contracts, spot market purchases, and new conservation and load management programs. These power supply resources are described below. Please see the section in this Report entitled "PLAN TO TRANSITION DWR NET SHORT RESPONSIBILITIES" for additional information on this subject.

FIGURE 4
ANNUAL NET SHORT CAPACITY REQUIREMENTS
(MW)



Voluntary Load Curtailment Programs

Initiatives are in place to encourage conservation and load management programs to reduce electricity demand, particularly during the summer months of 2002. These efforts include a continuation of certain conservation and load management efforts initiated during 2001 as well as a new initiative to produce load reductions during peak periods, as described in more detail in the section of this Report entitled "CAPACITY AND ENERGY REQUIREMENTS."

DWR Contracts

DWR has entered into contracts and developed a diversified portfolio of resources to meet a portion of the Customers' net short requirements. Exhibits 15 and 16 at the end of this Report provide a summary of the capacity and associated energy estimated to be used by DWR to supply the Customers through these contracts. Summary information on the long-term power supply contracts entered into by DWR is provided in Appendix I of this Report.

The contracts DWR has entered into are designed to meet a series of objectives established by DWR. These objectives include the following:

- Create a portfolio of contracts that reduce spot market reliance, give priority to contracts resulting in new supply resources, and restore reliability of supply;
- Meet as much of the net short as possible under contracts with known costs, while allowing for the flexibility to utilize other power supply opportunities in the future as the California energy market stabilizes;
- Optimize long-term commitments for capacity and energy purchases with short- and intermediate-term contracts, recognizing that longer-term contracts will reduce near-term prices relative to the spot market;

- Secure a portfolio of short-, intermediate-, and long-term contracts and peak-, intermediate-, and base-load power supplies;
- Secure a combination of fixed-price and tolling agreements;
- Secure contracts which result in expedited construction of new generation capacity to enhance near-term system reliability;
- Match intrastate regional electric needs (north and south of Path 15 transmission constraints, as described later in this section) to locations of supply; and
- Secure contracts for summer/winter seasonal exchanges of power with suppliers from the Pacific Northwest.

NCI believes the portfolio of contracts DWR has entered into generally achieves the objectives established for the power supply program. The general characteristics of these contracts are described below.

Types of Contracts

The specific source, firmness of supply, and seller of capacity and energy resources to DWR vary by contract. Some of these contracts are generator specific, with the delivery of energy being contingent upon operation of a specific generating facility ("unit-contingent"). Some of the agreements are subject to output availability, with the seller agreeing to make generation available to DWR to the extent the entity already purchasing the output of the generator does not use it ("as-available"). Other contracts are market or system sales, which are firm transactions from any power supply source under the control of the seller. The unit-contingent and as-available contracts allow for non-delivery of energy for such things as maintenance and outages beyond the control of the seller. The firm transactions require that energy is delivered in accordance with the contracts or the seller is to pay all reasonable costs incurred by the buyer (in this instance, DWR) to replace the energy not delivered.

Some of the contracts entered into by DWR are for base load purchases that require energy to be provided 24 hours per day, seven days per week ("7x24") for the period of the contract. Other contracts are for peaking resources that provide energy for a limited daily period and possibly for a limited number of days per week. Typically, these peaking contracts provide energy for 16 hours per day, six days per week ("6x16"). The advantage to such an arrangement is that energy would not be delivered when system loads are usually at their minimums (nighttime periods and Sundays). Other peaking resources can be further defined due to limitations in operating hours (emissions-limited resources or available hydroelectric capability) or by the dedication of generation to other loads. A mix of product types is necessary in order to have resources to serve the expected hourly load pattern during all months of the year.

Contracts Dependent on New Generation

In an effort to spur new generation, DWR has entered into contracts that contemplate the construction of new facilities. These facilities are generally new generating resources, but also include generating facilities that are being upgraded to provide additional generating capacity. As shown in Exhibit 4, approximately 1,398 MW of new or upgraded generating capacity under unit contingent contracts with DWR was constructed between January 1, 2001 and July 30, 2002. During this same timeframe, approximately 1,915 MW of new or upgraded generating capacity was constructed by owners with system sales contracts with DWR.

Over all, DWR has unit contingent contracts for 3,230 MW of new generating capacity in California. This total is comprised of the 1,398 MW of capacity that has already been constructed, 1,066 MW that is currently under construction and expected to be placed in commercial operation prior to July 2005, and 766 MW in siting review. Of the total capacity presently under construction, 886 MW of this capacity is expected to be completed and added during 2003. Additionally, all of the capacity in siting review with unit contingent contracts (766 MW) is scheduled to be completed by the summer of 2003.

In addition to the new generation supporting unit contingent contracts, DWR has system sales agreements with power suppliers that have installed or will be installing a total of 7,652 MW of new generating capacity by the summer of 2006. Of this total, 1,915 MW of new capacity has been constructed, 2,350 MW are under construction, and 3,387 MW are in siting review. Of the total capacity now under construction, 500 MW is scheduled to be in commercial operation by the summer of 2003. All of the new generation in siting review available to support system sales contracts with DWR are scheduled to enter commercial operation after the summer of 2004.

Tolling Agreements

A substantial portion of DWR's long-term power supply contracts consists of "tolling" agreements under which the contract price for energy is calculated based on the price for natural gas. Under these contracts, DWR pays a fixed price for the generation capability (a "capacity payment") and pays the seller to provide gas at agreed-upon terms or price formulas. It is typical for an energy purchaser to include some level of tolling agreements within its supply portfolio to mitigate the risk of being left with only fixed price contracts, should those fixed prices prove to be high relative to the available market. Such tolling agreements are expected to be favorable to DWR since gas prices were at historically high levels when many of the contracts where entered into and have subsequently declined. As of July 30, 2002, these contracts represent approximately 2,940 MW, or 36 percent of total DWR contract capacity during 2002, and increase to a high of 5,460 MW, or 55 percent of DWR contract capacity, in 2007.

A number of the tolling agreements provide DWR with the option of delivering all or a portion of the gas supplies needed to fuel the respective generating facilities. This option provides DWR the opportunity to lock in gas supplies and pricing for future delivery, thereby stabilizing generation costs and mitigating the negative effects of supply and price volatility. To enhance the benefits of this option, DWR has developed and implemented a formal fuel management program that it is relying on to manage the cost of natural gas in connection with the tolling agreements. This program includes specific objectives and guidelines for the acquisition and management of natural gas supplies, including the management of price risk associated with future potential fluctuations in gas supply costs.

In connection with its fuel management program, DWR relied on professional advisors with expertise in the development and implementation of gas purchasing strategies, risk management, and regional and national gas markets. These advisors have trained DWR staff who now perform the day-to-day execution of the fuel management program. Professional advisors continue to provide assistance with the program and the management of financial hedging instruments.

As of July 30, 2002, DWR has elected to directly acquire gas supplies in connection with three of the tolling agreements and is considering acquiring gas under three additional agreements. During 2002, these purchases are estimated to be five percent of total annual gas supplies consumed by generating facilities under contract to DWR. A portion of those tolling agreements that provide DWR the option to procure gas supplies also specify that the facility

operator must periodically submit fuel plans to DWR for review and approval. In the event DWR does not approve the fuel plan submitted by the operator, DWR will acquire and deliver the needed gas supplies to the generating facility. As a result of this approval process, the gas supply portfolio managed by DWR may vary from year to year. Also affecting this portfolio will be the completion of new generating facilities under contract to DWR with tolling agreements, as well as the prospective transition of the tolling agreements to the IOUs (in which case, the IOUs are expected to be responsible for securing gas supplies).

DWR's fuel management program is governed by a mission statement and objectives established by its fuels team, including its risk management consultant, and DWR management. A primary focus of this fuel management program is establishment of a spectrum of supply arrangements so that the supply portfolio is balanced and not overly exposed to any particular type of risk (such as term, location, or pricing mechanism). As a result, DWR's supply portfolio can be expected to include, over time, one-year contract purchases, multi-month purchases priced on either a fixed or indexed basis, and daily spot purchases. Actual make-up of the supply portfolio on a day-to-day basis can be expected to vary, in part due to periodic variations in natural gas market conditions.

DWR contracts for a limited amount of natural gas storage capacity on the SoCalGas and PG&E systems, which it uses to manage daily swings in gas requirements and to enhance supply reliability. DWR has also considered, but not executed, the short-term acquisition of intrastate and interstate pipeline capacity to hedge against supply basin price risk. To the extent economically viable in the future, DWR may rely on such capacity purchases to mitigate the need to acquire all gas supply at California border or city gate prices.

The composition of DWR's supply portfolio will change as conditions in the natural gas market change and as the dispatch of the various power contracts changes. DWR has been granted an initial authorization by the Secretary of the Resources Agency to purchase up to $260 million per year of natural gas and related operational assets.

Through May 2002, DWR expended approximately $36.2 million of its initial authorization for fuel supply and underground storage purposes, including approximately $31.3 million under fixed price contracts. For the three tolling agreements under which DWR is acquiring gas supplies, DWR has entered into fixed price contracts for approximately 69 percent of the associated July through October 2002 gas requirements totaling approximately $28.8 million. Additionally, DWR has executed financial hedges associated with approximately 9.2 percent of the July through December 2002 gas requirements associated with these tolling agreements. In the event the tolling agreements are transferred to the IOUs in the future, the IOUs are expected to assume responsibility for gas supply acquisition, with DWR assigning any gas supply contracts then in place to the IOUs or exercising early termination rights, if any, under those contracts.

CPA Contract

DWR has contracted with the California Consumer Power and Conservation Financing Authority ("CPA") to receive a minimum of 250 MW per month by October 2002 and 500 MW per month by June 2003 of load serving capability (the "CPA Contract"). The CPA was created pursuant to Senate Bill 6 of the First Extraordinary Session of 2001, which was signed into law on May 16, 2001, and is charged with ensuring, among other things, a sufficient and reliable supply of electricity and natural gas in California. The CPA Contract will extend from July 2002 through May 2007 and will provide DWR with load serving capability for up to 24 hours per month for meeting peak load requirements or providing ancillary services.

PX Block Forward Contracts

Prior to the suspension of its trading activities, the PX operated a market for the trading of forward contracts for the future delivery of electricity. These forward contracts were traded in multiples of 25 MW, known as "blocks," and the traded blocks were referred to as "Block Forward" contracts. Both PG&E and SCE were participants in the Block Forward market. PG&E and SCE purchased rights to capacity under Block Forward contracts for delivery dates in 2001.

On January 16, 2001, Standard & Poor's and Moody's Investors Service downgraded the credit ratings of PG&E and SCE below investment-grade status. As a result of such downgradings, the PX provided notice to PG&E and SCE that they were required under the PX tariff to post additional collateral. The two IOUs failed to post the required collateral and were suspended from trading in the PX markets on January 18, 2001. The PX contended that SCE and PG&E's failure to pay for their market purchases resulted in a substantial shortfall in funds available to the PX and gave the PX the right to liquidate the two IOUs' Block Forward contracts.

PG&E and SCE sought injunctions in two separate actions filed with the California Superior Court to prevent the liquidation of the Block Forward contracts. The judges in both cases granted preliminary injunctions until February 2 and February 5, 2001, respectively. In the interim, on January 31, 2001, the Governor, pursuant to his emergency powers, issued Executive Order D-20-01 commandeering the SCE Block Forward contracts and Executive Order D-21-01, commandeering the PG&E Block Forward contracts. These contracts were relied on by DWR to meet a portion of the Customers' net short requirements during 2001.

The contract price of the Block Forward contracts totaled approximately $352 million. The PX contends that the Block Forward contracts could have been liquidated following PG&E and SCE's default and that the combined market value of the contracts was in excess of $1.1 billion. The issue of whether and to what extent compensation is due is now before the Sacramento County Superior Court in a declaratory relief action filed by the State in September 2001 which names as defendants those market participants which have and those which, the State believes, might claim compensation as a result of the Governor's actions. DWR believes such claims for compensation to be substantially in excess of the contracts' true value. If the claimants prevail, the difference in value could become a DWR liability and an element of DWR's Retail Revenue Requirements to be recovered from the Customers.

Additional information on this and other legal proceedings associated with the Block Forward contracts may be found in the section in the Official Statement entitled "LITIGATION AND ADMINISTRATIVE PROCEEDINGS—Litigation Pending or Threatened in State and Federal Courts--*"Block Forward Contracts" Consolidated Actions.*" NCI cannot predict the outcome of these legal proceedings or the likely schedule for resolving this matter. Estimated DWR Operating Results, discussed later in this Report, are based on the assumption the claimants will not prevail in their monetary claim against the State.

Air Emissions

Some of the contracts entered into by DWR contain clauses requiring DWR to pay the cost of air emission offsets ("Offsets") that the seller must obtain to operate new generating resources or to extend the operating hours of existing resources. Offsets are reductions in air emission rates that are achieved from other sources in the same air quality basin. For new facilities, the procurement of adequate Offsets is a prerequisite to obtaining a construction permit. For existing facilities, there is an annual allocation of Offsets in line with annual emission limits under which the seller can operate the facility. Operation beyond the annual emissions limits requires

additional Offsets. In addition, some of the contracts contain clauses that may enable the seller to pass through to DWR the cost of installing new emission control equipment that is required by changes in air quality regulations. In total, as of July 30, 2002, two contracts representing 14 generating units and 3,231 MW of generating capacity contain one or both of these clauses.

Most of California is classified as non-attainment for either or both the federal and State Ambient Air Quality Standards ("AAQS") for ozone, the known cause of smog. Fossil fuel-fired electric generating facilities produce emissions of nitrogen oxides ("NO_x"), carbon monoxide, volatile organic compounds ("VOCs"), sulfur dioxide, and fine particulate matter of 10 microns or less in diameter ("PM_{10}"). Because NO_x and VOCs act as precursors to the formation of ozone, siting of power plants in California generally requires procurement of Offsets for these pollutants. Similarly, Offsets for other pollutants may be required, depending on the location of the generating facility.

Offsets are either procured from entities that have banked them in the non-attainment area or are created through the implementation of additional emissions controls on existing sources. Generally, Offsets are required at a ratio of greater than 1:1 (e.g., 1.1:1 or 1.3:1). While Offset transactions are conducted directly between the buyers and sellers, the 35 individual air districts in California maintain Offset banks to monitor the types and quantities of Offsets available. As required by State law, they also assist the California Air Resources Board ("CARB") in compiling an annual inventory of Offset transactions and costs. Similar to procurement, the creation of new Offsets (e.g., retrofitting more stringent NO_x emissions controls on an industrial facility in the non-attainment area) is conducted directly between the buyer and seller with the air district ensuring that the proper banking and transfer procedures are performed.

Due to the acute need for additional generating capacity for the summer of 2001, the Governor of California issued Executive Order D-24-01 on February 8, 2001, requiring California air districts to modify air permit requirements for existing generating facilities to allow increased hours of operation and for new facilities to allow expedited permitting. For existing facilities, which exceed their permitted emissions limits due to increased operations (to meet the need for power), the air districts developed programs whereby payment of mitigation fees for all emissions in excess of previously allowed limits are required. For new or expanded peaking facilities that came on-line by September 30, 2001, Executive Order D-24-01 also required CARB to establish a new emissions reduction credit ("ERC") bank. Normally, Offsets are transferred on a one-time, permanent basis. However, the ERC bank is a temporary (three-year) lease program that is intended to allow for the operation of peaking power units during the immediate- and short-term future crisis period. After three years the ERCs must be returned to CARB and the affected facilities must obtain replacement Offsets or shutdown. Return of the ERCs is necessary for the State to continue its progress toward attainment of the AAQS. In addition to the creation of a new ERC bank, CARB and many local air districts allowed peak power generation facilities that were scheduled to reach commercial operation in the summer of 2001 to forego installation of best available control technology ("BACT") for emissions until June 2002. Installation of BACT is normally required as a prerequisite to an authority to construct permit.

The 14 generating stations for which DWR could be exposed to Offset cost pass-through are located within the jurisdictions of the South Coast Air Quality Management District and San Diego Air Pollution Control District. Discussions with staff of these air districts, as well as with owners of these units, reveal that nearly all of the units have been retrofitted with selective catalytic reduction or other appropriate emission control equipment. The remaining units are scheduled for retrofit with new emission control equipment by the end of 2002. The retrofits will result in ample "headroom" under current annual emission limits such that the risk of cost pass-through to DWR of mitigation fees, penalties, or additional Offsets resulting from operation of

these units is expected to be low. Also, the owners of these units have indicated they do not expect to pass through the capital cost of these retrofits to DWR. Cost pass-through could occur, however, if demand for energy from these units in the future causes them to exceed their annual emission limits and mitigation fees and replacement costs are incurred.

Transfers of Contracted Energy Between CAISO Zones

Based on protocols of the CAISO, California is divided into three electric transmission delivery and system operation zones. Major electric transmission paths referred to as Path 15 and Path 26 divide these zones. The transfer capability of these paths is limited and results in transmission congestion between the northern and southern parts of California. The amount of congestion varies by time of year and as a function of different operating conditions. Path 15 constraints reduce the amount of electricity that can flow from south to north and Path 26 constraints reduce the amount of electricity that can flow from north to south. The two zones separated by these constraints are referred to as "north of Path 15" or "NP 15" and "south of Path 15" or "SP 15." The third transmission zone is referred to as ZP 26, which is bounded by Path 15 to the north and Path 26 to the south. California transmission constraints are discussed in greater detail in Appendix III of this Report.

Generally speaking, PG&E's service area is located within NP 15 and ZP 26 and SCE's and SDG&E's service areas are located within SP 15. Contracts entered into by DWR require that the provider identify whether delivery will occur in NP 15, SP 15, or ZP 26. Generally, energy from SP 15 and ZP 26 contracts will be used to decrease the net short position of Customers within SCE's and SDG&E's service areas and energy from NP 15 contracts will be used to decrease the net short position of Customers within PG&E's service area.

On March 30, 2001, the CPUC ordered PG&E to file for approval of a Certificate of Public Convenience and Necessity ("CPCN") for the construction of transmission improvements between the Los Banos and Gates substations to relieve transmission congestion on Path 15. PG&E's application was filed with the CPUC on April 13, 2001. As filed, this project would entail construction of an additional 500 kV transmission line between the Los Banos and Gates substations, certain substation additions, and reinforcements to the 230-kV system in the area, all of which PG&E estimates to cost approximately $225 million to $300 million. PG&E identified a construction period of approximately 12 months for these improvements. However, because of the current status of the planning, permitting, and development of the project, NCI does not expect the project to be completed prior to November 2004. This project is expected to add a minimum of 1,400 MW to 1,500 MW of south to north transfer capability to Path 15.

PG&E has completed the first phase of a planning process required by the WECC relative to the proposed Path 15 additions and reinforcements. A report summarizing the results of the Phase 1 planning effort was issued to the WECC by PG&E in September 2001. In addition, the CAISO and PG&E filed testimony with the CPUC on September 24 and 25, 2001, respectively, relative to the project. Evidentiary hearings were held by the CPUC during February and March 2002 to assess the costs and benefits of the proposed improvements. PG&E, the CAISO, and the CPUC Office of Ratepayer Advocates filed opening briefs regarding the economic benefits of the project with the CPUC in April 2002. The CPUC has not established a schedule for issuing a decision on PG&E's CPCN.

Western has developed its own proposal for undertaking the Path 15 improvements described above. Through an open solicitation, Western has secured commitments for project participation from PG&E and Trans-Elect. The parties have executed memoranda of understanding ("MOUs") related to project implementation agreements. The MOU parties are

currently negotiating the definitive participation agreements for the Path 15 upgrade project. FERC has conditionally preapproved PG&E's and Trans-Elect's tariffs for this project.

In addition to the transmission project described above, several projects have been identified by utilities in the State that would help to eliminate congestion on Path 15 or Path 26 or to improve the import capability to the San Francisco area or SP 15. These projects are described below.

- Construction of a new 500/230 kV substation near Newark and looping of the 500 kV Tesla to Los Banos transmission line into the new substation. A second 500 kV line would also be constructed from Metcalf to Moss Landing. These additions could be completed by June 2006 at an estimated cost of $260 million. Although these improvements would not alleviate congestion on Path 15, they are estimated to add 2,300 MW of additional import capability into the San Francisco area;
- Extension of the Path 15 improvements from Tracy to Bakersfield. This extension would consist of a third Tracy/Tesla-Los Banos line and a third 500 kV line from Gates to a new 500 kV substation in the Bakersfield area. This extension would help to alleviate congestion between southern and northern California by adding a minimum of 500 MW of bi-directional transfer capability to the system. The extension is estimated to cost approximately $300 million. A completion date of June 2008 could be expected; and
- Construction of a new 500 kV transmission line between the new Bakersfield substation and Adelanto. This improvement is estimated to cost approximately $265 million and could be completed by June 2008. This improvement is expected to add 1,000 MW of bi-directional capability to Path 26, which would enhance the import capability to southern California.

Although the above projects have been identified by various utilities in the State, these projects are not yet the subject of planning studies or regulatory review, nor has PG&E or any other party agreed to undertake any of these projects. The power supply cost projections discussed later in this Report are based on the assumption that the Path 15 improvements described above will be completed by the in-service dates indicated. NCI cannot predict whether any of the above projects will be undertaken or completed by PG&E, including the project described earlier for which it has filed a CPCN. Other utilities in the State, as well as Western, have expressed an interest in undertaking the Path 15 improvements. NCI believes it is reasonable to expect that a party other than PG&E would undertake one or more of these projects if PG&E elects not to or is prohibited from doing so as a result of its bankruptcy proceedings.

Other options for increasing transfer capability between northern and southern California that have been considered include the following. None of these projects currently have sponsors.

- Upgrade to the existing 500 kV system between the Midway and Vincent substations. This project may include new series capacitors and new remedial action schemes and could potentially increase transfer capability on Path 26 by 1,000 MW, at a cost of approximately $120 million. The project could be in service by 2008; and
- Construction of a 500 kV line between the Midway and Valley Substations. This project could be in service by 2011 and is estimated to cost up to $1.2 billion. Transfer capability on Path 26 is estimated to increase by approximately 1,200 MW with the addition of this project.

Excess Energy

In some months of some years, the total amount of energy to be purchased by DWR through the Priority Long Term Power Contracts is expected to be in excess of the Customers' needs. In these periods, DWR expects to either sell energy to out-of-state purchasers or to deliver that excess energy to owners of hydroelectric generation in the Pacific Northwest on a seasonal exchange basis. This energy would be returned to DWR during summer peak months, when the need for energy in California is the greatest.

In the months that such off-system and out-of-state sales are made, NCI anticipates that the price received by DWR will be lower than the cost of the energy purchased, since it will necessarily be sold during periods when regional demand is low. Revenues produced from the sale of excess contract energy by DWR will be used to offset DWR's revenue requirement to be recovered from the Customers. Since inception of the power supply program through July 30, 2002, DWR has sold 2,983 GWh of excess contract energy to purchasers in California and other areas of the WECC. This energy has been sold at an average price of $22.29 per MWh.

Renegotiation of DWR Contracts

As a result of recent improvements in the California power market, which have resulted in significant reductions in the costs of wholesale power resources compared to late 2000 and early 2001, DWR has sought to renegotiate a number of its long-term power supply contracts. During late April and early May 2002, DWR announced it had successfully renegotiated 16 contracts with six power suppliers resulting in approximately $2.0 billion in nominal net contract savings (after the cost of system impacts and additional dispatchable generation). These power suppliers consist of Calpine Energy Services, L.P. ("Calpine") (four contracts), Whitewater Energy Corporation ("Whitewater") (two contracts), Constellation Energy Corporation (one contract) and its subsidiary High Desert Power Plant, LLP (one contract) (together, "Constellation/High Desert"), Capitol Power, Inc. ("Capitol Power") (one contract), and CalPeak Power ("CalPeak") (seven contracts).

The renegotiated Calpine contracts provide for a shortening of contract terms, changes in the variable pricing of energy, and the addition of dispatchable capacity during 2002 and 2003, among other changes. Total nominal savings of the Calpine contract changes are estimated to be approximately $1.46 billion, a reduction of approximately 13 percent in the overall estimated cost of the Calpine contracts. The estimated nominal impact on DWR's Retail Revenue Requirements for 2002 and 2003 is an increase of approximately $115 million, which results from the cost of the additional dispatchable capacity, as well as the manner in which the contracts would be dispatched and other system impacts.

The Whitewater and Capitol Power contracts were renegotiated to provide for energy price reductions. The total expected costs for these contracts will also decrease to reflect later than expected on-line dates, by up to eight months for Capitol Power and eleven months for Whitewater. Total nominal savings for these two suppliers are estimated to be approximately $27 million.

For the Constellation/High Desert contracts, the renegotiated contracts replace certain 7x24 power obligations with dispatch rights, changes the energy pricing provisions, shortens the term by six months, and includes additional base load power during 2002 and 2003. Total nominal savings are estimated at approximately $447 million, more than a 13 percent reduction. The estimated nominal impact on DWR revenue requirements for 2002 and 2003 from the changes

to the Constellation/High Desert contracts, including consideration of how the contracts would be dispatched, is an increase of about $60 million.

The renegotiations of the CalPeak dispatchable peaking contracts resulted in the termination of one of the contracts, the shortening of one contract, and a reduction in the fixed capacity payments under the remaining five contracts. The estimated nominal impact on DWR revenue requirements of the renegotiated contracts is a reduction of approximately $71 million in payments to CalPeak over the life of the contracts.

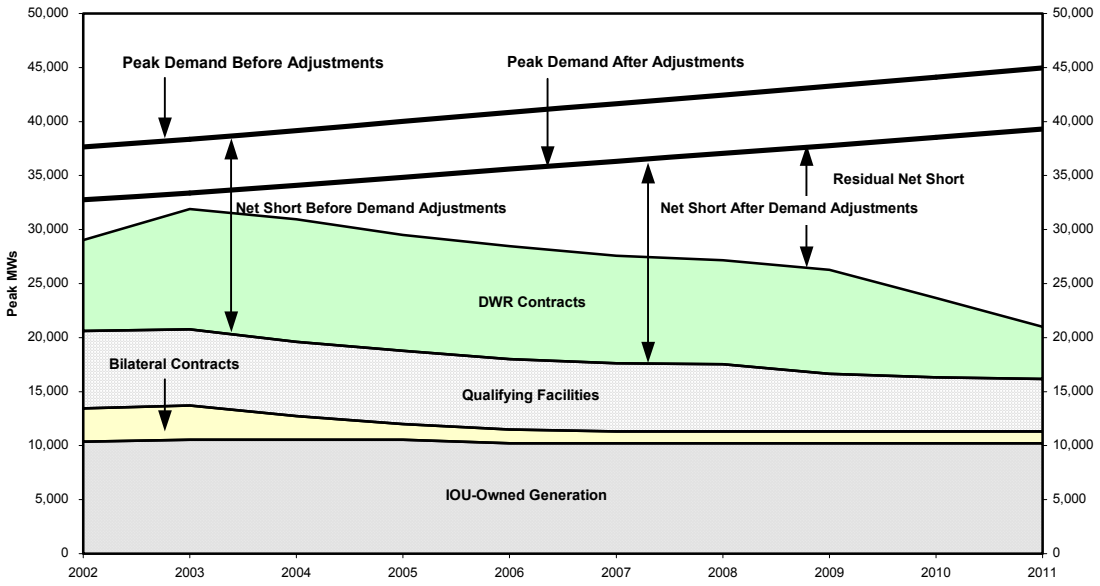
In late August 2002, DWR executed a renegotiated contract with GWF Energy LLC. The total estimated nominal savings to DWR associated with this renegotiated contract are $41 million. Due to the date of the contract execution, the savings associated with this contract have not been reflected in the Operating Results shown in this Report.

All estimates of nominal savings reported above reflect market conditions at the time the renegotiated contracts were executed.

RESIDUAL NET SHORT

Exhibit 14 presents the estimated residual net short requirements of the Customers for the Study Period, after deducting the capacity available through the DWR contracts. Figure 5 illustrates the estimated net short and residual net short requirements of the Customers for the Study Period.

FIGURE 5
NET SHORT AND RESIDUAL NET SHORT CAPACITY REQUIREMENTS
(MW)



RESOURCES TO MEET NET SHORT AND RESIDUAL NET SHORT REQUIREMENTS

Exhibit 17 provides a summary of the resources and associated generating capacity estimated to be available to satisfy the residual net short requirements of the Customers during the Study Period. In the aggregate, these resources are expected to be adequate to meet the

Customers' residual net short capacity requirements throughout the Study Period. Included in Exhibit 17 are the estimated residual net short capacity requirements to be met by these resources.

Through December 31, 2002, DWR is expected to rely on the resources shown in Exhibit 17 to meet the residual net short requirements of the Customers. These resources consist of additional short-term contracts, spot purchases in the CAISO day-ahead and hour-ahead markets, and (as necessary) reliability purchases by the CAISO in the imbalance market. This resource mix is also likely to be relied upon by the party responsible for the Customers' residual net short requirements after 2002. Additional information on the CAISO's day-ahead, hour-ahead, and imbalance markets may be found in Appendix III of this Report.

The availability of adequate resources to meet the needs of the Customers does not guarantee that blackouts resulting from involuntary load interruptions will not occur during the early years of the Study Period, particularly 2002. The potential unwillingness of power suppliers to make energy available in the spot market, the determination by DWR not to purchase such output at prices it considers unreasonable, or the unexpected outage of critical transmission or generating capacity, among other factors, could result in the CAISO requiring blackouts resulting from involuntary load reductions by the IOUs and other utilities in the State.

POWER SUPPLY COSTS

Presented below is a description of the methodology used by NCI in the development of estimated power supply costs to meet the net short requirements of the Customers during the Study Period.

MARKET SIMULATION

Wholesale power costs in the western United States are driven by a multitude of factors. These include weather and related electricity demand, precipitation and related hydropower production, the supply and price of natural gas and coal, the power transfer capability of major interties, the operating cost, outages and retirement of generating plants, and the cost, fuel efficiency, and timing of new generating resource additions. To analyze the fundamental drivers underlying the electricity market, NCI completed computer simulations of market activity throughout the WECC region. To complete those simulations, NCI utilized the PROSYM price forecasting and market simulation tool.

PROSYM is a widely accepted tool for simulating detailed power market activity and has a large market presence in the industry. According to its vendor, 80 percent of the major utilities in North America, and many utilities in Europe, Asia, and Australia, license PROSYM. It has been used to provide analytical support and to forecast market prices and revenues in a large number of financing transactions for merchant power plants and has gained strong acceptance in the financial community.

PROSYM is a detailed chronological model that simulates hourly operation of WECC generation and transmission resources. Within its simulation framework, PROSYM dispatches generating resources to match hourly electricity demand and establishes market-clearing prices based upon incremental resources used to serve load. Demand and energy forecasts used by PROSYM are developed and provided by the vendor. Annual updates of these forecasts are provided by the vendor based on data obtained from EIA filings and independent analysis by the vendor. For purposes of this Report, the demand and energy forecasts embedded in the model for the Customers have been replaced with the estimates developed by NCI, as described earlier in this Report.

In its hourly dispatch, PROSYM reflects the primary engineering characteristics and physical constraints encountered in operating generation and transmission resources, on both a system-wide and individual unit basis. Within PROSYM, thermal generating resources are characterized according to a range of capacity output levels. Generation costs are calculated based upon heat rate, fuel cost, and other operating costs, expressed as a function of capacity output. Physical operating limits related to expected maintenance and forced outage, start-up, unit ramping, minimum up and down time, and other related characteristics are reflected in the PROSYM simulation.

Hydroelectric resources are also characterized in PROSYM according to expected output levels, including monthly forecasts of expected energy production. PROSYM schedules run-of-river hydroelectric production based upon the minimum capacity rating of the unit. The dispatch of remaining hydroelectric energy is optimized on a weekly basis by scheduling hydro production in peak demand hours when it provides the most value to the electrical system.

Within the PROSYM framework, regional market-clearing prices are established based upon the incremental bid price of the last generating station needed to serve demand. For most of the existing supply, bid prices are composed primarily of incremental production costs. Hourly energy revenues for each generating unit are established as the product of market-clearing prices and the unit's energy production during the relevant hour. The PROSYM framework mirrors a "single-price" auction, so that each generator located within the same market area receives an identical price for its energy output, regardless of its actual bid price or production cost.

While the only "single-price" market auction that still exists in California is the CAISO imbalance energy market, this pricing mechanism is modeled as a proxy for the average price of the residual net short. Under a balanced supply and demand market, the average residual net short price should approximate the market-clearing price in an "as-bid" environment.

Within the PROSYM framework, bid prices are developed for each unit and reflect the estimated minimum clearing price the generator is willing to accept to operate. Market-clearing prices reflect the bid of the last generating resource used to meet the last increment of demand. The clearing price also includes an uplift component reflecting start-up and no-load costs of the marginal unit. Station revenues are based on these market-clearing prices within the market area in which the plant is located or assigned.

Based upon the bid price of the marginal generating station in a given hour, the market-clearing price is calculated using the following general approach (stated in dollars per MWh):

Market-Clearing Price = Incremental Production Cost + Start Cost + No-Load Cost + Price Markup

Incremental Production Cost is calculated as each station's fuel price multiplied by the incremental heat rate, plus variable operations and maintenance cost. Start Cost incorporates fuel costs and other operating costs encountered in starting the generating unit, beyond those reflected in the heat rate and variable operating cost assumptions. No-Load Cost reflects the difference between average and incremental fuel costs for generating stations that are dispatched at less than full output. The Price Markup factor recognizes that market forces may drive bid prices above variable production costs. NCI uses this factor to reflect observed market behavior where wholesale prices often rise above the underlying cost of production, particularly during times when supply/demand margins are tight. Such behavior is common in power markets, and was particularly present in California markets during 2001.

NCI assigns Price Markups to individual generators depending upon the underlying fuel efficiency, production cost, and technology type. The specific Price Markups are designed so that bid prices rise above the cost of production as less efficient resources are called upon for power production and as the intersection of supply and demand occurs at higher points on the supply curve. The level of Price Markups is determined through an iterative approach with the goal of benchmarking against recent actual wholesale prices, and against observable prices in the forward market.

Three specific bidding strategies were assigned in this study:

- *Incremental Cost Bidding*: Units assigned Incremental Cost bidding strategies incorporate only variable operating costs into their bid prices. This bidding strategy reflects a highly competitive market structure. All base load resources and generators with relatively low production costs are assigned this bidding strategy, which reflects the bulk of available supply resources;
- *Price Markup Bidding*: Units assigned Price Markup bidding strategies submit bids close to variable operating costs during all off-peak hours. During on-peak periods, when electricity demand is higher, these stations seek to markup price in proportion to the level of electricity demand. The price markups also vary by season, and are at higher levels during the summer and winter periods when supply/demand balances are the tightest. Intermediate-type generating resources such as older steam turbine units having relatively high production costs are assigned this bid strategy; and
- *Peak Period Bidding*: Units assigned Peak Period bidding strategies also submit close to variable operating costs during off-peak hours. Price markups are assigned to these resources during on-peak hours and seasonally. The markups for resources in this category tend to be higher than those applied under the Price Markup strategy. Resources that are assigned Peak Period bidding strategies tend to have the highest production costs, such as simple-cycle gas turbine generators and internal combustion oil-fired plants. Such resources are called upon to produce power only a small portion of the time each year.

Table 17 provides an overview of bid strategy assignment used in this study. As shown, bid prices are set for a majority of supply resources based on incremental production costs.

TABLE 17
CALIFORNIA AND WECC BID STRATEGY ASSESSMENT
(PERCENT OF SUPPLY)

	Incremental	Price Markup	Peak Period Bidding	Total
California.....	68%	28%	4%	100%
Non-California.....	80%	14%	6%	100%
Total WECC	75%	20%	5%	100%

Source: NCI.

FERC PRICE MITIGATION

On June 19, 2001, FERC issued an order on price mitigation throughout the WECC. Under this order, a soft price cap was set for the entire WECC based on the heat rate of the least efficient unit and the average natural gas price during the most recent Stage 1 Emergency ("Stage 1") warning period issued by the CAISO. During a Stage 1 (or higher) warning period, the cap

was set equal to the energy cost resulting from the heat rate of the least efficient resource being utilized in the market and the average natural gas price in California, plus a $6.00 per MWh cost for operation and maintenance expenses. A 10 percent risk premium was added for energy sold in California. If a Stage 1 warning or higher was not in effect, the effective cap was calculated as 85 percent of the last Stage 1 cap in effect. Based on this formula, the non-Stage 1 price cap at July 8, 2002, was $91.87 per MWh (before the 10 percent risk premium for California power sales). This value was calculated based on gas prices on July 3, 2001, which, until recently, was the date of the latest system emergency declared by the CAISO.

On July 9, 2002, the CAISO declared a Stage 1 emergency and recalculated the price cap at $57.14 per MWh (before the 10 percent risk premium and adjustment for Stage 1 pricing). On July 10, 2002, the CAISO again declared a Stage 1 emergency as well as a Stage 2 emergency and the price cap was recalculated at $55.26 per MWh. The lower price caps calculated on July 9 and 10, 2002, were principally the result of changes in the price of natural gas from July 2001 to July 2002. On July 11, 2002, FERC issued an order replacing the previous formula for calculating the price cap with a hard cap of $91.87 per MWh. FERC took this action as a result of concern that reductions in the price cap during July 2002, as well as future potential variations in the price cap, could cause severe supply disruptions in the western power markets. FERC ordered that the hard cap of $91.87 per MWh remain in effect from July 12, 2002 through September 30, 2002 (the expiration date of the June 19, 2001, FERC order).

On July 17, 2002, FERC issued an order related to CAISO market design initiatives (discussed in Appendix III to this Report) that established a hard price cap of $250 per MWh, effective October 1, 2002. FERC has indicated it established the price cap at this level to promote further development of new generating resources in California. For purposes of this Report, the new price cap is assumed to remain in effect from October 1, 2002 through the end of the Study Period. However, no assurance can be given that the FERC price cap will be continued through the end of the Study Period.

WECC Regional Market Definitions

WECC electricity markets sometimes experience binding transmission constraints. Binding transmission constraints occur at times when transmission capacity on a specific linear path is fully utilized and no additional energy can be transported via that line or path. During such times, low-cost generators are forced to reduce output in favor of higher-cost units located within the constrained region. To reflect transmission constraints encountered in WECC markets, NCI simulated 21 separate market regions, with transfer limitations between each region reflecting expected transmission system configurations. In selecting market regions, NCI examined WECC transmission system operations and also analyzed a number of transmission publications and studies prepared by the WECC.

Separate market-clearing prices were established within each regional market outlined in Figure 6. In establishing the market-clearing price for each region, the PROSYM simulation takes into account economic import and export possibilities and sets the market-clearing price as the bid price of the marginal generator needed to serve a final increment of demand within the region.

Simulation of New Resource Additions

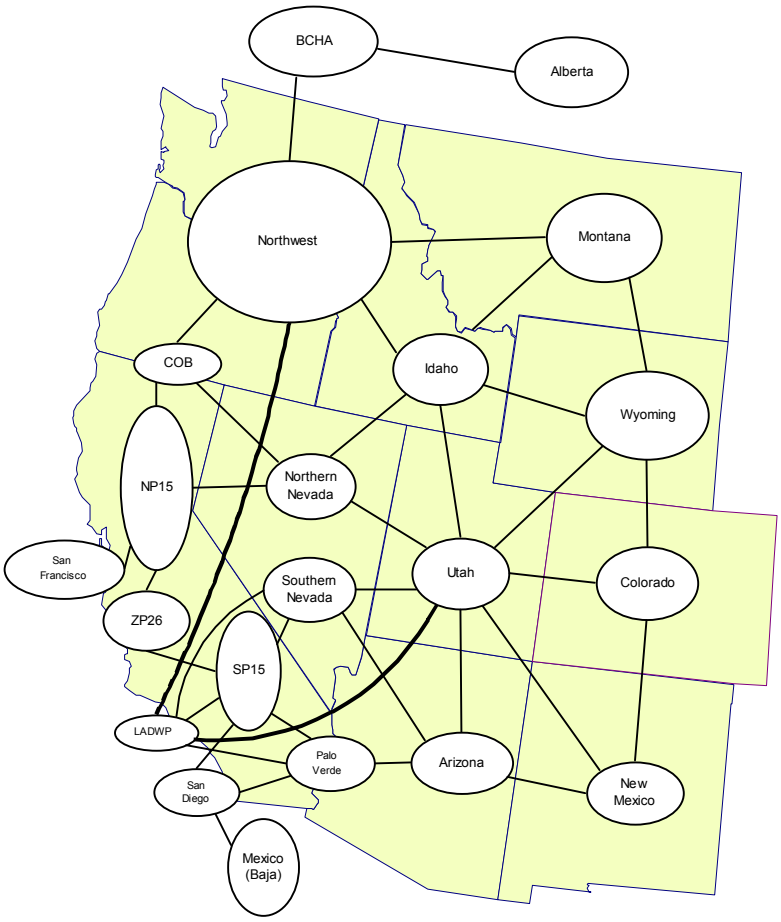
New resource additions must be included in the simulation in order to meet increases in peak demands. A review of potential and planned new resource additions throughout the WECC reveals that they will be built and owned primarily by independent power producers. Generally,

the technology, fuel type, size, and location of these new plants will depend primarily upon wholesale power market prices. Prices available to an independent power producer must be sufficient to allow it to earn a return on equity that is consistent with similar risk capital investments.

To forecast the amount of capacity added in each region of the WECC, known potential new generating resources were reviewed to identify those currently under construction. These plants have a high probability of completion and were added to the simulation resource base in their expected year of completion. Additionally, projects under contract to DWR that are undergoing siting review were included in the simulation resource base. Together with the projects under construction, these resource additions are referred to as "planning capacity."

To the extent the production simulation model determines that additional generating capacity, beyond that designated as planning capacity, is needed to meet the needs of the region, "generic" new combustion turbine or combined cycle generating units are assumed to be added to the resource mix. These generic units would actually be comprised of projects already identified in Exhibits 4 through 6, but not designated for planning capacity, or new projects that have not yet been identified or announced. Table 18 provides a summary of the assumptions used to estimate the costs of generic new combustion turbine and combined cycle combustion turbine plants during the Study Period.

FIGURE 6
WECC REGIONAL MARKET DEFINITIONS



DWR Contracts

The DWR contract resources were explicitly modeled in the simulation, accounting for their respective capacities, delivery points, minimum takes and other features. These contract resources are assumed to be called upon as a resource for meeting Customer needs and are expected to be dispatched in an economically efficient manner (from the Customers' perspective) as part of a complete resource mix that includes the URG, DWR contracts, and residual net short purchases.

Other Assumptions

A broad array of other inputs and assumptions were made in performing the WECC market simulation. These inputs and assumptions address resource availability, resource retirements, fuel prices, operation and maintenance costs, outage factors, transmission factors, and market conditions, among other factors, which are summarized in Exhibit 18.

Simulation Output

Results of the simulation include average monthly dispatch level, fuel cost, and variable operation and maintenance costs for each generating resource modeled. Average monthly power purchase levels for QF contracts, DWR contract resources, and IOU bilateral contracts were also generated. Finally, average monthly peak and average market-clearing prices for each modeled market region were generated. The operating cost of the plant dispatched to serve the last increment of load demand for a given region was considered the market-clearing price for that region.

TABLE 18
GENERIC RESOURCE ASSUMPTIONS

Unit Characteristic	Combustion Turbine	Combined Cycle
Heat Rate (Btu/kWh)	11,000	7,100
Fixed O&M ($/kW-year)	3.15	10.50
Variable O&M ($/MWh)	4.20	2.10
Forced Outage Rate (%)	0.00	2.00
Maintenance Outage Rate (%)	4.00	4.00
Financing Term (Years)	15	15
Interest Rate (%)	8.00	8.00
Return on Equity (%)[1]	18.00	18.00

Source: NCI. Cost figures represent 2002 dollars.
[1] After taxes.

ANCILLARY SERVICES PRICE FORECAST METHODOLOGY

DWR will incur ancillary service charges from the CAISO for scheduling and delivery of DWR-provided power to the Customers. DWR also incurs ancillary service charges associated with SDG&E's total energy requirements through 2002, in accordance with the Servicing Arrangement between DWR and SDG&E. The volume of ancillary services required in any given hour is based on the load scheduled for that hour. The price for ancillary services is based on prices that result from the day-ahead and hour-ahead bids for such services that the CAISO receives from its ancillary services auction process. After 2002, DWR is assumed to be responsible for ancillary service costs only on power delivered by DWR.

A correlation exists between energy prices and ancillary services prices. Based on hourly historical price data for the period from April 1998 through December 2000, a regression analysis was performed resulting in an econometric model of ancillary service price (spinning reserves were used as a proxy for ancillary services) as a function of several variables. The primary independent variable driving the price of ancillary services is energy price.

To develop the price forecast, the energy market-clearing price forecast and the system load were analyzed using the econometric model. Simulations were then conducted to calculate the forecasts of prices as well as the distributions and confidence intervals of the prices. DWR is assumed to be responsible for the cost of ancillary services, as follows:

Cost of Ancillary Services = 3.8 percent x Price of Residual Net Short x Power Supplied by DWR and, through 2002, SDG&E energy requirements

MARKET-CLEARING PRICES AND ANCILLARY SERVICES PRICES

Estimated electricity prices reach their highest levels and exhibit the greatest volatility during the 2002 through 2003 period. This pattern is consistent with the relatively tight supply and demand balances currently being experienced in the western markets. During the subsequent years of the Study Period, electricity prices are projected to decline and exhibit reduced volatility. That pattern occurs due to new market entry throughout the WECC. Electricity prices are estimated to reach their lowest level in 2004, when a number of new merchant power plant projects are assumed to be operational. For the remainder of the Study Period, electricity prices are estimated to increase modestly with real escalation in natural gas prices. Ancillary services prices are also expected to trend downward over the next two years as the underlying energy prices decline.

RESIDUAL NET SHORT PURCHASES

A load and resource table (capacity and energy) was constructed for each of the IOUs to forecast the amount of resources needed after the URG, new conservation and load management programs, and DWR contracts were considered. This information is shown in Exhibits 11 through 14. Prior to January 1, 2003, residual net short purchases will be made by DWR. After this date, consistent with current law, the IOUs are to be responsible for these purchases. Table 19 provides a summary of estimated quarterly residual net short costs, along with estimated DWR contract costs, through 2003.

DWR ESTIMATED OPERATING RESULTS

NCI's estimate of DWR's Operating Results for the Study Period is presented in Exhibit 19. Revenues and expenses shown in Exhibit 19 have been segregated between Bond Charges and Power Charges based on the provisions of the Rate Agreement and reflect the anticipated termination of DWR residual net short purchases on January 1, 2003. Presented below is a description of the development of DWR's Operating Results.

Exhibit 19 provides a comparison of estimated revenues from Power Charges and the expenditures to be funded from these revenues. Also included in Exhibit 19 is a comparison of estimated Bond Charges and the Bond-Related Costs to be funded through these charges. All amounts shown in Exhibit 19 are stated on a cash basis. For both Power Charges and Bond Charges, beginning account balances associated with the flow of funds under the Indenture are shown in Exhibit 19. For Power Charges, these accounts include the Operating Account, the Priority Contract Account, and the Operating Reserve Account. For Bond Charges, these

accounts include the Bond Charge Collection Account, the Bond Charge Payment Account, and the Debt Service Reserve Account. Amounts held in these accounts are based on the requirements of the Indenture and are intended to ensure the availability of adequate funds to pay Retail Revenue Requirements and Bond-Related Costs when due and provide reserves for unanticipated changes in future revenue or expenditure levels. For additional information on the flow of funds and various accounts established by the Indenture, please see the section entitled "SECURITY FOR THE BONDS—Accounts and Flow of Funds under the Indenture" in the Official Statement.

POWER CHARGE ACCOUNTS

Revenues collected through DWR's Power Charges are used to fund annual Retail Revenue Requirements. DWR's Retail Revenue Requirements consist of all Department Costs, excluding Bond-Related Costs, not otherwise funded through interest earnings or wholesale power sales.

Power Charge Account Balances

Three accounts comprise the Power Charge Accounts. These accounts include the Operating Account, the Priority Contract Account, and the Operating Reserve Account. As specified in the Indenture, the Operating Account is required to target a minimum balance of $1.0 billion at any given time while DWR is procuring the residual net short. The Operating Results shown in Exhibit 19 were developed based on the assumptions DWR will not procure the residual net short beyond December 31, 2002. However, at present there is no basis to determine what the disposition of funds within the Operating Account beyond the minimum required by the Indenture will be. Because of this, estimated Operating Results are modeled such that 2003 Power Charges are adequate to meet the $1.0 billion minimum balance at all times and Power Charges in future years are set to fully recover costs. This modeling procedure will maintain end of year 2003 balances in the Operating Account and allows for direct comparison to sensitivity cases and a more reasonable assessment of likely Power Charge revenues.

The Priority Contract Account is a holding account for payments under priority contracts. On the fifth business day of each month, the previous month's priority contract costs are transferred from the Operating Account to the Priority Contract Account. On the twentieth day of each month (or the first business day thereafter, if the twentieth day falls on a non-business day), priority contract costs for the previous month are paid from the Priority Contract Account. Because the period between the fifth business day of the month and the twentieth day of the month is the only time period during which there are any funds in the Priority Contract Account, the Operating Results presented in Exhibit 19 do not show any balance in this account since such balances are shown as of the first day of each January.

The amount to be included in the Operating Reserve Account is determined, and will be revised, through a two-pronged test each time a new revenue requirement is filed by DWR. This amount is calculated as the greater of (a) the largest aggregate amount projected by DWR by which Operating Expenses exceed Power Charge revenues during any consecutive seven months commencing in such Revenue Requirement Period (using DWR's choice of potential projected operating results, after consultation with the CPUC, such that a reasonable amount of financial stress is placed upon the Power Charge and Bond Charge Accounts) and (b) (i) 18 percent of projected annual Operating Expenses for any Revenue Requirement Period in which DWR is procuring all or a portion of the residual net short and which commences prior to 2006 or (ii) 12 percent of DWR's projected annual Operating Expenses for any Revenue Requirement Period in which DWR is not procuring all or a portion of the residual net short or which commences after

2005; provided, however, that solely for the purposes of (b) above, for Revenue Requirement periods commencing after 2003, the projected amount shall not be less than the applicable percentage of Operating Expenses for the most recent 12 month period for which reasonably full and complete Operating Expense information is available, adjusted if DWR is no longer financially responsible under a Power Supply Contract (all defined terms have the meaning given them in the Indenture). Because this calculation is made at least once each year, and the estimated Operating Results will change from year to year, the Operating Reserve Account Balance shown in Exhibit 19 is held constant after being calculated for 2003 in a manner commensurate with the 2003 revenue requirement filing. This modeling procedure allows for direct comparisons to sensitivity cases and maintains a reasonable assessment of likely Power Charge revenues

Revenues for Retail Revenue Requirements

NCI's estimate of revenues to meet DWR's Retail Revenue Requirements during the Study Period is summarized in Exhibit 19 and is shown in the line titled "Power Charges." This estimate reflects the level of revenues needed from Power Charges during the Study Period and represents the difference between total Department Costs (excluding Bond-Related Costs) described above, plus the incremental change in Power Charge Account balances necessary to maintain minimum account balances, and funds received from other sources, such as interest earnings or other wholesale power sales.

In addition to Power Charge revenues, DWR receives revenue from two additional sources: interest earnings on Power Charge Account balances and sales of excess contract energy to other wholesale purchasers (as described earlier in this Report). These are shown as "Other Power Charge Account Revenues" in Exhibit 19.

Retail Revenue Requirements

Retail Revenue Requirements consist of DWR purchased power costs under long-term contracts, short-term contracts, spot market power purchases, costs associated with ancillary services, and administrative and overhead costs. Purchased power costs have been estimated by NCI based on the use of its production simulation model, as described previously. These estimates reflect the assumed termination of DWR's purchases of residual net short effective January 1, 2003, and are summarized in Table 19 for the Study Period. Included in Table 19 are DWR's actual purchased power costs for the first six months of 2002.

DWR's administrative and overhead costs included in Retail Revenue Requirements consist of DWR labor costs (including benefits), professional service fees, capital expenditures attributable to DWR's role in the acquisition and management of power supply resources to meet the Customers' net short requirements, and costs billed by the IOUs under the Servicing Arrangements (as defined below). These costs have been estimated for 2002 based on approved budget levels. For the period after 2003, estimated administrative and overhead costs were based on preliminary DWR budget information and an assumed escalation rate of 2.5 percent per year. Estimated expenditures after 2002 reflect the transfer of residual net short purchasing requirements to a party other than DWR.

Net Transfers to Bond Charge Accounts

Transfers between Bond Charge Accounts and Power Charge Accounts may only occur as prescribed within the Indenture. Transfers from the Power Charge Accounts to the Bond

Charge Accounts are planned in 2002 to cover Bond-Related Costs as Bond Charges are initially implemented.

Net Debt Service (Other Than Bonds)

Net debt service represents interest payments DWR is obligated to make on the Interim Borrowing and General Fund Loans that are outstanding. For purposes of this Report, the remaining principal due on the Interim Borrowing and General Fund Loans are assumed to be repaid from proceeds of the Bonds on or before October 10, 2002.

TABLE 19
HISTORICAL AND ESTIMATED DWR CONTRACT AND RESIDUAL NET SHORT COSTS[1]
(DOLLARS PER MWH)

	DWR Contracts[2]	Residual Net Short[3]	Weighted Average[4]
Historical:			
Quarter 1, 2001	$ -	$293	$293
Quarter 2, 2001	142	279	244
Quarter 3, 2001	138	136	137
Quarter 4, 2001	102	57	80
Quarter 1, 2002	95	56	86
Quarter 2, 2002	108	43	98
Estimated:			
Quarter 3, 2002	$113	$ 52	$ 97
Quarter 4, 2002	113	38	96
Quarter 1, 2003	107	39	92
Quarter 2, 2003	136	32	122
Quarter 3, 2003	102	42	93
Quarter 4, 2003	112	38	99
2004	106	38	92
2005	97	42	88
2006	87	45	79
2007	83	51	77
2008	78	57	73
2009	75	66	72
2010	78	58	68
2011	77	66	69

Source: NCI.

[1] Values are shown on an accrual basis and reflect only the costs of purchased energy. Additional costs that will be recovered by DWR, such as DWR administrative and general costs, or debt service costs associated with the Bonds, are not included.

[2] Long term power contracts entered into by DWR through December 31, 2002.

[3] Residual net short requirements will be purchased by DWR through December 31, 2002, and by the IOUs after December 31, 2002.

[4] Weighted average cost of the DWR contracts and the residual net short.

BOND CHARGE ACCOUNTS

Revenues derived by DWR from Bond Charges are used to pay Bond-Related Costs. Bond-Related Costs are summarized in Exhibit 19 and have been developed for the Study Period based on estimates of Bond principal and interest payments, credit enhancement and liquidity facilities charges, and related costs provided to NCI by DWR's financial advisor.

Bond Charge Account Balances

Three accounts comprise the Bond Charge Accounts. These accounts include the Bond Charge Collection Account, the Bond Charge Payment Account, and the Debt Service Reserve Account. The Bond Charge Collection Account is the account where Bond Charge revenues are initially deposited and held until no later than the last business day of each month, at which time funds are transferred to the Bond Charge Payment Account such that the Bond Charge Payment Account contains funds adequate to pay debt service and other bond-related costs for the next succeeding three months. The Debt Service Reserve Account is funded at 100 percent of the maximum annual debt service of the Bonds and is maintained at that level throughout the Study Period.

Because of the seasonality of Bond Charge collections and the need to set initial Bond Charge rates at a level adequate to meet level Bond Charge revenue requirements prior to high volume consumption seasons (summer), substantial collections of Bond Charge revenues can occur, manifesting themselves in the form of higher-than-necessary Bond Charge Payment Account balances at year end. If Bond Charges are then set in the subsequent Revenue Requirement Period based strictly upon minimum Indenture requirements, a substantially lower Bond Charge would occur, resulting in lower Bond Charge Payment Account balances at year end. This cycle would repeat itself from year to year. While no assumption is made in this Report regarding the method of Bond Charge rate setting that the CPUC will undertake, for purposes of this Report the higher-than-necessary Bond Charge Payment Account balances at the end of 2003 are held in the Bond Charge Payment Account and Bond Charges in future years are set to fully recover Bond-Related Costs. This modeling procedure will maintain end of year 2003 balances in the Bond Charge Payment Account and allows for direct comparison to sensitivity cases and a more reasonable assessment of likely Bond Charge revenues.

Revenues for Bond-Related Costs

NCI's estimate of DWR's revenues from Bond Charges during the Study Period is summarized in Exhibit 19 and shown in the line titled "Bond Charge." This estimate reflects the level of revenues needed from DWR Bond Charges during the Study Period and represents the difference between Bond-Related Costs, plus the incremental change in Bond Charge Account balances necessary to maintain minimum account balances, and funds received from other sources, such as interest earnings or Bond proceeds.

In addition to Bond Charge revenues, Bond Charge Accounts receive revenue from two additional sources: interest earnings on Bond Charge Account balances and proceeds from sale of the Bonds (which are received only at the time of Bond issuance in 2002).

Bond-Related Costs

Bond-Related Costs include net debt service on the Bonds, credit enhancement and liquidity facility charges, costs of fiduciaries, and related costs, and are shown in Exhibit 19.

Net Transfers from Power Charge Accounts

Transfers between Bond Charge Accounts and Power Charge Accounts may only occur as prescribed within the Indenture. Transfers from the Power Charge Accounts to the Bond Charge Accounts are planned in 2002 to cover Bond-Related Costs as Bond Charges are initially implemented.

SUMMARY OF POWER CHARGES AND BOND CHARGES

Table 20 provides a summary of estimated average Power Charges and Bond Charges for each year of the Study Period. The estimated values shown in Table 20 are based on the Retail Revenue Requirements and revenues from Bond Charges shown in Exhibit 19. For 2001 and 2002, the CPUC established Power Charges that vary by IOU. Power Charges will be applied to power delivered to the Customers by DWR. Bond Charges will be applied to power delivered to the Customers by DWR, the IOUs, and, if authorized by the CPUC, ESPs.

APPLICATION OF POWER CHARGES AND BOND CHARGES

On September 6, 2001, the CPUC approved agreements entered into by DWR with SCE and SDG&E, as amended in March 2002 and approved by the CPUC in an order issued in April 2002 (the "Servicing Agreements"), and adopted an order for PG&E in May 2002 (the "Servicing Order") under which DWR's charges (Power Charges and Bond Charges) are collected from the Customers for DWR by the IOUs as the agents of DWR (the Servicing Agreements and Servicing Order are collectively referred to as the "Servicing Arrangements"). Under each Servicing Arrangement, each IOU is to transmit and distribute DWR power and collect Power Charges and Bond Charges until 180 days after the final Power Charges and Bond Charges are imposed in the IOUs' service territories. The Servicing Arrangements provide that all amounts to be remitted to DWR are to be held in trust by the IOUs for DWR. The IOUs are to remit amounts due DWR each business day, subject to periodic adjustment to correct errors.

TABLE 20
ESTIMATED AVERAGE POWER CHARGES AND BOND CHARGES TO THE CUSTOMERS[1]

Year	Retail Revenue Requirements[2] (Millions)	DWR Energy Deliveries[3] (GWh)	Power Charges[4] ($/MWh)	Bond Charge Revenues[5] (Millions)	Total Customer Energy[6] (GWh)	Bond Charges[7] ($/MWh)
2003.....	$4,648	36,994	$126	$1,140	151,550	$7.52
2004.....	4,266	42,248	101	945	154,833	6.10
2005.....	4,272	42,226	101	924	158,342	5.84
2006.....	4,140	46,344	89	925	161,854	5.72
2007.....	4,227	48,686	87	925	165,157	5.60
2008.....	4,353	52,913	82	925	168,623	5.49
2009.....	4,542	56,274	81	926	171,961	5.38
2010.....	3,594	39,602	91	926	175,456	5.28
2011.....	2,530	24,585	103	926	179,019	5.17

Source: NCI.
[1] For 2001 and 2002, DWR revenue requirements, including Bond-Related Costs, are recovered through an average charge of $93 per MWh.
[2] Estimated Retail Revenue Requirements. After December 31, 2002, estimated Retail Revenue Requirements exclude the costs of the residual net short. The estimated per unit costs of the residual net short after 2002 may be found in Table 19 of this Report.
[3] Energy delivered by DWR to the Customers.
[4] Charges per MWh, applied uniformly to all Customers, based on energy delivered to the Customers by DWR.
[5] Estimated revenues recovered through Bond Charges.
[6] Total aggregate energy delivered to the Customers by DWR, the IOUs, and, if authorized by the CPUC, ESPs.
[7] Charges per MWh, applied uniformly to all Customers, based on total energy delivered to the Customers by DWR, the IOUs, and, if authorized by the CPUC, ESPs.
Note: All dollar values shown on a cash basis.

Under each Servicing Arrangement, DWR has the right to request an audit, to be conducted by DWR, of the IOU's records and procedures related to matters covered in the Servicing Arrangement. Each Servicing Arrangement also requires the IOU to employ

independent accountants to audit annually the compliance of the IOU with its obligations under the Servicing Arrangement.

DWR pays each IOU for metering services, meter reading services, billing services, and collection services. In addition, DWR has paid each IOU a "set-up fee" covering each IOU's costs of establishing the procedures, systems and mechanisms necessary to perform the services required under the Servicing Arrangements. Fees for metering services, meter-reading services, billing services, and collection services are payable monthly in arrears by DWR. During 2002, fees paid by DWR for metering and related services are estimated to total approximately $550,000. As DWR transitions from its role of providing the Customers' residual net short requirements, the total fees paid to the IOUs are expected to decline accordingly. Additional charges to cover changes in costs or the costs of other services provided to DWR are to be negotiated by DWR and each IOU. Any disagreement as to additional fees is to be resolved by the CPUC.

SENSITIVITY ANALYSES

The Rate Agreement requires DWR to evaluate its costs and cash flows on a monthly basis and to file revised Retail Revenue Requirements with the CPUC no less often than once each year to ensure that Bond Charges and Power Charges are adequate to meet DWR's financial obligations associated with the Bonds and the power supply program, respectively. From the date DWR first initiates a revised Retail Revenue Requirement filing, it expects no more than seven months will elapse before revenues associated with the filing are received by DWR. In order to ensure its ability to meet its financial obligations during this seven month period, DWR must maintain reserve funds that are adequate to meet normal anticipated expenses, as well as unexpected variations in these expenses and/or reductions in revenue receipts, resulting from factors beyond its control. The determination of targeted reserve fund levels is, in part, made by DWR, with input from the CPUC, DWR's financial advisors, and the investment community, based on an assessment of potential variations in revenue receipts and power supply program expenses resulting from changes in certain key variables affecting Customer energy requirements, URG production levels, natural gas prices, and DWR contract operations, among other factors.

To assess the adequacy of targeted reserve fund levels, NCI has prepared additional assessments of DWR's Operating Results based on changes in certain key expense and operating assumptions ("Sensitivity Cases"). The Sensitivity Cases considered in this assessment reflect a sampling of groups of changes in key assumptions that could affect the volatility of DWR's expenses and revenue receipts. The Sensitivity Cases evaluated in this Report are not intended to reflect all possible scenarios or those most likely to occur. Additionally, the Sensitivity Cases conducted by NCI are not intended to represent a worst-case assessment of factors that could influence DWR's financial performance over the Study Period.

The Sensitivity Cases evaluated by NCI consist of the following:

- Case 1—Near-Term Sensitivity
  - Natural gas price spike
  - Reduced Customer demand and energy requirements

- Case 2—Near-Term Sensitivity with Extended DWR Procurement
  - Natural gas price spike
  - Reduced Customer demand and energy requirements
  - DWR retains responsibility for the residual net short throughout the Study Period

- Case 3—Long-Term Sensitivity without Extended DWR Procurement
    - Natural gas price spike
    - Increased Customer demand and energy requirements
    - Reduced hydroelectric production due to less than normal precipitation
    - Periodic extended forced outages at selected representative generation facilities
    - Delays in planned construction of new generation facilities

- Case 4—Long Term Sensitivity with Extended DWR Procurement
    - Natural gas price spike
    - Increased Customer demand and energy requirements
    - Reduced hydroelectric production due to lower than normal precipitation
    - DWR retains responsibility for the residual net short throughout the Study Period
    - Periodic extended forced outages at selected representative generation facilities
    - Delays in planned construction of new generation facilities

For each of these Sensitivity Cases, a market simulation was performed to generate revised net short requirements and associated power supply costs for DWR. These revised forecasts were used to generate revised estimated Operating Results for DWR. These revised results were compared against the base estimate of annual Operating Results (the "Base Case") reflected in Exhibit 19 of this Report.

CASE 1—NEAR-TERM SENSITIVITY

Case 1 focuses on changes to several key variables that are most likely to negatively affect DWR's Operating Results during the 2003 through 2005 period. The largest threats to adequate cash flows in this period are expected to be decreased Bond Charge and Power Charge revenues resulting from lower sales to Customers, increased costs of procuring the residual net short, and increased costs of providing energy under existing contracts.

Higher costs are primarily driven by increased fuel costs. In this case, a natural gas price forecast is used that includes a high price spike from mid-2003 through mid-2004. Lower Customer sales by DWR are primarily driven by a decrease in the net short, which can occur as a result of increased URG and/or decreased Customer load. In this case, URG is increased somewhat by assuming hydroelectric production at 110 percent of normal for 2003 and 2004.

Lower loads are estimated in this case by assuming cooler-than-normal summers during the 2003 through 2005 period, and by assuming increased non-programmatic conservation. The level of decreased Customer load due to temperature variation is simulated by decreasing the Base Case load forecast for 2003 through 2005 by 3.0 percent of total monthly load in June, by 3.0 percent of total monthly load in July, by 5.0 percent of total monthly load in August, and by 5.0 percent of total monthly load in September. In addition, an increase in the assumed level of non-programmatic conservation (above the Base Case) results in decreases in total annual load of 4.0 percent in 2003, 2.0 percent in 2004, and 0.5 percent in 2005.

CASE 2—NEAR-TERM SENSITIVITY WITH EXTENDED DWR PROCUREMENT

The assumptions in Case 2 mirror those in Case 1, except that DWR is assumed to retain responsibility for procuring the residual net short for the entire Study Period.

CASE 3—LONG-TERM SENSITIVITY

Case 3 focuses on changes to several key variables that are most likely to negatively affect DWR's power costs for the 2004 through 2010 period. The largest threat to adequate cash flows in this period is expected to be increased costs of providing energy under existing DWR long-term power supply contracts.

Higher costs are primarily driven by increased fuel costs. In this case, a natural gas price forecast is used that includes a high price spike from mid-2003 through mid-2004, and another price spike from mid-2008 to mid-2009. Average monthly gas prices during these periods increase by amounts ranging from 20 percent to 160 percent over the Base Case. Another cost driver in this period may be the existence of an imbalance in supply and demand. The following actions are modeled in an attempt to simulate greater demand and less available supply.

Load is increased from the Base Case by assuming load growth rates that are 1.4 percent of total load higher than those assumed in the Base Case in 2003, 1.3 percent higher in 2004, 0.5 percent higher in 2005, and 0.4 percent higher in 2006 through 2011. It is assumed that this growth occurs as a result of an accelerated economic recovery in California and decreases in the expected amount of non-programmatic conservation. In addition, load is increased by assuming the existence of warmer than normal summers throughout the Study Period. The level of increased Customer load due to temperature variation is simulated by increasing the Base Case load forecast (inclusive of the accelerated growth rates described above) each year of the Study Period by 3.2 percent of total monthly load in June, by 3.6 percent of total monthly load in July, by 5.4 percent of total monthly load in August, and by 4.6 percent of total monthly load in September. Decreased supply in the region is simulated by assuming continuing cycles of lower-than-normal hydroelectric generation in California and the Pacific Northwest, occasional long-term forced outages of nuclear generation units in California, and delays in the construction of planned generation in California.

For this case, hydroelectric generation in California and the Pacific Northwest is assumed to have cycles of dry years. The hydroelectric production is assumed to equal 90 percent of normal in 2003, 75 percent of normal in 2004, 90 percent of normal in 2005, 100 percent of normal in 2006, 90 percent of normal in 2007, 75 percent of normal in 2008, 90 percent of normal in 2009, and 100 percent of normal in 2010. A single nuclear generation unit is assumed to be forced out of service for three separate periods; April 1, 2003 through March 31, 2004 (in southern California); April 1, 2006 through March 31, 2007 (in northern California); April 1, 2009 through March 31, 2010 (in southern California). Construction on any generation facilities in California that are currently planned, but do not yet have financing in place, is assumed to be delayed for 18 months from the current expected commercial operation date.

CASE 4—LONG-TERM SENSITIVITY WITH EXTENDED DWR PROCUREMENT

The assumptions in Case 4 mirror those in Case 3, except that DWR is assumed to retain responsibility for procuring the residual net short for the entire Study Period.

SENSITIVITY CASE RESULTS

Table 21 provides a summary of the results of the Sensitivity Cases described above. The first two measures describe the estimated Retail Revenue Requirement and Power Charge resulting from each Sensitivity Case and the percent change from the Power Charge estimated in the Base Case. The next two measures describe the estimated Bond-Related Costs and Bond Charge resulting from each Sensitivity Case and the percent change from the Bond Charge estimated in the Base Case. The next two measures shown for each Sensitivity Case relate to per unit energy costs and are meant to show the impact that each Sensitivity Case has on the cost of DWR contracts and the residual net short. These measures help to illustrate the potential wholesale price volatility (or lack thereof) that could exist under various conditions. The final three descriptive lines in Table 21 of each Sensitivity Case describe the amount of power provided to the Customers by DWR, the amount of total Customer energy sales (by DWR and the IOUs), and southern California border gas prices that are assumed in each of the individual Sensitivity Cases.

Under Case 1, estimated Power Charges increase by 35.7 percent, 21.4 percent, and 17.3 percent, respectively, over the Base Case in 2003, 2004, and 2005. Bond Charges over the same period increase by 8.5 percent in 2003, 9.2 percent in 2004, and 7.8 percent in 2005, when compared to the Base Case. These increases (along with all other changes in Bond Charges and Power Charges in all Sensitivity Cases) are necessary to maintain the required Power Charge account and Bond Charge account balances in 2003, and to maintain end of year 2003 balances thereafter. Average per-unit costs of DWR contracts also increase over this period when compared to the Base Case. This is due to increased fuel costs and a reduction in the amount of energy sales over which these costs are recovered ("recovery base") compared to the Base Case.

Under Case 2, estimated Power Charges increase by 24.7 percent, 12.6 percent, and 6.8 percent, respectively, over the Base Case in 2003, 2004, and 2005. Power Charges increase less in Case 2 than in Case 1 due to the increased recovery base provided by DWR's continued procurement of the residual net short. Bond Charges increase by 8.5 percent over the Base Case in 2003, 9.2 percent in 2004, and 7.8 percent in 2005. Average per-unit costs of DWR contracts also increase over this period when compared to the Base Case. This is due to increased fuel costs and a decreased recovery base (as measured by the amount of DWR-provided power and the total Customer load) compared to the Base Case.

Under Case 3, estimated Power Charges increase by 9.2 and 20.3 percent over the Base Case in 2008 and 2009, respectively. In earlier years, Power Charges decrease when compared to the Base Case. This is due to the increased recovery base provided by the increased size of the total net short, and the corresponding increase in DWR contract dispatch amounts. Bond Charges decrease over the entire Study Period when compared to the Base Case due to the increased recovery base provided by the increased total IOU load. The average per-unit cost of DWR contracts generally decreases when compared with the Base Case due to increased dispatch of contract energy (for which capacity charges have already been paid). In 2008 and 2009, the average per-unit cost of DWR contracts increases compared to the Base Case because increased gas costs (reflected in tolling arrangements) more than offset any per-unit cost reductions realized due to increased dispatchability.

Under Case 4, estimated Power Charges increase by 6.8 and 20.1 percent over the Base Case in 2008 and 2009, respectively. In earlier years, Power Charges decrease when compared to the Base Case. This is due to the increased recovery base provided by DWR's continued procurement of the residual net short and the increased size of the total net short (regardless of who is responsible for the procurement of the residual net short). This increased recovery base

TABLE 21
RESULTS OF SENSITIVITY ANALYSES

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Base Case										
DWR Charges:										
Estimated Power Charge Rev. Req. (Millions)[1]	$ 4,667	$ 4,648	$ 4,266	$ 4,272	$ 4,140	$ 4,227	$ 4,353	$ 4,542	$ 3,594	$ 2,530
Estimated Power Charge ($/MWh)[2]	-	126	101	101	90	87	83	81	91	103
Estimated Bond Charge Rev. Req. (Millions)[3]	$ 6	$ 1,140	$ 945	$ 924	$ 925	$ 925	$ 925	$ 926	$ 926	$ 926
Estimated Bond Charge ($/MWh)[4]	-	7.52	6.10	5.84	5.72	5.60	5.49	5.38	5.28	5.17
Average Cost of DWR Contracts ($/MWh)[5]	98	99	92	85	77	74	70	68	72	71
Average Cost of Residual Net Short ($/MWh)[6]	44	35	35	38	42	47	52	61	53	60
DWR Provided Power (GWh)[7]	40,389	36,994	42,248	42,133	46,218	48,550	52,734	56,068	39,456	24,495
Total Customer Sales (GWh)[8]	149,110	151,550	154,833	158,342	161,854	165,157	168,623	171,961	175,456	179,019
Estimated Gas Price ($/MMBtu)[9]	3.00	3.29	3.40	3.51	3.63	3.85	4.06	4.27	4.44	4.60
Short-Term Sensitivity Without Extended DWR Procurement										
DWR Charges:										
Estimated Power Charge Rev. Req. (Millions)[1]	$ 4,667	$ 4,702	$ 4,165	$ 4,105	$ 3,955	$ 4,087	$ 4,647	$ 5,169	$ 3,574	$ 2,452
Estimated Power Charge ($/MWh)[2]	-	171	123	119	99	97	99	100	96	103
Percent Change from Base Case	-	36.3	21.5	17.3	10.8	10.9	19.5	23.1	5.4	0.1
Estimated Bond Charge Rev. Req. (Millions)[3]	$ 6	$ 1,145	$ 945	$ 928	$ 925	$ 925	$ 925	$ 926	$ 926	$ 926
Estimated Bond Charge ($/MWh)[4]	-	8.21	6.66	6.30	6.14	6.02	5.89	5.78	5.66	5.55
Percent Change from Base Case	-	9.1	9.2	7.8	7.4	7.4	7.4	7.3	7.3	7.3
Average Cost of DWR Contracts ($/MWh)[5]	98	135	112	100	86	82	84	81	74	72
Average Cost of Residual Net Short ($/MWh)[6]	44	51	35	35	39	49	78	83	53	60
DWR Provided Power (GWh)[7]	40,389	27,456	33,944	34,520	39,844	42,320	47,113	51,819	37,243	23,719
Total Customer Sales (GWh)[8]	149,110	139,523	141,746	147,392	150,690	153,792	157,046	160,181	163,463	166,809
Estimated Gas Price ($/MMBtu)[9]	3.00	5.58	4.17	3.44	3.63	3.85	4.06	4.27	4.44	4.60

TABLE 21
RESULTS OF SENSITIVITY ANALYSES
(CONTINUED)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Short-Term Sensitivity With Extended DWR Procurement										
DWR Charges:										
Estimated Power Charge Rev. Req. (Millions)[1]	$ 4,667	$ 4,870	$ 4,338	$ 4,330	$ 4,232	$ 4,489	$ 5,614	$ 6,523	$ 5,513	$ 5,741
Estimated Power Charge ($/MWh)[2]	-	159	114	108	92	89	96	97	77	74
Percent Change from Base Case	-	26.5	12.8	6.8	2.5	2.8	15.7	19.8	(15.6)	(28.1)
Estimated Bond Charge Rev. Req. (Millions)[3]	$ 6	$ 1,145	$ 945	$ 928	$ 925	$ 925	$ 925	$ 926	$ 926	$ 926
Estimated Bond Charge ($/MWh)[4]	-	8.21	6.66	6.30	6.14	6.02	5.89	5.78	5.66	5.55
Percent Change from Base Case	-	9.1	9.2	7.8	7.4	7.4	7.4	7.3	7.3	7.3
Average Cost of DWR Contracts ($/MWh)[5]	98	135	112	100	86	82	84	81	74	72
Average Cost of Residual Net Short ($/MWh)[6]	44	51	35	35	39	49	78	83	53	60
DWR Provided Power (GWh)[7]	40,389	30,628	38,088	39,973	46,102	50,162	58,780	67,198	71,714	77,338
Total Customer Sales (GWh)[8]	149,110	139,523	141,746	147,392	150,690	153,792	157,046	160,181	163,463	166,809
Estimated Gas Price ($/MMBtu)[9]	3.00	5.58	4.17	3.44	3.63	3.85	4.06	4.27	4.44	4.60
Long-Term Sensitivity Without Extended DWR Procurement										
DWR Charges:										
Estimated Power Charge Rev. Req. (Millions)[1]	$ 4,667	$ 5,190	$ 4,665	$ 4,369	$ 4,235	$ 4,431	$ 5,162	$ 5,668	$ 3,812	$ 2,659
Estimated Power Charge ($/MWh)[2]	-	112	90	90	82	83	90	97	94	107
Percent Change from Base Case	-	(11.0)	(10.5)	(11.4)	(8.7)	(5.0)	9.2	20.3	3.3	3.4
Estimated Bond Charge Rev. Req. (Millions)[3]	$ 5	$ 1,147	$ 945	$ 920	$ 925	$ 925	$ 925	$ 925	$ 925	$ 926
Estimated Bond Charge ($/MWh)[4]	-	6.90	5.51	5.40	5.27	5.12	4.98	4.84	4.71	4.58
Percent Change from Base Case	-	(8.2)	(9.7)	(7.6)	(7.9)	(8.6)	(9.3)	(10.1)	(10.8)	(11.5)
Average Cost of DWR Contracts ($/MWh)[5]	98	89	81	75	70	69	74	76	71	70
Average Cost of Residual Net Short ($/MWh)[6]	44	65	48	37	40	50	82	91	57	62
DWR Provided Power (GWh)[7]	40,389	46,417	51,606	48,617	51,773	53,554	57,258	58,172	40,526	24,909
Total Customer Sales (GWh)[8]	149,110	166,111	171,459	170,500	175,635	180,649	185,823	191,082	196,576	202,210
Estimated Gas Price ($/MMBtu)[9]	3.00	5.58	4.17	3.01	3.35	3.85	6.21	7.65	4.44	4.60

TABLE 21
RESULTS OF SENSITIVITY ANALYSES
(CONTINUED)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Long-Term Sensitivity With Extended DWR Procurement										
DWR Charges:										
Estimated Power Charge Rev. Req. (Millions)[1]	$ 4,667	$ 6,476	$ 6,026	$ 5,057	$ 5,296	$ 5,937	$ 8,143	$ 9,810	$ 7,831	$ 8,371
Estimated Power Charge ($/MWh)[2]	-	98	80	78	69	73	88	97	75	74
Percent Change from Base Case	-	(21.7)	(20.6)	(23.1)	(22.9)	(15.8)	6.8	20.1	(18.2)	(28.0)
Estimated Bond Charge Rev. Req. (Millions)[3]	$ 5	$ 1,147	$ 945	$ 920	$ 925	$ 925	$ 925	$ 925	$ 925	$ 926
Estimated Bond Charge ($/MWh)[4]	-	6.90	5.51	5.40	5.27	5.12	4.98	4.84	4.71	4.58
Percent Change from Base Case	-	(8.2)	(9.7)	(7.6)	(7.9)	(8.6)	(9.3)	(10.1)	(10.8)	(11.5)
Average Cost of DWR Contracts ($/MWh)[5]	98	89	81	75	70	69	74	76	71	70
Average Cost of Residual Net Short ($/MWh)[6]	44	65	48	37	40	50	82	91	57	62
DWR Provided Power (GWh)[7]	40,389	65,798	75,158	64,882	76,674	81,007	92,337	100,867	105,074	112,539
Total Customer Sales (GWh)[8]	149,110	166,111	171,459	170,500	175,635	180,649	185,823	191,082	196,576	202,210
Estimated Gas Price ($/MMBtu)[9]	3.00	5.58	4.17	3.01	3.35	3.85	6.21	7.65	4.44	4.60

Source: NCI.

[1] Estimated total revenue requirement to be recovered through Power Charges.
[2] Applied to, and recovered from, the Customers based on quantities of power supplied by DWR.
[3] Estimated total revenue requirement to be recovered through Bond Charges.
[4] Applied to, and recovered from, the Customers based on the total energy supplied to the Customers by DWR and the IOUs.
[5] Average cost of DWR contract power. Rounded to the nearest dollar.
[6] Average cost of residual net short. Rounded to the nearest dollar.
[7] Total energy supplied to the Customers by DWR. Power Charges are applied to these values.
[8] Total energy supplied to the Customers by DWR and the IOUs. Bond Charges are applied to these values.
[9] Estimated average annual nominal price of natural gas at the southern California border.

drives down Power Charges, even though the average price of the residual net short increases when compared to the Base Case. This is because the increased average per-unit cost of the residual net short is still lower than the average per-unit cost of DWR contracts. Bond Charges decrease over the entire Study Period when compared to the Base Case due to the increased recovery base provided by the increased total IOU load. As in Case 3, the average per-unit cost of DWR contracts in 2008 and 2009 increases compared to the Base Case because increased gas costs (reflected in tolling arrangements) more than offset any per-unit cost reductions realized due to increased dispatchability

PRINCIPAL ASSUMPTIONS AND CONSIDERATIONS

The results of the analyses performed in the preparation of this Report and the conclusions presented herein are predicated upon the general condition that the assumptions presented herein are reasonable and will continue, as stated, for the Study Period, without major modification or change. Although NCI believes the assumptions made are reasonable, NCI makes no representation or warranty that alternative or additional assumptions would necessarily be unreasonable or that the assumed conditions will, in fact, occur. In this connection, NCI's conclusions may be affected favorably or unfavorably by unforeseen future events, and therefore, to the extent conditions differ from those assumed herein, the results that will be achieved by DWR will vary from those forecast. NCI undertakes no obligation to update or revise any portion of this Report to reflect any events or circumstances after the date of this Report. In addition, NCI's studies, analyses, investigations, and projections have been based upon its understanding of certain documents and information provided to NCI by DWR, DWR's legal, financial, and accounting advisors, PG&E, SCE, SDG&E, the CAISO, the CPUC, the CEC, FERC, and others. While NCI believes these sources to be reliable, except as otherwise noted herein, they have not been independently verified for either accuracy or validity, and no assurances are offered with respect thereto. To the best of NCI's knowledge, the data and summaries presented herein accurately reflect the information furnished to NCI by DWR, DWR's legal, financial, and accounting advisors, PG&E, SCE, SDG&E, the CAISO, the CPUC, the CEC, FERC, and others. Further, NCI has assumed that all contracts and agreements that have been relied upon in the conduct of its investigations will be fully enforceable in accordance with their terms and conditions. NCI makes no representations or warranties, and provides no opinion, concerning the enforceability or legal interpretations of such contractual and legal requirements.

The assumptions on which this Report is based include, but are not limited to, the following:

DWR REVENUE RECOVERY

1. The imposition of Bond Charges and Power Charges under the Rate Agreement is legally enforceable under California and federal law.
2. The right of additional retail end-use customers to acquire electricity from ESPs will remain suspended throughout the Study Period.
3. DWR's Bond-Related Costs and Retail Revenue Requirements during the Study Period will approximate the amounts shown in Exhibit 19.
4. On or before October 10, 2002, DWR will issue the Bonds in amounts sufficient to fully repay the Interim Borrowing, reimburse outstanding General Fund Loans, fund deposits to accounts required under the Indenture, and pay costs of issuance. The Bonds will require debt service payments and Bond-Related Costs as set forth in Exhibit 19.
5. The IOUs will remit Bond Charges and Power Charges collected from the Customers to DWR in accordance with the Servicing Arrangements.
6. DWR will not be responsible for any portion of the IOUs' unpaid power supply costs as part of the Department Costs or Bond-Related Costs described in this Report.

7. Bond Charges and Power Charges collected from the Customers will be applied in accordance with the Indenture and the Rate Agreement.

8. The Rate Agreement will be adhered to by DWR and the CPUC.

9. DWR and the IOUs will adhere to the Servicing Arrangements.

10. DWR will sell all excess energy purchased under its power contracts at a price no less than 50 percent of the market-clearing price for energy purchased in the spot market to meet residual net short energy needs.

11. DWR will only be responsible for transmission charges levied by the CAISO on power delivered by DWR, including, but not limited to, grid management, URG-related congestion, wheeling, voltage support, or administrative charges.

12. DWR will incur charges for ancillary services on total power delivered by DWR and, through 2002, on total SDG&E energy requirements, and will include such charges in the Retail Revenue Requirements collected from the Customers, equal to (i) 3.8 percent times (ii) the price of the residual net short multiplied by (iii) energy requirements supplied by DWR, and, through 2002, SDG&E energy requirements.

13. DWR will not incur penalties under the CAISO tariffs for any under-scheduling of generating reserves.

14. DWR will communicate its Retail Revenue Requirements to the CPUC in a timely and complete manner to adjust its Power Charges to the Customers when and as needed to ensure timely and complete payment of its Retail Revenue Requirements. DWR will submit its revised Retail Revenue Requirements to the CPUC within one and one-half months of initiating a filing and will begin receiving additional revenues resulting from such adjustment within five and one-half months of the communication of the Retail Revenue Requirements to the CPUC.

15. DWR will submit its requirement for increased Bond Charges to the CPUC in a timely and complete manner as necessary to ensure timely and complete payment of Bond-Related Costs. DWR will submit its requirement for increased Bond Charges to the CPUC within one and one-half months of initiating its filing and will begin receiving additional revenues resulting from such adjustment within five and one-half months of the submittal of its revised requirement to the CPUC.

16. All costs included in revenue requirements submitted to the CPUC by DWR to be recovered through Power Charges and Bond Charges will be just and reasonable, to the extent required by the Act or the Rate Agreement.

17. Bond Charges and Power Charges billed and collected by the IOUs, as the servicing agents of DWR, will not be deemed to be the property of the IOUs or available to satisfy the claims of the IOUs' creditors in a bankruptcy proceeding.

18. The costs incurred by DWR for the transitioning of the residual net short and related functions, including the assignment of the DWR contracts, if applicable, are recoverable under the Rate Agreement and will be recovered by DWR from the Customers through Power Charges until such time as DWR is no longer supplying power to the Customers, after which any remaining transition costs will be recovered through Bond Charges.

19. The State will approve annual appropriations from the General Fund (to be reimbursed from revenues received from Power Charges or Bond Charges) sufficient to pay the administrative costs of DWR's power supply program.

POWER SUPPLY RESOURCES

20. Hydroelectric output in California and in the Pacific Northwest will average 95 percent of normal during 2002 and 100 percent of normal during the remainder of the Study Period.

21. Generating capacity available from the IOU-Owned Generation, QF contracts, and bilateral contracts will be as shown in Exhibit 7.

22. Power supply resources available to meet the residual net short requirements of the Customers will be as shown in Exhibit 7.

23. The IOUs will retain and utilize, in cooperation with DWR, through at least the end of the Study Period, the URG, their existing conservation and load management programs, and related supply-side and demand-side resources as may be available to them for the sole purpose of meeting the capacity and energy requirements of the Customers.

24. The QFs will operate under the terms of their existing contracts with the IOUs through the termination dates contained within their respective contracts with the IOUs and thereafter will operate as merchant generators.

25. The IOUs will continue making payments to the QFs on a going-forward basis in a timely manner for capacity and energy delivered to the IOUs through at least the end of the Study Period.

26. The IOUs, DWR, and the CPUC will collectively cooperate to effect a smooth transition of residual net short purchases and the IOUs will assume responsibility for the operation, dispatch, and administration of DWR's power supply contracts pursuant to CPUC Decision 02-09-053 effective January 1, 2003.

27. The IOUs will be responsible for, and will successfully purchase, either directly or in coordination with purchases by DWR (pursuant to the contract procurement process established under the Procurement Proceeding), the residual net short requirements of the Customers within the IOUs' respective service territories, beginning January 1, 2003, and extending through the remainder of the Study Period.

28. Once the IOUs have resumed purchasing the residual net short and are responsible for managing the DWR contracts, they will dispatch the DWR long-term contracts in a manner that minimizes the unit cost of power delivered to the Customers throughout the remainder of the Study Period.

29. The successful renegotiation of additional power contracts by DWR beyond the date of this Report will not result in a material increase in the aggregate Retail Revenue Requirements shown in Exhibit 19 for any given year of the Study Period.

30. The power suppliers that entered into long-term contracts with DWR will fulfill their obligations as set forth in the contracts.

31. Adequate emission offsets will be available to permit the IOU-Owned Generation and new and existing generating facilities owned by non-utility generators and municipal, state, and federal generators to operate at the levels and costs reflected in this Report.

32. Neither FERC nor the CPUC will re-establish a single market-clearing price method for establishing day-ahead or hour-ahead spot market pricing, other than small volumes of real-time energy, for as long as inadequate power supply capacity is available to avoid disruption of the California market.

33. DWR and the CAISO will notify FERC in a timely manner of charges by sellers in the day-ahead, hour-ahead, and real-time markets which are in excess of the FERC market mitigation price caps and FERC will timely and prudently pursue refunds for such charges by sellers which are found not to have a cost basis for prices above the applicable FERC price cap.

34. The FERC price cap of $250 per MWh will remain in effect from the date of this Report throughout the remainder of the Study Period.

35. There will be no changes in federal, state, or local laws or regulations or interpretation thereof that would prohibit or significantly alter in a materially adverse manner the analysis, assumptions, or conclusions of this Report, including, but not limited to, the capacity and energy supply capabilities of the IOU-Owned Generation, QF contracts, or bilateral contracts or negatively affect the price or ability to operate existing generating resources or site, construct, and operate new generating resources in the WECC.

36. DWR will not be required to pay more than the contract price for energy delivered under the PX Block Forward contracts.

37. DWR has the legal authority to purchase energy outside of the CAISO market on a "pay-as-bid" basis and is subject only to the June 19, 2001 FERC order on market mitigation for purchases made through the CAISO.

38. During the Study Period, there will not be a sustained disruption of DWR's and/or the IOUs' ability to procure, generate, transmit, or deliver power to the Customers resulting from a natural disaster or man-made event, including an act of war or terrorism.

DWR MANAGEMENT AND OPERATIONS

39. Throughout the Study Period, DWR will offer compensation to its employees and contract personnel retained to operate, manage, and administer the power supply program that is commensurate with the compensation offered by competing employers.

40. DWR will rely on out-sourced professional services to assist it with the operation, management, and administration of the energy supply program.

41. DWR will retain existing staff, contract personnel, and out-sourced professional services as may be needed to facilitate the transition of DWR's net short power supply responsibilities to the IOUs.

FUEL SUPPLIES

42. The interstate natural gas pipeline systems in the western United States, together with the intrastate natural gas pipeline systems within California, will be operated, maintained, and expanded in accordance with prudent utility practice and will not experience a failure or other constraints that would materially limit or preclude the delivery of natural gas supplies to electric generating facilities in California during the Study Period.

43. Natural gas producers in the western United States will continue their exploration and supply development efforts and will realize new sources of supply at levels presently being experienced through at least 2002, after which new sources of supply will be realized at levels approximating industry experience prior to 1999.

44. World oil prices will increase at a rate no greater than approximately 0.5 percent per year (in real dollars) over the Study Period, as projected in EIA's Annual Energy Outlook 2002.

45. In the event there are significant and extended increases in the basis differential in gas prices between California and the Henry Hub, FERC will investigate the actions of shippers and owners of gas transmission into California in a timely manner and will take timely action to eliminate any efforts by parties to exercise market power over gas transportation to California.

46. DWR will utilize its risk management program, as appropriate and necessary, to stabilize and manage the supply, availability, and cost of natural gas and power supply resources.

47. During the Study Period, there will not be a sustained disruption of domestic natural gas markets or world oil markets resulting from a natural disaster or man-made event, including an act of war or terrorism.

CAPACITY AND ENERGY REQUIREMENTS

48. The IOUs' annual capacity and energy requirements during the Study Period, including the impacts of incremental conservation and load management, self-generation, and direct access discussed herein, will be as set forth in Exhibits 2 and 3 of this Report.

49. The net short and residual net short capacity and energy requirements of the Customers will be as shown in Exhibits 11 through 14.

TRANSMISSION SYSTEM

50. The IOUs, in coordination with DWR, will schedule and arrange for dispatch of the IOU-Owned Generation in a manner that enables DWR to reasonably minimize the energy supply costs for the Customers.

51. The CAISO (or a successor entity) will provide timely information to DWR scheduling staff on current generation and transmission outage conditions, by generating unit and transmission path, and updated schedules for generation unit and transmission line outages to enable informed scheduling and dispatching of DWR contracted power supply resources and short-term market purchases.

52. CAISO regulations governing the conduct of energy suppliers and other entities whose activities affect the transmission system will be complied with by such energy suppliers and other entities.

53. By November 2004, PG&E or one or more other parties will place in service improvements to the transmission systems in California to enable a total increase of 1,500 MW in transfer capability on Path 15.

54. The IOUs or a successor owner of the transmission system serving California, along with transmission owners with transmission facilities interconnected with the California transmission system, will undertake timely transmission upgrades when and as economically justified to provide for the efficient transfer of power supplies between California and the interconnected systems in neighboring states.

In addition to the above, the Official Statement discusses risks and other considerations that are or may be relevant to the assumptions, analyses, and conclusions presented in this Report. Please see the sections entitled, "LITIGATION AND ADMINISTRATIVE PROCEEDINGS," "RISK FACTORS," and "RELATIONSHIPS" in the Official Statement.

This Report has been prepared solely for DWR for the purposes set forth in the Report and the Report may not be used for any other purpose. In particular, this Report does not express any recommendation, opinion, or advice as to the wisdom, desirability, or prudence of the issuance, sale, or purchase of the Bonds or as to the action any person should take in connection with the offer, issuance, purchase, or sale of the Bonds. NCI and its employees are independent contractors providing professional services to DWR and are not officers, employees, or agents of DWR. NCI and its employees are not and shall not be considered to be fiduciaries of DWR, any purchaser or offeree of the Bonds, or any other person named in this Report or the Official Statement. This Report and the Official Statement should be read in their entirety. A wide variety of information, including financial information, concerning the subject matter of this Report is publicly available from the State and other sources. These sources may include reports in the press attributed to NCI, its employees, or representatives. Any such information from any source that is inconsistent with the information set forth in this Report or the Official Statement should be disregarded.

EXHIBIT 1
HISTORICAL PEAK DEMAND AND ENERGY REQUIREMENTS OF THE IOUS

	Calendar Year				
	1997	**1998**	**1999**	**2000**	**2001**
PG&E					
Peak Demand (MW)	17,067	17,168	17,676	18,259	16,981
Energy Requirements (GWh)					
Retail Sales	76,241	75,676	79,209	81,783	77,218
Lost and Unaccounted For	7,551	7,532	8,482	8,178	6,993
Total Energy Requirements	83,792	83,208	87,691	89,961	84,211
Annual Load Factor[1]	0.56	0.55	0.57	0.56	0.57
SCE					
Peak Demand[2] (MW)	19,118	19,935	19,122	19,757	17,890
Energy Requirements (GWh)					
Retail Sales	76,057	76,258	78,207	83,435	78,455
Lost and Unaccounted For[3]	7,142	6,787	6,960	5,730	5,626
Total Energy Requirements	83,199	83,045	85,167	89,165	84,081
Annual Load Factor[1]	0.50	0.48	0.51	0.52	0.53
SDG&E					
Peak Demand (MW)	3,688	3,960	3,606	3,485	3,147
Energy Requirements (GWh)					
Retail Sales	16,747	17,249	17,930	18,423	17,463
Lost and Unaccounted For	1,231	1,183	883	1,051	1,041
Total Energy Requirements	17,978	18,432	18,813	19,474	18,504
Annual Load Factor[1]	0.56	0.53	0.60	0.64	0.67
Total IOU					
Peak Demand (MW)	39,873	41,063	40,404	41,501	38,018
Energy Requirements (GWh)					
Retail Sales	169,045	169,183	175,346	183,641	173,136
Lost and Unaccounted For	15,924	15,502	16,325	14,959	13,660
Total Energy Requirements	184,969	184,685	191,671	198,600	186,796
Annual Load Factor[1]	0.53	0.51	0.54	0.55	0.56

Source: FERC Form 1 and the IOUs.
[1] Compares Total Energy Requirements to Peak Demand.
[2] SCE Peak Demand includes the peak demands of the cities of Anaheim, Riverside, Azusa, Banning, and Colton, and certain other municipal loads.
[3] Lost and Unaccounted For energy is estimated for 1997 through 1999 based upon prior year data.
Note: Totals may differ slightly due to rounding.

EXHIBIT 2
ESTIMATED IOU PEAK DEMANDS[1]
(MW)

	Calendar Year									
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
PG&E										
Peak Demand[2]	16,906	17,207	17,502	17,783	18,038	18,296	18,557	18,805	19,057	19,313
Less: Incremental Conservation and Load Management[3]	26	-	-	-	-	-	-	-	-	-
Self-Generation	42	90	129	167	193	218	245	273	303	334
Direct Access	1,726	1,726	1,726	1,726	1,726	1,726	1,726	1,726	1,726	1,726
Peak Demand After Adjustments[4]	**15,112**	**15,391**	**15,647**	**15,891**	**16,120**	**16,352**	**16,587**	**16,806**	**17,029**	**17,254**
SCE										
Peak Demand	17,996	18,247	18,625	19,099	19,568	19,991	20,432	20,894	21,389	21,896
Less: Incremental Conservation and Load Management[3]	25	-	-	-	-	-	-	-	-	-
Self-Generation	55	116	165	215	248	281	315	351	389	429
Direct Access	2,363	2,363	2,363	2,363	2,363	2,363	2,363	2,363	2,363	2,363
Peak Demand After Adjustments[4]	**15,553**	**15,767**	**16,096**	**16,521**	**16,957**	**17,347**	**17,754**	**18,179**	**18,636**	**19,103**
SDG&E										
Peak Demand	3,765	3,935	4,098	4,235	4,368	4,496	4,642	4,759	4,879	5,001
Less: Incremental Conservation and Load Management[3]	6	-	-	-	-	-	-	-	-	-
Self-Generation	24	50	71	93	107	121	136	152	168	185
Direct Access	630	630	630	630	630	630	630	630	630	630
Peak Demand After Adjustments[4]	**3,105**	**3,255**	**3,397**	**3,512**	**3,632**	**3,745**	**3,876**	**3,977**	**4,081**	**4,186**
All IOUs[5]										
Peak Demand	38,667	39,389	40,225	41,117	41,974	42,783	43,631	44,458	45,324	46,210
Less: Incremental Conservation and Load Management[3]	57	-	-	-	-	-	-	-	-	-
Self-Generation	121	256	365	474	547	620	696	776	860	948
Direct Access	4,719	4,719	4,719	4,719	4,719	4,719	4,719	4,719	4,719	4,719
Peak Demand After Adjustments[4]	**33,769**	**34,413**	**35,140**	**35,924**	**36,708**	**37,445**	**38,216**	**38,963**	**39,746**	**40,543**

Source: Estimated peak demands obtained from the IOUs. Adjustments to estimated peak demands developed by NCI. Amounts shown for each IOU represent estimated values at the time of their annual system peak (PG&E – July; SCE – August; SDG&E – August).

[1] All values adjusted for distribution and transmission system losses. Amounts shown for self-generation are increases above levels experienced historically.

[2] Values for 2002 through 2004 exclude July peak requirements associated with the Western contract (379 MW).

[3] Estimated incremental peak demand reduction resulting from the 20/20 Program (2002).

[4] Peak demand to be met through electric generating resources or power purchases.

[5] Sum of the individual IOU values. Actual values at the time of the coincident peak for all IOUs will be lower.

Note: Totals may differ slightly due to rounding.

EXHIBIT 3
ESTIMATED IOU ENERGY REQUIREMENTS[1]
(GWH)

	Calendar Year									
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
PG&E										
Energy Requirements[2]	84,694	86,253	87,773	89,226	90,530	91,849	93,190	94,463	95,758	97,075
Less: Incremental Conservation and Load Management[3]	193	-	-	-	-	-	-	-	-	-
Self Generation	261	554	789	1,024	1,181	1,338	1,503	1,675	1,857	2,048
Direct Access	9,482	9,482	9,482	9,482	9,482	9,482	9,482	9,482	9,482	9,482
Energy Requirements After Adjustments[4]	**74,758**	**76,217**	**77,503**	**78,721**	**79,867**	**81,029**	**82,206**	**83,306**	**84,419**	**85,545**
SCE										
Energy Requirements	85,986	87,268	89,141	91,470	93,754	95,821	97,971	100,226	102,639	105,114
Less: Incremental Conservation and Load Management[3]	188	-	-	-	-	-	-	-	-	-
Self Generation	335	712	1,014	1,316	1,518	1,720	1,932	2,154	2,387	2,633
Direct Access	12,942	12,942	12,942	12,942	12,942	12,942	12,942	12,942	12,942	12,942
Energy Requirements After Adjustments[4]	**72,521**	**73,615**	**75,185**	**77,212**	**79,294**	**81,159**	**83,097**	**85,130**	**87,310**	**89,539**
SDG&E										
Energy Requirements	19,261	20,177	21,034	21,755	22,452	23,121	23,882	24,495	25,124	25,771
Less: Incremental Conservation and Load Management[3]	47	-	-	-	-	-	-	-	-	-
Self Generation	126	307	437	568	655	742	833	929	1,030	1,136
Direct Access	3,731	3,731	3,731	3,731	3,731	3,731	3,731	3,731	3,731	3,731
Energy Requirements After Adjustments[4]	**15,357**	**16,139**	**16,866**	**17,456**	**18,066**	**18,648**	**19,317**	**19,834**	**20,363**	**20,904**
All IOUs										
Energy Requirements	189,941	193,698	197,948	202,452	206,736	210,791	215,043	219,184	223,521	227,960
Less: Incremental Conservation and Load Management[3]	428	-	-	-	-	-	-	-	-	-
Self Generation	722	1,573	2,240	2,908	3,354	3,801	4,268	4,759	5,274	5,816
Direct Access	26,155	26,155	26,155	26,155	26,155	26,155	26,155	26,155	26,155	26,155
Energy Requirements After Adjustments[4]	**162,636**	**165,971**	**169,553**	**173,389**	**177,227**	**180,835**	**184,620**	**188,271**	**192,092**	**195,988**

Source: Estimated energy requirements obtained from the IOUs. Adjustments to estimated energy requirements developed by NCI.
[1] All values adjusted for distribution and transmission system losses. Amounts shown for self-generation are increases above levels experienced historically.
[2] Values for 2002 through 2004 exclude requirements associated with the Western contract (4,819 GWh for 2002 and 5,146 GWh for 2003 and 2004).
[3] Estimated incremental energy reduction resulting from the 20/20 Program (2002).
[4] Energy requirements to be met through electric generating resources or power purchases.
Note: Totals may differ slightly due to rounding.

EXHIBIT 4
NEW GENERATING FACILITIES IN CALIFORNIA
(MW)

Owner/Developer	Project Name	Scheduled On Line Date	Unit Type	Fuel Type	Project Capacity[1]	Planning Capacity[2]
Under Construction:						
PG&E NEG[3]	La Paloma Phase I	8-Aug-02	CC	NG	262	262
Valero Refining[3]	Valero Cogeneration	15-Aug-02	CT	NG	51	51
Burbank[3]	Lake Unit 1	15-Aug-02	CT	NG	43	43
Cabazon Wind Partners[3,4]	Cabazon	31-Aug-02	Wind	Wind	41	41
PG&E NEG[3]	La Paloma Phase II	11-Sep-02	CC	NG	262	262
PG&E NEG[3]	La Paloma Phase III	16-Oct-02	CC	NG	262	262
PG&E NEG[3]	La Paloma Phase IV	13-Nov-02	CC	NG	262	262
Capitol Power[4]	Capitol Power Biomass	29-Nov-02	WTE	Biomass	15	15
Calpine[4]	Los Esteros Critical Energy Facility (San Jose, US Dataport)	1-Dec-02	CT	NG	180	180
Sempra & Occidental Petroleum[3,5]	Elk Hills Power Project	1-Mar-03	ST	NG	500	500
Summit Energy Group or Caithness[3]	Blythe Energy Power Plant Project-unit 1	1-Mar-03	CC	NG	520	520
Modesto[3]	Woodland II	1-May-03	CT	NG	80	80
Navy	COSO Rerate	1-Jun-03	CT	NG	12	12
Constellation[3,4]	High Desert Power Plant	1-Jul-03	CC	NG	830	830
Calpine/Bechtel[5]	Metcalf Energy Center	3-May-04	CC	NG	600	-
Calpine[3,5]	Pastoria Energy Center	1-Jun-04	CC	NG	750	750
Calpine[5]	Otay Mesa-unit 1	1-Dec-04	CC	NG	250	-
Calpine[5]	Otay Mesa-unit 2	1-Dec-04	CC	NG	250	-
Mirant Delta	Contra Costa Expansion/Repowering (Unit 8)-1	1-Jun-05	CC	NG	265	-
Mirant Delta	Contra Costa Expansion/Repowering (Unit 8)-2	1-Jun-05	CC	NG	265	-
Summit Energy Group or Caithness[3]	Blythe Energy Power Plant Project-unit 2	1-Jul-05	CC	NG	520	-
Total Under Construction					**6,220**	**4,070**
In Siting Review:						
Whitewater Energy Corp.[3,4]	Whitewater Hill	31-Aug-02	Wind	Wind	66	66
Mark Tech/FORAS Energy[3]	Alta Mesa IV	1-Oct-02	Wind	Wind	25	-
Calpine[4]	Lambie Energy Center	15-Dec-02	CT	NG	45	45
Calpine[4]	Creed Energy Center	15-Dec-02	CT	NG	45	45
Calpine[4]	Goose Haven Energy Center	15-Dec-02	CT	NG	45	45
Calpine[4]	Feather River Energy Center	31-Dec-02	CT	NG	45	45
Enron Wind Development	Cottonwood	31-Dec-02	Wind	Wind	40	-
Calpine[4]	Pajaro Peaking Power Project (Watsonville 2)	30-Jan-03	CT	NG	45	45
GWF[4]	Tracy Peaker (Tesla Subst.)	28-Feb-03	CT	NG	162	162
FPL Energy	High Winds	31-May-03	Wind	Wind	70	-
CalPeak[4]	Midway Buttonwillow	1-Jun-03	CT	NG	48	48

EXHIBIT 4
NEW GENERATING FACILITIES IN CALIFORNIA
(MW) (CONTINUED)

Owner/Developer	Project Name	Scheduled On Line Date	Unit Type	Fuel Type	Project Capacity[1]	Planning Capacity[2]
In Siting Review (Cont.):						
Edison International[4]	Sunrise Power CC (Phase II)	1-Jul-03	ST	NG	265	265
Santa Cruz, County, Dept of Public Works[4]	Buena Vista Landfill Gas Recovery	1-Aug-03	WTE	Landfill Gas	3	3
FPL Energy	Green Ridge	1-Jan-04	Wind	Wind	110	-
FP&L	Southern Sierra	1-Jan-04	Wind	Wind	200	-
FPL Energy	Windridge Phase 2	1-Jan-04	Wind	Wind	30	-
Enron Wind Development	Victory Garden	1-Jan-04	Wind	Wind	30	-
City of Vernon	Malburg CC	1-Jan-04	CC	NG	134	-
Calpine	Russell City	1-Dec-04	CC	NG	594	-
NRG & Dynegy	El Segundo Power Redevelopment (5, 6 & 7)	1-Jan-05	CC	NG	624	-
Mirant	Potrero Expansion/Repowering, Unit 7a	1-Jan-05	CC	NG	270	-
Mirant	Potrero Expansion/Repowering, Unit 7b	1-Jan-05	CC	NG	270	-
Sempra[5]	Citracado (Palomar, Escondido)	1-Jan-05	CC	NG	600	-
Duke[3]	Morro Bay	1-Feb-05	CC	NG	1,188	-
Calpine[5]	East Altamont	1-Mar-05	CC	NG	1,089	-
Duke[3]	Avenal	1-Mar-05	CC	NG	575	-
Calpine[5]	Inland Empire	1-Mar-05	CC	NG	643	-
SCPPA	Magnolia Power Project	1-Mar-05	CC	NG	250	-
FPL	Tesla CC	1-Mar-05	CC	NG	1,074	-
Edison	Western Midway-Sunset Power Project-1	1-Mar-05	CC	NG	250	-
Edison	Western Midway-Sunset Power Project-2	1-Mar-05	CC	NG	250	-
SMUD	Consumnes Phase I	1-Mar-05	CC	NG	480	-
Enron	Roseville	1-Jun-05	CC	NG	863	-
Calpine[5]	Fresno CC	1-Jun-05	CC	NG	1,055	-
Ogden Pacific	Three Mountain Power	1-Mar-06	CC	NG	500	-
Total In Siting Review					**11,983**	**769**
Grand Total					**18,203**	**4,839**
Operational Since 1/1/01:						
Proctor & Gamble	Proctor & Gamble	1-Apr-01	Cogen	NG	44	
SMUD	McClellan Upgrade	1-May-01	CT	NG	22	
Honey Lake Power Company	Honey Lake	17-May-01	WTE	Wood Waste	30	
Energy Products of Idaho	Madera	1-Jun-01	WTE	Biomass	25	
Harbor Co-Gen Co/Port of Long Beach	Long Beach	14-Jun-01	Oil/Gas	NG	19	
NRG/NEO	Chowchilla II	15-Jun-01	CT	NG	49	
Edison International[4]	Sunrise Power Phase I	27-Jun-01	CT	NG	320	

EXHIBIT 4
NEW GENERATING FACILITIES IN CALIFORNIA
(MW) (CONTINUED)

Owner/Developer	Project Name	Scheduled On Line Date	Unit Type	Fuel Type	Project Capacity[1]	Planning Capacity[2]
Operational Since 1/1/01:						
Calpine[5]	Sutter Power Project – 1a	2-Jul-01	CC	NG	252	
Calpine[5]	Sutter Power Project – 1b	2-Jul-01	CC	NG	252	
Calpine[5]	Los Medanos Energy Center	9-Jul-01	CC	NG	532	
Coral/InterGen[4]	Wildflower Larkspur (Tejas Border)	13-Jul-01	CT	NG	90	
Soledad Energy, LLC	Soledad	19-Jul-01	WTE	Wood Waste	13	
Coral/InterGen[4]	Wildflower Indigo 1&2	26-Jul-01	CT	NG	90	
NEO	NEO Red Bluff	2-Aug-01	CT	NG	47	
Alliance[4]	Drews Energy Center (Colton-SRA)	15-Aug-01	CT	NG	40	
Wellhead[4]	Fresno Cogen	16-Aug-01	CT	NG	23	
GWF[4]	Hanford Energy Park Peaker	1-Sep-01	CT	NG	88	
LADWP	Sun Valley	1-Sep-01	CT	NG	47	
Coral InterGen[4]	Wildflower Indigo 3	10-Sep-01	CT	NG	45	
Alliance[4]	Century (Colton)	15-Sep-01	CT	NG	40	
SeaWest Power Inc.	Catellus 1–5	30-Sep-01	Wind	Wind	35	
CalPeak[4]	Enterprise #7 Peaker (Escondido)	30-Sep-01	CT	NG	50	
Sea West Wind Power	Riverside (Alenander)	1-Oct-01	Wind	Wind	57	
LADWP	Harbor	1-Oct-01	CT	NG	235	
NRG & Dynegy	El Segundo Re-rate 1	8-Oct-01	CC	NG	10	
CalPeak[4]	CalPeak San Diego Border (Otay Mesa)	26-Oct-01	CT	NG	50	
Calpine[4]	Gilroy Energy Center (Phase 1 Unit 1)	5-Dec-01	CC	NG	45	
Calpine[4]	Gilroy Energy Center (Phase 1 Unit 2)	5-Dec-01	CC	NG	45	
Wellhead[4]	Panoche - Los Banos	14-Dec-01	CT	NG	49	
CalPeak[4]	Fresno/Panoche	27-Dec-01	CT	NG	49	
Calpine[4]	King City Peaker Project	14-Jan-02	CT	NG	45	
Wellhead[4]	Gates (Huron)	31-Jan-02	CT	NG	45	
Calpine [4]	Gilroy Energy Center (Phase 1 Unit 3)	13-Feb-02	CC	NG	45	
NRG & Dynegy	El Segundo Re-rate 2	1-Mar-02	CC	NG	10	
Energy Transfer	Hanover	15-Apr-02	CT	NG	23	
Calpine/Bechtel[5]	Delta Energy Center-1a	1-May-02	CC	NG	293	
Calpine/Bechtel[5]	Delta Energy Center-1b	1-May-02	CC	NG	293	
Calpine/Bechtel[5]	Delta Energy Center-1c	10-May-02	CC	NG	293	
Redding	Redding Unit 5	1-Jun-02	CC	NG	54	
NRG & Dynegy	El Segundo Re-rate 3	1-Jun-02	CC	NG	8	
CalPeak[4]	El Cajon	1-Jun-02	CT	NG	50	
CalPeak[4]	Vaca-Dixon	4-Jun-02	CT	NG	49	
Duke Energy	Moss Landing Expansion-1	1-Jul-02	CC	NG	265	
Duke Energy	Moss Landing Expansion-2	1-Jul-02	CC	NG	265	
GWF[4]	Henrietta Lemoore Peaker	1-Jul-02	CT	NG	95	

EXHIBIT 4
NEW GENERATING FACILITIES IN CALIFORNIA
(MW) (CONTINUED)

Owner/Developer	Project Name	Scheduled On Line Date	Unit Type	Fuel Type	Project Capacity[1]	Planning Capacity[2]
Operational (Cont.):						
Duke Energy	Moss Landing Expansion-3	11-Jul-02	CC	NG	265	
Duke Energy	Moss Landing Expansion-4	11-Jul-02	CC	NG	265	
Calpine[4]	Yuba City Energy Center (Greenleaf #2 Expansion)	26-Jul-02	CT	NG	45	
AES	Huntington Beach-unit 3 modern	31-Jul-02	CC	NG	225	
Total Operational					**5,326**	

Source: CEC, WECC, and NCI updates through July 30, 2002. Units with operational dates after July 30 were verified by NCI through subsequent discussions with project developers.
[1] Projected net rated capacity in MW.
[2] Projects under construction and projects under contract to DWR in siting review.
[3] Developer reports that permanent financing has been arranged for the project.
[4] All or a portion of project capacity is under contract to DWR. Length of contract term varies by resource.
[5] Projects being developed by owners that have entered into system sales contracts with DWR.
Unit Type: CT = Combustion Turbine; CC = Combined Cycle; ST = Steam; Cogen = Cogeneration; WTE = Waste to Energy. Fuel Type: NG = Natural Gas; GE = Geothermal.
Note: Totals may differ slightly due to rounding.

EXHIBIT 5
NEW GENERATING FACILITIES IN THE PACIFIC NORTHWEST
(MW)

Owner/Developer	Project Name	Location	Scheduled On Line Date	Unit Type	Fuel Type	Project Capacity[1]	Planning Capacity[2]
Under Construction:							
Northwestern Corp	Montana First Megawatts SC	MO	1-Aug-02	CT	NG	160	160
WestCoast Energy	Frederickson CC I	WA	1-Sep-02	CC	NG	248	248
Mirant/Avista	Coyote Springs II	OR	1-Dec-02	CC	NG	280	280
Calpine	Goldendale	WA	1-May-03	CC	NG	236	236
Mirant	Mint Farm	WA	1-Jul-03	CC	NG	286	286
Northwestern Corp.	Montana First Megawatts CC	MO	1-Jul-03	CC	NG	80	80
Duke	Grays Harbor I (Satsop)	WA	1-Nov-03	CC	NG	650	650
Tractebel	Chehalis	WA	1-Nov-03	CC	NG	520	520
Ida West	Garnet	ID	1-Jul-04	CC	NG	270	270
Total Under Construction.....						**2,730**	**2,730**
Under Siting Review:							
BPA WA Winds	Maiden Wind Farm	WA	1-Oct-02	Wind	Wind	50	-
PPL/Global	Starbuck	WA	1-Sep-03	CC	NG	1,200	-
BP	BP Cherry Point	WA	1-Dec-03	CC	NG	720	-
Sumas Energy Inc.	Sumas CC	WA	1-Dec-03	CC	NG	660	-
Weyerheuser	Cowlitz Generation	WA	1-Feb-04	CC	NG	395	-
Wallula Generation, LLC	Wallula Project	WA	1-Jun-04	CC	NG	1,300	-
Continental Energy	Silver Bow	MO	1-Sep-04	CC	NG	500	-
Cogentrix	Mercer Ranch Generation	WA	1-Dec-04	CC	NG	850	-
PGE	Port Westward	OR	1-Jan-05	CC	NG	660	-
PG&E NEG	Umatilla Generating Project	OR	1-Jun-05	CC	NG	550	-
Cogentrix	Grizzly Power	OR	1-Jun-05	CC	NG	980	-
Coburg Power	Coburg Power Project	OR	1-Jan-06	CC	NG	600	-
Total Under Siting Review.....						**8,465**	**-**
Under Development:							
Hardin	Rocky Mountain Power Project	MO	1-Jul-03	Coal	Coal	100	-
Montana Wind	Montana Wind Harness	MO	1-Dec-03	Wind	Wind	50	-
SeaWest	Six Prong	OR	1-Dec-03	Wind	Wind	50	-
SeaWest	Roosevelt	WA	1-Dec-03	Wind	Wind	50	-
SeaWest	Waitsburg	WA	1-Dec-03	Wind	Wind	30	-
Washington Winds Inc.	Horse Heaven Hills	WA	1-Jun-04	Wind	Wind	50	-
Westward Energy	Summit Westward	OR	1-Jun-04	CC	NG	598	-

EXHIBIT 5
NEW GENERATING FACILITIES IN THE PACIFIC NORTHWEST
(MW) (CONTINUED)

Owner/Developer	Project Name	Location	Scheduled On Line Date	Unit Type	Fuel Type	Project Capacity[1]	Planning Capacity[2]
Under Development (Cont.):							
Morrow Generating Co.	Morrow Generating Project	OR	1-Jan-05	CC	NG	550	-
Adair International.....	Blackfeet	MO	1-Jun-11	CC	NG	160	-
Total Under Development						**1,638**	**-**
Grand Total						**12,833**	**2,730**
Operational Since 1/1/01:							
Pacificorp.....	Klamath Falls	OR	1-Mar-01	CC	NG	500	
Seattle City Light	Seattle Gen Farm	WA	1-Mar-01	CT	NG	50	
Clark County PUD.....	Clark Gen Farm	WA	1-Jul-01	IC	NG	50	
Puget Sound Energy	Fredonia 3 & 4	WA	1-Jul-01	CT	NG	106	
Cogentrix/Avista	Rathdrum	ID	1-Sep-01	CC	NG	270	
Idaho Power	Danskin	ID	1-Oct-01	CC	NG	90	
Florida Power and Light	Stateline Wind Project	WA	1-Dec-01	Wind	Wind	299	
Calpine	Hermiston Power Project	OR	1-Jun-02	CC	NG	549	
SeaWest	Condon Wind II	OR	1-Jun-02	Wind	Wind	6	
TransAlta	Centralia (Big Hanaford)	WA	12-Aug-02	CC	NG	248	
Total Operational						**2,168**	

Source: WECC and NCI updates through July 30, 2002. Units with operational dates after July 30 were verified by NCI through subsequent discussions with project developers.
[1] Projected net rated capacity in MW.
[2] For projects outside of California, only those projects under construction are included in planning capacity.
Unit Type: CT = Combustion Turbine; CC = Combined Cycle; ST = Steam; IC = Internal Combustion. Fuel Type: NG = Natural Gas; GE = Geothermal.
Note: Totals may differ slightly due to rounding.

EXHIBIT 6
NEW GENERATING FACILITIES IN OTHER AREAS OF THE WECC
(MW)

Owner/Developer	Project Name	Location	Scheduled On Line Date	Unit Type	Fuel Type	Project Capacity[1]	Planning Capacity[2]
Under Construction:							
Duke Luna	Deming, NM	NM	1-Dec-02	CC	NG	600	600
PPL/Global	Sundance Energy Project II	AZ	1-Sep-02	CC	NG	90	90
Black Hills Energy	LV Cogen II	NV	1-Sep-02	CC	NG	230	230
Public Service Company of New Mexico	Afton SC	NM	1-Jan-03	CT	NG	140	140
Coastal Power (Colorado Springs)	Ray D Nixon Ph. II	CO	1-Mar-03	CC	NG	440	440
Mirant	Apex Generating Station I	NV	1-Mar-03	CC	NG	550	550
Duke Energy NA	Moapa Energy Facility I	NV	1-Apr-03	CC	NG	600	600
Duke Energy NA	Moapa Energy Facility II	NV	1-Jun-03	CC	NG	600	600
Reliant	Bighorn Power Plant	NV	1-Jun-03	CC	NG	575	575
Sempra Energy Resources	Mesquite Power I	AZ	1-Jun-03	CC	NG	650	650
PG&E NEG	Harquahala	AZ	1-Aug-03	CC	NG	580	580
Total Under Construction						**5,055**	**5,055**
Under Siting Review:							
Naniwa Energy	TRI-Center Power Plant	NV	1-Dec-02	CC	NG	360	-
Duke	Arlington Valley II (Duke Buckeye)	AZ	1-Jul-03	CC	NG	580	-
Reliant	Arrow Canyon	NV	1-Mar-04	CC	NG	575	-
Unisource/Bechtel	Springerville Generation 3	AZ	1-May-05	ST	Coal	380	-
SRP/Dynegy	SRP Phoenix (Sandtown)	AZ	1-Jul-05	CC	NG	825	-
Sempra/Reliant	El Dorado II	NV	1-Feb-06	CC	NG	500	-
Pinnacle West/Reliant	Pinnacle West Red Hawk III	AZ	1-Jun-06	CC	NG	530	-
Pinnacle West/Reliant	Pinnacle West Red Hawk IV	AZ	1-Jun-07	CC	NG	530	-
Total Under Siting Review						**4,280**	**-**
Under Development:							
Intergen	La Rosita	Mexico	1-Apr-03	CC	NG	550	-
AEP	Mexicali	Mexico	1-Apr-03	CC	NG	500	-
Public Service of Colorado	PSCo GT	CO	1-Jun-03	CC	NG	150	-
Global Energy Partners	Shoshone Mountain Wind Farm	NV	1-Jun-03	Wind	Wind	255	-
Global Energy Partners	Table Mountain Wind Farm	NV	1-Dec-03	Wind	Wind	90	-
Calpine	Moapa Indian Reservation	NV	1-Jan-04	CC	NG	1,000	-
Pinnacle West	Silver Hawk Power	NV	1-Apr-04	CC	NG	570	-
Public Service of Colorado	PSCo GT	CO	1-Jun-04	CC	NG	150	-
Duke Energy NA	Washoe Power Plant	NV	1-Jun-04	CC	NG	540	-
Cogentrix	Toquop Energy Project	NV	1-Sep-04	CC	NG	1,100	-

EXHIBIT 6
NEW GENERATING FACILITIES IN OTHER AREAS OF THE WECC
(MW) (CONTINUED)

Owner/Developer	Project Name	Location	Scheduled On Line Date	Unit Type	Fuel Type	Project Capacity[1]	Planning Capacity[2]
Under Development (Cont):							
Allegheny	La Paz I	AZ	1-Nov-04	CC	NG	540	-
Duke Energy NA	Clovis I & 2	NM	1-Dec-04	CC	NG	1,200	-
Diamond Generating	Ivanpah Energy Center	NV	1-Mar-05	CC	NG	500	-
Sempra	Mexicali	Mexico	31-May-05	CC	NG	600	-
Public Service of Colorado	PSCo CC	CO	1-Jun-05	CC	NG	450	-
Unisource/Bechtel	Springerville Generation 4	AZ	1-Dec-05	ST	Coal	380	-
Blue Diamond Power Partners	Blue Diamond Pump Storage	NV	1-Dec-05	Hydro	Hydro	400	-
Newmont Mining	Boulder Valley Energy Center	NV	1-Jan-06	CC	NG	480	-
Arizona Independent Power	White Tank Mountain	AZ	1-Jan-11	Pump St.	Hydro	1,250	-
PG&E NEG	Meadow Valley	NV	1-Jan-11	CC	NG	1,191	-
Overton PUD	Tortoise Power Plant	NV	1-Jan-11	CT	NG	100	-
Total Under Development						**11,996**	**-**
Grand Total						**21,331**	**5,055**
Operational Since 1/1/01:							
Reliant	Desert Basin (Casa Grande, AZ)	AZ	1-Jun-01	CC	NG	500	
Calpine/Pinnacle	Phoenix Repowering Phase II	AZ	1-Jun-01	CC	NG	500	
Public Service of Colorado	Fort St. Vrain Expansion	CO	1-Jun-01	CC	NG	235	
Duke/PPL	Griffith Energy	AZ	1-Jul-01	CC	NG	650	
Pinnacle West	Phoenix Repowering Phase I	AZ	1-Aug-01	CC	NG	120	
Oasis LLC/SRP	Kyrene Oasis	AZ	2-Jan-02	CC	NG	250	
PPL/Global	Sundance Energy Project I	AZ	1-Mar-02	CC	NG	450	
Public Service Company of New Mexico	Lordsburg Power Plant	NM	1-Jun-02	CC	NG	80	
Pinnacle/Reliant	Pinnacle West Red Hawk I & II	AZ	1-Jul-02	CC	NG	1,060	
Duke	Arlington Valley I (Duke Buckeye)	AZ	1-Aug-02	CC	NG	580	
Total Operational						**4,425**	

Source: WECC and NCI updates through July 30, 2002. Units with operational dates after July 30 were verified by NCI through subsequent discussions with project developers.
[1] Projected net rated capacity in MW.
[2] For projects outside of California, only those projects under construction are included in planning capacity.
Unit Type: CT = Combustion Turbine; CC = Combined Cycle; ST = Steam; Pump St. = Pump Storage. Fuel Type: NG = Natural Gas; GE = Geothermal.
Note: Totals may differ slightly due to rounding.

EXHIBIT 7
ESTIMATED CAPACITY RESOURCES AVAILABLE TO THE CUSTOMERS
(MW)

	Calendar Year									
	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
IOU-Owned Generation	12,025	12,025	12,025	12,025	11,648	11,648	11,648	11,648	11,648	11,648
Hydroelectric Derating	(1,212)	(1,010)	(1,010)	(1,010)	(1,010)	(1,010)	(1,010)	(1,010)	(1,010)	(1,010)
Allowance for Forced and Scheduled Outages	(458)	(458)	(458)	(458)	(420)	(420)	(420)	(420)	(420)	(420)
Net IOU-Owned Generation	**10,355**	**10,557**	**10,557**	**10,557**	**10,218**	**10,218**	**10,218**	**10,218**	**10,218**	**10,218**
Bilateral Contracts	3,570	3,570	2,495	1,600	1,450	1,250	1,250	1,250	1,250	1,250
QF Capacity[1]	9,381	9,257	9,028	8,892	8,585	8,377	8,261	7,287	6,923	6,742
Allowance for Forced and Scheduled Outages[2]	(2,696)	(2,612)	(2,464)	(2,267)	(2,235)	(2,210)	(2,198)	(2,096)	(2,058)	(2,025)
Net QF and Bilateral Contract Capacity	10,255	10,215	9,059	8,225	7,800	7,417	7,313	6,441	6,114	5,967
Total Net URG Capacity	**20,610**	**20,772**	**19,616**	**18,782**	**18,018**	**17,635**	**17,531**	**16,659**	**16,333**	**16,185**
Existing Non-Utility Generation[3]	21,794	21,917	21,210	21,346	21,601	21,809	21,869	21,772	22,117	22,109
New California Resources[4]	1,779	6,549	7,302	8,052	8,052	8,652	8,652	8,952	12,007	12,307
Allowance for Forced and Scheduled Outages	(2,570)	(2,747)	(2,717)	(2,790)	(2,816)	(2,854)	(2,860)	(2,688)	(2,958)	(2,978)
Direct Access	(4,714)	(4,714)	(4,714)	(4,714)	(4,714)	(4,714)	(4,714)	(4,714)	(4,714)	(4,714)
Net Non-Utility and New Generation Resources	**16,289**	**21,005**	**21,081**	**21,895**	**22,123**	**22,893**	**22,947**	**23,323**	**26,452**	**26,724**
Total Before Governmental and Available Imports	**36,900**	**41,778**	**40,698**	**40,677**	**40,141**	**40,529**	**40,478**	**39,982**	**42,784**	**42,909**
Capacity Available from Pacific Northwest Imports[5]	5,165	5,165	5,165	5,465	5,465	5,565	5,565	5,565	5,565	5,565
Capacity Available from Remainder of WECC Imports[6]	2,941	3,076	3,076	3,076	3,876	3,414	2,795	1,369	1,565	1,004
Governmental Net-Surplus (Short)[7]	850	1,056	836	611	383	151	(109)	(368)	(813)	(1,276)
Total Resources Available to the Customers	**45,856**	**51,075**	**49,774**	**49,829**	**49,865**	**49,660**	**48,729**	**46,548**	**49,102**	**48,202**

Source: NCI.

[1] Adjusted for QF capacity that cannot be dispatched in response to changes in Customer electric demands.

[2] Allowance for forced and scheduled outages associated with resources available to the IOUs through bilateral contracts and QF agreements.

[3] Adjusted for known retirement dates of existing facilities. Includes the capacity of QF resources following the expiration of their contracts with the IOUs. Excludes Governmental resources.

[4] Net of new Governmental resource additions. Equals total planning capacity from Exhibit 4 plus generating capacity added from January 1 through July 31, 2002.

[5] From Exhibit 9. Includes imports under contract to DWR. Actual purchases may be less. Reliance on imports to meet peak loads will be affected by the cost of the power and transmission import constraints at the time of peak loads.

[6] From Exhibit 10. Actual purchases may be less. Reliance on imports to meet peak loads will be affected by the cost of the power and transmission import constraints at the time of peak loads.

[7] From Exhibit 8.

Note: Totals may differ slightly due to rounding.

EXHIBIT 8
ESTIMATED GENERATING CAPACITY AVAILABLE FROM GOVERNMENTAL POWER PRODUCERS
(MW)

	Calendar Year									
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Governmental Demand	**14,272**	**14,486**	**14,707**	**14,931**	**15,159**	**15,391**	**15,627**	**15,867**	**16,111**	**16,418**
Governmental Resources (Including Purchases)[1]	17,553	17,676	17,676	17,676	17,676	17,676	17,651	17,632	17,427	17,267
Derating Based on Forecast Hydroelectric Capability[2]	(2,260)	(1,960)	(1,960)	(1,960)	(1,960)	(1,960)	(1,960)	(1,960)	(1,960)	(1,960)
Allowance for Forced and Scheduled Outages	(171)	(174)	(174)	(174)	(174)	(174)	(173)	(173)	(169)	(166)
Net Governmental Resources[3]	**15,122**	**15,542**	**15,542**	**15,542**	**15,542**	**15,542**	**15,518**	**15,499**	**15,298**	**15,141**
Governmental Net Surplus (Short)[4]	**850**	**1,056**	**836**	**611**	**383**	**151**	**(109)**	**(368)**	**(813)**	**(1,276)**

Source: NCI.

[1] Values include planned resource additions and purchases of 731 MW per year for each year of the Study Period.

[2] Hydroelectric capacity is based upon average water availability. Actual availability may be higher or lower based upon hydrological conditions and owner operations. Adjusted to account for below normal hydroelectric conditions for 2002.

[3] Governmental Resources as adjusted for Forecast Hydroelectric Capability and Forced and Other Scheduled Outages.

[4] Net Governmental Resources less Governmental Demand.

Note: Totals may differ slightly due to rounding.

EXHIBIT 9
ESTIMATED GENERATING CAPACITY AVAILABLE FROM THE PACIFIC NORTHWEST
(MW)

	Calendar Year									
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Pacific Northwest Peak Demand	**46,039**	**46,646**	**47,483**	**48,341**	**49,029**	**49,729**	**50,461**	**51,329**	**52,119**	**52,964**
Pacific Northwest Resources (Including Planned Additions)	74,548	75,532	77,085	78,301	78,521	79,006	80,413	81,496	82,266	82,969
Derating Based on Forecast Hydroelectric Capability[1]	(11,206)	(9,345)	(9,346)	(9,347)	(9,344)	(9,349)	(9,349)	(9,349)	(9,349)	(9,349)
Resources Committed to DWR Contracts	(200)	(200)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	-
Allowance for Forced and Scheduled Outages	(1,393)	(1,440)	(1,518)	(1,578)	(1,590)	(1,613)	(1,683)	(1,738)	(1,776)	(1,811)
Net Pacific Northwest Capacity[2]	**61,749**	**64,547**	**65,921**	**67,076**	**67,287**	**67,744**	**69,080**	**70,110**	**70,841**	**71,809**
Pacific Northwest Net Surplus (Short)[3]	**14,376**	**16,567**	**17,104**	**17,700**	**17,224**	**17,080**	**17,685**	**17,846**	**17,788**	**17,911**
California Import Capability (Net)[4]	4,965	4,965	4,865	5,165	5,165	5,265	5,265	5,265	5,265	5,565
Pacific Northwest Net Surplus (Short) Available to Meet Residual Net Short (After DWR Contracts)[5]	**4,965**	**4,965**	**4,865**	**5,165**	**5,165**	**5,265**	**5,265**	**5,265**	**5,265**	**5,565**

Source: WECC reports and NCI.

[1] Hydroelectric capacity is based upon average water availability. Actual availability may be higher or lower based upon hydrological conditions and owner operations. Adjusted to account for below normal hydroelectric conditions for 2002.

[2] Pacific Northwest Resources less those resources already committed to DWR and as adjusted for Forecast Hydroelectric Capability and Forced and Other Scheduled Changes.

[3] Net Pacific Northwest Capacity less Northwest Peak Demand less approximately 1,335 MW of firm imports already under contract to California utilities during 2002 (declining to 935 MW by 2011).

[4] Represents the difference between the total import capability of 6,500 MW and firm imports already under contract to California utilities of approximately 1,535 MW during 2002 (which includes capacity under contract to DWR), declining to 935 MW by 2011.

[5] Equal to the lesser of Pacific Northwest Net Surplus (Short) and California Import Capability (Net).

Note: Totals may differ slightly due to rounding.

EXHIBIT 10
ESTIMATED GENERATING CAPACITY AVAILABLE FROM THE REMAINDER OF THE WECC
(MW)

	Calendar Year									
	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Remaining WECC Peak Demand	**34,907**	**35,894**	**36,844**	**37,839**	**38,838**	**39,614**	**40,507**	**41,604**	**42,534**	**43,461**
Remaining WECC Resources (Including Additions)	47,088	52,073	52,645	52,646	52,539	52,420	52,708	52,362	53,547	53,932
Derating Based on Forecast Hydroelectric Capability[1]	(689)	(574)	(574)	(574)	(574)	(574)	(574)	(574)	(574)	(574)
Allowance for Forced and Scheduled Outages	(2,107)	(2,356)	(2,385)	(2,385)	(2,379)	(2,373)	(2,388)	(2,370)	(2,430)	(2,449)
Net Remaining WECC Resources[2]	**44,292**	**49,143**	**49,686**	**49,687**	**49,585**	**49,472**	**49,746**	**49,417**	**50,543**	**50,909**
Remaining WECC Net Surplus (Short)[3]	**2,941**	**6,804**	**6,397**	**5,403**	**4,302**	**3,414**	**2,795**	**1,369**	**1,565**	**1,004**
California Import Capability[4]	3,076	3,076	3,076	3,076	3,876	3,876	3,876	4,776	4,776	4,776
Remaining WECC Surplus Available to Meet Residual Net Short[5]	**2,941**	**3,076**	**3,076**	**3,076**	**3,876**	**3,414**	**2,795**	**1,369**	**1,565**	**1,004**

Source: WECC reports and NCI.

[1] Hydroelectric capacity is based upon average water availability. Actual availability may be higher or lower based upon hydrological conditions and owner operations. Adjusted to account for below normal hydroelectric conditions for 2002.

[2] Remaining WECC Resources as adjusted for Forecast Hydroelectric Capability and Forced and Other Scheduled Outages.

[3] Net Remaining WECC Resources minus Remaining WECC Peak Demand minus approximately 6,444 MW of firm capacity already under contract to California utilities.

[4] Represents the difference between the total import capability of 9,520 MW during 2002 and approximately 6,444 MW of firm imports already under contract to California utilities. Includes changes in import capability associated with proposed future transmission improvements.

[5] Equal to the lesser of Remaining WECC Net Surplus (Short) and California Import Capability.

Note: Totals may differ slightly due to rounding.

EXHIBIT 11
ESTIMATED NET SHORT REQUIREMENTS – PG&E

	Calendar Year									
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Capacity[1] (MW)										
Peak Demand	16,906	17,207	17,502	17,783	18,038	18,296	18,557	18,805	19,057	19,313
Less: Incremental Conservation and Load Management[2]	26	-	-	-	-	-	-	-	-	-
Self-Generation	42	90	129	167	193	218	245	273	303	334
Direct Access	1,726	1,726	1,726	1,726	1,726	1,726	1,726	1,726	1,726	1,726
Peak Demand After Adjustments	**15,112**	**15,391**	**15,647**	**15,891**	**16,120**	**16,352**	**16,587**	**16,806**	**17,029**	**17,254**
Utility Retained Generation:										
IOU-Owned Generation[3]	5,530	5,685	5,685	5,685	5,346	5,346	5,346	5,346	5,346	5,346
QFs[3]	3,293	3,253	3,100	3,078	3,067	2,921	2,843	2,601	2,498	2,498
Bilateral Contracts	1,438	1,472	1,022	722	722	722	722	722	722	722
Total Utility Retained Generation	**10,260**	**10,410**	**9,806**	**9,485**	**9,134**	**8,988**	**8,911**	**8,668**	**8,566**	**8,566**
Net Short (Surplus)	**4,851**	**4,981**	**5,841**	**6,406**	**6,985**	**7,364**	**7,676**	**8,138**	**8,463**	**8,688**
DWR Contracts[4]	4,937	5,271	4,341	4,341	4,066	3,820	3,820	3,820	1,670	1,370
Residual Net Short (Surplus)	**(86)**	**(290)**	**1,501**	**2,065**	**2,920**	**3,544**	**3,856**	**4,319**	**6,794**	**7,319**
Energy[5] (GWh)										
Energy Requirements	84,694	86,253	87,773	89,226	90,530	91,849	93,190	94,463	95,758	97,075
Less: Incremental Conservation and Load Management[2]	193	-	-	-	-	-	-	-	-	-
Self-Generation	261	554	789	1,024	1,181	1,338	1,503	1,675	1,857	2,048
Direct Access	9,482	9,482	9,482	9,482	9,482	9,482	9,482	9,482	9,482	9,482
Energy Requirements After Adjustments	**74,758**	**76,217**	**77,503**	**78,721**	**79,867**	**81,029**	**82,206**	**83,306**	**84,419**	**85,546**
Utility Retained Generation:										
IOU-Owned Generation[3]	31,547	32,203	31,471	31,568	31,571	31,647	31,598	31,705	31,642	29,636
QFs[3]	21,926	21,616	20,365	20,076	19,959	18,806	18,130	16,042	15,199	14,211
Bilateral Contracts	(621)	(1,063)	(2,547)	2,375	2,582	2,582	2,582	2,582	2,582	2,582
Total Utility Retained Generation	**52,852**	**52,756**	**49,290**	**54,020**	**54,112**	**53,035**	**52,309**	**50,330**	**49,423**	**46,429**
Net Short (Surplus)	**21,906**	**23,461**	**28,213**	**24,701**	**25,756**	**27,994**	**29,896**	**32,976**	**34,997**	**39,117**
DWR Contracts[4]	18,702	21,836	22,114	22,945	22,660	22,853	23,338	23,741	5,513	3,793
Off-System Sales of Excess Contract Energy[6]	(1,934)	(2,706)	(1,674)	(3,359)	(2,883)	(2,162)	(1,749)	(805)	-	-
Residual Net Short (Surplus)	**5,138**	**4,331**	**7,773**	**5,115**	**5,978**	**7,303**	**8,308**	**10,041**	**29,484**	**35,324**

Source: Estimated peak demands and energy requirements obtained from PG&E. Adjustments to estimated peak demands and energy requirements developed by NCI.

[1] Capacity values represent July conditions (peak month). Exclude requirements associated with the Western contract.

[2] Estimated incremental reduction from the 20/20 Program (2002).

[3] Adjusted for hydroelectric derating, if appropriate, below normal hydroelectric conditions for 2002, and scheduled and forced outages.

[4] Adjusted for Customers within the IOU's respective service area.

[5] Energy values represent annual totals. Exclude requirements associated with the Western contract.

[6] Aggregate energy purchased under the DWR contracts in excess of the energy needed to meet the Customers' hourly residual net short requirements.

Note: Totals may differ slightly due to rounding.

EXHIBIT 12
ESTIMATED NET SHORT REQUIREMENTS – SCE

	Calendar Year									
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Capacity[1] (MW)										
Peak Demand	17,996	18,247	18,624	19,099	19,568	19,991	20,432	20,894	21,389	21,896
Less: Incremental Conservation and Load Management[2]	25	-	-	-	-	-	-	-	-	-
Self Generation	55	116	165	215	248	281	315	351	389	429
Direct Access	2,363	2,363	2,363	2,363	2,363	2,363	2,363	2,363	2,363	2,363
Peak Demand After Adjustments	**15,553**	**15,767**	**16,096**	**16,521**	**16,957**	**17,347**	**17,754**	**18,179**	**18,636**	**19,103**
Utility Retained Generation:										
IOU-Owned Generation[3]	4,417	4,464	4,464	4,464	4,464	4,464	4,464	4,464	4,464	4,464
QFs[3]	3,550	3,503	3,479	3,422	3,161	3,125	3,125	2,497	2,274	2,129
Bilateral Contracts	1,456	1,484	1,084	628	478	278	278	278	278	278
Total Utility Retained Generation	**9,424**	**9,450**	**9,027**	**8,514**	**8,102**	**7,866**	**7,866**	**7,239**	**7,016**	**6,871**
Net Short (Surplus)	**6,129**	**6,317**	**7,069**	**8,007**	**8,854**	**9,481**	**9,887**	**10,941**	**11,620**	**12,232**
DWR Contracts[4]	2,697	4,527	5,368	4,900	4,904	4,692	4,456	4,463	4,356	2,658
Residual Net Short (Surplus)	**3,432**	**1,790**	**1,701**	**3,107**	**3,951**	**4,789**	**5,431**	**6,477**	**7,264**	**9,574**
Energy[5] (GWh)										
Energy Requirements	85,986	87,268	89,141	91,470	93,754	95,821	97,971	100,226	102,639	105,114
Less: Incremental Conservation and Load Management[2]	188	-	-	-	-	-	-	-	-	-
Self Generation	335	712	1,014	1,316	1,518	1,720	1,932	2,154	2,387	2,633
Direct Access	12,942	12,942	12,942	12,942	12,942	12,942	12,942	12,942	12,942	12,942
Energy Requirements After Adjustments	**72,521**	**73,615**	**75,185**	**77,212**	**79,294**	**81,159**	**83,098**	**85,130**	**87,310**	**89,539**
Utility Retained Generation:										
IOU-Owned Generation[3]	32,614	32,678	32,313	33,513	32,107	32,700	33,080	31,844	32,099	32,900
QFs[3]	25,367	24,963	24,870	22,543	22,417	22,355	16,724	14,271	13,908	13,448
Bilateral Contracts	(298)	239	205	2,087	653	(83)	(80)	(83)	(83)	(83)
Total Utility Retained Generation	**57,683**	**57,881**	**57,388**	**58,142**	**55,176**	**54,973**	**49,723**	**46,032**	**45,924**	**46,266**
Net Short (Surplus)	**14,839**	**15,734**	**17,797**	**19,070**	**24,117**	**26,186**	**33,374**	**39,098**	**41,386**	**43,273**
DWR Contracts[4]	14,493	22,246	29,167	27,482	29,024	29,243	29,506	30,040	29,197	17,614
Off-System Sales of Excess Contract Energy[6]	(3,494)	(7,823)	(12,398)	(9,734)	(7,483)	(6,157)	(2,910)	(1,197)	(772)	(79)
Residual Net Short (Surplus)	**3,839**	**1,311**	**1,029**	**1,322**	**2,576**	**3,100**	**6,778**	**10,256**	**12,961**	**25,738**

Source: Estimated peak demands and energy requirements obtained from SCE. Adjustments to estimated peak demands and energy requirements developed by NCI.

[1] Capacity values represent August conditions (peak month).

[2] Estimated incremental reduction from the 20/20 Program (2002).

[3] Adjusted for hydroelectric derating, if appropriate, below normal hydroelectric conditions for 2002, and scheduled and forced outages.

[4] Adjusted for Customers within the IOU's respective service area.

[5] Energy values represent annual totals.

[6] Aggregate energy purchased under the DWR contracts in excess of the energy needed to meet the Customers' hourly residual net short requirements.

Note: Totals may differ slightly due to rounding.

EXHIBIT 13
ESTIMATED NET SHORT REQUIREMENTS – SDG&E

	Calendar Year									
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Capacity[1] (MW)										
Peak Demand	3,765	3,935	4,098	4,235	4,368	4,496	4,642	4,759	4,879	5,001
Less: Incremental Conservation and Load Management[2]	6	-	-	-	-	-	-	-	-	-
Self Generation	24	50	71	93	107	121	136	152	168	185
Direct Access	630	630	630	630	630	630	630	630	630	630
Peak Demand After Adjustments	**3,105**	**3,255**	**3,397**	**3,512**	**3,632**	**3,745**	**3,876**	**3,977**	**4,081**	**4,186**
Utility Retained Generation:										
IOU-Owned Generation[3]	409	409	409	409	409	409	409	409	409	409
QFs[3]	310	296	292	292	290	290	263	261	260	257
Bilateral Contracts	208	208	83	83	83	83	83	83	83	83
Total Utility Retained Generation	**926**	**912**	**783**	**783**	**781**	**781**	**754**	**753**	**751**	**748**
Net Short (Surplus)	**2,179**	**2,343**	**2,614**	**2,729**	**2,850**	**2,964**	**3,122**	**3,225**	**3,330**	**3,438**
DWR Contracts[4]	772	1,345	1,623	1,481	1,477	1,417	1,353	1,346	1,303	789
Residual Net Short (Surplus)	**1,407**	**997**	**991**	**1,248**	**1,373**	**1,548**	**1,770**	**1,879**	**2,027**	**2,649**
Energy[5] (GWh)										
Energy Requirements	19,261	20,177	21,034	21,755	22,452	23,121	23,882	24,495	25,124	25,771
Less: Incremental Conservation and Load Management[2]	47	-	-	-	-	-	-	-	-	-
Self Generation	126	307	437	568	655	742	833	929	1,030	1,136
Direct Access	3,731	3,731	3,731	3,731	3,731	3,731	3,731	3,731	3,731	3,731
Energy Requirements After Adjustments	**15,357**	**16,139**	**16,866**	**17,456**	**18,066**	**18,648**	**19,317**	**19,834**	**20,363**	**20,904**
Utility Retained Generation:										
IOU-Owned Generation[3]	3,371	3,370	3,222	3,521	3,157	3,309	3,351	3,083	3,079	3,355
QFs[3]	1,963	1,963	1,963	1,924	1,924	1,924	1,805	1,805	1,805	1,748
Bilateral Contracts	1,723	1,723	663	665	665	665	663	665	665	665
Total Utility Retained Generation	**7,057**	**7,056**	**5,848**	**6,110**	**5,746**	**5,898**	**5,820**	**5,554**	**5,550**	**5,768**
Net Short (Surplus)	**8,299**	**9,083**	**11,017**	**11,346**	**12,319**	**12,750**	**13,497**	**14,281**	**14,814**	**15,135**
DWR Contracts[4]	4,368	6,953	9,299	8,795	9,200	9,295	9,468	9,491	9,183	5,452
Off-System Sales of Excess Contract Energy[6]	(1)	(207)	(427)	(161)	(79)	(72)	(33)	(7)	(2)	-
Residual Net Short (Surplus)	**3,932**	**2,337**	**2,146**	**2,711**	**3,198**	**3,527**	**4,062**	**4,797**	**5,633**	**9,683**

Source: Estimated peak demands and energy requirements obtained from SDG&E. Adjustments to estimated peak demands and energy requirements developed by NCI.

[1] Capacity values represent August conditions (peak month).

[2] Estimated incremental reduction from the 20/20 Program (2002).

[3] Adjusted for hydroelectric derating, if appropriate, below normal hydroelectric conditions for 2002, and scheduled and forced outages.

[4] Adjusted for Customers within the IOU's respective service area.

[5] Energy values represent annual totals.

[6] Aggregate energy purchased under the DWR contracts in excess of the energy needed to meet the Customers' hourly residual net short requirements.

Note: Totals may differ slightly due to rounding.

EXHIBIT 14
ESTIMATED NET SHORT REQUIREMENTS – ALL IOUS

	Calendar Year									
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Capacity[1] (MW)										
Peak Demand	37,651	38,351	39,162	40,028	40,858	41,641	42,461	43,262	44,102	44,960
Less: Incremental Conservation and Load Management[2]	55	-	-	-	-	-	-	-	-	-
Self Generation	121	256	365	475	548	620	696	776	860	948
Direct Access	4,714	4,714	4,714	4,714	4,714	4,714	4,714	4,714	4,714	4,714
Peak Demand After Adjustments	**32,762**	**33,381**	**34,083**	**34,839**	**35,596**	**36,307**	**37,051**	**37,773**	**38,528**	**39,299**
Utility Retained Generation										
IOU-Owned Generation[3]	10,355	10,557	10,557	10,557	10,218	10,218	10,218	10,218	10,218	10,218
QFs[3]	7,152	7,051	6,870	6,792	6,517	6,335	6,231	5,359	5,032	4,884
Bilateral Contracts	3,102	3,164	2,189	1,433	1,283	1,083	1,083	1,083	1,083	1,083
Total Utility Retained Generation	**20,610**	**20,772**	**19,616**	**18,782**	**18,018**	**17,635**	**17,531**	**16,659**	**16,333**	**16,185**
Net Short (Surplus)	**12,151**	**12,609**	**14,467**	**16,057**	**17,578**	**18,672**	**19,520**	**21,113**	**22,196**	**23,114**
DWR Contracts[4]	8,407	11,143	11,332	10,721	10,446	9,928	9,628	9,628	7,328	4,817
Residual Net Short (Surplus)	**3,745**	**1,466**	**3,135**	**5,336**	**7,132**	**8,743**	**9,892**	**11,485**	**14,867**	**18,297**
Energy[5] (GWh)										
Energy Requirements	189,941	193,698	197,948	202,452	206,736	210,791	215,043	219,184	223,521	227,960
Less: Incremental Conservation and Load Management[2]	428	-	-	-	-	-	-	-	-	-
Self Generation	722	1,573	2,240	2,908	3,354	3,801	4,268	4,759	5,274	5,816
Direct Access	26,155	26,155	26,155	26,155	26,155	26,155	26,155	26,155	26,155	26,155
Energy Requirements After Adjustments	**162,636**	**165,971**	**169,553**	**173,389**	**177,227**	**180,835**	**184,620**	**188,270**	**192,093**	**195,989**
Utility Retained Generation										
IOU-Owned Generation[3]	67,532	68,251	67,006	68,601	66,834	67,656	68,029	66,632	66,819	65,891
QFs[3]	49,256	48,543	47,198	44,543	44,300	43,085	36,660	32,118	30,912	29,408
Bilateral Contracts	805	900	(1,678)	5,127	3,900	3,165	3,164	3,165	3,165	3,165
Total Utility Retained Generation	**117,593**	**117,693**	**112,526**	**118,272**	**115,035**	**113,906**	**107,853**	**101,915**	**100,896**	**98,464**
Net Short (Surplus)	**45,043**	**48,278**	**57,027**	**55,117**	**62,192**	**66,930**	**76,768**	**86,355**	**91,196**	**97,526**
DWR Contracts[4]	37,563	51,035	60,579	59,222	60,884	61,391	62,312	63,272	43,893	26,859
Off-System Sales of Excess Contract Energy[6]	(5,430)	(10,736)	(14,499)	(13,253)	(10,444)	(8,392)	(4,692)	(2,010)	(774)	(79)
Residual Net Short (Surplus)	**12,910**	**7,979**	**10,947**	**9,148**	**11,752**	**13,931**	**19,148**	**25,093**	**48,077**	**70,745**

Source: Estimated energy requirements obtained from the IOUs. Estimated July peak demands developed by NCI from data obtained from the IOUs. Adjustments to estimated peak demands and energy requirements developed by NCI.

[1] Capacity values represent July conditions (combined peak month) and therefore are less than the sum of the IOUs' individual peak demands.

[2] Estimated incremental reduction from the 20/20 Program (2002).

[3] Adjusted for hydroelectric derating, if appropriate, below normal hydroelectric conditions for 2002, and scheduled and forced outages.

[4] Adjusted for Customers within the IOUs' respective service area.

[5] Energy values represent annual totals.

[6] Aggregate energy purchased under the DWR contracts in excess of the energy needed to meet the Customers' hourly residual net short requirements.

Note: Totals may differ slightly due to rounding.

EXHIBIT 15
ESTIMATED CAPACITY FROM DWR CONTRACTS
(MW)

	Calendar Year									
	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Contract Capacity[1]										
SP 15										
Base Load[2]	740	1,610	2,080	2,400	2,850	2,850	2,850	2,850	2,850	2,250
Peak[3]	2,147	2,422	2,852	1,922	1,472	1,200	900	900	750	450
Dispatchable	549	1,780	2,015	2,015	2,015	2,015	2,015	2,015	2,015	704
Renewable/As-Available	33	60	44	44	44	44	44	44	44	44
Off-Peak[4]	200	200	200	-	-	-	-	-	-	-
Total SP 15	**3,469**	**5,872**	**6,991**	**6,381**	**6,381**	**6,109**	**5,809**	**5,809**	**5,659**	**3,448**
NP 15										
Base Load[2]	2,000	2,050	2,050	2,050	2,050	2,050	2,050	2,050	50	50
Peak[3]	923	1,003	828	828	778	550	550	550	400	400
Dispatchable	1,997	2,175	1,420	1,420	1,195	1,195	1,195	1,195	1,195	895
Renewable/As-Available	18	43	43	43	43	25	25	25	25	25
Off-Peak[4]	-	-	-	-	-	-	-	-	-	-
Total NP 15	**4,937**	**5,271**	**4,341**	**4,341**	**4,066**	**3,820**	**3,820**	**3,820**	**1,670**	**1,370**
Total Contract Capacity	**8,407**	**11,143**	**11,332**	**10,721**	**10,446**	**9,928**	**9,628**	**9,628**	**7,328**	**4,817**
Number of Contracts										
SP 15										
Base Load	6	6	6	5	4	4	4	4	4	3
Peak	10	7	7	5	3	3	3	3	3	2
Dispatchable	6	9	9	9	9	9	9	9	9	4
Renewable/As-Available	2	4	3	3	3	3	3	3	3	3
Off-Peak	1	1	1	-	-	-	-	-	-	-
Total SP 15	**25**	**27**	**26**	**22**	**19**	**19**	**19**	**19**	**19**	**12**
NP 15										
Base Load	5	4	3	3	3	3	3	3	1	1
Peak	5	4	2	2	1	1	1	1	1	1
Dispatchable	10	13	11	11	10	10	10	10	10	9
Renewable/As-Available	2	3	3	3	3	1	1	1	1	1
Off-Peak	-	-	-	-	-	-	-	-	-	-
Total NP 15	**22**	**24**	**19**	**19**	**17**	**15**	**15**	**15**	**13**	**12**

Source: DWR.

1 Peak loads can vary by area within the State and even by year. To maintain consistency, July, the most common month in which peak loads occur, has been used for all comparisons in this exhibit.

2 Base load contracts provide full capacity during all hours of all months during the year.

3 Peak contracts generally provide full capacity Monday through Saturday from hour ending 0700 through hour ending 2200 each month of the year. This grouping also includes a subset of contracts that provide full capacity seven days a week from hour ending 0700 through hour ending 2200 each month of the year, contracts that provide full capacity Monday through Friday from hour ending 0700 through hour ending 2200, and the CPA Contract.

4 Off-peak contracts provide full capacity during those hours not generally defined as peak (Monday through Saturday from hour ending 0700 through hour ending 2200 each month of the year). Off-peak capacity amounts are not added to total peak capacity.

Note: Totals may differ slightly due to rounding.

EXHIBIT 16
ESTIMATED ENERGY FROM DWR CONTRACTS
(GWH)

	Calendar Year									
	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Energy										
SP 15										
Base Load[1]	5,948	11,110	17,247	20,050	23,992	23,991	24,879	24,876	24,876	16,969
Peak[2]	9,736	10,416	12,494	7,664	5,419	5,419	4,295	4,295	3,980	1,695
Dispatchable	2,057	6,393	7,582	8,179	8,429	8,744	9,417	9,975	9,141	4,055
Renewable/As-Available	365	524	384	384	384	384	384	384	384	348
Off-Peak[3]	756	757	758	-	-	-	-	-	-	-
Total SP 15	**18,862**	**29,200**	**38,466**	**36,277**	**38,224**	**38,538**	**38,975**	**39,531**	**38,381**	**23,066**
NP 15										
Base Load[1]	11,888	15,831	17,869	17,869	17,869	17,866	17,872	17,869	346	346
Peak[2]	4,266	2,735	2,103	2,419	2,176	2,176	2,176	2,176	1,860	1,583
Dispatchable	2,457	2,915	1,786	2,300	2,257	2,576	3,065	3,470	3,079	1,636
Renewable/As-Available	91	354	354	354	354	230	219	219	219	219
Off-Peak[3]	-	1	2	3	4	5	6	7	8	9
Total NP 15	**18,702**	**21,836**	**22,114**	**22,945**	**22,660**	**22,853**	**23,338**	**23,741**	**5,513**	**3,793**
Total Energy	**37,563**	**51,035**	**60,579**	**59,222**	**60,884**	**61,391**	**62,312**	**63,272**	**43,893**	**26,859**
Number of Contracts										
SP 15										
Base Load	6	6	6	5	4	4	4	4	4	3
Peak	10	8	7	5	3	3	3	3	3	2
Dispatchable	6	10	9	9	9	9	9	9	9	6
Renewable/As-Available	4	4	3	3	3	3	3	3	3	3
Off-Peak	1	1	1	-	-	-	-	-	-	-
Total SP 15	**27**	**29**	**26**	**22**	**19**	**19**	**19**	**19**	**19**	**14**
NP 15										
Base Load	6	4	3	3	3	3	3	3	1	1
Peak	5	4	2	2	1	1	1	1	1	1
Dispatchable	10	13	11	11	10	10	10	10	10	10
Renewable/As-Available	3	3	3	3	3	2	1	1	1	1
Off-Peak	-	-	-	-	-	-	-	-	-	-
Total NP 15	**24**	**24**	**19**	**19**	**17**	**16**	**15**	**15**	**13**	**13**

Source: DWR.

1 Base load contracts provide energy during all hours of all months during the year.

2 Peak contracts generally provide energy Monday through Saturday from hour ending 0700 through hour ending 2200 each month of the year. This grouping also includes a subset of contracts that provide energy seven days a week from hour ending 0700 through hour ending 2200 each month of the year, contracts that provide energy Monday through Friday from hour ending 0700 through hour ending 2200, and the CPA Contract.

3 Off-peak contracts provide energy during those hours not generally defined as peak (Monday through Saturday from hour ending 0700 through hour ending 2200 each month of the year).

Note: Totals may differ slightly due to rounding.

EXHIBIT 17
ESTIMATED RESOURCES AVAILABLE TO MEET NET SHORT AND RESIDUAL NET SHORT
(MW)

	Calendar Year									
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Resources Available for Net Short[1]										
Existing Non-Utility Generation (Net)[2]	14,851	14,959	14,298	14,376	14,604	14,787	14,841	14,749	15,058	15,036
New Generation (Net)	1,743	6,332	7,070	7,805	7,805	8,393	8,393	8,860	11,680	11,974
Capacity Available from PNW Imports	5,165	5,165	5,165	5,465	5,465	5,565	5,565	5,565	5,565	5,565
Capacity Available from Southwest Imports	2,941	3,076	3,076	3,076	3,876	3,414	2,795	1,369	1,565	1,004
Governmental Net Surplus (Short)	850	1,056	836	611	383	151	(109)	(368)	(813)	(1,276)
Total Resources Available for Net Short	**25,550**	**30,588**	**30,444**	**31,333**	**32,133**	**32,310**	**31,484**	**30,175**	**33,055**	**32,303**
DWR Contract Resources[3]										
Existing Non-Utility Generation	7,023	7,999	8,085	7,475	7,376	6,873	6,573	6,573	5,134	3,815
New Generation	1,184	2,944	2,947	2,947	2,770	2,756	2,756	2,756	1,894	1,003
PNW Imports	200	200	300	300	300	300	300	300	300	0
Total DWR Contract Resources	**8,407**	**11,143**	**11,332**	**10,721**	**10,446**	**9,928**	**9,628**	**9,628**	**7,328**	**4,817**
Resources Available for Residual Net Short[4]										
Existing Non-Utility Generation (Net)	7,828	6,961	6,213	6,902	7,228	7,914	8,268	8,176	9,924	11,221
New Generation (Net)	560	3,388	4,123	4,858	5,034	5,637	5,637	6,104	9,786	10,972
Capacity Available from PNW Imports	4,965	4,965	4,865	5,165	5,165	5,265	5,265	5,265	5,265	5,565
Capacity Available from Southwest Imports	2,941	3,076	3,076	3,076	3,876	3,414	2,795	1,369	1,565	1,004
Governmental Net Surplus (Short)	850	1,056	836	611	383	151	(109)	(368)	(813)	(1,276)
Total Available for Residual Net Short	**17,143**	**19,446**	**19,112**	**20,612**	**21,687**	**22,382**	**21,856**	**20,547**	**25,727**	**27,486**
Estimated Residual Net Short[5]	**3,745**	**1,466**	**3,135**	**5,336**	**7,132**	**8,743**	**9,892**	**11,485**	**14,867**	**18,297**

Source: NCI.

1 Derived from Exhibit 7. Includes resources committed under the DWR contracts. Adjustments have been made, where appropriate for allowances for forced and scheduled outages and hydroelectric deratings.

2 Direct access loads have been subtracted from total net existing non-utility generation.

3 Sources of capacity under contract to DWR.

4 Capacity resources estimated to be available to meet the residual net short, after subtracting resources committed under the DWR contracts. Availability of these resources will be influenced by unplanned outages, transmission availability, willingness of the seller to make the resource available, and the willingness of DWR (through December 31, 2002) or the IOUs (after December 31, 2002) to acquire the resources at the price and under the conditions offered.

5 From Exhibit 14.

Note: Totals may differ slightly due to rounding.

EXHIBIT 18
SUMMARY OF KEY INPUTS AND ASSUMPTIONS FOR WECC MARKET SIMULATION

Category	Assumption
Study Period	January 2002 through December 2011.
Load Forecast	From the EIA-411 filings of the WECC, except for IOU forecasts, which were developed as described elsewhere in this Report.
Load Profiles	Derived from hourly Edison Electric Institute load data files for each utility from the FERC web site.
Existing Resources	From the WECC EIA-411 filings.
Pacific Northwest Hydro	BPA 2000 Pacific Northwest Loads and Resources Study used to calculate monthly capacity and energy values for each hydroelectric station in the region, choosing median conditions from a recorded database of 50 years. Amounts derated during 2002, as described in the Report.
California Hydro	WECC Coordinated Bulk Power Supply report for summer and winter capacity ratings for existing hydro resources. Amounts derated during 2002, as described in the Report.
Resource Retirements	No nuclear retirements at license expiration.
Gas Prices	Ten-year projection of delivered gas prices by NCI fuel specialists.
Coal and Oil Prices	Ten-year projection of delivered coal and oil prices by NCI fuel specialists.
O&M Costs	Historical, power plant-specific, non-fuel operation and maintenance ("O&M") costs reported by utilities to FERC, averaged and normalized to develop average starting O&M costs.
	Amounts allocated between fixed and variable O&M costs. Both fixed and variable O&M costs are assumed to escalate with inflation.
Thermal Resource Models	Multi-segment incremental heat rate curves.
	Fixed and variable O&M costs.
	Scheduled outages based on annual maintenance cycles.
	Random forced outages based on unit-forced outage rates.
Contracts	Known firm purchase/sales reported in the WECC Form OE-411 filing.
	Transactions are reflected in the load requirements of the buying and selling utilities, in transactions between regions, and by adjusting the transmission capacity.
	Transmission capacity between zones required for these transactions is assumed to have priority. Any remaining transmission capacity is used to facilitate additional power transactions between regions, based on economic dispatch and delivery over the remaining transmission capacity.
Thermal Resource Commitment and Dispatch	Unit commitment order determined by marginal operating cost (fuel and variable O&M costs).
	Commitment determined to satisfy load plus spinning reserve.
Transmission Model	Transmission system and constraints represented using transport model across regions.
Market Structure	Assumed open market across all the regions (region-wide dispatch).
	Energy interchange between regions occurs when spot price differentials exceed transmission tariff costs.

Source: NCI.

EXHIBIT 19
DWR POWER PURCHASE PROGRAM ESTIMATED OPERATING RESULTS
(MILLIONS OF DOLLARS)

	Calendar Year									
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
POWER CHARGE ACCOUNTS[1]										
Beginning Balance in Power Charge Accounts										
Operating Account	$ 2,574	$ 1,228	$ 1,745	$ 1,674	$ 1,787	$ 1,784	$ 1,790	$ 1,789	$ 1,785	$ 1,790
Priority Contract Account	-	-	-	-	-	-	-	-	-	-
Operating Reserve Account	-	777	777	777	777	777	777	777	777	777
Total Beginning Balance in Power Charge Accounts	**$ 2,574**	**$ 2,005**	**$ 2,522**	**$ 2,451**	**$ 2,565**	**$ 2,561**	**$ 2,568**	**$ 2,566**	**$ 2,563**	**$ 2,568**
Revenues for Retail Revenue Requirements										
Power Charges[2]	$ 4,667	$ 4,648	$ 4,266	$ 4,272	$ 4,140	$ 4,227	$ 4,353	$ 4,542	$ 3,594	$ 2,530
Other Power Charge Account Revenues[3]	137	188	271	251	219	195	154	107	84	74
Total Revenues for Retail Revenue Requirements	**$ 4,803**	**$ 4,836**	**$ 4,537**	**$ 4,523**	**$ 4,358**	**$ 4,422**	**$ 4,508**	**$ 4,649**	**$ 3,678**	**$ 2,604**
Retail Revenue Requirements										
Power Costs[4]	$ 4,446	$ 4,120	$ 4,422	$ 4,129	$ 4,027	$ 4,046	$ 4,094	$ 4,170	$ 3,199	$ 2,065
Ancillary Services	146	170	158	250	304	338	382	450	440	491
Administrative and Overhead	45	28	29	30	31	31	32	33	34	35
Total Retail Revenue Requirements	**$ 4,638**	**$ 4,319**	**$ 4,608**	**$ 4,409**	**$ 4,362**	**$ 4,415**	**$ 4,509**	**$ 4,652**	**$ 3,673**	**$ 2,591**
Net Operating Revenues	**$ 165**	**$ 517**	**$ (71)**	**$ 113**	**$ (3)**	**$ 6**	**$ (1)**	**$ (4)**	**$ 5**	**$ 13**
Net Transfers to Bond Charge Accounts[5]	$ (155)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Debt Service (Other Than Bonds)[6]	(579)	-	-	-	-	-	-	-	-	-
Net Revenues for Power Charge Accounts	**$ (568)**	**$ 517**	**$ (71)**	**$ 113**	**$ (3)**	**$ 6**	**$ (1)**	**$ (4)**	**$ 5**	**$ 13**
Ending Aggregate Balance in Power Charge Accounts	**$ 2,005**	**$ 2,522**	**$ 2,451**	**$ 2,565**	**$ 2,561**	**$ 2,568**	**$ 2,566**	**$ 2,563**	**$ 2,568**	**$ 2,581**

EXHIBIT 19
DWR POWER PURCHASE PROGRAM ESTIMATED OPERATING RESULTS
(MILLIONS OF DOLLARS)
(CONTINUED)

	Calendar Year									
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
BOND CHARGE ACCOUNTS										
Beginning Balance in Bond Charge Accounts										
Bond Charge Collection Account	$ -	$ 56	$ 238	$ 246	$ 232	$ 221	$ 209	$ 196	$ 182	$ 168
Bond Charge Payment Account	-	269	622	633	645	657	669	682	696	711
Debt Service Reserve Account	-	974	974	974	974	974	974	974	974	974
Total Beginning Balance in Bond Charge Accounts	**$ -**	**$ 1,298**	**$ 1,834**	**$ 1,852**	**$ 1,851**	**$ 1,852**	**$ 1,852**	**$ 1,852**	**$ 1,852**	**$ 1,852**
Revenues for Bond-Related Costs										
Bond Charges	$ 6	$ 1,140	$ 945	$ 924	$ 925	$ 925	$ 925	$ 926	$ 926	$ 926
Bond Proceeds (Net)[7]	1,184	-	-	-	-	-	-	-	-	-
Interest Earnings[8]	-	27	49	51	51	50	50	50	50	50
Total Revenues for Bond-Related Costs	**$ 1,190**	**$ 1,167**	**$ 994**	**$ 975**	**$ 976**	**$ 976**	**$ 976**	**$ 976**	**$ 976**	**$ 976**
Bond-Related Costs[9]	$ 47	$ 632	$ 976	$ 976	$ 976	$ 976	$ 976	$ 976	$ 976	$ 976
Net Transfers from Power Charge Accounts[5]	155	-	-	-	-	-	-	-	-	-
Net Bond Charge Account Revenues	**$ 1,298**	**$ 536**	**$ 18**	**$ (1)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Ending Aggregate Balance in Bond Charge Accounts	**$ 1,298**	**$ 1,834**	**$ 1,852**	**$ 1,851**	**$ 1,852**	**$ 1,852**	**$ 1,852**	**$ 1,852**	**$ 1,852**	**$ 1,852**

Source: NCI.

[1] Prior to issuance of the Bonds, includes entire Electric Power Fund.

[2] For 2002, reflects Power Charges established through the Rate Order. For the remainder of the Study Period, values are estimated.

[3] Represents revenues from wholesale energy sales to off-system customers and interest earnings on Power Charge Accounts.

[4] Represents all power purchases made by DWR to meet the net short requirements of the Customers. After December 31, 2002, the IOUs are assumed to have responsibility for the purchases of residual net short power.

[5] Transfers from the Power Charge Accounts to the Bond Charge Accounts are planned in 2002 to cover Bond-Related Costs as Bond Charges are initially implemented.

[6] Represents interest payments that DWR is obligated to make on the Interim Borrowing and General Fund Loans that are outstanding.

[7] Represents proceeds from the sale of the Bonds that are deposited to the Bond Charge Accounts.

[8] Represents interest earnings on Bond Charge Accounts.

[9] Includes net debt service on the Bonds, credit enhancement and liquidity facility charges, and related costs.

Note: Totals may differ slightly due to rounding. All values shown on a cash basis.

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APPENDIX I
SUMMARY OF DWR CONTRACTS

This appendix provides a summary description of DWR's long-term power supply contract portfolio. The contracts described below are listed alphabetically by supplier and are segregated between those that are Priority Long Term Power Contracts and those that are not. The relative size or importance of any contract should not be inferred from the order in which it is presented. The descriptions below do not purport to be comprehensive and are qualified in all respects to the full text of the actual contracts, which are available upon written request to DWR upon the payment of a reproduction fee. These descriptions of contracts are for the form of the contracts as they exist as of August 23, 2002. DWR is in negotiation with some of the contract counter parties to modify the terms of the contracts, which could result in changes in quantity, price, product, or term of the contracts from that described herein.

As used in this appendix, the following terms have the following general meanings. A "unit-contingent" contract is generally one in which the supplier's obligation to deliver power is conditioned upon the operation of a particular generating facility. A "firm" contract is generally one in which the supplier's obligation to deliver power is not conditioned upon the operation of the generating facility. However, a "firm" obligation may be excused by other causes, such as a natural disaster or labor difficulties. "Base load" in the context of this section generally means power for delivery seven days per week, 24 hours per day. "Peaking power" or power for delivery during "peak hours" generally refers to power for delivery during peak periods in the daily or weekly cycle of electricity demand. A common definition for "peak hours" is from 6:00 a.m. to 10:00 p.m., Monday through Saturday. "Off-peak hours" generally refers to the periods during a day that are not peak hours, and all hours on Sundays and holidays. "Seasonally-shaped" generally means varying according to season. "Dispatchable" power is power that may be purchased according to demand, often with advance notice.

PRIORITY LONG TERM POWER CONTRACTS

Priority Long Term Power Contracts are contracts (and fuel contracts) entered into by DWR in connection with its power supply program that provide, in effect, that payments by DWR under the contracts are to be paid or are payable prior to bonds, notes, or other indebtedness of DWR secured by a pledge or assignment of the revenues of DWR under the Act and other amounts in the Electric Power Fund. Priority Long Term Power Contracts in effect as of August 23, 2002, are summarized below.

Allegheny Energy Supply Company, LLC. This supplier has entered into two long-term power supply contracts with DWR. The first is a unit-contingent contract providing for 250 MW of base load power through 2003, 500 MW during 2004, and 1,000 MW from 2005 through 2011, all at a fixed price of $61 per MWh. The second is a firm contract providing for 150 MW of peaking power in 2003 at a fixed price of $76 per MWh.

Alliance Colton LLC. This supplier has entered into a unit-contingent contract providing for 80 MW of power through 2010, during the months of June through October only. The supplier is entitled to an average capacity payment of $17.9 million annually, plus the actual costs of fuel.

CalPeak Power Border LLC. This supplier has entered into a unit-contingent contract providing for 48 MW of dispatchable peaking power through October 2011, dispatchable for a limited number of hours each year. The supplier is entitled to seasonally-shaped capacity payments totaling $120 per kW-yr. less $150,000, plus variable operation and maintenance costs at $5 per MWh and actual fuel costs.

CalPeak Power El Cajon LLC. This supplier has entered into a unit-contingent contract providing for 48 MW of dispatchable peaking power through 2011, dispatchable for a limited number of hours each year. The supplier is entitled to seasonally-shaped capacity payments totaling $120 per kW-yr. less $150,000, plus variable operation and maintenance costs at $5 per MWh and actual fuel costs.

CalPeak Power Enterprise LLC. This supplier has entered into a unit-contingent contract providing for 48 MW of dispatchable peaking power through October 2011, dispatchable for a limited number of hours each year. The supplier is entitled to seasonally-shaped capacity payments totaling $120 per kW-yr. less $150,000, plus variable operation and maintenance costs at $5 per MWh and actual fuel costs.

CalPeak Power Midway LLC. This supplier has entered into a unit-contingent contract providing for 49 MW of dispatchable peaking power through May 2012, dispatchable for a limited number of hours each year. The supplier is entitled to seasonally-shaped capacity payments totaling $120 per kW-yr, plus variable operation and maintenance costs at $5 per MWh and actual fuel costs.

CalPeak Power Panoche LLC. This supplier has entered into a unit-contingent contract providing for 50 MW of dispatchable peaking power through 2011, dispatchable for a limited number of hours each year. The supplier is entitled to seasonally-shaped capacity payments totaling $120 per kW-yr. less $150,000, plus variable operation and maintenance costs at $5 per MWh and actual fuel costs.

CalPeak Power Vaca Dixon LLC. This supplier has entered into a unit-contingent contract providing for 48 MW of dispatchable peaking power through 2011, dispatchable for a limited number of hours each year. The supplier is entitled to seasonally-shaped capacity payments totaling $120 per kW-yr. less $150,000, plus variable operation and maintenance costs at $5 per MWh and actual fuel costs.

Calpine Energy Services, L.P. This supplier has entered into two firm power supply contracts with DWR. The first provides for (i) 350 MW of base load power through 2002, 600 MW during 2003, and 1,000 MW from 2004 through 2009, all at a fixed price of $58.60 per MWh; and (ii) 400 to 650 MW of dispatchable power during peak hours and an additional 400 MW of dispatchable power during off-peak hours through the end of 2003, at a variable operation and maintenance cost of $1.50 per MWh, plus fuel costs and a capacity charge of $12.50 per kW-mo. The second contract provides for (i) 1,000 MW of base load power through 2009 at a fixed price of $59.60 per MWh; and (ii) 500 MW of dispatchable power during peak hours through the end of 2002, as well as during June through September of 2003, and 400 MW of off-peak, dispatchable power through 2003, at a variable operation and maintenance cost of $1.50 per MWh, plus fuel costs and a capacity charge of $12.50 per kW-mo.

This supplier has also entered into two unit-contingent contracts with DWR. The first contract provides for 495 MW of dispatchable power through July 2011, dispatchable for up to 2,000 peak hours per year, for capacity charges varying from $162 to $182 per kW-yr (with potential reductions to $120 per kW-yr), plus variable operation and maintenance costs at $4 per MWh and fuel costs. The second contract provides for 180 MW of power from January 2003 through March 2004, dispatchable for up to 4,000 peak hours per year, for a capacity payment of $240 per kW-yr, plus variable operation and maintenance costs of $4 per MWh and actual fuel costs; then 225 MW of power from April 2004 through the end of 2005, also dispatchable for up to 4,000 peak hours per year, for a capacity payment ranging from $192 to $216 per kW-yr, plus variable operation and maintenance costs of $4 per MWh and actual fuel costs.

Constellation Power Source, Inc. This supplier has entered into a firm contract that provides for 200 MW of power during peak hours through June 2003 at a fixed price of $154 per MWh and 400 MW of base load power through October 2002 and during May through October 2003 at a fixed price of $55 per MWh.

Coral Power, LLC. This supplier has entered into a firm contract providing for 100 MW of seasonally-shaped base load power through June 2012, between 300 and 400 MW of seasonally-shaped power during peak hours through June 2010, and 100 MW of seasonally-shaped power during peak hours from July 2010 through June 2012. DWR is to pay a capacity payment of $1.79 million per month through 2005, plus energy costs ranging from $73 to $169 per MWh through 2005, and energy costs of $25 per MWh plus fuel costs from 2006 forward. This contract also gives the supplier the right to sell additional blocks of peaking power of 175 MW from July 2003 through June 2012 and 175 MW from July 2004 through June 2012.

Dynegy Power Marketing, Inc. This supplier has entered into a firm contract providing for 200 MW of base load power and an additional 600 MW of power during peak hours through 2004, all at a fixed energy cost of $119.50 per MWh. This contract also provides for "system-contingent" power as follows: (i) 500 MW of power during peak hours through 2004, with rights to an additional 1,000 MW on a day-ahead basis; and (ii) 200 MW of off-peak power through 2004, with rights to an additional 1,300 MW on a day-ahead basis, at a cost of $20.25 per MWh, plus variable operation and maintenance costs averaging approximately $1.45 per MWh, fuel costs, emissions costs, and start-up costs.

El Paso Merchant Energy. This supplier has entered into a firm contract providing for 100 MW of power during peak hours through 2005. Of this total, 50 MW is to be available south of Path 15 at a fixed cost of $115 per MWh and 50 MW is to be available north of Path 15 at a fixed cost of $127 per MWh.

GWF Energy LLC. This supplier has entered into a unit-contingent contract providing for 176 MW increasing to 340 MW of power dispatchable at any time during the year except in April or May for up to 2,000 hours per year through 2011 (164 MW continuing through October, 2012). DWR is to pay capacity payments averaging $177 per kW-yr, plus variable operation and maintenance costs of $5 per MWh and actual fuel costs.

High Desert Power Project. This supplier has entered into a unit contingent contract providing for 840 MW of dispatchable power for up to all hours in a year through March 2011. DWR is to pay capacity payments of $12.1 million per month, plus variable operating costs of $2.25 per MWh and fuel costs.

Mirant Americas Energy Marketing LP. This supplier has entered into a firm contract providing for 500 MW of power during peak hours through 2002, at a fixed price of $148.65 per MWh.

Morgan Stanley Capital Group. This supplier has entered into a firm contract providing for 50 MW of base load power through 2005, at a fixed price of $95.50 per MWh.

PacifiCorp. This supplier has entered into a contract providing for 200 MW of firm base load power (subject to an outage allowance) through 2002 at a fixed price of $70 per MWh and up to between 200 to 300 MW of unit-contingent power at peak and/or off-peak hours (pursuant to monthly DWR supply election) from January 2003 through June 2011, for capacity payments of $15 per kW-mo, fixed operating expense payments of $1.75 per kW-mo, variable operation and maintenance costs of $3.50 per MWh, actual fuel costs, and other charges.

PG&E Trading. This supplier has entered into a contract providing for 66 MW of wind power on an "as available" basis through September 2011, at a fixed price of $58.50 per MWh, plus CAISO charges.

Sempra Energy Resources. This supplier has entered into a contract providing for deliveries of unit-contingent power of 150 to 220 MW of base load through May 2003 and 300 MW of peaking power through September 2002, at fixed prices ranging from $69 to $160 per MWh and deliveries of firm power, subject to the generating units achieving commercial operation, of 800 to 1,200 MW of base load power and 350 to 700 MW of power during peak hours from June 2003 through September 2011, at prices ranging from $26 to $31 per MWh, plus fuel charges.

Sunrise Power Company, LLC. This supplier has entered into a unit-contingent contract providing for 325 MW of dispatchable power, subject to limitations, through February 2003, for seasonally-shaped capacity payments averaging $120 per kW-yr., plus variable operation and maintenance costs of $3 per MWh and fuel and other costs. The contract also provides for 560 MW of dispatchable power from August 2003 through 2012, with similar pricing terms except an increase of the average capacity payment to $180 per kW-yr.

(Wellhead) Fresno Congestion Partners. This supplier has entered into a unit-contingent contract providing for 21 MW of power dispatchable during peak hours, subject to limitations, through October 2011, for capacity payments averaging $110 per kW-yr., plus variable operation and maintenance costs of $12 per MWh and fuel and other costs.

Wellhead Power, LLC (Gates Project). This supplier has entered into a unit-contingent contract providing for 46 MW of power dispatchable during peak hours, subject to limitations, through October 2011, for capacity payments averaging $110 per kW-yr., plus variable operation and maintenance costs of $12 per MWh and fuel and other costs.

Wellhead Power, LLC (Panoche Project). This supplier has entered into a unit-contingent contract providing for 50 MW of power dispatchable during peak hours, subject to limitations, through October 2011, for capacity payments averaging $110 per kW-yr., plus variable operation and maintenance costs of $12 per MWh and fuel and other costs.

Whitewater Energy Trading (Cabazon Project). This supplier has entered into a contract providing for 43 MW of power on an "as available" basis through 2013 at a fixed price of $54 per MWh.

Whitewater Energy Trading (Whitewater Hill Project). This supplier has entered into a contract providing for 65 MW of power on an "as available" basis through 2013 at a price ranging from $40 to $54 per MWh.

Williams Energy Marketing & Trading. This supplier has entered into a unit-contingent contract providing for an average of 70 MW of base load power through 2005, ramping up to 600 MW of base load power from 2006 through 2010, all at a fixed price of $62.50 per MWh. This contract also provides for additional unit-contingent power during peak hours, increasing from 360 MW to 700 MW of capacity from 2002 through 2005, then 300 MW of capacity during 2006 through 2010, at prices ranging from $62.50 to $87 per MWh. This supplier may also sell up to an additional 500 MW of peak hour power, decided on a monthly basis, from 2003 through 2010.

OTHER POWER SUPPLY CONTRACTS

The following contracts do not qualify as Priority Long Term Power Contracts.

Capitol Power, Inc. This supplier has entered into a unit-contingent contract providing for 15 MW of base load power through 2006 for a fixed price of $87 per MWh.

Clearwood Electric Company, LLC. This supplier has entered into a unit-contingent contract providing for 25 MW of base load power through May 2012 for a fixed price of $67.40 per MWh.

Imperial Valley Resource Recovery, LLC. This supplier has entered into a firm contract providing for 16 MW of base load power through 2003, at an average fixed price of $92.50 per MWh.

InterCom. This supplier has entered into a firm contract providing for 200 MW of power during peak hours through August 2003, at a fixed price of $45 per MWh.

Santa Cruz County (California). This supplier has entered into a unit-contingent contract providing for 3 MW of base load power through June 2007, at a fixed price of $65 per MWh.

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APPENDIX II
UTILITY-RETAINED GENERATION

Presented below is a summary description of the generating and power supply resources owned by the IOUs or available through contracts with other power suppliers.

IOU-OWNED GENERATION

As shown in Table II-1, IOU-Owned Generation totals approximately 12,025 MW of generating capacity. These facilities consist of nuclear, hydroelectric, and thermal resources, with approximately 9,840 MW of the generating capability of these facilities located within California.

TABLE II-1
IOU-OWNED GENERATION RESOURCES
(MW)

Fuel Type	PG&E	SCE	SDG&E	Total
Coal	-	1,595	-	1,595
Gas	579	-	-	579
Hydro	3,890	1,158	-	5,048
Diesel	-	9	-	9
Nuclear	2,160	2,204	430	4,794
Total	**6,629**	**4,966**	**430**	**12,025**

Source: IOU Form 10-K filings with the U.S. Securities and Exchange Commission for 2001 and information obtained from the CEC.

Nuclear Generation

The IOUs have retained all of their nuclear resources. These resources consist of (i) Diablo Canyon, which is wholly owned by PG&E (2,160 MW); (ii) San Onofre, which is operated by SCE and owned in part by SCE and SDG&E (1,614 MW and 430 MW, respectively); and (iii) Palo Verde, which is partially owned by SCE (590 MW).

Diablo Canyon. The Diablo Canyon facility includes two Westinghouse pressurized water reactors and is located near the town of San Luis Obispo, California. Diablo Canyon Unit 1 is rated at 1,073 MW and began commercial operation in May 1985 under an NRC license that expires in September 2021. The second unit, Diablo Canyon Unit 2, is rated at 1,087 MW and began commercial operation in March 1986 under an NRC license that expires in April of 2025.

San Onofre. The San Onofre facility consists of two Combustion Engineering pressurized water reactors and is located near the Pacific Ocean near the town of San Clemente, California. SCE owns 75.05 percent of the plant and is responsible for its operation. Other plant owners are SDG&E (20.00 percent), City of Anaheim Public Utilities Department (3.16 percent) and City of Riverside Utilities Department (1.79 percent). The first unit, San Onofre Unit 2, is rated at 1,070 MW and began operation in September 1982 under an NRC license that expires in 2022. The second unit, San Onofre Unit 3, is rated at 1,080 MW and began operation in September 1983 under an NRC license that expires in 2022. San Onofre Unit 1 is the original nuclear unit on-site and was permanently closed in 1992.

Palo Verde. The Palo Verde facility consists of three Combustion Engineering pressurized water reactors located west of Phoenix, Arizona. SCE owns 15.8 percent of the facility. Other owners of Palo Verde are Arizona Public Service ("APS") (29.1 percent), Salt River Project (17.5 percent), El

Paso Electric (15.8 percent), Public Service Company of New Mexico (10.2 percent), Southern California Public Power Authority (5.9 percent) and LADWP (5.7 percent). The first unit, Palo Verde Unit 1, is rated at 1,243 MW and began operation in 1986 under an NRC license that expires in 2024. Palo Verde Unit 2 is also rated at 1,243 MW and began operation in 1986 under an NRC license that expires in 2025. Palo Verde Unit 3 is rated at 1,247 MW and began operation in 1988 under an NRC license that expires in 2027.

During recent years, Diablo Canyon and Palo Verde have operated at levels in excess of industry averages. Over the calendar year 1997 through 2001 period, Diablo Canyon Unit 1 and Diablo Canyon Unit 2 operated at average annual capacity factors of 90.3 percent and 92.0 percent, respectively. During this same period, Palo Verde Unit 1, Palo Verde Unit 2, and Palo Verde Unit 3 operated at average annual capacity factors of 92.4 percent, 90.0 percent, and 91.6 percent, respectively. San Onofre Unit 2 and San Onofre Unit 3 operated at average annual capacity factors of 93.4 percent and 83.6 percent, respectively, during the calendar year 1997 through 2001 period. The lower capacity factor for San Onofre Unit 3 was the result of an extended outage caused by a fire in the non-nuclear portion of the plant during February 2001.

In comparison to the above operating statistics, the average industry-wide capacity factor over this same three-year period was 89.0 percent.

The NRC performs safety performance reviews at all nuclear plants in the United States through an integrated assessment of plant performance. The reviews consist of quarterly performance indicators and NRC inspection findings. Under current procedures, the NRC monitors seven cornerstones of safety to generate information about the safety significance of plant operations: (i) initiating events; (ii) mitigating systems; (iii) barrier systems; (iv) emergency preparedness; (v) occupational radiation safety; (vi) public radiation safety; and (vii) physical protection. In 2001 and within the first quarter of 2002, the NRC conducted inspections at Diablo Canyon, San Onofre, and Palo Verde. The NRC generally classified performance at Diablo Canyon, San Onofre, and Palo Verde as within an expected performance level in which the performance indicators are met, the NRC best rating level. In March 2002, the NRC informed the management of each facility that the plants had been performing at levels requiring no additional NRC oversight. Therefore, the NRC will only conduct baseline inspections of the facilities during the remainder of 2002.

In general within the industry, steam generators at pressurized water reactors have been experiencing corrosion and mechanically induced degradation. The nuclear industry conducts eddy-current testing of steam generator tubes during refueling outages and seals or sleeves tubes with defects. Steam generators are sometimes chemically cleaned during outages. Defective tubes at Diablo Canyon, San Onofre, and Palo Verde Unit 1 and Unit 3 have been sealed, where necessary, and the respective owners expect the existing steam generators to last through the end of the current license periods. SCE has advised NCI that the steam generator at Palo Verde 2 is expected to be replaced during 2003.

Contracts are in place at all of the nuclear generating facilities for uranium requirements, conversion, enrichment, and fabrication of new fuel assemblies. These contracts expire at varying times and provide for varying levels of fuel deliveries. The IOUs have indicated to NCI that they are confident that adequate supplies of nuclear fuel will be available during the Study Period, either through the renewal of existing contracts, the award of new contracts, or purchases from the spot market, to meet the needs of the nuclear facilities.

Spent fuel is placed in spent fuel pools at the nuclear generating facility sites. Space in the spent fuel pools must be reserved to receive the off-loading of all assemblies in the core. All three nuclear facilities will exhaust the capacity of their on-site spent fuel pools before the end of the Study

Period. The owners of these facilities are evaluating alternatives for the storage of spent fuel, including storing fuel assemblies on site in dry storage containers, as is being used at other nuclear plants in the United States.

The total estimated cost to decommission and dismantle Diablo Canyon is approximately $1.6 billion in 2002 dollars. The cost to SCE and SDG&E of decommissioning and dismantling their shares of San Onofre and Palo Verde is estimated to total approximately $2.6 billion in 2001 dollars. In accordance with NRC guidelines and requirements, the IOUs have been collecting decommissioning fund allowances in their retail rates and are expected to have accumulated adequate funds to meet their obligations for decommissioning upon the retirement of these facilities. PG&E has accumulated nuclear decommissioning trust funds for Diablo Canyon of approximately $1.2 billion, on a market value basis, as of December 31, 2001. For its share of San Onofre and Palo Verde, SCE maintains a fund balance of approximately $1.98 billion, on a market value basis as of December 31, 2001. SDG&E reported a decommissioning fund balance of approximately $0.386 billion for San Onofre at December 31, 2001, based on market valuation.

Hydroelectric Generation

PG&E and SCE own a combined total of 147 hydroelectric facilities (5,048 MW) located in the Sierra Nevada Mountains, the San Gabriel Mountains and the San Bernardino Mountains that supply energy in proportion to the rainfall captured by dams and diversions. SDG&E does not own any hydroelectric generation.

PG&E. The hydroelectric generation facilities of PG&E are all located in northern and central California and use water from reservoirs and diversions that capture water from the drainage of five watersheds. These watersheds consist of the DeSabla Watershed, the Drum Watershed, the Helms/Kings Crane Watershed, the Motherlode Watershed, and the Shasta Watershed. These hydroelectric facilities were constructed between 1898 and 1986 and, in some cases, the facilities were predated by earlier water collection and transport systems used for gold mining and for consumptive water uses. Over the 1997 through 2001 period, PG&E's hydroelectric facilities operated at an average annual capacity factor of 56 percent.

PG&E's hydroelectric facilities include reservoirs, dams, pipelines, tunnels, transmission lines, and powerhouses that are licensed by FERC. These facilities are licensed as "projects" and may include multiple powerhouses under one license (referred to hereinafter as "FERC Projects"). The licenses generally carry terms of 30 to 50 years. PG&E's FERC Projects are due for relicensing from the early 2000s to as late as 2033. The FERC Projects are inspected annually by FERC staff to ensure, among other things, compliance with license requirements. Each inspection results in a report that contains, among other information, a summary of the inspector's overall findings, as well as specific findings on safety, operation and maintenance, and structural items.

NCI reviewed FERC reports for 16 of PG&E's FERC Projects, comprising 39 powerhouses and approximately 3,100 MW of PG&E's total of 3,890 MW of hydroelectric generating capacity. All of these FERC Projects were reported by the FERC inspector to appear to have met all license requirements during the reporting period. The inspector reported no deficiencies in the operation or maintenance of the facilities and, in most cases, the facilities were reported to be well operated and maintained.

SCE. The hydroelectric generation facilities of SCE are separated into the Northern Hydro Region (the "Big Creek System") and the Eastern Hydro Region. The Big Creek System consists of seven FERC Projects located in the watershed of the south fork of the San Joaquin River. The Eastern Hydro Region consists of 13 FERC Projects and five non-FERC licensed projects located in the

watershed basins of the Sierra Nevada Mountains, San Bernardino Mountains, and San Gabriel Mountains. Over the 1997 through 2001 period, SCE's hydroelectric facilities have operated at an average annual capacity factor of 96 percent. These facilities are generally due for re-licensing in the early 2000s through 2029. Several FERC Projects, whose licenses expired prior to 2000, are operating under annual licenses. All of SCE's FERC Projects, which total 1,130 MW of generating capacity, are inspected annually by FERC staff to ensure, among other things, compliance with license requirements. Each inspection report contains a summary of the overall findings, as well as specific findings on safety, operation and maintenance, and structural items.

NCI reviewed FERC reports for nine FERC Projects comprising 17 powerhouses and approximately 600 MW of SCE's total of 1,158 MW of hydroelectric generating capacity. All of these FERC Projects were reported by the FERC inspector to appear to have met all license requirements during the reporting period. The inspector reported no deficiencies in the operation or maintenance of the FERC Projects and, in most cases, that the facilities were well operated and maintained.

Exhibit II-1 provides a listing of expiration dates for the FERC licenses held by PG&E and SCE in connection with their hydroelectric facilities. FERC Projects with license expiration dates that have already passed are believed to be undergoing relicensing efforts by PG&E or SCE.

Fossil Generation

PG&E has retained certain critical gas-fired units (579 MW) that are necessary for areas that are transmission constrained. SCE operates and owns a 56 percent interest (885 MW) in Mojave in southern Nevada and owns a 48 percent interest (710 MW) in Units 4 and 5 of Four Corners in northwest New Mexico, both coal-fired generating plants (9 MW). SCE also owns and operates one diesel-fueled generating plant located on Santa Catalina Island, California.

PG&E. After its divestiture program, PG&E retained ownership of 579 MW of non-nuclear thermal generation. This generation consists of 97 MW of combustion turbine generation and 482 MW of conventional steam turbine generation. Among this retained generation is the Hunters Point facility located in San Francisco. This plant has been operational since 1948 and consists of three units with a total capacity of 377 MW. This facility is important to the San Francisco peninsula as it provides voltage support to an area that is radial to the remainder of the PG&E load. PG&E also retained ownership of the 105 MW oil- and gas-fired Humboldt facility located near Eureka, California, which has been operational since 1956. The Humboldt facility serves radial PG&E load in the Eureka area (northern coastal area of California) in the same manner as the Hunters Point facility serves the San Francisco area. Over the 1997 through 2001 period, the Hunters Point and Humboldt facilities operated at average annual capacity factors of 22 percent and 30 percent, respectively.

SCE. After its divestiture program, SCE retained ownership of approximately 1,604 MW of non-nuclear thermal generation. SCE operates and owns a 56 percent undivided interest (885 MW) in the Mojave Station, which consists of two coal-fueled steam electric generating units in Clark County, Nevada, constructed in 1971. Other owners of the Mojave Station are LADWP (20 percent), Nevada Power Company (14 percent), and the Salt River Project ("SRP") (10 percent).

SCE also owns a 48 percent undivided interest (710 MW) in Units 4 and 5 at the Four Corners Station, which is a coal-fired steam electric generating plant located in New Mexico and constructed in 1969 (Unit 4) and 1971 (Unit 5). The station is operated by APS, which owns 15 percent of the units (APS also owns 100 percent of Units 1 through 3). The remaining owners of the Four Corners Station are Public Service of New Mexico (13 percent), SRP (10 percent), Tucson Electric Power (7 percent), and El Paso Electric (7 percent). Over the 1997 through 2001 period, the Mojave and Four Corners units operated at average annual capacity factors of 68 percent and 72 percent, respectively. In

addition to the coal-fired facilities, SCE owns and operates the Pebbly Beach Generating Station, a small (8.6 MW) diesel-fueled generating plant located on Santa Catalina Island. During the 1997 through 2001 period, this facility operated at an average annual capacity factor of 37 percent.

BILATERAL PURCHASES

The IOUs have historically been net purchasers of energy. Over the years, they have developed long-term power purchase agreements with utilities, primarily in the Pacific Northwest and Southwest, to meet their needs. These purchases are reliant on the operation of the extra-high voltage transmission lines that interconnect California with adjacent states and are assumed to continue through their term without interruption.

The IOUs also have in-state power purchase agreements with other entities that allow them to provide energy to, and accept energy from, the other party in a way that is beneficial to both parties. Exhibit II-2 at the end of this Report provides a listing of the bilateral contracts in place with each IOU as of July 31, 2002. The information presented in Exhibit II-2 is summarized in Table II-2 below.

TABLE II-2
IOU BILATERAL CONTRACTS[1]

IOU	MW
PG&E	1,639
SCE	1,723
SDG&E	208
Total	**3,570**

Source: SCE and SDG&E responses to April 30, 2002, NCI data requests, PG&E from 2001 FERC Form 1, and NCI conversations with IOU staff and industry sources.
[1] As of December 31, 2001.

QUALIFYING FACILITIES

A significant amount of the electrical capacity and associated energy requirements of the IOUs is provided by power generated by QFs. Table II-3 provides a summary of the installed QF capacity by type under contract to the IOUs.

As a result of the dramatic increase in spot market prices in California, and the resulting impact on the purchased power bills incurred by the IOUs, PG&E and SCE unilaterally deferred payment to the QFs for power production from November 2000 through March 2001. Although the majority of the QFs continued to operate despite the payment deferrals, a small number of QFs discontinued operations during 2001. While it is presumed that some of these plants were off-line due to normal maintenance, others were believed to have been off-line due to the lack of payments for past energy deliveries or for cash flow or credit reasons.

In a March 17, 2001, ruling (Decision 01-03-067), the CPUC ordered the IOUs to begin, no later than April 17, 2001, making payments to the QFs for power deliveries going forward. Each of the IOUs complied with this ruling and are making payments to the QFs for electricity produced and made available to them. Following the resumption of energy payments, most of the QFs that were off-line during 2001 returned to service and resumed generating electricity for sale to the IOUs. For purposes of this Report, all QF generating capacity is assumed to be in service during the summer of 2002 and to remain in service through the earlier of their respective QF contract termination dates or December 31, 2011. Some of the QF facilities under contract to the IOUs are renewable or clean energy

resources, such as wind, solar, biomass, and geothermal. Most of these resources cannot be operated by the IOUs in a manner that enables their output to be matched with the capacity and energy requirements of the Customers (e.g., are not dispatchable resources). Consequently, for resource planning purposes, only about three-quarters of the total QF capacity under contract to the IOUs can be counted on to be available to meet peak load additions.

TABLE II-3
QF GENERATING RESOURCES BY IOU[1]
(MW)

Fuel Type	PG&E	SCE	SDG&E	Total
Bio-gas	38	-	30	68
Biomass	465	253	-	718
Cogeneration	2,630	2,183	308	5,121
Steam Turbine	-	-	7	7
Solar[2]	-	379	-	379
Geothermal	153	751	-	904
Hydroelectric	221	-	5	226
Small Hydroelectric	-	96	-	96
Waste-to-Energy	130	-	-	130
Wind[3]	676	1,056	-	1,732
Photovoltaic[4]	-	-	-	-
Total	**4,313**	**4,718**	**350**	**9,381**

Source: Capacities based on operational projects only. Projects not on-line were not included. IOU termination data from IOU responses to NCI data requests. SCE and SDG&E provided QF termination data in April 2002. PG&E provided termination data in May 2001. Additional QF information obtained from the CEC, IOUs' public listings, and related investigations.

[1] Represents the nameplate rating of the facilities under contract as of January 31, 2002. Actual dependable generating capacity of the facilities may vary from these levels.

[2] PG&E's solar data includes 0.023 MW, which rounds to zero in this table.

[3] SDG&E's wind data includes 0.004 MW, which rounds to zero in this table.

[4] SDG&E's photovoltaic data includes 0.036 MW, which rounds to zero in this table.

Exhibit II-3 provides a summary listing of QF contract capacity.

EXHIBIT II-1
RELICENSING SCHEDULE FOR HYDROELECTRIC PLANTS

	PG&E		SCE	
Licence Expiration	**Number to Relicense[1]**	**MW**	**Number to Relicense[1]**	**MW**
Pre 2001[2]	6	681	5	109
2002	-	-	-	-
2003	2	460	2	2
2004	4	512	-	-
2005	1	12	2	23
2006	-	-	-	-
2007	2	11	1	181
2008	-	-	-	-
2009	1	27	5	691
2010	-	-	-	-
2011	1	341	-	-
Beyond 2011	15	1,846	10	152
Total	**32**	**3,890**	**25**	**1,158**

Source: FERC.
[1] Some licenses applied to multiple hydroelectric units operated as a system.
[2] Hydroelectric projects with licenses due to be renewed prior to 2001 have either been renewed on a year-to-year basis or for an unidentified longer term.

EXHIBIT II-2
IOU BILATERAL CONTRACTS

IOU	Seller	Contract Expiration	Capacity (MW)	Delivery Point
PG&E	Marketer	12/31/2003	225	Various
	Marketer	12/31/2003	225	Various
	Puget	12/31/2004	300	COB
	Merced ID[1]	[5]	104	At Generator
	Nevada ID[1]	[5]	63	At Generator
	Oakdale & SSJID[1]	[5]	94	At Generator
	Owyhee ID[1]	[5]	93	At Generator
	Placer County WA[2]	[5]	109	At Generator
	Yuba County WA[2]	[5]	374	At Generator
	Others	[5]	52	At Generator
	Total		**1,639**	
SCE	BPA[3]	04/30/04	500	COB/NOB
	SWP	12/31/04	120	Devil Canyon
	SWP	12/31/04	225	Midway/Vincent
	SWP	12/31/04	350	Hyatt-Thermalito
	TEP[4]	05/21/05	(100)	Palo Verde
	Marketer	12/31/05	50	Midway
	Marketer	12/31/05	100	Midway
	PacifiCorp	09/30/06	100	Four Corners
	PacifiCorp	09/30/06	100	COB
	Western	09/30/17	278	Mead
	Total		**1,723**	
SDG&E	Marketer	12/31/03	50	SP-15
	Marketer	12/31/03	50	SP-15
	Marketer	12/31/03	25	SP-15
	Unit Contingent	12/31/13	83	SP-15
	Total		**208**	
Total IOU Bilateral Contracts			**3,570**	

Source: FERC Form 1 reports and NCI conversations with IOU staff and industry sources.
[1] Irrigation district.
[2] Water agency.
[3] Contract may be extended five years.
[4] Summer for Winter power exchange
[5] Resources integrated into the PG&E system for unspecified terms.
Note: Totals may differ slightly due to rounding.

EXHIBIT II-3
CAPACITY FROM QF CONTRACTS WITH IOUS
(MW)

IOU	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
PG&E										
Bio-Gas	38	38	38	38	38	34	34	33	31	31
Biomass	465	465	439	439	439	439	439	439	439	439
Cogeneration	2,630	2,580	2,438	2,420	2,409	2,252	2,202	2,001	1,889	1,889
Geothermal	153	153	153	153	153	153	131	84	84	84
Hydroelectric	221	221	211	210	208	204	204	200	200	200
Waste to Energy	130	130	130	130	130	130	116	98	98	98
Wind	676	676	676	656	656	656	656	656	656	656
Total PG&E QF Capacity	**4,313**	**4,263**	**4,085**	**4,046**	**4,033**	**3,868**	**3,782**	**3,511**	**3,397**	**3,397**
SCE										
Biomass	253	252	252	246	241	211	211	198	198	198
Cogeneration	2,183	2,129	2,129	2,084	1,798	1,798	1,798	1,113	866	792
Geothermal	751	751	751	751	751	739	739	739	739	664
Small Hydroelectric	96	96	48	48	48	47	47	47	45	45
Solar	379	379	379	379	379	379	379	379	379	379
Wind	1,056	1,056	1,056	1,010	1,010	1,010	1,010	1,007	1,007	979
Total SCE QF Capacity	**4,718**	**4,662**	**4,615**	**4,518**	**4,227**	**4,183**	**4,183**	**3,482**	**3,234**	**3,057**
SDG&E										
Bio-Gas	30	13	13	13	13	12	12	11	9	5
Cogeneration	308	308	303	303	301	301	271	271	271	271
Steam Turbine	7	7	7	7	7	7	7	7	7	7
Hydroelectric	5	5	5	5	5	5	5	5	5	5
Photovoltaic[1]	-	-	-	-	-	-	-	-	-	-
Wind Turbine[2]	-	-	-	-	-	-	-	-	-	-
Total SDG&E QF Capacity	**350**	**332**	**328**	**328**	**326**	**326**	**296**	**294**	**292**	**288**
Capacity Available to IOUs	**9,381**	**9,257**	**9,028**	**8,892**	**8,585**	**8,377**	**8,261**	**7,287**	**6,923**	**6,742**

Source: Capacities based on operational projects only. Projects not on-line were not included. IOU termination data from IOU responses to NCI data requests. Capacity available to PG&E during 2011 assumed to equal the level experienced in 2010. SCE and SDG&E provided QF termination data in April 2002. PG&E provided termination data in May 2001. Additional QF information obtained from the CEC, IOUs' public listings, and related investigations.

[1] SDG&E's capacity of 0.036 MW from photovoltaic sources rounds to zero in this table.

[2] SDG&E's capacity of 0.0004 MW from wind turbines rounds to zero in this table

Note: Totals may differ slightly due to rounding.

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APPENDIX III
TRANSMISSION

The electric transmission system in California links the State to power supply resources in the surrounding region and permits the transfer of power between different regions of the State. The IOUs, various municipal utilities, and state and federal entities own the system. The majority of the transmission resources in the State are managed by the CAISO, as described below.

ROLE OF THE CAISO IN MANAGING THE TRANSMISSION SYSTEM

The CAISO is responsible for providing open and non-discriminatory access to the CAISO-controlled transmission system. The CAISO fulfills this function through its role in scheduling, congestion management, and transmission facility planning and construction.

Scheduling of energy in the CAISO is performed between certified "Scheduling Coordinators" and the CAISO. To become a Scheduling Coordinator, a party must execute an agreement with the CAISO agreeing to comply with CAISO scheduling procedures and related requirements. A Scheduling Coordinator must also provide and maintain sufficient credit to support its transactions in the marketplace.

The CAISO scheduling procedures for energy and ancillary services follow several basic steps:

- Forecast of system loads, generation, and transmission conditions;
- Initial schedules of energy, loads, and ancillary services;
- Transmission congestion management analysis and schedule revision; and
- Final energy and ancillary services schedules.

The CAISO currently operates three basic markets for managing transmission service on the CAISO-controlled transmission system. These are the day-ahead, hour-ahead, and real-time markets. The day-ahead market represents the majority of scheduled energy in the market. Although there have been periods in which the amount of energy in the day-ahead market dropped to about 50 percent of total energy needs, the desired outcome is for the majority of energy and loads to be scheduled in the day-ahead market. Pursuant to an order issued by FERC on December 15, 2000, the CAISO imposes a surcharge, or penalty, for utilities that do not schedule at least 95 percent of their needs into the daily energy market.

Schedules of energy generation and transmission to end-use loads are analyzed and balanced by the CAISO as part of its day-ahead congestion management procedures. In this procedure, the CAISO operates a congestion management model simulating the implementation of the proposed energy schedules based on transmission system conditions. Congestion of the transmission system is resolved through bids submitted for use of the transmission system or curtailment priorities established by firm transmission rights, existing contracts, or emergency procedures. These adjustments result in the elimination of congestion for day-ahead energy schedules. It is only in the day-ahead market that Scheduling Coordinators have an opportunity to adjust or modify their schedules in response to congestion.

The hour-ahead market is used by the CAISO to balance or adjust scheduled energy flows in response to market variations in electrical requirements and supply availability. The procedures are similar to the day-ahead market except that there is not a timeframe for responding to initial schedules

or schedule adjustments. Instead, the CAISO balances schedules of energy to meet loads according to adjustment bids submitted by the Scheduling Coordinators.

The CAISO operates a real-time market to manage instantaneous changes in energy supply, needs, and transmission conditions. This market relies on bids or offers of ancillary services and supplemental energy as well as other resources that may be available to the CAISO (for example, out-of-market calls, bilateral transactions resulting from one-on-one negotiations, and energy from must-run generation).

CAISO management of the three basic markets is directed toward managing the supply and delivery of energy to meet electric end-user loads. These CAISO efforts in the three markets described are focused on the near-term management of transmission services for California. Beyond these activities, the CAISO also is responsible for coordinating the long-term planning for that portion of the statewide transmission system under its control. The CAISO has instituted a coordination planning process to evaluate transmission system conditions and identify and analyze any proposed transmission facility additions or improvements to meet the reliability needs of the State at minimum cost to the consumer.

Under the CAISO's planning process, transmission owners prepare studies, in coordination with the CAISO, to analyze the ability of the transmission system to serve forecasted load for the next five to 10 years. The results of these studies are used to develop recommended system improvements that can be instituted by the transmission owners or, if feasible, third parties. The role of the CAISO is to coordinate these proceedings to ensure proper system conditions are evaluated and planned system improvements will meet reliability criteria consistent with the WECC guidelines. Figure III-1 provides a summary of the CAISO's long-term transmission planning process, including the role of the Participating Transmission Owners ("PTO").

State and Federal Oversight of the CAISO

The CAISO is a not-for-profit public benefit corporation organized under California law. The CAISO is responsible for managing the transmission system in California. In addition to the CAISO, the original electricity deregulation legislation passed in California in 1996 included a provision for the Electricity Oversight Board. The role of the Electricity Oversight Board, which includes legislators and appointed members, is to oversee the operation of the CAISO. Included among these duties were appointment of the CAISO Board and representation of the State's interest before the FERC.

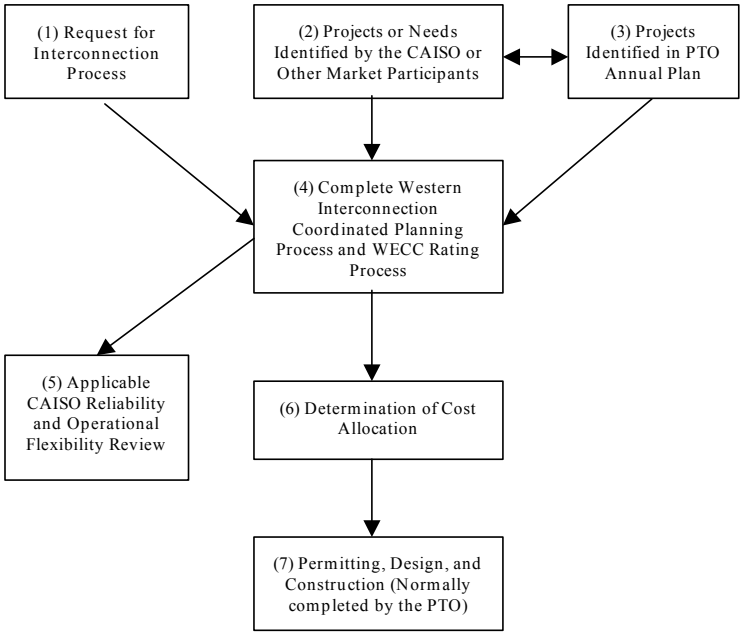
The CAISO Board is currently in a stage of transition. Recent state legislation modified the governing board characteristics from the previous years. Previously, the Board had over 20 members, including several non-voting members. As a result of a FERC order dated December 15, 2000, and subsequent state legislation, the CAISO Board is now comprised of five members nominated by the Governor and approved by the Electricity Oversight Board. Because the CAISO has responsibilities that are subject to FERC jurisdiction (including the setting of rates, terms, and conditions of service), all aspects of the CAISO operational procedures and governance must be reviewed and approved by FERC.

On July 17, 2002, FERC issued an order in Docket Nos. EL01-35-000, et. al., that found the CAISO's Board, as presently constituted, is not capable of acting in a manner independent of the State. FERC has ordered the CAISO to adopt a two-tier organizational structure by January 1, 2003. The top tier is to consist of a nine-member independent, non-stakeholder Board and the second-tier to consist of stakeholder advisors and an Electricity Oversight Board advisory committee (to act as the State's representative). All decision making power will be vested in the top tier of the organizational

structure. The CAISO filed a Request and Motion for Stay on August 13, 2002. NCI cannot predict what the outcome of this challenge will be or what the impact, if any, to DWR will be.

On August 16, 2002, FERC filed a complaint for declaratory judgment and injunctive relief in the U.S. District Court for the District of Columbia (Case no. 1:02cv01625) seeking an order mandating the CAISO to comply with orders issued by the FERC that directed the CAISO to take certain steps to reorganize the CAISO Board. FERC also seeks a judgment declaring that the governance provisions of the CAISO tariff fall within the exclusive jurisdiction of the FERC; that the creation, composition and continued operation of the current CAISO Board under State law is unlawful; and that failure to comply with certain orders of the FERC will constitute violations of federal law and subject the CAISO to penalties. NCI cannot predict what the outcome of this legal action will be or the impact, if any, it may have upon DWR.

FIGURE III-1
OVERVIEW OF CAISO GRID COORDINATED PLANNING



CAISO Market Redesign Efforts

The CAISO is undergoing a process of redesign for the operation of the transmission system and the movement of bulk (wholesale) power in California. The redesign, called Market Design 2002 ("MD02"), is being carried out in response to orders issued by FERC. The FERC Order on Clarification and Rehearing of December 19, 2001 directed the CAISO to file its revised congestion management proposal and a plan for implementation of a day-ahead market.

The CAISO introduced its new market design proposals through a *Preliminary Report on Project Approach and Key Market Design Elements Under Consideration* on December 21, 2001. The *Preliminary Draft Comprehensive Design Proposal* was released on January 8, 2002, followed by a series of technical workshops.

The MD02 comprehensive design proposal, filed at FERC on May 1, 2002, consisted of ten parts.

- **Available Capacity ("ACAP") Obligation** - Load-serving entities would face an obligation to maintain an ACAP, defined as a percentage margin above their monthly peak load, through a combination of their own generation, firm energy contracts, capacity contracts, and demand-side management.
- **Forward Congestion Management ("CM")** - The CAISO proposes to use a full network model to adjust schedules to clear congestion.
- **Firm Transmission Rights ("FTRs")** - Redesign of CM requires redesign of FTRs.
- **Forward Day-Ahead Spot Energy Market** - The Day-Ahead market would perform energy trades within the CM procedures.
- **Residual Forward Unit Commitment** - After the close of the day-ahead market, the CAISO would determine whether there is a need for additional generation resources to be brought on-line for the next day's needs.
- **Ancillary Services** - Bidders would be required to submit a single energy curve for all services offered by a particular resource. Currently, different energy curves may be submitted for each ancillary service for which a resource is qualified.
- **Modification to the Hour-Ahead Market** - The Hour-Ahead market would be simplified by performing only CM and energy trading.
- **Real-time Economic Dispatch Using a Full Network Model** - This would be a 10-minute dispatch that would take into account inter- and intra-zonal congestion, resulting in nodal real-time prices.
- **Real-time Bid Mitigation for Locational Needs** - This would reduce local market power.
- **Damage Control Price Cap on CAISO Markets** - Beginning October 1, 2002, and continuing until market conditions are competitive enough to support a higher price cap, the CAISO proposed to set the price cap at three times the estimated variable cost of a gas-fired generating unit with an incremental heat rate of 20,000 Btu or $250 per MWh, whichever is greater.

The CAISO released *Draft October First Design Elements* on March 27, 2002, and released proposed tariff language for the October First Design Elements on April 19, 2002. On May 1, 2002, the CAISO made a comprehensive filing to FERC consisting of specific tariff language proposed to go into effect on October 1, 2002. The elements proposed for October 1, 2002, were simplified from the comprehensive market design and represented the first phase of the CAISO's efforts to implement the above changes. The changes proposed for October 1, 2002, include the following eight elements.

- **Must-Offer Obligation** - This is similar to the current must-offer obligation under the FERC's western mitigation system.
- **Residual Unit Commitment** - This would be similar to the RUC system proposed in the comprehensive design, with the exception that the October 1, 2002 version allows for competition between intertie energy bids and internal units.
- **Changes to Day-Ahead and Hour-Ahead Markets** - Bidders would submit a single bid for all energy and ancillary services.
- **Damage Control Bid Cap** - This would be a single cap for all energy and ancillary services.

- **Bid Screens and Mitigation** - There would be individual resource bid screens to mitigate bids that exceed explicit threshold limits and have a material effect on projected market-clearing prices.
- **12-Month Market** - Competitiveness Index and Pre-authorized Additional Mitigation Provisions. This would be an explicit measure of the competitiveness of the market to determine if or when the market should be declared unjust and unreasonable.
- **Other Market Power Mitigation Measures** - This would include local market power mitigation measures and penalties for failure to honor binding real-time bids.
- **Transitional Available Capacity Obligation** - Because the ACAP is not likely to be feasible by the beginning of October 2002, the CAISO proposed a monthly assessment process to take account of all available resources, including DWR power contracts, and would identify a potential shortfall early enough to enable load-serving entities and other responsible parties to procure additional supply.

On July 17, 2002, FERC issued an order in Docket Nos. ER02-1656-000 and EL01-68-017 in response to the CAISO's proposed tariff changes. This order rejected the CAISO's price cap proposal and established a hard cap of $250 per MWh to be effective October 1, 2002. Additionally, the order rejected the CAISO's proposals for local market power mitigation, implementation of an interim residual unit commitment process, and the 12-month market competitive index mechanism. FERC directed the CAISO to file tariff language on day-ahead, ancillary services, and hour-ahead and real-time reforms, as well as a schedule and process for integrating demand signals into its market design, among other issues, all by October 21, 2002. FERC approved several of the CAISO's proposals, including the acquisition of software and equipment for calculating location marginal prices, penalties for excessive generation deviations not requested by the CAISO, and a cap on decremental energy bids.

NCI cannot predict the outcome of the CAISO's MD02 process, the schedule for implementation of changes approved by FERC, or the impact, if any, it may have on DWR.

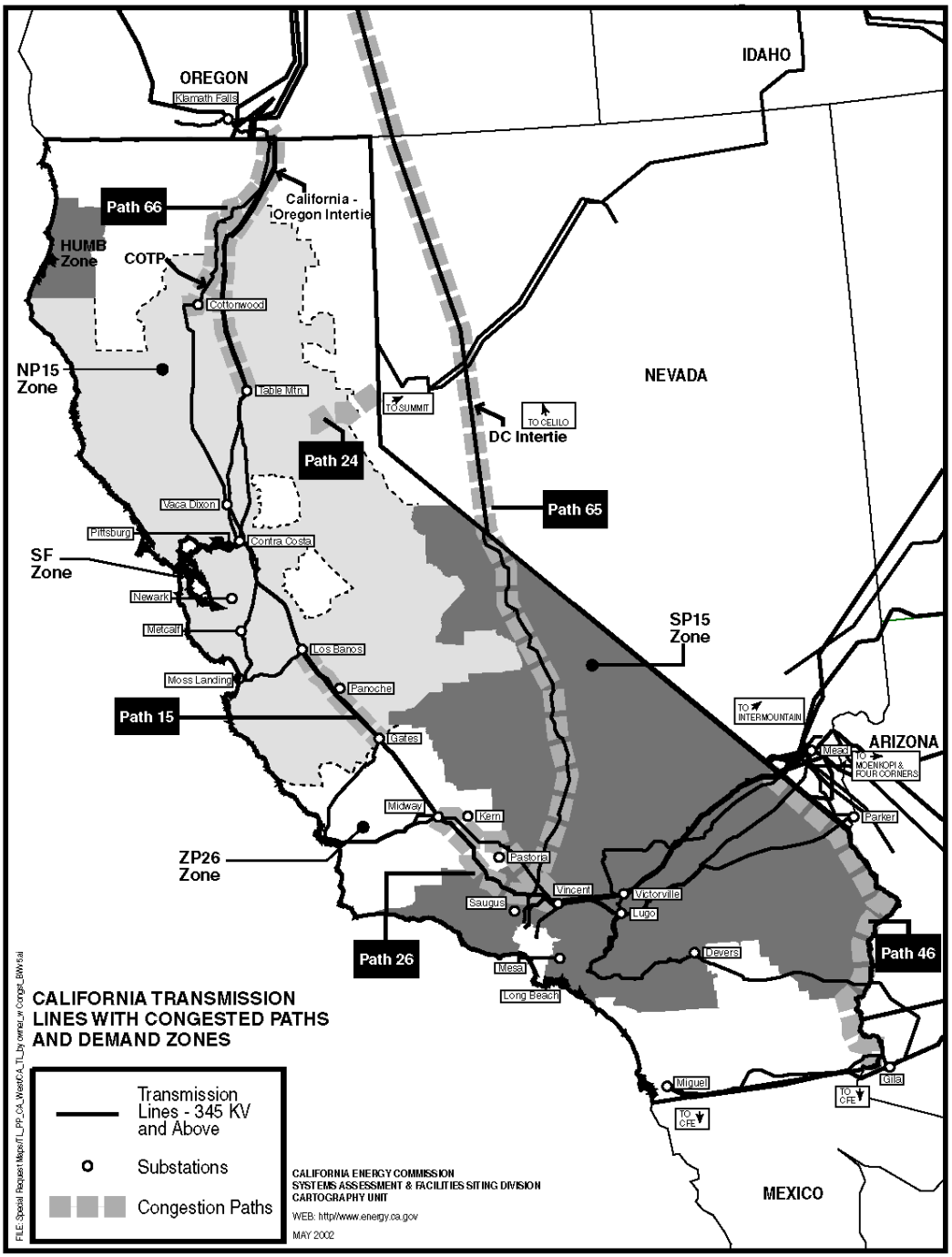
INTRASTATE TRANSMISSION AND NP 15/SP 15 TRANSFER CAPABILITIES

Transmission limitations within California result in the division of statewide energy needs into five distinct zones. Zones referred to as "inactive" are areas that do not have competitive markets for generation dispatch. Zones referred to as "active" are areas along the main statewide transmission system that have competitive markets for generation dispatch and to which energy transfers can be limited due to limitations in transmission capability between other active zones. These zones and the major transmission lines in California are depicted in Figure III-2.

Of the five zones in California, three are classified as active. These zones are located in northern California (NP 15), central California (referred to as "ZP 26"), and southern California (SP 15). CAISO created ZP 26 when it determined there was additional transmission congestion in SP 15 south of Midway Substation or "Path 26."

The primary load centers in NP 15 are the San Francisco area and the metropolitan Sacramento area. The primary load centers in SP 15 are the Los Angeles Basin and the metropolitan San Diego area. Between these zones is ZP 26, an area in which a large amount of electric generating resources is located. The primary generators in this region are Diablo Canyon and a variety of independent, non-utility generators, primarily QFs.

FIGURE III-2
CALIFORNIA TRANSMISSION LINES BY OWNERSHIP WITH CONGESTED PATHS



The interface between zones ZP 26 and NP 15 is designated "Path 15" by the WECC. The capabilities of the components of this path, plus its interaction with other defined WECC paths, limit flows both south to north, and north to south. Path 15 is comprised of two 500 kV lines and four 230 kV lines and is rated at 3,900 MW in the south to north direction and procedures are in place that allow operation up to 3,950 MW. The transmission lines are owned by the IOUs, but are encumbered

pursuant to contracts that existed prior to the advent of the CAISO. However, various factors (such as ambient temperatures and flows over other transfer paths) can limit the real-time capability of Path 15 to between 900 MW and 3,950 MW. Therefore, during periods when NP 15 is in an energy deficit and both SP 15 and ZP 26 are in an energy surplus, transmission system capability from ZP 26 to NP 15 may be insufficient to deliver surplus capacity from ZP 26 and SP 15 to NP 15.

The interface between ZP 26 and SP 15 has been identified by the WECC as Path 26. Path 26 is composed of three 500 kV lines collectively rated at 3,000 MW. These transmission lines are owned by IOUs, but also are encumbered pursuant to contracts that existed prior to the advent of the CAISO. During periods when SP 15 is in an energy deficit and both NP 15 and ZP 26 are in an energy surplus, the amount of transmission capability from ZP 26 to SP 15 may not be sufficient to deliver surplus capacity from ZP 26 and NP 15 into SP 15. The ability to deliver power northward over Path 26 is limited by the amount of generation on-line in the Midway area and the south-to-north capability of Path 15 discussed above.

INTERSTATE TRANSMISSION AND IMPORT CAPABILITIES

California receives generation imports primarily from the Pacific Northwest, western Canada, and the Southwest. Minor amounts of generation are imported from Mexico and across the Sierra Nevada Mountains from northern Nevada. Provided below is a brief description of the intrastate, interstate, and import transmission capability from these regions. All values stated below represent non-simultaneous (non-coincident) capabilities. Due to various operational variables, including interaction between these paths, the actual transmission capability between California and each region may fall below these values at certain times. This information is depicted in Table III-1.

TABLE III-1
CALIFORNIA MAJOR HIGH VOLTAGE INTERCONNECTIONS AND RATINGS

Description	Interconnected Areas	Normal Rating (MW)
Path 66–AC Pacific Intertie	Pacific Northwest-Northern California	4,800[1]
Path 65–DC Pacific Intertie	Pacific Northwest–Southern California	3,100[2]
Path 27-Intermountain DC.....	Southwest-Southern California	1,920[3]
Path 45-SDG&E-CFE.....	Mexico–Southern California	408[4]
Path 46–West-of-River	Southwest–Southern California	10,118[5]

Source: WECC 2002 Path Rating Catalog, February 2002.
[1] North to south rating. South to north rating is 3,675 MW.
[2] Bi-directional rating. South to north rating is reduced to 2,200 MW if Direct Service Industry customers in the Pacific Northwest are not operating.
[3] Northeast to southwest rating. Southwest to northeast rating is 1,400 MW.
[4] North to south rating. South to north rating is 800 MW.
[5] East to west rating.

California-Pacific Northwest

The extra-high voltage transmission system interconnecting California with the Pacific Northwest is through a collection of alternating current ("AC") and direct current ("DC") transmission lines (the "Pacific Northwest-Southwest AC-DC Intertie"). The three-line 500 kV AC portion of this system is known as the California-Oregon Intertie (the "COI"). The COI interconnects with the Pacific Northwest at the California-Oregon Border ("COB"), and has been identified by the WECC as "Path 66." Path 66 has an import capability of 4,800 MW north to south in northern California. The IOUs own or have rights to two of the three AC lines south of the COB. The third AC line south of the COB is primarily owned by municipal utilities in northern California. The owners of

the portion of the Pacific Northwest-Southwest AC-DC Intertie north of the COB are primarily BPA, PacifiCorp, and Portland General Electric Company.

SCE owns 50 percent of the DC portion of the Pacific Northwest-Southwest AC-DC Intertie south of the Nevada-Oregon Border ("NOB"). LADWP owns 40 percent of this line and the cities of Glendale, Burbank, and Pasadena own the remaining 10 percent. The WECC has identified this single ±500 kV DC line as "Path 65." This DC line terminates at Sylmar Substation in southern California and at Celilo, Oregon. It is capable of delivering 3,100 MW. The portion of this line north of NOB is owned by BPA. The DC line enables deliveries between southern California and the Pacific Northwest within the capability of the line as long as there are no major outages on the facilities comprising Path 66, Path 26, and Path 15.

California–Southwest

Southern California is electrically interconnected with the Southwest through an AC network of transmission lines known as the "West-of-River" transmission system and a DC line interconnecting southern California with the Intermountain Power Project in western Utah.

The West-of-River transmission system has been identified by the WECC as "Path 46" and has an import capability of 10,118 MW. Path 46 consists of seven 500 kV transmission lines, one 287 kV transmission line, and six 230 kV transmission lines. The IOUs collectively have entitlements to 59.7 percent of this transmission system. The remaining entitlements are allocated to LADWP and other municipal utilities.

The Intermountain Power Project DC Line has been identified by the WECC as "Path 27." It consists of a single ±500 kV DC transmission line interconnecting the Intermountain Power Project with LADWP's Adelanto Substation in the high desert east of Los Angeles. The line has a rated import capability of 1,920 MW and is 100 percent allocated to a collection of municipal utilities in southern California, including LADWP.

California–Other

Northern California is interconnected with northern Nevada through a small AC interconnection with Sierra Pacific Power Company ("SPP"). This interconnection has been identified by the WECC as "Path 24." Path 24 consists of two 115 kV lines and a 60 kV line crossing the Sierra Nevada Mountains. The WECC Path Rating Catalog states that the import capability of this interconnection is 160 MW. However, recent operating studies have indicated that Path 24 is only capable of a maximum of 120 MW of import capability and up to a maximum of 100 MW of export capability due to internal limitations within the PG&E and SPP systems.

Southern California is interconnected with Mexico through a pair of 230 kV AC transmission lines controlled by the Commission Federal de Electricidad. This interconnection has been identified by the WECC as "Path 45." The import capability of this interconnection is limited to 800 MW.

PLANNED TRANSMISSION SYSTEM IMPROVEMENTS/ADDITIONS

Major transmission system improvements and additions are reviewed and approved by the WECC before path ratings can be increased. As of April 1, 2002, there were two projects outside of California under consideration within the WECC region that have the potential to enhance the ability of utilities in California to import power from the Northwest and Southwest.

The first project is the Navajo Transmission Project, which is being proposed by the Navajo Tribal Utility Authority and other parties. This project consists of a new 500 kV line from the Four Corners area (Shiprock) to southern Nevada via an intermediate connection to the existing system at Moenkopi, Arizona. The proposed rating of this project is 1,189 MW from Shiprock to Moenkopi and 1,339 MW from Moenkopi to southern Nevada. This project, if built, could increase the import capability of the southern Nevada system, thereby making more resources available to California. Even though this project would not directly increase the import capability into California, by allowing more resources to move into southern Nevada, this project could potentially increase the utilization of the existing West-of-River import path.

The second project is the Midpoint–Summer Lake ("Path 75") re-rate. This project would increase the non-simultaneous west to east rating of the existing Midpoint–Summer Lake 500 kV line by 250 MW (to a total of 650 MW). The impact this project could have on California is that as the west to east flow on the Midpoint–Summer Lake line increases, the amount of power that can be imported into California decreases. If this re-rate is approved, there is a potential that resources that previously were available to California from the Northwest would be utilized to serve loads elsewhere. This re-rate is currently in Phase II of the WECC rating process.

Given the tentative nature of the Navajo Transmission Project and the minimal change proposed for the Midpoint–Summer Lake line rating, NCI does not believe that the impacts of these two projects on the availability of Northwest and Southwest resources to serve California loads will be significant.

On March 30, 2001, the CPUC ordered PG&E to file for approval of a Certificate of Public Convenience and Necessity ("CPCN") for the construction of transmission improvements between the Los Banos and Gates substations to relieve transmission congestion on Path 15. PG&E's application was filed with the CPUC on April 13, 2001. As filed, this project would entail construction of an additional 500 kV transmission line between the Los Banos and Gates substations, certain substation additions, and reinforcements to the 230-kV system in the area, all of which PG&E estimates to cost approximately $225 million to $300 million. PG&E identified a construction period of approximately 12 months for these improvements. However, because of the current status of the planning, permitting, and development of the project, NCI does not expect the project to be completed prior to November 2004. This project is expected to add a minimum of 1,400 MW to 1,500 MW of south to north transfer capability to Path 15.

PG&E has completed the first phase of a planning process required by the WECC relative to the proposed Path 15 additions and reinforcements. A report summarizing the results of the Phase 1 planning effort was issued to the WECC by PG&E September 2001. In addition, the CAISO and PG&E filed testimony with the CPUC in September 2001 relative to the project. Evidentiary hearings were held by the CPUC during February and March 2002, to assess the costs and benefits of the proposed improvements. PG&E, the CAISO, and the CPUC Office of Ratepayer Advocates filed opening briefs regarding the economic benefits of the project with the CPUC in April 2002. The CPUC has not established a schedule for issuing a decision on PG&E's CPCN.

Western has developed its own proposal for undertaking the Path 15 improvements described above. Through an open solicitation, Western has secured commitments for project participation from PG&E and Trans-Elect. The parties have executed memoranda of understanding ("MOU") related to project implementation agreements. The MOU parties are currently negotiating the definitive participation agreements for the Path 15 upgrade project. FERC has conditionally preapproved PG&E's and Trans-Elect's tariffs for this project.

In addition to the above transmission project, several projects have been identified by utilities in the State that would help to eliminate congestion on Path 15 or Path 26 or to improve the import capability to the San Francisco area or SP 15. These projects are described below.

- Construction of a new 500/230 kV substation near Newark and looping of the 500 kV Tesla to Los Banos transmission line into the new substation. A second 500 kV line would also be constructed from Metcalf to Moss Landing. These additions could be completed by June 2006 at an estimated cost of $250 million. Although these improvements would not alleviate congestion on Path 15, they are estimated to add 2,300 MW of additional import capability into the San Francisco area;
- Extension of the Path 15 improvements from Tracy to Bakersfield. This extension would consist of a third Tracy/Tesla-Los Banos line and third 500 kV line from Gates to a new 500 kV substation in the Bakersfield area. This extension would help to alleviate congestion between southern and northern California by adding a minimum of 500 MW of bi-directional transfer capability to the system. The extension is estimated to cost approximately $300 million. A completion date of June 2008 could be expected; and
- Construction of a new 500 kV transmission line between the new Bakersfield substation and Adelanto. This improvement is estimated to cost approximately $265 million and could be completed by June 2008. This improvement is expected to add 1,000 MW of bi-directional capability to Path 26, which would enhance the import capability to southern California.

Although the above projects have been identified by various utilities in the State, these projects are not yet the subject of planning studies or regulatory review, nor has PG&E or any other party agreed to undertake any of these projects. The power supply cost projections discussed previously in this Report are based on the assumption that the Path 15 improvements described above will be completed by the in-service dates indicated. NCI cannot predict whether any of the above projects will be undertaken or completed by PG&E, including the project described earlier for which it has filed a CPCN. Other utilities in the State, as well as Western, have expressed an interest in undertaking the Path 15 improvements. NCI believes it is reasonable to expect that a party other than PG&E would undertake one or more of these projects if PG&E elects not to or is prohibited from doing so as a result of its bankruptcy proceedings.

Other options for increasing transfer capability between northern and southern California that have been considered include the following. None of these projects currently have sponsors.

- Upgrade to the existing 500 kV system between the Midway and Vincent substations. This project may include new series capacitors and new remedial action schemes and could potentially increase transfer capability on Path 26 by 1,000 MW, at a cost of approximately $120 million. The project could be in service by 2008; and
- Construction of a 500 kV line between the Midway and Valley Substations. This project could be in service by 2011 and is estimated to cost up to $1.2 billion. Transfer capability on Path 26 is estimated to increase by approximately 1,200 MW with the addition of this project.

In addition to the above improvements, SCE, SDG&E, and certain municipal utilities within the State have proposed improvements to the transmission system in southern California. These plans are summarized below:

- Construction of an additional 500 kV transmission line between Palo Verde and Devers, a second 500/230 kV transformer at Devers, and certain other improvements to the existing Palo Verde to Devers and Palo Verde to Miguel transmission lines. These improvements are estimated to cost $260 million and would add approximately 1,700 MW of import capability to the West-of-River transmission system (Path 46). The estimated completion date is June 2006 for the first 800 MW of import capability and June 2009 for the second 900 MW;
- Construction of the Valley-Rainbow Transmission Project by SDG&E. This project includes a 500 kV transmission line, two new substations near San Diego, and reinforcement of SDG&E's 230 kV transmission system. This project would improve SDG&E's access to the Southwest market and could be completed by June 2005. The total estimated cost is $350 million;
- Construction of an additional 500 kV transmission line from Palo Verde through the Imperial Valley substation, terminating at the Miguel substation. The estimated completion date of this project is June 2008 at a cost of approximately $450 million. This project would add 1,200 MW of import capability into southern California from Path 46;
- Reinforcement of the existing 230 kV interconnection between CFE and SP 15, which is estimated to increase transfer capability by approximately 800 MW; and
- Construction of a 500 kV line between southern Nevada and southern California for the purpose of delivering new generation to California. This project is estimated to cost up to $1 billion and could be in service by 2011. This project is estimated to be capable of increasing the import capability on Path 46 by 1,000 MW to 1,500 MW.

With the exception of the Valley-Rainbow Transmission Project, the above projects do not presently have sponsors and NCI cannot predict whether any of these projects will be undertaken or, if undertaken, completed within the schedules indicated. If completed, these projects would increase the import capability to southern California and potentially expand the power supply options available to Customers in this area.

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APPENDIX B

BOOK-ENTRY SYSTEM

The information in this Appendix concerning The Depository Trust Company, New York, New York ("DTC") and DTC's book-entry system has been obtained from sources that DWR, the Underwriters and the Trustees believe to be reliable, but DWR, the Underwriters and the Trustees take no responsibility for the accuracy thereof.

DTC will act as securities depository for the Series 2002A Bonds. The Series 2002A 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 Series 2002A Bond certificate will be issued for each maturity of Series 2002A Bonds, each in the aggregate principal amount of such maturity, and will be deposited with DTC. If, however, the aggregate principal amount of any maturity exceeds $500 million, one certificate will be issued with respect to each $500 million of principal amount, and an additional certificate will be issued with respect to any remaining principal amount of such maturity.

DTC, the world's largest 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 2 million issues of U.S. and non-U.S. equity issues, corporate and municipal debt issues, and money market instruments from over 85 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, in turn, is owned by a number of Direct Participants of DTC and Members of the National Securities Clearing Corporation, Government Securities Clearing Corporation, MBS Clearing Corporation, and Emerging Markets Clearing Corporation, (NSCC, GSCC, MBSCC, and EMCC, also subsidiaries of DTCC), as well as by the New York Stock Exchange, Inc., the American Stock Exchange LLC, and the National Association of Securities Dealers, Inc. 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 Standard & Poor's highest rating: AAA. 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.

Purchases of Series 2002A Bonds under the DTC system must be made by or through Direct Participants, which will receive a credit for the Series 2002A Bonds on DTC's records. The ownership interest of each actual purchaser of each Series 2002A 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 Series 2002A 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 Series 2002A Bonds, except in the event that use of the book-entry system for the Series 2002A Bonds is discontinued.

To facilitate subsequent transfers, all Series 2002A 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 Series 2002A 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 Series 2002A Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such Series 2002A 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 Series 2002A Bonds may wish to take certain steps to augment the transmission to them of notices of significant events with respect to the Series 2002A Bonds, such as redemptions, tenders, defaults, and proposed amendments to the Series 2002A Bond documents. For example, Beneficial Owners of Series 2002A Bonds may wish to ascertain that the nominee holding the Series 2002A Bonds for their benefit has agreed to obtain and transmit notices to Beneficial Owners.

Redemption notices shall be sent to DTC. If less than all of the Series 2002A Bonds within an issue are being redeemed, DTC's practice is to determine by lot the amount of the interest of each Direct Participant in such issue to be redeemed.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to Series 2002A Bonds unless authorized by a Direct Participant in accordance with DTC's Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to Issuer 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 Series 2002A Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Payment of principal, interest, redemption proceeds and other distributions on the Series 2002A 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 DWR or the Trustees, 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, its nominee, DWR or the Trustees, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of redemption proceeds, distributions, and dividend payments to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is the responsibility of DWR or the Trustees, 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 depository with respect to the Series 2002A Bonds at any time by giving reasonable notice to DWR or the Trustees. Under such circumstances, in the event that a successor depository is not obtained, Series 2002A Bond certificates are required to be printed and delivered.

DWR and the Trustees may decide to discontinue use of the system of book-entry transfers through DTC (or a successor securities depository). In that event, Series 2002A Bond certificates will be printed and delivered.

THE TRUSTEES, AS LONG AS A BOOK-ENTRY ONLY SYSTEM IS USED FOR THE SERIES 2002A BONDS, WILL SEND ANY NOTICE OF REDEMPTION OR OTHER NOTICES TO OWNERS ONLY TO DTC. ANY FAILURE OF DTC TO ADVISE ANY PARTICIPANT, OR OF ANY PARTICIPANT TO NOTIFY ANY BENEFICIAL OWNER, OF ANY NOTICE AND ITS CONTENT OR EFFECT WILL NOT AFFECT THE VALIDITY OR SUFFICIENCY OF THE PROCEEDINGS RELATING TO THE REDEMPTION OF THE SERIES 2002A BONDS CALLED FOR REDEMPTION OR OF ANY OTHER ACTION PREMISED ON SUCH NOTICE.

DWR and the Trustees cannot and do not give any assurances that DTC will distribute to Participants, or that Participants or others will distribute to the Beneficial Owners, payments of principal of and interest and premium, if any, on the Bonds paid or any redemption or other notices or that they will do so on a timely basis or will serve and act in the manner described in this Official Statement. Neither DWR nor the Trustees is responsible or liable for the failure of DTC or any Direct Participant or Indirect Participant to make any payments or give any notice to a Beneficial Owner with respect to the Series 2002A Bonds or any error or delay relating thereto.

The foregoing description of the procedures and record keeping with respect to beneficial ownership interests in the Series 2002A Bonds, payment of principal of and interest and other payments with respect to the Series 2002A Bonds to Direct Participants, Indirect Participants or Beneficial Owners, confirmation and transfer of beneficial ownership interest in such Bonds and other related transactions by and between DTC, the Direct Participants, the Indirect 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 Direct Participants, the Indirect 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 Participants, as the case may be.

SO LONG AS CEDE & CO. IS THE REGISTERED OWNER OF THE SERIES 2002A BONDS, AS NOMINEE OF DTC, REFERENCES HEREIN TO THE HOLDERS SHALL MEAN CEDE & CO., AS AFORESAID, AND SHALL NOT MEAN THE BENEFICIAL OWNERS OF THE SERIES 2002A BONDS.

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APPENDIX C

SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE

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SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE

The following is a summary of certain provisions of the Indenture. The summary does not purport to be complete or definitive and is qualified in its entirety by reference to the Indenture, copies of which are on file with the Trustee and Co-Trustee.

Definitions

For purposes of this Summary, capitalized terms shall have the meanings assigned to them below, or in other cases as contained elsewhere in this Official Statement as indicated in APPENDIX H.

"**Accreted Value**" means, with respect to any Capital Appreciation Bonds, (i) as of any Valuation Date, the amount set forth for such date in the Supplemental Indenture authorizing such Capital Appreciation Bonds and (ii) as of any date other than a Valuation Date, the sum of (a) the Accreted Value on the preceding Valuation Date and (b) the product of (1) a fraction, the numerator of which is the number of days having elapsed from the preceding Valuation Date and the denominator of which is the number of days from such preceding Valuation Date to the next succeeding Valuation Date, and (2) the difference between the Accreted Values for such Valuation Dates. Accreted Value shall be computed on a 30/360–day basis.

"**Act**" means Division 27 (commencing with Section 80000) of the State Water Code, as amended from time to time.

"**Additional Emergency Measures**" or "**Emergency Measures**" means Executive Order No. D-56-02 dated May 23, 2002, or any Proclamation or Order of the Governor of the State hereafter issued pursuant to the California Emergency Services Act (Chapter 7, Division 1, Title 2 of the California Government Code, as amended) (including, but not limited to, any regulations issued pursuant thereto) adopted in response to or in anticipation of the need to assure the availability of power to retail end-use customers in the State due to the inability or failure of an Electrical Corporation to purchase such power following the end of the Department's authority to enter into new Power Supply Contracts under Assembly Bill 1X.

"**Administrative Cost Account**" means the Account by that name established under the Indenture.

"**Aggregate Debt Service**" means, for any period and as of any date of calculation, the sum of the amounts of Debt Service for such period with respect to all Series of Bonds.

"**Alternate Debt Service Reserve Account Deposit**" means any irrevocable surety bond, insurance policy, letter of credit or any other similar obligation provided to the Trustee as a substitute for the deposit of cash and/or Authorized Investments, or another Alternate Debt Service Reserve Account Deposit, in the Debt Service Reserve Account.

"**Assembly Bill 1X**" means Chapter 4 of the Statutes of 2001 (AB 1 of the First Extraordinary Session) of the State, as amended from time to time, including, but not limited to, Chapter 9 of the Statutes of 2001 (SB 31 of the First Extraordinary Session).

"**Authorized Investments**" means and includes any of the following securities, if and to the extent the same are at the time legal for investment of the Department's funds pursuant to any law, and to the extent permitted under any applicable regulation, guideline and policy of the Department, as each is in effect from time to time:

(i) bonds or interest-bearing notes or obligations of the United States, or those for which the faith and credit of the United States are pledged for the payment of principal and interest;

(ii) bonds or interest-bearing notes or obligations that are guaranteed as to principal and interest by a federal agency of the United States;

(iii) bonds of the State or bonds for which the faith and credit of the State are pledged for the payment of principal and interest;

(iv) bonds or warrants, including, but not limited to, revenue warrants, of any county, city, metropolitan water district, California water district, California water storage district, irrigation district in the State, municipal utility district or school district of the State;

(v) bonds, consolidated bonds, collateral trust debentures, consolidated debentures or other obligations issued by general land banks or federal intermediate credit banks established under the Federal Farm Loan Act, as amended, debentures and consolidated debentures issued by the Central Bank for Cooperatives and banks for cooperatives established under the Farm Credit Act of 1933, as amended, bonds or debentures of the Federal Home Loan Bank Board established under the Federal Home Loan Bank Act, stocks, bonds, debentures and other obligations of the Federal National Mortgage Association established under the National Housing Act, as amended, and the bonds of any federal home loan bank established under said act, obligations of the Federal Home Loan Mortgage Corporation, and bonds, notes and other obligations issued by the Tennessee Valley Authority under the Tennessee Valley Authority Act, as amended;

(vi) commercial paper rated within the top Rating Category by a Rating Agency and issued by corporations (1) organized and operating within the United States, (2) having total assets in excess of $500,000,000 and (3) approved by the Pooled Money Investment Board of the State, provided, however that eligible commercial paper may not exceed one hundred eighty (180) days' maturity, represent more than 10% of the outstanding paper of an issuing corporation nor exceed 30% of the resources of an investment program, and that at the request of the Department, such investment shall be secured by the issuer by depositing with the Trustee securities authorized by Section 53651 of the California Government Code of a market value of at least 10% in excess of the amount of the Department's investment;

(vii) bills of exchange or time drafts drawn on and accepted by a commercial bank the general obligations of which are rated within the top two Rating Categories by a Rating Agency, otherwise known as banker's acceptances, which are eligible for purchase by the Federal Reserve System;

(viii) negotiable certificates of deposit issued by a nationally or state-chartered bank or savings and loan association or by a state-licensed branch of a foreign bank which, to the extent they are not insured by federal deposit insurance, are issued by an institution the general obligations of which are rated in one of the top two Rating Categories by a Rating Agency;

(ix) bonds, debentures and notes issued by corporations organized and operating within the United States which securities are rated in one of the top two Rating Categories by a Rating Agency;

(x) interest-bearing accounts in state or national banks or in state or federal savings and loan associations having principal offices in the State, the deposits of which shall be secured at all times and in the same manner as state moneys are by law required to be secured;

(xi) deposits in the Surplus Money Investment Fund as referred to in the California Government Code;

(xii) repurchase agreements or reverse repurchase agreements, as such terms are defined in and pursuant to the terms of Section 16480.4 of the California Government Code;

(xiii) collateralized or uncollateralized investment agreements or other contractual arrangements with corporations, financial institutions or national associations within the United States, provided that the senior long-term debt of such corporations, institutions or associations is rated within the top two Rating Categories by a Rating Agency;

(xiv) money market funds that invest solely in obligations described in clause (i) of this definition; or

(xv) such other investments as may be authorized by a Supplemental Indenture, provided that each Rating Agency has confirmed in writing to the Trustee that the use of such additional investments will not, by itself, result in the withdrawal, suspension or downgrade of any rating issued by such Rating Agency with respect to any Outstanding Bonds.

"**Authorized Officer**" means the Director, any Deputy Director, the Chief, Division of Fiscal Services, Deputy Controller and Chief Counsel of the Department, and any other individual authorized by the Director to perform the act or sign the document in question.

"**Bank**" means any (i) bank or trust company organized under the laws of any state of the United States of America, (ii) national banking association, (iii) savings bank or savings and loan association chartered or organized under the laws of any state of the United States of America, or (iv) federal branch or agency pursuant to the International Banking Act of 1978 or any successor provisions of law, or 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.

"**Bond Charge**" has the same meaning as that term is defined in the 2002 Rate Agreement, including, without limitation, any Bond Charges imposed on power furnished by an Electric Service Provider (as defined in the 2002 Rate Agreement).

"**Bond Charge Collection Account**" means the account by that name established under the Indenture.

"**Bond Charge Payment Account**" means the account by that name established under the Indenture.

"**Bond Charge Revenues**" means Revenues received by the Department arising from Bond Charges.

"**Bond Related Costs**" has the same meaning as that term is defined in the 2002 Rate Agreement, and shall include the items of cost specified in section D.3 under the caption "Application and Flow of Funds" below.

"**Bonds**" means any obligations, issued in any form of debt, authorized by the Indenture and secured by a pledge of and lien on the Trust Estate on a parity with each other and with Parity Obligations, including, but not limited to, bonds, notes, bond anticipation notes, and commercial paper, but such term shall not include any Subordinated Indebtedness or Subordinated Obligations.

"**Business Day**" means (a) any day of the year other than (i) a Saturday or Sunday, (ii) a State legal holiday, (iii) any day which shall be in the city of Sacramento, California, or the city in which the Co-Trustee or relevant office of any Paying Agent, Registrar or Securities Depository or, if any Bond is supported by an Enhancement Facility, the provider of such Enhancement Facility is located, a legal holiday or a day on which Banks in any of such cities are required or authorized by law or other government action to close, or (b) with respect to any Series of Bonds, as may be provided by Supplemental Indenture.

"**Capital Appreciation Bonds**" means Bonds as to which interest is payable only at the maturity or prior redemption of such Bonds; provided, however, that if any such Bonds are converted to or from Bonds as to which interest is payable periodically, such Bonds shall be deemed to be Capital Appreciation Bonds only after or until such conversion, as the case may be. For the purposes of (i) receiving payment of the Redemption Price if a

Capital Appreciation Bond is redeemed prior to maturity, or (ii) computing the principal amount of Bonds held by the Owner of a Capital Appreciation Bond in giving to the Department or the Trustee any notice, consent, request, or demand pursuant to the Indenture for any purpose whatsoever, the principal amount of a Capital Appreciation Bond on any date shall be deemed to be its Accreted Value as of such date.

"**Commercial Paper**" means Bonds issued as part of a program of short-term Bonds having the characteristics of commercial paper in that (i) such Bonds have a stated maturity not later than 270 days from their date of issue and (ii) maturing Bonds of such program may be paid with the proceeds of Bonds having the characteristics of Commercial Paper. Notwithstanding the foregoing, Commercial Paper may be paid with the proceeds of other Bonds.

"**Commission**" means the Public Utilities Commission of the State, or any successor to the rights, duties and obligations of the Commission under the Act.

"**Consultant**" means an accountant or firm of accountants (which may be the accountant or firm of accountants then serving as the auditor of the Department), or a management consultant or firm of management consultants, or an engineer or firm of engineers, which, in any case, shall be of recognized standing in the field of electric utility rate consulting, selected by the Department, and may be regularly retained to provide services to the Department but shall not be an officer or employee of the State.

"**Costs**" means costs, expenses and purposes for which Bonds may be issued under the Act, including, but not limited to, the following: (i) costs of Power and transmission, scheduling, and other related expenses incurred by the Department, including, but not limited to, all amounts payable by the Department, of whatever kind and nature, under and pursuant to Power Supply Contracts and costs of avoiding purchasing Power for retail end-use customers paid or incurred pursuant to an Additional Emergency Measure; (ii) reimbursement of expenditures made from the Electric Power Fund for such purposes; (iii) repayment to the General Fund of the State of appropriations made to the Electric Power Fund pursuant to Assembly Bill 1X or Senate Bill 7X, repayment to the General Fund of appropriations made to the Electric Power Fund after the effectiveness of Assembly Bill 1X for purposes of Division 27 of the State Water Code, and repayment of General Fund moneys expended by the Department pursuant to the 2001 Emergency Measures; (iv) costs of establishing or maintaining reserves required or permitted by the Indenture, including, but not limited to, debt service and operating reserves; (v) costs of issuing Bonds or costs incidental to their payment or security, including, but not limited to, fees, expenses, and costs payable, and reimbursements, under Enhancement Facilities; (vi) capitalized interest on Bonds; and (vii) payment of principal, interest, and redemption, tender or purchase price of any (a) Bonds issued by the Department for the payment of any Costs, (b) Bonds issued to refund other Bonds, or (c) any other bonds, notes, or other evidences of indebtedness issued by the Department for purposes of the Act. Notwithstanding the foregoing, Costs shall not include (1) depreciation or obsolescence charges or reserves therefor, (2) amortization of intangibles or other bookkeeping entries of a similar nature; or (3) any costs of the Department relating to a Separately Financed Program.

"**Co-Trustee**" means U.S. Bank, N.A., and its successor or successors and any other Person which may at any time be substituted in its place pursuant to the Indenture.

"**Counsel's Opinion**" means an opinion signed by an attorney or firm of attorneys of nationally recognized standing in the field of law relating to municipal bonds selected by the Department.

"**Credit Facility Reimbursement Obligation**" has the meaning as defined under "Special Provisions Relating to Enhancement Facilities, Qualified Swaps and Other Similar Arrangements" below.

"**Debt Service**" means, for purposes of determining deposits to and balances required to be on deposit in the Bond Charge Payment Account, the Debt Service Reserve Requirement, and the additional Bonds test as provided in the Indenture, for any period and as of any date of calculation, with respect to any Outstanding Bonds, an amount equal to the sum of (i) interest accruing during such period on such Bonds, except to the extent that

such interest is to be paid from deposits in the Bond Charge Payment Account made from the proceeds of Bonds or Subordinated Indebtedness, and (ii) that portion of each Principal Installment for such Bonds which would accrue during such period if such Principal Installment were deemed to accrue daily in equal amounts from the next preceding Principal Installment due date for such Bonds (or, if there shall be no such preceding Principal Installment due date or such preceding Principal Installment due date is more than one (1) year (or in the case of initial Principal Installment due no later than December 31, 2004 for Bonds delivered in 2002, such period as may be provided by Supplemental Indenture) prior to the due date of such Principal Installment, then from a date one (1) year preceding the due date of such Principal Installment or from the date of issuance of such Bonds, whichever date is later). For purposes of such calculations, the following assumptions are to be used:

(i) such interest and Principal Installments shall be calculated on the assumptions that (a) no Bonds (except for Option Bonds actually tendered for payment and not purchased in lieu of redemption prior to the redemption date thereof) Outstanding at the date of calculation will cease to be Outstanding except by reason of the payment of each Principal Installment on the due date thereof and (b) the principal amount of Option Bonds tendered for payment shall be deemed to be payable on the date required to be paid pursuant to such tender;

(ii) if 20% or more of the principal of such Bonds is not due until the final stated maturity of such Bonds, principal and interest on such Bonds may, at the option of the Department, written notice of which shall be signed by an Authorized Officer and filed with the Trustee, be treated as if such principal and interest were due based upon an amortization of principal resulting in approximately level debt service (principal and interest) over the respective terms of such Bonds;

(iii) interest accruing on Variable Rate Bonds during any future period shall be assumed to accrue at a rate equal to the greater of (a) 130% of the highest average interest rate on such Variable Rate Bonds in any calendar month during the twelve (12) calendar months ending with the month preceding the date of calculation, or such shorter period that such Variable Rate Bonds shall have been Outstanding, or (b) 4.0%,

(iv) the principal of Bonds issued as Commercial Paper will be treated as if such principal were due based upon level amortization of principal from the date of calculation to the latest maturity date of any Bonds, and the interest on such Commercial Paper shall be calculated as if such Commercial Paper were Variable Rate Bonds;

(v) the principal and interest portions of the Accreted Value of Capital Appreciation Bonds becoming due at maturity or by virtue of a Sinking Fund Installment shall be included in the calculations of accrued and unpaid and accruing interest or Principal Installments in such manner and during such period of time as is specified in the Supplemental Resolution authorizing such Capital Appreciation Bonds;

(vi) notwithstanding paragraphs (iii) or (iv) above, if the Department, in connection with any Variable Rate Bonds or Commercial Paper, has entered into a Qualified Swap that provides that the Department is to pay to the counterparty an amount determined based upon a fixed rate of interest on such Outstanding principal amount of such Variable Rate Bonds or Commercial Paper, and that the counterparty is to pay to the Department an amount determined based upon a variable rate of interest on such Outstanding principal amount of such Variable Rate Bonds or Commercial Paper (a "variable rate payment") or the amount by which the rate at which such Variable Rate Bonds or Commercial Paper bear interest exceeds a stated rate of interest or, if the Department has entered into a Qualified Swap that provides that the Department is to pay to the counterparty one variable rate payment and that the counterparty is to pay to the Department a different variable rate payment, for so long as and to the extent that such Qualified Swap remains in full force and effect it shall be assumed that such Variable Rate Bonds and Commercial Paper bear interest at a rate equal to the sum of (A) the fixed rate of interest to be paid by the Department or the rate in excess of which the counterparty is to make payment to the

Department in accordance with such Qualified Swap, and (B) the greater of (if positive) (1) the average difference between the actual interest rate paid by the Department on such Variable Rate Bonds or Commercial Paper and the variable interest rate the relevant counterparty paid to the Department, taking into account all variable rate payments, during the twelve (12) calendar months ending with the calendar month preceding the date of calculation, or such shorter period that such Variable Rate Bonds or Commercial Paper shall have been Outstanding, and (2) the difference between the actual interest rate paid by the Department on such Variable Rate Bonds or Commercial Paper and the variable interest rate received from the relevant counterparty, taking into account all variable rate payments, as calculated at the end of the calendar month preceding the date of calculation;

(vii) if the Department, in connection with any fixed rate Bonds, has entered into a Qualified Swap that provides that the Department is to pay to the counterparty an amount determined based upon a variable rate of interest on the Outstanding principal amount of such Bonds, it shall be assumed that such Bonds bear interest at the variable rate of interest to be paid by the Department, with interest on such Bonds calculated as if they were Variable Rate Bonds as described in paragraph (iii) above; provided, however, if the counterparty is to pay to the Department a fixed rate of interest on the amount of such Bonds that is less than the fixed rate payable thereon by the Department, it shall be assumed that such Bonds bear additional interest at the rate which is the difference between the fixed rates payable by and to the Department; and

(viii) principal and interest payments on Bonds shall be excluded to the extent such payments are to be paid from amounts then currently on deposit with the Trustee or other Fiduciary in escrow specifically therefor and restricted to Defeasance Securities.

"**Debt Service Reserve Account**" means the account by that name established under the Indenture.

"**Debt Service Reserve Requirement**" means, as of any date of calculation, an amount equal to Maximum Aggregate Annual Debt Service. In furtherance of the covenant described below under "Covenant Relating to Retirement of Bonds", for the purpose of calculating the Debt Service Reserve Requirement at the time of, and deposit to be made into the Debt Service Reserve Account in connection with, the issuance of the initial Series of Bonds (or more than one Series of Bonds delivered on the same date as the initial Series of Bonds) (collectively, the "initial Bonds"), Debt Service on the initial Bonds shall be calculated by assuming that the initial Bonds will mature in such amounts and at such times (with the initial Bonds assumed to bear interest as provided in the definition of Debt Service) as will result in substantially level debt service (to the extent contemplated by such covenant of the Department) on the initial Bonds, without regard to any additional Series of Bonds.

"**Defeasance Security**" means:

(i) cash;

(ii) an Authorized Investment specified in clauses (i), (ii), (iii) or (v) of the definition thereof, which is not callable or redeemable at the option of the issuer thereof;

(iii) an Authorized Investment specified in clause (iv) of the definition thereof (a "Municipal Bond"), which Municipal Bond is fully secured as to principal and interest by an irrevocable pledge of moneys or direct and general obligations of, or obligations guaranteed by, the United States of America, which moneys or obligations are segregated in trust and pledged for the benefit of the holder of the Municipal Bond, and which Municipal Bond is rated in the highest Rating Category by at least two Rating Agencies and provided, however, that such Municipal Bond is accompanied by a Counsel's Opinion to the effect that such Municipal Bond is not subject to redemption prior to the date the proceeds of such Municipal Bond will be required for the purposes of the investment being made therein; or

(iv) any other investment designated in a Supplemental Indenture as a Defeasance Security for purposes of defeasing the Bonds authorized by such Supplemental Indenture, provided that each Rating Agency has confirmed in writing to the Trustee that the use of such other investment will not, by itself, result in the withdrawal, suspension or downgrade of any rating issued by such Rating Agency with respect to any such Bonds to be defeased.

"**Department**" means the State of California Department of Water Resources, existing pursuant to Article 1 (commencing with Section 120) of Chapter 2 of Division 1 of the California Water Code, or any successor to the rights, duties and obligations of the Department under the Act and the Indenture.

"**Direct Access Power Charge**" means any charge imposed by the Commission (by an order that is final and non-appealable) on, and received by the Department from, any Person receiving power from an Electric Service Provider intended to recover the Department's Revenue Requirements other than Bond Related Costs, and shall in no event include Bond Charges; provided, however, that Bond Charges may be separately imposed on such Persons.

"**Direct Access Power Charge Revenues**" means Revenues received by the Department arising from Direct Access Power Charges.

"**Director**" means the Director of Water Resources of the State, or any successor to the rights, duties and obligations of the Director under the Act and the Indenture.

"**Electrical Corporation**" has the same meaning as that term is defined in Section 218 of the Public Utilities Code.

"**Electric Power Fund**" means the fund by that name established under the Indenture.

"**Electric Service Provider**" has the meaning given in the 2002 Rate Agreement.

"**Enabling Measures**" means, collectively, the Act and the Additional Emergency Measures, or any of them, as appropriate.

"**Enhancement Facility**" means any letter of credit, standby purchase agreement, line of credit, policy of bond insurance, surety bond, guarantee or similar instrument, or any other agreement, securing, providing liquidity for, supporting or enhancing Outstanding Bonds, or any combination of the foregoing, or any agreement relating to the reimbursement thereof whether or not such instrument or agreement has been drawn upon, obtained by the Department.

"**Events of Default**" means the events defined as such under caption "Events of Default and Remedies" below.

"**Excess Amounts**" has the meaning specified in section F under the caption "Application and Flow of Funds" below.

"**Fiduciary**" or "**Fiduciaries**" means the Trustee, the Co-Trustee, any Registrar, any Paying Agent, or any or all of them, as may be appropriate.

"**Financing Documents**" means any resolution, indenture (including the Indenture), trust agreement, loan agreement, revolving credit agreement, reimbursement agreement, standby purchase agreement or other agreement or instrument adopted or entered into by the Department authorizing, securing or enhancing any evidence of indebtedness issued pursuant to the Act, including the Bonds, Parity Obligations and Subordinated Indebtedness, as from time to time amended or supplemented in accordance therewith.

"**Fiscal Year**" means the twelve-month period commencing on July 1 of each year; provided, however, that the Department may at any time adopt a different twelve-month period as the Fiscal Year, in which case July 1, when used herein with reference to Fiscal Year, shall be construed to mean the first day of the first calendar month of such different Fiscal Year.

"**Indenture**" means the Trust Indenture among the Department, the Trustee and the Co-Trustee, as from time to time amended or supplemented by Supplemental Indentures.

"**Liquidity Facility Reimbursement Obligation**" has the meaning as defined under "Special Provisions Relating to Enhancement Facilities, Qualified Swaps and Other Similar Arrangements" below.

"**Maximum Aggregate Annual Debt Service**" means, as of any date of calculation, an amount equal to the maximum Aggregate Debt Service coming due on Bonds then Outstanding in any calendar year thereafter, commencing with the then current calendar year, excluding interest to be paid from the proceeds of Bonds or Subordinated Indebtedness and on deposit in the Bond Charge Payment Account.

"**Minimum Operating Expense Available Balance**" means, at the time Revenue Requirements are submitted to the Commission pursuant to the Indenture, (i) for so long as the Department is procuring all or a portion of the Residual Net Short, $1 billion, and (ii) thereafter, the maximum amount projected by the Department by which Operating Expenses exceed Power Charge Revenues during any one calendar month during that Revenue Requirement Period. Such projections shall be based on such assumptions as the Department deems to be appropriate after consultation with the Commission and may take into account a range of possible future outcomes.

"**Operating Account**" means the account by that name established under the Indenture.

"**Operating Expenses**" means the following costs and expenses of the Department in connection with its activities as permitted under the Enabling Measures: (i) payments for the purchase of Power and the delivery of such Power including, but not limited to, amounts paid under short-term Power Supply Contracts, Priority Long Term Power Contracts and other long-term Power Supply Contracts, termination and liquidation damage payments thereunder, payments thereunder relating to emission costs and emission opportunity costs, amounts payable in respect of balance of month-ahead Power, hour-ahead Power and real time balancing Power, including in-market and out-of-market purchases, costs of transmission, distribution, scheduling, dispatch and other expenses of the Department in connection with the delivery of its Power, and costs of avoiding purchasing Power for retail end-use incurred pursuant to an Additional Emergency Measure; (ii) payments for or in connection with fuel to be used in the production of Power purchased by the Department, whether paid as a charge under a Power Supply Contract or a separate agreement for the purchase, transportation or storage of fuel for use in the generation of Power, including, but not limited to, termination and liquidated damage payments under fuel purchase agreements, payments under options or other fuel or electricity instruments, and payments under financial instruments relating to fuel costs or costs related to fuel costs; (iii) payments under any security agreements executed in connection with Power Supply Contracts or in connection with agreements for the purchase, transportation and storage of fuel, or any other agreement, relating to the purchase of Power; (iv) reasonable administrative, general and overhead expenses and payments for employee benefits, including, but not limited to, payments to savings, pension, retirement, health and hospitalization funds; (v) insurance premiums including, but not limited to, bond and Qualified Swap insurance premiums; (vi) legal and engineering expenses; (vii) expenses for consulting and technical services; (viii) charges paid by the Department pursuant to any licenses, orders or mandates from any agency or regulatory body having lawful jurisdiction; (ix) any taxes, governmental charges, and any other similar costs and expenses required to be paid by the Department, and costs required by the California Independent System Operator to be paid by the Department or imposed on the Department by regulatory or other governmental requirements; (x) costs of complying with any arbitrage restrictions or rebate requirements relating to the Bonds under Section 148 of the Internal Revenue Code of 1986 as amended, or a successor statute, and applicable regulations thereunder; (xi) such other costs and expenses as may be provided for in a Rate Agreement as being recoverable as part of Revenue Requirements; and (xii) such

other costs and expenses with respect to the sale of Power to local publicly owned electric utilities, as defined in Assembly Bill 1X, or in connection with the exchange of Power or the sale, transfer or other disposition of Power not required for use within the State as permitted by the Act, which would constitute current operating expenses under generally accepted accounting principles or statutory accounting principles as in effect from time to time and applicable to governmental units such as the Department. Notwithstanding the foregoing, Operating Expenses shall not include (a) any repayments to the General Fund of the State of advances made to the Department from amounts appropriated to the Electric Power Fund or interest thereon payable at the Pooled Money Investment Rate; (b) principal, Redemption Price and Purchase Price of and interest on Bonds; (c) debt service on or payments under Parity Obligations, Subordinated Indebtedness or Subordinated Obligations; (d) depreciation or obsolescence charges or reserves therefor; (e) amortization of intangibles or other bookkeeping entries of a similar nature; (f) any amounts paid from Bond Charge Revenues pursuant to section D.1 under the caption "Application and Flow of Funds" below; or (g) any costs and expenses attributable to a Separately Financed Program.

"**Operating Reserve Account**" means the account by that name established under the Indenture.

"**Operating Reserve Account Requirement**" or "**Minimum Operating Reserve Account Requirement**" means, during each Revenue Requirement Period, the greater of (i) the largest aggregate amount projected by the Department by which Operating Expenses exceed Power Charge Revenues during any consecutive seven (7) calendar months commencing in such Revenue Requirement Period, and (ii) either (A) 18% of the Department's projected annual Operating Expenses for any Revenue Requirement Period in which the Department is procuring all or a portion of the Residual Net Short and which commences prior to 2006, or (B) 12% of the Department's projected annual Operating Expenses for any Revenue Requirement Period in which the Department is not procuring all or a portion of the Residual Net Short or which commences after 2005; provided, however, that solely for purposes of (A) and (B) above for Revenue Requirement Periods commencing after 2003, the projected amount shall not be less than the applicable percentage of the Department's Operating Expenses for the most recent twelve (12) calendar month period for which the Department determines that reasonably full and complete Operating Expense information is available, adjusted as described in the next sentence. If the Department was financially responsible and liable under a Power Supply Contract during all or a portion of the applicable twelve (12) calendar month period, but financial responsibility has been assumed by another Person and the Department has been entirely relieved of financial liability and all other liabilities under the contract, or the contract has terminated or will terminate by its terms prior to the end of the Revenue Requirement Period for which the Operating Reserve Account Requirement is being calculated, then the relevant costs associated with that contract shall be excluded from the calculation of the historical Operating Expenses. If amended Revenue Requirements are filed with the Commission during any Revenue Requirement Period, the Operating Reserve Account Requirement shall be recalculated for the remainder of such Revenue Requirement Period as provided above. Notwithstanding the foregoing, in connection with the determination of whether additional Bonds may be issued upon compliance with the Indenture, the relevant calculation under clause (i) above shall be made in respect of a consecutive seven (7) calendar month period in the test period specified by the applicable provision of the Indenture. All projections referenced in this paragraph shall be based on such assumptions as the Department deems to be appropriate after consultation with the Commission and, in the case of clause (i) above, may take into account a range of possible future outcomes. The Operating Reserve Account Requirement shall include, but shall not be limited to, the Priority Contract Contingency Reserve Amount.

"**Option Bonds**" means Bonds which by their terms may be tendered by and at the option of the Owner thereof to the Department or to the issuer of an Enhancement Facility providing liquidity with respect to such Bonds, for purchase prior to the stated maturity thereof, or the maturities of which may be extended by and at the option of the Owner thereof.

"**Outstanding**," when used with reference to Bonds or Bonds of a Series, means, as of any date, Bonds or Bonds of such Series theretofore or thereupon being delivered under the Indenture except:

(i) Any Bonds canceled at or prior to such date;

(ii) Bonds the principal and Redemption Price, if any, of and interest on which have been paid in accordance with the terms thereof;

(iii) Bonds in lieu of or in substitution for which other Bonds shall have been delivered pursuant to the Indenture;

(iv) Bonds deemed to have been paid as provided in the Indenture;

(v) Option Bonds tendered or deemed tendered in accordance with the provisions of the Supplemental Indenture authorizing such Bonds on the applicable tender date, if the purchase price thereof and interest thereon shall have been paid or amounts are available and set aside for such payment as provided in such Supplemental Indenture, except to the extent such tendered Option Bonds are held by the Department or an issuer of an Enhancement Facility and/or thereafter may be resold pursuant to the terms thereof and of such Supplemental Indenture; and

(vi) as may be provided with respect to such Bonds by the Supplemental Indenture authorizing such Bonds.

"**Owner**" or any similar term means the registered owner of any Bond as shown on the books for the registration and transfer of Bonds maintained in accordance with the Indenture.

"**Parity Obligations**" means Reimbursement Obligations and amounts payable under Qualified Swaps. For purposes of certain provisions of the Indenture, any Parity Obligations entered into or issued subsequent to the date of delivery of this Indenture shall specify, to the extent applicable, the interest and principal components of, or the scheduled payments corresponding to interest under, such Parity Obligations. Parity Obligations shall comply with the second paragraph under "Events of Default and Remedies" below.

"**Paying Agent**" means any paying agent for the Bonds of any Series and its successor or successors and any other Person which may at any time be substituted in its place pursuant to the Indenture.

"**Person**" means any individual, corporation, firm, partnership, joint venture, association, joint-stock company, trust, unincorporated association, limited liability company or partnership, or other legal entity or group of entities, including, but not limited to, a governmental entity or any agency or subdivision thereof.

"**Pooled Money Investment Rate**" means, for any amounts deposited in the Electric Power Fund from the General Fund and for any period, the rate of interest to be paid on such amounts to the State's Pooled Money Investment Account as determined from time to time for such period.

"**Power**" means electric power and energy, including, but not limited to, capacity and output, or any of them.

"**Power Charge Revenues**" means Revenues received by the Department arising from Power Charges.

"**Power Charges**" has the same meaning as that term is defined in the 2002 Rate Agreement.

"**Power Supply Contract**" means any contract or agreement entered into by the Department pursuant to the Enabling Measures and under which the Department purchases Power, or purchases fuel for conversion to or in exchange for Power, or any option with respect thereto.

"**Principal Installment**" means, as of any date of calculation and with respect to any Series so long as any Bonds thereof are Outstanding, (i) the principal amount of Bonds (including the principal amount of any Option Bonds tendered for payment and not purchased) of such Series due (or so tendered for payment and not purchased) on any date for which no Sinking Fund Installments have been established, or (ii) the unsatisfied

balance (determined as provided in section D.4 under the caption "Application and Flow of Funds" below) of any Sinking Fund Installments due on any date for Bonds of such Series, plus the amount of the sinking fund redemption premiums, if any, which would be applicable upon redemption of such Bonds on such date in a principal amount equal to said unsatisfied balance of such Sinking Fund Installments, or (iii) if both clause (i) and clause (ii) apply on the same date with respect to different Bonds of such Series, the sum of such principal amount of Bonds and of such unsatisfied balance of Sinking Fund Installments due on such date plus such applicable redemption premiums, if any.

"**Priority Contract Contingency Reserve Amount**" means, during each Revenue Requirement Period or, for the purpose of the additional Bonds test, during the test period specified in the Indenture, the maximum amount projected by the Department to be payable by the Department under and pursuant to Priority Long Term Power Contracts in any calendar month during such Revenue Requirement Period. Each such projection shall be made at the beginning of the relevant Revenue Requirement Period. Such projections shall be based on such assumptions as the Department deems to be appropriate after consultation with the Commission and may take into account a range of possible future outcomes.

"**Priority Contract Account**" means the account by that name established under the Indenture.

"**Priority Contract Costs**" means all costs and expenses payable by the Department under or pursuant to Priority Long Term Power Contracts.

"**Priority Long Term Power Contract**" has the same meaning as that term is defined in the 2002 Rate Agreement.

"**Purchase Price**" means, with respect to any Bond, 100% of the principal amount thereof plus accrued and unpaid interest, if any, plus, in the case of a Bond subject to mandatory tender for purchase on a date when such Bond is also subject to optional redemption at a premium, an amount equal to the premium that would be payable on such Bond if redeemed on such date.

"**Qualified Swap**" means, to the extent from time to time permitted by law, with respect to Bonds, (a) any financial arrangement (i) which is entered into by the Department with an entity that is a Qualified Swap Provider at the time the arrangement is entered into, (ii) which is a cap, floor or collar, forward rate, future rate, swap (such swap may be based on an amount equal either to the principal amount of such Bonds of the Department as may be designated or a notional principal amount relating to all or a portion of the principal amount of such Bonds), asset, index, price or market-linked transaction or agreement, other exchange or rate protection transaction agreement, other similar transaction (however designated), or any combination thereof, or any option with respect to any of the foregoing, executed by the Department, and (iii) which has been designated as a Qualified Swap with respect to such Bonds in a written determination signed by an Authorized Officer and filed with the Trustee and the Co-Trustee, and (b) any letter of credit, line of credit, policy of insurance, surety bond, guarantee or similar instrument securing the obligations of the Department under any financial arrangement described in clause (a) above.

"**Qualified Swap Provider**" means an entity whose senior long term obligations, other senior unsecured long term obligations, financial program rating, counterparty rating, or claims paying ability, or whose payment obligations under an interest rate exchange agreement are guaranteed by an entity whose senior long term debt obligations, other senior unsecured long term obligations, financial program rating, counterparty rating, or claims paying ability, are rated at the time of the execution of such Qualified Swap either (i) at least as high as the third highest Rating Category of each Rating Agency then maintaining a rating for the Qualified Swap Provider, but in no event lower than any Rating Category designated by any such Rating Agency for the Bonds subject to such Qualified Swap, or (ii) any such lower Rating Categories which each such Rating Agency indicates in writing to the Department and the Trustee will not, by itself, result in a reduction or withdrawal of its rating on the Outstanding Bonds subject to such Qualified Swap that is in effect prior to entering into such Qualified Swap.

"**Rate Agreement**" means any agreement between the Department and the Commission pursuant to the Act and other applicable provisions of law with respect to Revenue Requirements or charges in connection with Power sold by the Department and/or Electrical Corporations, as supplemented and amended from time to time.

"**Rating Agency**" means each nationally recognized securities rating agency then maintaining a rating on the Bonds at the request of the Department.

"**Rating Category**" means one of the generic rating categories of any Rating Agency without regard to any refinement or gradation of such rating by a numerical modifier or otherwise.

"**Redemption Price**" means, with respect to any Bond, 100% of the principal amount thereof plus the applicable premium, if any, payable upon the redemption thereof pursuant to the Indenture, or such other price as may be specified in a Supplemental Indenture.

"**Registrar**" means any registrar for the Bonds of any Series and its successor or successors and any other Person which may at any time be substituted in its place pursuant to the Indenture.

"**Reimbursement Obligation**" has the meaning provided under the caption "Special Provisions Relating to Enhancement Facilities, Qualified Swaps and Other Similar Arrangements" below.

"**Residual Net Short**" means the total electric requirements of the retail electric end-users served by and within the service areas of Electrical Corporations whose customers receive Power from the Department, minus electric generation available from both Utility Retained Generation and Department contract purchases. "Utility Retained Generation" means generating resources retained by Electrical Corporations, bilateral contracts held by Electrical Corporations and Qualifying Facility contracts. "Qualifying Facility" means a renewable power production or co-generation facility not primarily engaged in the generation or sale of electric power and that qualifies under Section 201 of the federal Public Utilities Regulatory Policy Act of 1978, the output from which facility is sold to an Electrical Corporation.

"**Responsible Officer**" means (i) with respect to the Trustee, any officer or employee of the State having direct responsibility for the administration of the Indenture, and in each case also, with respect to a particular matter, any other officer or employee to whom such matter is referred because of such officer's or employee's knowledge of and familiarity with the particular subject, and (ii) with respect to the Co-Trustee, any officer assigned to the corporate trust office of the Co-Trustee, including, but not limited to, any managing director, principal, vice president, assistant vice president, assistant treasurer, assistant secretary or any other officer of the Co-Trustee customarily performing functions similar to those performed by any of the above designated officers.

"**Revenue Requirement Period**" means any period for which the Department determines, and submits to the Commission, the Department's Revenue Requirements. Revenue Requirement Period also includes the period commencing with the delivery of the initial Series of Bonds and ending December 31, 2002.

"**Revenue Requirements**" means the amounts needed from time to time by the Department to satisfy its obligations under the Enabling Measures.

"**Revenues**" means all revenues, receipts, charges, income, profits, proceeds or other moneys actually received by the Department, from whatever source, arising from or in connection with the conduct of the Department's program for the purchase and sale of Power and related activities pursuant to the Enabling Measures and Senate Bill 7X, including, but not limited to, (i) all money paid directly or indirectly to or for the account of the Department with respect to any sale, exchange, transfer or disposition of Power acquired by the Department pursuant to the Enabling Measures and Senate Bill 7X, (ii) all moneys actually received by the Department which have been recovered as compensation or damages from providers of Power or other commodities or services acquired by the Department pursuant to the Enabling Measures, provided that nothing in the Indenture shall obligate the Department to recover and actually receive moneys as such compensation or damages from such

providers, (iii) net payments to the Department under Qualified Swaps and (iv) Direct Access Power Charges. Revenues shall include, but shall not be limited to, Bond Charge Revenues, Power Charge Revenues, and Direct Access Power Charge Revenues, as and when received by the Department. Revenues shall not include (a) any revenues, receipts, charges, income, profits, proceeds or other money or monetary benefits attributable directly or indirectly to the ownership or operation of any Separately Financed Program, (b) any federal or state grant moneys to the extent receipt is conditioned upon their expenditure for a particular purpose or in a particular manner other than as provided in the Indenture for Revenues, (c) money actually received as compensation or damages recovered from providers of Power or other commodities or services acquired by the Department pursuant to the Enabling Measures, if and to the extent the Department's entitlement thereto is not final and is subject to appeal, other review or refund, (d) the proceeds of any Bonds or Subordinated Indebtedness, (e) any amounts received as a result of a deposit of moneys or Defeasance Securities for the defeasance of Bonds pursuant to the Indenture, except to the extent not required for such purpose as provided in the Indenture, and (f) the proceeds of any draw on or payment under any Enhancement Facility which is intended for the payment of particular Bonds.

"**Securities Depository**" means, with respect to Bonds of a Series, the securities depository, if any, appointed for such Bonds in a Supplemental Indenture providing with respect to the issuance and payment of such Bonds.

"**Senate Bill 7X**" means Chapter 3 of the Statutes of 2001 (Senate Bill 7 of the First Extraordinary Session) of the State.

"**Separately Financed Program**" means, collectively, (i) any program, project or purpose described as such under the caption "Separately Financed Programs" below and (ii) the State Water Resources Development System.

"**Series**" means all of the Bonds delivered on original issuance pursuant to a single Supplemental Indenture and denominated therein a single series, and any Bonds thereafter delivered in lieu of or in substitution therefor pursuant to certain provisions of the Indenture, regardless of variations in maturity, interest rate, or other provisions.

"**Servicing Agreement**" means any agreement, as supplemented and amended, between the Department and one or more Electrical Corporations, or, if approved by the Commission, other Persons if a Consultant advises the Trustee or Co-Trustee in writing that such other Person is reasonably expected to be capable of carrying out the provisions thereof, to provide the functions or services specified in the Indenture as agent of the Department.

"**Servicing Arrangements**" means, collectively, the Servicing Agreements and Servicing Orders, or any of them, as appropriate.

"**Servicing Order**" means each order of the Commission described below under the caption "Servicing Arrangements; Collection of Revenues".

"**Sinking Fund Installment**" means an amount so designated for the retirement prior to maturity of Bonds of a Series of like maturity and interest rate.

"**State**" means the State of California.

"**Subordinated Indebtedness**" means any bond, note or other indebtedness authorized by a resolution or indenture of the Department and permitted under the Act and designated as constituting "Subordinated Indebtedness" in a certificate of an Authorized Officer delivered to the Trustee, which shall be payable from the Trust Estate subject and subordinate to the prior payments to be made therefrom as provided for in the Indenture. Subordinated Indebtedness may be secured by a lien on and pledge of the Trust Estate junior and inferior to the lien on and pledge of the Trust Estate created in the Indenture for the payment of the Bonds and Parity

Obligations to the extent permitted by the Indenture, and may also be payable from such other sources and additionally secured as provided by the Indenture.

"**Subordinated Obligation**" means any payment obligation (other than a payment obligation constituting a Parity Obligation or Subordinated Indebtedness) of the Department incurred pursuant to the Act arising under any contract, agreement or other obligation incurred pursuant to the Act not constituting Bonds, Parity Obligations or Operating Expenses, provided that if such contract, agreement or other obligation is not incurred in connection with the Bonds, it shall have been approved by the Commission. Each Subordinated Obligation shall be payable from the Trust Estate subject and subordinate to the prior payments to be made therefrom as provided for in the Indenture. Subordinated Obligations may be secured by a lien on and pledge of the Trust Estate junior and inferior to the lien on and pledge of the Trust Estate created in the Indenture for the payment of the Bonds and Parity Obligations to the extent permitted by the Indenture, and may also be payable from such other sources and additionally secured as provided by the Indenture.

"**Supplemental Indenture**" means any indenture supplemental to or amendatory of the Indenture, adopted by, or adopted pursuant to authorization granted by, the Department in accordance with the Indenture.

"**Treasurer**" means the Treasurer of the State, or any successor to the rights, duties and obligations of the Treasurer under the Indenture.

"**Trustee**" means the Treasurer.

"**Trust Estate**" means, collectively:

(i) all Revenues;

(ii) all right, title and interest of the Department in and to Revenues, and all rights to receive the same; including but not limited to the assignment of amounts payable under the Servicing Arrangements as provided by the Indenture (see "Servicing Arrangements; Collection of Revenues");

(iii) the Operating Account, the Operating Reserve Account, the Bond Charge Collection Account, the Bond Charge Payment Account and the Debt Service Reserve Account, subject to the application thereof as provided in the Indenture; and

(iv) all funds, moneys and securities and any and all other rights and interests in property, whether tangible or intangible, from time to time hereafter by delivery or by writing of any kind conveyed, mortgaged, pledged, assigned or transferred as and for additional security under the Indenture for the Bonds and Parity Obligations by the Department, or by anyone on its behalf, or with its written consent, to the Trustee, which is authorized by the Indenture to receive any and all such property at any and all times, and to hold and apply the same subject to the terms of the Indenture; provided, however, that no such additional security shall be received, held or applied by the Trustee unless accompanied by a Counsel's Opinion to the effect that such additional security may be pledged under the Act and that it would not cause the Bonds or Parity Obligations to constitute a debt or liability of the State within the meaning of any constitutional or statutory provision or restriction, unless such constitutional or statutory provision or restriction shall have been complied with;

provided, however, that the Trust Estate shall not include, as to any Bond, any moneys or securities set aside under the Indenture specifically for the payment of other Bonds pursuant to the Indenture and, as to any Option Bond, any moneys or securities set aside for the purchase thereof as may be provided in the Indenture.

"**2001 Emergency Measures**" means all Proclamations and Orders of the Governor of the State issued in calendar year 2001 pursuant to the California Emergency Services Act (Chapter 7, Division 1, Title 2 of the California Government Code, as amended) as amended, including, but not limited to, any regulations issued

pursuant thereto, issued in response to or in anticipation of the need to assure the availability of power to retail end-use customers in the State due to the inability or failure of an Electrical Corporation to purchase such power.

"**2002 Rate Agreement**" means the Rate Agreement, dated as of March 8, 2002, between the Department and the Commission, as supplemented and amended from time to time.

"**Valuation Date**" means, with respect to any Capital Appreciation Bonds, the date or dates set forth in the Supplemental Indenture authorizing such Bonds on which specific Accreted Values are assigned to the Capital Appreciation Bonds.

"**Variable Rate Bonds**" means, as of any date of determination, any Bonds on which the interest rate borne thereby may vary thereafter.

Security for the Bonds

The Bonds are special obligation of the Department, payable solely from the Trust Estate. Under the Indenture, the Trust Estate is assigned and pledged to the Trustee and Co-Trustee for the benefit of the Owners of the Bonds and the holders, issuers or other parties to Parity Obligations, as security for the payment of the principal and Redemption Price of and interest on the Bonds, payments due under Parity Obligations, in each case in accordance with their terms and the provisions of the Indenture, subject to the use of the Trust Estate for the purposes and on the terms and conditions provided in the Indenture. The Bonds and Parity Obligations are not payable from any income, receipts, or revenues of the Department other than those included in the Trust Estate, except as permitted by the last sentence of this paragraph, nor do the Bonds or Parity Obligations constitute a legal or equitable pledge, charge, lien, or encumbrance upon any of the property or upon any of the income, receipts, or revenues of the Department, except the Trust Estate. The Bonds, Parity Obligations, Subordinated Obligations and Subordinated Indebtedness (i) shall not be or be deemed to constitute a debt or liability of the State or of any political subdivision thereof, other than, to the extent provided in the Indenture, the Department, or a pledge of the faith and credit of the State or of any such political subdivision, other than the Department to the extent provided in the Indenture, but are payable solely from the funds pledged therefor pursuant to the Indenture, and (ii) do not directly or indirectly or contingently obligate the State or any political subdivision thereof to levy or to pledge any form of taxation whatever therefor or to make any appropriation for their payment. Subordinated Obligations and Subordinated Indebtedness may be secured by the Trust Estate, pursuant to a Supplemental Indenture, to the extent not contrary or inconsistent with the Indenture as theretofore in effect. Nothing contained in the Indenture shall prevent an Enhancement Facility from being provided with respect to any particular Bonds or Parity Obligations and not others, or different reserves being provided pursuant to the Indenture with respect to Bonds than are provided for Parity Obligations, or with respect to particular Parity Obligations than are provided for other Parity Obligations.

In the Indenture the Department represents that, pursuant to California Government Code Section 5451 and California Water Code Section 80132(g), the Indenture creates a valid and binding pledge of the Trust Estate for the benefit of the Owners of the Bonds and the holders, issuers or other parties to Parity Obligations, as security for the payment of the Bonds and Parity Obligations, respectively, to the extent set forth in the Indenture, enforceable in accordance with the terms thereof. The pledge created by the Indenture shall be valid and binding from and after the date the Indenture is executed and delivered, and the Trust Estate shall immediately be subject to the lien of the pledge without any physical delivery thereof or further act, and the lien of the pledge shall be valid and binding as against all parties having claims of any kind in tort, contract or otherwise against the Department irrespective of whether such parties have notice thereof.

Protection of Security

The Department shall at all times, to the extent permitted by law, defend, preserve and protect the pledge created by the Indenture and all interests of the Owners of Bonds and the holders, issuers or other parties to Parity Obligations under the Indenture against all claims and demands of all Persons whomsoever.

Without limiting the generality of the foregoing, if any regulatory or judicial investigation of or challenge to any action taken by the Department in the performance of its obligations under the Act, the Indenture or the Rate Agreement is initiated, the Department shall take all legally available action which, in the judgment of the Department, may be necessary or desirable to assure that such challenge will not result in the inability of the Department to pay amounts payable under the Bonds and Parity Obligations when due.

General Provisions for the Issuance of Bonds

Bonds may be issued pursuant to the Indenture in such principal amount or amounts for each Series of the Bonds as may be specified in the applicable Supplemental Indenture. The aggregate principal amount of the Bonds that may be executed and delivered under the Indenture is not limited except as provided in the Indenture or as may be limited by law. Bonds may be issued for any purpose of the Department authorized by the Act, including, but not limited to, the payment of Costs.

Bonds may be sold in one or more Series (each of which shall contain a designation distinguishing it from other Series), and shall be delivered by the Department under the Indenture but only upon receipt by the Trustee of, among other documents, a Supplemental Indenture authorizing the Bonds, a Counsel's Opinion with respect to validity of the Bonds, a copy of the Rate Agreement applicable to such Bonds, certificates of an authorized representative of the Commission and an Authorized Officer as to the maximum aggregate principal amount of Bonds and Subordinated Indebtedness approved by or pursuant to Rate Agreements, and a certificate of an Authorized Officer stating that, upon the delivery of such Bonds, no Event of Default as defined in the Indenture, or event which, with the giving of notice or passage of time, or both, would constitute an Event of Default, shall have occurred and be continuing.

Prior to the issuance of Bonds, the Trustee shall also receive a certificate or report of a Consultant setting forth (i) the estimated Revenues for the twenty-four (24) calendar month period commencing on the first day of the calendar month next succeeding the date of delivery of such Bonds (the "test period"), (ii) the estimated Debt Service, and estimated amounts payable under all Parity Obligations, during the test period, (iii) the projected Debt Service on Bonds, and projected amounts payable under Parity Obligations, projected to be issued or entered into for any purpose during the test period, (iv) the sum of the estimated and projected amounts required to be paid for Operating Expenses, Subordinated Indebtedness and Subordinated Obligations during the test period, (v) the sum of the amounts estimated and projected to be available in the Operating Account, Bond Charge Collection Account and Bond Charge Payment Account for the payment of the items of cost referred to in clauses (ii) through (iv) above at the commencement of the test period, and (vi) the balances on deposit in the Debt Service Reserve Account and Operating Reserve Account at the commencement of, and projected to be on deposit therein throughout, the test period, and showing that (1) for the test period, the sum of the amounts set forth in clauses (i) and (v) above is at least equal to 100% of the sum of the amounts set forth in clauses (ii), (iii) and (iv) above, (2) the Debt Service Reserve Account is maintained throughout the test period at an amount at least equal to the Debt Service Reserve Requirement and (3) the Operating Reserve Account is maintained throughout the test period at an amount at least equal to the Operating Reserve Account Requirement. Such certificate or report shall reflect, among other things, the issuance of such Bonds and the Debt Service estimated to be payable thereon. The Consultant may base its estimates and projections upon such factors as it shall consider reasonable, including, but not limited to, future increases in Revenue Requirements, a statement to which effect shall be included in such certificate or report. For purposes of this requirement, any Debt Service, Parity Obligations, Subordinated Indebtedness and payments shall not include any amounts thereof expected by the Department to be paid from any funds, other than Revenues, reasonably expected by the Department to be available therefor (including, without limitation, the anticipated receipt of proceeds of sale of Bonds or Subordinated Indebtedness,

or moneys not a part of the Trust Estate), which expectations, if included in a written determination signed by an Authorized Officer and filed with the Trustee, shall be conclusive. This paragraph shall not apply to (w) the initial Series of Bonds, (x) any Bonds assumed to be issued as part of the plan of finance of the Department's program for the purchase and sale of Power, as described in the public offering statement issued by the Department in connection with the initial Series of Bonds, (y) any Bonds issued to refund any other Bonds, and (z) any Bonds issued to refund bonds, notes or other evidences of indebtedness issued in anticipation of the issuance of such Bonds, if the requirements of this paragraph shall have been satisfied upon issuance of such bonds, notes or other evidences of indebtedness, assuming for such purpose that they are Bonds with principal due based upon level amortization of principal and interest over a period commencing on the date of issue and ending on the latest maturity date of any Bonds, and bearing interest as described for Bonds in the definition of Debt Service.

Separately Financed Programs

Nothing in the Indenture shall prevent the Department from authorizing and issuing bonds, notes, or other obligations or evidences of indebtedness, other than Bonds, Parity Obligations, Subordinated Indebtedness or Subordinated Obligations, for any program, project or purpose authorized by the Enabling Measures or by other then applicable State statutory provisions, or from financing any such program, project or purpose from other available funds (a "Separately Financed Program"), if the debt service on such bonds, notes, or other obligations or evidences of indebtedness, if any, and the Department's share of any operating expenses related to such program, are not payable from the Trust Estate.

Special Provisions Relating to Enhancement Facilities, Qualified Swaps and Other Similar Arrangements

Any Supplemental Indenture may provide that:

(a) So long as an Enhancement Facility relating to any Series of Bonds is in full force and effect, and the issuer of the Enhancement Facility is not in default thereunder, then, in all such events, the Supplemental Indenture for such Series of Bonds may specify that either (i) the issuer of such Enhancement Facility shall be deemed to be the sole Owner of the Outstanding Bonds the payment of which such Enhancement Facility secures or secured when the approval, consent or action of the Owners of such Bonds is required or may be exercised under the Indenture, or (ii) the approval, consent or action of the issuer of such Enhancement Facility shall be required in addition to the approval, consent or action of the applicable percentage of the Owners of the Outstanding Bonds the payment of which such Enhancement Facility secures or secured when the approval, consent or action of the Owners of such Bonds is required or may be exercised under the Indenture.

(b) In the event that the principal, Sinking Fund Installments, if any, Purchase Price and Redemption Price, if applicable, or interest due on any Outstanding Bonds shall be paid under the provisions of an Enhancement Facility, all covenants, agreements and other obligations of the Department to the Owners of such Bonds shall continue to exist, and the issuer of the Enhancement Facility shall be subrogated to the rights of such Owners in accordance with the terms of such Enhancement Facility.

In addition, such Supplemental Indenture may establish such provisions as are necessary (i) to comply with the provisions of any Enhancement Facility that are not inconsistent with the Indenture, (ii) to provide relevant information and notices to the issuer of the Enhancement Facility, and (iii) to provide a mechanism for paying principal of and Sinking Fund Installments of and interest on Bonds secured by, or purchased pursuant to, the Enhancement Facility.

The Department may enter into agreements with the issuer of any Enhancement Facility providing for, among other things: (i) the payment of fees, costs, expenses and, to the extent permitted by law, indemnities to such issuer, its parent and its assignees and participants in connection with such Enhancement Facility, (ii) the terms and conditions of such Enhancement Facility and the Bonds to which the Enhancement Facility relates, and (iii) the security, if any, to be provided for the issuance of such Enhancement Facility. Any such agreement may

provide for the purchase of Bonds to which the Enhancement Facility relates by the issuer of such Enhancement Facility, with such adjustments to the rate of interest, method of determining interest, maturity (which shall not be inconsistent with the requirements of the next paragraph), or redemption provisions, as shall be specified by the Supplemental Indenture authorizing the issuance of such Bonds.

The Department may, in an agreement with the issuer of any Enhancement Facility, agree to directly reimburse such issuer (or its assignees and participants, or any agent for the issuer or its assignees) for amounts paid by the issuer of the Enhancement Facility for the payment of the principal of, interest on, and Redemption Price or Purchase Price of Bonds under the terms of such Enhancement Facility (together with interest thereon, if any, and the amounts and obligations described in the next following two paragraphs, a "**Reimbursement Obligation**"), whether evidenced by an obligation to reimburse such issuer that is separate from the Department's obligations on Bonds (a "**Credit Facility Reimbursement Obligation**") or by modified debt service obligations on Bonds acquired by such issuer (a "**Liquidity Facility Reimbursement Obligation**"); provided, however, that no such obligation to reimburse or modified debt service obligation shall require payments, other than from remarketing proceeds, to be made faster than on a level debt service (principal and interest) basis (calculated in three (3) month intervals) over a period ending no sooner than three (3) years following the date on which such reimbursement obligation is incurred (or, if less, extending to the final maturity date of the related Bonds) with the first installment commencing no earlier than six (6) months after the date from which the Liquidity Facility Reimbursement Obligation is incurred; and provided further, however, that the immediately preceding proviso shall not apply to any amounts payable to any issuer of any policy of bond insurance that is a subrogee of an Owner of Bonds with respect to amounts payable by the Department under such Bonds, or to any Alternate Debt Service Reserve Account Deposit. Notwithstanding anything to the contrary contained in this paragraph, no Reimbursement Obligation shall be created, for purposes of the Indenture, until amounts are paid under the related Enhancement Facility.

Any Credit Facility Reimbursement Obligation may include interest calculated at a rate higher than the interest rate on the related Bond. The following obligations also shall constitute Credit Facility Reimbursement Obligations: (i) payments of any fees, costs, expenses, indemnification, or other obligations to any such provider, its parent and its assignees and participants or any agent thereof, and (ii) payments pursuant to any advance, term-loan or other principal amortization requirements in reimbursement of any such advance or term-loan, provided that the total amount to be paid (including interest thereon) either (a) shall not be required to be paid faster than on a level debt service (principal and interest) basis (calculated in three (3) month intervals) over a period ending no sooner than three (3) years following the date on which such reimbursement obligation is incurred, with the first installment commencing no earlier than six (6) months after the date from which the Reimbursement Obligation is incurred, or (b) shall be paid from remarketing proceeds.

Any Liquidity Facility Reimbursement Obligation evidenced by Bonds of a Series may include interest calculated at a rate higher than the interest rate on other Bonds of such Series. The following obligations also shall constitute Liquidity Facility Reimbursement Obligations: (i) payments of any fees, costs, expenses, indemnification, or other obligations to any such provider, its parent and its assignees and participants, or any agent thereof, and (ii) payments of differential and/or excess interest amounts.

In connection with the issuance of any Bonds or at any time thereafter so long as Bonds remain Outstanding, the Department may, to the extent from time to time permitted pursuant to law, enter into Qualified Swaps. The total amount of the termination payment under a Qualified Swap, shall not be required to be paid by the Department faster than on a level amortization basis (calculated in three (3) month intervals) over a period ending no sooner than three (3) years following the date of termination, with the first installment commencing no earlier than six (6) months after the date of termination (in which case the termination payment also may include interest thereon); provided, however, that if the Department elects to terminate any Qualified Swap at its option, any termination payments shall be made as provided in such Qualified Swap.

Establishment of Funds

The Indenture establishes in the Electric Power Fund seven separate accounts, to be known as the "Operating Account", the "Priority Contract Account", the "Bond Charge Collection Account", the "Bond Charge Payment Account", the "Debt Service Reserve Account", the "Operating Reserve Account" and the "Administrative Cost Account". The Department may establish under the Indenture one or more additional funds, accounts or subaccounts, if not inconsistent with any Rate Agreement, by delivering to the Trustee a direction to that effect signed by an Authorized Officer, except to the extent the establishment thereof is required by other provisions of the Indenture.

The Operating Account, the Priority Contract Account, the Operating Reserve Account, the Bond Charge Collection Account and the Administrative Cost Account shall be under the control of the Department, except if an Event of Default shall happen and shall not have been remedied, in which case the Operating Account, the Priority Contract Account, the Operating Reserve Account, the Bond Charge Collection Account and the Administrative Cost Account shall be under the control of the Treasurer as Trustee. The Bond Charge Payment Account and the Debt Service Reserve Account shall be under the control of the Treasurer as Trustee at all times; provided, however, that moneys in the Bond Charge Payment Account may be held by any Paying Agent to the extent determined by the Trustee to be necessary or desirable as an administrative convenience.

All moneys and securities deposited under the Indenture in any fund, account or subaccount shall be held in trust for the benefit of the Department, the Owners of the Bonds and the parties to or holders of Parity Obligations, in each case to the extent provided in the Indenture, and applied only in accordance with the provisions of the Indenture, and each of such funds, accounts and subaccounts shall be a trust fund for purposes set forth in the Indenture.

Application and Flow of Funds

In this caption any references to sections or subsections refer to sections and subsections in this "Application and Flow of Funds" caption.

A. Operating Account. 1. The Department shall pay or cause to be paid into the Operating Account, (i) upon the delivery of the initial Series of Bonds, all moneys and securities on deposit in the Electric Power Fund, except as may be provided by Supplemental Indenture, (ii) as and when received, all net proceeds of Bonds, except as may be provided by Supplemental Indenture, and (iii) all Power Charge Revenues and other Revenues, other than Bond Charge Revenues and payments to the Department under Qualified Swaps relating to Bonds. Net proceeds of Bonds shall be paid out or transferred pursuant to section A.2 below. Other amounts in the Operating Account shall be paid out, transferred, retained, accumulated or withdrawn from time to time for the following purposes and, as of any time, in the following order of priority:

(a) Amounts in the Operating Account shall be transferred to the Priority Contract Account on or before the fifth Business Day of each month in such amount as is necessary to make the amount in the Priority Contract Account sufficient to pay Priority Contract Costs estimated to be due during the balance of such month and for the first five Business Days of the next succeeding month. Additional amounts in the Operating Account also shall be transferred to the Priority Contract Account, at any time, to the extent amounts on deposit in the Priority Contract Account are insufficient to pay Priority Contract Costs then payable. Amounts on deposit in the Priority Contract Account shall be used solely to pay Priority Contract Costs then payable.

(b) Amounts in the Operating Account shall be applied to the payment of Operating Expenses then due and owing, other than Priority Contract Costs and any other costs specified in another paragraph of this section A.1, provided, however, that Operating Expenses that constitute administrative costs described in section G below shall be paid through the Administrative Cost Account pursuant to section G below subject to the priority afforded Priority Contract Costs pursuant to section A.1(a).

(c) Amounts in the Operating Account shall be withdrawn and deposited in the Bond Charge Collection Account to reimburse the Bond Charge Collection Account for any amounts previously transferred therefrom pursuant to section C.1 below, to the Priority Contract Account for the payment of Priority Contract Costs.

(d) Amounts in the Operating Account shall be applied as provided by section D.7 below but only to the extent not paid from the Bond Charge Payment Account. In addition, prior to the time Bond Charge Revenues are received in the amounts sufficient to make the transfers required by section D.1 below, amounts in the Operating Account shall be transferred to the Bond Charge Payment Account in the amounts, at the times and otherwise as required by said section D.1.

(e) Amounts in the Operating Account shall be withdrawn to deposit in the Debt Service Reserve Account amounts as provided by section E below, but only to the extent such deposit is required as a result of (i) the use of Bond Charge Revenues for the payment of Priority Contract Costs, pursuant to section C.1(a) below, or (ii) a change in value of Authorized Investments on deposit in the Debt Service Reserve Account.

(f) Amounts in the Operating Account shall be withdrawn to repay to the General Fund of the State advances made to the Department from amounts appropriated to the Electric Power Fund after November 15, 2001, including interest thereon payable at the Pooled Money Investment Rate, to the extent not theretofore repaid. The Department shall file with the Trustee, on or prior to the delivery of the initial Series of Bonds, a statement of the outstanding amount required to be repaid to the General Fund and promptly shall revise the same, and file such revised statement with the Trustee, upon each repayment until no amount remains to be repaid.

(g) Amounts in the Operating Account shall be withdrawn to repay to the General Fund of the State advances made to the Department from amounts appropriated to the Electric Power Fund, and General Fund moneys expended by the Department pursuant to the 2001 Emergency Measures, on or prior to November 15, 2001, including interest payable thereon at the Pooled Money Investment Rate, to the extent not theretofore repaid, in accordance with the schedule described in the immediately succeeding sentence. At such time as a schedule is established by the Commission for repayments to the General Fund described in this section A.1(g), the Department shall file such schedule with the Trustee, and shall promptly file with the Trustee each revised schedule that is similarly established until no amount remains to be repaid.

(h) Amounts in the Operating Account shall be withdrawn to deposit in the Operating Reserve Account amounts as provided by section F below.

(i) Amounts in the Operating Account shall be withdrawn for the following purposes, on a parity basis:

(i) to pay the principal of and interest on any Subordinated Indebtedness, and the redemption price or purchase price of Subordinated Indebtedness payable from mandatory sinking fund installments therefor,

(ii) to the extent not paid from the proceeds of Subordinated Indebtedness, to pay costs of issuing Subordinated Indebtedness or costs incidental to their payment and security,

(iii) to pay amounts due under any Subordinated Obligation, but only to the extent not paid from the Bond Charge Payment Account, and

(iv) to establish and maintain reserves for the payment of Subordinated Indebtedness or Subordinated Obligations to the extent required by a Financing Document; provided, however, that such a reserve may also be accumulated in the Operating Account. Any such reserve for Subordinated Indebtedness or Subordinated Obligations accumulated in the Operating Account shall be maintained in a

separate subaccount which shall be established therein for such respective purpose pursuant to the Indenture.

(j) Amounts remaining in the Operating Account may be withdrawn for any purpose relating to the Department's program for the purchase and sale of Power and related activities only as permitted under the Enabling Measures, to the extent not specified in sections A.1(a) through A.1.(i) above, as determined by the Department, including, without limitation, to pay or provide for the purchase or redemption of Bonds or Subordinated Indebtedness, and the payment of expenses in connection therewith to the extent not constituting Operating Expenses. Purchases of Bonds or Subordinated Indebtedness from amounts in the Operating Account pursuant to this section A.1(j) shall be made at the written direction of an Authorized Officer filed with the Trustee, with or without advertisement and with or without notice to other Owners of Bonds or Subordinated Indebtedness. Such purchases shall be made at such price or prices as determined by the Department, subject to limitations, if any, of the Supplemental Indenture authorizing the issuance of such Series of Bonds; provided, however, that such purchases shall be made at prices exceeding the next applicable Redemption Price (or, if none, the principal amount) of such Bonds, plus accrued interest, if any, only after consultation with the Commission and if the Department determines that to do so will not result in any insufficiency in the Operating Account or the Bond Charge Payment Account for any other purpose.

It shall be a condition to any withdrawal pursuant to sections A.1(i) and A.1(j) above that (1) there shall be no deficiency in either the Debt Service Reserve Account or the Operating Reserve Account without regard to the operation of the provisions of sections E.3, E.6 and F.4 permitting the replenishment thereof over time, and (2) the Department shall have determined, taking into account, among other considerations, anticipated future receipts of Revenues and other moneys constituting part of the Trust Estate, that the funds to be so withdrawn are not, and are not expected to be, needed for any of the purposes set forth in any prior lettered paragraph of this section A.1.

Notwithstanding the foregoing provisions of this section A.1, if at any time the Department determines that Power Charge Revenues are available for any of the purposes set forth in sections A.1(i) or A.1(j) above, (i) such Power Charge Revenues shall instead be used to satisfy any remaining outstanding amounts due to the General Fund of the State (without regard to any schedule for repayment referred to in section A.1(g) above), and to replenish any deficiency in the Debt Service Reserve Account and the Operating Reserve Account (without regard to the provisions of the Indenture sections E.3, E.6 and F.4 below permitting the replenishment thereof over time), in the order of priority established by the Indenture as described in section A.1 above, until the General Fund, and all interest as described in sections A.1(f) and A.1(g) above shall be paid in full, and there shall be no deficiency in the Debt Service Reserve Account or the Operating Reserve Account, and (ii) after all outstanding amounts due to the General Fund of the State, and all interest payable as described by sections A.1(f) and A.1(g) above, shall be paid in full, and any deficiency in the Debt Service Reserve Account and the Operating Reserve Account shall be replenished, any use of such Power Charge Revenues for any of the purposes set forth in such sections A.1(i) and A.1(j) above shall require the consent of the Commission.

2. Amounts in the Operating Account representing proceeds of each Series of Bonds shall be paid out or transferred from time to time by the Department to pay Costs of the Department, subject to limitations, if any, of the Supplemental Indenture authorizing the issuance of such Series of Bonds.

3. That amount, if any, set aside by the Department as reserves in subaccounts in the Operating Account for the purposes specified in clause (iv) of section A.1(i) above shall be used by the Department solely for the respective purposes specified in said clauses, shall not be available for the payment of any other purpose for which amounts in the Operating Account may be applied, and shall not constitute part of the Trust Estate.

4. The Department shall separately notify the Commission in writing whenever the Minimum Operating Expense Available Balance has been reduced as a result of the Department no longer purchasing the Residual Net Short. Whenever such reduction in the Minimum Operating Expense Available Balance occurs, any

resulting excess in the Operating Account shall be utilized in the same manner as Excess Amounts are required to be utilized pursuant to section F.5 below.

5. While the Department is purchasing the Residual Net Short, if on any date the Operating Account balance falls below $750 million, unless the Operating Account balance has been restored to at least the Minimum Operating Expense Available Balance on the thirty-first (31st) day thereafter, then on or prior to the forty-fifth (45th) day following the date on which the Operating Account balance fell below $750 million, the Department will submit a new Revenue Requirement to the Commission providing for Revenues sufficient to restore the Operating Account to the Minimum Operating Expense Available Balance within a period ending no later than two hundred forty (240) days following the date of the submission of such new Revenue Requirement to the Commission. While the Department is purchasing the Residual Net Short, if on any date the Operating Account balance falls below $500 million and the Department has not yet submitted a Revenue Requirement pursuant to the preceding sentence, then on or prior to the earlier of (a) the tenth (10th) Business Day following the date on which the Operating Account balance falls below $500 million or (b) the date on which a Revenue Requirement is required to be submitted to the Commission in accordance with the preceding sentence, the Department will submit a new Revenue Requirement to the Commission providing for Revenues sufficient to restore the Operating Account to the Minimum Operating Expense Available Balance within a period ending no later than two hundred forty (240) days following the date of the submission of such new Revenue Requirement to the Commission.

6. If and when the Department no longer is responsible for the payment of costs under any Power Supply Contract, all amounts in the Operating Account shall be utilized in the same manner as Excess Amounts are required to be utilized pursuant to section F.5 below, provided, however, that amounts required to satisfy a particular contingency shall be retained in the Operating Account only until the contingency has been satisfied or discharged; and provided further, however, that there may be retained in the Operating Account the amount, if any, determined by the Department to be required to pay Bond Related Costs that otherwise would have to be paid from the Bond Charge Payment Account pursuant to section D.1(d) below; and provided further, however, that any amounts not required for the purposes described in the preceding provisos shall be utilized in the same manner as Excess Amounts are required to be utilized pursuant to section F.5 below.

B. Priority Contract Account. 1. Amounts transferred to the Priority Contract Account from the Operating Account pursuant to A.1(a) above, from the Operating Reserve Account pursuant to F.3 below or from the Bond Charge Collection Account pursuant to C.1(a) below shall be applied solely to the payment of Priority Contract Costs.

2. If and when the Department no longer is responsible for the payment of costs under any Priority Long Term Power Contract, the balance if any, on deposit in the Priority Contract Account shall be utilized in the same manner as Excess Amounts are required to be utilized pursuant to section F.5 below.

C. Bond Charge Collection Account. 1. The Department shall pay or cause to be paid into the Bond Charge Collection Account, as and when received, (i) all Bond Charge Revenues, and (ii) all payments to the Department under Qualified Swaps relating to Bonds. Bond Charge Revenues shall be paid out, transferred, retained, accumulated or withdrawn from time to time for the following purposes and, as of any time, in the following order of priority:

(a) Amounts in the Bond Charge Collection Account shall be withdrawn and deposited in the Priority Contract Account, upon the written direction of an Authorized Officer filed with the Trustee, for the purpose of paying Priority Contract Costs then due and payable, but only to the extent moneys are not available for such purpose in the Operating Account, the Priority Contract Account or the Operating Reserve Account; provided, however, that no such withdrawal shall be made if and when the Department no longer responsible and liable for the payment of costs under any Priority Long Term Power Contract.

(b) Amounts in the Bond Charge Collection Account shall be transferred to the Bond Charge Payment Account and applied for the purposes of, in the amounts and at the times required by, and otherwise as provided in section D below.

(c) Amounts in the Bond Charge Collection Account shall be withdrawn for the following purposes, on a parity basis:

(i) to deposit in the Debt Service Reserve Account amounts as provided by section E below, but only to the extent amounts are not available therefor pursuant to section A.1(e) above, and

(ii) upon the written direction of an Authorized Officer filed with the Trustee, to establish and maintain reserves for the payment of Parity Obligations to the extent required by a Financing Document. Any such reserve for Parity Obligations accumulated in the Bond Charge Collection Account shall be maintained in a separate subaccount which shall be established by a supplemental indenture for such purpose pursuant to the Indenture.

2. That amount, if any, set aside as reserves in subaccounts in the Bond Charge Collection Account pursuant to clause (ii) of section C.1(c) above shall be used by the Department solely for the respective purposes specified in said clause, shall not be available for the payment of any other purpose for which amounts in the Bond Charge Payment Account may be applied, and shall not constitute part of the Trust Estate.

D. Bond Charge Payment Account. 1. There shall be transferred from the Bond Charge Collection Account to the Bond Charge Payment Account pursuant to section C.1(b) above, no later than the last Business Day of each calendar month, the amount, if any, required so that the balance in the Bond Charge Payment Account and available for Bond Related Costs as specified below shall at least equal the respective amounts as follows, on a parity basis:

(a) the Debt Service accrued and unpaid as of such Business Day and to accrue thereafter through the end of the third next succeeding calendar month;

(b) the amount accrued and unpaid as of such Business Day and estimated to be payable in the next succeeding three calendar months (i) under Reimbursement Obligations, (ii) under agreements, constituting Parity Obligations, relating to other financial instruments entered into in connection with the Bonds, including, but not limited to, investment agreements, hedges, interest rate swaps, caps, options and forward purchase agreements, (iii) under agreements, relating to the remarketing of Bonds, including, but not limited to, remarketing agreements, dealer agreements and auction agent agreements, (iv) for any Subordinated Obligations constituting Bond Related Costs, and (v) otherwise as may be permitted by a Rate Agreement to be paid from Bond Charge Revenues or the Bond Charge Payment Account;

(c) the amount accrued and unpaid as of such Business Day and estimated to be payable in the next succeeding three (3) calendar months for the cost to the Department of Fiduciaries associated with the issuance and administration of the Bonds; and

(d) if and when the Department no longer is responsible for the payment of costs under any Power Supply Contract and Bonds remain Outstanding, the amount accrued and unpaid as of such Business Day and estimated to be payable in the next succeeding three (3) calendar months for the Department's Bond Charge servicing costs, costs of preparing and providing the information and reports required under the Financing Documents, the 2002 Rate Agreement and the Act, related audit, legal and consulting costs, related administrative costs, and costs of complying with arbitrage restrictions and rebate requirements, and otherwise as may be permitted by a Rate Agreement to be paid from Bond Charge Revenues or the Bond Charge Collection Account to the extent moneys are not available therefor in the Operating Account; provided, however, that administrative costs described in section G below shall be paid through the Administrative Cost Account pursuant to section G below.

For the purpose of computing the amount to be deposited in the Bond Charge Payment Account pursuant to the foregoing provisions of this section D, there shall be excluded from the balance in the Bond Charge Payment Account (i) the amount, if any, set aside in the Bond Charge Payment Account from the proceeds of Bonds for the payment of interest on Bonds which, pursuant to section D.6 below, is to be applied on an interest payment date or dates occurring after the period specified above in this paragraph, and (ii) amounts scheduled to be paid by the Department under Qualified Swaps within the relevant period. The estimates required by the foregoing provisions of this section D shall be made by the Department, based on such assumptions and projections as the Department deems to be appropriate after consultation with the Commission, and shall be included in a written direction of an Authorized Officer filed with the Trustee.

In addition to the foregoing provisions of this section D, there shall be transferred from the Bond Charge Collection Account to the Bond Charge Payment Account, no later than the time required to make the payments required by section D.3 below, the amount, if any, required, in good funds, so that the balance in the Bond Charge Payment Account and available for the purpose shall at least equal the amount required to be paid pursuant to such section D.3 below at such time.

2. The Redemption Price of any Bonds called for redemption, other than to satisfy Sinking Fund Installment requirements, may be deposited in the Bond Charge Payment Account from the Bond Charge Collection Account or, pursuant to section A.1(j) above, from the Operating Account, in the amounts and at the times required therefor, in each case subject to any limitation set forth in any conditional notice of redemption as permitted by the Indenture. The Redemption Price of any Bonds called for redemption to satisfy Sinking Fund Installment requirements shall be deposited in the Bond Charge Payment Account pursuant to section D.1(a) above.

3. The Trustee shall pay Bond Related Costs out of the Bond Charge Payment Account as follows:

(a) The Trustee shall pay to the respective Paying Agents (i) on or before each interest payment date for any of the Bonds, whether scheduled or upon earlier redemption, the amount required for the interest payable on such date; (ii) on or before each Principal Installment due date, the amount required for the Principal Installment payable on such date; and (iii) on or before any redemption date for the Bonds, to the extent of moneys deposited in the Bond Charge Payment Account therefor, the amount required for the payment of the Redemption Price of the Bonds then to be redeemed. Such amounts shall be applied by the Paying Agents to such purposes on or before the due dates thereof.

(b) The Trustee shall pay to the holder or issuer of each Parity Obligation specified in section D.1(b) above and their participants to which an amount is due and payable thereunder, or other Person to whom an amount specified in such section D.1(b) above is due and payable, such amounts and at such times, as shall be specified in a written direction of an Authorized Officer filed with the Trustee.

(c) The Trustee shall pay to each Person to whom an amount specified in section D.1(d) above is due and payable, in such amounts and at such times as shall be specified in a written direction of an Authorized Officer filed with the Trustee.

(d) The Trustee shall pay to each Person to whom an amount specified in section D.1(d) above is due and payable, in such amounts and at such times as shall be specified in a written direction of an Authorized Officer filed with the Trustee.

4. Amounts accumulated in the Bond Charge Payment Account with respect to any Sinking Fund Installment (together with amounts accumulated therein with respect to interest on the Bonds for which such Sinking Fund Installment was established) may and, if so directed in writing by an Authorized Officer, shall be applied by the Trustee, on or prior to the forty-fifth (45th) day preceding the due date of such Sinking Fund Installment, to (i) the purchase of Bonds of the Series, maturity and interest rate within each maturity for which such Sinking Fund Installment was established, subject to section D.10 below, or (ii) the redemption at the

applicable sinking fund Redemption Price of such Bonds, if then redeemable by their terms. The applicable sinking fund Redemption Price (or principal amount of maturing Bonds) of any Bonds so purchased or redeemed shall be deemed to constitute part of the Bond Charge Payment Account until such Sinking Fund Installment date, for the purpose of calculating the amount of such Account. After the forty-fifth (45th) day preceding the due date of any such Sinking Fund Installment, the Trustee shall proceed to call for redemption, by giving notice as provided in the Indenture, on such due date, Bonds of the Series, maturity and interest rate within each maturity for which such Sinking Fund Installment was established (except in the case of Bonds maturing on a Sinking Fund Installment date) in such amount as shall be necessary to complete the retirement of the unsatisfied balance of such Sinking Fund Installment after making allowances for any Bonds purchased or redeemed which the Department has directed the Trustee to apply as a credit against such Sinking Fund Installment as provided in section D.5 below.

5. If at any time Bonds of any Series or maturity for which Sinking Fund Installments shall have been established are purchased or redeemed other than pursuant to section D.4 above, or are deemed to have been paid pursuant to the Indenture, and, with respect to such Bonds which are deemed paid, irrevocable instructions have been given to the Trustee to redeem or purchase the same on or prior to the due date of the Sinking Fund Installment to be credited under this section D, an Authorized Officer may from time to time and at any time by written notice to the Trustee specify the portion, if any, of such Bonds so purchased, redeemed or deemed to have been paid and not previously applied as a credit against any Sinking Fund Installment which are to be credited against future Sinking Fund Installments for such Bonds, but in all cases subject to section D.10 below. Such notice shall specify the amounts of such Bonds to be applied as a credit against such Sinking Fund Installment or Installments and the particular Sinking Fund Installment or Installments against which such Bonds are to be applied as a credit; provided, however, that none of such Bonds may be applied as a credit against a Sinking Fund Installment to become due less than forty-five (45) days after such notice is delivered to the Trustee. All such Bonds which have been purchased or redeemed and are to be applied as a credit shall be surrendered to the Trustee for cancellation on or prior to the due date of the Sinking Fund Installment against which they are being applied as a credit. The portion of any such Sinking Fund Installment remaining after the deduction of any such amounts credited toward the same (or the original amount of any such Sinking Fund Installment if no such amounts shall have been credited toward the same) shall constitute the unsatisfied balance of such Sinking Fund Installment for the purpose of calculation of Sinking Fund Installments due on a future date.

6. The amount, if any, deposited in the Bond Charge Payment Account from the proceeds of any Series of Bonds shall be applied to the payment of interest on the Bonds, or paid to the issuers of Enhancement Facilities to satisfy Reimbursement Obligations relating to such interest, if any, paid under such Enhancement Facilities, in accordance with written directions signed by an Authorized Officer and filed with the Trustee or, in the event that the Department shall modify or amend any such direction by a subsequent direction signed by an Authorized Officer of the Department and filed with the Trustee, then in accordance with the most recent such direction or amended direction.

7. If at any time the amount in the Bond Charge Payment Account shall be less than the amount required to be on deposit pursuant to paragraphs (a), (b) and (c) of section D.1 above at the times required thereby, or to pay the items of cost specified in paragraphs (a), (b) and (c) of section D.3 above when due and payable, the Department shall apply all available amounts, if any, in the Operating Account to such deposits or payments, as the case may be, on parity basis. If at any time, after the application of moneys pursuant to the preceding sentence, the amount in the Bond Charge Payment Account shall be less than the amount required to pay the items of cost specified in paragraphs (a), (b) and (d) of said section D.3, all available amounts, if any, in the Debt Service Reserve Account shall be applied to such purposes on a parity basis. Any such application of moneys from the Operating Account or the Debt Service Reserve Account may be made directly or through the Bond Charge Payment Account.

8. In the event of the refunding of any Bonds, the Trustee shall, upon the written direction of an Authorized Officer, withdraw from the Bond Charge Payment Account all or any portion of amounts accumulated therein with respect to the principal of and redemption premium, if any, and interest on the Bonds being refunded

and apply such amounts in accordance with such direction; provided, however, that such withdrawal shall not be made unless (i) immediately thereafter the Bonds being refunded shall be deemed to have been paid pursuant to the Indenture, and (ii) subject to section D.9 below, the amount remaining in the Bond Charge Payment Account with respect to Debt Service on Bonds, after such withdrawal, shall be sufficient to satisfy the requirements of section D.1 above.

9. Whenever there shall be held in the Bond Charge Payment Account, and in the Debt Service Reserve Account, without giving effect to any Alternate Debt Service Reserve Account Deposit, an aggregate amount sufficient to pay in full all Outstanding Bonds in accordance with their terms (including the maximum amount of principal or applicable sinking fund Redemption Price and interest which could become payable thereon), no transfers shall be required to be made to the Bond Charge Payment Account.

10. Any purchases of Bonds pursuant to sections D.4 and D.5 above shall be made at the direction of an Authorized Officer filed with the Trustee, with or without advertisement and with or without notice to other Owners of Bonds. Such purchases shall be made at such price or prices as is determined by an Authorized Officer; provided, however, that such purchases may be made at prices exceeding the next applicable Redemption Price (or, if none, the principal amount) of such Bonds, plus accrued interest, if any, only after consultation with the Commission and if the Department determines that to do so will not result in any insufficiency in the Bond Charge Payment Account for any other purpose.

E. Debt Service Reserve Account. 1. At the time any Series of Bonds is delivered pursuant to the Indenture, the Department shall pay into the Debt Service Reserve Account from the proceeds of such Bonds or other available funds, the amount, if any, necessary for the amount on deposit in the Debt Service Reserve Account to equal the Debt Service Reserve Requirement, after giving effect to any Alternate Debt Service Reserve Account Deposit, calculated immediately after the delivery of such Series of Bonds.

2. Amounts on deposit in the Debt Service Reserve Account shall be applied as provided in this section E and section D.7 above. Fiduciary charges and expenses (including, but not limited to, legal fees and expenses) shall not be paid from the Debt Service Reserve Account.

3. If a deficiency exists in the Debt Service Reserve Account, no later than the last Business Day of each calendar month the Department shall transfer (i) to the extent such transfer is required as a result of the use of Bond Charge Revenues for the payment of Priority Contract Costs pursuant to section C.1(a) above, or a change in value of investments, first, from the Operating Account to the extent that there are sufficient moneys available therein, pursuant to section A.1(e) above, and second, to the extent necessary, from the Bond Charge Collection Account, to the extent that there are sufficient moneys available therein, pursuant to clause (i) of section C.1(c) above, and (ii) to the extent such transfer is required otherwise than as described in clause (i), or in the event transfers pursuant to clause (i) are not sufficient, from the Bond Charge Collection Account to the extent that there are sufficient moneys available therein, and deposit in the Debt Service Reserve Account the amount, if any, required for the amount on deposit in the Debt Service Reserve Account to equal the Debt Service Reserve Requirement as of the last day of such calendar month, after giving effect to any Alternate Debt Service Reserve Account Deposit; provided, however, that any deficiency in the Debt Service Reserve Account, after giving effect to any Alternate Debt Service Reserve Account Deposit, may be cured by depositing into the Debt Service Reserve Account each month during the period commencing no later than the seventh month following such determination of the deficiency, approximately equal or greater amounts such that the deficiency shall be cured by no later than the twelfth month following such determination of the deficiency.

4. Any amount in the Debt Service Reserve Account in excess of the Debt Service Reserve Requirement, after giving effect to any Alternate Debt Service Reserve Account Deposit, may be retained therein or, upon the written direction of an Authorized Officer filed with the Trustee, may be transferred to the Bond Charge Collection Account; provided, however, that any such excess as of the last Business Day of each calendar year shall be so transferred.

5. Whenever the amount in the Debt Service Reserve Account, without giving effect to any Alternate Debt Service Reserve Account Deposit, together with the amount in the Bond Charge Payment Account with respect to Debt Service on Bonds, is sufficient to pay in full all Outstanding Bonds in accordance with their terms (including the maximum amount of principal or applicable sinking fund Redemption Price and interest which could become payable thereon), the funds on deposit in the Debt Service Reserve Account shall be transferred to the Bond Charge Payment Account, and thereupon no further deposits shall be required to be made into the Debt Service Reserve Account. Prior to said transfer, all investments held in the Debt Service Reserve Account shall be liquidated to the extent necessary in order to provide for the timely payment of principal and interest (or Redemption Price) on Bonds.

6. Alternate Debt Service Reserve Account Deposits may be made for the benefit of the Owners of the Bonds as provided in this section E.6. In lieu of any required transfers of moneys to the Debt Service Reserve Account, the Department may cause to be deposited into the Debt Service Reserve Account for the benefit of the Owners of the Bonds an Alternate Debt Service Reserve Account Deposit in an aggregate amount equal to the difference between the Debt Service Reserve Requirement and the sums of moneys or value of Authorized Investments then on deposit in the Debt Service Reserve Account, if any. In lieu of retaining all or any portion of the moneys theretofore on deposit in the Debt Service Reserve Account, the Department may cause to be deposited into the Debt Service Reserve Account an Alternate Debt Service Reserve Account Deposit in an aggregate amount equal to such moneys, subject to section E.4 above. Each Alternate Debt Service Reserve Account Deposit shall be payable (upon the giving of notice as required thereunder) on any date on which moneys may be required to be withdrawn from the Debt Service Reserve Account and applied to the payment of a Principal Installment of or interest on any Bonds, or to reimburse any issuer of an Enhancement Facility constituting a Parity Obligation for any such payment made by such issuer, and such withdrawal cannot be met by amounts on deposit in the Debt Service Reserve Account. Any insurer providing an Alternate Debt Service Reserve Account Deposit surety bond or insurance policy shall be an insurer whose municipal bond insurance policies insuring the payment, when due, of the principal of and interest on municipal bond issues results in such issues being rated in the highest Rating Category by at least one (1) Rating Agency. Any Alternate Debt Service Reserve Account Deposit letter of credit issuer shall be a bank or trust company which on the date of issuance of the letter of credit has an outstanding unsecured, uninsured and unguaranteed debt issue which is rated in the highest Rating Category by at least one (1) Rating Agency. Any provider of any other Alternate Debt Service Reserve Account Deposit obligation shall have the qualifications set forth in a Supplemental Indenture; provided, however, that prior to the deposit of such other Alternate Debt Service Reserve Account Deposit obligation in the Debt Service Reserve Account, the Trustee shall have received written confirmation from each Rating Agency to the effect that the deposit of such Alternate Debt Service Reserve Account Deposit will not, by itself, result in the withdrawal, suspension or downgrade of any rating issued by such Rating Agency with respect to any Outstanding Bonds. If a disbursement is made pursuant to an Alternate Debt Service Reserve Account Deposit, the Department shall either (i) reinstate the maximum limits of such Alternate Debt Service Reserve Account Deposit or (ii) deposit into the Debt Service Reserve Account funds in the amount of the disbursement made under such Alternate Debt Service Reserve Account Deposit, or a combination of such alternatives, at the times and in the amounts required by section E.3 above. In the event that the rating attributable to any provider of any Alternate Debt Service Reserve Account Deposit shall fall below that required as provided above, such Alternate Debt Service Reserve Account Deposit shall no longer be deemed to be an Alternate Debt Service Reserve Account Deposit and the Department shall either (i) replace such Alternate Debt Service Reserve Account Deposit with an Alternate Debt Service Reserve Account Deposit which shall meet the requirements provided above or (ii) deposit into the Debt Service Reserve Account sufficient funds, or a combination of such alternatives, at the times and in the amounts required by section E.3 above.

7. In the event of the refunding of any Bonds, the Trustee shall, upon the written direction of an Authorized Officer, withdraw from the Debt Service Reserve Account all or any portion of amounts accumulated therein with respect to the Bonds being refunded and apply such amounts in accordance with such direction; provided, however, that such withdrawal shall not be made unless (i) immediately thereafter the Bonds being refunded shall be deemed to have been paid pursuant to the Indenture, and (ii) subject to section E.5 above, the

amount remaining in the Debt Service Reserve Account, after giving effect to any Alternate Debt Service Reserve Account Deposit, after such withdrawal shall not be less than the Debt Service Reserve Requirement.

F. Operating Reserve Account. 1. At the time any Series of Bonds is delivered pursuant to the Indenture, the Department shall pay into the Operating Reserve Account from the proceeds of such Bonds or other available funds, the amount, if any, necessary for the amount on deposit in the Operating Reserve Account to equal the Operating Reserve Account Requirement.

2. Amounts on deposit in the Operating Reserve Account shall be applied as provided in this section F.

3. If at any time the amounts in the Operating Account shall be less than the then current requirements thereof for any payment, retention, accumulation, transfer or withdrawal required by sections A.1(a) through A.1(e) above, the Department shall withdraw from the Operating Reserve Account and deposit in the Operating Account the amounts necessary (or all the moneys in the Operating Reserve Account, if less than the amounts necessary), applying available amounts in the order of priority and otherwise as specified in sections A.1(a) through A.1(e) above to make up such deficiency; provided, however, that if and for so long as the balance on deposit in the Operating Reserve Account is equal to or less than the Priority Contract Contingency Reserve Amount, amounts in the Operating Reserve Account may only be withdrawn for deposit in the Priority Contract Account for the payment of Priority Contract Costs.

4. If at any time the amount on deposit in the Operating Reserve Account is less than the Operating Reserve Account Requirement, no later than the last Business Day of each calendar month the Department shall transfer from the Operating Account to the Operating Reserve Account pursuant to section A.1(h) above the amount, if any, required for the Operating Reserve Account to equal the Operating Reserve Account Requirement as of the last day of such calendar month; provided, however, that any deficiency in the Operating Reserve Account may be cured by depositing into the Operating Reserve Account each month during the period commencing no later than the seventh month following such determination of the deficiency, approximately equal or greater amounts such that the deficiency shall be cured by no later than the twelfth month following such determination of the deficiency.

5. The Department shall separately notify the Commission in writing each time the Operating Reserve Account Requirement is reduced pursuant to the Indenture. Whenever such reduction in the Operating Reserve Account Requirement occurs, any excess amounts in the Operating Reserve Account ("Excess Amounts") will be used at such time to satisfy any deficiencies existing at such time in the transfers, applications and withdrawals required by sections A.1(a) through A.1(g) above, including repayment in full of the General Fund of the State for all advances made to the Department from amounts appropriated to the Electric Power Fund, whether before or after November 15, 2001, including interest payable thereon at the Pooled Money Investment Rate. Unless otherwise agreed by both the Department and the Commission, each acting in their own discretion, any Excess Amounts remaining after application to the uses described in the preceding sentence shall be used, at the direction of the Commission after consultation with the Department, to (i) adjust Department charges or (ii) with the agreement of the Department, reduce debt outstanding under the Indenture, in all instances upon consideration of, the interests of the retail customers of the Electrical Corporations and the Department, and, if applicable, Electric Service Provider retail customers.

6. If and when the Department no longer is responsible for the payment of costs under any Power Supply Contract, the entire balance, if any, on deposit in the Operating Reserve Account shall be applied as provided by section F.5 above.

G. Administrative Cost Account. Notwithstanding anything to the contrary in the Indenture, including but not limited to the provisions described in sections A, C and D above, all administrative costs of the Department incurred in administering Division 27 (commencing with Section 80000) of the Water Code, if and to the extent the payment thereof is subject to appropriation by the State Legislature pursuant to Section 80200(c) of

the Water Code or other provision of law, shall be paid and accounted for through the Administrative Cost Account. Transfers shall be made from the Operating Account or, after the Department no longer is responsible for the payment of costs under any Power Supply Contract, the Operating Account or the Bond Charge Payment Account to the extent necessary to permit compliance with this section G.

Investment of Amounts in Accounts

Unless otherwise provided in a Supplemental Indenture, all amounts held in any fund, account or subaccount under the Indenture shall be invested by the Trustee in Authorized Investments. Unless otherwise determined by any Supplemental Indenture, earnings on moneys and investments in (i) the Operating Reserve Account shall be credited to and deposited in the Operating Account, and (ii) any other fund, account or subaccount under the Indenture shall be credited to and deposited in such fund, account or subaccount. Authorized Investments purchased as an investment of moneys in any such fund, account or subaccount shall be deemed at all times to be a part of such fund, account or subaccount, any profit realized from the liquidation of such investment shall be credited thereto and any loss resulting from the liquidation of such investment shall be charged thereto.

Revenue Requirements

The Department shall cause to be established, fixed and revised from time to time charges sufficient, together with any other available moneys and securities on deposit in the Electric Power Fund, to satisfy all of the Department's Revenue Requirements at the times and in the amounts needed. Without limiting the generality of the foregoing, such charges shall be sufficient, after taking into account any moneys and securities on deposit in the Operating Account, to produce Revenues sufficient in each calendar year: to pay all Operating Expenses in such calendar year as the same become due and payable; to make all deposits to the Bond Charge Payment Account in the amounts and at the times required by section D under the caption "Application and Flow of Funds" above in such calendar year; to pay all Parity Obligations as and when the same become due and payable in such calendar year; to repay to the General Fund of the State advances made to the Department from amounts appropriated to the Electric Power Fund, and to repay General Fund moneys expended by the Department pursuant to the 2001 Emergency Measures, including interest thereon payable at the Pooled Money Investment Rate, at the times and in the amounts provided in the Indenture; to pay the debt service on all Subordinated Indebtedness then outstanding, and all Subordinated Obligations, as and when the same respectively become due and payable in such calendar year; to replenish the Debt Service Reserve Account as and to the extent required by section E under the caption "Application and Flow of Funds" above in the event of any deficiency therein; to replenish the Operating Reserve Account as and to the extent required by Section F under the caption "Application and Flow of Funds" above in the event of any deficiency therein; to retain on deposit in or make any deposit to any fund, account or subaccount pursuant to and to the extent necessary under the Act or required by any Financing Document, including, but not limited to, such retentions or deposits as shall be required to maintain the Minimum Operating Expense Available Balance as may be required by section 4.5 under the caption "Application and Flow of Funds" above or to maintain reserves as may be required by clause (iv) of section A.1(j) under the caption "Application and Flow of Funds" above, and by clause (ii) of section C.1(c) under the caption "Application and Flow of Funds" above; and to pay such other obligations of the Department, payable by the Department, in such calendar year as shall be incurred in accordance with both the Enabling Measures and the Indenture.

The Department will include in its Revenue Requirements amounts estimated to be sufficient:

(a) to cause the amount on deposit in the Operating Account (except any amounts set aside as reserves in subaccounts in the Operating Account for the purposes specified in clause (iv) of section A.1(i) under the caption "Application and Flow of Funds" above, at all times during any calendar month to equal the Minimum Operating Expense Available Balance;

(b) to cause the amount on deposit in the Bond Charge Collection Account, on the first Business Day of each calendar month, to equal the amounts projected to be required to be paid out of the Bond Charge Payment Account pursuant to section D.3 under the caption "Application and Flow of Funds" above in such calendar month, which projections shall be based on such assumptions, and which may take into account a range of possible outcomes, as the Department deems to be appropriate after consultation with the Commission, and

(c) for the payment of interest on Variable Rate Bonds during the relevant Revenue Requirement Period, assuming that interest accrues on such Variable Rate Bonds at a rate equal to the greater of (i) of 130% of the highest average interest rate in any calendar month during the twelve (12) calendar months, or such shorter period that such Variable Rate Bonds shall be Outstanding, ending with the month preceding the date such Revenue Requirements are filed with the Trustee or the Commission, as the case may be, or (ii) 4.0%.

For purposes of the covenant set forth in this paragraph, the Department may take into account the issuance of Bonds or other obligations anticipated to occur prior to the applicable Revenue Requirement Period.

No later than 90 days prior to the commencement of each calendar year beginning on and after January 1, 2003, the Department shall file with the Trustee an estimate of the Department's Revenue Requirements for such calendar year. The estimate for each calendar year shall demonstrate compliance with the requirements of this caption, and shall specify, on a monthly basis and in the aggregate for such calendar year, receipts of Revenues and deposits to, retentions in and transfers and withdrawals from the funds, accounts or subaccounts under the Indenture pursuant to sections A.1 and C under the caption "Application and Flow of Funds" above, including, but not limited to, withdrawals (i) for the payment of Priority Contract Costs and other Operating Expenses, principal and Redemption Price of and interest on Bonds, Parity Obligations, Subordinated Obligations and Subordinated Indebtedness, taking into account any proceeds of Bonds or other amounts on deposit in the Operating Account, in the Priority Contract Account, in the Bond Charge Collection Account and in the Bond Charge Payment Account, (ii) to maintain the Debt Service Reserve Account and Operating Reserve Account in the amounts required by sections E and F under the caption "Application and Flow of Funds", respectively, and (iii) to repay to the General Fund of the State advances made to the Department from amounts appropriated to the Electric Power Fund, including interest thereon payable at the Pooled Money Investment Rate in accordance with the Act at the times and in the amounts provided in the Indenture.

Such estimates may be revised from time to time for any calendar year or for the balance of any then-current calendar year to reflect actual results and revised estimates; provided, however, that such estimates (i) shall be confirmed or revised in each calendar month during which the Department is permitted by the Act to enter into new contracts for the purchase of Power, and (ii) shall be revised as soon as practicable after the amount on deposit in any fund, account or subaccount under the Indenture shall be less than the amount required by the Indenture. Each confirmation or revision required by clause (i) of the foregoing proviso shall be filed with the Trustee as soon as practicable but no later than thirty (30) days (whether or not a Business Day) after the end of each calendar month to which it relates. Each confirmation or revision pursuant to this paragraph shall contain the same information required for the annual estimates by the foregoing paragraph.

Each such estimate and confirmation or revision thereof shall be accompanied by a written statement from a Consultant to the effect that the estimate or revision, as the case may be, reasonably can be expected to result in Revenues sufficient to satisfy the requirements of the Indenture or, if not, specifying the reasons therefor in reasonable detail.

The Department shall submit to the Commission such Revenue Requirements as shall be the subject of Rate Agreements, at such times and in such manner as the Department reasonably determines will enable the Commission to take action with respect thereto pursuant to the Rate Agreements to enable the Department to receive moneys in such amounts and at such times as shall permit the Department to fully comply with the provisions of the first two paragraphs under this caption. Without limiting the generality of the foregoing, the Department shall make projections, submit requests for changes in Revenue Requirements, Bond Charges and Power Charges, and take all other actions as are required of it under or pursuant to Section 4.1(b) and other

provisions of the 2002 Rate Agreement, and by the provisions of any other Rate Agreement, to enable the Department to comply with the preceding sentence.

Rate Agreements

The Department shall enter into and maintain in effect at all times one or more Rate Agreements. Nothing contained in the Indenture shall (i) require the Department to continue to purchase or sell Power or (ii) prevent the Department from assigning, terminating or suspending any Power Supply Contract if (a) a Rate Agreement is in full force and effect, and (b) the Bond Charges established under the Rate Agreement are in full force and effect. The Department shall not voluntarily consent to or permit any amendment, termination or suspension, or waive any provision, of any Rate Agreement unless the Department shall determine, in a written determination signed by an Authorized Officer and delivered to the Trustee, that the same will not have a material adverse affect on the ability of the Department to comply with the provisions of the Indenture. The Department shall perform all of the obligations and conditions required to be performed and observed by it under each Rate Agreement, and shall take such actions from time to time as shall be necessary and available to enforce all of the obligations and conditions required to be performed and observed under each Rate Agreement by the Commission, in each case to the extent material to the payment of or security for the Bonds or Parity Obligations. An Authorized Officer shall promptly notify the Trustee and Co-Trustee in writing of any dispute or default, in each case if determined by the Department to be material to the payment of or security for the Bonds or Parity Obligations, and of each event of default, arising under any Rate Agreement as soon as practicable after the Department has actual knowledge thereof. If the Department shall have defaulted under its obligations contained in any Financing Document, such default is continuing and the Department has failed to enforce such Rate Agreement to the extent it is permitted to do so thereunder, the Co-Trustee shall have the right to enforce such Rate Agreements, as permitted by and subject to such Rate Agreements. All right, title and interest of the Department in, to and under each Rate Agreement is collaterally assigned to the Co-Trustee for the benefit of the Owners of Bonds and the holders or issuers of or other parties to Parity Obligations, to the extent necessary for purposes of such enforcement, subject to the terms of such Rate Agreements. The Co-Trustee agrees to comply with all provisions of any Rate Agreement necessary to enable it to exercise the rights granted by the Indenture and described in this paragraph.

Cooperation with Commission

Wherever the Indenture requires the Department to consult with the Commission with respect to assumptions made by the Department, the Department shall involve the Commission in the development of these assumptions by conferring regularly in a manner consistent with the Department's obligations under the 2002 Rate Agreement.

Servicing Arrangements; Collection of Revenues

The Department shall enter into and maintain in effect at all times one or more Servicing Agreements which, in aggregate, shall provide for all of the following functions and services: transmit or provide for the transmission of, and distribute, all Power; billing, collection and remittance of all moneys constituting Bond Charges, Power Charges, Direct Access Power Charges or other charges; and all other services related to the foregoing; provided, however, that separate Servicing Agreements may be entered into and maintained for separate functions and services; and provided further, however, that no Servicing Agreement shall be required for any functions or services to the extent such functions or services are performed directly by the Department, subject to the following sentence, or pursuant to an order ("Servicing Order") of the Commission. The Department shall not attempt to assert any authority to perform any such function or service except as permitted under an applicable Servicing Agreement or Servicing Order. The Department shall request such Servicing Orders of the Commission as the Department determines to be necessary or appropriate in connection with the performance of such functions or services and the implementation or enforcement of any Servicing Agreement.

The Department shall not voluntarily consent to or permit any amendment, termination or suspension, or waive any provision, of any Servicing Arrangement unless the Department determines, in a written determination signed by an Authorized Officer and delivered to the Trustee, that the same will not have a material adverse affect on the ability of the Department to comply with the provisions of the Indenture. The Department shall perform and observe all of the obligations and conditions required to be performed and observed by it under each Servicing Arrangement, and shall take such actions from time to time as shall be necessary and available to enforce all of the obligations and conditions required to be performed and observed under each Servicing Agreement by the other party thereto, and to enforce each Servicing Order in accordance with its terms, in each case to the extent material to the payment of and security for the Bonds or Parity Obligations.

If an Event of Default shall have occurred and be continuing, the Co-Trustee shall have the right to enforce the Servicing Arrangements to the extent the Department fails to do so, as permitted by and subject to such Servicing Arrangements. All right, title and interest of the Department in, to and under the Servicing Arrangements is hereby collaterally assigned to the Co-Trustee for the benefit of the Owners of Bonds and the holders or issuers of or other parties to Parity Obligations, to the extent necessary for purposes of such enforcement, subject to the terms of such Servicing Arrangements. If the Department shall have defaulted under its obligations contained in any Financing Document and such default is continuing, the Co-Trustee shall have the right to request Servicing Orders with respect to the Servicing Agreements or the functions and services described above, and to request the Commission to enforce the same, to the extent the Department fails to do so. All right, title and interest of the Department in, to and under the Servicing Arrangements, insofar as it relates to such requests and enforcement, is hereby collaterally assigned to the Co-Trustee for the benefit of the Owners of Bonds and the holders or issuers of or other parties to Parity Obligations, to the extent necessary for purposes of such requests and enforcement, subject to the terms of such Servicing Arrangements. The Co-Trustee agrees to comply with all provisions of any Servicing Arrangements necessary to enable it to exercise the rights described above, and in doing so shall be subject to the provisions of the Indenture.

The Department shall use its best efforts to collect or cause to be collected all moneys due and payable to the Department, which, upon receipt by the Department, would constitute Revenues, as soon as practicable after the same are due and payable; provided, however, that nothing contained in the Indenture shall prohibit the effectuation of the program provided by Executive Order No. D-56-02 dated May 23, 2002, including the financing thereof, as provided thereby.

All right, title and interest of the Department in, to and under the Servicing Arrangements to amounts payable, and payments, to the Department pursuant to and under the Servicing Arrangements are hereby collaterally assigned to the Trustee and Co-Trustee for the benefit of the Owners of the Bonds and the holders or issuers of or other parties to Parity Obligations, subject to the terms of such Servicing Arrangements.

Non-Impairment Covenant of State; Extension of Sunset Date

Under the Indenture, the State pledges and undertakes that while any obligations of the Department incurred under Division 27 of the State Water Code, including without limitation the Indenture, the Bonds and Parity Obligations, remain outstanding and not fully performed or discharged, the rights, powers, duties, and existence of the Department and the Commission shall not be diminished or impaired in any manner that will affect adversely the interests and rights of the holders of or parties to such obligations. This pledge and undertaking is included in the Indenture pursuant to the authority to do so contained in Section 80200(e) of the State Water Code.

Any extension of the January 1, 2003, termination date for the authority of the Department to contract for the purchase of Power, contained in Section 80260 of the State Water Code, shall not constitute a violation of the foregoing pledge and undertaking of the State, nor shall any such extension constitute a violation of or default under the Indenture.

Covenant Relating to Retirement of Bonds

The Department shall schedule the maturity of, redeem or otherwise retire Bonds in accordance with the Indenture at such times and in such amounts as are necessary to assure that the Department complies with Paragraph II of the Summary of Material Terms referred to in Section 7.10 of the Rate Agreement, as such Summary of Material Terms was amended by Paragraph 18 of the Amended and Restated Addendum to Summary of Material Terms of Financing Documents dated as of August 8, 2002. Such provisions require that the plan of finance of the Bonds provide for substantially level debt service with principal payments commencing no later than 2004.

Continuing Disclosure

The Department will post on its website, so long as it maintains a website, (i) within forty-five (45) days after the end of each fiscal year quarter except the fourth quarter, unaudited financial statements of the Department relating to its Electric Power Fund for such quarter, (ii) within one hundred twenty (120) days after the end of each fiscal year, audited financial statements of the Department relating to its Electric Power Fund for such fiscal year, and (iii) each Revenue Requirement filing made by the Department with the Commission pursuant to the Indenture, within ten (10) Business Days after such filing. Such audited and unaudited financial statements shall separately state the balances in the Operating Account, Priority Contract Account, Operating Reserve Account, Bond Charge Collection Account, Bond Charge Payment Account and Debt Service Reserve Account.

The Department will send to each Nationally Recognized Municipal Securities Information Repository ("NRMSIR") for purposes of 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, each document referred to in, and at the times required by, clause (i) of the immediately preceding paragraph.

The Department shall send, by first class mail to any Person filing with the Chief, Division of Fiscal Services, or the Deputy Controller of the Department a written request therefor, to the address specified by such Person, unless and until it appears to the Department that notices sent are not being delivered, (i) notice of each posting and filing required by the foregoing provisions (or, if the Department no longer maintains a website and/or there is no NRMSIR, as applicable, the documents that otherwise would have been posted or filed), within ten (10) Business Days after such posting or filing, as the case may be, (ii) notice of each Commission action establishing charges relating to each Revenue Requirement filing, within ten (10) Business Days after such action, (iii) notice of each draw on the Operating Reserve Account and Debt Service Reserve Account, within ten (10) Business Days after such draw, (iv) while the Department is purchasing the Residual Net Short, if the Operating Account balance falls below, or is restored to, both $750 million and $500 million, notice within ten (10) Business Days thereof, and (v) notice of any litigation to which the Department is a party, in which a party seeks to restrain or enjoin the implementation of any Bond Charge in whole or part, within ten (10) Business Days of service of process on the Department.

Notwithstanding anything in the Indenture to the contrary (including but not limited to the definition of Event of Default and limitations on the exercise of remedies), (i) any failure on the part of the Department to comply with its obligations described under this caption shall not be deemed to be a default or an Event of Default under the Indenture, and (ii) the Trustee may (and, at the request of the Owners of at least 50% in aggregate principal amount of Outstanding Bonds, shall), or any Owner or Beneficial Owner of the Bonds may (unless the Department has so complied within 20 days after written notice from the Trustee, such Owner or Owners, or such Beneficial Owner or Beneficial Owners, as the case may be, of the Department's failure to comply) seek specific performance by court order, to cause the Department to comply with its obligations described under this caption, as the sole remedy. For this purpose, "Beneficial Owner" means any Person which has or shares the power, directly or indirectly, to make investment decisions concerning ownership of any Bonds (including persons holding Bonds through nominees, depositories and other intermediaries).

Supplemental Indentures and Amendments

The Department, the Trustee and the Co-Trustee may adopt (without the consent of or notice to any Owner) Supplemental Indentures to, among other purposes, prohibit, or provide limitations and restrictions in addition to the limitations and restrictions contained in the Indenture on, the delivery on original issuance of Bonds or the issuance of other evidences of indebtedness; add to the covenants and agreements of the Department in the Indenture other covenants and agreements to be observed by the Department which are not contrary to or inconsistent with the Indenture as theretofore in effect; add to the limitations and restrictions in the Indenture other limitations and restrictions to be observed by the Department which are not contrary to or inconsistent with the Indenture as theretofore in effect; surrender any right, power or privilege reserved to or conferred upon the Department by the Indenture; authorize Bonds of a Series or to amend, modify or rescind any such authorization, specification or determination at any time prior to the first delivery of such Bonds; authorize Subordinated Indebtedness and provide with respect thereto to the extent provided by, and otherwise not inconsistent with, the Indenture theretofore in effect; subject Subordinated Obligations and Subordinated Indebtedness to the lien on and pledge of the Trust Estate pursuant to the Indenture on a subordinate basis; confirm, as further assurance, any pledge under, and the subjection to any lien or pledge created or to be created by, the Indenture, of any additional security other than that previously granted or pledged under the Indenture; modify, amend or supplement the Indenture in such manner as to permit the qualification of the Indenture under the Trust Indenture Act of 1939, as amended, or any similar Federal statute hereafter in effect or to permit the qualification of the Bonds for sale under the securities laws of any of the states of the United States of America, and, if the Department so determines, to add to the Indenture such other terms, conditions and provisions as may be permitted by said Trust Indenture Act of 1939 or similar Federal statute; comply with regulations and procedures as are from time to time in effect relating to any book-entry-only system, whether within or without the United States, for the registration of beneficial ownership interests in Bonds; to evidence the assignment and transfer of rights, and the delegation of duties and obligations, of the Department by operation of law to another department, agency or instrumentality of the State that has indicated in writing its willingness to accept the rights of the Department and to assume and discharge the duties and obligations of the Department; modify any of the provisions of the Indenture in any other respect whatever with respect to any Bonds, provided that (i) (a) such modification relates only, and is to be effective prior to the issuance of, such Bonds, or (b) such modification relates only, and is to be effective only upon the remarketing of, such Bonds in connection with an optional or mandatory tender thereof for purchase by or on behalf of the Department, and (ii) such modification is disclosed in an offering or reoffering document applicable to such issuance or remarketing; or modify any of the provisions of the Indenture in any other respect whatever, provided that such modification shall be, and shall be expressed to be, effective only after all Bonds Outstanding and outstanding or unpaid Parity Obligations at the date of the execution and delivery of such Supplemental Indenture shall cease to be Outstanding or owing, as the case may be.

For any one or more of the following purposes and at any time or from time to time, a Supplemental Indenture may be executed by the Department, the Trustee and the Co-Trustee without the consent of or notice to any Owner, which, upon delivery to the other parties thereto and the satisfaction of the requirements of the Indenture, shall be effective in accordance with its terms: (1) to cure any ambiguity, supply any omission, or cure or correct any defect or inconsistent provision in the Indenture; or (2) to insert such provisions, or to make such other amendments to the Indenture, as are necessary or desirable which are not materially adverse to the rights under the Indenture of the Owners of Bonds and the holders or issuers of or other parties to Parity Obligations.

Any modification or amendment of the Indenture and of the rights and obligations of the Department and of the Owners, in any particular, may be made by a Supplemental Indenture, with the written consent given as provided in the Indenture (i) of the Owners of a majority in principal amount of the Bonds Outstanding at the time such consent is given, and (ii) in case less than all of the Bonds then Outstanding are affected by the modification or amendment, of the Owners of a majority in principal amount of the Bonds so affected and Outstanding at the time such consent is given; provided, however, that if such modification or amendment will, by its terms, not take effect so long as particular Bonds remain Outstanding, the consent of the Owners of such Bonds shall not be required and such Bonds shall not be deemed to be Outstanding for the purpose of any calculation of Outstanding Bonds under this caption. No such modification or amendment shall (a) permit a change in the terms of

redemption or maturity of the principal of any Outstanding Bond or of any installment of interest thereon or a reduction in the principal amount or the Redemption Price thereof or in the rate of interest thereon without the consent of the Owner of such Bond, (b) reduce the percentages or otherwise affect the classes of Bonds the consent of the Owners of which is required to waive an Event of Default or otherwise effect any such modification or amendment, (c) create a preference or priority of any Bond or Bonds over any other Bond or Bonds, without the consent of the Owners of all such Bonds, (d) create a lien prior to or on parity with the lien of the Indenture, without the consent of the Owners of all of the Bonds then Outstanding, except to the extent permitted by the Indenture, or (e) change or modify any of the rights or obligations of any Fiduciary without its written assent thereto. For the purposes of this paragraph, a Bond shall be deemed to be affected by a modification or amendment of the Indenture if the same materially and adversely affects the rights of the Owner of such Bond. The Trustee may in its discretion determine whether or not in accordance with the foregoing powers of amendment particular Bonds would be affected by any modification or amendment of the Indenture and any such determination shall be binding and conclusive on the Department and all Owners of Bonds.

The terms and provisions of the Indenture and the rights and obligations of the Department and of the Owners of Bonds may be modified or amended in any respect upon the execution by the Department, the Trustee and the Co-Trustee of a Supplemental Indenture, the filing of a fully executed copy with the Trustee and the Co-Trustee, and the consent of the Owners of all of the Bonds then Outstanding, such consent to be given as provided in the Indenture; provided, however, that no such modification or amendment shall change or modify any of the rights or obligations of any Fiduciary without the filing with the Trustee of the written assent thereto of such Fiduciary in addition to the consent of the Owners of Bonds.

Events of Default and Remedies

Pursuant to the Indenture, any one or more of the following events shall constitute "Events of Default": (1) if default shall be made in the due and punctual payment of the principal or Redemption Price of any Bond, or in the due and punctual payment of the principal or redemption price, if any, of any Parity Obligation when and as the same shall become due and payable, whether at maturity or by call for redemption, or otherwise; (2) if default shall be made in the due and punctual payment of any installment of interest on any Bond or of interest, if any, on any Parity Obligation when and as such interest installment shall become due and payable, and such default shall continue for a period of 5 days; (3) if the Department defaults in the performance or observance on its part of any of the covenants or agreements contained in the Indenture relating to the submission by the Department of Revenue Requirements to the Commission, relating to the Rate Agreements or relating to the Servicing Arrangements, and such default shall continue for a period of 10 days after written notice thereof to the Department by the Trustee or the Co-Trustee, or to the Department, the Trustee and the Co-Trustee by the Owners of a majority in principal amount of the Bonds Outstanding; provided, however, that no such default relating to submission by the Department of Revenue Requirements to the Commission shall constitute an Event of Default if and for so long as the Commission is taking action to cure the Department's default pursuant to Section 4.1(a) of the 2002 Rate Agreement or otherwise; (4) if an "event of default," as defined in any Rate Agreement, on the part of the Commission shall have occurred and be continuing; (5) if any "event of default," as defined in any Parity Obligation, on the part of the Department shall have occurred and be continuing; (6) if the Department defaults in the performance or observance on its part of any other of the covenants or agreements contained in the Indenture or in the Bonds to be performed, other than as specified in clauses (1) through (3) above, and such default shall continue for a period of 60 days after written notice thereof to the Department by the Trustee or Co-Trustee, or to the Department, the Trustee and the Co-Trustee by the Owners of a majority in principal amount of the Bonds Outstanding; provided, however, that if such default shall be such that it cannot be remedied by the Department within such 60 day period, it shall not constitute an Event of Default if corrective action is instituted by the Department within such period and diligently pursued by the Department until the default is remedied; or (7) with respect to a Series of Bonds, any additional events as may be specified in the Supplemental Indenture authorizing the issuance of such Series.

Anything in the Indenture to the contrary notwithstanding, neither the Trustee nor the Co-Trustee nor the Owners nor the issuer of any Enhancement Facility nor a party to any Swap Obligation shall have the right to

accelerate the maturity of any Bond or Parity Obligation. The preceding sentence shall not be construed to prohibit any redemption of Bonds or Parity Obligations at the option of the Owner, holder or issuer thereof or other party thereto, or if required pursuant to any Enhancement Facility, or any optional or mandatory tender of Bonds or Parity Obligations pursuant to the terms thereof, or any early termination of a Qualified Swap (subject to the Indenture).

During the continuance of an Event of Default, the Trustee shall take control of the Operating Account, the Priority Contract Account, the Operating Reserve Account and the Administrative Cost Account and apply all amounts on deposit therein, Revenues and the income therefrom to payments as follows and in the following order:

(i) The reasonable and proper charges and expenses of the Trustee and the Co-Trustee (including, but not limited to, reasonable legal fees and expenses and charges and expenses of any management consultant or consulting engineer, or firm of either thereof, selected by the Trustee or Co-Trustee pursuant to paragraph (ii) below. Such charges and expenses shall only be paid from Power Charge Revenues or Bond Charge Revenues.

(ii) The amounts required for reasonable and necessary Operating Expenses, including, but not limited to, reasonable and necessary reserves and working capital. The Trustee or the Co-Trustee may retain a management consultant or consulting engineer, or firm of either thereof, of recognized standing (who may be an engineer or management consultant, or firm of either thereof, retained by the Department for other purposes) for the purpose of rendering advice with respect to such matters. For this purpose the books of record and account of the Department shall at all times be subject to the inspection of such consultant, engineer or firm of consultants or engineers during the continuance of such Event of Default.

(iii) The interest and principal or Redemption Price then due on the Bonds, and the interest and principal components of Parity Obligations (which, in the case of Swap Obligations shall consist of scheduled payments and termination payments, respectively) as follows:

First: To the payment to the Persons entitled thereto of all installments of interest then due on the Bonds and the interest component of Parity Obligations, in the order of the maturity of such installments, and, if the amount available shall not be sufficient to pay in full any installment or installments maturing on the same date, then to the payment thereof ratably, according to the amounts due thereon, to the Persons entitled thereto, without any discrimination or preference; and

Second: To the payment to the Persons entitled thereto of the unpaid principal or Redemption Price of any Bonds and the unpaid principal component of Parity Obligations, which shall have become due, whether at maturity or by call for redemption, in the order of their due dates, and, if the amount available shall not be sufficient to pay in full all the Bonds and the principal component of Parity Obligations, due on any date, then to the payment thereof ratably, according to the amounts of principal or Redemption Price due on such date, to the Persons entitled thereto, without any discrimination or preference.

If and whenever all overdue installments of interest on all Bonds and Parity Obligations, together with the reasonable and proper charges and expenses of the Trustee and the Co-Trustee, and all other sums payable by the Department under the Indenture, including, but not limited to, the principal and Redemption Price of and accrued unpaid interest on all Bonds and Parity Obligations which shall then be payable, shall either be paid by or for the account of the Department, or provision satisfactory to the Trustee and the Co-Trustee shall be made for such payment, and all defaults under the Indenture or the Bonds and all agreements, instruments or notes evidencing Parity Obligations shall be made good or secured to the satisfaction of the Trustee and the Co-Trustee or provision deemed by the Trustee and the Co-Trustee to be adequate shall be made therefor, all Revenues shall

thereafter be applied as provided under the caption "Application and Flow of Funds" above, and the Trustee shall return control of the Operating Account, the Priority Contract Account, the Operating Reserve Account, the Bond Charge Collection Account and the Administrative Cost Account to the Department. No such resumption of the application of Revenues as provided under the caption "Application and Flow of Funds" above shall extend to or affect any subsequent default under the Indenture, the Credit and Security Agreement and all agreements, instruments or notes evidencing Parity Obligations, or impair any right consequent thereon.

If (i) an Event of Default shall happen and shall not have been remedied, and (ii) whether or not an Event of Default has happened or shall have been remedied, in the event of any failure of the Department to pay into the Operating Account, as and when received, Power Charge Revenues as described under Section A under the caption "Application and Flow of Funds" above or to pay into the Bond Charge Collection Account, as and when received, Bond Charge Revenues, as described under section C under the caption "Application and Flow of Funds" above, or to collect or cause to be collected Revenues as required by the Indenture, or in the event of a violation of the pledge and agreement of the State in the Indenture, then and in every such case, the Co-Trustee, by its agents and attorneys, if the Co-Trustee shall deem it advisable, may proceed to protect and enforce its rights and the rights of the Owners of Bonds and the holders or issuers of or other parties to Parity Obligations under the Indenture forthwith by a suit or suits in equity or at law, whether for the specific performance of any covenant contained in the Indenture, or in aid of the execution of any power granted in the Indenture, or for an accounting against the Department as if the Department were the trustee of an express trust, or in the enforcement of any other legal or equitable right as the Co-Trustee, being advised by counsel, shall deem most effectual to enforce any of its rights or to perform any of its duties under the Indenture. Notwithstanding the occurrence of an Event of Default, the Co-Trustee shall have only such rights to enforce the Rate Agreements as are set forth in such Rate Agreements.

No Owner shall have any right to institute any suit, action or proceeding at law or in equity 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 such Owner shall have previously given to the Trustee and the Co-Trustee written notice of the happening of an Event of Default, and the Owners of at least twenty-five percent (25%) in principal amount of the Bonds then Outstanding shall have filed a written request with the Trustee and the Co-Trustee, and shall have offered the Co-Trustee reasonable opportunity, either to exercise the powers granted as described under this caption or to institute such action, suit or proceeding in its own name, and unless such Owners shall have offered to the Co-Trustee adequate security and indemnity against the costs, expenses and liabilities to be incurred therein or thereby, and the Co-Trustee shall have refused to comply with such request within a reasonable time; it being understood and intended that no one or more Owners of Bonds shall have any right in any manner whatever by his or their action to affect, disturb or prejudice the pledge created by the Indenture, or to enforce any right under the Indenture, except in the manner therein provided; and that all proceedings at law or in equity to enforce any provision of the Indenture shall be instituted, had and maintained in the manner provided in the Indenture and for the equal benefit of all Owners of the Outstanding Bonds.

Resignation and Removal of Co-Trustee

The Co-Trustee may at any time resign and be discharged of the duties and obligations created by the Indenture by giving not less than 90 days' written notice to the Department and the Trustee, and the Trustee thereupon shall mail notice thereof to the Owners of the Bonds, specifying the date when such resignation shall take effect, at least 30 days prior to the effective date, provided that such resignation shall take effect upon the later of (i) the day specified in such notice and (ii) the day a successor shall have been appointed by the Department or the Owners of Bonds as provided in the Indenture.

The Co-Trustee may be removed at any time by an instrument or concurrent instruments in writing, filed with the Trustee and the Co-Trustee, and signed by the Owners of a majority in principal amount of the Bonds then Outstanding or their attorneys-in-fact duly authorized, excluding any Bonds held by or for the account of the Department; provided, however, that the Co-Trustee may be removed only for cause unless and until an Event of Default shall have occurred and be continuing under the Indenture. In addition, so long as no Event of Default

shall have occurred and be continuing under the Indenture and the Co-Trustee is not pursuing any right or remedy available to it pursuant to the Indenture, the Co-Trustee may be removed by the Department at any time for failure to provide reasonably acceptable services, failure to charge reasonably acceptable fees or any other reasonable cause, all as determined by a written determination signed by an Authorized Officer and filed with the Trustee and the Co-Trustee, which determination shall be conclusive. Any such removal shall not be effective until a successor shall have been appointed by the Department or the Owners of Bonds as provided in the Indenture.

Defeasance

If the Department shall pay or cause to be paid to the Owners of all Bonds then Outstanding the principal or Redemption Price, if any, and interest to become due thereon, to the other parties to the Credit and Security Agreement all amounts payable thereunder, and to the holders or issuers of or other parties to all Parity Obligations all amounts payable thereunder and upon the termination thereof, at the times and in the manner stipulated therein and in the Indenture, then the covenants, agreements and other obligations of the Department to the Owners of Bonds, the other parties to the Credit and Security Agreement, and the holders or issuers of or other parties to all Parity Obligations shall be discharged and satisfied. In such event, the Trustee shall, upon the request of the Department, execute and deliver to the Department all such instruments as may be desirable to evidence such discharge and satisfaction and the Fiduciaries shall pay over or deliver to the Department all money, securities and funds held by them pursuant to the Indenture which are not required for the payment or redemption of Bonds not theretofore surrendered for such payment or redemption, or required to make payments under Parity Obligations.

Outstanding Bonds or any portion thereof shall, prior to the maturity or redemption date thereof, be deemed to have been paid within the meaning and with the effect expressed in the Indenture either (A) as provided in the Supplemental Indenture authorizing their issuance or (B) if (a) in case any of said Bonds are to be redeemed on any date prior to their maturity, the Department shall have given to the Trustee, in form satisfactory to it irrevocable instructions to mail, as provided in the Indenture notice of redemption on said date of such Bonds, (b) there shall have been irrevocably deposited with the Trustee or other Paying Agent either moneys in an amount which shall be sufficient, or Defeasance Securities the principal of and the interest on which when due will provide moneys which, together with the moneys, if any, deposited with the Trustee or such Paying Agent at the same time, shall be sufficient, without further investment or reinvestment of either the principal amount thereof or the interest earnings thereon, to pay when due, the principal or Redemption Price, if applicable, and interest due and to become due on such Bonds on and prior to the redemption date or maturity date thereof, as the case may be, (c) in the event such Bonds are not by their terms maturing or are not to be redeemed within the next succeeding 60 days, the Department shall have given the Trustee in form satisfactory to it irrevocable instructions to mail, as soon as practicable, a notice to the Owners of such Bonds that the deposit required by clause (b) above has been made with the Trustee and that said Bonds are deemed to have been paid as described under this caption and stating such maturity or redemption date upon which moneys are to be available for the payment of the principal or Redemption Price, if applicable, on such Bonds, and (d) in the case of Bonds subject to optional or mandatory tender for purchase prior to the maturity or earlier redemption date specified for its payment pursuant to this paragraph, the Trustee or such Paying Agent shall have received written confirmation from each Rating Agency to the effect that the deposit and provisions for defeasance made pursuant to this paragraph will not, by themselves, result in the withdrawal, suspension or downgrade of any rating issued by such Rating Agency with respect to such Bonds. Neither Defeasance Securities nor moneys deposited with the Trustee or other Paying Agent as described under this caption nor principal or interest payments on any such Defeasance Securities shall be withdrawn or used for any purpose other than, and shall be held in trust for, the payment of the principal or Redemption Price, if applicable, and interest on said Bonds; provided, however, that any moneys on deposit with the Trustee or such Paying Agent, (i) to the extent such moneys will not be required at any time for such purpose, shall be deposited in the Bond Charge Collection Account or, if the first paragraph of this caption applies, paid over to the Department as received by the Trustee or such Paying Agent, free and clear of any trust, lien or pledge securing said Bonds or otherwise existing under the Indenture, and (ii) to the extent such moneys will be required for such purpose on another date, shall, to the extent practicable, be reinvested in Defeasance Securities maturing at times and in amounts sufficient, together with any moneys available to the Trustee or Paying Agent for such

purpose, to pay when due the principal or Redemption Price, if applicable, and interest to become due on said Bonds on and prior to the redemption date or maturity date thereof, as the case may be. Notwithstanding ay other provision of the Indenture, the Department may, at the time any Bonds are deemed to have been paid within the meaning and with the effect as set forth above, elect to retain the right to redeem or require the tender of any such Bonds; provided, however, that such Bonds shall at all times comply with the requirements described above for such Bonds to be deemed to have been paid as aforesaid.

Anything in the Indenture to the contrary notwithstanding, all instructions by the Department, accepted by the Trustee or any Paying Agent, given pursuant to the Indenture to mail notice of redemption of the Bonds of a Series (other than Bonds of such Series which have been purchased by the Trustee at the direction of the Department as therein provided prior to the mailing of such notice of redemption) shall be irrevocable and shall foreclose the exercise by the Department of any other optional redemption right with respect to such Bonds, except that any such instructions may be. revoked prior to any deposit pursuant to the Indenture.

Unclaimed Moneys

The amounts held by any Fiduciary for the payment of the interest, principal or Redemption Price due on any date with respect to particular Bonds or any amount payable under the Credit and Security Agreement or Parity Obligations shall, on and after such date and pending such payment, be set aside on its books and held in trust by it for the Owners of Bonds or the holders or issuers of or other parties to Parity Obligations entitled thereto. Anything in the Indenture to the contrary notwithstanding, any moneys so held by the Fiduciary, which remain unclaimed for two (2) years after the date when such principal, Redemption Price, interest or amounts, respectively, became due and payable, either at their stated maturity or due dates or by call for earlier redemption, if such moneys were held by the Fiduciary at such date, or for two (2) years after the date of deposit of such moneys if deposited with the Fiduciary after the date when such principal, Redemption Price, interest or amounts, respectively, became due and payable, shall, at the written request of the Department, be repaid by the Fiduciary to the Department or such officer, board or body as then may be entitled by law to receive the same, as its absolute property and free from trust, and the Fiduciary shall thereupon be released and discharged with respect thereto and the Owners of Bonds, the other parties to the Credit and Security Agreement and the holders or issuers of or other parties to Parity Obligations, as applicable, shall look only to the Department or such officer, board or body for the payment of such principal, Redemption Price, interest or amounts, respectively. Before being required to make any such payment to the Department, the Fiduciary shall, at the expense of the Department, cause to be mailed to the Owners, holders, issuers or parties entitled to receive such moneys, at their last addresses, if any, appearing upon the registry books or other notice addresses on file with the Fiduciary or the Department, a notice that said moneys remain unclaimed and that, after a date named in said notice, which date shall be not less than 30 days after the date of the mailing, the balance of such moneys then unclaimed will be returned to the Department or such officer, board or body. The failure of any Owner of Bonds, holders, issuers or parties to receive such notice shall not affect the application of moneys as described under this caption.

Successors and Assigns

Whenever in the Indenture, the Bonds, any agreement, instrument or note evidencing a Parity Obligation, Subordinated Indebtedness, Subordinated Obligation, or any other obligation of the Department under or pursuant to the Indenture, the Department is named or referred to, it shall be deemed to include its successors and assigns and all the covenants and agreements in the Indenture or in the Bonds or such other obligations contained by or on behalf of the Department shall bind and inure to the benefit of its successors and assigns whether so expressed or not; provided, however, that such successor or assign is permitted by law to assume the Department's obligations thereunder and shall agree to be bound by the terms thereof.

Governing Law and Venue

The Indenture shall be governed by and interpreted in accordance with internal laws of the State without regard to conflicts of law principles. All legal actions and proceedings arising from the Indenture or the Bonds

shall be brought in the courts of the State located in the County of Sacramento, except as otherwise may be expressly agreed to by the Department. The parties to the Indenture, and the Owners by their acceptance of Bonds, consent to and accept for themselves and in respect of their property, generally and unconditionally, the jurisdiction of the aforesaid courts, and to the extent permitted by law, irrevocably waive any objection, including, without limitation, any objection to the laying of venue or based on the grounds of forum non conveniens, which they may now or hereafter have to the bringing of any such action or proceeding in such respective jurisdictions, except as otherwise may be agreed to in writing by the Department, the Trustee and the Co-Trustee.

APPENDIX D

RATE AGREEMENT

By and Between

STATE OF CALIFORNIA DEPARTMENT OF WATER RESOURCES

and

STATE OF CALIFORNIA PUBLIC UTILITIES COMMISSION

Dated as of March 8, 2002

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RATE AGREEMENT, dated as of March 8, 2002, by and between **STATE OF CALIFORNIA DEPARTMENT OF WATER RESOURCES** and **STATE OF CALIFORNIA PUBLIC UTILITIES COMMISSION.**

The parties mutually agree as follows:

ARTICLE I
DEFINITIONS

Section 1.1 Definitions. The terms set forth in this Section shall have the meanings ascribed to them herein for all purposes of this Agreement unless the context clearly requires otherwise. Words in the singular shall include the plural and words in the plural shall include the singular where the context so requires.

"Act" shall mean Chapter 4 of the Statutes of 2001 (AB 1 of the First 2001-02 Extraordinary Session) of the State, as amended from time to time.

"Agreement" shall mean this Rate Agreement, as from time to time hereafter amended or supplemented in accordance with the provisions hereof.

"Beneficiaries" shall mean, at any given time, the persons to whom the Department is then obligated to pay Bond Related Costs described in clauses (i) through (iv) of the definition of such term, in each case solely to the extent of such obligations.

"Bond Charge" shall mean a charge imposed by the Commission, by order promulgated as a result of this Agreement, upon customers in each of the Service Areas of Pacific Gas & Electric, Southern California Edison Company and San Diego Gas & Electric Company or any of their respective successors based on the aggregate amount of electric power sold to that customer by an Electrical Corporation and the Department, and to the extent determined under Section 4.3 hereof, by an Electric Service Provider, such charge to be revised from time to time by the Commission in such a manner that amounts on deposit in the Bond Charge Payment Account as a result of the charge are always sufficient to pay or provide for the payment of the Bond Related Costs; provided, that Bond Charges shall be imposed upon such customers in each Service Area at all times required by this Agreement whether or not the Department is at the time selling, or deemed to be selling, Power to such customers until such time as the Department has recovered the portion of the Department's revenue requirements under Section 80134 of the Act constituting Bond Related Costs.

"Bond Charge Collection Account" shall have the meaning set forth in the Financing Documents. Revenues that the Department receives from Bond Charges shall be deposited in the Bond Charge Collection Account.

"Bond Charge Payment Account" shall have the meaning set forth in the Financing Documents. The primary purpose of the Bond Charge Payment Account is to hold amounts that the Financing Documents require to be periodically transferred from the Bond Charge Collection Account to provide for the payment of Bond Related Costs.

"Bond Related Costs" shall mean payments of, or deposits or other provision to be made by the Department under Financing Documents or the Act for the following components of the Department's revenue requirements under Section 80134 of the Act:

(i) principal of, premium, if any, and interest on Bonds and any additional amount required under the Financing Documents to be deposited into the Bond Charge Collection Account to provide debt service coverage of the Bonds;

(ii) payments required to be made (A) under agreements with issuers of credit and liquidity facilities and their participants, including but not limited to, letters of credit, bond insurance, guarantees, debt service reserve fund surety bonds, lines of credit, reimbursement agreements, and standby bond purchase agreements, (B) under agreements relating to other financial instruments entered into in connection with the Bonds, including but not limited to investment agreements, hedges, interest rate swaps, caps, options and forward purchase agreements and (C) under agreements relating to the remarketing of Bonds, including but not limited to remarketing agreements, dealer agreements and auction agent agreements;

(iii) deposits to the Debt Service Reserve Account established under the Financing Documents to the extent necessary to provide therein an amount equal to the requirement for such account under the Financing Documents if not otherwise replenished from Power Charges;

(iv) the cost of Fiduciaries associated with the issuance and administration of the Bonds; and

(v) when and if the Department no longer sells Power under the Act and Bonds remain outstanding, the Department's Bond Charge servicing costs, costs of preparing and providing the information and reports required under the Financing Documents, this Agreement and the Act, related audit, legal and consulting costs, related administrative costs, and costs of complying with arbitrage restrictions and rebate requirements.

"Bonds" shall mean State of California Department of Water Resources evidences of indebtedness issued for the purposes specified in the Act pursuant to Section 80130 of the Act and the Executive Order of the Governor of the State of California, dated June 18, 2001, in an aggregate principal amount up to $ 13,423,000,000; provided, however, that (i) notes issued in anticipation of the issuance of Bonds and retired from the proceeds of those Bonds shall not be counted against said dollar limitation, and (ii) Bonds shall include indebtedness issued to refund prior Bonds, but such refunding indebtedness

shall not be counted against said dollar limitation; and, provided, further that, for all purposes of this definition, the Bonds shall exclude the Interim Loan.

"Commission" shall mean the State of California Public Utilities Commission and any board, commission, department, corporation, authority or officer succeeding to the functions thereof, or to whom the powers conferred on the Commission by the Act shall be given by law.

"Debt Service Reserve Account" shall have the meaning set forth in the Financing Documents. The purpose of the Debt Service Reserve Account is to provide for the payment of Bond Related Costs in the event that amounts in the Bond Charge Payment Account, after deposits from the Bond Charge Collection Account or other funds under the Indenture, are insufficient. The Debt Service Reserve Account is expected to be initially funded with Bond proceeds.

"Department" shall mean the State of California Department of Water Resources.

"Department Costs" shall mean, at any given time, all amounts which the Department is then entitled under Section 80110 of the Act to recover, as a revenue requirement, to enable it to comply with Section 80134 of the Act, (including amounts payable under the Interim Loan), except that Department Costs, unless specifically provided in this Agreement, exclude Bond Related Costs to the extent that such Bond Related Costs have been recovered from Bond Charges.

"Electrical Corporation" shall have the meaning ascribed thereto in Section 218 of the Public Utilities Code, including any successor and assign thereof.

"Electric Service Provider" shall mean an entity that provides electrical service to one or more retail customers located within the Service Areas of Pacific Gas & Electric, Southern California Edison Company, or San Diego Gas & Electric Company or any of their respective successors, except that Electric Service Provider excludes: the Department, any other public agency to the extent that it offers electrical service to customers within its jurisdiction or within the service territory of a local publicly owned electric utility, and Electrical Corporations. Electric Service Provider includes the unregulated affiliates and subsidiaries of an Electrical Corporation.

"Fiduciary" shall mean any Trustee, any bond registrar and any paying agent in connection with Bonds pursuant to the Financing Documents, and their respective successors and assigns.

"Financing Documents" shall mean any resolution, indenture, trust agreement, loan agreement, revolving credit agreement, reimbursement agreement, standby purchase agreement or other agreement or instrument adopted or entered into by the Department authorizing, securing or enhancing the Bonds, including any bond offering documents, as from time to time amended or supplemented in accordance therewith. Copies of all Financing Documents shall be provided to the Commission.

"Fund" shall mean the Department of Water Resources Electric Power Fund established by the Act.

"Interim Loan" shall mean obligations issued under the Credit and Security Agreement, dated as of June 26, 2001, among the Department and various lenders identified therein and Morgan Guaranty Trust Company of New York, in its capacity as agent for the lenders, and other documents and agreements described therein.

"Minimum Operating Reserve Account Requirement" shall have the meaning set forth in the Financing Documents, and shall include an amount solely limited to make payments due under the Priority Long Term Power Contracts if funds are not available in the Operating Account or the Priority Contract Account.

"Operating Account" shall have the meaning set forth in the Financing Documents. The purpose of the Operating Account is to provide for the payment of Department Costs, including by transfer to the Priority Contract Account. Power Charges will generally be deposited into the Operating Account.

"Operating Reserve Account" shall have the meaning set forth in the Financing Documents. The purpose of the Operating Reserve Account is to provide for the payment of Department Costs in the event that amounts in the Operating Account are insufficient, or amounts in the Priority Contract Account are insufficient to make payments due under the Priority Long Term Power Contracts.

"Power" shall have the meaning ascribed thereto in Section 80010 of the Water Code.

"Power Charges" shall mean charges imposed by the Commission upon Retail End Use Customers for electric power deemed sold to Retail End Use Customers by the Department, except that Power Charges exclude Bond Charges.

"Priority Contract Account" shall have the meaning set forth in the Financing Documents. The purpose of the Priority Contract Account is to provide solely for the payment of amounts due under Priority Long Term Power Contracts.

"Priority Long Term Power Contracts" shall mean (i) those long-term electric power contracts identified in Appendix A, and shall not include any electric power contracts entered into after August 14, 2001; provided, however, that such term shall include any priority long term electric power contract entered into after August 14, 2001, as an amendment or novation of any Priority Long Term Power Contract and (ii) any contracts entered into for the purpose of securing fuel for use at generating facilities being operated pursuant to such Priority Long Term Power Contracts, if that fuel supply contract contains a provision to the general effect that payments by the Department under the contract are to be paid or payable prior to bonds, notes, or other indebtedness of the Department secured by a pledge or assignment of the revenues of the Department under the Act and other amounts in the Fund. The Department shall consult with the Commission prior to entering into any additional contract for the purpose of securing fuel

if that contract contains such a provision. Contracts shall cease to be treated as Priority Long Term Power Contracts under the circumstances described in Section 7.8.

"Retail End Use Customer" shall mean each customer within the Service Area of an Electrical Corporation that is deemed to purchase electric power from the Department under the Act.

"Retail Revenue Requirements" shall mean the amounts required to pay Department Costs that are to be generated from Power Charges imposed by the Commission from time to time.

"Service Area" shall mean the geographic area in which an Electrical Corporation distributes electricity.

"State" shall mean the State of California.

"Trustee" shall mean any bank or trust company, or the State Treasurer, appointed as trustee, co-trustee or collateral agent in connection with the Bonds or bond related obligations pursuant to the Financing Documents, and its successors and assigns.

ARTICLE II
REPRESENTATIONS AND WARRANTIES

Section 2.1 Representations and Warranties of Department. The Department makes the following representations and warranties as the basis for the undertakings on its part herein contained:

(a) It is a department within the Resources Agency of the State, validly existing under the Constitution and laws of the State, and has full power and authority to execute, deliver and perform and observe all of the terms and provisions of this Agreement.

(b) The execution, delivery and performance of this Agreement have been duly authorized by all necessary action on the part of the Department.

(c) This Agreement is a legal, valid and binding agreement of the Department and is enforceable against the Department in accordance with its terms.

Section 2.2 Representations and Warranties of Commission. The Commission makes the following representations and warranties as the basis for the undertakings on its part herein contained:

(a) It is a commission of the State, validly existing under the Constitution and laws of the State, and has full power and authority to execute, deliver and perform and observe all of the terms and provisions of this Agreement.

(b) The execution, delivery and performance of this Agreement, have been duly authorized by all necessary action on the part of the Commission.

(c) This Agreement is a legal, valid and binding agreement of the Commission and is enforceable against the Commission in accordance with its terms.

ARTICLE III
AGREEMENTS FOR BOND ISSUANCE

Section 3.1 Agreement for Bond Issuance. The Department and the Commission agree that this Agreement is executed to facilitate the issuance of Bonds and solely for the benefit of the Beneficiaries.

Section 3.2 No Indebtedness. Nothing contained in the Agreement shall be deemed to create or constitute a debt or liability of the State or of any political subdivision thereof, or a pledge of the full faith and credit or taxing power of the State or of any such political subdivision.

Section 3.3 No Pecuniary Liability of Commission. Nothing in this Agreement shall be deemed to create any pecuniary liability of the Commission, its Commissioners, employees or agents to any person, the sole remedy for any default, breach or other nonperformance by the Commission hereunder being the exercise of remedies specifically afforded hereunder and under the Act.

ARTICLE IV
RETAIL REVENUE REQUIREMENTS; JUST AND REASONABLE COSTS

Section 4.1 Retail Revenue Requirements.

(a) Generally. The Commission agrees to cooperate with and assist the Department in its review, determination and revision of its Retail Revenue Requirement at the request of the Department. The Department shall promptly notify the Commission following any determination or revision of the Retail Revenue Requirements. If any such annual or more frequent review indicates that the Power Charges are, or will be, insufficient to meet the requirements of the Act, and the Department so notifies the Commission, the Commission shall take necessary action to cure or avoid any such deficiency, including adjustment of existing, and the calculation and imposition of additional, Power Charges. To the extent that the Department has not provided a revised Retail Revenue Requirement to the Commission within the time periods required by subsection (b) below for any reason and the Commission determines based on the record before it, that Power Charges are not sufficient to pay Department Costs (which for this purpose include replenishment of the Bond Charge Collection Account, Bond Charge Payment Account or Debt Service Reserve Account), the

Commission may modify Power Charges to cover such shortfall on an interim basis pending receipt of a revised Retail Revenue Requirement from the Department.

(b) Communication. The Department shall, at least annually, and more frequently as deemed reasonably necessary or appropriate by the Department or the Commission, review, determine and revise its Retail Revenue Requirements. The Department agrees that it shall revise and communicate to the Commission its Retail Revenue Requirement within 20 days of the occurrence of any of the following circumstances, whether or not the Commission notifies the Department of such events: (i) the Department projects that, within 120 days, there will be insufficient funds in the Priority Contract Account to pay costs incurred by the Department under the Priority Long Term Power Contracts, or (ii) the Department projects that, within 120 days, there will be less than the Minimum Operating Reserve Account Requirement in the Operating Reserve Account, or (iii) the Department projects that, within 120 days, shortfalls in the Priority Contract Account, Operating Account and the Operating Reserve Account will require the usage of moneys in the Bond Charge Collection Account to pay costs incurred by the Department under the Priority Long Term Power Contracts, or (iv) the Department projects that, moneys in the Debt Service Reserve Account will be used within 120 days to pay Bond Related Costs. The Department further agrees that if a revised Retail Revenue Requirement has not previously been submitted pursuant to the preceding sentence of this Section 4.1 the Department shall revise and communicate to the Commission within 3 business days its Retail Revenue Requirement in the event that the Department makes any withdrawal from the Bond Charge Collection Account to pay specified Department Costs, or from the Operating Reserve Account or the Debt Service Reserve Account such that, in either case, the amount in such account is less than that required under the Financing Documents.

(c) Information. In any determination of the Retail Revenue Requirements, the Department shall include the amount required to be recovered in the applicable period and shall set forth amounts projected to be required to be collected during subsequent periods in which either Bonds will remain outstanding or the Department will continue to sell Power, but not exceeding the five years succeeding the applicable revenue requirement period. The Retail Revenue Requirements for any period shall take into account any deficiency or any surplus in amounts recovered in earlier periods, as well as any anticipated surpluses in the Priority Contract Account, Operating Account and the Operating Reserve Account in the period. The Department's notification to the Commission of the Retail Revenue Requirements shall include a statement containing the Department's projections (with reasonable detail) of the following information for each month during the period covered by the Retail Revenue Requirements:

(i) the beginning balance of funds on deposit in the Fund, including the amounts on deposit in each account and subaccount of the Fund;

(ii) the amounts necessary to pay or provide for the principal of, premium, if any, and interest on all Bonds and all other Bond Related Costs under the

Financing Documents as and when the same shall become due and the amount of Bond Charges to be collected for such purpose;

(iii) the amount of its Retail Revenue Requirement for that month;

(iv) any other information requested by the Commission in its proceedings implementing a Retail Revenue Requirement.

(d) Additional Information. The Department shall provide the Commission as soon as practicable, but no later than 30 days after the end of each month, a report of Department receipts and Department Costs for the prior month, based upon the sums of known actual Department receipts and Department Costs and estimated accruals for those receipts and costs which are subject to final invoicing or accounting settlement processes. Such monthly report shall be presented in a form which enables reasonable comparison to the monthly estimates contained in the latest Retail Revenue Requirement for (i) long term Department contract electric power purchases, (ii) short term Department electric power purchases, (iii) other electric power purchases or reimbursement by the Department of purchases of electric power by others for which the Department is responsible for payment, and (iv) Department administrative costs. For items (i), (ii) and (iii) above, the Department shall report information with a level of detail that lists each counterparty, the volumes provided by the counterparty, and the cost of those volumes. In addition, for those items, the costs and volumes will be separated into day ahead, hour ahead, "out of market" purchases, and contract categories, or such comparable categories as shall be in place at the time. The Department shall also report to the Commission on a monthly basis the balance in each of the accounts or subaccounts the Department is required to keep pursuant to the Financing Documents. When actual or additional information becomes available for any of the reports identified in this Section 4.1(d), the Department will communicate such information to the Commission. In addition, the Department's monthly reports shall contain the information required by Section 4.1(c)(ii).

(e) The Commission shall receive any financial reports prepared by the Department as required by the Financing Documents at the same time as the recipients under the Financing Documents.

Section 4.2 Just and Reasonable Costs. The Department agrees that prior to including any cost in the Retail Revenue Requirements communicated to the Commission in accordance with Section 4.1(a), the Department will conduct whatever procedures are required by law to determine that such cost is just and reasonable within the meaning of Section 451 of the California Public Utilities Code.

Section 4.3 ESP Power. Bond Charges may be based on electric power provided to customers by Electric Service Providers only after an order of the Commission providing for such charges becomes final and unappealable.

ARTICLE V
RATE COVENANT

Section 5.1 Rate Covenant.

(a) The Commission hereby covenants and agrees to calculate, revise and impose from time to time, Bond Charges sufficient to provide moneys so that the amounts available for deposit in the Bond Charge Payment Account from time to time, together with amounts on deposit in the Bond Charge Payment Account, are at all times sufficient to pay or provide for the payment of all Bond Related Costs when due in accordance with the Financing Documents.

(b) As provided by Section 80112 of the Act and as authorized by Section 80110 of the Act, including by reference to Article 5.5 (commencing with Section 840) of Chapter 4 of Part 1 of Division 1 of the California Public Utilities Code, the Bond Charges authorized by Commission Order and the right of the Department to receive Bond Charges as provided in this Agreement shall be property of the Department for all purposes under California law.

(c) As authorized by Section 80110 of the Act by reference to Article 5.5 (commencing with Section 840) of Chapter 4 of Part 1 of Division 1 of the California Public Utilities Code, Sections 5.1(a) and 5.1(b) of this Agreement shall have the force and effect of a "financing order" adopted thereunder and shall be irrevocable and enforceable in accordance with the terms hereof, including, without limitation, in circumstances in which the Department has breached its obligations under this Agreement or in respect of the Financing Documents.

(d) If the Department has complied with Article IV hereof to the extent applicable, but nevertheless projects that there will be insufficient monies on deposit in the Bond Charge Payment Account to make timely payment of Bond Related Costs, the Department shall submit to the Commission a request that the Commission increase Bond Charges to make timely payment of Bond Related Costs and the Commission agrees that it shall calculate and impose revised Bond Charges to pay such Bond Related Costs no later than 120 days from the date following the delivery to the Commission by the Department of its request for revised Bond Charges, provided, to the extent the insufficiency in the Bond Charge Payment Account relates to an insufficiency of Power Charges to provide for certain specified Department Costs, the Commission agrees that, no later than 120 days from the date on which the Department submits a revised Retail Revenue Requirement pursuant to Article IV covering the same projected insufficiency in the Bond Charge Payment Account, it shall respond to the revised Retail Revenue Requirement or the Bond Charge request. Whether or not the Department makes the foregoing requests, the Commission shall, in all instances, be bound by its covenants in this Article V.

ARTICLE VI
COVENANTS OF THE COMMISSION

Section 6.1 Power Charges.

(a) The Commission hereby covenants and agrees to calculate, revise and impose, from time to time, Power Charges sufficient to provide moneys in the amounts and at the times necessary to satisfy the Retail Revenue Requirements as specified by the Department.

(b) Power Charges and Bond Charges shall be established by the Commission without regard to the levels or amounts of any particular rates or charges authorized by the Commission to be charged by any Electrical Corporation for electrical power sold by such Electrical Corporation.

(c) The Commission acknowledges that, as provided by Section 80112 of the Act, Power Charges shall be property of the Department for all purposes under California law.

(d) The Commission agrees that it shall calculate and impose Power Charges no later than 120 days following the delivery to the Commission by the Department of a statement of new or revised Retail Revenue Requirements that complies with Article IV hereof.

Section 6.2 Compliance with Agreement.

(a) The Commission hereby covenants with the Department that the Commission shall take all such actions or refrain from taking all such actions, as the case may be, so as to comply with the terms and provisions of the Act and this Agreement.

(b) The Commission hereby covenants that, so long as any Bonds shall be outstanding, it will not take any action, or fail to take any action, which, if taken or not taken, as the case may be, would adversely affect the tax-exempt status of the interest payable on Bonds or Interim Loan obligations then outstanding, the interest on which, at the time of issuance thereof, was exempt from Federal income taxation or not includable in gross income for purposes of Federal income taxation. In furtherance of the foregoing, the Commission agrees to act with respect to those matters within its control that could adversely affect the exclusion of interest on Bonds or Interim Loan obligations from gross income for purposes of federal income taxation.

Section 6.3 Liens. Until the Bonds have been paid in full or provision has been made therefor in accordance with the Financing Documents, the Commission, to the extent it has the power to do so, shall not permit to be created any purported lien upon or pledge of the Power Charges or the Bond Charges except any lien and pledge thereon created by or pursuant to the Act as security for the enforcement of the Department's obligations (including the Interim Loan) entered into pursuant thereto.

Section 6.4 Commission Acknowledgment. The Commission acknowledges that the Department intends to enter into Financing Documents that permit certain specified Department Costs to be funded out of amounts available in the Bond Charge Collection Account if insufficient moneys are available in the Priority Contract Account, Operating Account and the Operating Reserve Account to pay such specified Department Costs. In the event that such Department Costs are funded out of the Bond Charge Collection Account, the Department shall take such actions as are required under this Agreement so that the amounts applied from the Bond Charge Collection Account for such purpose shall be replenished from Power Charges, provided that any failure to do so by the Department shall not mitigate or alter the Commission's obligations under Article V.

ARTICLE VII
COVENANTS OF THE DEPARTMENT

Section 7.1 Retail Revenue Requirement. The Department hereby covenants and agrees to calculate and revise its Retail Revenue Requirement only for the purpose of recovering costs which it is permitted to collect under the Act, (including amounts payable under the Interim Loan), and not to cover any costs in connection with its responsibilities under the Act which it cannot include in such a Retail Revenue Requirement.

Section 7.2 Department Participation. Consistent with the limitations set forth in Water Code Section 80110, upon the request of the Commission, the Department will participate in any Commission proceedings, including providing witnesses, attending public hearings and providing any other materials necessary to facilitate the Commission's completion of its proceedings, taken in connection with the establishment of Power Charges or Bond Charges by the Commission.

Section 7.3 Compliance with Agreement.

(a) The Department hereby covenants with the Commission that the Department shall take all such actions or refrain from taking all such actions, as the case may be, so as to comply with the terms and provisions of the Act and this Agreement, including but not limited to, complying with the legal requirements referenced in Article IV and the requirement to review its Retail Revenue Requirement at least annually.

(b) The Department hereby covenants that, so long as any Bonds shall be outstanding, it will not take any action, or fail to take any action, which, if taken or not taken, as the case may be, would adversely affect the tax-exempt status of the interest payable on Bonds or Interim Loan obligations then outstanding, the interest on which, at the time of issuance thereof, was exempt from Federal income taxation or not includable in gross income for purposes of Federal income taxation. In furtherance of the foregoing, the Department agrees to act with respect to those matters within its control

that could adversely affect the exclusion of interest on Bonds or Interim Loan obligations from gross income for purposes of federal income taxation.

Section 7.4 Charges. The Department acknowledges the Commission's exclusive authority to spread the Department's revenue requirement among customer classes and service territories and to determine the extent or timing of rate changes that may be required in the future, consistent with the Commission's obligations in this Rate Agreement. As long as this Agreement is in effect the Department agrees that it will not attempt to fix or establish charges on retail end use customers for the purpose of paying Department Costs or Bond Related Costs. Nothing in this Agreement shall be read to establish that the Department does or does not have the authority to fix or establish such charges.

Section 7.5 Department Audits. The Department shall provide to the Commission when available a copy of any audit conducted pursuant to Section 80270 of the Act and a copy of each of the Department's audited annual financial statements for the Fund.

Section 7.6 Proceeds. The Department shall sell Bonds, as soon as practicable, in amounts sufficient to provide for the repayment to the General Fund of the State of the advances made under the Act to the Fund, together with interest on such advances as provided by the Act. The Department shall apply the proceeds of the Bonds to repayment of the General Fund with the understanding that repayment of the Interim Loan in full has priority and that the following costs may have priority: creation of adequate reserves for the payment of Bond Related Costs and payment of costs of issuance.

Section 7.7 Renegotiation of Power Contracts. The Department shall use its best efforts to renegotiate or modify its long term Power contracts.

Section 7.8 Priority Long Term Power Contracts. Any Priority Long Term Power Contract that is amended, replaced or terminated so that any resulting contract no longer contains a provision to the general effect that payments by the Department under the contract are to be paid or payable prior to bonds, notes, or other indebtedness of the Department secured by a pledge or assignment of the revenues of the Department under the Act and other amounts in the Fund shall no longer be treated as a Priority Long Term Power Contract. The Department shall immediately notify the Commission of any such amendment, replacement or termination.

Section 7.9 Appointment of Trustee. To the extent practicable, the Department shall appoint as Trustee a bank, trust company or other qualified entity or person that does not itself, or by or through any of its corporate affiliates, trade in electricity or natural gas commodity markets, and does not itself, or any of its affiliates, appear on the list of top twenty creditors for any Electrical Corporation or any entity providing electric power to the Department that has petitioned for bankruptcy.

Section 7.10 Financing Documents. The Department shall involve, to the fullest extent possible, the Commission in the development and completion of all Financing Documents and shall consult with the Commission on the sizing of operating and debt service reserves, debt service coverage, the maturity and maximum amount of Bonds to be issued and any other matters in the Financing Documents which the Commission deems material. The Department has submitted to the Commission a summary (the "Summary") of the material terms of the Financing Documents securing its Bonds. ("Material terms" means the maximum amount of the Bonds authorized, their maturity, a description of the flow of funds and a description of the sizing or methodology of sizing of reserves held or created pursuant to the Financing Documents or debt service coverage required thereby.) If the Department makes any material change to any such terms it must obtain the approval of the Commission's designee. For purposes of the last sentence, "material change" means (i) a change in the sizing or methodology of sizing of debt service reserves that would increase the projected net debt service on the Bonds by more than an amount specified in the Summary; (ii) an increase in debt service coverage required by the Financing Documents by more than an amount specified in the Summary; (iii) a change in the sizing or method of sizing of operating reserves by more than an amount specified in the Summary; (iv) any increase in the maximum amount of the Bonds authorized; (v) a change in the maturity of the Bonds beyond those changes permitted in the Summary; or (vi) a change in the flow of funds beyond those changes permitted in the Summary. At the time the Commission adopts the Rate Agreement, it will appoint a designee for purposes of this Section 7.10. Nothing in this Section 7.10 shall imply that the Commission or its designee shall have the right to approve (i) the final amortization, interest rates, or methods of determination, denominations, redemption provisions or pricing of the Bonds or (ii) final sizing of reserves and debt service coverage based on pricing considerations, or (iii) except to the extent set forth above in this Section 7.10, the terms of any revolving credit agreement, reimbursement agreement, standby purchase agreement, liquidity or credit enhancement facility, or swap agreement or other hedging agreement entered into in connection with the Bonds, or (iv) any agreements or arrangements with any Fiduciary incident to the issuance of the Bonds or (v) any offering document used in connection with the offering of the Bonds (except with respect to sections of the offering document relating to the Commission.)

ARTICLE VIII
EVENTS OF DEFAULT AND REMEDIES

Section 8.1 Events of Default. An "event of default" or a "default" shall mean, whenever they are used in this Agreement, a failure of the Commission to calculate and impose Bond Charges in accordance with Article V.

Section 8.2 Remedies.

(a) Whenever any event of default shall have occurred and be continuing, and written notice of the default shall have been given to the Commission by the Department and the default shall not have been cured within 30 days, the Department

may take whatever action at law or in equity may appear necessary or desirable to enforce performance and observance of any obligation, agreement or covenant of the Commission under Article V.

(b) Whenever any event shall have occurred and be continuing, such that either the Commission or the Department is not in compliance with any covenant or obligation of this Agreement, and written notice of the breach of such covenant or obligation shall have been given to either the Commission or the Department and the breach shall not have been cured within 30 days, both the Commission or the Department may take whatever action at law or in equity that may appear necessary or desirable to enforce performance and observance of any obligation, agreement or covenant under this Agreement.

Section 8.3 Consent to Assignment.

(a) The Commission consents to the collateral assignment by the Department to the Trustee for the benefit of the Beneficiaries, as such, of the covenants of the Commission contained in Article V; provided, however, that any rights so granted to the Trustee shall not be greater than the rights of the Department under such Sections of this Agreement, and such right on the part of the Trustee to enforce such covenants shall only commence after the Department has both defaulted under its obligations contained in the Financing Documents and has failed to enforce such covenants in accordance with the terms of this Agreement. Prior to exercising any rights granted to the Trustee in accordance with this Section 8.3, the Trustee shall be required to (i) give prior written notice within the time period required in Section 8.3(b) below, (ii) certify to the Commission that an event of default, other than an event of default predicated solely on the Commission's failure to act hereunder, has occurred under the Financing Documents and (iii) comply or cause the Department to comply with the provisions of this Agreement relating to the Department's rights, duties and obligations hereunder.

(b) In addition to the requirements of Section 8.3(a) for exercising its rights hereunder, unless a default has resulted in the amount in the Debt Service Reserve Account being insufficient to pay or provide for the timely payment of all Bond Related Costs in accordance with the Financing Documents, the Trustee shall give the Commission 30 days prior written notice of the exercise by the Trustee of any of the Department's rights under Section 5.1 hereof.

ARTICLE IX
TERMINATION

Section 9.1 Termination. The Agreement shall terminate, and the covenants and other obligations contained in the Agreement shall be discharged and satisfied, when payment of the Bonds and all other Bond Related Costs required to be paid by the Department under the Financing Documents have been made or provided for in accordance with the Financing Documents.

ARTICLE X
AMENDMENTS

Section 10.1 Amendments to Agreement. No amendment to the Agreement shall be effective unless it is in writing and signed by each of the parties hereto, provided, however, on or after the issuance of the Bonds, Sections 5.1(a) and (b) may not be amended.

ARTICLE XI
MISCELLANEOUS

Section 11.1 No Waiver. No failure to exercise, and no delay in exercising by the parties hereto, any right, power or privilege hereunder shall operate as a waiver thereof; nor shall any single or partial exercise of any right, power or privilege hereunder preclude any other or further exercise thereof, or the exercise of any right, power or privilege. The rights and remedies herein provided are cumulative and not exclusive of any rights or remedies provided by law, including the Act.

Section 11.2 Notices. All notices, requests and other communications under this Agreement shall be deemed to have been duly given if in writing and delivered personally or by certified mail (a) to the Department at 1416 9th Street, 11th Floor, Sacramento, California 95814, attention: Director; (b) to the Commission at 505 Van Ness Avenue, San Francisco, California 94102, attention: Executive Director and General Counsel; or such other address as the Department, or the Commission, as the case may be, shall hereafter designate by notice in writing to the other party.

Section 11.3 Severability. In the event that any one or more of the provisions contained in the Agreement is or are invalid, irregular or unenforceable in any respect, the validity, regularity and enforceability of the remaining provisions contained in this Agreement shall be in no way affected, prejudiced or disturbed thereby.

Section 11.4 Headings. The descriptive headings of the several articles of the Agreement are inserted in the Agreement for convenience only and shall not be deemed to affect the meaning or construction of any of the provisions of the Agreement.

Section 11.5 Governing Law. The Agreement shall be governed by, and construed in accordance with, the Constitution and laws of the State of California, without regard to the provisions thereof regarding conflicts of law.

Section 11.6 Counterparts. This 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.

Section 11.7 Date of Agreement. The date of this Agreement shall be for identification purposes only. This Agreement shall become effective immediately upon execution and delivery by the parties hereto.

Section 11.8 Third Party Beneficiaries. Nothing in this agreement express or implied shall be construed to give any person or entity, other than the parties hereto and the Beneficiaries, any legal or equitable right, remedy, or claim under or in respect of the agreement or any covenants, agreements, representations, or provisions contained herein.

Section 11.9 Applicability. This Agreement does not apply to any Retail Revenue Requirement under consideration by the Commission as of the date of this Agreement, but does apply to any Retail Revenue Requirement submitted thereafter. Prior to the issuance of any Bonds, any provision of this Agreement referring to an account or subaccount under the Financing Documents shall be interpreted to achieve the intent of such provision as nearly as practicable.

Section 11.10 No Implied Waivers. Nothing in this Agreement shall be construed to limit the rights of the Commission or the Department to assert any rights it may have with respect to any contract entered into by the Department with respect to its obligations under the Act, or to contest in any proceeding the legality or effect of any contract entered into by the Department with respect to its obligations under the Act.

Section 11.11 No Assignment. Except as set forth in Section 8.3, neither the Department nor the Commission shall assign any of its rights or delegate any of its duties under this Agreement without the express written consent of the other party hereto, provided, however, if, with respect to either party, another governmental entity is created or designated by law to carry out the rights, powers, duties and obligations of such party, then such party may, if required by such law, transfer and assign its right, title and interest in this Agreement to such successor, provided, that such successor entity is permitted by law to assume such party's obligations under this Agreement and agrees in writing to be bound by the terms of this Agreement.

IN WITNESS WHEREOF, the Department has caused this Agreement to be executed in its name by the Director of Water Resources and the Commission by the affirmative vote of the Commission (Decision No. 02-02-051) has caused this Agreement to be executed in its name by those Commissioners who constituted a majority of the Commission when it approved this agreement, all as of the date first above written.

STATE OF CALIFORNIA
DEPARTMENT OF
WATER RESOURCES

By: _____
Director of Water Resources

STATE OF CALIFORNIA PUBLIC
UTILITIES COMMISSION

By: _____
Commissioner

By: _____
Commissioner

By: _____
Commissioner

By: _____
Commissioner

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APPENDIX E

PROPOSED FORM OF OPINION OF ATTORNEY GENERAL

Upon delivery of the Series 2002A Bonds, the Honorable Bill Lockyer, Attorney General of the State of California, proposes to deliver an opinion in substantially the following form:

California Department of Water Resources
Sacramento, California

Ladies and Gentlemen:

We have acted as Attorney General of the State of California in connection with the issuance by the State of California Department of Water Resources (the "Department") of $6,313,500,000 aggregate principal amount of Power Supply Revenue Bonds, Series 2002A (the "Series 2002A Bonds"). The Series 2002A Bonds are issued under and pursuant to the Constitution and laws of the State, including, but not limited to, Division 27 (commencing with Section 80000) of the California Water Code, as amended (the "Act"), and a Trust Indenture dated as of October 1, 2002, among the Department, the Treasurer of the State of California, as Trustee (the "Trustee") and U.S. Bank, N.A., as Co-Trustee (the "Co-Trustee"), as amended and supplemented by a supplemental indenture dated as of November 1, 2002, among the Department, the Trustee and the Co-Trustee (collectively, the "Indenture").

In such connection, we have examined the Indenture, the Rate Agreement dated as of March 8, 2002, (the "Rate Agreement") by and between the Department and the California Public Utilities Commission (the "CPUC"), certifications of the Department, the Trustee, the Co-Trustee, and others, opinions of special counsel to the Department and counsel to the CPUC, and such other documents, opinions and matters to the extent we deemed necessary to render the opinions set forth herein. We have assumed, without undertaking to verify, the genuineness of all documents, certifications and opinions and signatures thereon presented to us (whether as originals or as copies); the accuracy of the factual matters represented, warranted or certified in such documents, certificates and opinions; the correctness of the legal conclusions contained in such opinions; and the due and legal execution of such documents and certificates by, and validity thereof against, any parties other than the Department; and compliance with all covenants and agreements contained in the Indenture and the Rate Agreement.

This opinion is issued as of the date hereof. 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. We assume no obligation to update, revise or supplement this opinion to reflect any action hereafter taken or not taken, or any facts or circumstances, or any changes in law or in interpretations thereof, that may hereafter arise or occur, or for any other reason.

In addition, we call attention to the fact that the rights and obligations under the Bonds, the Indenture 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 the State of California. We express no opinion with respect to any indemnification, contribution, penalty, choice of law, choice of forum or waiver provisions contained in the documents described herein.

Finally, we express no opinion as to the accuracy, adequacy or sufficiency of any financial or other information which has been or will be supplied to purchasers of the Series 2002A Bonds and undertake no responsibility for the accuracy, completeness or fairness of the Official Statement dated November 7, 2002,

pertaining to the Bonds or other offering material relating to the 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 Department is a department of the State of California, duly established and validly existing under the laws of the State of California.

2. The Indenture has been duly authorized, executed and delivered by the Department, and constitutes the valid and binding agreement of the Department, enforceable against the Department in accordance with its terms.

3. The Series 2002A Bonds constitute valid and binding limited special obligations of the Department payable solely from the Trust Estate (as defined in the Indenture), including the Revenues (as defined in the Indenture), as and to the extent provided in the Indenture. The Series 2002A Bonds do not constitute a debt or liability of the State or of any political subdivision thereof, and do not constitute a general obligation of the Department. Neither the faith and credit nor the taxing power of the State or of any political subdivision thereof is pledged to the payment of the principal of, premium, if any, or interest on the Bonds. The Department has no taxing power.

4. The Indenture permits the Department to issue additional Bonds, and incur Parity Obligations and other obligations thereunder from time to time on the terms and conditions and for the purposes stated therein.

5. The Indenture creates a valid pledge of the Trust Estate, including the Revenues, as set forth in the Indenture, subject only to the provisions of the Indenture permitting the payment or use of the Trust Estate for the purposes, in the manner and upon the terms and conditions set forth in the Indenture. Pursuant to the Act, the pledge of the Trust Estate, including the Revenues, made by the Department in the Indenture is valid, binding and perfected without any physical delivery, recordation, filing or further act, and the lien thereof is valid, binding and perfected against all parties having claims of any kind in tort, contract or otherwise against the Department irrespective of whether such parties have notice thereof.

6. The Rate Agreement has been duly authorized, executed and delivered by the Department and constitutes a valid and binding agreement of the Department, enforceable against the Department in accordance with its terms.

Sincerely,

Deputy Attorney General

For: BILL LOCKYER
Attorney General

APPENDIX F

PROPOSED FORM OF OPINION OF BOND COUNSEL

[Closing Date]

California Department of Water Resources
Sacramento, California

Ladies and Gentlemen:

We have acted as bond counsel to the State of California (the "State") Department of Water Resources (the "Department") in connection with the issuance by the Department of $6,313,500,000 aggregate principal amount of its Power Supply Revenue Bonds, Series 2002A (the "Offered Bonds"). The Offered Bonds are issued under and pursuant to the Constitution and laws of the State, including, but not limited to, Division 27 (commencing with Section 80000) of the California Water Code, as amended (the "Act"), and a Trust Indenture dated as of October 1, 2002, as amended (the "Trust Indenture"), among the Department, the Treasurer of the State as Trustee (the "Trustee") and U.S. Bank, N.A., as Co-Trustee (the "Co-Trustee"), as supplemented by a Supplemental Indenture dated as of November 1, 2002, among the Department, the Trustee and the Co-Trustee (collectively, with the Trust Indenture, the "Indenture"). Capitalized terms used but not defined herein shall have the respective meanings given to them in the Indenture.

We have examined a record of proceedings relating to the issuance of the Offered Bonds, and based thereon and on our examination of existing law, such legal proceedings and such other documents as we deem necessary to render this opinion, we are of the opinion that:

1. The Department is duly existing under the laws of the State. Under the laws of the State, including the Constitution of the State, and under the Constitution of the United States, the Act is valid with respect to all provisions thereof material to the subject matters of this opinion letter.

2. The Department is validly authorized under the laws of the State, particularly the Act, to execute and deliver the Indenture and to perform its obligations thereunder. The Indenture has been duly authorized, executed and delivered by the Department and constitutes a valid and binding agreement of the Department, enforceable against the Department in accordance with its terms. You have received separate opinions from Sidley Austin Brown & Wood LLP, counsel to the Trustee, and Dorsey & Whitney LLP, counsel to the Co-Trustee, to the effect that, among other things, the Indenture has been duly authorized, executed and delivered by the Trustee and Co-Trustee and constitutes a valid and binding agreement of the Trustee and Co-Trustee, and with your permission we have assumed such matters for purposes of the opinions in this paragraph 2.

3. The Offered Bonds have been duly and validly authorized and issued in accordance with the laws of the State, including the Constitution of the State, the Act and the Indenture, and constitute valid and binding limited special obligations of the Department payable solely from the Trust Estate, including the Revenues, as provided in the Indenture. The Offered Bonds do not constitute a debt or liability of the State or of any political subdivision thereof, and do not constitute a general obligation of the Department. Neither the faith and credit nor the taxing power of the State or of any political subdivision thereof is pledged to the payment of the principal of, premium, if any, or interest on the Bonds. The Department has no taxing power.

The Trust Indenture permits the Department to issue additional Bonds, and incur Parity Obligations and other obligations, thereunder from time to time on the terms and conditions and for the purposes stated therein. The Offered Bonds, such additional Bonds, if issued, and such Parity Obligations, if incurred, will be equally and ratably secured under the Trust Indenture except as otherwise provided therein.

4. The Indenture creates the valid pledge which it purports to create of the Trust Estate, including the Revenues, subject only to the provisions of the Indenture permitting the payment or use of the Trust Estate for the purposes, in the manner and upon the terms and conditions set forth in the Indenture. Pursuant to the Act, the pledge of the Trust Estate, including the Revenues, made by the Department in the Indenture is valid, binding and perfected without any physical delivery, recordation, filing or further act, and the lien thereof is valid, binding and perfected against all parties having claims of any kind in tort, contract or otherwise against the Department irrespective of whether such parties have notice thereof.

5. The Department has duly and validly covenanted in the Indenture to cause to be established, fixed and revised from time to time charges with respect to Department Power sufficient, together with any other available moneys and securities on deposit in the Electric Power Fund, to satisfy all the Department's Revenue Requirements at the times and in the amounts needed. In furtherance of such covenant, the Department has entered into a Rate Agreement dated as of March 8, 2002 (the "Rate Agreement") with the California Public Utilities Commission (the "Commission") pursuant to the Act providing for the imposition by the Commission of rates and charges to satisfy the Department's Revenue Requirements. The Rate Agreement has been duly authorized, executed and delivered by the Department.

6. The Rate Agreement is valid and binding on the parties thereto and is enforceable against the parties thereto in accordance with its terms. The Commission has full power and authority to impose Bond Charges as provided in the Rate Agreement. Under the Rate Agreement, the Department has covenanted, among other things, that prior to including any cost in the Retail Revenue Requirements communicated to the Commission in accordance with the Rate Agreement, the Department will conduct whatever procedures are required by law to determine that such cost is just and reasonable within the meaning of Section 451 of the California Public Utilities Code. However, under the rate covenant in the Rate Agreement, the Commission has the obligation to impose Bond Charges to provide moneys sufficient to pay all Bond Related Costs when due, including debt service on the Bonds (including the Offered Bonds), and this obligation as set forth in the rate covenant is not conditioned upon any determination that the Department's costs are just and reasonable under Section 451 of the California Public Utilities Code.

7. No registration with, consent of, or approval by any governmental officer, agency or commission is necessary for the execution and delivery by the Department of the Indenture, the Offered Bonds or the Rate Agreement, other than those that have been obtained.

8. The Department has validly included in the Indenture and the Offered Bonds the pledge and undertaking of the State that so long as any obligations of the Department incurred under the Act, including without limitation the Indenture and the Bonds, remain outstanding and not fully performed or discharged, the rights, powers, duties and existence of the Department and the Commission shall not be diminished or impaired in any manner that will adversely affect the interests and rights of the holders of or parties to such obligations.

9. Under existing statutes, interest on the Offered Bonds is exempt from State of California personal income taxes.

Except as stated in paragraphs 9 and 10 above, we express no opinion as to any Federal, State or local tax consequences arising with respect to the Offered Bonds or the ownership or disposition thereof. Furthermore, we express no opinion as to the effect of any action hereafter taken or not taken in reliance upon an opinion of counsel other than ourselves on the exclusion from gross income for federal income tax purposes of interest on the Offered Bonds, or under State and local tax law.

You have received an opinion of Gary M. Cohen, Esq., General Counsel to the Commission, to the effect that, among other things, (i) the Commission's Decision No. 02-02-051 dated February 21, 2002, approving the Rate Agreement is final and unappealable under the laws of the State, (ii) the Rate Agreement has been duly executed and delivered by the Commission, and (iii) the Commission has lawfully consented to, in accordance with the Rate Agreement and such Decision, the issuance by the Department of the principal amount

of the Bonds, and with your permission we have assumed such matters for purposes of the opinions expressed in this letter.

We call attention to the fact that the enforceability of rights and remedies with respect to the Offered Bonds, the Indenture and the Rate Agreement may be limited by, and may be subject to: bankruptcy, insolvency, reorganization, arrangement, fraudulent conveyance, moratorium and other laws relating to or affecting creditors' rights; the application of equitable principles; the exercise of judicial discretion in appropriate cases; and generally applicable limitations on legal remedies against the State. We express no opinion with respect to any indemnification, contribution, choice of law, choice of forum or waiver provisions contained in the foregoing documents.

We express no opinion as to the accuracy, adequacy or sufficiency of any financial or other information which has been or will be supplied to purchasers of the Offered Bonds.

This letter is issued as of the date hereof, and we assume no obligation to update, revise or supplement this opinion to reflect any action hereafter taken or not taken, or any facts or circumstances, or any changes in law or in interpretations thereof, that may hereafter arise or occur, or for any other reason.

Very truly yours,

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APPENDIX G

PROPOSED FORM OF OPINION OF CPUC COUNSEL

Upon delivery of the Series 2002A Bonds, General Counsel to the CPUC proposes to deliver an opinion in substantially the following form:

To each of the Parties
listed on Schedule A hereto

Ladies and Gentlemen:

I am the General Counsel to the State of California Public Utilities Commission (the "CPUC"). This opinion is given in connection with the (i) Purchase Agreement, dated as of November 7, 2002 (the "Purchase Agreement"), by and among the State of California acting through the Department of Water Resources ("DWR") and J.P. Morgan Securities Inc. (on behalf of itself and the several underwriters listed on the signature page therein) at the request of DWR as provided by Section 10(f)(xvii) of the Purchase Agreement and (ii) the Master Credit, Liquidity and Participation Agreement (the "Credit Agreement"), dated as of October 30, 2002, among DWR, the "Banks" defined therein and JP Morgan Chase Bank, as administrative agent for the Banks, at the request of DWR as provided by Section 4.1(d) of the Credit Agreement. Capitalized terms used and not otherwise defined have the respective meanings given those terms in the Purchase Agreement and the Documents (as hereinafter defined).

Discussion

The CPUC has previously promulgated a series of final orders, including the Rate Agreement Decision (D.) 02-02-051, issued on February 22, 2002, which approved the Rate Agreement that was executed on March 8, 2002; the Rate Order Decision D.02-02-052, issued on February 22, 2002, which implemented the cost recovery of the DWR's revenue requirements for the period between January 17, 2001 through December 31, 2002. The CPUC approved Servicing Agreements between DWR and each of the utilities (San Diego Gas and Electric Company ("SDG&E"), Southern California Edison Company ("Edison"), and Pacific Gas and Electric Company ("PG&E"), collectively "Utilities") in three separate decisions: D.01-09-013 (SDG&E), issued on September 12, 2001, D.01-09-014 (Edison), issued on September 10, 2001 and D.01-09-015 (PG&E), issued on September 10, 2001. The CPUC subsequently approved Restated Servicing Agreements for SDG&E and SCE in two separate decisions: D.02-04-047 (Edison) and D.02-04-048 (SDG&E), issued on April 24, 2002. DWR and PG&E were unable to agree upon a Servicing Agreement between themselves, and so, at DWR's request, pursuant to Water Code §80106(b), the CPUC subsequently issued a decision (D.02-05-048), on May 17, 2002, that ordered PG&E to comply with the terms of a Servicing Order. Finally, the CPUC approved amendments to the SDG&E and Edison Restated Servicing Agreements in two separate decisions: D.02-07-038 (SDG&E), issued on July 22, 2002 and D.02-07-039 (Edison) issued July 23, 2002. The Restated Servicing Agreements (as amended) for SDG&E and Edison and the Servicing Order for PG&E are hereinafter referred to collectively as the "Servicing Arrangements". The CPUC decisions referred to in this paragraph are hereinafter referred to collectively as the "Decisions".

Applications for rehearing of D.01-09-015 (PG&E Servicing Agreement), D.02-02-051 (Rate Agreement), D.02-02-052 (Rate Order), and D.02-05-048 (PG&E Servicing Order) were filed, challenging the legality of these decisions. The rehearing applications of these decisions were denied by the CPUC in D.01-10-034 (issued October 11, 2001), D.02-03-063 (issued March 21, 2002), D.02-03-062 (issued March 21, 2002), and D.02-06-028 (issued June 7, 2002) respectively. No petitions for writ of review were filed in the California Supreme Court on any of these decisions, as would have been required pursuant to SB 31X in order for any of these decisions to be challenged. Thus, these decisions are final and unappealable, as a matter of California law.

Under California law, CPUC decisions not directly challenged in an application for rehearing to the CPUC and in a petition for writ of review to a court having jurisdiction to consider such a petition, in the manner and time provided by law, are final and conclusive. (See Municipal Water Dist. v. North Coast Water Company (1918) 178 Cal. 324, 328; Miller v. Railroad Comm. of California (1937) 9 Cal.2d 190, 199.) A party who does not file an application for rehearing may not seek a challenge in court. (Pub. Util. Code, §1731, subd. (b); see also, Pub. Util. Code, §§1756 & 1768; Consumers Lobby Against Monopolies v. Public Utilities Com. (1979) 25 Cal. 3d 891, 902-903.) Also, a party who fails to raise an issue in an application for rehearing may not subsequently raise that issue in court. Public Utilities Code Section 1732 provides that "[n]o corporation or person shall in any court urge or rely on any ground not" set forth specifically in the application for rehearing. (Pub. Util. Code, §1732.)

If a party fails to directly challenge a CPUC decision in court, it may not do so collaterally. Public Utilities Code Section 1709 further provides that CPUC decisions which have become final shall be conclusive in all collateral actions or proceedings. (Pub. Util. Code, §1709; see, Miller v. Railroad Comm. of California, supra, 9 Cal.2d at p.199; Coast Truck Line v. Asbury Truck Co. (1933) 218 Cal. 337, 340; see also, Hickey v. Roby (1969) 273 Cal.App.2d 752, 763-764.)

Further, pursuant to Public Utilities Code Section 1759, a superior court may not consider any challenge to a CPUC decision, and lacks jurisdiction to consider any action which would conflict with, hinder or frustrate, or interfere with the general regulatory policy of the CPUC. (San Diego Gas & Electric Co. v. Superior Court ("Covalt") (1996) 13 Cal. 4th 893, 944; Waters v. Pacific Telephone Co. (1974) 12 Cal.3d 1, 11.)

The Rate Agreement Decision contains the following "conclusions of law" in pertinent part that execute the mandates of AB 1X, as amended by SB 3IX (which the Rate Agreement Decision and this opinion refer to collectively as "the Act") pertaining to the CPUC:

1. Section 5.1(b) of the Rate Agreement states that Bond Charges authorized by the CPUC and DWR's right to receive Bond Charges as provided in the Rate Agreement shall be the property of DWR for all purposes under California law.

2. Section 80110 of Division 27 of the California Water Code ("Water Code"), added by Chapter 4 of the Statutes of 2001 (Assembly Bill No. 1 of the First Extraordinary Session of 2001) as approved by the Governor of the State on February 1, 2001 (the "Act") provides authority for Section 5.1(c) of the Rate Agreement, which states that Sections 5.1(a) and 5.1(b) of the Agreement shall have the force and effect of an irrevocable financing order adopted by the CPUC pursuant to Public Utilities Code Section 840, et. seq.

3. Section 80134(b) of the Act and Sections 451 and 701 of the Public Utilities Code provide authority for Section 6.1(b) of the Rate Agreement, which states that the CPUC shall establish Power Charges and Bond Charges without regard to the rates or charges for electric power sold by Electrical Corporations.

4. The creation of Bond Charges and Power Charges as authorized by the Water Code and the Public Utilities Code is consistent with the State and Federal constitutions.

5. The effect of Section 6.1(b) of the Rate Agreement is that the utilities' ability to recover their own revenue requirements over time cannot be affected by Bond Charges. However, the timing of a utility's recovery of its revenue requirements and decisions about which customers' rates will pay for revenue requirements may be affected by the size of Bond Charges.

6. Sections 80110 and 80112 of the Act provide authority for Section 6.1(c) of the Rate Agreement, which states that Power Charges shall be the property of DWR for all purposes under California law.

7. In the Rate Agreement, DWR covenants that its obligations are valid and enforceable. This means that under existing law, DWR can comply with its obligations, and that, at the time of closing, when DWR indicates the Rate Agreement is valid and enforceable, it will confirm that it can so comply, and the CPUC will be able to rely on such confirmation.

8. Once the Rate Agreement is executed by DWR and finalized through the CPUC's rehearing process, Sections 5.1(a) and 5.1(b) of the CPUC-adopted Rate Agreement will have the force and effect of an irrevocable financing order issued pursuant to Public Utilities Code Section 840, et. seq.

9. After adoption of the Rate Agreement Decision, all that remains to be determined in order to fix the initial Bond Charges is the total amount of Bond-Related Costs and how those costs shall be allocated among service territories and customer classes. This determination may include a decision about whether Bond Charges should be based on the amount of power sold by ESPs, but absent such a decision that has become final and unappealable, ESP power will not be included in the determination of Bond Charges.

The Servicing Arrangements between DWR and each of the Utilities contain language to the following effect (with minor variations):

1. In accordance with Section 80110 of the Act, each Utility and DWR agree that DWR shall retain title to all DWR Power sold by DWR to Bundled Customers.

2. [Each] Utility is acting solely as the servicing agent for DWR with respect to Aggregate power provided to Customers.

3. DWR Charges (e.g. Bond Charges and Power Charges) shall be the property of DWR for all purposes.

4. If billing services are provided by a third party, [each] Utility shall bill any applicable Bond Charges and other DWR Charges to, and collect such charges from, the third party on behalf of DWR, and remit the same to DWR upon collection.

5. All DWR Revenues and DWR charges shall constitute property of DWR. To the extent any moneys are received by the Utility during the process of collection, and pending their transfer to DWR, the moneys shall be held in trust for the benefit of DWR.

In connection with this opinion, I have examined originals, or copies certified or otherwise identified to my satisfaction, of the following documents (collectively, the "Documents"):

(a) the Purchase Agreement;

(b) the Credit Agreement;

(c) Rate Agreement;

(d) the Servicing Arrangements; and

(e) the Decisions.

In addition, I have examined those other certificates, agreements and documents that I deemed relevant and necessary as a basis for my opinion. I have also relied upon the factual matters contained in the

representations and warranties of the CPUC made in the Documents and upon certificates of public officials and the CPUC.

In my examination of the documents referred to above, I have assumed, without independent investigation, the genuineness of all signatures (other than those of the CPUC), the legal capacity of all individuals who have executed any of the documents reviewed by me, the authenticity of all documents submitted to me as originals, the conformity to the originals of all documents submitted to us as certified, photostatic, reproduced or conformed copies of valid existing agreements or other documents, the authenticity of the latter documents and that the statements regarding matters of fact in the certificates, records, agreements, instruments and documents that I have examined are accurate and complete. I have also assumed, without independent investigation, the enforceability of the Rate Agreement against DWR.

Whenever I indicate that my opinion is based upon my knowledge or words of similar import, my opinion is based solely on the actual knowledge of the attorneys in the CPUC Legal Division who are representing the CPUC in connection with the Documents.

In reaching the opinions set forth in paragraphs 2, 3 and 4 below, to the extent such opinions relate to the imposition of Power Charges, I advise you that Division 27 of the California Water Code, the Rate Agreement and the Rate Agreement Decision establish that DWR, and not the CPUC has the authority to determine DWR's revenue requirement. The CPUC has no authority or responsibility to determine whether DWR's costs submitted in its revenue requirements are "just and reasonable" within the meaning of Section 451 of the Public Utilities Code. In Pacific Gas and Electric Company v. The California Department of Water Resources filed in August 2001 in Sacramento County Superior Court (Case no. 01 CS01200), PG&E contended that when DWR determined that its revenue requirement for 2001-2002 was "just and reasonable," DWR failed to follow the California Administrative Procedure Act (the "APA"). On June 7, 2002, the Superior Court issued a judgment finding that DWR failed to follow the APA in making its "just and reasonable" determination and ordered DWR to follow the procedures mandated by the APA before making any "just and reasonable" determination. On October 17, 2002, PG&E filed a lawsuit in Sacramento County Superior Court (Pacific Gas and Electric Company v. The California Department of Water Resources, et al., Case no. 02CS01631) concerning the matters cited in PG&E's request for reconsideration of DWR's determination of its revenue requirements for 2003 (and its re-examination and redetermination of its revenue requirements for 2001 and 2002). As DWR, and not the CPUC, is charged under AB 1X with the exclusive responsibility to determine whether DWR's costs are "just and reasonable", I express no views on this pending litigation or any other potential litigation that might challenge the DWR revenue requirements for 2001-2002 or any future year or how Division 27 of the California Water Code might be construed regarding DWR's determination of its revenue requirement.

Based upon the foregoing, and subject to the assumptions, exceptions and qualifications stated below, I am of the opinion that:

1. The Decisions are final and unappealable under the laws of the State of California.

2. The CPUC has full power and authority to execute the Rate Agreement, and to perform its obligations under the Rate Agreement; the Rate Agreement has been duly executed and delivered by the CPUC and constitutes the legal, valid and binding obligation of the CPUC, enforceable against the CPUC in accordance with its terms.

3. The CPUC has full power and authority to impose Bond Charges as provided in the Rate Agreement. Under the Rate Agreement, DWR has covenanted, among other things, that prior to including any cost in the Retail Revenue Requirements communicated to the CPUC in accordance with the Rate Agreement, DWR will conduct whatever procedures are required by law to determine that such cost is just and reasonable within the meaning of Section 451 of the Public Utilities Code; however, under the rate covenant in the Rate Agreement, the CPUC has the

obligation to impose Bond Charges to provide moneys sufficient to pay all Bond Related Costs when due, including debt service on the Bonds, and this obligation as set forth in the rate covenant is not conditioned upon any determination that DWR's costs are just and reasonable under Section 451 of the Public Utilities Code.

4. The execution and delivery by the CPUC of the Rate Agreement and the performance by the CPUC of its obligations under the Rate Agreement do not (i) violate any Covered Law (as defined below) or (ii) violate any order, writ, injunction or decree of which I have knowledge of any court or governmental authority or agency binding upon the CPUC or to which the CPUC is subject.

5. The Bond Charges and Power Charges and all revenues collected in respect of such charges are property of DWR for all purposes under California law.

6. To my knowledge, there are no legal proceedings pending or threatened challenging the Rate Agreement or the Rate Agreement Decision which are reasonably likely to have a material adverse effect on the validity or enforceability of either the Rate Agreement or the Rate Agreement Decision.

7. The CPUC has lawfully consented, in accordance with the Rate Agreement and the Rate Agreement Decision, to the issuance by DWR of the principal amount of Bonds issued under the Trust Indenture, denominated as the Power Supply Revenue Bonds, Series 2002 A.

This opinion is subject to the following assumptions, exceptions and qualifications:

The enforceability of the Rate Agreement with respect to the parties thereto may be: (i) subject to bankruptcy, insolvency, reorganization, fraudulent conveyance or transfer, moratorium or similar laws affecting creditors' rights generally and (ii) subject to general principles of equity, including, without limitation, concepts of materiality, reasonableness, good faith and fair dealing and the possible unavailability of specific performance or injunctive relief (regardless of whether enforceability is considered in a proceeding at law or in equity).

I express no opinion as to: (i) the enforceability of forum selection clauses in the Federal courts; (ii) the enforceability of any provisions for indemnification of Persons for liability under Federal or state securities laws; or (iii) general indemnities that do not include gross negligence and willful misconduct.

This opinion is limited to the laws of the State of California and the federal laws of the United States of America that, in each case, in my experience, are normally applicable to transactions of the type contemplated by the Documents (collectively, the "Covered Laws"). This opinion is rendered only with respect to the laws (including case law), and the rules, regulations and orders under those laws, which are currently in effect.

This opinion is expressly premised on the standard for rendering of opinions set forth in "Legal Opinion Principles" as established by the American Bar Association's Committee on Legal Opinions set forth in 53 Bus. Law. 831 (1998). Legal Opinion Principle 1(D) states in pertinent part "[t]he opinions contained in an opinion letter are expressions of professional judgment regarding the legal matters addressed and not guarantees that a court will reach any particular result."

Very truly yours,

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APPENDIX H

INDEX OF PRINCIPAL DEFINITIONS

The following is an index of certain terms used in the forepart of this Official Statement, with references to the pages on which the definitions or descriptions of such terms may be found. Other terms used but not defined or described in the forepart of this Official Statement have the meanings given in APPENDIX C – "SUMMARY OF CERTAIN PROVISIONS OF THE INDENTURE – Definitions."

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APPENDIX I

FORM OF CONTINUING DISCLOSURE CERTIFICATE

This Continuing Disclosure Certificate (the "Disclosure Certificate") is executed and delivered by the State of California Department of Water Resources (the "Department") in connection with the issuance of its Power Supply Revenue Bonds, Series 2002A and Series 2002E (collectively, the "Bonds"). The Bonds are being issued pursuant to the Trust Indenture among the Department, the Treasurer of the State of California, as Trustee, and U.S. Bank, N.A., as Co-Trustee, dated as of October 1, 2002, as amended and supplemented (the "Indenture"). The Department covenants and agrees as follows:

SECTION 1. *Purpose of the Disclosure Certificate*. This Disclosure Certificate is being executed and delivered by the Department for the benefit of the Owners and Beneficial Owners of the 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 Certificate unless otherwise defined in this Section, the following capitalized terms shall have the following meanings:

"Annual Report" shall mean any Annual Report provided by the Department pursuant to, and as described in, Sections 3 and 4 of this Disclosure Certificate.

"Beneficial Owner" shall mean any person which has or shares the power, directly or indirectly, to make investment decisions concerning ownership of any Bonds (including persons holding Bonds through nominees, depositories and other intermediaries).

"Consultant's Report" shall mean the report of Navigant Consulting, Inc., appended to the Official Statement as Appendix A.

"Dissemination Agent," if any, shall mean the person or firm, or any successor Dissemination Agent, designated in writing by the Department pursuant to Section 7 of this Disclosure Certificate and which has filed with the Department and the Trustee a written acceptance of such designation.

"Listed Event" shall mean any of the events listed in Section 5(a) of this Disclosure Certificate.

"National Repository" shall mean any Nationally Recognized Municipal Securities Information Repository for purposes of the Rule. The National Repositories currently approved by the Securities and Exchange Commission can be obtained at http://www.sec.gov/info/municipal/nrmsir.htm.

"Official Statement" shall mean the Department's final Official Statement relating to each series of the Bonds.

"Participating Underwriter" shall mean any of the original underwriters of the Bonds required to comply with the Rule in connection with the offering of the Bonds.

"Repository" shall mean each National Repository and the State Repository.

"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.

"State" shall mean the State of California.

"State Repository," if any, shall mean any public or private repository or entity designated by the State as the state repository for the purpose of the Rule and recognized as such by the Securities and Exchange Commission. As of the date of this Certificate, there is no State Repository.

SECTION 3. *Provision of Annual Reports*. For so long as any Bonds are Outstanding:

(a) The Department shall, or shall cause the Dissemination Agent to, not later than nine (9) months after the end of the Department's Fiscal Year (presently June 30), commencing with the report due on or before March 31, 2003, provide to each Repository an Annual Report which is consistent with the requirements of Section 4 of this Disclosure Certificate, with a copy to the Trustee. The Annual Report may be submitted as a single document or as separate documents comprising a package, and may cross-reference other information as provided in Section 4 of this Disclosure Certificate; provided that the audited financial statements of the Department 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 Department's Fiscal Year changes, it shall give notice of such change in the same manner as for a Listed Event under Section 5(b).

(b) Not later than fifteen (15) Business Days prior to the due date of each Annual Report as specified in subsection (a), the Department shall provide the Annual Report to the Dissemination Agent, if any. If the Department is unable to provide the Repositories an Annual Report by its due date, the Department shall send a notice to each Repository or the Municipal Securities Rulemaking Board and the State Repository, if any, in substantially the form attached as Exhibit A.

(c) If a Dissemination Agent is appointed by the Department, the Dissemination Agent shall:

(i) determine, prior to the due date of each Annual Report, the name and address of each National Repository and the State Repository, if any; and

(ii) file a report with the Department certifying that the Annual Report has been provided pursuant to this Disclosure Certificate, stating the date it was provided and listing all the Repositories to which it was provided.

SECTION 4. *Content of Annual Reports*. The Department's Annual Report shall contain or include by reference the following:

(a) The audited financial statements of the Department relating to its Electric Power Fund for the prior Fiscal Year, prepared in accordance with generally accepted accounting principles applicable to governmental entities, as specified from time to time by the Government Accounting Standards Board. If such 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 and such audited financial statements shall be filed in the same manner as the Annual Report when they become available.

(b) Operating results and other financial data for the prior calendar year (to the extent not otherwise included in the Annual Report pursuant to this Section 4), in the categories set forth in the table under the caption "Summary of Historical and Projected Financial Results" in the Official Statement, but only to the extent such information is or becomes historical and does not constitute projections.

(c) Financial and operating data for the prior calendar year (to the extent not otherwise included in the Annual Report pursuant to this Section 4), in the categories set forth in Table 20 - "Estimated Average Power Charges and Bond Charges to the Customers" in the Consultant's Report, but only to the extent such information is or becomes historical information and does not constitute projections.

(d) The Department's residual net short costs and direct access surcharge revenues, if any, for the prior calendar year (to the extent not otherwise included in the Annual Report pursuant to this Section 4).

(e) The Department's staffing, of its power supply program, specifying the number of permanent staff, number of contract employees and consulting advisors and number of employees on loan from other departments within State government, as of December 31 of the prior calendar year.

Any or all of the items listed above may be included by specific reference to other documents, including official statements relating to debt issues of the Department, which have been submitted to each of the Repositories or the Securities and Exchange Commission. If the document included by reference is a final official statement, it must be available from the Municipal Securities Rulemaking Board. The Department shall clearly identify each document so included by reference.

SECTION 5. *Reporting of Material Events*. For so long as any Bonds are Outstanding:

(a) Pursuant to the provisions of this Section 5, the Department shall give, or cause to be given, notice of the occurrence of any of the following events with respect to the Bonds, if material:

1. principal and interest payment delinquencies;

2. non-payment related defaults;

3. modifications to rights of Bondholders;

4. optional, contingent, or unscheduled bond calls;

5. defeasances;

6. rating changes;

7. adverse tax opinions or events affecting the tax-exempt status of the Bonds;

8. unscheduled draws on the debt service reserves reflecting financial difficulties;

9. unscheduled draws on the credit enhancements reflecting financial difficulties.;

10. substitution of the credit or liquidity providers or their failure to perform; and

11. release, substitution or sale of property securing repayment of the Bonds.

(b) The Department shall promptly file a notice of each occurrence of a Listed Event, if material, with the Repositories or the Municipal Securities Rulemaking Board and the State Repository, with a copy to the Trustee.

SECTION 6. *Termination of Reporting Obligation*. The Department's obligations under this Disclosure Certificate shall terminate upon the legal defeasance, prior redemption or payment in full of all of the Bonds. If such termination occurs prior to the final maturity of the Bonds, the Department shall give notice of such termination in the same manner as for a Listed Event under Section 5(b).

SECTION 7. *Dissemination Agent*. The Department may, from time to time, appoint or engage a Dissemination Agent to assist it in carrying out its obligations under this Disclosure Certificate, 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 Department pursuant to this Disclosure Certificate. Initially, the Department will serve as its own dissemination agent.

SECTION 8. *Amendment; Waiver*. The Department may amend this Disclosure Certificate, and any provision of this Disclosure Certificate may be waived, provided that all of the following conditions are satisfied:

(a) If the amendment or waiver relates to the provisions of Sections 3(a), 4, 5(a) or (b), or 8, it may only be made in connection with a change in circumstances that arises from a change in legal requirements, change in law, or change in the identity, nature or status of an obligated person with respect to the Bonds, or the type of business conducted;

(b) The undertakings contained in this Disclosure Certificate, as amended or taking into account such waiver, would, in the opinion of nationally recognized bond counsel, have complied with the requirements of the Rule at the time of the original issuance of the Bonds, after taking into account any amendments or interpretations of the Rule, as well as any change in circumstances; and

(c) The amendment or waiver either (i) is approved by the Owners of the Bonds in the same manner as provided in the Indenture for amendments to the Indenture with the consent of Owners, or (ii) does not, in the opinion of the Trustee or nationally recognized bond counsel, materially impair the interests of the Owners or Beneficial Owners of the Bonds. The Department also may amend this Disclosure Certificate without approval by the Owners of the Bonds to the extent permitted by rule, order or other official pronouncement of the Securities and Exchange Commission.

In the event of any amendment or waiver of a provision of this Disclosure Certificate, the Department shall describe such amendment in the 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 Department. 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 same manner as for a Listed Event under Section 5(b), 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 Certificate shall be deemed to prevent the Department from disseminating any other information, using the means of dissemination set forth in this Disclosure Certificate 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 Certificate. If the Department 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 Certificate, the Department shall have no obligation under this Certificate to update such information or include it any future Annual Report or notice of occurrence of a Listed Event.

SECTION 10. *Default*. In the event of a failure of the Department to comply with any provision of this Disclosure Certificate, the Trustee may (and, at the request of the Owners of at least 50% in aggregate principal amount of Outstanding Bonds, shall), or any Owner or Beneficial Owner of the Bonds may (unless the Department has so complied within 20 days after written notice from the Trustee, such Owner or Owners, or such Beneficial Owner or Beneficial Owners, as the case may be, of the Department's failure to comply) seek specific performance by court order, to cause the Department to comply with its obligations under this Disclosure Certificate, as the sole remedy. A default under this Disclosure Certificate shall not be deemed a default or an Event of Default under the Indenture.

SECTION 11. *Duties, Immunities and Liabilities of Dissemination Agent*. The Dissemination Agent shall have only such duties as are specifically set forth in this Disclosure Certificate, and the Department agrees to indemnify and save the Dissemination Agent, its officers, directors, employees and agents, harmless against any loss, reasonable expense and liabilities which it may incur arising out of or in the exercise or performance of its powers and duties hereunder, including the reasonable costs and expenses (including reasonable attorneys fees) of defending against any claim of liability, but excluding liabilities due to the Dissemination Agent's default or negligence or willful misconduct. The obligations of the Department under this Section shall survive resignation or removal of the Dissemination Agent and termination of this Disclosure Certificate.

SECTION 12. *Beneficiaries*. This Disclosure Certificate shall inure solely to the benefit of the Owners and Beneficial Owners from time to time of the Bonds, and shall create no rights in any other person or entity.

Date: November 14, 2002

DEPARTMENT OF WATER RESOURCES

By: _____
Name:
Title:

EXHIBIT A

Notice to Repositories of Failure to File Annual Report

Name of Issuer:	State of California Department of Water Resources
Name of Bond Issue:	Department of Water Resources Power Supply Revenue Bonds, Series 2002A and Series 2002E
Date of Issuance:	November 14, 2002

NOTICE IS HEREBY GIVEN that the Department has not provided an Annual Report with respect to the above-named Bonds as required by Section 3 of the Continuing Disclosure Certificate dated November 14, 2002 of the Department. The Department anticipates that the Annual Report will be filed by _____.

Dated:_____

DEPARTMENT OF WATER RESOURCES

By: _____

cc: Trustee
Co-Trustee

Department of Water Resources
Electric Power Fund

Financial Statements
For the period from January 19, 2001
(date of inception) to June 30, 2001, and for the
ten months ended April 30, 2002 (unaudited)

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Department of Water Resources Electric Power Fund
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Report of Independent Accountants

The Director of the State of California
Department of Water Resources

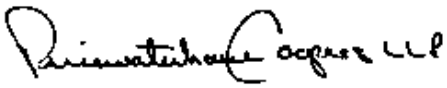
In our opinion, the accompanying statement of net assets and the related statements of activities and cash flows present fairly, in all material respects, the financial position of the Department of Water Resources Electric Power Fund (Fund), a component unit of the State of California, as of June 30, 2001, and the results of its operations and its cash flows for the period from January 19, 2001 (date of inception) to June 30, 2001, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of management of the Department of Water Resources Electric Power Fund; our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards*, issued by the Comptroller General of the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit 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, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

As explained in Note 1 to the financial statements, the Fund is involved in certain lawsuits and regulatory proceedings that could impact the revenue requirements and rate structure needed to repay debt and the terms and conditions of the power purchase contracts. Because of the early stage of the legal and regulatory proceedings, the ultimate outcome of these matters cannot be presently determined.

As explained in Note 2 to the financial statements, the Fund has implemented the provisions of Governmental Accounting Standards Board Statement No. 34, *Basic Financial Statements – Management's Discussion and Analysis – for State and Local Governments,* as amended, as of January 19, 2001 (date of inception).

The Management's Discussion and Analysis is not a required part of the basic 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 measurements and presentation of the supplementary information. However, we did not audit the information and express no opinion on it.

In accordance with *Government Auditing Standards*, we have also issued our report dated December 14, 2001, on our consideration of the Fund's internal control over financial reporting and on our tests of its compliance with laws and regulations, contracts and grants. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* and should be read in conjunction with this report in considering the results of our audit.



December 14, 2001,
except for Notes 1 and 6,
as to which the date is
September 16, 2002.

HISTORY AND FINANCING

The Department of Water Resources Electric Power Fund (Fund) was established in January 2001, in connection with the Governor of California's emergency proclamation and subsequent legislation to assist in mitigating the effect of a statewide energy supply emergency. The enabling legislation included the following powers and requirements:

- Authorization to secure and requirement to retain title to power for resale to end use customers of the State's investor owned utilities (IOUs).
- Authorization to enter in servicing arrangements with IOUs for transmission, distribution, billing and collection services.
- Entitlement to recover revenue requirements for authorized activities, including debt service, the costs of power purchases, administrative costs and reserves.
- Authorization to enter into agreements with California Public Utility Commission (CPUC) to ensure collection of revenue requirements.
- Restriction from entering into new contracts after December 31, 2002.
- Authorization to administer contracts after December 31, 2002.
- Authorization to issue revenue bonds not to exceed $13.4 billion.

Additional background is provided in Note 1 to the financial statements.

The original funding for the Fund came from advances from the State's General Fund as permitted by the enabling legislation. Through June 26, 2001, advances aggregating $6.2 billion were made to the Fund, to make payments for purchased power. There have been no additional advances since that date. In July 2001, $116 million, the amount of cash on hand at June 26, 2001, was repaid to the General Fund.

On June 26, 2001, the Fund received the net proceeds from a $4.3 billion interim loan from a financial consortium led by JPMorgan Chase Bank. Under the terms of the Credit and Security Agreement, the loan was converted to a term loan on October 31, 2001. Principal payments are payable quarterly from April 30, 2002 through October 31, 2004. Repayment of the interim loan has priority over repayment of the advances from the General Fund. Interest is payable quarterly and has been paid through June 30, 2002.

It is anticipated that revenue bonds will be sold in the second half of calendar year 2002 to repay both the interim loan and the General Fund advances, and respective accrued interest thereon.

USING THIS REPORT

This financial report consists of three financial statements with accompanying notes for the Fund. The Statements of Net Assets, prepared on the accrual basis of accounting, includes all assets and liabilities of the Fund. The Statements of Activities, also prepared on the accrual basis, take into account all revenues and expenses for the Fund regardless of when cash is received or paid. The Statements of Cash Flow reflect the actual cash receipts and disbursements for a specified period of time.

STATEMENT OF NET ASSETS

The Funds assets and liabilities as of June 30, 2001 and April 30, 2002, are summarized as follows (dollars in millions):

	June 30, 2001	April 30, 2002
Cash and investments, including restricted cash	$ 4,427	$ 2,055
Recoverable costs, current portion	1,591	1,754
Other current assets	17	26
Recoverable costs, net of current portion	6,127	6,747
Total assets	$ 12,162	$ 10,582
Long-term debt, including current portion	$ 10,585	$ 10,303
Other current liabilities	1,577	279
Total capital and liabilities	$ 12,162	$ 10,582

Cash decreased by approximately $2.4 billion from June 30, 2001 to April 30, 2002. The cash balance at June 30, 2001, is directly attributable to the proceeds of the $4.3 billion interim loan, which were received on June 26, 2001. $1.3 billion of the decrease from June 30, 2001 to April 30, 2002, is attributable to a decrease in accounts payable. $.8 billion of the decrease is attributable to payments of principal and interest on the interim loan and advances from the General Fund. The remaining $.3 billion is attributable to the excess of payments for power purchased over cash received from power sold. The majority of this decrease took place from July to October 2001. Since October 2001, cash receipts from power sales have approximated payments for the cost of power.

The current portion of recoverable costs reflects billings to the IOU customers that have not yet been collected. Until recently, the IOUs were required to make payment to the Fund only for energy supplied under bi-lateral contracts and not for imbalance energy supplied through the California Independent System Operator (ISO) market. As a result, the current portion of recoverable costs grew slightly between June 30, 2001 and April 30, 2002. Effective April 1, 2002, the IOUs are required under a CPUC order to repay the Fund for imbalance energy supplied through the ISO market since January 2001, in monthly payments through September 1, 2002. Thereafter, the IOU's will make payments to the Fund for such energy when collected from the end-use customers.

Other current assets consist primarily of interest receivable on cash and investments.

Long-term recoverable costs consist of costs that are recoverable through future billings. While the balance has increased from June 30, 2001 to April 30, 2002, the majority of this increase occurred from July to September 2001, when the cost per megawatt of power continued to be in excess of the rate per megawatt hour that the Fund was able to charge to customers of the IOUs. Currently, the recovery rate from customers is in excess of the cost of power per megawatt hour; thus this asset should decrease over time.

Long-term debt has decreased by $.2 billion through the repayment of $116 million to the State General Fund and repayment of $451 million of the interim loan. These two decreases are offset by accrued interest expense for the ten-month period ended April 30, 2002.

In addition to the purchase of power through both the spot market and long-term contracts, the Fund has been the creditworthy party for certain costs incurred for the benefit of two major IOUs in the ISO market. The large accounts payable balance at June 30, 2001, is attributable to settlement problems with the ISO Market. The Fund was not billed for the ISO Market charges until November 2001, and did not begin making payments until December 2001. The Fund is now current on all payments to the ISO; therefore, accounts payable at April 30, 2002 reflects one month's activity for the bi-lateral market and two months (the normal billing cycle) for the ISO markets, at costs per megawatt hour significantly less than were in effect at June 30, 2001.

REVENUES

The cost of providing energy is recoverable primarily through power sales to the customers of the IOUs. These charges are collected by the IOUs as agent for the Fund and then forwarded to the Fund daily. Charges are determined by applying a rate approved by the CPUC for each IOU to the megawatt hours delivered by the fund to each IOU's service area. Therefore, revenues are directly related to the amount of power used by customers. Interim rates were initially established by the CPUC in March 2001. Final rates for calendar years 2001 and 2002, which approximated the interim rates, were adopted by the CPUC in February 2002. The following reflects power sales and cash receipts during each period and current accounts receivable at the end of each reporting period (dollars in millions):

	Power Sales During Period	Cash Receipts During Period	Current Accounts Receivable at End of Period
January 17, 2001 - June 30, 2001	$ 2,733	$ 1,135	$ 1,591
July 1, 2001 - April 30, 2002	$ 3,837	$ 3,675	$ 1,754

EXPENDITURES

The following reflects purchases and payments during each period and accounts payable at the end of each reporting period (dollars in millions):

	Power Purchases During Period	Payments During Period	Accounts Payable at End of Period
January 17, 2001 - June 30, 2001	$ 8,764	$ 7,203	$ 1,574
July 1, 2001 - April 30, 2002	$ 4,008	$ 5,361	$ 260

Early in the Fund's existence, energy costs were extremely high. The average cost was $268/MWh for the period ending June 30, 2001. The monthly averages ranged from $453/MWh in January 2001, down to $174/MWh in June 2001. The average cost for the ten-month period ended April 2002 was $95/MWh and the monthly averages have ranged from $71/MWh to $125/MWh. The monthly average cost for April 2002 was $84/MWh.

The Fund began operations in January 2001, and had no long-term contracts in place; therefore, over 90% of the Fund's energy purchases in the period ended June 30, 2001, were made in the spot market. For the ten-month period ended April 30, 2002, approximately 13% of the energy purchases were made in the spot market as the Fund has been able to enter into long-term power purchase contracts, ranging from one to eleven years. The long-term contracts and declining spot market prices, which began in June 2001, helped to drive down the average cost of energy for the period ended April 30, 2002, compared to the period ended June 30, 2001.

Payments made under the long-term power contracts approximated $1.1 billion and $2.3 billion for the period from January 19, 2001 (date of inception) to June 30, 2001, and for the ten months ended April 30, 2002, respectively. The amounts of fixed obligations under the long-term contracts as of June 30, 2001 and April 30, 2002, totaled $31.7 and $24.9 billion, respectively. DWR has been renegotiating some of the contracts in order to improve reliability, procure more dispatchable power, increase the number of contracts that are assignable to the IOUs, and reduce cost. Subsequent to June 30, 2001, 17 contracts were renegotiated, reducing the future fixed obligations by approximately $4.5 billion.

Generally, the terms of payment under the power purchase contracts require the Fund to pay by the 20th of the month following delivery of power. Through June 2001, the Fund often made payment on an expedited basis because of suppliers' concerns about the newness of the Fund, the Fund's ability to make timely payments, and the size of the energy purchases. All payments were made on time, thus accounts payable for bi-lateral purchases of power have always been kept at minimal levels.

FUTURE OF THE FUND

Management of the Fund has always envisioned obtaining long-term financing for repayment of the advances from the State General Fund and the interim loan. Until recently, the anticipated revenue bond issue has been delayed pending the resolution of certain regulatory proceedings and finalization of certain necessary agreements. In February 2002, the Department of Water Resources (DWR), which operates the Fund, and the CPUC entered into a Rate Agreement, a part of which outlines the structure for a revenue bond program. In addition, the CPUC issued a rate order and related amendment that establishes the revenue stream from the customers through the later of December 2002 or until a new rate order is adopted. The Fund has submitted the revenue requirement for calendar year 2003 to the CPUC and expects the CPUC to issue rate orders for the 2003 charges in December 2002. Management of the Fund believes that revenue bonds, the proceeds of which will retire the interim loan and repay the General Fund advances, will be sold during the second half of calendar year 2002.

The Fund will administer the revenue bonds until such time as the bonds are completely redeemed. Revenue requirements for the repayment of the bonds will be determined at least annually by the Fund and submitted to the CPUC. Under the terms of the Rate Agreement between the CPUC and DWR, the CPUC is required to set rates for the customers of the IOUs such that the Fund will receive monies to retire the debt.

In addition, the Fund has the authority to manage all contracts entered into before December 31, 2002, for the life of the contracts. Revenue requirements for the payment of energy purchased under the long-term contracts will be determined annually by the Fund and submitted to the CPUC. Under the terms of the Rate Agreement between the CPUC and DWR, the CPUC is required to implement rates such that the Fund will receive necessary monies to pay for energy purchased.

The Fund is proceeding with a transition process that could transfer the scheduling and ultimately the financial responsibility for the contracts to the IOUs. However, there are a number of issues to be addressed, including the assignment of the long-term contracts to the IOUs, which could affect the timing of the transition process.

Department of Water Resources Electric Power Fund
Statements of Net Assets
June 30, 2001 and April 30, 2002 (unaudited) (in millions)

	June 30, 2001	April 30, 2002 (unaudited)
Assets		
Current assets:		
Cash and investments	$ 4,241	$ 2,055
Restricted cash on deposit with agent	186	-
Recoverable costs, current portion	1,591	1,754
Interest receivable	10	21
Due from other funds	7	5
Total current assets	6,035	3,835
Recoverable costs, net of current portion	6,127	6,747
Total assets	$ 12,162	$ 10,582
Capitalization and Liabilities		
Capitalization:		
Long-term debt, less current maturities:		
Advances from State General Fund including accrued interest of $75 and $360, net of current portion	$ 6,169	$ 6,454
Interim loan	3,909	2,309
Total capitalization	10,078	8,763
Current liabilities:		
Current portion of interim loan	391	1,540
Current portion of advances from State General Fund	116	-
Accounts payable (including $779 due to California Independent System Operator Corporation at June 30, 2001)	1,574	260
Accrued interest on interim loan	3	19
Total current liabilities	2,084	1,819
Commitments and Contingencies (Notes 1 and 6)		
Total capitalization and liabilities	$ 12,162	$ 10,582

The accompanying notes are an integral part of these financial statements.

Department of Water Resources Electric Power Fund
Statements of Activities
For the period from January 19, 2001 (date of inception) to June 30, 2001, and for the ten months ended April 30, 2002 (unaudited)

(in millions)

	For the period from January 19, 2001 (date of inception) to June 30, 2001	Ten months ended April 30, 2002 (unaudited)
Operating revenues:		
Power sales	$ 2,733	$ 3,837
Total operating revenues	2,733	3,837
Operating expenses:		
Power purchases	8,764	4,008
Administrative expenses	13	41
Deferral of operating expenses	(6,127)	(621)
Total operating expenses	2,650	3,428
Income from operations	83	409
Costs incurred in anticipation of sale of long-term bonds	(15)	(13)
Interest income	10	89
Interest expense	(78)	(485)
Net income	-	-
Net assets, beginning of period	-	-
Net assets, end of period	$ -	$ -

The accompanying notes are an integral part of these financial statements.

Department of Water Resources Electric Power Fund
Statements of Cash Flows
For the period from January 19, 2001 (date of inception) to June 30, 2001, and for the ten months ended April 30, 2002 (unaudited)

(in millions)

	For the period from January 19, 2001 (date of inception) to June 30, 2001	Ten months ended April 30, 2002 (unaudited)
Cash flows from operating income:		
Receipts from customers	$ 1,135	$ 3,675
Payments for power purchases and other costs	(7,203)	(5,361)
Net cash used in operating activities	(6,068)	(1,686)
Cash flows from non-capital financing activities:		
Proceeds from (payments on) interim loan	4,300	(451)
Advances from (payments to) State of California General Fund	6,210	(116)
Payment of financing costs	(15)	(13)
Payment of interest on interim loan	-	(184)
Net cash provided by (used in) non-capital financing activities	10,495	(764)
Cash flows from investing activities:		
Interest received on investments	-	78
Net cash provided by investing activities	-	78
Net increase (decrease) in cash and investments	4,427	(2,372)
Cash and investments, beginning of period	-	4,427
Cash and investments, end of period	$ 4,427	$ 2,055
Reconciliation of operating income to net cash used in operating activities:		
Operating income	$ 83	$ 409
Changes in net assets and liabilities to reconcile operating income to net cash used in operations:		
Recoverable costs	(7,718)	(783)
Due from other funds	(7)	2
Accounts payable	1,574	(1,314)
Total adjustments	(6,151)	(2,095)
Net cash used in operating activities	$ (6,068)	$ (1,686)

The accompanying notes are an integral part of these financial statements.

1. Reporting Entity

Background

In January 2001, the Governor of California issued an emergency proclamation directing the Department of Water Resources (DWR) to enter into contracts and arrangements for the purchase and sale of electric power to assist in mitigating the effect of a statewide energy supply emergency.

The Department of Water Resources Electric Power Fund (a component unit of the State of California) (Fund) was established on January 19, 2001, by Senate Bill 7 from the First Extraordinary Session of 2001 (SB7X). Assembly Bill 1 from the First Extraordinary Session of 2001 (AB1X), enacted on February 1, 2001, added Division 27 to the California Water Code to clarify and expand the powers of DWR to incur debt for the purposes of the Fund and to use amounts in the Fund for the purchase of power. The Fund is administered by DWR. Division 27 of the California Water Code (as subsequently amended by Senate Bill 31 from the First Extraordinary Session of 2001) includes the following powers and requirements:

- Authorizes DWR to act on behalf of the State of California to secure necessary power supplies for resale to customers of Pacific Gas & Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) (collectively referred to as the investor owned utilities or IOUs).
- Requires DWR to retain title to all power sold, but authorizes DWR to enter into service agreements with the IOUs for transmission, distribution, billing and collection services.
- Authorizes DWR and the California Public Utilities Commission (CPUC) to enter into an agreement with respect to charges to provide for recovery by DWR of its revenue requirements.
- Authorizes DWR to issue bonds in an amount not to exceed $13.4 billion and payable solely from the Fund, and to deposit the proceeds of the bonds in the Fund for use for any of the purposes of the Fund.
- Entitles DWR to recover its revenue requirements incurred in connection with its authorized activities, including debt service, the costs of power purchases, administrative costs and reserves.
- Restricts DWR from entering into new power purchase agreements after December 31, 2002, but allows DWR to continue to administer existing contracts and enforce revenue requirements beyond that date.

The Fund is proceeding with a transition process that could transfer the scheduling and ultimately the financial responsibility for the contracts to the IOUs. However, there are a number of issues to be addressed, including the assignment of the long-term contracts to the IOUs, which could affect the timing of the transition process.

DWR began selling electricity to approximately ten million retail customers in California in January 2001. DWR purchases power from wholesale suppliers under long-term contracts and in short-term and spot market transactions. DWR power is delivered to the customers through the transmission and distribution systems of the IOUs and payments from the customers are collected for DWR by the IOUs pursuant to servicing arrangements approved and/or ordered by the CPUC. DWR has financed

its power purchases with advances from the General Fund of the State of California, loans from financial institutions, and revenues from power sales to customers.

Litigation and Uncertainties
DWR is involved in several lawsuits and regulatory proceedings. In one action, an IOU contested the determination of DWR's revenue requirement submissions for calendar years 2001 and 2002 to the CPUC as just and reasonable. The Court found that DWR had failed to follow the California Administrative Procedures Act (APA) and ordered DWR to do so. The Court also ruled that its decision did not affect any action taken by the CPUC, including the implementation of cost recovery of DWR's calendar years 2001 and 2002 revenue requirements. DWR has filed its 2003 and amended 2001-2002 revenue requirements with the CPUC, following APA requirements in the internal development of its revenue requirements.

In another matter, two energy suppliers have petitioned the Federal Energy Regulatory Commission, contending that amounts totaling $58 million are owed by DWR for power purchased in the last half of January 2001, by DWR on behalf of PG&E and SCE in the California Independent System Operator (ISO) market. DWR maintains that the Fund has remitted the appropriate payments to the ISO for distribution to the energy suppliers. ISO distributed the Fund's January payment on a pro-rata basis to all market participants for the entire month although DWR purchased power on behalf of the two IOUs beginning in late January. As a result, energy suppliers did not receive full payment for the amounts owed them for power purchased in January by DWR on behalf of the two IOUs. FERC has not announced when it will rule on this matter or whether it will require DWR to make additional payments to ISO.

Additionally, various actions are underway contesting certain long-term power contracts entered into by DWR.

There are a number of other lawsuits and regulatory proceedings in which DWR is not a party but may be affected by the result because of potential impacts on the price or supply of energy in California. In one case, California Power Exchange Corporation (CalPX), certain IOUs and others have brought suit against the State of California claiming that the State's commandeering of CalPX's block forward contracts after CalPX filed bankruptcy in early 2001 was unconstitutional. The plaintiffs argue that they are entitled to damages of $1.1 billion, which is their estimation of the fair value of the block forward contracts at the time of commandeering. Under the block forward contracts, which expired in December 2001, the Fund paid approximately $350 million for energy provided by the contracts.

These lawsuits and regulatory proceedings could impact the revenue requirements and rate structure needed to repay debt and the terms and conditions of the power purchase contracts (Note 6).

Management believes that the existing lawsuits and regulatory proceedings will be resolved in calendar year 2003. Because of the early stage of the legal and regulatory proceedings, the ultimate outcome of these matters cannot be presently determined.

2. Summary of Significant Accounting Policies

Basis of Presentation

The Fund is accounted for as an enterprise fund and is financed and operated in a manner similar to that of a private business enterprise. The Fund uses the economic resources measurement focus and the accrual basis of accounting. Under this method, revenues are recorded when earned and expenses are recorded at the time liabilities are incurred. As allowed by governmental accounting standards, the Fund has elected not to apply statements and related interpretations issued by the Financial Accounting Standards Board after November 30, 1989. The Fund is accounted for with a set of self-balancing accounts that comprise its assets, liabilities, fund equity, revenues and expenses.

Cash and Investments

Cash and investments, for purposes of the statement of cash flows, includes cash on hand and amounts in short-term investments. Amounts in short-term investments include deposits in the State of California Pooled Money Investment Account-Surplus Money Investment Fund (SMIF).

Cash not required for current use is invested in SMIF. SMIF has an equity interest in the State of California Pooled Money Investment Account (PMIA). The investments in PMIA are carried at fair value, which approximates amortized cost. Generally, the investments in PMIA are available for withdrawal on demand.

PMIA funds are on deposit with the State's Centralized Treasury System and are managed in compliance with the California Government Code, according to a statement of investment policy which sets forth permitted investment vehicles, liquidity parameters and maximum maturity of investments. These investments consist of U.S. government securities, securities of federally-sponsored agencies, U.S. corporate bonds, interest bearing time deposits in California banks, prime-rated commercial paper, bankers' acceptances, negotiable certificates of deposit, repurchase and reverse repurchase agreements. The PMIA policy limits the use of reverse repurchase agreements subject to limits of no more than 10% of PMIA. The PMIA does not invest in leveraged products or inverse floating rate securities. The PMIA cash and investments are recorded at amortized cost, which approximates market.

The investment in PMIA, an investment pool managed by the State of California, does not meet the criteria to require risk categorization.

Restricted Cash on Deposit with Agent

Restricted cash on deposit with agent consists of pre-funded interest costs associated with the interim loan. The cash was held by JPMorgan Chase Bank as agent for the lenders and was uncollateralized at June 30, 2001. The restricted cash was used to pay interest through December 31, 2001, with the remaining balance used to reduce the interim loan by $68 million (unaudited) in March 2002.

Revenues and Recoverable Costs

The cost of providing energy is intended to be recovered through charges to the customers of three investor owned utilities and other entities as allowed by AB1X and regulated by the CPUC. Revenues are recognized when energy is delivered to the customers. The billings cover debt service, the costs of power purchases, administrative costs and reserves. These costs are recovered over a

period of time as determined by the rate making process between DWR and the CPUC through the IOU's billings to the customers.

In June 2001, the billings were reduced by $64 million for rebates given to the customers of the IOUs under the Governor's "20-20 Energy Rebate Program," which, from June 1, 2001 through September 30, 2001, generally granted the customers a 20% reduction in their monthly power bills if they reduced their energy use by 20% from the same period in 2000. These reductions extend the period of time over which the Fund will recover its costs. For the period from July 1, 2001 through April 30, 2002, billings were reduced by $221 million (unaudited).

Amounts that have been earned but not collected are recorded as the current portion of recoverable costs. Costs that are recoverable through future billings are recorded as long-term.

Change in Accounting Principle
In 1999, the Governmental Accounting Standards Board (GASB) issued Statement No. 34, *Basic Financial Statements – Management's Discussion and Analysis – for State and Local Governments* (GASB 34). In 2001, the GASB issued Statement No. 37, *Basic Financial Statements – Management's Discussion and Analysis – for State and Local Governments: Omnibus* and Statement No. 38, *Certain Financial Statement Note Disclosures,* which amended certain provisions of GASB 34. DWR has adopted the provisions of GASB 34, as amended, as required on July 1, 2001. The adoption of GASB 34 requires presentation of the Fund's Management Discussion and Analysis (MD&A) for each period presented. The MD&A is considered to be required supplementary information and precedes the financial statements. The other provisions of GASB 34 did not significantly impact presentation of the Fund's financial statements; nor did the adoption of GASB 34 impact the net assets of the Fund.

3. Cash and Investments

Interest on deposits in PMIA varies with the rate of return of the underlying portfolio and approximated 5.73% and 2.97% (unaudited) at June 30, 2001 and April 30, 2002, respectively. For the period from January 19, 2001 (date of inception) to June 30, 2001, and for the ten months ended April 30, 2002, interest earned on the deposit with PMIF was $10 million and $89 million (unaudited), respectively.

4. Long-Term Debt

Advances from State General Fund
In conjunction with the Governor's emergency proclamation in January 2001, approximately $302 million of DWR general fund appropriations were expended for energy purchases. SB7X appropriated an additional $400 million for the Fund on January 19, 2001. AB1X appropriated an additional $500 million on February 1, 2001, and provided for additional appropriations upon a 10-day notice to the Legislature. Through June 30, 2001, the total AB1X appropriations transferred from the State of California General Fund to the Fund were $5.508 billion. There have been no additional appropriations through April 30, 2002. As of June 30, 2001 and April 30, 2002, a total of $6.210

billion and $6.094 billion, plus interest, respectively, is due to the General Fund. The $116 million cash balance in the Fund at the time the interim loan described below was implemented was transferred back to the General Fund in July 2001, and was therefore recorded as a current liability at June 30, 2001. The remaining amount due the General Fund is recorded as a long-term obligation as the enabling legislation requires that the remaining General Fund appropriations be repaid when revenue bonds are sold, currently anticipated for completion in the second half of calendar year 2002.

Interest on the advances from the General Fund is calculated at the stated PMIA interest rate in effect on the date of each appropriation from the General Fund. The average interest rate on advances approximated 5.64% at June 30, 2001 and April 30, 2002 (unaudited). For the period from January 19, 2001 (date of inception) to June 30, 2001, and for the ten months ended April 30, 2002, interest expense on the advances from the General Fund was $75 million and $285 million (unaudited), respectively.

Interim Loan
On June 26, 2001, the Fund received an interim loan from a financial consortium lead by JPMorgan Chase Bank. The net proceeds from the interim loan, equal to $4.3 billion gross proceeds less $194 million in origination fees, pre-funded interest, and other costs, were used to fund power purchases. The interim loan was structured with both taxable and tax-exempt components of $2.3 billion and $2.0 billion, respectively, and is payable from revenues. The interim loan is collateralized by revenues described in Note 2 and investment income. The financing was structured as a term loan due to be paid on or before October 31, 2001, from the proceeds of the sale of long-term bonds. As bonds were not issued by October 31, 2001, the interim financing converted to a three-year term loan with quarterly principal and interest payments. DWR made principal payments of $451 million (unaudited) during the ten months ended April 30, 2002. As of April 30, 2002, principal payments due by fiscal year are as follows:

For the year ending June 30,	Amount (in millions)
2003	$ 1,540
2004	1,540
2005	769
	$ 3,849

The interest rate for the three-year term loan, which became effective October 31, 2001, is based on the greater of prime (4.75% (unaudited) at April 30, 2002) or Federal Funds rate plus 0.5%, and is applicable to both the taxable and non-taxable components of the loan. In the case of an event of non-compliance the interest rate is increased 2%. From the period from October 29, 2001 through March 22, 2002, the interest rate increased by 2% due to an event of non-compliance, the lack of having a rate agreement in place between DWR and CPUC. As of May 1, 2002, the interest rate increased by an additional 1% as required by the loan agreement.

5. Retirement Plan

Plan Description
The State of California is a member of the California Public Employees' Retirement System (PERS), an agent multiple-employer pension system that provides a contributory defined-benefit pension for substantially all State employees. DWR is included in the State Miscellaneous Category (Tier 1 and Tier 2) within PERS, thereby limiting the availability of certain System pension data. PERS functions as an investment and administrative agent for participating public agencies within the State of California. Departments and agencies within the State of California, including DWR, are in a cost-sharing arrangement in which all risks and costs are shared proportionately by participating State agencies. Copies of PERS' comprehensive annual financial report may be obtained from their executive office at 400 P Street, Sacramento, California 95814.

The pension plan provides retirement benefits, survivor benefits, and death and disability benefits based upon employee's years of credited service, age and final compensation. Vesting occurs after five years of credited service except for second tier benefits, which require ten years of credited service. Employees who retire at or after age 50 with five or more years of service are entitled to a retirement benefit, payable monthly for the remainder of their lives. Several survivor benefit options which reduce a retiree's unmodified benefit are available. Benefit provisions and all other requirements are established by state statute.

Annual Pension Cost
For both the period from January 19, 2001 (date of inception) to June 30, 2001, and for the ten months ended April 30, 2002 (unaudited), DWR's pension cost and actual contribution allocated to the Fund based on the Fund's payroll costs amounted to less than $1 million.

6. Commitments and Contingencies

Commitments
DWR has entered into long-term power purchase contracts ranging from one to eleven years. Payments made under these contracts approximated $1.1 billion and $2.3 billion (unaudited) for the period from January 19, 2001 (date of inception) to June 30, 2001, and for the ten months ended April 30, 2002, respectively.

The amounts of fixed obligations under the long-term contracts as of April 30, 2002 (unaudited), are as follows:

For the year ending June 30,	Fixed Obligation (in millions)
2002	$ 492
2003	3,326
2004	3,578
2005	3,032
2006	2,777
Thereafter	11,702
	$ 24,907

In addition to the fixed costs there are variable costs associated with several of the contracts. Management expects that the amount of fixed and variable obligations associated with long-term power purchase contracts to approximate $42 billion and $32 billion (unaudited) as of June 30, 2001 and April 30, 2002, respectively. The difference between the fixed costs and the expected total costs of the contracts are primarily due to the variable factors associated with dispatchable contracts and costs of natural gas:

a. Dispatchable contracts: Dispatchable contracts provide DWR with the ability to call on more energy as required. The total amount of fixed and variable obligations associated with long-term power purchase contracts is based on the forecasted dispatch of these contracts to meet the forecasted IOU load. The variability of energy requirements fluctuate with the weather (on hot summer days with heavy air conditioner usage, energy requirements can increase substantially over forecasted amounts).

b. Gas prices: Many of the contracts contain a pass through component whereby DWR has the ability to purchase the natural gas that is used to power the generating plants. The total amount of fixed and variable obligations associated with long-term power purchase contracts is based on forecasted natural gas prices used in the modeling of these contracts. Natural gas prices are subject to market forces and so will vary throughout the duration of the contracts.

DWR has been renegotiating some of the contracts in order to improve reliability, procure more dispatchable power, increase the number of contracts that are assignable to the IOUs, and reduce cost. Subsequent to June 30, 2001, 17 contracts were renegotiated, reducing the future fixed obligations by approximately $4.5 billion.

Contingencies
The Fund is self-insured for most risks, including general liability and workers' compensation. Management believes that any costs associated with such losses are recoverable from the customers of the IOU's.

7. Related Party Transactions

During the period from January 19, 2001 (date of inception) to June 30, 2001, and for the ten months ended April 30, 2002, the Fund purchased power approximating $80 million and $10 million (unaudited), respectively, from the State Water Resources Development System, another enterprise fund administered by DWR.

APPENDIX K

INFORMATION CONERNING THE BOND INSURERS AND FORMS OF FINANCIAL GUARANTY INSURANCE POLICIES

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AMBAC ASSURANCE CORPORATION

Payment Pursuant to Financial Guaranty Insurance Policy

Ambac Assurance has made a commitment to issue a financial guaranty insurance policy (the "Ambac Policy") relating to the Series 2002A Bonds identified on the inside cover of this Official Statement (collectively, the "Ambac-Insured Bonds"), effective as of the date of issuance of the Ambac-Insured Bonds. Under the terms of the Ambac Policy, Ambac Assurance will pay to The Bank of New York, New York, New York or any successor thereto (the "Insurance Trustee") that portion of the principal of and interest on the Ambac-Insured Bonds which shall become Due for Payment but shall be unpaid by reason of Nonpayment by the Obligor (as such terms are defined in the Ambac Policy). Ambac Assurance will make such payments to the Insurance Trustee on the later of the date on which such principal and interest becomes Due for Payment or within one business day following the date on which Ambac Assurance shall have received notice of Nonpayment from the Trustee. The insurance will extend for the term of the Ambac-Insured Bonds and, once issued, cannot be canceled by Ambac Assurance.

The Ambac Policy will insure payment only on stated maturity dates and on mandatory sinking fund installment dates, if any, in the case of principal, and on stated dates for payment, in the case of interest. If the Ambac-Insured Bonds become subject to mandatory redemption and insufficient funds are available for redemption of all outstanding Ambac-Insured Bonds, Ambac Assurance will remain obligated to pay principal of and interest on outstanding Ambac-Insured Bonds on the originally scheduled interest and principal payment dates including mandatory sinking fund redemption dates, if any. In the event of any acceleration of the principal of the Ambac-Insured Bonds, the insured payments will be made at such times and in such amounts as would have been made had there not been an acceleration.

In the event the Trustee has notice that any payment of principal of or interest on a Ambac-Insured Bond which has become Due for Payment and which is made to an Owner by or on behalf of the Obligor has been deemed a preferential transfer and theretofore recovered from its registered owner pursuant to the United States Bankruptcy Code in accordance with a final, nonappealable order of a court of competent jurisdiction, such registered owner will be entitled to payment from Ambac Assurance to the extent of such recovery if sufficient funds are not otherwise available.

The Ambac Policy does **not** insure any risk other than Nonpayment, as defined in the Policy. Specifically, the Ambac Policy does **not** cover:

1. payment on acceleration, as a result of a call for redemption (other than any mandatory sinking fund redemption) or as a result of any other advancement of maturity.

2. payment of any redemption, prepayment or acceleration premium.

3. nonpayment of principal or interest caused by the insolvency or negligence of any Trustee, Paying Agent or Bond Registrar, if any.

If it becomes necessary to call upon the Ambac Policy, payment of principal requires surrender of Ambac-Insured Bonds to the Insurance Trustee together with an appropriate instrument of assignment so as to permit ownership of such Ambac-Insured Bonds to be registered in the name of Ambac Assurance to the extent of the payment under the Ambac Policy. Payment of interest pursuant to the Ambac Policy requires proof of Owner entitlement to interest payments and an appropriate assignment of the Owner's right to payment to Ambac Assurance.

Upon payment of the insurance benefits, Ambac Assurance will become the owner of the Ambac-Insured Bond, appurtenant coupon, if any, or right to payment of principal or interest on such Ambac-Insured Bond and will be fully subrogated to the surrendering Owner's rights to payment.

The Ambac Policy does not insure against loss relating to payments made in connection with the sale of Ambac-Insured Bonds at Auctions or losses suffered as a result of an Owner's inability to sell Ambac-Insured Bonds.

The Ambac Policy does not insure against loss relating to payments of the purchase price of Ambac-Insured Bonds upon any tender by a registered owner thereof or any preferential transfer relating to payments of the purchase price of Ambac-Insured Bonds upon any tender by a registered owner thereof.

In the event that Ambac Assurance were to become insolvent, any claims arising under the Ambac Policy would be excluded from coverage by the California Insurance Guaranty Association, established pursuant to the laws of the State of California.

Ambac Assurance Corporation

Ambac Assurance Corporation ("Ambac Assurance") is a Wisconsin-domiciled stock insurance corporation regulated by the Office of the Commissioner of Insurance of the State of Wisconsin and licensed to do business in 50 states, the District of Columbia, the Territory of Guam and the Commonwealth of Puerto Rico, with admitted assets of approximately **$5,587,000,000** (unaudited) and statutory capital of **$3,453,000,000** (unaudited) as of **June 30, 2002**. Statutory capital consists of Ambac Assurance's policyholders' surplus and statutory contingency reserve. Standard & Poor's Credit Markets Services, a Division of The McGraw-Hill Companies, Moody's Investors Service and Fitch, Inc. have each assigned a triple-A financial strength rating to Ambac Assurance.

Ambac Assurance has obtained a ruling from the Internal Revenue Service to the effect that the insuring of an obligation by Ambac Assurance will not affect the treatment for federal income tax purposes of interest on such obligation and that insurance proceeds representing maturing interest paid by Ambac Assurance under policy provisions substantially identical to those contained in its financial guaranty insurance policy shall be treated for federal income tax purposes in the same manner as if such payments were made by the Obligor of the Ambac-Insured Bonds.

Ambac Assurance makes no representation regarding the Ambac-Insured Bonds or the advisability of investing in the Ambac-Insured Bonds and makes no representation regarding, nor has it participated in the preparation of, the Official Statement other than the information supplied by Ambac Assurance and presented under the heading "AMBAC BOND INSURANCE" in this Appendix.

Available Information

The parent company of Ambac Assurance, Ambac Financial Group, Inc. (the "Company"), is subject to the informational requirements of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and in accordance therewith files reports, proxy statements and other information with the Securities and Exchange Commission (the "SEC"). These reports, proxy statements and other information can be read and copied at the SEC's public reference room at 450 Fifth Street, N.W., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the public reference room. The SEC maintains an internet site at http://www.sec.gov that contains reports, proxy and information statements and other information regarding companies that file electronically with the SEC, including the Company. These reports, proxy statements and other information can also be read at the offices of the New York Stock Exchange, Inc. (the "NYSE"), 20 Broad Street, New York, New York 10005.

Copies of Ambac Assurance's financial statements prepared in accordance with statutory accounting standards are available from Ambac Assurance. The address of Ambac Assurance's administrative offices and its telephone number are One State Street Plaza, 17th Floor, New York, New York 10004 and (212) 668-0340.

Incorporation of Certain Documents by Reference

The following documents filed by the Company with the SEC (File No. 1-10777) are incorporated by reference in this Official Statement:

1) The Company's Current Report on Form 8-K dated January 23, 2002 and filed on January 25, 2002;

2) The Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2001 and filed on March 26, 2002;

3) The Company's Current Report on Form 8-K dated April 17, 2002 and filed on April 18, 2002;

4) The Company's Quarterly Report on Form 10-Q for the fiscal quarterly period ended March 31, 2002 and filed on May 13, 2002;

5) The Company's Current Report on Form 8-K dated July 17, 2002 and filed on July 19, 2002;

6) The Company's Current Report on Form 8-K dated August 14, 2002 and filed on August 14, 2002; and

7) The Company's Quarterly Report on Form 10-Q for the fiscal quarterly period ended June 30, 2002 and filed on August 14, 2002.

8) The Company's Current Report on Form 8-K dated October 16, 2002 and filed on October 17, 2002.

All documents subsequently filed by the Company pursuant to the requirements of the Exchange Act after the date of this Official Statement will be available for inspection in the same manner as described above in "Available Information."

Form of Financial Guaranty Insurance Policy

The form of the Ambac Policy is set forth on the following pages.

Ambac

Financial Guaranty Insurance Policy

Ambac Assurance Corporation
One State Street Plaza, 15th Floor
New York, New York 10004
Telephone: (212) 668-0340

Obligor:

Policy Number:

Obligations:

Premium:

Ambac Assurance Corporation (Ambac), a Wisconsin stock insurance corporation, in consideration of the payment of the premium and subject to the terms of this Policy, hereby agrees to pay to The Bank of New York, as trustee, or its successor (the "Insurance Trustee"), for the benefit of the Holders, that portion of the principal of and interest on the above-described obligations (the "Obligations") which shall become Due for Payment but shall be unpaid by reason of Nonpayment by the Obligor.

Ambac will make such payments to the Insurance Trustee within one (1) business day following written notification to Ambac of Nonpayment. Upon a Holder's presentation and surrender to the Insurance Trustee of such unpaid Obligations or related coupons, uncanceled and in bearer form and free of any adverse claim, the Insurance Trustee will disburse to the Holder the amount of principal and interest which is then Due for Payment but is unpaid. Upon such disbursement, Ambac shall become the owner of the surrendered Obligations and/or coupons and shall be fully subrogated to all of the Holder's rights to payment thereon.

In cases where the Obligations are issued in registered form, the Insurance Trustee shall disburse principal to a Holder only upon presentation and surrender to the Insurance Trustee of the unpaid Obligation, uncanceled and free of any adverse claim, together with an instrument of assignment, in form satisfactory to Ambac and the Insurance Trustee duly executed by the Holder or such Holder's duly authorized representative, so as to permit ownership of such Obligation to be registered in the name of Ambac or its nominee. The Insurance Trustee shall disburse interest to a Holder of a registered Obligation only upon presentation to the Insurance Trustee of proof that the claimant is the person entitled to the payment of interest on the Obligation and delivery to the Insurance Trustee of an instrument of assignment, in form satisfactory to Ambac and the Insurance Trustee, duly executed by the Holder or such Holder's duly authorized representative, transferring to Ambac all rights under such Obligation to receive the interest in respect of which the insurance disbursement was made. Ambac shall be subrogated to all of the Holders' rights to payment on registered Obligations to the extent of any insurance disbursements so made.

In the event that a trustee or paying agent for the Obligations has notice that any payment of principal of or interest on an Obligation which has become Due for Payment and which is made to a Holder by or on behalf of the Obligor has been deemed a preferential transfer and theretofore recovered from the Holder pursuant to the United States Bankruptcy Code in accordance with a final, nonappealable order of a court of competent jurisdiction, such Holder will be entitled to payment from Ambac to the extent of such recovery if sufficient funds are not otherwise available.

As used herein, the term "Holder" means any person other than (i) the Obligor or (ii) any person whose obligations constitute the underlying security or source of payment for the Obligations who, at the time of Nonpayment, is the owner of an Obligation or of a coupon relating to an Obligation. As used herein, "Due for Payment", when referring to the principal of Obligations, is when the scheduled maturity date or mandatory redemption date for the application of a required sinking fund installment has been reached and does not refer to any earlier date on which payment is due by reason of call for redemption (other than by application of required sinking fund installments), acceleration or other advancement of maturity; and, when referring to interest on the Obligations, is when the scheduled date for payment of interest has been reached. As used herein, "Nonpayment" means the failure of the Obligor to have provided sufficient funds to the trustee or paying agent for payment in full of all principal of and interest on the Obligations which are Due for Payment.

This Policy is noncancelable. The premium on this Policy is not refundable for any reason, including payment of the Obligations prior to maturity. This Policy does not insure against loss of any prepayment or other acceleration payment which at any time may become due in respect of any Obligation, other than at the sole option of Ambac, nor against any risk other than Nonpayment.

In witness whereof, Ambac has caused this Policy to be affixed with a facsimile of its corporate seal and to be signed by its duly authorized officers in facsimile to become effective as its original seal and signatures and binding upon Ambac by virtue of the countersignature of its duly authorized representative.

President

AMBAC ASSURANCE CORPORATION CORPORATE SEAL WISCONSIN

Secretary

Effective Date:

Authorized Representative

THE BANK OF NEW YORK acknowledges that it has agreed to perform the duties of Insurance Trustee under this Policy.

Authorized Officer of Insurance Trustee

SPECIMEN

Ambac Assurance Corporation
One State Street Plaza,
New York, New York 10004
Telephone: (212) 668-0340

Endorsement

Policy for:

Attached to and forming part of Policy No.:

Effective Date of Endorsement:

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In the event that Ambac Assurance Corporation were to become insolvent, any claims arising under the Policy would be excluded from coverage by the California Insurance Guaranty Association, established pursuant to the laws of the State of California.

Nothing herein contained shall be held to vary, alter, waive or extend any of the terms, conditions, provisions, agreements or limitations of the above mentioned Policy other than as above stated.

In Witness Whereof, Ambac has caused this Endorsement to be affixed with a facsimile of its corporate seal and to be signed by its duly authorized officers in facsimile to become effective as its original seal and signatures and binding upon Ambac by virtue of the countersignature of its duly authorized representative.

Ambac Assurance Corporation

AMBAC ASSURANCE CORPORATION
CORPORATE
SEAL
WISCONSIN

President

Secretary

Authorized Representative

Form No.: 2B-0004 (7/97)

FINANCIAL SECURITY ASSURANCE INC.

Bond Insurance Policy

Concurrently with the issuance of the Series 2002A Bonds, Financial Security Assurance Inc. ("Financial Security") will issue its Municipal Bond Insurance Policy (the "FSA Policy") for the Series 2002A Bonds identified on the inside cover of this Official Statement (collectively, the "FSA-Insured Bonds"). The FSA Policy guarantees the scheduled payment of principal of and interest on the FSA-Insured Bonds when due as set forth in the form of the FSA Policy included as an exhibit to this Official Statement.

The FSA Policy is not covered by any insurance security or guaranty fund established under New York, California, Connecticut or Florida insurance law.

Financial Security Assurance Inc.

Financial Security is a New York domiciled insurance company and a wholly owned subsidiary of Financial Security Assurance Holdings Ltd. ("Holdings"). Holdings is an indirect subsidiary of Dexia, S.A., a publicly held Belgian corporation. Dexia, S.A., through its bank subsidiaries, is primarily engaged in the business of public finance in France, Belgium and other European countries. No shareholder of Holdings or Financial Security is liable for the obligations of Financial Security.

At June 30, 2002, Financial Security's total policyholders' surplus and contingency reserves were approximately $1,710,044,000 and its total unearned premium reserve was approximately $898,579,000 in accordance with statutory accounting principles. At June 30, 2002, Financial Security's total shareholders' equity was approximately $1,817,013,000 and its total net unearned premium reserve was approximately $744,499,000 in accordance with generally accepted accounting principles.

The financial statements included as exhibits to the annual and quarterly reports filed by Holdings with the Securities and Exchange Commission are hereby incorporated herein by reference. Also incorporated herein by reference are any such financial statements so filed from the date of this Official Statement until the termination of the offering of the FSA-Insured Bonds. Copies of materials incorporated by reference will be provided upon request to Financial Security Assurance Inc.: 350 Park Avenue, New York, New York 10022, Attention: Communications Department (telephone (212) 826-0100).

The FSA Policy does not protect investors against changes in market value of the FSA-Insured Bonds, which market value may be impaired as a result of changes in prevailing interest rates, changes in applicable ratings or other causes. Financial Security makes no representation regarding the FSA-Insured Bonds or the advisability of investing in the FSA-Insured Bonds. Financial Security makes no representation regarding the Official Statement, nor has it participated in the preparation thereof, except that Financial Security has provided to DWR the information presented under this caption for inclusion in the Official Statement.

Form of FSA Policy

The form of the FSA Policy is set forth on the following pages.

FINANCIAL SECURITY ASSURANCE®

MUNICIPAL BOND INSURANCE POLICY

ISSUER:

BONDS:

Policy No.: -N

Effective Date:

Premium:

FINANCIAL SECURITY ASSURANCE INC. ("Financial Security"), for consideration received, hereby UNCONDITIONALLY AND IRREVOCABLY agrees to pay to the trustee (the "Trustee") or paying agent (the "Paying Agent") (as set forth in the documentation providing for the issuance of and securing the Bonds) for the Bonds, for the benefit of the Owners or, at the election of Financial Security, directly to each Owner, subject only to the terms of this Policy (which includes each endorsement hereto), that portion of the principal of and interest on the Bonds that shall become Due for Payment but shall be unpaid by reason of Nonpayment by the Issuer.

On the later of the day on which such principal and interest becomes Due for Payment or the Business Day next following the Business Day on which Financial Security shall have received Notice of Nonpayment, Financial Security will disburse to or for the benefit of each Owner of a Bond the face amount of principal of and interest on the Bond that is then Due for Payment but is then unpaid by reason of Nonpayment by the Issuer, but only upon receipt by Financial Security, in a form reasonably satisfactory to it, of (a) evidence of the Owner's right to receive payment of the principal or interest then Due for Payment and (b) evidence, including any appropriate instruments of assignment, that all of the Owner's rights with respect to payment of such principal or interest that is Due for Payment shall thereupon vest in Financial Security. A Notice of Nonpayment will be deemed received on a given Business Day if it is received prior to 1:00 p.m. (New York time) on such Business Day; otherwise, it will be deemed received on the next Business Day. If any Notice of Nonpayment received by Financial Security is incomplete, it shall be deemed not to have been received by Financial Security for purposes of the preceding sentence and Financial Security shall promptly so advise the Trustee, Paying Agent or Owner, as appropriate, who may submit an amended Notice of Nonpayment. Upon disbursement in respect of a Bond, Financial Security shall become the owner of the Bond, any appurtenant coupon to the Bond or right to receipt of payment of principal of or interest on the Bond and shall be fully subrogated to the rights of the Owner, including the Owner's right to receive payments under the Bond, to the extent of any payment by Financial Security hereunder. Payment by Financial Security to the Trustee or Paying Agent for the benefit of the Owners shall, to the extent thereof, discharge the obligation of Financial Security under this Policy.

Except to the extent expressly modified by an endorsement hereto, the following terms shall have the meanings specified for all purposes of this Policy. "Business Day" means any day other than (a) a Saturday or Sunday or (b) a day on which banking institutions in the State of New York or the Insurer's Fiscal Agent are authorized or required by law or executive order to remain closed. "Due for Payment" means (a) when referring to the principal of a Bond, payable on the stated maturity date thereof or the date on which the same shall have been duly called for mandatory sinking fund redemption and does not refer to any earlier date on which payment is due by reason of call for redemption (other than by mandatory sinking fund redemption), acceleration or other advancement of maturity unless Financial Security shall elect, in its sole discretion, to pay such principal due upon such acceleration together with any accrued interest to the date of acceleration and (b) when referring to interest on a Bond, payable on the stated date for payment of interest. "Nonpayment" means, in respect of a Bond, the failure of the Issuer to have provided sufficient funds to the Trustee or, if there is no Trustee, to the Paying Agent for payment in full of all principal and interest that is Due for Payment on such Bond. "Nonpayment" shall also include, in respect of a Bond, any payment of principal or interest that is Due for Payment made to an Owner by or on behalf of the Issuer which has been recovered from such Owner pursuant to the

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United States Bankruptcy Code by a trustee in bankruptcy in accordance with a final, nonappealable order of a court having competent jurisdiction. "Notice" means telephonic or telecopied notice, subsequently confirmed in a signed writing, or written notice by registered or certified mail, from an Owner, the Trustee or the Paying Agent to Financial Security which notice shall specify (a) the person or entity making the claim, (b) the Policy Number, (c) the claimed amount and (d) the date such claimed amount became Due for Payment. "Owner" means, in respect of a Bond, the person or entity who, at the time of Nonpayment, is entitled under the terms of such Bond to payment thereof, except that "Owner" shall not include the Issuer or any person or entity whose direct or indirect obligation constitutes the underlying security for the Bonds.

Financial Security may appoint a fiscal agent (the "Insurer's Fiscal Agent") for purposes of this Policy by giving written notice to the Trustee and the Paying Agent specifying the name and notice address of the Insurer's Fiscal Agent. From and after the date of receipt of such notice by the Trustee and the Paying Agent, (a) copies of all notices required to be delivered to Financial Security pursuant to this Policy shall be simultaneously delivered to the Insurer's Fiscal Agent and to Financial Security and shall not be deemed received until received by both and (b) all payments required to be made by Financial Security under this Policy may be made directly by Financial Security or by the Insurer's Fiscal Agent on behalf of Financial Security. The Insurer's Fiscal Agent is the agent of Financial Security only and the Insurer's Fiscal Agent shall in no event be liable to any Owner for any act of the Insurer's Fiscal Agent or any failure of Financial Security to deposit or cause to be deposited sufficient funds to make payments due under this Policy.

To the fullest extent permitted by applicable law, Financial Security agrees not to assert, and hereby waives, only for the benefit of each Owner, all rights (whether by counterclaim, setoff or otherwise) and defenses (including, without limitation, the defense of fraud), whether acquired by subrogation, assignment or otherwise, to the extent that such rights and defenses may be available to Financial Security to avoid payment of its obligations under this Policy in accordance with the express provisions of this Policy.

This Policy sets forth in full the undertaking of Financial Security, and shall not be modified, altered or affected by any other agreement or instrument, including any modification or amendment thereto. Except to the extent expressly modified by an endorsement hereto, (a) any premium paid in respect of this Policy is nonrefundable for any reason whatsoever, including payment, or provision being made for payment, of the Bonds prior to maturity and (b) this Policy may not be canceled or revoked. THIS POLICY IS NOT COVERED BY THE PROPERTY/CASUALTY INSURANCE SECURITY FUND SPECIFIED IN ARTICLE 76 OF THE NEW YORK INSURANCE LAW.

In witness whereof, FINANCIAL SECURITY ASSURANCE INC. has caused this Policy to be executed on its behalf by its Authorized Officer.

[Countersignature]

FINANCIAL SECURITY ASSURANCE INC.

By _____

By _____
Authorized Officer

A subsidiary of Financial Security Assurance Holdings Ltd.
350 Park Avenue, New York, N.Y. 10022-6022

(212) 826-0100

Form 500NY (5/90)

SPECIMEN

FINANCIAL SECURITY ASSURANCE®

ENDORSEMENT NO. 1 TO MUNICIPAL BOND INSURANCE POLICY (California Insurance Guaranty Association)

ISSUER:

BONDS:

Policy No.:

Effective Date:

Notwithstanding the terms and provisions contained in this Policy, it is further understood that the insurance provided by this Policy is not covered by the California Insurance Guaranty Association established pursuant to Article 14.2 (commencing with Section 1063) of Chapter 1 of Part 2 of Division 1 of the California Insurance Code.

Nothing herein shall be construed to waive, alter, reduce or amend coverage in any other section of the Policy. If found contrary to the Policy language, the terms of this Endorsement supersede the Policy language.

In witness whereof, FINANCIAL SECURITY ASSURANCE INC. has caused this Endorsement to be executed on its behalf by its Authorized Officer.

FINANCIAL SECURITY ASSURANCE INC.

By: _____
Authorized Officer

SPECIMEN

A subsidiary of Financial Security Assurance Holdings Ltd.
350 Park Avenue, New York, N.Y. 10022-6022

(212) 826-0100

Form 560NY (CA 1/91)

MBIA INSURANCE CORPORATION

The following information has been furnished by MBIA Insurance Corporation ("MBIA") for use in this Official Statement. MBIA insures only those Series 2002A Bonds identified as being so insured on the inside cover of this Official Statement (the "MBIA-Insured Bonds").

MBIA Insurance Corporation Policy

MBIA's policy (the "MBIA Policy") unconditionally and irrevocably guarantees the full and complete payment required to be made by or on behalf of DWR to the Paying Agent or its successor of an amount equal to (i) the principal of (either at the stated maturity or by an advancement of maturity pursuant to a mandatory sinking fund payment) and interest on, the MBIA-Insured Bonds as such payments shall become due but shall not be so paid (except that in the event of any acceleration of the due date of such principal by reason of mandatory or optional redemption or acceleration resulting from default or otherwise, other than any advancement of maturity pursuant to a mandatory sinking fund payment, the payments guaranteed by MBIA's policy shall be made in such amounts and at such times as such payments of principal would have been due had there not been any such acceleration); and (ii) the reimbursement of any such payment which is subsequently recovered from any owner of the MBIA-Insured Bonds pursuant to a final judgment by a court of competent jurisdiction that such payment constitutes an avoidable preference to such owner within the meaning of any applicable bankruptcy law (a "Preference").

MBIA's policy does not insure against loss of any prepayment premium which may at any time be payable with respect to any MBIA-Insured Bonds. MBIA's policy does not, under any circumstance, insure against loss relating to: (i) optional or mandatory redemptions (other than mandatory sinking fund redemptions); (ii) any payments to be made on an accelerated basis; (iii) payments of the purchase price of MBIA-Insured Bonds upon tender by an owner thereof; or (iv) any Preference relating to (i) through (iii) above. MBIA's policy also does not insure against nonpayment of principal of or interest on the MBIA-Insured Bonds resulting from the insolvency, negligence or any other act or omission of the Paying Agent or any other paying agent for the MBIA-Insured Bonds.

Upon receipt of telephonic or telegraphic notice, such notice subsequently confirmed in writing by registered or certified mail, or upon receipt of written notice by registered or certified mail, by MBIA from the Paying Agent or any owner of an MBIA-Insured Bond the payment of an insured amount for which is then due, that such required payment has not been made, MBIA on the due date of such payment or within one business day after receipt of notice of such nonpayment, whichever is later, will make a deposit of funds, in an account with State Street Bank and Trust Company, N.A., in New York, New York, or its successor, sufficient for the payment of any such insured amounts which are then due. Upon presentment and surrender of such MBIA-Insured Bonds or presentment of such other proof of ownership of the MBIA-Insured Bonds, together with any appropriate instruments of assignment to evidence the assignment of the insured amounts due on the MBIA-Insured Bonds as are paid by MBIA, and appropriate instruments to effect the appointment of MBIA as agent for such owners of the MBIA-Insured Bonds in any legal proceeding related to payment of insured amounts on the MBIA-Insured Bonds, such instruments being in a form satisfactory to State Street Bank and Trust Company, N.A., State Street Bank and Trust Company, N.A. shall disburse to such owners or the Paying Agent payment of the insured amounts due on such MBIA-Insured Bonds, less any amount held by the Paying Agent for the payment of such insured amounts and legally available therefor.

MBIA

MBIA Insurance Corporation ("MBIA") is the principal operating subsidiary of MBIA Inc., a New York Stock Exchange listed company (the "Company"). The Company is not obligated to pay the debts of or claims against MBIA. MBIA is domiciled in the State of New York and licensed to do business in and subject to regulation under the laws of all 50 states, the District of Columbia, the Commonwealth of Puerto Rico, the Commonwealth of the Northern Mariana Islands, the Virgin Islands of the United States and the Territory of

Guam. MBIA has three branches, one in the Republic of France, one in the Republic of Singapore and one in the Kingdom of Spain. New York has laws prescribing minimum capital requirements, limiting classes and concentrations of investments and requiring the approval of policy rates and forms. State laws also regulate the amount of both the aggregate and individual risks that may be insured, the payment of dividends by MBIA, changes in control and transactions among affiliates. Additionally, MBIA is required to maintain contingency reserves on its liabilities in certain amounts and for certain periods of time.

MBIA does not accept any responsibility for the accuracy or completeness of this Official Statement or any information or disclosure contained herein, or omitted herefrom, other than with respect to the accuracy of the information regarding the policy and MBIA set forth under the heading "MBIA INSURANCE CORPORATION" in this Appendix. Additionally, MBIA makes no representation regarding the MBIA-Insured Bonds or the advisability of investing in the MBIA-Insured Bonds.

The Financial Guarantee Insurance Policies are not covered by the Property/Casualty Insurance Security Fund specified in Article 76 of the New York Insurance Law.

MBIA Information

The following documents filed by the Company with the Securities and Exchange Commission (the "SEC") are incorporated herein by reference:

(1) The Company's Annual Report on Form 10-K for the year ended December 31, 2001; and

(2) The Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2002.

Any documents filed by the Company pursuant to Sections 13(a), 13(c), 14 or 15(d) of the Exchange Act of 1934, as amended, after the date of this Official Statement and prior to the termination of the offering of the MBIA-Insured Bonds offered hereby shall be deemed to be incorporated by reference in this Official Statement and to be a part hereof. Any statement contained in a document incorporated or deemed to be incorporated by reference herein, or contained in this Official Statement, shall be deemed to be modified or superseded for purposes of this Official Statement to the extent that a statement contained herein or in any other subsequently filed document which also is or is deemed to be incorporated by reference herein modifies or supersedes such statement. Any such statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this Official Statement.

The Company files annual, quarterly and special reports, information statements and other information with the SEC under File No. 1-9583. Copies of the SEC filings (including (1) the Company's Annual Report on Form 10-K for the year ended December 31, 2001, and (2) the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2002), are available (i) over the Internet at the SEC's web site at http://www.sec.gov; (ii) at the SEC's public reference room in Washington D.C.; (iii) over the Internet at the Company's web site at http://www.mbia.com; and (iv) at no cost, upon request to MBIA Insurance Corporation, 113 King Street, Armonk, New York 10504. The telephone number of MBIA is (914) 273-4545.

As of December 31, 2001, MBIA had admitted assets of $8.5 billion (audited), total liabilities of $5.6 billion (audited), and total capital and surplus of $2.9 billion (audited) determined in accordance with statutory accounting practices prescribed or permitted by insurance regulatory authorities. As of June 30, 2002, MBIA had admitted assets of $8.7 billion (unaudited), total liabilities of $5.7 billion (unaudited), and total capital and surplus of $3.0 billion (unaudited) determined in accordance with statutory accounting practices prescribed or permitted by insurance regulatory authorities.

Financial Strength Ratings of MBIA

Moody's Investors Service, Inc. rates the financial strength of MBIA "Aaa."

Standard & Poor's, a division of The McGraw-Hill Companies, Inc. rates the financial strength of MBIA "AAA."

Fitch Ratings rates the financial strength of MBIA "AAA."

Each rating of MBIA should be evaluated independently. The ratings reflect the respective rating agency's current assessment of the creditworthiness of MBIA and its ability to pay claims on its policies of insurance. Any further explanation as to the significance of the above ratings may be obtained only from the applicable rating agency.

The above ratings are not recommendations to buy, sell or hold the MBIA-Insured Bonds, and such ratings may be subject to revision or withdrawal at any time by the rating agencies. Any downward revision or withdrawal of any of the above ratings may have an adverse effect on the market price of the MBIA-Insured Bonds. MBIA does not guaranty the market price of the MBIA-Insured Bonds nor does it guaranty that the ratings on the MBIA-Insured Bonds will not be revised or withdrawn.

In the event MBIA were to become insolvent, any claims arising under a policy of financial guaranty insurance are excluded from coverage by the California Insurance Guaranty Association, established pursuant to Article 14.2 (commencing with Section 1063) of Chapter 1 of Part 2 of Division 1 of the California Insurance Code.

Form of MBIA Policy

The form of the MBIA Policy is set forth on the following pages.

FINANCIAL GUARANTY INSURANCE POLICY

MBIA Insurance Corporation
Armonk, New York 10504

Policy No. [NUMBER]

MBIA Insurance Corporation (the "Insurer"), in consideration of the payment of the premium and subject to the terms of this policy, hereby unconditionally and irrevocably guarantees to any owner, as hereinafter defined, of the following described obligations, the full and complete payment required to be made by or on behalf of the Issuer to [PAYING AGENT/TRUSTEE] or its successor (the "Paying Agent") of an amount equal to (i) the principal of (either at the stated maturity or by any advancement of maturity pursuant to a mandatory sinking fund payment) and interest on, the Obligations (as that term is defined below) as such payments shall become due but shall not be so paid (except that in the event of any acceleration of the due date of such principal by reason of mandatory or optional redemption or acceleration resulting from default or otherwise, other than any advancement of maturity pursuant to a mandatory sinking fund payment, the payments guaranteed hereby shall be made in such amounts and at such times as such payments of principal would have been due had there not been any such acceleration); and (ii) the reimbursement of a such payment which is subsequently recovered from any owner pursuant to a final judgment by a court of competent jurisdiction that such payment constitutes an avoidable preference to such owner within the meaning of any applicable bankruptcy law. The amounts referred to in clauses (i) and (ii) of the preceding sentence shall be referred to herein collectively as the "Insured Amounts." "Obligations" shall mean:

[PAR]
[LEGAL NAME OF ISSUE]

Upon receipt of telephonic or telegraphic notice, such notice subsequently confirmed in writing by registered or certified mail, or upon receipt of written notice by registered or certified mail, by the Insurer from the Paying Agent or any owner of an Obligation the payment of an Insured Amount for which is then due, that such required payment has not been made, the Insurer on the due date of such payment or within one business day after receipt of notice of such nonpayment, whichever is later, will make a deposit of funds, in an account with State Street Bank and Trust Company, N.A., in New York, New York, or its successor, sufficient for the payment of any such Insured Amounts which are then due. Upon presentment and surrender of such Obligations or presentment of such other proof of ownership of the Obligations, together with any appropriate instruments of assignment to evidence the assignment of the Insured Amounts due on the Obligations as are paid by the Insurer, and appropriate instruments to effect the appointment of the Insurer as agent for such owners of the Obligations in any legal proceeding related to payment of Insured Amounts on the Obligations, such instruments being in a form satisfactory to State Street Bank and Trust Company, N.A., State Street Bank and Trust Company, N.A. shall disburse to such owners, or the Paying Agent payment of the Insured Amounts due on such Obligations, less any amount held by the Paying Agent for the payment of such Insured Amounts and legally available therefor. This policy does not insure against loss of any prepayment premium which may at any time be payable with respect to any Obligation.

As used herein, the term "owner" shall mean the registered owner of any Obligation as indicated in the books maintained by the Paying Agent, the Issuer, or any designee of the Issuer for such purpose. The term owner shall not include the Issuer or any party whose agreement with the Issuer constitutes the underlying security for the Obligations.

Any service of process on the Insurer may be made to the Insurer at its offices located at 113 King Street, Armonk, New York 10504 and such service of process shall be valid and binding.

This policy is non-cancellable for any reason. The premium on this policy is not refundable for any reason including the payment prior to maturity of the Obligations.

In the event the Insurer were to become insolvent, any claims arising under a policy of financial guaranty insurance are excluded from coverage by the California Insurance Guaranty Association, established pursuant to Article 14.2 (commencing with Section 1063) of Chapter 1 of Part 2 of Division 1 of the California Insurance Code.

IN WITNESS WHEREOF, the Insurer has caused this policy to be executed in facsimile on its behalf by its duly authorized officers, this [DAY] day of [MONTH, YEAR].

MBIA Insurance Corporation

SPECIMEN

President

Attest:

Assistant Secretary

STD-R-CA-6
4/95

XL CAPITAL ASSURANCE INC.

XL Capital Assurance Inc. ("XL Capital Assurance" or "XLCA") will issue the financial guaranty insurance policy insuring the Series 2002A Bonds identified on the inside cover of this Official Statement (the "XLCA-Insured Bonds"). The following information has been supplied by XLCA for inclusion in this Official Statement. No representation is made by XLCA as to the accuracy or completeness of the information.

XLCA accepts no responsibility for the accuracy or completeness of this Official Statement or any other information or disclosure contained herein, or omitted herefrom, other than with respect to the accuracy of the information regarding XLCA and its affiliates set forth under this heading. In addition, XLCA makes no representation regarding the XLCA-Insured Bonds or the advisability of investing in the XLCA-Insured Bonds.

General

XLCA is a monoline financial guaranty insurance company incorporated under the laws of the State of New York. XLCA is currently licensed to do insurance business in, and is subject to the insurance regulation and supervision by, the State of New York, forty-six other states, the District of Columbia, Puerto Rico, the U.S. Virgin Islands and Singapore. XLCA has license applications pending, or intends to file an application, in each of those states in which it is not currently licensed.

XLCA is an indirect wholly owned subsidiary of XL Capital Ltd, a Cayman Islands corporation ("XL Capital Ltd"). Through its subsidiaries, XL Capital Ltd is a leading provider of insurance and reinsurance coverages and financial products to industrial, commercial and professional service firms, insurance companies and other enterprises on a worldwide basis. The common stock of XL Capital Ltd is publicly traded in the United States and listed on the New York Stock Exchange (NYSE: XL). **XL Capital Ltd is not obligated to pay the debts of or claims against XLCA.**

XLCA was formerly known as The London Assurance of America Inc. ("London"), which was incorporated on July 25, 1991 under the laws of the State of New York. On February 22, 2001, XL Reinsurance America Inc. ("XL Re") acquired 100% of the stock of London. XL Re merged its former financial guaranty subsidiary, known as XL Capital Assurance Inc. (formed September 13, 1999) with and into London, with London as the surviving entity. London immediately changed its name to XL Capital Assurance Inc. All previous business of London was 100% reinsured to Royal Indemnity Company, the previous owner at the time of acquisition.

Reinsurance

The Insurer has entered into a facultative quota share reinsurance agreement with XL Financial Assurance Ltd ("XLFA"), an insurance company organized under the laws of Bermuda, and an affiliate of XLCA. Pursuant to this reinsurance agreement, XLCA expects to cede up to 90% of its business to XLFA. The Insurer may also cede reinsurance to third parties on a transaction-specific basis, which cessions may be any or a combination of quota share, first loss or excess of loss. Such reinsurance is used by XLCA as a risk management device and to comply with statutory and rating agency requirements and does not alter or limit XLCA's obligations under any financial guaranty insurance policy. With respect to any transaction insured by XLCA, the percentage of risk ceded to XLFA may be less than 90% depending on certain factors including, without limitation, whether XLCA has obtained third party reinsurance covering the risk. As a result, there can be no assurance as to the percentage reinsured by XLFA of any given financial guaranty insurance policy issued by XLCA, including the policy relating to the XLCA-Insured Bonds.

As of December 31, 2001, XLFA had total assets, liabilities, redeemable preferred shares and shareholders' equity of US$543,538,559 (audited), US$244,403,576 (audited), US$39,000,000 (audited) and US$260,134,983 (audited) respectively, determined in accordance with generally accepted accounting principles in the United States. XLFA's insurance financial strength is rated "Aaa" by Moody's and "AAA" by Standard & Poor's and Fitch. In addition, XLFA has obtained a financial enhancement rating of "AAA" from Standard & Poor's.

The obligations of XLFA to XLCA under the reinsurance agreement described above are unconditionally guaranteed by XL Insurance (Bermuda) Ltd ("XLI"), a Bermuda company and one of the world's leading excess commercial insurers. XLI is a wholly owned indirect subsidiary of XL Capital Ltd. In addition to having an "A+" rating from A.M. Best, XLI's insurance financial strength is rated "Aa2" by Moody's and "AA" by Standard & Poor's and Fitch.

Notwithstanding the capital support provided to XLCA described in this section, the Owners of the XLCA-Insured Bonds will have direct recourse against XLCA only, and neither XLFA nor XLI will be directly liable to the Owners of the XLCA–Insured Bonds.

Financial Strength and Financial Enhancement Ratings

XLCA's insurance financial strength is rated "Aaa" by Moody's and "AAA" by Standard & Poor's and Fitch, Inc. ("Fitch"). In addition, XLCA has obtained a financial enhancement rating of "AAA" from Standard & Poor's. These ratings reflect Moody's, Standard & Poor's and Fitch's current assessment of XLCA's creditworthiness and claims-paying ability as well as the reinsurance arrangement with XLFA described under "Reinsurance" above.

The above ratings are not recommendations to buy, sell or hold securities, including the XLCA–Insured Bonds and are subject to revision or withdrawal at any time by Moody's, Standard & Poor's or Fitch. Any downward revision or withdrawal of these ratings may have an adverse effect on the market price of the XLCA–Insured Bonds. The Insurer does not guaranty the market price of the XLCA–Insured Bonds nor does it guaranty that the ratings on the XLCA–Insured Bonds will not be revised or withdrawn.

Capitalization of XL Capital Assurance

As of December 31, 2000, XLCA had total admitted assets of $86,959,000 (audited), total liabilities of $5,275,000 (audited) and total capital and surplus of $81,684,000 (audited) determined in accordance with statutory accounting practices prescribed or permitted by insurance regulatory authorities ("SAP"). As of December 31, 2001, XLCA had total admitted assets of $158,442,157 (audited), total liabilities of $48,899,461 (audited) and total capital and surplus of $109,542,696 (audited) determined in accordance with SAP.

For further information concerning XLCA and XLFA, see the financial statements of XLCA and XLFA, and the notes thereto, incorporated by reference in this Official Statement. The financial statements of XLCA and XLFA are included as exhibits to the periodic reports filed with the Securities and Exchange Commission (the "Commission") by XL Capital Ltd and may be reviewed at the EDGAR website maintained by the Commission. All financial statements of XLCA and XLFA included in, or as exhibits to, documents filed by XL Capital Ltd pursuant to Section 13(a), 13(c), 14 or 15(d) of the Securities and Exchange Act of 1934 on or prior to the date of this Official Statement, or after the date of this Official Statement but prior to termination of the offering of the XLCA–Insured Bonds, shall be deemed incorporated by reference in this Official Statement. Copies of the statutory quarterly and annual statements filed with the State of New York Insurance Department by XLCA are available upon request to the State of New York Insurance Department.

Regulation of XL Capital Assurance

XLCA is regulated by the Superintendent of Insurance of the State of New York. In addition, XLCA is subject to regulation by the insurance laws and regulations of the other jurisdictions in which it is licensed. As a financial guaranty insurance company licensed in the State of New York, XLCA is subject to Article 69 of the New York Insurance Law, which, among other things, limits the business of each insurer to financial guaranty insurance and related lines, prescribes minimum standards of solvency, including minimum capital requirements, establishes contingency, loss and unearned premium reserve requirements, requires the maintenance of minimum surplus to policyholders and limits the aggregate amount of insurance which may be written and the maximum size of any single risk exposure which may be assumed. XLCA is also required to file detailed annual financial statements with the New York Insurance Department and similar supervisory agencies in each of the other jurisdictions in which it is licensed.

The extent of state insurance regulation and supervision varies by jurisdiction, but New York and most other jurisdictions have laws and regulations prescribing permitted investments and governing the payment of dividends, transactions with affiliates, mergers, consolidations, acquisitions or sales of assets and incurrence of liabilities for borrowings.

IN THE EVENT THAT XLCA WERE TO BECOME INSOLVENT, ANY CLAIMS ARISING UNDER THE XLCA POLICY ARE NOT COVERED BY THE CALIFORNIA GUARANTY INSURANCE FUND SPECIFIED IN ARTICLE 12119(b) OF THE CALIFORNIA INSURANCE CODE.

The principal executive offices of XL Capital Assurance are located at 250 Park Avenue, 19th Floor, New York, New York 10177 and its telephone number at this address is (646) 658-5900, and as of November 12, 2002 will be located at 1221 Avenue of the Americas, New York, New York 10020 and its telephone number at this address will be (212) 478-3400.

Form of Financial Guaranty Insurance Policy

The form of XLCA Policy is set forth on the following pages.

XL CAPITAL ASSURANCE

250 Park Avenue
New York, New York 10177
Telephone: (646) 658-5900

MUNICIPAL BOND INSURANCE POLICY

ISSUER: [ ] **Policy No:** [ ]

BONDS: [ ] **Effective Date:** [ ]

XL Capital Assurance Inc. (XLCA), a New York stock insurance company, in consideration of the payment of the premium and subject to the terms of this Policy (which includes each endorsement attached hereto), hereby agrees unconditionally and irrevocably to pay to the trustee (the "Trustee") or the paying agent (the "Paying Agent") (as set forth in the documentation providing for the issuance of and securing the Bonds) for the benefit of the Owners of the Bonds or, at the election of XLCA, to each Owner, that portion of the principal and interest on the Bonds that shall become Due for Payment but shall be unpaid by reason of Nonpayment.

XLCA will pay such amounts to or for the benefit of the Owners on the later of the day on which such principal and interest becomes Due for Payment or one (1) Business Day following the Business Day on which XLCA shall have received Notice of Nonpayment (provided that Notice will be deemed received on a given Business Day if it is received prior to 10:00 a.m. New York time on such Business Day; otherwise it will be deemed received on the next Business Day), but only upon receipt by XLCA, in a form reasonably satisfactory to it of (a) evidence of the Owner's right to receive payment of the principal or interest then Due for Payment and (b) evidence, including any appropriate instruments of assignment, that all of the Owner's rights with respect to payment of such principal or interest that is Due for Payment shall thereupon vest in XLCA. Upon such disbursement, XLCA shall become the owner of the Bond, any appurtenant coupon to the Bond or the right to receipt of payment of principal and interest on the Bond and shall be fully subrogated to the rights of the Owner, including the Owner's right to receive payments under the Bond, to the extent of any payment by XLCA hereunder. Payment by XLCA to the Trustee or Paying Agent for the benefit of the Owners shall, to the extent thereof, discharge the obligation of XLCA under this Policy.

In the event the Trustee or Paying Agent has notice that any payment of principal or interest on a Bond which has become Due for Payment and which is made to an Owner by or on behalf of the Issuer of the Bonds has been recovered from the Owner pursuant to a final judgment by a court of competent jurisdiction that such payment constitutes an avoidable preference to such Owner within the meaning of any applicable bankruptcy law, such Owner will be entitled to payment from XLCA to the extent of such recovery if sufficient funds are not otherwise available.

The following terms shall have the meanings specified for all purposes of this Policy, except to the extent such terms are expressly modified by an endorsement to this Policy. "Business Day" means any day other than (a) a Saturday or Sunday or (b) a day on which banking institutions in the State of New York or the Insurer's Fiscal Agent are authorized or required by law or executive order to remain closed. "Due for Payment", when referring to the principal of Bonds, is when the stated maturity date or a mandatory redemption date for the application of a required sinking fund installment has been reached and does not refer to any earlier date on which payment is due by reason of call for redemption (other than by application of required sinking fund installments), acceleration or other advancement of maturity, unless XLCA shall elect, in its sole discretion, to pay such principal due upon such acceleration; and, when referring to interest on the Bonds, is when the stated date for payment of interest has been reached. "Nonpayment" means the failure of the Issuer to have provided sufficient funds to the Trustee or Paying Agent for payment in full of all principal and interest on the Bonds which are Due for Payment. "Notice" means telephonic or telecopied notice, subsequently confirmed in a signed writing, or written notice by registered or certified mail, from an Owner, the Trustee or the Paying Agent to XLCA which notice shall specify (a) the person or entity making the claim, (b) the Policy Number, (c) the claimed amount and (d) the date such claimed amount became Due for Payment. "Owner" means, in respect of a Bond, the person or entity who, at the time of Nonpayment, is entitled under the terms of such Bond to payment thereof, except that "Owner" shall not include the Issuer or any person or entity whose direct or indirect obligation constitutes the underlying security for the Bonds.

XLCA may, by giving written notice to the Trustee and the Paying Agent, appoint a fiscal agent (the "Insurer's Fiscal Agent") for purposes of this Policy. From and after the date of receipt by the Trustee and the Paying Agent of such notice, which shall specify the name and notice address of the Insurer's Fiscal Agent, (a) copies of all notices required to be delivered to XLCA pursuant to this Policy shall be simultaneously delivered to the Insurer's Fiscal Agent and to XCLA and shall not be deemed received until received by both and (b) all payments required to be made by XLCA under this Policy may be made directly by XLCA or by the Insurer's Fiscal Agent on behalf of XLCA. The Insurer's Fiscal Agent is the agent of XLCA only and the Insurer's Fiscal Agent shall in no event be liable to any Owner for any act of the Insurer's Fiscal Agent or any failure of XLCA to deposit or cause to be deposited sufficient funds to make payments due hereunder.

Except to the extent expressly modified by an endorsement hereto, (a) this Policy is non-cancelable by XLCA, and (b) the Premium on this Policy is not refundable for any reason. This Policy covers only against loss of any prepayment or other acceleration payment which at any time may become due in respect of any Bond other than at the sole option of XLCA, nor against any risk other than Nonpayment. This Policy sets forth the full understanding of XLCA and shall not be modified, altered or affected by any other agreement or instrument, including any modification or amendment thereto.

IN THE EVENT THAT XLCA WERE TO BECOME INSOLVENT, ANY CLAIMS ARISING UNDER THE THIS POLICY ARE NOT COVERED BY THE CALIFORNIA GUARANTY INSURANCE FUND SPECIFIED IN ARTICLE 12119(b) OF THE CALIFORNIA INSURANCE CODE.

In witness whereof, XLCA has caused this Policy to be executed on its behalf by its duly authorized officers.

SPECIMEN

SPECIMEN	**SPECIMEN**
Name:	Name:
Title:	Title:

XLCAP-005
Form of Municipal Policy [Specimen]

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