Memorandum

To: Michael Pace, Chairman of the Board

From: John D. Clark, Operations Division Head

Date: December 23, 2002

Re: Summary – Review of Power Marketing Alternatives

This memorandum provides a summary of CRRA's consideration of electrical power marketing options for the Mid-Connecticut Project.

Review of Power Marketing Options

In performing this review, CRRA engaged the services of PLM, a consulting firm that has specialized expertise in power marketing and marketplace operations. CRRA's engineering and operations staff supported PLM in this effort. A memorandum prepared by PLM is attached as Exhibit 1, which summarizes the results of their work.

CRRA has performed a formal analysis of three primary options for the sale of power from the Mid-Connecticut Project, as follows:

- Option 1 – Sell All Power to CL&P At the "Buy-Down" Contract Price
- Option 2 –Wholesale Market One-Half the Output, and Sell One-Half To CL&P at the "Buy-Down" Contract Price
- Option 3 –Market One-Half the Output to a Designated Load of State Facilities and Sell One-Half To CL&P at the "Buy-Down" Contract Price

In addition, staff has also reviewed two additional options. These additional options were not incorporated into the financial model that was developed for the purpose of considering the three primary options, described above. These two additional options are summarized as:

- Option 4 –Negotiate a new arrangement with CL&P for 100 percent of the output from the Mid-Connecticut Project. This option has been discussed with CL&P, and viewed by CRRA as a means of providing benefits to both CL&P and CRRA. A copy of CRRA's proposed Memorandum of Understanding (MOU) that would be used as the basis for further negotiations is attached as Exhibit 2. This MOU has been reviewed by CL&P and a conference call between CL&P and CRRA was held on December 18, 2002. During that conference call, CL&P raised a concern that the MOU reduced certain CL&P benefits and would not likely be acceptable to DPUC.

- Option 5 – CRRA becomes a member of the New England Power Pool (NEPOOL), and sells power directly into the electric grid. Selling power directly to the NEPOOL means that the Mid-Connecticut Project would be paid the actual marketplace "clearing price", which is set by NEPOOL from time-to-time. The clearing price constantly changes throughout each day, and is a function of many factors, including but not limited to load, availability of other units, and similar factors. While this option does not provide price certainty, it may warrant further investigation as an interim strategy for use while the Project undertakes the process of evaluating, selecting, and implementing a permanent solution. Recent pricing suggests this fifth option could yield more total revenue than CL&P would pay under the "buy-down" contract schedule. However, there is no assurance that average price would yield increased revenues in the future.

Further information on each of the three primary options identified above, and the results of the analysis is presented in the sections below. An overall summary and suggestions for future action are presented at the end of this memorandum. A copy of a Memo presented to the Board of Directors at the July Board Meeting is attached as Exhibit 3. The July Memo provides background associated with this effort.

Option 1 – Sell All Power To CL&P At the "Buy-Down" Contract Price

This option would involve selling all of net electrical energy output of the Mid-Connecticut Project each year to CL&P at the stipulated contract pricing. This option is the simplest to evaluate in that the rates that would apply each year are established in the agreement, and the transaction involves relying upon a single buyer.

Option 2 –Wholesale Market One-Half the Output, and Sell One-Half To CL&P at the "Buy-Down" Contract Price

This option involves selling the first 250,000 MWh of net electrical output from the Mid-Connecticut Project each year to an electric supplier, who will use the energy in its portfolio. The balance would be sold to CL&P at the pricing stipulated in the existing contract.

This option was somewhat more complex than Option 1, because it involved marketing the electrical power to another electric supplier. The best information available, including the information presented in the July 19, 2002 memo has been used in estimating the revenues the Project is expected to receive under this option.

Option 3 –Market One-Half the Output to a Designated Load of State Facilities and Sell One-Half To CL&P at the "Buy-Down" Contract Price

This option is highly complex, and has been approached by considering a number of technical and business factors, including:

- For almost all of the time, the Mid-Connecticut Project will produce either too little power to perfectly match the load of the selected facilities (such as a summer daytime load), or too much power (such as an early weekend morning). When it produces too little, the Project would need to buy power from another source to serve the load. When the Project has too much power to serve the load, it will need to sell the surplus into the wholesale marketplace.
- The Mid-Connecticut Project is not available 100% of the time, and there will be occasions when system maintenance or outages will affect some or even all of the output, requiring the purchase of replacement power in the market, occasionally on an emergency, unplanned basis.
- Those times when the output of Mid-Connecticut will least be able to serve the load (a summer afternoon, for example) will coincide with the times when the cost of replacement power in the market will be the highest, and has been as much as $1.00 per KWh in the NEPOOL.
- Those times when Mid-Connecticut will have the most power to sell into the wholesale market (such as early in the morning on a September weekend), pricing in the wholesale market will be the lowest.

In order to evaluate these factors, with the assistance of PLM, it was necessary to first develop a business model for the various power purchasing and marketing transactions that would be associated with the option. Additionally, preliminary estimates were prepared of the administrative and operational costs that would be incurred to operate this new business. Finally, in combination with forecasts of the wholesale power market, a cash-flow model of the overall business was prepared that considered a wide range of factors, including:

1. Estimated amounts of power to be purchased by the state and pricing;
2. Estimated amounts of power to be purchased by the new business to meet the projected loads, and to address planned and unplanned outages at the Project;
3. Estimated costs associated with the replacement power;
4. The cost of purchasing financial instruments ("hedges") that would protect the Project from market pricing fluctuations;

5. Administrative costs;
6. Capacity payments;
7. Transmission charges; and,
8. Metering costs.

It should be noted that the financial instruments associated with protecting the Project from market conditions in serving the load are both sophisticated in their structure, and costly. However, in light of the potential for the Project to suffer substantial losses in the absence of such mechanisms, they are an important component of the business model, and have been included in the business model. These, and similar financial instruments are typically used by companies that serve a customer base to protect themselves from significant losses.

As is somewhat the case under Option 2, Option 3 presents even greater risk as compared to Option 1. Consequently, for Option 3 to be sufficiently appealing to be recommended for consideration, it must provide superior expectations of net Project revenue that exceed both the expected net revenue of Options 1 and 2.

Summary And Suggestions For Future Action

Although the concept of selling power to the State has a measure of initial appeal, the analysis performed by our consultant indicates that option is the least attractive, given current retail pricing in Connecticut, and the other aspects of the business that may pose additional risk. However, the analysis does indicate that CRRA may be able to "wholesale" one-half the output of the Mid-Connecticut Project to a supplier at greater prices than provided for in the existing CL&P agreement.

Following is the summary analysis performed by PLM:

Base Case Results – Current Market Conditions for Wholesale Offers and Retail Pricing First 250,000 MWhrs only					
		Projected Calendar 2003 Net Income	Rank	Variance from Option 2	Pricing ($/MWhr)
Option 1	100% of Output to CL&P	$14,594,784	3	-8.1%	32.0
Option 2	Wholesale first 250,000 MWhr	$15,879,319	1	-	34.8
Option 3	Retail Service of State Load	$14,970,413	2	-5.7%	45.9

The model developed by PLM is adaptable to numerous variations of the options. If it is determined that CRRA is able to wholesale or retail the entire output of the facility (as compared to only the first 250,000 MWhrs of output) the model can be modified and rerun with these parameters.

Based upon the above, and the current pricing in the market, and, assuming the Authority's goal is to maximize revenues without taking undue risk, I believe that the best course of action is to simultaneously pursue the following courses of action:

- Gain approval to market power to the Power Pool (Option 5),
- Negotiate with CL&P (Option 4), and
- Continue to negotiate with energy suppliers interested in the wholesale purchase of the output (Option 2).

Depending upon the outcome of the CL&P discussions, CRRA could then either move forward with CL&P, begin selling to the Pool at the marketplace clearing pricing, or sell the output on the wholesale market.

Exhibit 1
PLM Report

PLM

ELECTRIC POWER ENGINEERING

35 MAIN STREET, HOPKINTON, MA 01748 - TEL: (508) 435-0200 - FAX: (508) 435-6163

- PRIVILEGED AND CONFIDENTIAL –

To: John Clark (CRRA)

CC: Ann Stravalle-Schmidt (CRRA)
Peter Boucher (H&S)

From: Mark J. Cordeiro

Date: December 6, 2002

Subject: Evaluation of Use of CRRA's Mid-Connecticut Project For Retail Supply

INTRODUCTION

As requested, we have analyzed the feasibility of the Connecticut Resources Recovery Authority ("CRRA") utilizing part of the electric output from its Mid-Connecticut Project as part of a retail access program. Specifically, the first 250,000 MWh of energy produced from Mid-Connecticut, also known as South Meadows 5 & 6. This energy, plus additional energy and other required electric commodities assumed to be purchased in the wholesale electric market were the basis for the supply-side of the analysis. Specified state load currently served by Connecticut Light & Power ("CL&P") and identified by the Office of Policy and Management ("OPM") served as the demand-side of the analysis.

There are three basic options available to CRRA for the sale of part or all of South Meadows 5 & 6 discussed in this report. They include:

1. Sale of 100% of the output directly to CL&P at specified contract rates. For 2003, the rate will be $32/MWh, rising to $33/MWh in 2004.
2. Selling the first 250,000 MWh of energy produced each contract year commencing July 1st into the wholesale market(s). For this option, CRRA could either sell directly to a wholesaler via a bilateral contract or into the wholesale spot market(s) administered by the Independent System Operator of New England (ISO NE).[1] This report specifically considers recent bilateral offers for South Meadows 5 & 6.
3. The third option the CRRA is considering is the use of the first 250,000 MWh as part of a retail supply portfolio to serve specified state loads. The principal purpose of this report was to assess the feasibility of this third option.

[1] Currently, the ISO NE administered energy market includes a single energy-clearing price for each hour of the day. However, as part of a proposed Standard Market Design scheduled for implementation in Spring 2003, there will be a multi-settlement system including separate Day Ahead and Real Time prices for energy and certain other electric commodities.

CONCLUSION

Based on current conditions in the wholesale electricity market (emphasis added), we recommend CRRA pursue Option 2 identified above and pursue a wholesale transaction for the sale of the first 250,000 MWh from South Meadows 5 & 6 formerly sold to Enron, rather than pursue the use of this same resource as a supply component for the retail supply of specified state load. Our results from base case assumptions are summarized in Table 1 below.

As discussed in our introduction, the CL&P contract is scheduled to pay $32/MWh in calendar 2003. That translates into $14.6 million annually (option 1). When recent offers for the first 250,000 MWh of energy produced each contract year commencing July 1st are coupled with the $32/MWh from CL&P for the balance of the output (option 2), we estimate CRRA would earn $15.88 million in calendar 2003, an average of $34.8/MWh. However, when we evaluated the use of the first 250,000 MWh as part of a supply portfolio to supply specified state loads at retail (option 3) we estimated the net income in the test year 2003 to be only $14.97 million, a 5.7% loss compared to option 2. This base case analysis of option 3 assumed current Standard Offer pricing for the specified state loads, which we calculate to average $45.9/MWh, or 4.59 cents per kWh.

Table 1

Base Case Results - Current Market Conditions for Wholesale Offers & Retail Pricing

		Projected Calendar 2003 Net Income	Rank	Delta (%) vs. Option 2	Applicable Pricing ($/MWh)
Option 1:	100% of Output to CL&P	$ 14,594,784	3	-8.1%	32.0
Option 2:	First 250,000 MWh Wholesale	15,879,319	1	0.0%	34.8
Option 3:	Retail Service of State Load	14,970,413	2	-5.7%	45.9

This conclusion is not static. Rather, it is subject to change with price variations in the wholesale and retail electric markets. We tested the effects of such market fluctuations for two scenarios:

Scenario 1 focused on what retail pricing level CRRA would need to charge in order to achieve specific income targets;

Scenario 2 focused on how much the wholesale market would need to fall from current levels in order to make retail (option 3) more lucrative, based on current retail pricing assumptions.

SCENARIO 1 – Current Wholesale Prices Coupled with Increasing Retail Prices

We tested what level of retail price increases would be necessary for the retail access plan (Option 3) to produce net income at least 10% greater than Option 2 (a wholesale bilateral for the initial 250,000 MWh of energy produced each contract year). Table 2a below summarizes our results.

Table 2a

Scenario 1 Results - Current Wholesale Offers & Targeted Retail Pricing Resulting in Retail Net Income 10% Greater Than Wholesale					
		Projected Calendar 2003 Net Income	Rank	Delta (%) vs. Option 2	Applicable Pricing ($/MWh)
Option 1:	100% of Output to CL&P	$ 14,594,784	3	-8.1%	32.0
Option 2:	First 250,000 MWh Wholesale	15,879,319	2	0.0%	34.8
Option 3:	Retail Service of State Load	17,547,008	1	10.5%	50.9

As we can see from Table 2a, CRRA would need to charge $50.9/MWh, or almost 5.1 cents per kWh in order to achieve net income at least 10% greater than the wholesale transaction (option2).

Table 2b below summarizes the results if CRRA wanted net income via retail (option 3) to be 20% greater than wholesale (option 2). As shown in Table 2b, CRRA would need to charge approximately 5.4 cents per kWh in order to achieve the target net income.

Table 2b

Scenario 1 Results - Current Wholesale Offers & Targeted Retail Pricing Resulting in Retail Net Income 20% Greater Than Wholesale					
		Projected Calendar 2003 Net Income	Rank	Delta (%) vs. Option 2	Applicable Pricing ($/MWh)
Option 1:	100% of Output to CL&P	$ 14,594,784	3	-8.1%	32.0
Option 2:	First 250,000 MWh Wholesale	15,879,319	2	0.0%	34.8
Option 3:	Retail Service of State Load	19,186,659	1	20.8%	54.1

We recommend CRRA focus on targeting net income from retail (option 3) to be measurably greater than a wholesale bilateral (option 2) in order to justify the higher risks associated with retail supply.

Risks associated with retail supply but not necessarily applicable to wholesale transactions include:

A. Greater exposure to dramatic price fluctuations in the wholesale market during periods when CRRA would either be:

a. Selling surplus energy (e.g. off-peak hours) when prices can actually be negative and therefore a seller must pay to inject energy into the system, or;

b. Buying energy during on-peak hours with extremely high Real Time prices when the output of South Meadows 5 & 6 is either less than retail demand or South Meadows 5 & 6 in contractually obligated to CL&P (e.g. January through June).

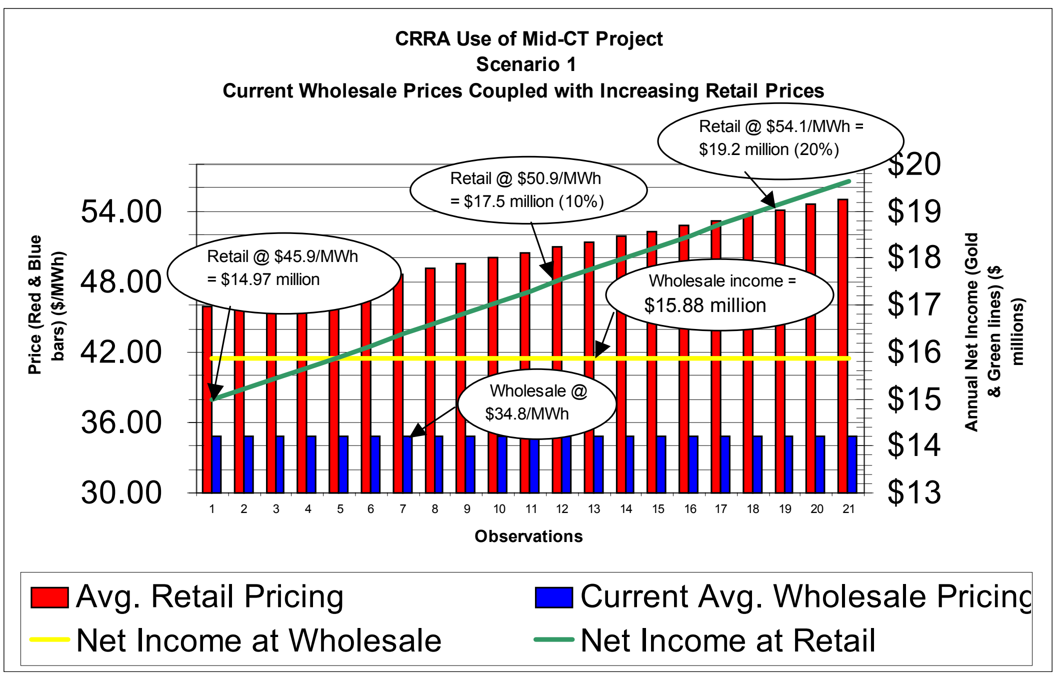
B. There will be periods when the actual spot price of electricity is significantly different from that assumed in this analysis. Therefore, sufficient capital reserves are required to address those times.

C. Hourly load forecasting error, exposing CRRA to spot market purchases in magnitudes different than those planned for and thus the financial implications;

D. Loss of the South Meadows 5 & 6 facility during periods of high demands and corresponding high spot market prices; and,

E. Higher than anticipated congestion exposure under the Standard Market Design scheduled for implementation by the Independent System Operator of New England (ISO NE) in the spring of 2003.

The graph below summarizes the results of our sensitivity analysis for scenario 1. The red bars reflect increases in retail pricing of 1% from the previous observation. Wholesale

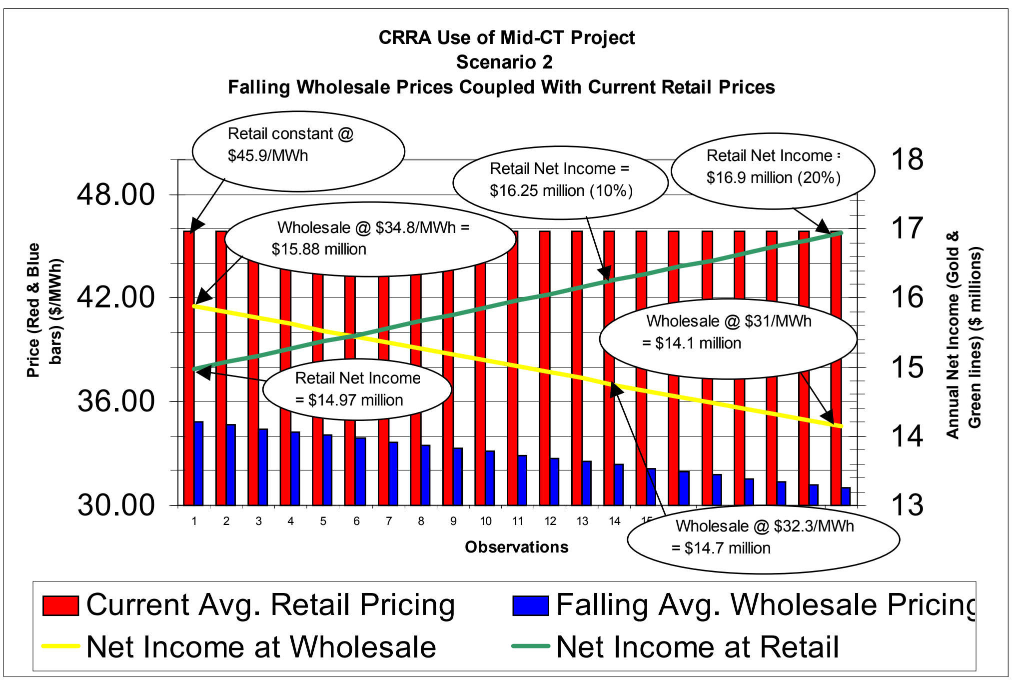


conditions are held constant in scenario 1 as displayed by the blue bars. Net income via retail (option 3) is displayed by the green line while net income via a wholesale bilateral (option 2) is displayed by the gold line.

SCENARIO 2 – Falling Wholesale Prices Coupled With Current Retail Prices

The next scenario for consideration reflects falling prices in the wholesale electric market. The effect of such decreases in wholesale prices is two-fold. First, it reduces the value of the Mid-Connecticut project through a wholesale bilateral sale to a third party. Secondly, it would reduce the cost of additional supplies to CRRA during periods when South Meadows 5 & 6 is contractually obligated to CL&P. Specifically, all energy production beyond the initial 250,000 MWh per contract year formerly sold to Enron.

The results of scenario 2 are graphically displayed below. We can see the impact of falling wholesale prices on CRRA's projected net income via a retail supply scenario. As discussed earlier, recent offers for the first 250,000 MWh from South Meadows 5 & 6, coupled with revenues from CL&P for the balance of energy and all other commodities averages $34.8/MWh for the 12 month period January through December, 2003 (blue bar, observation point 1 of Scenario 2 graph below). This would result in net income to CRRA of approximately $15.88 million (gold line, observation point 1 of Scenario 2 graph below). At the existing average retail price of $45.9/MWh (red bar, observation point 1 of Scenario 2 graph below) we estimate the net income to CRRA for the same period (January through December, 2003) as a retail supplier to be approximately $14.97 million, (green line, observation point 1 of Scenario 2 graph below) or 5.7% less than the wholesale option.



To expand the analysis, we held the retail price assumptions constant (the red bars in Scenario 2 graph) and reduced wholesale pricing offers for South Meadows 5 & 6 by decrements of 1% (blue bars in Scenario 2 graph). With retail sales price assumptions held constant at $45.9/MWh (or 4.6 cents per kWh), net income via both wholesale and retail changes. As displayed by the Scenario 2 graph, net income via retail is greater than the wholesale option at observation point 6, which reflects the combination of the most recent offers for South Meadows 5 & 6 reduced by 5% and then combined with CL&P contract prices for an annual average of $33.86/MWh.

To be consistent with Scenario 1 analysis discussed above, we determined how far prices in the wholesale electric market must fall in order to achieve net income from retail (option 3) at least 10% greater than wholesale (option 2). Table 3a below summarizes our results. As mentioned earlier, option 2 wholesale revenue is a combination of market based pricing for the initial 250,000 MWh of energy production from South Meadows 5 & 6 coupled with already established pricing with CL&P for the balance of the facility's energy output. We can see wholesale revenue would need to fall to an average of $32.33/MWh, resulting in net income via retail (option 3) of approximately $16.25 million versus $14.75 million wholesale in the same year.

Table 3a

Scenario 2 Results - Retail Prices Held Constant & Decling Wholesale Pricing Resulting in Retail Net Income 10% Greater Than Wholesale					
		Projected Calendar 2003 Net Income	Rank	Delta (%) vs. Option 2	Applicable Pricing ($/MWh)
Option 1:	100% of Output to CL&P	$ 14,594,784	3	-1.0%	32.0
Option 2:	First 250,000 MWh Wholesale	14,745,791	2	0.0%	32.3
Option 3:	Retail Service of State Load	16,252,647	1	10.2%	45.9

To expand scenario 2 further, we considered if CRRA wanted net income via retail (option 3) to be at least 20% greater than wholesale (option 2). Assuming existing retail prices, such a scenario would require approximately $16.94 million of net income via retail versus $14.1 million wholesale in the same year and we can see wholesale revenue would need to fall to an average of $31.00/MWh. These results are summarized in Table 3b below.

Table 3b

Scenario 2 Results - Retail Prices Held Constant & Decling Wholesale Pricing Resulting in Retail Net Income 20% Greater Than Wholesale					
		Projected Calendar 2003 Net Income	Rank	Delta (%) vs. Option 2	Applicable Pricing ($/MWh)
Option 1:	100% of Output to CL&P	$ 14,594,784	2	3.2%	32.0
Option 2:	First 250,000 MWh Wholesale	14,135,430	3	0.0%	31.0
Option 3:	Retail Service of State Load	16,943,080	1	19.9%	45.9

With the underlying models that generated these results, CRRA may quickly estimate the impact on net income of changes in the wholesale market and or Standard Offer pricing as a benchmark for retail prices.

BACKGROUND

The evaluation began with the basic components of the proposed business plan, specified state loads and the CRRA's Mid-Connecticut Project. Historic hourly load characteristics for specified CL&P rate classes were provided by OPM. Table 4 summarizes the identified loads for the fiscal year 2001. These rate class specific energy requirements were adjusted for transmission and distribution losses, for both Pool Transmission Facilities ("PTF") and non-PTF facilities. For analysis purposes, PTF loss factors of 1.5% were applied to all the loads. Non-PTF loss factors depend on whether the customer is connected at primary or secondary voltage. For analysis purposes, we assumed all but one rate class were secondary voltage customers with

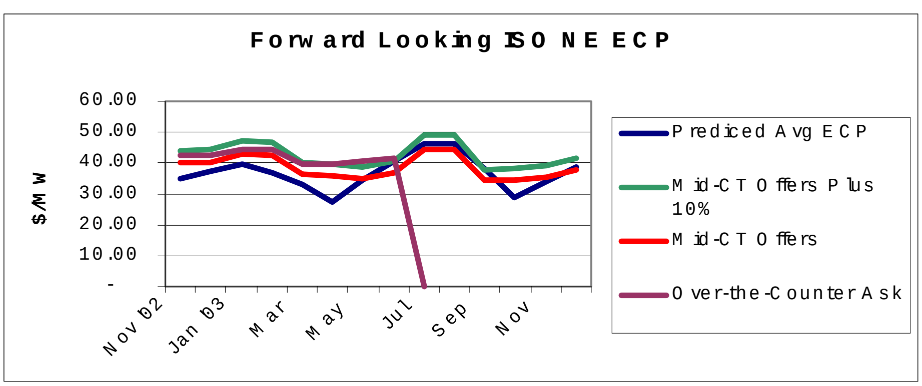
Table 4

CL&P Rate Class	Description	Annual Metered Sales (kWh)	Customer Counts	Avg Monthly Use (kWh/mo)	Approximate Peak (kW/mo)	Assumed PTF & Non-PTF Loss Factors	Annual Energy Requirements (kWh)
1	Residential Non-Space Heat	3,654,011	237	1,285	3	6.7%	3,911,489
5	Residential Space Heat	613,595	15	3,409	10	6.7%	656,831
30	Small General Service	42,403,317	1007	3,509	9	6.7%	45,391,240
35	Intermediate General Service	71,041,057	176	33,637	74	6.7%	76,046,922
40	Small Church & Schools	4,210,571	20	17,544	58	6.7%	4,507,266
56	Intermediate TOD Non-Manufacturers	381,447,795	34	934,921	2,032	3.8%	396,494,978
115	Unmetered Lighting	3,462,493				6.7%	3,706,475
116	Street / Security Lighting	3,745,154				6.7%	4,009,054
		510,577,992	1,489				534,724,255

non-PTF loss factors of 5.16%. Rate 56 (Intermediate Time-of-Day Non-Manufacturing) meters are assumed to be connected at primary voltage with a non-PTF loss factor of 2.33%. If the Rate 56 customers are all secondary customers of CL&P, the difference in non-PTF loss factors (i.e. 5.16% vs. 2.33%) is worth approximately $500,000 per year. We have asked the Office of Policy and Management to confirm the interconnection voltage of these customers but have yet to receive confirmation.

As part of our evaluation, we tested the feasibility of serving all the state load summarized in Table 4 above and tested all combinations of rate classes. That is, we built into the detailed model the ability to serve only certain rate classes of load and assessed the impact on the economics of each combination. We found no significant benefit from eliminating any of the state loads. Therefore, all combinations discussed earlier include all state loads summarized above.

A detailed model was developed comparing hourly supply with hourly demands. The model was benchmarked with actual market pricing data for the fiscal years 2001 and 2002. Based on the results of this benchmarking effort, forward projections for the



calendar year 2003 were developed. For forecasting purposes, we first looked at our own in-house projections of monthly spot market pricing for the short run period through December 2003. We then compared those projections to currently available over-the-counter pricing (i.e. the broker market) and recent purchase offers for South Meadows 5 & 6. As can be seen from the graph above, they all follow the same pattern (over-the-counter pricing was only available through June 2003).

Table 5

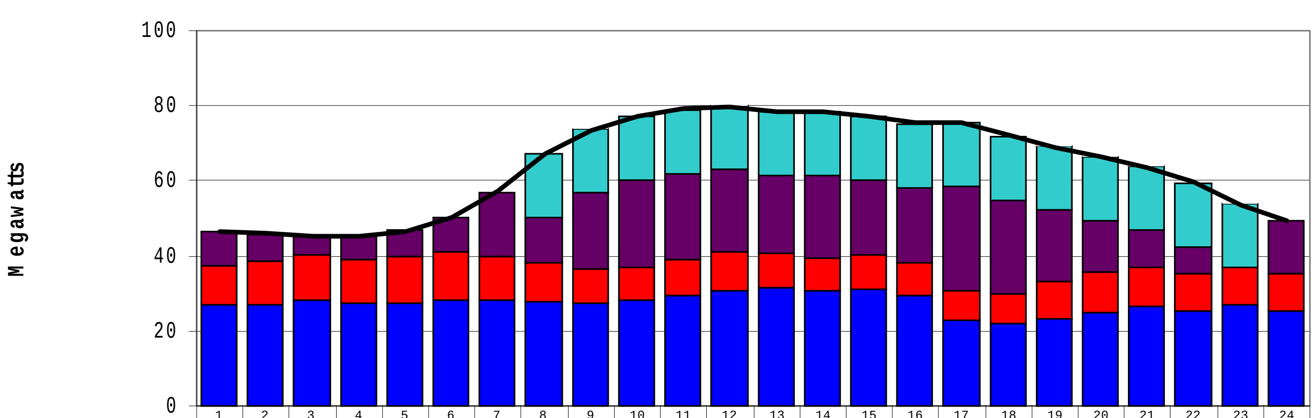
Market Price Assumptions ($/MWh)

Month	On-Peak	Off-Peak
Jan-03	52.50	37.50
Feb-03	52.50	37.50
Mar-03	45.00	35.00
Apr-03	45.00	35.00
May-03	46.00	35.50
Jun-03	48.25	36.00
Jul-03	61.90	35.20
Aug-03	61.90	35.20
Sep-03	43.20	31.40
Oct-03	42.60	31.40
Nov-03	42.60	33.80
Dec-03	42.60	38.50

For analysis purposes, we used the asking prices of suppliers as quoted from the broker market, extrapolated out to December 2003 as the basis for energy hedges during periods when internal supply (i.e. South Meadows 5 & 6) was less than projected demands. These specific price assumptions are summarized in Table 5.

Monthly hedge amounts assumed in the analysis followed the pattern of supply vs. demand on a monthly basis. A sample of the type of hedging assumptions contained in the analysis is displayed in graph below. As can be seen from the graph below, for analysis purposes we assumed that hedges would only be utilized during on-peak periods and that any energy requirements not supplied by South Meadows 5 & 6 and/or hedged would be served from the energy markets administered by the ISO NE. As discussed in previous memos, the current single settlement market is scheduled to evolve into a multi-settlement system in the spring of 2003, with both Day-Ahead and Real Time pricing.

Sample CRRA Actual Load & Resource Schedule



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Balancing	-0.23	-0.27	-0.19	-0.27	0.17	-0.03	-0.48	-0.03	0.39	-0.15	-0.09	0.39	0.17	0.09	-0.06	-0.05	0.07	-0.41	0.43	0.29	0.33	-0.20	0.44	-0.29
Bilateral or Hedge	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.02	17.02	17.02	17.02	17.02	17.02	17.02	17.02	17.02	17.02	17.02	17.02	17.02	17.02	17.02	17.02	0.00
DAM Bid	9.00	7.00	5.00	6.00	7.00	9.00	17.00	12.00	20.00	23.00	23.00	22.00	21.00	22.00	20.00	20.00	28.00	25.00	19.00	14.00	10.00	7.00	0.00	14.00
South Meadows 6	10.37	11.59	11.72	11.70	12.40	12.89	11.83	10.15	9.41	9.02	9.56	10.21	9.05	8.86	9.00	8.78	7.74	7.78	10.01	10.62	10.19	9.90	9.90	9.85
South Meadows 5	26.98	27.02	28.39	27.43	27.43	28.28	28.13	27.99	27.27	28.06	29.43	30.73	31.52	30.64	31.19	29.50	22.88	22.05	23.31	24.86	26.64	25.49	26.91	25.45
Load	46.58	45.88	45.29	45.40	46.66	50.20	57.44	67.19	73.31	77.24	79.10	79.55	78.42	78.41	77.27	75.36	75.57	72.25	68.91	66.20	63.52	59.61	53.39	49.59

Monthly metering expenses (line 24 of the attached budget) were based on the assumption that CRRA would take limited advantage of CL&P retail metering options. Specifically, pay the identified carrying costs associated with installing hourly interval metering at specific customer points. For analysis purposes, we have assumed all Rate 35 and Rate 56 customers were utilize such metering. This accounts for 14% of the metering points, however, also accounts for nearly 89% of the load at a budgeted cost of $75,600 per year. If 100% participation were assumed, the carrying costs would exceed $500,000 per year.

Monthly congestion cost exposure (line 15 of the attached budget) assumed in the analysis reflects a very preliminary estimate based on limited data available to-date from ISO NE. The source of the estimate are zonal Locational Marginal Price assumptions contained in specific scenarios included in the ISO NE's recently published Regional Transmission Expansion Plan.

Our conclusion that under current market conditions (both wholesale and existing Standard Offer Pricing), CRRA's risk in the retail market may not be justified by the potential rewards when compared to simply selling the same output at wholesale, we believe is substantiated by the retail market as it exists today. Or more specifically, where it does not exist. There is relatively little competitive activity at the retail level, we believe, for the very reasons that we conclude here. The potential economic reward from participating in the retail market is not substantial enough versus the lower risk wholesale market and therefore there are not many retail electric suppliers competing in the Northeastern United States, including Connecticut.

On the following page we are including our initial draft budget for your review and comments. We welcome your feedback on any and all line items. I look forward to discussing this further. Please let me know if there are any questions regarding this.

Initial Draft November,

Connecticut Resources Recovery Authority
Initial 12 Months Retail Electric Supply Operating Budget

		Jan-03	FEB-03	MAR-03	APR-03	MAY-03	JUN-03	JUL-03	AUG-03	SEP-03	OCT-03	NOV-03	DEC-03	Total
	Administrative and General													
1	Rent, Utilities, Phone	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	1,333	**16,000**
2	Office Equipment & Supplies	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	**18,000**
3	Board Expenses	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	**20,000**
4	Salaries	5,583	5,583	5,583	5,583	5,583	5,583	5,583	5,583	5,583	5,583	5,583	5,583	**67,000**
5	Miscellaneous	2,571	2,571	2,571	2,571	2,571	2,571	2,571	2,571	2,571	2,571	2,571	2,571	**30,851**
6	Insurance	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	**15,000**
7	Legal	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	6,250	**75,000**
8	Accounting	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	**30,000**
9	Electronic Data Interchange	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	**24,000**
10	Other Consultants	4,167	4,167	4,167	4,167	4,167	4,167	4,167	4,167	4,167	4,167	4,167	4,167	**50,000**
11	Power Supply Services	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	**150,000**
12	**Total ($)**	**$41,321**	**$41,321**	**$41,321**	**$41,321**	**$41,321**	**$41,321**	**$41,321**	**$41,321**	**$41,321**	**$41,321**	**$41,321**	**$41,321**	**$495,851**
	Power Supply													
13	Over-the Counter Hedges	1,259,220	924,000	807,840	740,880	812,544	632,268	493,746	597,869	289,092	265,387	293,475	378,701	7,495,022
14	Bilaterals													
15	Congestion Expense / (Income)	26,457	26,457	19,070	19,072	27,275	34,005	35,811	35,814	22,522	26,254	32,200	32,364	337,301
16	Project Outage Insurance							200,000						
17	ISO Balancing (Income)	(4,932)	0	0	0	0	0	(30,815)	(31,959)	(44,301)	(110,139)	(105,430)	(98,412)	(425,988)
18	ISO Balancing Expense	1,225,394	1,880,427	1,799,399	1,667,530	1,783,581	1,894,433	522,985	737,934	559,357	276,829	319,672	306,170	12,973,712
19	ISO Forward Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
20	**Total ($)**	**$2,506,138**	**$2,830,884**	**$2,626,309**	**$2,427,482**	**$2,623,401**	**$2,560,706**	**$1,221,728**	**$1,339,659**	**$826,670**	**$458,331**	**$539,917**	**$618,823**	**$20,380,047**
21	**ISO ICAP/UCAP Requirement**	**$ 91,602**	**$ 91,602**	**$ 91,602**	**$ 91,602**	**$ 91,602**	**$ 91,602**	**$ 91,602**	**$ 91,602**	**$ 91,602**	**$ 91,602**	**$ 91,602**	**$ 91,602**	$1,099,226
22	**ISO Membership Expenses**	**$10,000**	**$10,000**	**$10,000**	**$10,000**	**$10,000**	**$10,000**	**$10,000**	**$10,000**	**$10,000**	**$10,000**	**$10,000**	**$10,000**	$120,000
23	**ISO Transmission Charges**	**10,000**	**10,000**	**10,000**	**10,000**	**10,000**	**10,000**	**10,000**	**10,000**	**10,000**	**10,000**	**10,000**	**10,000**	$120,000
24	Metering Expense	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	6,300	$75,600
25	Contingency													
26	Interest Expense													
27	**Total Operating Cost ($)**	**$2,665,361**	**$2,990,107**	**$2,785,532**	**$2,586,705**	**$2,782,624**	**$2,719,929**	**$1,380,951**	**$1,498,882**	**$985,893**	**$617,554**	**$699,140**	**$778,046**	**$22,490,724**
	Demand and Energy Rate Calculation													
28	Peak Demand (kW)													0
29	Demand ($/kW-mo)	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
30	Demand Revenues ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31	CL&P Rate for SM 5 & 6 ($/MWh)	**32.00**	32.00	32.00	32.00	32.00	32.00	32.00	32.00	32.00	32.00	32.00	32.00	
32	Energy Requirements (MWh)	44,655	41,021	44,344	41,150	42,824	44,159	49,192	49,985	46,072	43,705	42,627	44,991	534,724
33	Avg. Revenue ($/MWh)	43.81	43.82	43.82	43.81	43.80	43.81	43.81	43.80	43.78	43.79	43.80	43.81	43.80
34	Energy Revenues ($)	$1,956,455	$1,797,593	$1,943,109	$1,802,609	$1,875,663	$1,934,482	$2,154,861	$2,189,390	$2,017,230	$1,913,834	$1,867,272	$1,971,092	$23,423,589
35	Hedge Revenue $	$1,259,220	$924,000	$807,840	$740,880	$812,544	$632,268	$330,765	$607,230	$379,891	$299,012	$293,475	$378,701	$7,465,825
36	Replacement Power Rev ($)													$0
37	ICAP Revenue ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0
38	Other Revenue (CL&P for above 25(	$ 369,683	$ 1,008,561	$ 1,360,745	$ 1,288,820	$ 1,284,625	$ 1,259,289	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,571,722
39	Other Revenue													0
40	Other Credits													
41	Total Revenues ($)	**$3,585,357**	**$3,730,154**	**$4,111,693**	**$3,832,309**	**$3,972,832**	**$3,826,039**	**$2,485,627**	**$2,796,620**	**$2,397,121**	**$2,212,846**	**$2,160,747**	**$2,349,793**	**$37,461,137**
42	Over/(Under) Collection	**$919,996**	**$740,047**	**$1,326,161**	**$1,245,604**	**$1,190,208**	**$1,106,109**	**$1,104,676**	**$1,297,737**	**$1,411,228**	**$1,595,292**	**$1,461,607**	**$1,571,747**	**$14,970,413**
	Adjustments to Previous Years Working Cash:													
43	Net Assetts	$919,996	$1,660,044	$2,986,205	$4,231,809	$5,422,017	$6,528,126	$7,632,802	$8,930,540	$10,341,767	$11,937,059	$13,398,666	$14,970,413	
	ISO Cumulative Errors	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	
			$1,660,044	$2,986,205	$4,231,809	$5,422,017	$6,528,126	$7,632,802	$8,930,540	$10,341,767	$11,937,059	$13,398,666	$14,970,413	

Notes:

Line 27 : equals lines 12 plus lines 20 through 23.
Line 33 : equals line 34 divided by line 32.
Line 41 : equals line 30 plus lines 34 through 40.

CRRA Customer Classes

Metered Energy Sales (kWh) & Revenues ($)

CL&P Rate Class	Description	Jan-03	FEB-03	MAR-03	APR-03	MAY-03	JUN-03	JUL-03	AUG-03	SEP-03	OCT-03	NOV-03	DEC-03	TOTAL
		Forecast												
1	Residential Non-Space Heat	319,009	324,898	338,142	270,344	268,658	291,113	329,740	327,791	272,136	279,525	301,852	330,803	3,654,011
5	Residential Space Heat	70,574	66,771	64,260	45,926	39,053	39,532	42,340	42,065	37,665	43,457	51,881	70,070	613,595
30	Small General Service	3,970,509	3,525,429	3,694,687	3,249,122	3,180,607	3,304,240	3,649,632	3,715,684	3,226,228	3,365,959	3,565,376	3,955,845	42,403,317
35	Intermediate General Service	6,238,069	5,575,721	5,977,677	5,399,356	5,532,199	5,665,425	6,442,495	6,550,005	5,747,497	5,837,463	5,860,446	6,214,705	71,041,057
40	Small Church & Schools	374,155	356,909	387,913	344,319	349,759	329,536	321,623	334,371	329,189	349,263	366,827	366,707	4,210,571
56	Intermediate TOD Non-Manufacturers	30,970,986	28,682,424	31,251,764	29,419,261	30,988,203	32,030,226	35,663,467	36,209,595	33,817,859	31,219,946	29,887,422	31,306,643	381,447,795
115	Unmetered Lighting	287,741	287,691	290,915	287,182	287,728	287,792	289,602	287,430	287,168	287,897	289,794	291,554	3,462,493
116	Street / Security Lighting	381,688	331,864	325,489	278,378	256,400	232,169	248,071	277,069	301,346	348,904	363,888	399,888	3,745,154
		42,612,729	39,151,707	42,330,847	39,293,888	40,902,605	42,180,034	46,986,970	47,744,010	44,019,088	41,732,414	40,687,486	42,936,215	510,577,992
														0
		Revenue												0
1	Residential Non-Space Heat	17,992	18,324	19,071	15,247	15,152	16,419	18,597	18,487	15,348	15,765	17,024	18,657	206,086
5	Residential Space Heat	3,486	3,299	3,174	2,269	1,929	1,953	2,092	2,078	1,861	2,147	2,563	3,461	30,312
30	Small General Service	192,173	170,631	178,823	157,257	153,941	159,925	176,642	179,839	156,149	162,912	172,564	191,463	2,052,321
35	Intermediate General Service	289,446	258,713	277,364	250,530	256,694	262,876	298,932	303,920	266,684	270,858	271,925	288,362	3,296,305
40	Small Church & Schools	18,109	17,274	18,775	16,665	16,928	15,950	15,567	16,184	15,933	16,904	17,754	17,749	203,792
56	Intermediate TOD Non-Manufacturers	1,406,083	1,302,182	1,418,830	1,335,634	1,406,864	1,454,172	1,619,121	1,643,916	1,535,331	1,417,386	1,356,889	1,421,322	17,317,730
115	Unmetered Lighting	13,898	13,895	14,051	13,871	13,897	13,900	13,988	13,883	13,870	13,905	13,997	14,082	167,238
116	Street / Security Lighting	15,268	13,275	13,020	11,135	10,256	9,287	9,923	11,083	12,054	13,956	14,556	15,996	149,806
		$ 1,956,455	$ 1,797,593	$ 1,943,109	$ 1,802,609	$ 1,875,663	$ 1,934,482	$ 2,154,861	$ 2,189,390	$ 2,017,230	$ 1,913,834	$ 1,867,272	$ 1,971,092	$ 23,423,589
	Average Price ($/MWh)	45.91	45.91	45.90	45.88	45.86	45.86	45.86	45.86	45.83	45.86	45.89	45.91	45.88

Exhibit 2
DRAFT Memorandum of Understanding Between CRRA and CL&P

DRAFT
FOR DISCUSSION PURPOSES ONLY

MEMORANDUM OF UNDERSTANDING BETWEEN
THE CONNECTICUT RESOURCES RECOVERY AUTHORITY (“CRRA”) AND
THE CONNECTICUT LIGHT AND POWER COMPANY (“CL&P”)

Memorandum of Understanding dated this ___________day of ____________, 2002 by and between CRRA and CL&P.

WHEREAS, CRRA, Enron Power Marketing, Inc. (“EPMI”) and CL&P are parties to certain energy purchase agreements (the “EPA’s) concerning the purchase and sale of electricity generated at the South Meadow Station (the "Facility"), which is owned by the CRRA; and

WHEREAS, pursuant to the EPA’s, in each fiscal year, which is the period July 1 through June 30, CRRA sells to EPMI, and EPMI resells to CL&P, the first 250,000,000 kWh of electricity generated at the "Facility"); and

WHEREAS, also pursuant to the EPA’s CRRA sells all of the remaining energy products produced at the Facility after the first 250,000,000 kWh of electricity are produced in each fiscal year directly to CL&P, thereby causing CL&P effectively to purchase all of the Energy Products produced at the Facility each fiscal year through fiscal year 2012; and

WHEREAS, beginning on December 2, 2001 and thereafter, Enron and its debtor subsidiaries and affiliates, including EPMI, filed voluntary petitions for relief under chapter 11 of the Bankruptcy Code (the “Enron Bankruptcy”); and

WHEREAS, EPMI has failed to deliver to CL&P the first 250,000,000 kWh of electricity it is required to deliver under the pertinent EPA for fiscal year 2002, and under the terms thereof, CRRA has the right, but not the obligation, to assume EPMI's obligations to CL&P; and

WHEREAS, CRRA has advised CL&P that CRRA will not assume EPMI's obligations to CL&P under the terms of the EPA’s, and will consider the electricity EPMI was to have delivered to CL&P from the Facility under the EPA’s to be electricity belonging to CRRA which CRRA is free to sell or otherwise utilize for its own purposes; and

WHEREAS, in light of CRRA’s determination not to assume EPMI's obligations under the EPA’s, CL&P has determined that its only recourse is to terminate its obligation under the EPA’s to purchase any of the Energy Products produced at the Facility; and

WHEREAS, CL&P utilizes the electricity it purchases pursuant to the EPA's to serve load and fulfill other contractual obligations, and thereby provides CL&P with certain benefits, including but not limited to the opportunity to purchase a certain amount of electricity at relatively low rates and to resell such power into the ISO-NE spot market and to apply the proceeds in excess of cost to reduce CL&P's stranded costs; to the extent CL&P is no longer able to purchase electricity from the Facility pursuant to the EPA's, CL&P may lose the benefit of its bargain as reflected in the EPA's and may be required to pay a higher price for replacement power should it need to purchase replacement power; and

WHEREAS, in the event all of the EPA's are so terminated CRRA may benefit to an extent equivalent to CL&P's loss by CRRA's ability to sell the Energy Products produced at the facility into the ISO-NE spot markets or under a bilateral contract, in either case at terms more favorable than under the EPA's; and

WHEREAS, in the event all of the EPA's are so terminated CRRA may lose the certainty of a contracted price and fixed term for the sale of the Energy Products produced at the facility through fiscal year 2012; and

WHEREAS, CRRA and CL&P desire to reestablish certain of the benefits of the bargains accruing to each of them in the EPA's which have been lost as a result of the Enron Bankruptcy,

NOW THEREFORE, this memorandum of understanding confirms the intent of CRRA and CL&P to negotiate a mutually satisfactory New EPA the key elements of which are as follows:

1. CRRA agrees to sell to CL&P, and CL&P agrees to purchase from CRRA, all of the Energy Products produced by the Facility which CL&P previously purchased under the EPA's for the remainder of the original term of the EPA's.

2. CL&P agrees to pay to CRRA the following amounts for the Energy Products:

   a) the price paid by CL&P for the Energy Products under the EPA's, plus
   b) 70% of the proceeds, if any, resulting from the resale of the Energy Products by CL&P into the ISO-NE spot market, or from any other such resale of the Energy Products by CL&P.
   c) CRRA agrees to assume the obligations of EPMI under its EPA with CL&P for fiscal year 2002.

CRRA and CL&P agree that nothing herein shall be construed to constitute a new contractual arrangement between CRRA and CL&P for the purchase and sale of Energy Products from the Facility

Exhibit 3
June 19, 2002 Board Memo

Memorandum

To: CRRA Board of Directors

From: John D. Clark, Operations Division Head

Date: June 19, 2002

Re: Power Sales Commencing on July 1, 2002

CRRA produces approximately 460,000 MWhrs of net electric output at its Mid-Connecticut facility annually. In March 2001, CRRA entered into an Agreement with Enron Power Marketing Inc. (EPMI), a subsidiary of Enron, pursuant to which EPMI was to receive the first 250,000 MWhrs (commencing July 1 of each year) of CRRA's electrical output and, in return, was to pay CRRA 3.1¢/kwhr. This represents approximately $1.1 to $1.3 million per month in energy revenue. EPMI was also required to pay a $2.2 million per month capacity payment. In a parallel, but separate agreement between CL&P and EPMI, EPMI was then to sell that same electrical energy output to CL&P for 3.1¢/kwhr. CRRA sells the electrical output in excess of the 250,000 MWhr (approximately 210,000 MWhrs) directly to CL&P for 3.1¢/kwhr.

Enron declared bankruptcy on December 3, 2001. EPMI failed to pay CRRA for electric output delivered under the Agreement for November 2001, December 2001 and January 2002, and has not paid the $2.2 million monthly capacity payments since November 2001. CRRA has declared EPMI in default for non-payment. Currently, EPMI owes CRRA approximately $2.904 Million for electrical output and $15.4 million for capacity payments.

Subsequent to the EPMI bankruptcy, CL&P (which received the first 250,000 MWhrs from EPMI) placed the money owed to EPMI for electric output into an escrow account. The balance in the escrow is reported to be the same $2.904 million ultimately owed to CRRA.

The Enron Bankruptcy has resulted in the Mid-Connecticut Project's loss of the $2.2 million per month capacity payment provided from EPMI, and has also raised significant concern regarding payments for the electrical energy output delivered to the electric grid commencing on July 1, 2002. The anticipated payment for electrical energy output is approximately $1.1 to $1.3

million per month. There are ongoing discussions between CRRA, CL&P, representatives of the Attorney General's Office, CRRA's bankruptcy counsel, and CL&P's bankruptcy counsel, seeking a final resolution of the issues associated with the Enron bankruptcy and the related contracts.

While the Enron bankruptcy and legal issues surrounding the Enron transaction are being resolved, CRRA, in an attempt to maximize revenues for the Mid-Connecticut Project and to insure that CRRA has available to it all feasible alternatives for power marketing for the period beginning on July 1, 2002, has done the following:

- Pursued issuance to CRRA of a Connecticut Electric Suppliers License through the Department of Public Utility Control (DPUC), which would allow CRRA to sell the electrical energy output to the State of Connecticut, as recommended by the Governor's Advisory Panel and as incorporated into Public Act 02-46.
- Pursued offers from wholesale electric suppliers interested in purchasing part or all of the electric output from the Facility, and commenced efforts to prepare an Agreement for marketing the Project's electrical energy output.

CRRA has, in particular, taken the following actions:

1. Supplier License

- Engaged in ongoing discussions with the Office of Policy and Management regarding the electric loads of State Buildings. A load curve of the combined "aggregated" load is being developed to help the parties identify which state buildings could be effectively served by the CRRA Mid-Connecticut Project.
- Submitted an Application to the DPUC on May 16 for an Electric Supplier License for the Connecticut Resources Recovery Authority.
- Responded to Interrogatories by the DPUC and the Office of Consumer Counsel (OCC) on June 7, 2002.
- Participated in a Hearing on June 12, 2002 at which time John Clark and Ann R. Stravalle-Schmidt appeared as witnesses for CRRA.
- Engaged in ongoing discussions with energy experts and consultants regarding the implications and practicality of entering the retail suppliers market with a single generation source.
- Pursued investigation of membership in the New England Power Pool to ensure proper balancing provisions associated with the concept of CRRA entering the retail suppliers market.
- Responded to DPUC and OCC requests for Late Filed Exhibits.

One of the Late Filed Exhibits requested by the DPUC was verification that the CRRA staff representing CRRA had been properly authorized to seek

Licensure as an Electric Supplier. CRRA stated that it would provide a copy of the Resolution passed by the previous Board of Directors and that it would make a request that the new Board of Directors pass a Resolution at the June 20, 2002 Board of Director's Meeting directing CRRA to obtain an Electric Suppliers License. The DPUC also requested evidence of authorization and commitment for a Surety Bond. A copy of the Bond and the proposed Resolution for the Board's consideration are attached.

On June 18, 2002 the DPUC suspended the hearing schedule and its review of the Supplier Application, citing, among other issues, DPUC's rights to rule on the prudence of CL&P's involvement.

2. Wholesale Market Indicative Offers

CRRA, with the assistance of PLM, an outside consulting firm with expertise in wholesale marketing, conducted a competitive solicitation process, known as a Request For Offers (RFO) in order to obtain proposals from the wholesale marketplace for the purchase of the electrical energy output from CRRA's Mid-Connecticut facility.

CRRA procurement documents were structured to test a variety of arrangements because many variables contribute to pricing in the wholesale markets, including:

- A short-term sale, perhaps through the winter of 2003 or June 2003, allowing CRRA to re-enter the market if there is reason to believe prices will be more favorable to CRRA next year;
- A longer term sale of the unit's output (e.g. 10 years);
- Ancillary market variables, including premiums for renewable energy and Installed Capacity (ICAP) were incorporated

The final RFO was distributed electronically to a distribution list of approximately twenty wholesale electric suppliers actively involved in the wholesale power market in New England.

A summary of the bid results is included at the end of this Memo. Key issues associated with the proposals are:

- Select Energy was the only bidder that provided pricing for all options;
- PGET submitted a second proposal that excluded the backstop provision. While this information was valuable, it is not consistent with the other bids or the project requirements and the revised bid was not ultimately considered; and,
- Based upon the review of submittals, Select Energy and Constellation Power were "short-listed" for further review.

CRRA will continue discussions with these two parties and prepare a summary of the results of this process for review and consideration by the Board at a future meeting. In addition, we will prepare a proposed contract for consideration by the Board that is based upon the results of this process.

SUMMARY OF PROJECTED ANNUAL REVENUES

	Annual Revenues ($)				
	100% Output				First 250 GWh Only Plus CL&P
Fiscal Year	Dominion	Select	Constellation	PGET	Select & CL&P
2003	$ 14,850,653	$ 16,144,563	$ 16,701,618	$ 14,866,712	$ 15,592,882
2004	15,008,425	16,104,978	-	14,853,030	15,354,236
2005	15,092,841	16,346,712	-	14,926,004	15,582,327
2006	15,163,823	15,975,363	-	15,103,877	15,605,235
2007	15,337,077	15,508,570	-	15,272,630	15,138,442
2008	15,538,405	15,505,236	-	15,359,286	15,138,442
2009	15,705,291	15,508,570	-	15,409,456	15,138,442
2010	15,805,020	15,508,570	-	15,555,404	15,138,442
2011	16,217,112	15,508,570	-	15,591,891	15,138,442
2012	16,671,089	15,505,236	-	15,664,864	15,138,442
	$ 155,389,737	$ 157,616,368	$ 16,701,618	$ 152,603,153	$ 152,965,332
Rank	Dominion	Select	Constellation	PGET	Select & CL&P
2003	4	2	1	3	
2004	2	1	4	3	
2005	2	1	4	3	
2006	2	1	4	3	
2007	2	1	4	3	
2008	1	2	4	3	
2009	1	2	4	3	
2010	1	3	4	2	
2011	1	3	4	2	
2012	1	3	4	2	
Delta %	Dominion	Select	Constellation	PGET	Select & CL&P
2003	-11%	-3%	0%	-11%	
2004	-7%	0%		-8%	
2005	-8%	0%		-9%	
2006	-5%	0%		-5%	
2007	-1%	0%		-2%	
2008	0%	0%		-1%	
2009	0%	-1%		-2%	
2010	0%	-2%		-2%	
2011	0%	-4%		-4%	
2012	0%	-7%		-6%	

Resolution Regarding Application for Electric Supplier License

RESOLVED: That the Chairman is hereby authorized to direct the CRRA Operations and Legal staff to complete an Application for Electric Supplier License, to submit such Application to the DPUC, and to take all other actions necessary to obtain an Electric Supplier License, including the obtaining of a surety bond for $250,000, the premium for which shall not exceed $5,000.

FURTHER RESOLVED: That the Chairman is authorized to sign the aforementioned surety bond on behalf of the Authority.