A Blueprint For Renegotiating California's Worst Electricity Contracts

A Consumer/Environmental Agenda

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**Utility Consumers' Action Network, Environmental Defense,
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Consumers Union and Sierra Club**

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EXECUTIVE SUMMARY

I. The Problem

California's dysfunctional energy markets have been nothing short of a nightmare for the last 18 months. Since the summer of 2000, utilities have gone bankrupt, consumers' bills have skyrocketed and the state treasury has hemorrhaged millions of dollars in an attempt to keep the lights on.

Now for the bad news. It could get worse.

The California State Auditor analyzed the long-term energy contracts signed last year by the state and concluded that the California Department of Water Resources (CDWR) bought too much power, without enough flexibility and without meeting the legislative requirement to secure renewable power.

The auditor's analysis confirms the results of this study. Our in-depth analysis of the long-term contracts show that the state:

- Purchased at least $4-5 billion worth of energy beyond our needs;
- Locked the state into inflexible "take-or-pay" contracts;
- Purchased too much off-peak power and not enough on-peak power;
- Purchased too much power in Southern California and not enough in Northern California;
- Purchased too much dirty, gas-fired power and too little clean, renewable power. Renewables account for a mere 1-2% of the current DWR portfolio.
- Signed 6 contracts priced above Federal Energy Regulatory Commission (FERC) price caps.

As a result, the state is on course to lose almost a billion dollars in electricity sales in 2002 alone! By CDWR's own estimates, it would have to sell as much as 31% of its 2002 contract power at fire sale prices. Our analysis shows that total losses to the state could reach close to $5 billion by 2010.

The facts are clear. Unless the state takes action now to renegotiate some long-term contracts, the energy crisis threatens to turn into a quagmire of skyrocketing consumer bills, state budget deficits, dirty energy sources and no stability in the energy market.

II. The Solution

The good news is that the state can do something to solve this problem. This report is a joint effort of consumer and environmental organizations to aid in solving the problem. While the goals and philosophies of these groups are not identical, the goal remains the same: to develop a workable solution to renegotiate the worst of the long-term contracts and put California on the path to a sustainable, stable and affordable energy future.

A coalition of consumer and environmental organizations joined to analyze all the long-term contracts, and found that the state can fix much of the problem by renegotiating the twelve worst contracts. We chose these contracts based upon the following criteria:

- "Take-or-pay" requirements that prevent operational flexibility and trigger power surpluses;
- Cost (particularly as compared to other contracts for similar resources);
- Failure to protect consumers by hedging against future natural gas price spikes. This criteria includes:
    1. One-sided power sales deals, where the buyer is required to buy, but the seller can refuse to sell if it can get a higher price elsewhere;
    2. Fixed high short-term prices (when gas prices are low) then a shift of long-term gas price risk to ratepayers with no sharing of the risk with the seller;
    3. The lack of any renewable power as a hedge against volatile future gas prices;
- Environmental "blank checks" which require the state to pay for pollution cleanup costs and other environmental risks;
- Planning inflexibility (contracts offering small quantities of energy at high prices early, but requiring CDWR to buy large quantities of energy for long periods later in the contract);
- Length of contract and timing of contract signature; (Contracts under three years were unlikely to be considered for this list unless they contained other egregious provisions. One-year contracts that terminate in 2001 were not considered at all. Those contracts signed after the power surplus became known are considered to be worse than earlier contracts with similar costs.)

When we measured all the long-term contracts against these criteria, we found that the majority of the problems could be solved by renegotiating the twelve worst contracts. Those contracts are:

1. Sempra Energy
2. Williams Energy
3. Calpine Los Esteros
4. Calpine Peakers
5. Constellation Energy (High Desert)
6. Coral Energy
7. Dynegy
8. Pacificorp
9. El Paso Merchant Energy
10. Alliance Colton
11. Mirant
12. Morgan Stanley

These twelve contracts contain:

- 59% of the “take-or-pay” power;
- 59% of the total capacity;
- 56% of the energy; and
- 59% of the costs of CDWR’s entire contract portfolio for the period from 2002-2011.

We recommend that the state renegotiate or attempt to void these twelve contracts in order to meet the following five goals:

1. Reduce the quantity of gas-fired generated electricity purchased between 2003 and 2011 by at least 25%.

2. Increase total renewable energy deliveries to 15-20% within existing contracts.

3. Increase operational flexibility for gas-fired energy and reduce the “take-or-pay” energy straightjacket contract provisions for gas-fired energy by more than half.

4. Increase gas-price hedging to reduce risk to the state by: 1) shifting some of the gas price risk to the contractor; 2) increasing use of renewable energy and 3) reducing “take-or-pay” quantities.

5. Reduce prices by 9-10%.

If we renegotiate the worst twelve contracts using these five goals, we can avoid a decade-long energy crisis. A successful renegotiation could:

- Reduce the cost of the long-term contracts by one-third;
- Slash the power surplus by more than 50%;
- Increase renewable power by 13%;
- Reduce prices by 9%.

III. What's In It for Them: Why the Beneficiaries Will Want to Renegotiate

At first blush, it might seem that the power generators and marketers who signed these contracts have no reason to renegotiate. They got great deals and have the state on the hook for billions of dollars, so why should they let us off the hook?

Following are six sources of leverage that the state could use as part of an aggressive, comprehensive strategy to renegotiate the contracts:

1. The state can challenge the worst of the contracts in federal court, under Section 206 of the Federal Power Act.
2. California's Attorney General is investigating conflicts of interest as part of a challenge of all contracts tainted violations of disclosure and conflict of interest laws.
3. Consumer groups are preparing to challenge the worst contracts through a taxpayer's lawsuit.
4. The Enron bankruptcy has opened the door to the details of and the extent of market manipulation in electricity markets. The California and Federal authorities' investigations into Enron's activities will likely prove that California was subjected to economic duress by the energy industry.
5. Contracts can be challenged through the California Energy Commission and local government permitting processes.
6. Public interest groups are mobilizing a statewide public education campaign to demand accountability and fairness from the companies holding the worst contracts.

<u>I. The Problem: Power Surpluses Threaten Taxpayers, Consumers, and the Environment</u>

Consumers, taxpayers and the environment will all be harmed if the power purchase contracts entered into by CDWR are not renegotiated. Consumers will continue to face today's high electricity rates long after the energy crisis is behind us. Although a well-designed portfolio of long-term contracts can effectively hedge such risks, the CDWR contracts needlessly expose consumers to the price and supply volatility of the natural gas market. California's environment and public health will also suffer as a result of the CDWR contract inflexibility and over-reliance on fossil fuel fired energy generation. Take-or-pay provisions in several contracts mean that dirtier plants may be dispatched ahead of clean, renewable power sources. The artificial power surpluses created by the CDWR contracts also threaten to derail California's leadership in developing renewable energy resources to replace polluting fossil fuel fired generation. Even worse, the surpluses are also creating incentives for the state to abandon the cleanest and most economic energy sources of all – efficiency and conservation.

Causes of the Surplus: Take-or-Pay Provisions

One of the two main causes of the projected power surpluses is the take- or-pay provisions that force the state to buy electricity regardless of whether it is needed. These provisions slap energy straightjackets on California's energy planners. CDWR admits that in addition to buying too much power during off peak hours, it bought <u>too little</u> power during peak hours.[1] These one-sided provisions prevent CDWR from simply re-scheduling the power to allow CDWR to dispatch or match available power to demand in a cost-effective manner.

The magnitude of the power surplus problem can be seen by looking at the estimated CDWR statewide surplus power sales for 2002 (shown on a quarterly basis as part of Table 1). Consumers could lose nearly a billion dollars ($893 million) in estimated surplus power sales in 2002, an approximate loss of $2 million to $4 million daily from having to sell surplus off-peak power for a fraction of its purchased price. Unless the take-or-pay (non-dispatchable) provisions of the state's power contracts are renegotiated, starting this January CDWR will have to sell as much as 31% of its 2002 contracted power at fire sale prices, according to CDWR internal data. CDWR estimates that electricity bought for an average $121/MWh may have to be sold for as little as $19/MWh (MWh = megawatt hour). From April to June 2002, CDWR data estimates consumers will lose about $348 million or nearly $4 million a day. By October to December the loss is expected to drop to about $1.7 million a day.

[1] **<u>Ibid</u>**

Unfortunately, this power surplus is not a one-year problem. CDWR estimates (summarized in Tables 1 and 2 in Appendix C) that about 20-25% of the long-term contract electricity purchased will have to be dumped on the spot markets through 2006 for a fraction of its purchase price unless take-or-pay provisions are renegotiated. The total loss would be $4.9 billion from 2002-2010, as shown in Table 1. There are additional losses in 2001.

Information made available on February 4, 2002 provides an even grimmer picture of the enormity of the surplus. In 2004, DWR predicts that it will be selling surplus power in more than 4000 hours per year (47% of the hours of the year). In every year from 2003-2008, DWR predicts it will sell power during at least 30% of the hours of the year.[2]

But it's not as simple as saying that CDWR just bought too much power. CDWR admits it bought too much power during off peak hours (3 o'clock in the morning or late at night) and too little power at peak hour periods late in the afternoon.[3] Additionally, it appears CDWR bought too much power in Southern California[4] and too little in Northern California.[5] In the event of transmission line congestion, as early as next year CDWR may be selling surplus power at a fraction of its contract price in Southern California while buying power in Northern California to meet shortages.

Causes of the Surplus: Large Electric Customers Leaving the Regulated Rate Base

The second cause of these huge power surpluses is the fact that about 20 billion kWh of commercial and industrial load left the CPUC regulated rate base and negotiated direct access power contracts in spring and summer of 2001. By reducing CDWR loads, these new direct access purchases have increased the need to sell surplus contract power, particularly in the period between 2003 and 2007. If customers who shifted to direct access before September 20th are allowed to stay on direct access, a determination that will be reached by the CPUC at its March 6, 2002 hearing, it becomes even more imperative that a

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[2] California Department of Water Resources, Responses To Data Requests by Interested Parties on Rate Stabilization Plan Proceeding – Cost Responsibility of Direct Access Customers for DWR's Revenue Requirement Phase. CPUC App. 00-11-038 et al. February 4, 2002. Response to Question CLECA-16, p. 51.

[3] See Appendix D: Memorandum From Thomas M. Hannigan, Director, Department of Water Resources, to S. David Freeman, Consumer Power and Conservation Financing Authority, Re: Coordination Policy between California Energy Resources Scheduling and Consumer Power and Conservation Financing Authority, October 4, 2001 "…And during non-peak conditions, we expect to have surplus power that could be used for seasonal exchanges and power sales."

[4] California State Auditor, California Energy Markets: Pressures Have Eased but Cost Risks Remain, Report 2001-009 (Sacramento: December, 2001), p. 52

[5] Op. Cit. Memorandum From Thomas Hannigan, Director, DWR

serious contract renegotiation take place. Negotiations will allow us to reduce the effect of unfairly requiring small residential and small commercial customers to pay for the costs of the billions of dollars in surplus power contained in the contracts.

Too Much of the $43 Billion in Power Is Simply Too Dirty

Less than 2 percent of the $43 billion in power CDWR purchased is clean, renewable power (wind, solar, hydro and others). The State Auditor noted this failure and defined its significance to consumers: "A diverse fuel and technology mix helps ensure reasonably reliable supplies and stable prices because this mix can help mitigate against cost increases in one fuel or performance problems with a particular technology. Renewables displace fossil fuels, in this case, natural gas, and by doing so can moderate spot prices, a major objective of AB 1X.[6]

This inexplicable failure to invest in a balanced portfolio also violated the clear intent of the Legislature when it explicitly told CDWR to "…secure as much… renewable energy as possible." [7] Besides buying too much power and at the wrong time of day, CDWR now reluctantly admits its $43 billion in contracts presents "…a continuing challenge … to diversify its resource mix with renewables…"[8] California, once a leader in renewable energy development, now faces a "green black-out". More than 600 MW of clean, renewable wind, geothermal and biomass capacity have already been approved for funding from the CEC but may not be built for lack of a buyer.

But the story of the renewable failure doesn't end there. Renewable power is by its very nature inflexible and often requires take-or-pay contract provisions. When the wind blows or the water flows, the power must be taken or it's lost. Sound energy planning requires that the cleaner, sometimes cheaper, energy sources be scheduled for first use. Dirtier non-renewable power such as natural gas-fired electricity, especially that from older, less efficient plants, can be relatively easily ramped up or down, turned on or off, to meet varying demands for electricity at different times of the day. In other words, common sense dictates that clean power should run first and dirtier power should run last and only if it is needed.

However, CDWR's giant "take-or-pay" contracts turn sound energy management principles and common sense on their heads. Dirty gas-fired power from old, inefficient plants, as with 1400 MW of the Williams Energy contract, is take-or-pay and must be dispatched ahead of all other sources. Even worse, for 500 MW of Williams' old, dirty gas-fired power CDWR must buy it whenever Williams makes it available. Yet, if Williams can get a better price somewhere else, Williams doesn't have to sell it. Not only did CDWR agree to these inflexible

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[6] Op. cit.. California State Auditor, p. 55.

[7] AB 1X, 2001-2001 First Extraordinary Session, Section 80100 (f), page 10, lines 12-13

[8] Ibid

terms, but three of the major contracts (Mirant, Williams Energy, and Dynegy) also contain environmental blank-checks whereby consumers are required to pay the contract holders costs for complying with clean air laws**.**

State's Successful Conservation Program Threatened

The very energy conservation and efficiency efforts that helped keep the lights on and stabilized electricity prices earlier this year are now jeopardized by power surpluses. CDWR has quietly begun to dismantle its own demand-side management conservation programs[9]. If large amounts of hydroelectric power become available in any future year, as now looks likely with above normal rainfall as early as 2002, the state will have an even stronger incentive to abandon energy saving programs. Worse yet, continued power surpluses could jeopardize the new residential rate structure, put in place by the California Public Utilities Commission (CPUC), that rewards consumers for conserving power. In the long run, this could raise consumers' electric bills by causing them to buy electricity that cheaper conservation investments could displace.

Renegotiating the CDWR Contracts: A Manageable Problem

A crucial misconception surrounding the Department of Water Resources' $43 billion in power contracts is the notion that all 57 contracts must be renegotiated to address the identified problems. It is not generally understood that the lion's share of these problems are from a small handful of contracts. For example, six contracts with five entities - Sempra, Williams Energy, Constellation Energy (two contracts, High Desert and one for short-term power), Calpine (combined cycle), and Allegheny Energy contain: [10]

- 61% of the $43 billion in costs;
- 66% of the total quantity of power purchased; and
- 89% of the gas-fired take-or-pay power.

For further example, ten other contracts with nine companies (Alliance Colton, Calpine peakers, Calpine Los Esteros, Coral Energy, Dynegy, two contracts with El Paso Merchant Energy, Mirant, Morgan Stanley, and Pacificorp) contain:

- 27% of the $43 billion in costs;
- 21% of the total quantity of power purchased, and
- 11% of gas-fired take-or-pay power.

[9] The 20-20 program will not be extended for another summer, and interruptible bidding programs are being suspended.

[10] Unless otherwise noted, all costs and prices quoted in this report assume a gas price averaging $4/MMBtu over the ten-year period when costing out contracts that are sensitive to gas prices. No attempt was made to forecast gas prices in individual years.

The remaining 41 in the package of CDWR contracts are less significant, especially in the 2002-2011time period, and contain less than 1% of gas-fired take-or-pay energy.[11] Seven of these contracts, comprising less than 2% of the energy purchased, are for renewable power and most of the other contracts are either fully dispatchable peaking units, or expire in 2001 or 2002.

The energy that is explicitly priced above the Federal Energy Regulatory Commission ((FERC) price caps is concentrated in six contracts extending to at least the end of 2002 - Sempra, Coral, Dynegy, El Paso Merchant Energy, Mirant, and Morgan Stanley[12].

The 12 contracts that we have identified as the state's worst contracts contain 59% of the take-or-pay power, 59% of the total capacity, 56% of the energy, and 59% of the costs of CDWR's entire contract portfolio for the period from 2002-2011.[13] (See Table 3 in Appendix C.) In short, renegotiating as few as 12 of 57 contracts could reduce the overall cost of the contracts by 20%, slash the power surplus by more than 50%, and increase renewable power by 13%, despite reducing electricity rates by only 9%. The 9% reduction in overall rates occurs because the overall costs of the contracts, with the operational changes, is one-third, and energy is about one-third of total bills, hence the small overall rate reduction. Eight of these 12 long term contracts were negotiated during the initial 30-day period when CDWR was signing a billion dollars a day in power contracts to simply keep the lights on. The State Auditor found, that during the 30 day period in which CDWR bought most of its power for the next decade, it had virtually no strategy or concern for future energy management and planning. To avoid repeating the errors of the past, CDWR should follow the State Auditor's recommendation to upgrade its renegotiating team and perform a study to develop a renegotiation strategy.

The following discussion is an attempt to establish the clear public interest principles that should guide any renegotiation process.

[11] The Intercom Energy contract, signed on August 24, 2001, requires the purchase of take-or-pay energy during peak periods for a two year period (September 1, 2001 through August 31, 2003). Its price is $45/MWh, considerably less than other contracts, though possibly still above spot market prices at the time.

[12] A number of shorter term contracts that expired in 2001 also have this problem. This report has not focused on them, because it is dealing with long-term implications of the contracts.

[13] A few contract renegotiations (Coral, Calpine peakers) also affect the period beyond 2011, but those impacts have not been analyzed quantitatively.

II. The Solution: A Public Interest Blueprint for Renegotiating The 12 Worst DWR Contracts

Sempra Energy
Williams Energy
Calpine (Los Esteros and Peakers)[14]
Constellation Energy (High Desert)
Coral Energy
Dynegy
Pacificorp
El Paso Merchant Energy
Alliance Colton
Mirant
Morgan Stanley

The above-listed contracts [15] were chosen for renegotiation based upon the following factors:

- "Take-or-pay" requirements that prevent operational flexibility and trigger power surpluses;

- Cost (particularly as compared to other contracts for similar resources);

- Failure to protect consumers by hedging against future natural gas price spikes and other one-sided contract provisions. These include: 1) one-sided power sales deals, where the buyer is required to buy, but the seller can refuse to sell if it can get a higher price somewhere else; 2) fixed high short-term prices when gas prices are low, then a shift of long-term gas price risk to ratepayers with no sharing of the risk with the seller; and 3) lack of any renewable power as a hedge against volatile future gas prices;

- Environmental "blank checks" which require the state to pay for pollution cleanup costs and other environmental risks;

[14] Calpine has four CDWR power contracts. Peakers and Los Esteros qualify for this list. The combined cycle contract has relatively low long-term prices (compared to other contracts) and a natural gas hedge so it fails to meet the "12 Worst" criteria. However, its 2000 MW of "take-or-pay" energy requires "adjustment" if the state is to address its projected power surplus. The fourth contract was very high-priced, but relatively short-term, expiring in 2001.

[15] This list of 12 contracts should not be considered the final list for renegotiation. The Attorney General is investigating possible conflict of interest violations, which may increase our ability to challenge the legality of more of the contracts. The State Auditor is currently conducting an investigation of the contract approval process and its final audit report may also add contracts to this list. Finally, two other contracts (Calpine combined cycle, and Allegheny Energy). expose the state to take-or-pay obligations for 3000 MW of power on a seven-day-a-week-24-hours-a-day basis. They are likely to need adjustment to reduce take-or-pay quantities of electricity delivered because of their sheer size.

- Planning inflexibility (contracts offering small quantities of energy at high prices early, but requiring CDWR to buy large quantities of energy for long periods later in the contract); and

- Length of contract and timing of contract signature. In particular, contracts under three years were unlikely to be considered for this list unless they contained other egregious provisions, and one-year contracts that terminate in 2001 were not considered at all. Those contracts signed after the power surplus became more apparent are considered to be worse than earlier contracts with similar costs.

Five Public Interest Principles for Contract Renegotiation

The following renegotiation principles have been jointly developed by a coalition of consumer and environmental stakeholders:

1) Reduce the quantity of gas-fired generated electricity purchased between 2003 and 2011 by at least 25%;

2) Increase total renewable energy deliveries to 15-20% within existing contracts;

3) Increase operational flexibility for gas-fired energy and reduce the take-or-pay energy straightjacket contract provisions for gas-fired energy by more than half; and

4) Increase hedging of gas prices to reduce risk to the state by: 1) shifting some of the gas price risk to the contractor; 2) increasing use of renewable energy; and 3) reducing "take-or-pay" quantities.

5) Reduce cost by: 1) eliminating high-cost one-sided provisions, such as prices above FERC price caps and very high peaker prices and 2) eliminating or limiting environmental blank check provisions that shift the responsibility and cost for pollution from the generator to the state.

Strategies for Applying Public Interest Principles

Specifically, we propose the following strategies for applying the public interest renegotiation principles. We estimate that successful application of these principles to the 12 worst contracts would reduce prices by approximately 9%, diminish vulnerability of consumers to price volatility and decrease air pollution from fossil fuel fired generation.

1) Reduce quantities of gas-fired electricity purchased between 2003 and 2011 by 25%.

Suggested strategies:

- Reduce total megawatts purchased every year in high-priced or unbalanced hedge contracts;

- Delay gas-fired purchases ramping up in 2003-05 to reduce near-term surplus; and
- Shorten longest contracts, with particular attention to contracts extending past 2011.

2) Increase total renewable energy deliveries to 15-20% within existing contracts.

Suggested strategies:

- Substitute renewable power for gas within existing contract quantities (the 15-20% goal does not have to be tied to specific plants);
- Provide an alternative to some megawatt reductions or operational flexibility modifications; and
- Use fixed priced renewables as a hedge against volatile gas prices.

3) Increase operational flexibility and reduce "take-or-pay" provisions of gas-fired energy by more than 50%.

Suggested strategies:

- Allow CDWR to schedule 7X24 (seven-day-week, 24-hour-a-day) contracts and 6X16 (six-day-a-week, 6AM-to-10PM) contracts to reduce deliveries by up to 25% (alternatively convert to lesser number of hours) to reduce surplus purchases in the late night and early morning hours;
- Reform some of the gas generator contracts containing the highest fuel costs to allow CDWR to fully schedule deliveries to the extent consistent with operational characteristics of specific plants; and
- Reform contracts with flexible gas generators to allow CDWR to self-provide ancillary services, while paying generators appropriately for the service.

4) Improve hedging of price and quantity risks.

Suggested strategies:

- Modify risky pricing structures for contracts that contain both high fixed prices in the short term and risky gas-based prices in the long-term. (This single principle creates about half of the approximately 10% price reduction identified below. It's heavily weighted to 2002-2004 because of the drop in natural gas prices since the contracts were signed);

- Eliminate unbalanced hedges or "put" options where CDWR is required to buy the power even if its not needed, but the seller isn't obligated to sell if the seller can find a higher price (Reduces capacity commitments by 750 MW in two contracts - Williams Energy and Coral);
- Substitute renewable energy; and
- Remove or limit environmental blank checks that shift the polluter-pays principle to state-pays for existing gas plants.

Impact of Principles of Renegotiation

If the principles of renegotiation were applied only to the 12 worst contracts, the impact would be:

- Approximately 20% of the combined cost of all the contracts could be reduced by renegotiating take-or-pay provisions, reducing total megawatts, and reducing prices by as little as 9% from the worst contracts. Reductions in take-or-pay quantities or megawatt purchases from the two other very large contracts (Calpine and Allegheny) could provide further reductions in costs and the surplus costs;

- 2/3 or more of the state's power surplus could be eliminated;

- 50% or more of the take-or-pay power would be reduced to substantially increase CDWR's operational flexibility. (These benefits could accrue by renegotiating as few as three contracts - Sempra, Williams Energy, and Constellation Energy (High Desert));[16]

- 21% of the total megawatt capacity in these twelve contracts would be reduced, in addition to a 25% reduction in MWh, and 32% reduction in costs;

- 13% of the remaining maximum contract quantities would be provided from new renewable power over the entire time period from 2002-2011; and

- Approximately 670 MW (and about 35,000 GWh) of new green power (counting wind as 30% of a MW of other green sources) is added to the mix. This factor would potentially create a contract "home" for a significant portion of the projects funded by the CEC.

[16] 41% of all the "take-or-pay" power is contained in two other huge contracts (Calpine combined cycle, and Allegheny Energy). They provide 3000 MW of take-or-pay-seven-day-a-week-24-hours-a-day CDWR obligations to buy whether the power is needed. Any attempt to address the need for greater CDWR flexibility to reduce power surpluses and match demand and supply will probably require some adjustment of these giant contracts if for no other reason than the large magnitude of their "take-or-pay" quantities.

In conclusion, applying our Principles of Renegotiation to the 12 worst power contracts will slash total costs of all contracts by 20%, cut the wasteful surplus power by 2/3, reduce capacity, energy, and price impacts, while increasing the use of dispatchable (non-“take-or-pay”) gas and new renewable energy. See Table 4 in Appendix C. Going beyond the 12 worst contracts and seeking adjustments in the Calpine combined cycle and Allegheny Energy contracts would deliver even more operational flexibility. In short, this problem is far more manageable than originally considered.

Applying Public Interest Principles To The Worst 12 Contracts

Our contract-by-contract analysis (see Appendix B) provides a detailed policy map showing exactly how to reduce the total costs of the long-term contracts by 20% by simply reducing the take-or-pay provisions and making other operational changes to as few as 12 contracts while only reducing prices by 9%. The recommended reductions in energy deliveries, particularly off-peak in early morning and late evening hours, will reduce the cost of energy to ratepayers by allowing CDWR to substitute cheaper power for contract power. It would reduce wasteful dumping of contract power into the spot market at fire sale prices. This analysis represents an aggressive strategy for renegotiating power contracts by implementing public interest principles on a contract-by-contract basis. The most serious single misconception surrounding the power contracts is the notion that price is the only determinant of value and that price is the central variable when considering costs to ratepayers. To accomplish a 20% savings, we recommend a mix of reductions in capacity commitments, price concessions, substitution of green power for gas-fired power within existing contract limits, balancing of asymmetrical hedges, and increased flexibility for CDWR in scheduling energy deliveries from gas-fired projects.

Our recommendations avoid the temptation to impose a simple cookie-cutter approach. Instead, these renegotiation strategies provide a contract-by-contract approach that recognizes the specific strengths and weaknesses of each individual contract.

III. What's In It for Them: Six Reasons Why The Beneficiaries of the Power Contracts Will Renegotiate

Uncertainty swirls around these contracts. Continued public controversy over the CPUC rate agreement, adopted February 21, 2002, the CPUC's petition to FERC to challenge to the contracts, the Attorney General's conflict of interest investigation of possible criminal violations that may invalidate some contracts and the threat of civil litigation to challenge the contracts and continued legislative investigations create uncertainty. Investor-owned power companies who hold CDWR contracts want certainty.[17] Wall Street investors are questioning whether the one-sided, high priced, "take-or-pay" straightjacket agreements CDWR signed will be renegotiated.[18] It's important to note that after renegotiation, these contracts will remain among the most lucrative power contracts ever signed in California. The uncertainties of continued controversy provide an incentive for companies holding these contracts to voluntarily agree to alter the most egregious portions of the worst contracts or take their chances with the CPUC, FERC, the AG, and the Legislature. We have identified the following six sources of leverage that the state could use as part of an aggressive, comprehensive strategy to renegotiate the contracts.

1. The CPUC is expected to challenge the worst contracts before FERC or in federal court under the provisions of Sections 205 and 206 of the Federal Power Act.

Although FERC has resisted the state's requests for refunds from power generators' windfall profits from earlier this year, there is a significant likelihood that FERC may require concessions for contracts entered into during the 6 month period when FERC ruled that generators exercised illegal market power. FERC is likely to help provide relief from take-or-pay provisions, as well as reduce the volume and duration for contracts resulting in excessive surplus power.

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[17] Steve Fleishman, an analyst with Merrill Lynch in New York, was recently quoted as about the need to remove the uncertainties surrounding at least one of the CDWR contracts: "If the contracts are renegotiated sooner it could be a positive first step for Calpine," Fleishman said. Jason Leopold, Dow Jones Newswire, December 17, 2001

[18] See Sempra Financial Analyst Presentation, October 4, 200; Nancy Rivera Brooks, "Calpine Stock Hit by Comparison With Enron, Analyst's Downgrade," Business Section, Los Angeles Times, December 11, 2001, Page C1 Kit Konolige, utility analyst with Moirgan Stanley Dean Witter & Co says "he is taking a more cautious stance on such unregulated power producers in the near term, reflecting weak electricity and natural gas prices, ***the increasing likelihood that California will renegotiate its long-term power contracts at lower prices*** and negative investor sentiment lingering from the Enron debacle." [Emphasis added.]

2. California's Attorney General is investigating conflicts of interest as part of a potential challenge to all contracts tainted by violations of disclosure and conflict of interest laws.

From January to May 2001, CDWR retained consultants to negotiate the long-term power contracts. CDWR signed the last major power contract on July 26, 2001 with about the time the first economic disclosure reports were being filed by CDWR's consultants. CDWR failed to demand disclosure in a timely and accurate fashion, failed to properly police potential conflicts of interest and violations of law and allowed CDWR consultants to participate in discussions related to contract negotiations.

As a result of the apparent disregard by CDWR of enforcement of state conflict of interest laws, one or more of the contracts negotiated by CDWR's consultants could be set aside or voided pursuant to Section 1090 of the California State Government Code, either by the Attorney General, or by a public interest lawsuit. Consumer groups have unveiled some very important facts concerning the conflicts of interest of one CDWR consultant, Mr. Vikram Budhraja:

- In January 2001, Mr. Budhraja and his company, Electric Power Group, a limited liability company, were hired by DWR under the terms of a two year $6.2 million contract to negotiate power contracts on behalf of the state. The scope of work under the contract states in part: "Power Acquisition: negotiate and/or participate in meetings with bidders...." Power Portfolio Plan: define amount of energy, duration of contracts, types of contracts, evaluation of bids, selection of beneficial bids, negotiation and writing of contracts."
- The Office of Chief Counsel of DWR determined that persons hired under contract as Spot Market Traders, Energy Contractor Negotiators and Energy Market Advisors are consultants and thus, public officials, within the meaning of the Political Reform Act. Mr. Budhraja has acknowledged that he is a "public official" by filing his Statement of Economic Interests (SEI) and amendments thereto. In his initial SEI, the only source of income Mr. Budhraja disclosed was Edison International.
- Approximately three weeks after Mr. Budhraja was hired, Williams Energy signed a contract with the state to provide power. In his Amended Assuming Office SEI, filed seven months after he was hired on August 13, 2001, Mr. Budhraja disclosed for the first time that Williams Energy had provided more than $10,000 of income to his company, Electric Power Group, during the previous 12 months. Mr. Budhraja appears to have been involved to some extent in negotiations and other activities leading to the Williams Energy contract.
- Mr. Budhraja reported stock ownership in energy companies with which the State may have had discussions, negotiations and other contacts resulting in governmental decisions which could have affected the companies. He reported stock ownership of more than $10,000 in Edison International (also a source of income), Dynegy, and more than $2,000 in Scottish Power, all of which he later disposed.

3. Consumer groups are preparing to challenge the worst contracts through a taxpayer's lawsuit.

A number of consumer groups have already raised serious conflict of interest issues relating to the negotiators for the state. Attorney General Lockyer's office is currently investigating the documented conflicts of interest. A San Diego-based legal group filed a court challenge to the contracts citing similar conflicts that would nullify most of the state contracts.

4. The Legislature is investigating allegations of market manipulation and economic duress.

In addition to the review of the Auditor General's investigation of the CDWR contracts by the Joint Legislative Audit Committee, the Senate Select Committee on Market Manipulation, chaired by Senator Joe Dunn has planned hearings early next year to review the results of depositions and subpoenas issued to generating companies and the management of the California Independent System Operator. These investigations are likely to be expanded in response to the Enron bankruptcy.

Federal investigations into the Enron bankruptcy have raised questions about whether other unregulated power producing companies with trading company subsidiaries may have engaged in some of the same practices that triggered the Enron bankruptcy. The CPUC and the Legislature have indicated they will pursue separate investigations.

5. Contracts can be challenged through the CEC and local government permitting processes.

Consumer and environmental groups are challenging the siting permits of some projects being built to service the CDWR contracts. The California Energy Commission, local agencies and the ISO are being strongly urged to take advantage of the CEC siting process to require natural gas-fired plants to provide operational flexibility, agree to reduce emissions and mitigate the environmental justice impacts related to the contracts as a condition for receiving siting approval.

6. Public interest groups are mobilizing a statewide public education campaign demanding accountability and fairness from the companies holding the worst contracts.

The continuing controversy and bad publicity for the beneficiaries of the worst contracts has been exacerbated by the response of investors, regulators, and legislators to the Enron bankruptcy. These one-sided contracts are becoming a public relations nightmare for the generators, and increasing public pressure and media scrutiny are creating incentives for generators to do the right thing and renegotiate their contracts in the public interest and get their companies name out of the newspapers.

Appendix A: A Summary of the State Auditors' Findings

Reliability of Electricity Supplies

The terms and conditions of the majority of contracts may not provide a reliable supply of energy as required by AB 1X (p. 67)

And while the penalties for the state's failure to pay for the power are enormous, the State Auditor warns that most of the contracts fail to penalize power producers for withholding power as they did in 2000 and 2001 (p. 58):

> "…The legal terms and conditions of those contracts, particularly the early ones, may not adequately assure that the generator will physically deliver the electricity the State needs to keep the lights on, especially in periods of tight supply and high prices. (p. 67-68) …The majority of the power is under contracts that may not assure that reliable sources of power will be available to the department. In other words, when the market price for power increases above the contract price and demand for electricity exceeds supply, the terms and conditions of a majority of the contracts may not ensure that the department will be able to provide the power needed in California." (p.68)

> "The contracts' terms and conditions may not meet other reliability goals of the contracting effort, including ensuring that generators are making appropriate progress in building the facilities that will supply the power the department has contracted for…Contracts in which the State pays a premium for construction of new generation may not ensure that the new generating units will be built and that the power will actually be made available." (p.68)

The lack of seller penalties in the contract language fails to protect ratepayers:

> "If sellers [power producers] fail to deliver in the early years---especially if they aggressively seek to enforce excuses for nonperformance---the department might very well be left with its obligation to pay lucrative prices over the long term without having received the immediate benefit it was bargaining for." (p. 91-92)

Continued Power Shortages and Surpluses

Despite purchasing $42.6 billion worth of power over the next decade, CDWR still faces a shortage of peak hour power. (p. 1, 46)

> "Calculations by a department consultant reflect that the contracts will not cover a substantial portion of the estimated load during hot summer days, when demand for electricity is high. (p. 46)…The risk in the portfolio that the department must carefully manage is that the portfolio leaves it

> exposed to substantial market risk in high-demand periods if supply shortages occur and to substantial market risk with surplus contract amounts in other hours of the year. Compounding this problem is that many of the contracts are nondispatchable, meaning that the department must pay for the power whether or not it is needed. Further, based on present forecasts, from the fourth quarter of 2003 through the first quarter of 2005, the department has procured more power than consumers in Southern California need." (p.23)

At the same time, "the majority of CDWR appears to have bought too much power in Southern California and there is likely to be power surpluses of an average of 2000 megawatts during the last quarter of 2003 through the first quarter of 2005." (p. 47, 23, 52-53)

The Legislature's Mandate: Renewable Energy

> "A diverse fuel and technology mix helps ensure reasonably reliable supplies and stable prices because this mix can help mitigate against cost increases in one fuel or performance problems with a particular technology. Renewables displace fossil fuels, in this case, natural gas, and by doing so can moderate spot prices, a major objective of AB 1X." (p. 55)

Only 2% of the 12,000 megawatts of capacity purchased is renewable. "Despite the legislative mandate to secure as much renewable as possible, the department did not do so in its contracting efforts and missed a significant opportunity to add environmentally friendly power." (p.56)

DWR Purchases Lacked Planning and Analysis

> "The department's rush to obtain contracts quickly---it entered about 40 agreements with a value of $35.9 billion in just 30 days----may have played a role in the composition of the portfolio because it precluded the planning and analysis that are necessary for developing a portfolio of this magnitude." (p. 24)

Analysis of Troubling Contract Provisions (p. 197-213)

> "Contracts of this magnitude negotiated at a rapid pace, create the potential for costly errors and omissions" (p. 57).
>
> "Three of the largest long-term contracts (Calpine, Williams, and Dynegy), all of which were executed quite early in the contract negotiation process, contain troubling provisions." (p. 197)

Dynegy

> "If Dynegy's power is restricted in *any* way for *any* reason related to the performance of its contracts with the department, the department must provide power to Dynegy (rather than receive it) for an underdetermined period of time after the end of the contracts. The scope of events that could trigger this extremely broad and uncapped obligation for the department is unclear at present." (p. 199)
>
> "The department is responsible for costs or restrictions imposed by any environmental agency at any time over the life of the contracts…For the life of the contracts, the department pays for Dynegy's costs relating to air emissions to the extent that those costs are "attributable" to performing the contracts. At best, determining what costs are "attributable" to the department's contracts seems ripe for litigation." (p. 199)

Williams[19]

The cost risk of air emissions laws and "any new governmental charges" are shifted from Williams to the department. (p. 198) "The department is exposed to between $400 million and $688 million in potential emissions credit pass-through costs over the life of the contracts." (p. 199)

The contract gives Williams an incentive to generate the department's power using the dirtiest units. (p. 200)

> "The Williams agreement…is almost as burdensome for the department as it could possibly be." (p. 202) The Williams government charges provision "…gives Williams almost unfettered discretion to walk away from the contract in the face of any action or inaction by any of the California actors as governmental entities, and it exposes the department to the substantial risk not only that it might bear the cost of increases in Williams' costs of doing business due to events as remote as local property tax increases or increases in rates for workers compensation insurance but, that, in a rising energy market, Williams might seize on one of these remotely related government actions to claim that a default has occurred, terminate its contract with the department, and take advantage of the higher market prices." (p. 205)
>
> "…The contract poses hundreds of millions of dollars of exposure for the department; however, most the triggering events are outside the department's control." (p. 171) "The department's strategy needs to be attempting to reform the terms of the contract itself, whether voluntarily through renegotiation or forcibly through litigation." (p. 171)

[19] For the most detailed analysis of the problems found in the Williams Contract see p. 197-205 in the audit report.

Calpine[20]

> "The early Calpine agreements standout overall as having the most seller-friendly (and least favorable to the department) provisions of any major contract we reviewed. " (p. 118)

If the 11 contemplated commercial units do not come on line "…there is a legal risk that the department is not protected against having to make capacity payments in the following years for power plant capacity that does not come on-line." (p. 207)

Sempra

The contract contains "… no provision for the department to monitor Sempra's financial condition, much less terminate the contracts should Sempra lose the financial wherewithal to complete the projects." (p. 99)

Key Recommendations:

> "Conduct within 90 days an in-depth economic assessment of its contracts and the overall supply portfolio that serves customers of the investor-owned utilities…." (p. 7)
> "Develop a contract renegotiation strategy, informed by legal and economic reviews, that centers on improving the reliability and the overall balance and performance of the portfolio. " (p. 7)

The department "…should not limit its interest in renegotiating the contracts to just the base price of the delivered power. The department would benefit significantly if it could renegotiate out of the contracts, the terms that make the contracts expensive and difficult to manage." (p. 176)

> "Establish an ongoing legal services function that specializes in power contract management…When necessary to avoid conflicts, this legal function should be distinct from counsel retained to sell bonds…" (p. 7)

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[20] See p. 205-213; also 82-83; 101

Appendix B: Contract-by-Contract Analysis

Sempra Energy

Contract Issues

This is the state's worst contract. This $7 billion contract signed on May 4, 2001, cumulatively contains the worst flaws found among all the other contracts. More specifically, the Sempra contract provides:

- High costs – the Sempra contract is the second most costly state power contract.[21] [22];
- 250 Megawatts (MW) of very expensive fixed price power ($189/MWh) from 2001 to 2003 after natural gas prices have dropped 60% and are expected to be low until 2003 or beyond;
- The full risk of higher gas prices, which shift to the state in 2003,exposing consumers to higher natural gas prices;
- A capacity factor that is far too low. The quantity of energy delivered rises to 1900 MW in 2004. This giant 10 year "take-or-pay" contract requires power deliveries at an 80% capacity factor; and
- No means for the state to ensure that promised new plants will be built. On its face, the contract appears to contemplate the construction of new power plants, but the State Auditor warns that the contract contains "… no provision for the department to monitor Sempra's financial condition, much less terminate the contracts should Sempra lose the financial wherewithal to complete the projects."[23]

[21] Calpine Energy's 2000 MW "take-or-pay" combined cycle contract is the most costly and the largest state power contract although its average price per kWh is less than Sempra's price. The Calpine contract comes on line fast and is 100% "take-or-pay".

[22] Like other facts related to CDWR's power contracts, Sempra mistakenly refers to its contract as "… the largest single contract in merchant plant history. It's a 10-year contract with 1900 megawatts with peak supply. Over the period of the period of the contract, it's $7 billion in revenues. … There's no fuel price risk. All prices after June1, 2003 are indexed and *we pass those costs on to the Department of Water Resources*." [Emphasis added.] Donald Felsinger, Group President, Sempra Energy Enterprises, Analyst Meeting, October 4, 2001

[23] Op. Cit. California State Auditor, p. 99

Recommended Actions

- Reduce the quantity of power purchased by 500 MW;[24]
- Add 150 MW of green renewable power;[25]
- Reduce fixed prices in 2001 to 2003 to balance the lack of any gas hedge and reflect changes in the natural gas market conditions;[26]
- Increase flexibility by reducing take-or-pay provisions by about 20%;[27] and
- Reduce prices $2 to $5 per MWh.[28] (This price reduction is modest by comparison to recent contract offers made not long after the Sempra deal was signed. For example, Nevada Power was offered a ten-year 7X24 combined cycle contract that had the same gas risk as the Sempra contract but is $11/MWh cheaper than the 7X24 combined cycle portion of the Sempra contract. [29])

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[24] More specifically, reduce total contract quantity from 1900 MW to 1400 MW (1150 MW in 2003).

[25] Replace 150 MW of 7X24 gas tolling contract with 7X24 green power at $60/MWh for June, 2003 through 2011.

[26] Reduce fixed prices from January 2002 through June 2003 to $70/MWh to reflect the drop in natural gas prices.

[27] 1) Allow CDWR to dispatch up to 25% of 2002-2003 fixed price power. 2) Allow CDWR to dispatch up to 25% of the 6X16 heavy load gas tolling power. And 3) Allow CDWR to dispatch 7X24 gas tolling contracts to reduce capacity factor of those contracts an additional 10% over the year. (A 10% reduction is taken here, compared to the greater reduction called for on other contracts, because Sempra reduces power deliveries in April and May by over one-third. This reduction in required output in the spring months accommodates both Sempra's own maintenance needs and system conditions. Nevertheless Sempra's spring reduction is unimpressive when compared to the Coral Energy contract).

[28] The price reduction would be achieved by reducing the Tolling Charge from $31 to $26 per MWh for heavy load hour portion of contract and from $26 to $24 per MWh for baseload portion of contract. 2) Reduce gas payment from 10000 Btu/kWh to 9000 Btu/kWh for heavy load hour portion of contract because the contract is largely based on combined cycle generators.

[29]It is even farther below the full cost of the contract including the high-priced power that DWR is required to take in the early years. The source of the data on cheaper contracts is Nevada Power Company, Response to Federal Executive Agencies Data Request 2-09. Nevada Public Utility Commission Docket 01-10001, November, 2001.

Implementation Impacts

Table 7 in Appendix C shows the impacts of the recommendations for the 2002-2011 period. A 500 MW reduction in total capacity is included. This reduction in capacity plus the reduction in "take-or-pay" energy gives CDWR more flexibility to use power from the contract in hours and seasons when demand is low and reduces the total amount of energy purchased from Sempra by 38%. About 20% of the remaining energy purchased is green energy, reducing environmental impacts. The sum of all of these effects cause take-or-pay gas generation to be reduced by 51%. The overall cost of the contract is slashed by $3 billion with only a relatively modest reduction in price.

<u>Williams Energy</u>

Contract Issues

This contract runs a close second as the worst state power contract. This contract, signed on February 5, 2001, provides for 350 MW of power in summer of 2001, rising to 1400 MW by 2006. The contract includes the most extraordinary provision (Product B, Tier 3) found in the 57 contracts. CDWR is obligated to purchase 500 MW of power <u>if</u> Williams wants to sell the power. Williams, on the other hand, can decide each month whether it can get a better price somewhere else and, if it can, it isn't obligated to sell the power to CDWR. In other words, this provision provides a kind of cost-free put option to sell power at a minimum price to CDWR, if Williams can't find a better price from some other buyer. It limits CDWR's flexibility by requiring CDWR to buy power at high prices when market prices are low. But, when market prices rise, Williams is not obligated to sell CDWR power. The contract gives Williams an environmental blank check that requires CDWR to reimburse Williams for all environmental emissions credit costs without limit. This provision shifts responsibility for pollution from the polluter to the state of California.

The State Auditor indicated that this contract is so one-sided and egregious that the state should litigate the issue.[30] This contract may be vulnerable to legal challenge based on the results of the Attorney General's investigation into whether a consultant to CDWR, Vikram Budhaja, participated in the making of this contract while Williams was a source of income to his firm, Electric Power Group.

[30] <u>Op. Cit.</u> California State Auditor, p. 171

The electricity generated pursuant to this contract comes from three dirty, old, inefficient Edison gas-fired plants.[31] While this generation could be critically important to increasing CDWR's flexibility in providing for load following, peaking, and reserves[32], the current take-or-pay provisions straightjacket CDWR into calling on this power before other cleaner sources rather than providing a backup during high usage peak hours and other heavy-use hours. Our renegotiation strategy for this contract will attempt to restore flexibility through a different method of pricing.

Recommended Actions

- Reduce total contracted electricity by 500 MW;**[33]**
- Add 100 MW of green renewable power;[34]
- Increase flexibility by reducing take-or-pay provisions by over 90%; and
- Eliminate Williams' environmental blank-check.[35]

The Preferred Approach

We recommend revamping the contract to turn all but the green portion into a capacity and energy contract, by:

- Setting the capacity price at $75/kW-year; subject to reductions for availability below 75%;

- Using a gas-based energy price (actual heat rate multiplied by actual gas price plus $5/MWh for O&M and tolling profit, plus allowance for plant start-ups);

[31] Williams Energy and Allegheny Energy share a marketing contract with AES, the Owner of three old, polluting former Edison power plants (AES Alamitos, AES Redondo Beach, and AES Huntington Beach.) In other words, Williams and Allegheny are reselling electricity to CDWR that is produced by the three AES plants.

[32] The reserves that could be provided by Williams could be particularly valuable to the state if PG&E is allowed to transfer its hydropower to an affiliate in its bankruptcy proceeding.

[33] Cancel the 2003 Product B, Tier 3 "put option" for 500 MW.

[34] Substitute new green power for 100 MW of gas-fired power for Product A (7X24) in 2005, 150 MW in 2006-2011 at $60/MWh.

[35] Allegheny Energy's sold power to CDWR generated by the same three dirty old power plants Williams is selling power to CDWR. However, the Allegheny contract doesn't have the same "environmental blank check" provision.

- Giving CDWR the right to schedule energy or spinning reserves from Williams on 24 hours notice and request Williams provide regulation or ramp for an additional fee, with the requirements that it must 1) take a minimum of 20% of its peak hour schedule of energy plus ancillary services as actual generation in each of the 24 hours scheduled and 2) pay a $5/MW-hour tolling fee when ancillary services are scheduled but resource is not called upon by the ISO; and

- Allowing CDWR to schedule energy and ancillary services above 50% of the contract capacity for no more than 4,000 hours per year. Williams may sell its unscheduled generation into the market unless such a sale would prevent CDWR from meeting a scheduled ancillary services commitment.

A less preferable alternative would be to retain the existing contract structure with increased dispatchability and a lower fixed price, by:

- Providing for 25% dispatchability by CDWR of non-green portion of Product A;

- Changing Product B, Tier 1 and 2 (6X16 contracts) to a block of unit-contingent power dispatchable at a 70% capacity factor during the 6X16 period, scheduled at CDWR's option. Giving CDWR the option to schedule Product B, Tier 1 and 2 power on a ten-minute basis in morning and evening (subject to reasonable technical constraints) for ramping, in exchange for an additional fee to reflect use of capacity for ramping;

- Giving CDWR an option to call upon Tier 1 and 2 power that is not dispatched, up to 25% of Product B, Tiers 1 and 2, in any given hour for use as spinning reserves (if otherwise unscheduled) for an additional fee; and

- Reducing price for all power to $60/MWh plus environmental credits (equivalent to Allegheny price) effective 1/1/2002 under the less preferable alternative. The preferred alternative yields a cost in the same range (with gas at $4/MMBtu) but with a capacity and energy pricing structure.

Implementation Impacts

Table 8 in Appendix C provides a summary comparison of the renegotiated contract to the original contract. The key points are that the 500 MW put option is removed and all gas energy becomes dispatchable. About 16% of the contract's maximum output is green.

Other critical aspects of the contract renegotiation would:

- Make the contract fully dispatchable, subject only to technical constraints regarding plant operations;

- Return flexibility associated with gas plant operation to CDWR, including ramping and spinning reserve capability; and

- Eliminate the environmental blank check and include any environmental costs in the price.

The alternative case would yield 29 billion kWh costing $1.78 billion ($61.60/MWh) but none of those kWh would be dispatchable.

Calpine (Los Esteros and Peakers)

Contract Issues

Calpine has four power contracts. Calpine's ten-year, 2000 MW, combined cycle contract is the most expensive in terms of total dollars expended. Nevertheless, the combined cycle contract doesn't warrant being placed on our list. Among those contracts signed during the height of the power crisis, this combined cycle contract, signed February 26, 2001, has relatively low long-term prices ($59.80/MWh). Further, this contract contains natural gas hedge provisions that protect consumers from spiraling gas prices in the future. However, simply because of the size of the contract, the ten-year take-or-pay provisions should be adjusted to reduce the take-or-pay power by 20-25% and/or concessions in total megawatts should be granted, particularly in the 2004-2005 time frame, to allow CDWR operational flexibility to help reduce the projected power surplus. Calpine also signed a very high-priced contract covering only the summer of 2001 that is not further addressed in this report.

Calpine's 495 MW of peakers (included in the same contract as the 2000 MW of combined cycles) and its third contract for the Los Esteros project in the San Jose area are prime candidates for the 12 worst contracts list.

Calpine (Los Esteros)

Contract Issues

The Los Esteros contract provides power to CDWR for three years before turning the plant over to the investors in US Dataport, a server farm. The plant is located in an expensive area and includes redundancy and other designs to meet US Dataport's future needs, and these high costs were factored into contract prices, so the plant is more expensive than virtually all other combined-cycle based contracts. It was signed late in the process - June 11, 2001.

The contract's strength is that it is dispatchable. Its weakness is that it provides for very high capacity payments ($656/kW over three years). The cost of the plant is high and it is less efficient than many other combined cycle generators. The lack of efficiency means it will use 17% more natural gas to produce the same amount of electricity generated by a more efficient Coral plant [36] because of its location and its configuration. It's configured to meet the needs of the US Dataport server farm. Los Esteros' four turbines for redundancy cause a loss of economies of scale and an undersized combined cycle unit (installed because US Dataport was planning to use heat from the power plant to run its air conditioners) and reduce its efficiency. In short, this plant was designed to meet the needs of US Dataport, not the needs of those who will pay for it for the first three years, the ratepayers. This is the state's most expensive combined-cycle-based contract at $73.50/MWh (assuming $4 gas). A final decision on this contract rests with the California Energy Commission's (CEC) final ruling on whether to grant siting approval. Consumer and environmental groups oppose this project.

Recommended Action

- Conduct an analysis of peaking needs and the best way to meet them.
    - Before purchasing these expensive thermal peakers, CDWR should examine the best ways of meeting peaking needs (a combination of peakers, other resources including pumped storage, demand responsiveness, etc.) in an integrated programmatic fashion, rather than continuing to build new peaker facilities piecemeal without regard to cost or environmental impact. Other less expensive peaking alternatives to the Los Esteros project should be reviewed prior to any final permitting approval.

[36] Calpine Los Esteros has a heat rate of 8500 Btu/kWh that requires the use of 17% more gas than the 7250 Btu/kWh heat rate contained in the Coral contract.

- Reduce capacity commitment and price.

    - Convert the project at the CEC to a 12-month Application for Certification (AFC), which will delay the plant's start date about 8 months. Reduce the contract term by 8 months in lieu of termination for failure to meet start date.

    - Reduce capacity payment by eliminating the first 8 months of capacity payments at $22/kW-month. The remaining two-year and four-month contract has 4 months of $22, 12 months at $20 and 12 months at $18.

Implementation Impacts

These recommendations will save ratepayers about $140 million. The contract term is reduced by 8 months in 2002-03.

Recommended Action

- Conduct an analysis of peaking needs and the best way to meet them.

    - Before purchasing these expensive thermal peakers, CDWR should identify the best ways of meeting peaking needs (a combination of peakers, other resources including pumped storage, demand responsiveness, etc.) in an integrated programmatic fashion, rather than continuing to build new peaker facilities piecemeal without regard to cost or environmental impact. Other less expensive peaking alternatives to the Calpine peakers project should be reviewed prior to any final permitting approval.

- Reduce capacity commitment.

    - Reduce this 20-year contract to 10 years by terminating the contract in 2011.

- Increase flexibility.

    - Change fixed price to a price that is variable with gas for half of the megawatts to make plants more flexibly dispatchable in the event that gas stays below $5/MMBtu.
    - Allow CDWR to bid the plant for non-spinning reserves for small fee.

- Reduce price.
    - Cut capacity payment from $90 million in the early years, and $80 million in the later years to $74.25 million ($150/kW).

Implementation Impacts

The term of the contract is reduced by 8 years, ending in 2011 instead of 2020. This reduces contract capacity payments by $720 million (nominal dollars). See Appendix C for the impacts for the 2002-2011 period.

The contract revisions also increase flexibility in the event that gas prices stay low (by allowing half to be bid at $46/MWh compared to $73) and allow CDWR to bid the plant into the reserve market.

<u>Constellation Energy (Short-Term Contract and High Desert)</u>

Contract Issues

The two Constellation contracts (200 MW short-term from 2001-2003 and the full output of the 750 MW High Desert project starting in 2003) comprise one of the three most important giant take-or-pay CDWR contracts. 12% of all the take-or-pay power is contained in this contract. This is one of the earliest large power contracts signed – March 9, 2001. The short-term provisions of this contract require CDWR to buy a limited amount of very expensive power at $154/MWh through 2003. This short-term price is 70% above the FERC price caps imposed on June 19, 2001.

After 2003, the full output of about 800 MW of the High Desert power project is provided to the state on a take-or-pay basis through 2011. The long-term $58/MW price is less expensive than other long-term power purchased.

Constellation Energy is expected to build a 750 MW combined cycle plant in the Mojave Desert in San Bernardino County in mid-2003. However, like many of the power contracts, this contract has a marketing provision that allows Constellation to simply market power to the state whether it builds the new generation facility or not. Starting in mid-2003, the full 800 MW output of the High Desert power project is provided to the state on a take-or-pay basis through 2011. The long-term $58/MWh price is less expensive than most other long-term power purchased.

Recommended Actions

- Increase flexibility by reducing take-or-pay provisions;[37]
- Reduce quantity of power purchased by reducing the length of the contract by 21 months;[38]
- Add 100 MW of green renewable power;[39] and
- Reduce short-term price by over 50% for 18 months.[40]

Implementation Impacts

Shortening the contract by 21 months and slashing the take-or-pay provisions reduces the cost of this contract by $1.3 billion and reduces energy deliveries by 36%. See Appendix C for Table 11 comparing the original contract and illustrative renegotiation strategy starting in 2002.

<u>Coral Power</u>

Contract Issues

The greatest public-interest strength of Coral's combined cycle contract, signed on May 24, 2001, is that it allows CDWR substantial operational flexibility. [41] In other words, its take-or-pay elements only require CDWR to purchase power at a 49% annual capacity factor, compared to required take-or-pay purchases at about an 80% capacity factor for Sempra and 100% (24 hours per day, 7 days per week) for Calpine. Purchase requirements are reduced by 50% in <u>five</u> spring and fall months (compared to a one-third reduction in only two months in the Sempra contract), giving CDWR flexibility to meet its needs. However, this contract also contains another (Williams contains the other) 350 MW put option that gives Coral a one-time right to choose whether to deliver energy. If Coral decides to provide it, CDWR is obligated to buy it. This provision runs from 2003/04 to 2012. In addition, the contract provides for unbalanced hedges. The

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[37] Allow CDWR to dispatch the contract downward by a total of 22% capacity factor (25% capacity factor on remaining gas-fired power).

[38] Another Alternative would be to reduce the equivalent amount of energy through a phase-down from 2008-2011.

[39] High Desert owners could agree to substitute 100 MW of Green Power (especially considering solar thermal because of its load shape and location) for power generated at High Desert at the fixed price contract and sell 100 MW of High Desert power into the market.

[40] Reduce short-term power price (from 1/1/02 through on-line date of High Desert Project) to $70/MWh to reflect current market conditions.

[41] The operational flexibility is allowed for because it requires DWR to purchase power only at an a annual capacity factor of about 49% starting in 2006.

contract contains very high-cost fixed price power through 2005 only to expose ratepayers to the risk of natural gas price volatility starting in 2006. However, the fixed tolling payments associated with combined cycle power offered after 2006 are considerably cheaper than the power provided by Sempra, Pacificorp, and Mission Sunrise (Edison). Coral's post-2006 combined cycle power is especially cheaper given the more flexible terms and low capacity factor. The average cost of the TOTAL contract is higher than the other contracts because of the very high prices in 2001-2005.

This contract made the list of worst contracts because: 1) it contains a one-sided put option; 2) the need to reduce quantity of purchased power and very high prices through 2005, and 3) it was signed on May 24, after DWR consultants knew they faced a significant power surplus. Additional operational flexibility concessions are not needed in this contract because of its positive annual capacity factor of only 49%.

Recommended Action

- Reduce quantity of power purchased and eliminate the one-sided put option that requires CDWR to buy power only if Coral wants to sell it;[42]

- Add 100 MW of green renewable power;[43] and

- Balance hedges/reduce prices by 13% (concentrated in the early years of the contract).[44]

Implementation Impacts

See Table 12 in Appendix C for a comparison of original and renegotiated contracts from 2002-2011. The contract extends into 2012 and there would be an additional reduction in energy deliveries in that year that is not shown here.

In addition, the contract renegotiation strategy specifically reduces deliveries in the surplus period of July 2003 to June 2005 by 350 MW.

[42] Cancel the "additional quantity" ("put" option) of 175 MW of 6X16 energy from July 1, 2003 through June 30, 2012.

[43] Defer the start date for the second "additional quantity" of 175 MW of 6X16 now deliverable from July 1, 2004 through June 30, 2012 to July 1, 2005, and convert it to 100 MW of 7X24 to new green power at $60/MWh.

[44] During the fixed price period, reduce energy price to $65/MWh from January 1, 2002 to December 31, 2005 to reflect market conditions. The requested energy price reduction is slightly larger for this contract than for other contracts because contract also contains a capacity payment in this period of time.

Dynegy

Contract Issues

The Dynegy contract, signed March 2, 2001, is based on running dirty, old, gas-fired generators. It has several components. A portion of the power is sold at a high cost fixed price of $120/MWh. The remainder is gas-based. It consists of a minimum quantity that must be purchased at about $21/MWh plus the price of gas and a relatively large dispatchable portion, also priced at $21/MWh plus the price of gas. The contract is more expensive than most because of its high fixed cost portion and the relatively large margin above gas costs at a relatively inefficient heat rate. However, a significant portion of its gas-based power is dispatchable (starting in 2002) and it will not be purchased at the high prices (actual gas costs plus $21/MWh) because spot market power will often be cheaper. This fact provides the possibility for a win-win renegotiation. The contract also contains an environmental blank-check provision that requires CDWR to pay for all emissions credits and potentially makes the state liable for the cost of any hardware required to cleanup the plant's dirty emissions.

Recommended Actions

- Reduce "take-or-pay" provisions, or add green renewable power to the fixed price portion of contract;[45]
- Increase flexibility and reduce prices in gas-based portion of contract;[46] [47] [48] [49]

[45] Allow CDWR to reduce must-take output by 25% subject to reasonable technical limits, or alternatively replace 100 MW 7X24 and 100 MW 6X16 with green power.

[46] Convert $20/MWh tolling charge for gas-based energy into a capacity payment of $75/kW-year, plus a lower variable tolling charge of only $5/MWh (including variable O&M and emissions credits but not including startup charges) for energy above the minimum quantity that is actually dispatched. This action, which provides better signals for economic dispatch, could be a win-win for both parties, if it causes the plant to be operated more.

[47] Reduce minimum take to 200 MW around the clock, increasing peak period dispatchable energy by 300 MW. (the 200 MW is plant that must run for technical reasons if more energy is to be taken during the day).

[48] Give CDWR option to schedule energy above the minimum on a ten-minute basis in morning and evening (subject to reasonable technical constraints) for ramping and to bid energy above the minimum into the ISO's BEEP stack, in exchange for an additional fee to reflect use of capacity for ramping and to assure that Dynegy is indifferent to whether BEEP stack energy is used or not. This would be subject to reasonable technical constraints to be negotiated.

[49] For power that is not dispatched by DWR or used for ramp or BEEP, give CDWR an option to call upon that power, up to 25% of the contract quantity above the minimum, in any given hour for use as spinning reserves (if otherwise unscheduled) in exchange for the $5/MWh tolling fee. Allow Dynegy to sell unscheduled energy into the market unless it would prevent DWR from meeting an ancillary services commitment.

- Reduce price on fixed portion of contract to $70/MWh to reflect market conditions; and

- Eliminate environmental blank check and other environmental costs to be paid as part of other contract costs.

Implementation Impacts

Without adding green renewable power to the fixed price portion of contract, the original and renegotiated contracts are compared in Table 13 in Appendix C from 2002-2004.

If renewable power is added to the fixed priced portion of the contract, 1,401 GWh of green power would be provided and maximum GWh would increase to 46,116 GWh. The contract cost would increase to $3,180 million.

Regardless of the green choice option, the renegotiation would increase CDWR's flexibility in using gas-fired energy to self-provide ancillary services.

<u>Pacificorp</u>

Contract Issues

This is the last large contract signed - July 6, 2001. On the positive side, most of this power is dispatchable starting in 2003. However, the capacity price is extremely high (in excess of $200 per kW-year) from 2003-2011. Moreover, energy provided in 2001-2002 is not dispatchable and there is an unbalanced hedge because of its fixed price of $70/MWh. After the fixed $70/MWh price expires in 2002, ratepayers will be vulnerable to the increased price risk of natural gas price volatility, beginning in 2003. The price for combined cycle energy reflects the added costs of delivering the power from the Pacific Northwest and is, therefore, about 10% higher than the price set for energy produced by California-based combined cycle plants. It is significant that the overall contract is also 20% more expensive (assuming $4 gas) than the firmed-up wind power contract Pacificorp has recently signed with Seattle City Light.

Recommended Actions

- Add green power/reduce energy and capacity commitment/reduce prices[50]

[50] From June 2004 to the end of the contract in 2011, provide 400 MW of firmed wind power to replace 200 MW of combined cycle (instead of increasing from 200 to 300 MW, combined cycle capacity decreases from 200 to 100 MW) at $55/MWh from 2004-2011. (The approximate price at which Pacificorp is delivering wind to Seattle City Light is $50/MWh; a $55/MWh price includes escalation to 2004 and extra costs for delivery to California.)

- Balance hedges/reduce prices
    - Price energy and capacity in 2002 on the same basis as in 2003, and thereby giving ratepayers the benefit of expected low gas prices in 2002.
    - Reduce combined cycle capacity capital-related payment by 10% from $180 to $162/kW. This brings the contract closer in line to other cheaper projects such as Sunrise and Coral.

Implementation Impacts

The Pacificorp contract revisions shown above would substitute 400 MW of wind for 200 MW of gas for seven years. Table 14 in Appendix C shows the overall impacts from 2002-2011; capacity figures in the renegotiated case are based on a 1 kW nameplate of wind equaling 0.3 average kW (30% capacity factor).

El Paso Merchant Energy

Contract Issues

During the height of the January to July market power abuses, El Paso Merchant Energy's parent company, El Paso Corporation, was fined by FERC for abuses related to its natural gas pipeline to California.[51] This February 7, 2001 contract is a take-or-pay must-take agreement for 6X16 heavy load hours for five years at the high price of $121/MWh. During peak hours the prices are about $30/MWh above the FERC price caps.

Recommended Actions

There are two ways to address this contract:

1. Reform it:

- Add Green Power
    - Assure that 20 MW of power delivered is green – allow it to remain 6X16.

[51] "California; El Paso Corp. Seeks to Minimize Fine." Los Angeles Times, October 11, 2001

- Increase Flexibility
    - Convert remaining 80 MW converted to 75% capacity factor (72 hour per week) delivery scheduled during the 6X16 period by CDWR starting 1/1/2002.
- Reduce Prices
    - Reduce power price to $75 starting 1/1/2002 to reflect market conditions.

2. Terminate it:

- End contract September 30, 2002 and pay limited amount of compensation for liquidation.

Implementation Impacts

Table 15 in Appendix C shows the effects in 2002-2005 of implementing of all of these changes on the reform path.

<u>Alliance Colton</u>

Contract Issues

This April 23, 2001 contract is a peaking contract that uses highly inefficient and dirty gas. It includes extremely high capacity payments (in excess of $235/kW-year). Unlike all other peaking contracts, it has a number of provisions that limit CDWR's flexibility. The provisions include some very expensive take-or-pay energy. $1350 per run hour per 9 MW unit, equivalent to 15 cents/kWh, must be paid regardless of whether energy is used or not in some years and must be scheduled nearly a year in advance in other years.

Recommended Actions

- Increase flexibility
    - Remove all take-or-pay run-hour requirements, given the contract's substantial capacity payments to Alliance-Colton. These charges currently run for 1000-3000 hours per year at prices as high as $150/MWh ($1350 per run-hour for each of eight units with a nameplate rating of 10 MW and a typical summer rating of 9 MW).
    - Allow CDWR to call upon the plant for up to 2500 hours per year (real power or reserves) with no additional charge.

- Allow CDWR to make a decision to call upon the plant for either real power or reserves on 24 hours notice for reserves and 1 hour for energy, not identifying the maximum number of hours at the beginning of the year and being committed to those hours on a take-or-pay basis.
- Eliminate all issues related to CDWR purchases of gas for this specific plant, since the plant is likely to run only infrequently, and a gas purchase plan designed specifically for this plant limits the flexibility of using this inefficient peaker only occasionally. Allow CDWR the option to deliver gas to this plant from a portfolio of gas acquired for a number of plants.

- Reduce prices

    - Reduce $1350 per unit-hour run charge to $96 (for hours of operation over 1000 per year, which are included in capacity price) to reflect 1.2 cents/kWh of variable O&M (consistent with Wellhead and Calpeak contracts), not 15 cents/kWh, and remove advance notice take-or-pay requirements.
    - Reduce capacity payment by 50% in 2002 and 20% in other years to bring the price in line with other peakers.

Implementation Impacts

Table 16 in Appendix C shows the impacts of the proposed changes to this contract from 2002-2010.

Another significant part of the price reduction is the $34 million reduction of fixed take-or-pay hourly charges.

Moreover, CDWR gains flexibility through the lower O&M dispatch cost (1.2 cents/kWh vs. 15 cents/kWh), the elimination of inflexible take-or-pay payments for hours run, and inflexible gas contracting provisions.

<u>Mirant</u>

Contract Issues

This is a two-year contract at a premium price of $148.65/MWh for 500 MW. Mirant is being sued over the operations of uncontrolled peaking generation at Potrero Hill, San Francisco. The California ISO is refusing to allow Mirant to shutdown to repower its 600 MW at Pittsburg to meet clean air requirements, which have been in place since before Mirant bought the power plants. Mirant is threatening to shut down over 600 MW of generation at Pittsburg if pollution control requirements, scheduled to take effect in 2002, are not waived. Nevertheless, Mirant received a 500 MW contract with CDWR for two years at nearly 15 cents/kWh (total payments over $700 million) from June 2001 through December 2002.

Recommended Actions

- Increase flexibility
  - Allow dispatch for 25% of hours for CDWR flexibility, starting January 1, 2002.
- Reduce prices to $85/MWh, starting January 1, 2002, to reflect market conditions (higher price reflects environmental commitment).
- Commit to making the Potrero plant one of the nation's premiere zero emissions power plants by:
  - Equipping the new Potrero Unit 7 and existing Unit 3 with dry-cooling technology to eliminate the need for 465 million gallons of bay water per day;[52]
  - Using state-of-the art technologies to control NOx, PM-10 and other pollutants (including installing new advanced technologies that provide controls in excess of the currently defined Best Available Control Technology (BACT)) to meet the competing objectives of assuring environmental justice, while providing local generation at an existing site in San Francisco to meet required system reliability needs. The goal should be emissions which are as close to zero as possible; and
  - Agreeing to shutdown and remove the older units to reduce the community's exposure to harmful pollutants.[53]

Implementation Impacts

Table 17 in Appendix C compares the original and renegotiated contracts in 2002.

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[52] The National Marine Fisheries Service is pressing Mirant to use dry-cooling technology to eliminate the negative impacts on bay fisheries or face action under the Section 7 of the federal Endangered Species Act. See: Patrick Rutten, Northern California Supervisor, Protected Resources Division, United States Department of Commerce, National Oceanic and Atmospheric Administration, National Maricne Fisheries Service, Memorandum to LTC Timothy O'Rourke, District Engineer, US Department of the Army, and Gerardo Rios, Acting Supervisor, Permits Office, US Environmental Protection Agency, December 7, 2001.

[53] It is imperative that the nearby old, polluting PG&E plant at Hunters Point be shutdown and dismantled. This facility exposes the low income communities of Hunters Point, Bayview and Potrero Hill to unconscionable levels of air pollution.

Morgan Stanley

Contract Issues

Morgan Stanley's contract is for 50 MW 7X24 for five years at $95.50/MWh. It is above current FERC price caps. Morgan Stanley is also a key participant (co-manager) in CDWR's $12 billion bond issue.

Recommended Actions

There are two potential paths for the contract – to reform it or unwind it:

1. Reform It:

- Add green renewable power or increase flexibility
  - Allow CDWR to curtail the power in 25% of the hours of the year. The curtailment provision will be waived if Morgan Stanley replaces at least half of the power with green power, at the time when such green power is made available.
- Reduce prices
  - Reduce power price to $70, starting January 1, 2002, to reflect market conditions

2. Terminate It: Terminate the contract September 30, 2002 and pay limited amount of compensation for liquidation

Implementation Impacts

Table 18 in Appendix C shows results for the last four years of the contract (2002-2005), if green power is not substituted and the contract is reformed.

Appendix C: Index of Tables

Table 1: CDWR Losses from Selling Off Power Purchased Under Long-Term Contracts, 2002-2010

	Long-term contract purchases (GWh)	cost $/MWh	power sold off (GWh)	revenue from sale $/MWh	average cost of power sold off ($'000)	payment received for power sold off ($'000)	loss on power sold off ($'000)
2002							
1Q	5,466	121.4	1,370	18.6	166,386	25,415	140,971
2Q	4,391	155.0	2,503	15.8	387,914	39,657	348,257
3Q	7,660	125.2	2,391	19.3	299,354	46,258	253,096
4Q	7,239	116.7	1,520	17.5	177,317	26,622	150,695
2002 Total	24,756	127.2	7,784	17.7	1,030,970	137,952	893,018
2003	46,959	83.2	11,246	15.8	935,790	177,201	758,589
2004	63,290	72.4	15,851	14.9	1,147,582	236,487	911,095
2005	61,042	67.7	12,068	14.8	816,930	179,130	637,800
2006	62,574	65.5	11,330	15.0	742,087	169,874	572,213
2007	62,629	65.4	10,047	15.3	657,442	153,643	503,799
2008	62,397	65.4	5,983	16.4	391,098	98,273	292,825
2009	62,740	65.6	4,556	17.5	298,930	79,935	218,995
2010	62,452	65.9	3,235	18.1	213,326	58,578	154,748
TOTAL	508,839	71.3	82,100	1,151.5	6,234,156	1,291,073	4,943,083

Table 2: Annual Percentage of Surplus Power Sales

	DWR power sales	Long-term contract purchases	% of contracts sold on spot market
2002	7,784	24,756	31%
2003	11,246	46,959	24%
2004	15,851	63,290	25%
2005	12,068	61,042	20%
2006	11,330	62,574	18%
2007	10,047	62,629	16%
2008	5,983	62,397	10%
2009	4,556	62,740	7%
2010	3,235	62,452	5%

Table 3

	Cost ($MM)		Maximum GWh		Take-or-Pay gas GWh	
Sempra *	$7,039	17%	116,233	18%	116,233	25%
Constellation *	$3,370	8%	57,114	9%	57,114	12%
Williams *	$3,357	8%	49,201	8%	49,201	10%
Calpine Combined Cycle	$7,959	19%	133,113	21%	133,113	28%
Allegheny	$3,863	9%	63,151	10%	63,151	13%
Subtotal	$25,588	61%	418,811	66%	418,811	89%
Others on "12 Worst List"	$11,356	27%	132,306	21%	52,066	11%
All Others	$5,307	13%	83,402	13%	0	0%
TOTAL	$42,251		634,520		470,878	

** identified for renegotiation*

Table 4: Increased Renewables, Reductions in "Take-or-Pay," Quantity, & Cost 2002-2011

	Total all contracts	12 contracts as written	After recommended changes	*% difference*	Other contracts
MW (average over 10 yrs)	9,859	5,780	4,559	*-21.1%*	4,079
MWh	634,520	354,854	265,505	*-25.2%*	279,666
Green MWh	5,238	0	35,144		5,238
Dispatchable MWh	158,404	79,333	102,755	*29.5%*	79,071
Non-dispatchable gas	470,878	275,521	127,606	*-53.7%*	195,356
Non-dispatchable gas %	74.2%	77.6%	48.1%		69.9%
Cost ($ million, before dispatch)	$ 42,251	$ 24,732	$ 16,907	*-31.6%*	$17,518
Price ($/MWh)	66.59	69.70	63.68	*-8.6%*	62.64

Table 5: Contract Renegotiation Strategy (Annual MW and MWh)

	12 contracts as written					After recommended changes				
	summer MW	Total GWh	dispatchable	new green	non-dispatchable gas	summer MW	Total GWh	dispatchable	new green	non-dispatchable gas
2002	4,987	27,975	11,306	-	16,669	4,807	25,578	15,701	100	9,776
2003	6,846	38,408	14,347	-	24,062	6,332	32,740	18,136	595	14,010
2004	7,862	51,573	15,231	-	36,342	6,515	41,432	19,079	1,446	20,907
2005	5,805	34,951	5,755	-	29,195	4,530	26,322	7,680	3,959	14,684
2006	5,755	35,107	5,712	-	29,395	4,425	25,662	7,729	5,361	12,572
2007	5,755	35,107	5,712	-	29,395	4,425	25,662	7,729	5,361	12,572
2008	5,755	36,369	5,712	-	30,657	4,425	25,662	7,729	5,361	12,572
2009	5,755	36,369	5,712	-	30,657	4,425	25,662	7,729	5,361	12,572
2010	5,530	33,977	5,712	-	28,265	3,462	19,532	7,729	4,440	7,363
2011	3,756	25,017	4,132	-	20,885	2,249	13,430	3,319	3,161	6,950

Table 6: Annual Impact of Price Reduction Renegotiation Strategy

	12 contracts as written			After recommended changes		
	Total Gwh	Total cost ($ millions)	price ($/MWh)	Total GWh	Total cost ($ millions)	price ($/MWh)
2002	27,975	$ 2,701	96.57	25,578	$ 1,728	67.57
2003	38,408	$ 3,080	80.19	32,740	$ 2,123	64.83
2004	50,070	$ 3,584	71.58	40,229	$ 2,545	63.25
2005	34,951	$ 2,394	68.49	26,322	$ 1,662	63.15
2006	35,107	$ 2,267	64.57	25,662	$ 1,580	61.57
2007	35,107	$ 2,262	64.42	25,662	$ 1,580	61.59
2008	36,369	$ 2,339	64.30	25,662	$ 1,581	61.60
2009	36,369	$ 2,339	64.32	25,662	$ 1,581	61.61
2010	33,977	$ 2,187	64.35	19,532	$ 1,228	62.86
2011	25,017	$ 1,580	63.17	13,430	$ 841	62.61

Table 6 shows the annual changes in energy deliveries and costs parameters. Cost reductions are spread throughout the contract term. There are significant price reductions in the fixed price portion of contracts in early years. In the later years, there are larger quantity reductions and smaller price reductions.

Table 7: Sempra Energy - Impacts of the Recommendations for the <u>2002-2011 Period</u>

<u>Sempra 2002-2011</u>	Original	Renegotiated	% Difference
MW (average 10 year)	1,700	1280	-25%
MW (maximum)	1,900	1400	-26%
Maximum GWh purchased	116,233	71,844	-38%
New green GWh	0	14,986	
Dispatchable GWh	0	0	
Non-dispatchable gas GWh	116,233	56,858	-51%
$ millions before dispatch	$ 7,039	$ 4,107	-42%
$/MWh	60.6	57.2	-6%

Table 8: Sempra Energy - Impacts of the Recommendations for the <u>2002-2011 Period</u>

Williams	Original	Renegotiated	% difference
MW (average 10 year)	1,090	690	-37%
MW (maximum)	1,400	900	-36%
Maximum GWh purchased	49,201	34,965	-29%
New green GWh	0	5,424	
Dispatchable GWh	0	29,540	
Non-dispatchable gas GWh	49,201	0	-100%
$ millions before dispatch	$ 3,357	$ 2,168	-35%
$/MWh	68.2	62.0	-9%

Table 9: Calpine's Los Esteros - Impacts of the Recommendations for the <u>2002-2011 Period</u>

Calpine Los Esteros	Original	Renegotiated	Difference
MW (average 10 year)	62	45.50	-27%
MW (maximum)	220	220	0%
Maximum GWh purchased	4,353	3,573	-18%
New Green GWh	0	0	
Dispatchable GWh	4,353	3,573	-18%
Non-dispatchable gas GWh	0	0	
$ millions before dispatch	$ 320	$ 245	-23%
$ millions capacity payment	$ 149	$ 104	-30%
$/MWh	73.5	68.7	-7%

Table 10: Calpine Peakers - Impacts of the Recommendations for the 2002-2011 Period

Calpine Peakers	Original	Renegotiated	Difference
MW (average 10 year)	493	493	0%
MW (maximum)	495	495	0%
Maximum GWh purchased	23,190	23,190	0%
New green GWh	0	0	
Dispatchable GWh	23,190	23,190	0%
Non-dispatchable gas GWh	0	0	
$ millions before dispatch	$ 2,520	$2,140	-15%
$ millions capacity	$ 827	$ 739	-11%
$/MWh	108.7	92.3	-15%

Table 11: Constellation High Desert – Comparison of Original Contract and Renegotiation Strategy Starting in 2002

Constellation-High Desert	Original	Renegotiated	Difference
MW (average 10 year)	704	556	-21%
MW (maximum)	800	800	0%
Maximum GWh purchased	55,611	35,625	-36%
New green GWh	0	5,694	
Dispatchable GWh	0	0	
Non-dispatchable gas GWh	55,611	29,931	-46%
$ millions before dispatch	$ 3,370	$ 2,069	-39%
$/MWh	60.6	58.1	-4%

Table 12: Coral Energy – Comparison of Original Contract and Renegotiation Strategy Starting in 2002

Coral Energy	Original	Renegotiated	Difference
MW (average 10 year)	767	495	-35%
MW (maximum)	850	600	-29%
Maximum GWh purchased	29,477	24,287	-18%
New green GWh	0	5,784	
Dispatchable GWh	4,021	4,021	0%
Non-dispatchable gas GWh	25,457	14,482	-43%
$ millions before dispatch	$ 2,045	$ 1,462	-29%
$/MWh	69.4	60.2	-13%

Table 13: Dynegy – Comparison of Original and Renegotiated Contracts from 2002-2004

Dynegy

	Original	Renegotiated	Difference
MW (average 10 year)	630	630	0%
MW (maximum)	2,100	2100	0%
Maximum GWh purchased	46,116	43,481	-6%
New green GWh	0	0	
Dispatchable GWh	26,088	30,832	18%
Non-dispatchable gas GWh	20,028	12,649	-37%
$ millions before dispatch	$ 3,680	$ 2,717	-26%
$/MWh	79.8	62.5	-22%

Table 14: PacifiCorp – Comparison of Original and Renegotiated Contracts from 2002-2011

Pacificorp

	Original	Renegotiated	Difference
MW (average 10 year)	254	195	-23%
MW (maximum)	300	220	-27%
Maximum GWh purchased	21,048	16,836	-20%
New green GWh	0	7,377	
Dispatchable GWh	19,737	9,459	-52%
Non-dispatchable gas GWh	1,311	0	-100%
$ millions before dispatch	$ 1,268	$ 966	-24%
$/MWh	60.3	57.4	-5%

Table 15: El Paso Merchant Energy – Comparison of Original and Renegotiated "Reform Path" Contracts from 2002-2011

El Paso Merchant Energy

	Original	Renegotiated	Difference
MW (average 10 year)	40	40	0%
MW (maximum)	100	100	0%
Maximum GWh purchased	2,008	1,606	-20%
New green GWh	0	400	
Dispatchable GWh	0	0	
Non-dispatchable gas GWh	2,008	1,206	-40%
$ millions before dispatch	$ 243	$ 120	-50%
$/MWh	121.0	75.0	-38%

Table 16: Alliance Colton – Comparison of Original and Renegotiated Contracts from 2002-2010

Alliance Colton

	Original	Renegotiated	Difference
MW (average 10 year)	65	65	0%
MW (maximum)	72	72	0%
Maximum GWh purchased	1,944	1,944	0%
New green GWh	0	0	
Dispatchable GWh[54]	1,944	1,944	
Non-dispatchable gas GWh	0	0	
$ millions before dispatch	$ 359	$ 228	-36%
$ millions capacity	$ 176	$ 117	-33%
$/MWh	184.6	117.5	-36%

Table 17: Mirant – Comparison of Original and Renegotiated Contracts in 2002

Mirant

	Original	Renegotiated	Difference
MW (average 10 year)	50	50	0%
MW (maximum)	500	500	0%
Maximum GWh purchased	2,510	1,882	-25%
New green GWh	-	-	
Dispatchable GWh	-	-	
Non-dispatchable gas GWh	2,510	1,882	-25%
$ millions before dispatch	$ 373	$ 160	-57%
$/MWh	148.7	85.0	-43%

[54] On Alliance Colton contract the gas is dispatchable, but there are take-or-pay provisions for fixed payments per hour of operation in the years 2003-04 and requirements that CDWR specify in advance and convert those specified obligations to take-or-pay fixed payments if it wants to use the plant at all from 2005-2011.

Table 18: Morgan Stanley – Comparison of Original and Renegotiated Contracts in 2002-2005

Morgan Stanley	Original	Renegotiated	Difference
MW (average 10 year)	20	20	0%
MW (maximum)	50	50	0%
Maximum GWh purchased	1,661	1,246	-25%
New green GWh	-	-	
Dispatchable GWh			
Non-dispatchable gas GWh	1,661	1,246	-25%
$ millions before dispatch	$ 159	$ 87	-45%
$/MWh	95.5	70.0	-27%

Appendix D: Memorandum from Thomas M. Hannigan, Director, Department of Water Resources, to S. David Freeman, Consumer Power and Conservation Financing Authority, dated October 4, 2001

State of California

The Resources Agency

Memorandum

Date : October 4, 2001

To : S. David Freeman
Consumer Power and
Conservation Financing Authority
901 P Street, Suite 142A
Sacramento, California 95814

From : Department of Water Resources

Subject : Coordination Policy between California Energy Resources Scheduling and Consumer Power and Conservation Financing Authority

California Energy Resources Scheduling has had several discussions and exchanged letters with your management in an effort to consider ways in which our two organizations can collaborate and work together to meet California's electricity needs. We share common objectives of resource diversity, reliability, price stability, and cost minimization for the State. CERS believes it is important to start with a common viewpoint of need, contracts and policy issues. The purpose of this memorandum is to provide you with our perspective and invite a constructive dialog on working together.

As you know, CERS has assembled a portfolio of long-term contracts that at their maximum provide in excess of 12,000 MW of capacity. Much of the net short need will be met from this portfolio, and during non-peak conditions, we expect to have surplus power that could be used for seasonal exchanges and power sales. This portfolio includes approximately 3,000 MW of dispatchable resources of which 1,500 MW are peakers. Over 8,000 MW are in SP15 with the balance of over 4,000 MW in NP15. The amount of power under long-term contracts to CERS will increase from about 5,000 MW today to over 12,000 MW in 2004, or an increase of 7,000 MW. The contract portfolio increases by approximately 3,000 MW in 2002, 3,000 MW in 2003, and over 1,000 MW in 2004.

Demand not covered by CERS contracts and utility retained generation is currently being met with spot market purchases at favorable prices. A major continuing challenge for CERS is to diversify its resource mix with renewables and to obtain capacity that provides full dispatch control and ancillary services, including ramping, regulation, and spinning reserves. In contracting for additional supplies, we are concerned that while peakers provide for nonspinning reserves, they do not directly provide many of the ancillary services that are needed for daily operations and cost minimization.

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We are also very concerned about uncertainties surrounding the net short needs. Given the effectiveness of conservation and demand management programs, the expected loss of load due to direct access, and the slowing of the economy, CERS net short needs may be substantially lower than current estimates. Consequently, additional supplies must be compatible with CERS portfolio needs and consistent with the current outlook for net short need, resource availability, market conditions, and local area reliability.

The factors I mention above which contribute to lower demand, combined with new generation coming on-line in California by next summer—some as result of CERS contracts—and in other western states that have also implemented demand reduction measures, are contributing to an overall trend of growing available capacity in the spot market and increasing reserve margins throughout the west. At this time CERS is concerned that contracting for substantial additional supplies may lead to unnecessary costs for Californians. The Letters of Intent already approved by the Power Authority could far exceed CERS' ability to absorb that power given the outlook for net short need, as well as the revenue requirement forecasts made in support of California Public Utilities Commission filings and bond sales. CERS is also concerned that the generation under the Letters of Intent may be incompatible with the systems operational needs, and ability to integrate resources in real-time.

CERS recommends that the California Power Authority enter into final contracts only after a determination is made that the proposed contracts:

- Fit within CERS net short need assessment.
- Are priced such that costs are within the parameters of CERS revenue forecasts.
- Are consistent with current outlook for market prices.
- Fit within the parameters of operational needs for dispatch, load following, reserves, ancillary service requirements, and local area reliability requirements.
- Can be integrated in real-time dispatch.

We are available to assist you in making these determinations, evaluating contracts for due diligence and other functions if needed. While we ourselves are resource and budget constrained, we are open to exploring interagency

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agreements or other means to share workload, resources and costs. CERS feels it is most appropriate to have a representative from the Power Authority participate in our weekly contract committee meetings, where the CERS needs analysis and revenue requirements are periodically reviewed and updated.

Our assessment to date indicates that CERS has a very limited need for new resources. Up to 1,000 MW of intermittent renewables could be added to provide resource diversity. Resources that provide capacity insurance, dispatchability and ancillary services could also be considered on a very selective basis. In general, new supplies should be located in NP15 given that CERS already has excess resources in SP15. There may be locations in the SP15 zone where certain types of new resources could significantly improve system reliability. Such resources should not be excluded from consideration. Also, any new supplies should be in operation in time to meet summer 2002 peak needs. The value of supplies coming on-line after summer 2002 is substantially lower given CERS existing portfolio of contracts. Spot market prices for standard products are estimated to range between $35/MWh to $55/MWh in 2002 and beyond and could serve as a guideline for contracting. CERS has efforts underway to get an updated assessment of need, resource availability, ancillary service costs, gas price and spot market outlook, and load and resource balance. We intend to continue to share our analysis with your staff and provide updated guidance on what could be integrated with the CERS portfolio. Once the Department has ascertained its portfolio needs in terms of products and pricing as described above, it can then determine if a purchase arrangement can be structured with the Authority in a manner that is consistent with the Department's overall power supply financing plan, without exposing the Department to inappropriate risks.

CERS looks forward to working with the Power Authority collaboratively to serve Californian's interest for reliability, resource diversity, environmental protection and reasonably priced electricity.

Thomas M. Hannigan
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cc: See attached list.

Attachment

10/08/2001 TUE 15:38 [TX/RX NO 5303] 004

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