Chapter 7 – PRL Business Model

Introduction

NYSERDA desires to develop a better understanding of the needs of business entities that are currently providing, or could provide, price-responsive load (PRL) services to end-use customers. A more in-depth characterization of how PRL services contribute to achieving various entities' core business goals can help NYSERDA design and administer Program Opportunity Notice (PON) programs that increase customer participation in PRL programs, and create sustainable business models for service providers. Last year, the PRL evaluation included a process survey that focused on how satisfied NYSERDA PON recipients were with the PONs in which they participated. This year, to broaden its perception on how it can promote demand response, NYSERDA expanded the scope of the analyses to a characterization of demand response as a business opportunity.

In addition to focus groups with PON recipients to solicit recommendations for improving existing programs, NYSERDA commissioned two additional inquiries directed at the content of future program design. The first involved conducting a survey with a variety of firms that either are, or might become, involved in promoting demand response in New York. A survey instrument was designed, tested, and administered to firms from a range of business interests that are or could be complemented by promoting demand response program participation, including regulated and competitive LSEs and technology vendors. The results of the survey shed light on the barriers to entry and identify leverage opportunities that NYSERDA must address in designing its PONs in order to expand the number of firms offering PRL products and services.

The second inquiry involved developing a financial representation of how demand response programs contribute to the bottom line of a curtailment service provider (CSP). A pro forma income statement was developed and used to explore the margin contribution that might be expected from recruiting customers to EDRP or ICAP service. To evaluate DADRP, a financial model was constructed to model DADRP as a call option. A more complex financial model is required to capture the inherent risk in bidding into the NYISO's market, which involves benefits and costs that are highly volatile.

NYSERDA PON Focus Groups

In 2001, NYISO and NYSERDA included a process survey for PRL program providers as part of the demand response program evaluation. In 2002, NYSERDA's interest focused on contractors who use NYSERDA funding to attract customers to participate in NYISO's price-responsive load programs. NYSERDA has designed two Project Opportunity Notices (PONs) primarily to facilitate participation in the NYISO programs: PON 609-01 (Enabling Technology) and PON 620-01 (Peak Load Reduction).

PON 609-01 was aimed specifically at demonstration projects that would enable customers to participate in the NYISO's PRL programs. The second initiative, PON 620-01, fosters the same ethic, but provided funding for a wider variety of investments that would help customers understand the time pattern of how they use electricity, and underwrite some of the cost of technologies and equipment (such as interval meters), that in the long run would enable them to exercise more control over that profile to reduce demand charges or to provide NYISO with additional system reserves.

PON 609-01: Enabling Technology for Price Sensitive Load Management

In support of NYISO's price responsive load programs, NYSERDA issued PON 609-01 to fund projects that developed and demonstrated technologies that facilitate load reduction in response to emergency and/or market-based price signals from NYISO. Emphasis was placed on innovative technology and organizational solutions, including communications, networking, advanced metering, and controls. Proposals sought project teams consisting of a NYISO market participant, a technology solution provider, and end-use customers that subscribed to one of the NYISO programs.

PON 609-01 was issued on November 20, 2001 with $1.0 million available and sought projects with co-funding of at least 50%. Responses were due to NYSERDA on January 9, 2002. Seven proposals were selected for awards for projects expected to provide participants for the summer 2002 PRL programs.

PON 620-01: Peak-Load Reduction Program

The Peak-Load Reduction Program offered funding for projects that result in reduced peak electric demand through short-duration load curtailment measures, permanent demand reduction efforts, or through critically dispatched emergency generators. In addition, NYSERDA offered funding under this PON for installation of interval meters to encourage participation in NYISO's price responsive load programs. Public utilities, private-sector contractors and end-use customers participated in the programs. Participation in NYISO's EDRP program was strongly encouraged, but not mandatory to receive funding.

PON 620-01 was issued on December 24, 2001 with $10.5 million targeted for summer peak load reduction measures and grid connected photovoltaic (PV) systems. Applications were accepted on a first-come, first-served basis through October 1, 2002. NYSERDA awarded $2,387,300 to 223 projects in the Short Duration Load Curtailment, Dispatchable Emergency Generation or Interval Meter categories that were completed by early August, 2002. This funding produced 125 EDRP participants (including two that also received funding under PON 609, for projects that were awarded $6,000 of the PON 620 total). Seven EDRP participants who applied for funds under PON 577-00 completed projects for the summer 2002 season and were awarded $393,280.00 for these Peak Load Reduction projects. Additional projects completed by December 19, 2002 brought the PON 620-01 total to 481 projects awarded for a total of $4,906,230.42.

Details of performance metrics for NYSERDA's PON recipients enrolled in NYISO programs can be found in Appendix 7A.

Focus Group Meeting Objectives

NYSERDA wanted to learn from its PON contractors what barriers they encountered in enrolling customers in NYISO programs, particularly in downstate, and to solicit suggestions for improving the PON application process and interactions with NYSERDA, and ideas for improving NYSERDA and NYISO programs. Contractors from PONs 609 and 620 who had participants in NYISO's demand response programs were invited to participate in one of two focus group meetings conducted by Neenan Associates and held in September. Representatives from four PON contractors attended the Syracuse, NY meeting, six attended in New York City, and two who were unable to attend but provided their comments to Neenan Associates in writing.

Challenges in Recruiting Customers

This year, the NYISO programs experienced substantial growth in participation in two of the three demand response programs, EDRP and ICAP/SCR. DADRP registrations changed only slightly with six participants leaving the program and four new participant registering. With the exception of the LIPA *Edge* Program, the majority of new participants in EDRP were primarily upstate, especially in western and central New York. Enrollments in New York City doubled from 2001, but still lagged far behind enrollments upstate. The focus group participants were asked what aspects of the NYISO programs presented challenges in subscribing participants and what issues they encountered when signing up participants for NYSERDA funding.

The following challenges were cited in recruiting customers for NYISO demand response programs:

- Some aspects of program too complex;
- Uncertainty about program features and longevity of programs;
- DEC permit changes regarding participation in EDRP did affect some participants in NYC;
- Delay of payments - experience with or word of mouth regarding 2001's delays in settlement payments;
- For DADRP, the 1 MW bid minimum was cited as a major reason for not participating; most customers in NYC could not accommodate a minimum load reduction of this size; and
- Landlord/tenant issues are a significant barrier to subscribing participants in New York City.

Contractors indicated that the multiple steps required to obtain project approval for a PON application was a major factor in reduced applications in New York City; customers would lose interest after a number of steps and cancel the project.

Suggestions to NYSERDA

The focus group participants offered several suggestions for NYSERDA on how to improve PON applications, public awareness of NYSERDA and the demand response programs, and create an environment in which more contractors would participate in NYSERDA programs. Most themes were common to both upstate and downstate focus group participants:

1. **Education is a necessity for end-users.**

NYSERDA has historically funded hardware to support energy efficiency. Demand response programs require education about how electricity is being used and strategies for behavioral changes to achieve new levels of energy efficiency. This can only be achieved through continuing education, both at the contractor and end-user level. Since much of the interaction occurs at the contractor to end-user level, PON contractors suggest that a greater portion of PON funding be allocated to contractor-to-end-user education activities, and support the development and execution of behavioral strategies for participation in demand response programs.

2. **Milestone billing for PON projects.**

   Most of the PON contractors who participated in the focus groups are small to medium sized firms. As such, it is difficult for these firms to independently fund large installations of PON projects, and receive no reimbursement until they have been completed. All focus group participants agreed that they are strongly in favor of some type of milestone billing for PON projects.

3. **PON cycles don't match customers' budget cycles.**

   Typically, PONs for demand response programs are issued at the end of the calendar year or at the beginning of the calendar year with the intent of having projects installed for the summer. This does not coincide favorably with the budget planning process of most businesses, even those on a calendar year budget where planning is usually done in late summer or early fall. Contractors feel that this is a significant barrier to getting customers to apply for NYSERDA funding – it's either too early or too late to match the customer's planning cycle. *See also #5 – PON contracting process takes too long.*

4. **Improve communication and support for PON application process.**

   Focus group participants emphasized the need for better communication and support for the PON application process. Specifically:

   - For open-enrollment PONs, an up-to-date funding availability status is essential to contractors, perhaps on the NYSERDA web site. Continuing to enroll customers in a PON that is exhausted is embarrassing to the contractor, and reduces customer's confidence in both the contractor and NYSERDA.

- During the PON application period, staffing should correspond to the anticipated response to the PON – contractors suggested that staffing should be determined based on PON funding amount.
- PONs should be released on time – some PONs have been promised for several months before release. This makes it difficult to keep a customer's interest in NYSERDA funding, and causes delays in project implementation.
- Implement a method to get answers for projects that cut across multiple PONs – Contractors indicated that when a project could receive funding from multiple PONs for various aspects of the project, it was difficult to obtain clear answers regarding how the applications might affect one another.

5. **PON contracting process takes too long.**

   Most contractors mentioned of having been notified of awards to PON applications with adequate time to complete the project, but the contracting process to get the P.O. usually dragged on, causing the project to be severely delayed or canceled. Customers would then become disappointed and not interested in future projects with the contractor or NYSERDA. For PONs with payments based on installation by a certain date, there can be a significant difference in the amount of funding received. *See #6 – Timeframes for PON applications and project completion need more flexibility and simplicity.*

6. **Timeframes for PON application and project completion need more flexibility and simplicity.** Contractors felt that, particularly when PON releases are delayed or when the response period includes holiday periods, more time should be given for response to a PON. In addition, because of the delays experienced between award notification and contract signing, PONs should have a more flexible completion date that is tied to the contract date instead of a fixed date specified by NYSERDA at the time the PON is first issued. It was also suggested that PONs specify different completion dates and incentives for summer peak vs. winter.

7. **PONs should track the NYISO programs they are targeting.**

   PONs issued specifically to support participation in NYISO demand response programs should have extended application and fulfillment periods that correspond to the duration of the NYISO demand response programs they are targeting for participation. This would allow contractors to attract new participants on a schedule that is favorable for the customer with minimal changes to PON requirements during the limited time windows for current PONs. It was suggested that updates to payment amounts would be acceptable, but criteria for eligibility for funding should remain constant to reduce confusing customers and contractors as well.

8. **Become involved in seminars and industry groups.**

   It was suggested that NYSERDA become more involved with industry groups and participate in industry seminars. While most contractors acknowledged that they have attended NYSERDA-sponsored seminars, they indicated that repeat participation in industry trade groups and seminars would increase end-user awareness of NYSERDA funding opportunities. This increased awareness would create a more vibrant follow-on market for NYSERDA contractors.

Characterizing Market Maker Preferences

As part of the 2002 PRL program evaluation, NYSERDA supported an initiative that involves extending the inquiry to a wide variety of firms that are, or potentially might become, involved with the provision of PRL services to retail customers. Such firms are referred to as market makers and this section describes research conducted to characterize how these firms view demand response as a business opportunity.

To solicit market makers' views on how PONs can best serve their needs, an interview instrument was developed and administered to 15 different firms. The firms included representatives from six enterprise categories that are characterized as follows:

1. POLR/ default service providers comprised of the existing six IOUs in the state, NYPA, LIPA, and cooperatives. We expect that their primary interest is to reduce their supply costs, although some may use PRL services to better manage the local distribution system, or contribute to the maintenance of system reliability.

2. Competitive Retailers that offer commodity services to end-use customers. These include those that are currently active and potential new entrants. PRL might be used as a loss leader to attract customers to their commodity services, or integrated into their service portfolio to be able to offer a wider variety of choices in service plans.

3. Performance ESCO contractors that integrate PRL participation into more conventional DSM and energy services provision under some form of performance contractual arrangement.

4. Wholesale traders/brokers that deal in the physical commodity that could trade PRL rights and obligations and use them to cover short supply positions in day-ahead or real-time markets.

5. CSP boutiques whose sole objective is to profit from providing customers with access to NYISO PRL programs on terms that better accommodate individual capabilities and preferences for risks.

6. Enabling technology firms that manufacture and/or distribute technologies that aid customers in designing and executing curtailment strategies that facilitate participation in PRL programs.

The interview instrument was constructed to collect basic business activity information from each firm and to characterize their past and current activity in electricity markets, with an emphasis on experience with demand response programs. A copy of the survey instrument is provided in Appendix 7B.

Neenan Associates recruited firms to participate, and scheduled and conducted the interviews. The survey responses were characterized by categories that share common objectives with regard to how PRL can help them achieve their business goals, and then the results were used to characterize the perspectives of market makers, which have some common elements, but also display considerable diversity of opinion as to how NYSERDA funding can be effective in promoting demand response.

Surveys were completed by 16 firms, including three regulated LSEs, one competitive LSE, three information service providers, six controls companies and two ESCOs. Over half of these firms are already operating in the NY state market, and the rest say they are considering entry. These firms were asked what investment return criteria they would apply in considering investments in demand response. The rate of return thresholds ranged from as low as 10% to as high as 75%, and averaged 33%. The average payback period reported was 2.7 years. Clearly, these firms have high hurdle rates for investment in demand response as a business. This finding is all the more striking, since all but one indicated that they view demand response as a means of complementing their main, much larger, business aspirations. They apparently are not so optimistic about the potential of demand response complementing their business that they are willing to use it as loss leader or to subsidize it.

Survey respondents offered their views as to the major barriers to demand response as a vital aspect of their business. Market design uncertainty (i.e. the lack of a clear, concise, and permanent role for demand response in the standard market design) was identified as the number one barrier by four respondents and three named it as the number two barrier. Several respondents opined that generation or regulated LSE interests prevailed in making the rules, and they would be biased against demand response. Another considers it a fad that would go away in a year or two.

Three respondents named customer uncertainty about program benefits as the number one barrier, and another three named it as the number two barrier. Uncertainty on the customer's part translates into resistance to overtures to participate, and results in higher customer acquisition costs. Remarks included the observation that only the very largest customers are aware of, and have any experience with curtailment programs to draw upon, that there is too little information about how NYISO prices are set to dispel customers' almost primal fear of market uncertainty, and that misconceptions on customers' part of legacy programs act as deterrents to participation. This theme was echoed by the four respondents that said that low ROIs for participation is the main barrier to their participation - they cannot justify the investment expense. One named CBL uncertainty as the source of low ROI, another attributes it to the speculative nature and low incidence of curtailment events. Only one respondent named the imposition of noncompliance penalties as a barrier to its participation, and that respondent rates it as the third greatest barrier it faces.

Twelve of the 15 respondents said that they favored the expenditure of public benefit funds to promote demand response program participation. The dissenters were two regulated LSEs and an ESCO, each expressing the belief that demand response should not be subsidized, but left to the competitive market to establish value. Of those that responded, about 40% felt that the ISO should be the entity to design and implement demand respond programs directly to customers, while about half felt

Table 7-1. Who Should Offer DRP Programs to Retail Customers?

Response	Freq	Respondent type
ISO directly	4	2 LSEs 2 ESCOs
ISO through CSPs	5	1 LSE, 4 CSPs
LSEs (not the ISO)	1	1 CSP

the ISO should design them, but use CSPs to implement the programs. One respondent expressed the belief that the ISO should leave the promulgation of such programs to the competitive retail market (see Table 7-1).

Eight respondents said that they had experience with legacy load management programs operated by a utility in a vertically integrated electricity market, three have experience with an ISO program other than in New York, and three different respondents have been involved in the NYISO's PRL programs. Those involved in legacy programs reported that the program has been either abandoned or closed to new subscriptions, due to changes in the market that have rendered the design no longer cost effective.

A key aspect of the survey was an exercise whereby survey respondents first ranked alternative PON areas of focus according to their value to the respondent's business interests, and then indicated how they would like to see PON funding allocated over these program focus areas. The focus areas respondents considered are as follows:

1. **General customer education**. Providing customers with workshops and seminars, and preparing and distributing brochures that describe the benefits of program participation.

2. **Customized customer education and consulting**. Conducting audits of customer premises to identify curtailment capabilities, and using the results to develop a curtailment strategy.

3. **Marketing and administrative support**. Providing funds explicitly to offset the costs of marketing programs to customers and administering their participation.

4. **Essential Technology funding**. Incentives for the purchase and installation of interval meters, and offsets for the costs of meter reading.

5. **Enabling Technology funding**. Incentives for investments in technology that enable the customers to retrieve prices, event information, and its own meter readings, and to use the data to develop and execute a curtailment strategy.

6. **Back office funding.** Funding to offset the cost of program administration and billing.

7. **Augment Program benefits**. Supplement to the NYISO market-based curtailment payment levels to enhance program participation.

Results of the ranking exercise are displayed in Fig. 7-1. Respondents scored the seven program features on a scale of one (little or no value) to six (very high value), based on how they would contribute to each's business interest regarding demand response. Funding for technology investment by customers received the highest ratings (based on the average score), with that for enabling technologies (information services and controls) slightly higher (4.9) than the score for essential technologies (meters), which received an average score of 4.6. Subsidies for program benefits received almost the same average score (4.6). All other features scored below the overall average score of 3.8 out of six.

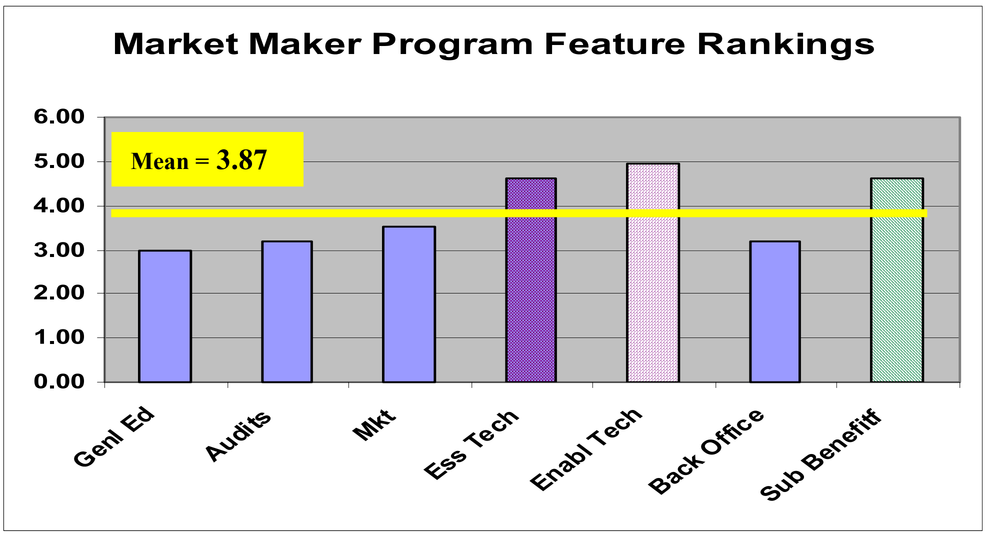


Fig. 7-1 Program Feature Rankings

Scores were the most dispersed for the general education, customized audits, and marketing services program categories, each of which received at least six scores of one or two (low preferences for these programs) but also received at least two scores of 6 (high preference). Subsidies also showed diversity of interest, with six scores of six, including one regulated LSE, but two scores of two or less (one competitive and one regulated LSE). LSEs are obviously not of one mind as to how PON funding to promote demand response can contribute to their business interests.

Responses for the second program feature rating exercise (allocating funding over the various categories) are displayed in Fig. 7-2. (Allocations were made on a relative basis, so scores represent the percent of PON funds to be allocated.)

The allocation of PON funds by respondents over the features offered mirror the preferences in that technology subsidies received the greatest emphasis (27% of funding allocated, on average, to enabling technology PONs and 20% to essential technologies). However, the funding priorities diverge from the ranking for the other factors. Customer-specific audits received the third highest allocation, on average. Subsidies for benefits, which were third in the relative rankings, received the third lowest allocation on average, about 9%.

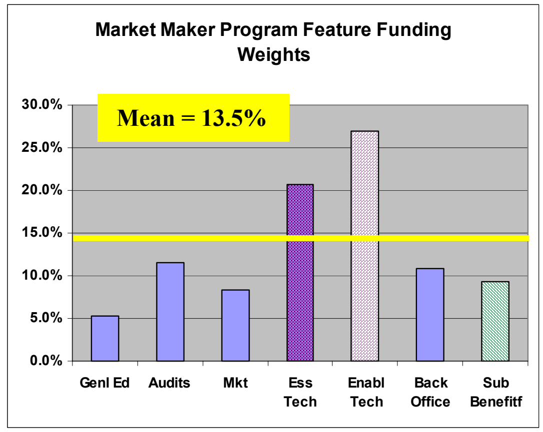
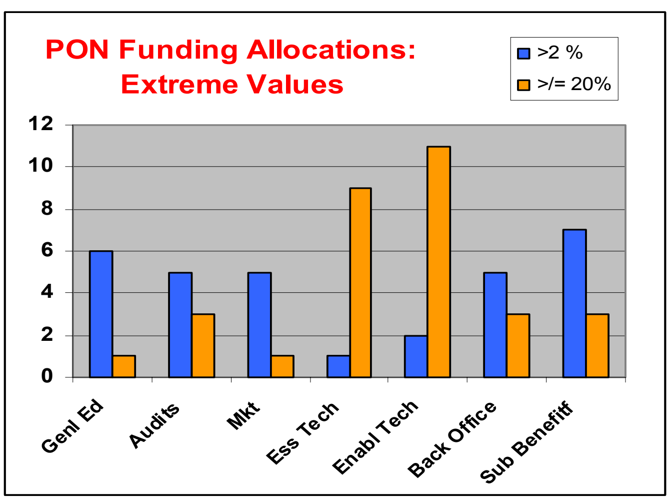


Fig. 7-2 Program Feature Funding Weights

Individual funding allocations varied widely for some features, but were quite uniform for others. The largest allocation was 60% for enabling technologies (offered by a technology supplier). Two 50% allocations were also made (one to each technology category), with both made by an unregulated retailer. There were many zero allocations, which make the distribution of allocations interesting.



The two technology categories received a high number of allocations above 20% (the mean allocation was about 14%), and only 1 or 2 zero allocations. (It was an ESCO that voted no allocation to either technology category.) The same distribution, but with the opposite results, characterized allocations for general education, (which received six zero funding allocations and only one value over 20%), and for marketing, which has approximately the same distribution of scores.

The other categories exhibit more highly polarized opinions. Allocations for PRL audits, back office costs, and subsidies for benefits had a much more even mix of high and low allocations. Respondents are clearly not of one mind regarding PON funding of these initiatives.

Business Case Studies

Two financial models were developed to explore how demand response programs could contribute to market makers' business interests. The first, described below, utilizes a financial pro forma income statement to characterize the costs and benefits that flow from recruiting participants to the EDRP and ICAP/SCR programs. The following section extends the analysis to DADRP using a more complex representation of market conditions and their uncertainties.

EDRP/ICAP SCR Pro forma Income Statement

Description of Income Statement Approach

The Income Statement Approach characterized the PRL business opportunity by simulating three years of financial performance for a hypothetical curtailment service provider (CSP) that recruits customers to participate in the EDRP and/or ICAP programs.[1] This performance was simulated under a variety of representative market conditions and PRL program rules to demonstrate the sensitivity of the performance to parameter levels. The combinations of conditions modeled are shown in Fig. 7-4.

Fig. 7-4 Perspectives on CSP Business Opportunity

	Spring 2002		Spring 2003
Upstate	EDRP&ICAP / PON		EDRP / PON
	EDRP&ICAP / No PON		EDRP / No PON
			ICAP / PON
			ICAP / No PON
Downstate	EDRP&ICAP / PON		EDRP / PON
	EDRP&ICAP / No PON		EDRP / No PON
			ICAP / PON
			ICAP / No PON

Notes: Spring 2002 perspective is more advantageous than Spring 2003. For Spring 2002:
a) It was assumed that event hours would continue at 2001 levels.
b) It was assumed that loads could remain enrolled in both EDRP and ICAP.
c) It was assumed that EDRP are received, in full, for all events.

These variations in input were organized into two main groups, called Perspectives. The Spring 2002 Perspective reflects the view of a prospective CSP entrepreneur, considering entering into business in advance of the 2002 season, and expecting that the experience of 2001 would continue for (at least) three years. Thus the pro forma modeling for the Spring 2002 cases

[1] ICAP in this discussion refers to ICAP Special Case Resources.

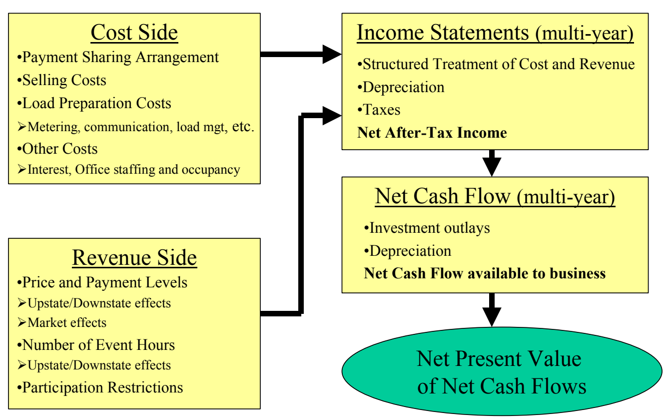
assumes 2001 values for program rules, actual event hours experienced, and curtailment prices. Within those "2001 repeats" assumptions, the modeling explores the effects of location (upstate vs. downstate) and the availability of NYSERDA cost sharing (PON vs. No PON) on performance.

The Spring 2003 perspective updates the previous year's perspective with the experience of the 2002 season, and incorporates recent revisions in the NYISO program rules. In the Spring 2003 perspective, it is 2002 conditions that are expected to continue for three years. Within these "2002 repeats" assumptions, a similar set of variations is explored. Since one of the important changes between 2002 and 2003 is that dual EDRP/ICAP registration of a given load is no longer permitted, the Spring 2003 perspective breaks out EDRP and ICAP, and explores the alternatives of registering customers entirely in EDRP versus entirely in ICAP.

Analysis Method

To calculate and describe the results of each combination of assumed conditions, two standard tools of financial analysis and project evaluation were used (see Fig. 7-5). A pro forma Income Statement was produced for each of the three years of operations. An income statement is the classic way to show the financial performance of a business over a specified time period. In addition to the obvious costs and revenues, an income statement reflects the need of a real-world business to pay less obvious costs, such as interest and office rent. It also provides for the proper accounting for depreciation and taxes. All of these components are summarized into the classic "bottom line" – which in our case is net cash flow available to the business.[2]

Fig. 7-5 Income Statement Modeling Approach



[2] For an established enterprise, net after-tax income is commonly used as the bottom line. Because our hypothetical CSP is created in the first year, we want to reflect the up-front investment necessary to start operations.

The second standard tool is Net Present Value (NPV) of the net cash flows available to the business. Using NPV allows further summarization of the financial performance results into a single figure of merit for each scenario.[3]

Assumptions

The CSP is assumed to be managing 50MW of enrolled capacity. The load consists of commercial (25%), industrial (15% with cogeneration, 25% without cogeneration), institutional (10% with cogeneration, 20% without cogeneration), and residential (5%). Key inputs that drive the income statement are revenue sharing arrangements with end users, event hours and payment levels, program design (e.g. can a load be in both EDRP and ICAP?), one-time and recurring costs of enrolling and preparing loads to perform, and the availability of NYSERDA cost sharing.

Revenue Assumptions:

- The CSP was assumed to retain 40% of its gross curtailment payments, with the other 60% being paid out to subscribers.
- EDRP summer event hours were based on actual values 2001 and 2002. (Note: the April 2002 events were not included, because they occurred before most loads were registered and ready.) In 2001 there were 17 events hours upstate and 23 event hours downstate. In 2002 there were 12 event hours statewide.
- Prices for ICAP were taken from the results of the May auction for the entire summer capability period. The payments per MW for downstate were $52,500 and $55,200 for 2001 and 2002 respectively. For upstate, the payments were $11,400 and $11,500 for 2001 and 2002, respectively.
- EDRP energy payment levels were assumed to be $500/MWh, which was the case in all event hours of 2002 and most event hours of 2001.[4]

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[3] Another commonly used figure of merit is Return on Investment (ROI). Because ROI is undefined unless a series of cash flows has at least one change of sign, it does not work for such a broad range of input assumptions.

[4] EDRP provisions call for the payment of the higher of $500/MWH or the prevailing NYISO real-time LBMP for all hours of event that are four or more hours in duration.

- In accord with the recent change in NYISO program rules, EDRP will no longer be called automatically when there is an event. For the Spring 2003 perspective, it was assumed that loads in EDRP would be called only 2/3 of the time that an event was declared.
- Another recent change in program rules, that a given load may not be registered in both EDRP and ICAP, is modeled in the Spring 2003 perspective.
- Energy payments are a new feature of ICAP for 2003. These payments are separate from those paid to EDRP participants, and will be market determined. For modeling purposes, ICAP energy payments were estimated to be $250/MWh (or half of historic EDRP levels).[5]

Cost Assumptions: Costs were assumed to be invariant to changes in either location (upstate or downstate), or program (EDRP or ICAP). Thus the different financial performance results are being driven by differences in revenues. The assumed total costs for enrolling 50 MW of loads, and for preparing them to perform, were $138K and $564K, respectively. On a $/kW basis, these costs are $2.76 and $11.28. PON cost sharing was assumed to be 60% of load preparation costs. Compared to actual experience of PON participants, these costs are considered reasonable, or even optimistic. Fixed office and salary costs of ~$150K per year also seem conservative.[6]

Performance Assumptions: All registered loads were assumed to perform at 100% when called. This assumption has two favorable impacts on the pro forma results. First, ICAP performance penalties are avoided. Second, EDRP energy payment revenues are received at maximum value.

Taxation Assumptions: Income tax liability was allowed to assume negative values when pre-tax income was negative. These negative tax liabilities thus had a positive effect on net cash flows for the years in which they occurred. There is a two-part rationale for this treatment of taxes:

- It was assumed that the CSP line of business was part of a larger tax-paying entity.

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[5] Under the new rules, ICAP/SCR customers must submit strike prices with their applications, and those prices are used to construct a bid curve that is used to determine which resources are dispatched. Those that are dispatched receive the price they bid.

- It was assumed that the larger entity was profitable, and could take full advantage of any tax losses generated in CSP operations.

A related taxation assumption is the treatment of depreciation (which was only applied to out-of-pocket load preparation costs, after cost sharing). Depreciation is deducted from operating revenue to calculate taxable income, then added back in to after-tax income to calculate net cash flow. This treatment has the effect of sheltering depreciation from taxes, but recognizing that the charge does not actually reduce available cash.

Because the above assumptions are either well within observed experience, standard practice, or actually favor the modeled financial results for our hypothetical CSP, the modeling approach used is unlikely to understate the results for a real-world CSP.

Results and Conclusions from the Income Statement Approach

Figure 7-6 summarizes the results of pro forma modeling of the PRL business opportunity using the Income Statement Approach. For each box in the figure, the monetary amount is the model result (in thousands) for the net present value of cash flows available to a hypothetical CSP business from 3 years of operations. The boxes represent different assumptions about where the CSP is located, program rules and market conditions that will determine his revenues, the availability of NYSERDA cost sharing, and the PRL programs in which its customers and their curtailment loads are registered. The salient model results are:

Fig. 7-6 Pro Forma Modeling Results
(NPV in $Thousands)

	Spring 2002	Spring 2003
Upstate	EDRP&ICAP / PON $128	EDRP / PON ($263)
	EDRP&ICAP / No PON ($162)	EDRP / No PON ($552)
		ICAP / PON ($54)
		ICAP / No PON ($344)
Downstate	EDRP&ICAP / PON $1,632	EDRP / PON $280
	EDRP&ICAP / No PON $1,343	EDRP / No PON ($9)
		ICAP / PON $1,471
		ICAP / No PON $1,181

- It is difficult to make money upstate. Of all the upstate cases examined, only the combination of Spring 2002 assumptions and NYSERDA cost-sharing lead to a positive NPV. (This result will be discussed more fully below.)

[6] It would seem, however, from the amount of observed CSP activity upstate that some real-world CSPs

- The change from a Spring 2002 to a Spring 2003 perspective decreases NPV for every case modeled, but especially for EDRP. The only non-negative NPV for EDRP alone under 2003 assumptions is downstate, assuming PON cost sharing for load preparation costs.
- Under Spring 2003 assumptions, stand-alone ICAP is much more profitable (or less money-losing) than EDRP. This is especially true downstate, where the ICAP auction prices are much higher.

Regarding the business prospects for a start-up CSP specializing in either EDRP or ICAP, two key conclusions can be drawn from these results:

Only under very favorable cost conditions does EDRP make economic sense as a stand-alone business opportunity.

If 2002 market conditions and 2003 program rules persist in the future, only some of the costs can be recovered from the revenue to be expected from EDRP. The only likely scenarios in which a profit-seeking, start-up CSP would be prudent to pursue EDRP loads is as part of a portfolio of products, in which at least one of the following occur:

- The EDRP line of business produces other benefits (such as cross-selling opportunities) that justify or offset its minimal or negative contribution to profits.
- The costs of enrolling and preparing loads are either very small, or can appropriately be charged to some other line of business (without destroying the profitability of that line of business).
- The CSP is already established and its customer acquisition costs are sunk.

Downstate EDRP was considered, and rejected, as a possible exception to this statement. Both the PON and No PON cases produced positive cash flows in the first year, but went negative in 2003, as the exclusion of EDRP loads from ICAP took effect.

Only downstate is ICAP a viable stand-alone business opportunity

Both modeled ICAP cases lose money upstate. Downstate, where auction prices are more than 5 times the upstate values, ICAP makes money with or without PON cost sharing.

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have been able to register and deliver loads at costs lower than these.

Inclusion of DADRP in the CSP Business Case

A natural extension of this analysis is to see if these stand-alone prospects could be substantially improved if a CSP were also to participate in DADRP. As shown in the next section, economic valuation of DADRP revenues requires the valuation of a strip of options. A rough, preliminary valuation of DADRP is done in that section, and the results are used here to simulate the effects on CSP financial performance of combining DADRP with ICAP. In addition to using preliminary results for DADRP option valuation, the analysis is subject to the following simplifying assumptions:

- Only the combination of DADRP with ICAP is evaluated.
- A simple comparison of the present values of expected costs and revenues is used, instead of the income statement approach.
- It is assumed that the same loads can participate in both DADRP and ICAP, and full value can be derived from each program (i.e. there is no modeling of interactions between payments received for DADRP and for ICAP).
- Load enrollment and preparation costs are modeled parametrically.
- Operations costs are assumed to be \$500K/yr (compared to \$150K, above). The increase is to reflect the complexity in monitoring and bidding required for DADRP participation.

Table 7-2 Revenue and Cost Values Used in Simplified DADRP/ICAP Model

	Natural Units	Present Value (\$/MW)
Revenue Components		
DADRP Option Value		
100 Hours/Month	40% of Option Value of **100** Hrs/Month, Bid@ \$100/MWh	**28,000**
200 Hours/Month	40% of Option Value of **200** Hrs/Month, Bid@ \$100/MWh	**55,600**
PV of ICAP Payment Stream		
Upstate		
3 Years	40% of \$13,500/yr for **3** yrs, discounted at 7%	**14,171**
5 Years	40% of \$13,500/yr for **5** yrs, discounted at 7%	**22,141**
Downstate		
3 Years	40% of \$58,200/yr for **3** yrs, discounted at 7%	**61,094**
5 Years	40% of \$58,200/yr for **5** yrs, discounted at 7%	**95,453**
Cost Components		
Operating Costs	\$500K/yr for 50 MW --> \$10K/yr/MW for 5 yrs, discounted at 7%	**16,401**
Acquisition Costs		
Low	\$**15**/kW (incurred in Year 0)	**15,000**
Medium	\$**30**/kW (incurred in Year 0)	**30,000**
High	\$**60**/kW (incurred in Year 0)	**60,000**

The various values used for revenue and costs are displayed in Table 7-2, both in “natural” units, and converted to present values. To avoid having to model every possible combination of input values, the cost and revenue “components” of Table 7-2 are combined into nine distinct scenarios (see Table 7-3), and the scenario set was simulated once for downstate ICAP prices, and once for upstate ICAP prices. Moving down the rows of Table 7-3, what changes are the amount of hours of DADRP bid per month (200 in the “High” and “Medium” revenue scenarios, 100 in “Low”), and the number of years of ICAP payments expected (5 in “High”, 3 in “Medium” and “Low”). Moving across the columns, the only changes are to the $/kW values assumed for the cost of enrolling loads and preparing them to perform (15, 30, and 60 for “Low”, “Medium”, and “High”, respectively).

Table 7-3 Scenario Cost & Revenue Components
DADRP and ICAP

Revenues		Costs: Low	Costs: Medium	Costs: High
High	DADRP Bids (Hrs/Month)	200	200	200
High	ICAP Duration (Yrs)	5	5	5
High	Load Acquisition Cost ($/kW)	15	30	60
Medium	DADRP Bids (Hrs/Month)	200	200	200
Medium	ICAP Duration (Yrs)	3	3	3
Medium	Load Acquisition Cost ($/kW)	15	30	60
Low	DADRP Bids (Hrs/Month)	100	100	100
Low	ICAP Duration (Yrs)	3	3	3
Low	Load Acquisition Cost ($/kW)	15	30	60

Financial performance results for these scenarios, expressed as the present value of revenues minus the present value of costs, are given in Table 7-4 for downstate, and Table 7-5 for upstate. Since ICAP Alone was profitable downstate, it is not surprising that it is profitable downstate in combination with DADRP. Note, however, that even here, the value is marginal under the Low Revenue/High Cost scenario. (100 hrs/month of DADRP bids, 3 years of ICAP payments, $60/kW load acquisition cost). Note also that $60/kW is not “high” relative to the acquisition costs experienced by NYSERDA PON contractors.

Table 7-4 Simplified NPV: Downstate
1 MW CSP w DADRP and ICAP Loads
Using Downstate ICAP Auction Values
($Thousands/MW)

Revenues	Costs: Low	Costs: Medium	Costs: High
High	120	105	75
Medium	85	70	40
Low	58	43	13

Table 7-5 Simplified NPV: Upstate
1 MW CSP w DADRP and ICAP Loads
Using Upstate ICAP Auction Values
($Thousands/MW)

Revenues	Costs: Low	Costs: Medium	Costs: High
High	46	31	1
Medium	38	23	(7)
Low	11	(4)	(34)

The picture changes more dramatically upstate, where stand-alone ICAP was a money loser even with PON cost sharing. The simplified analysis indicates that if the load acquisition costs are sufficiently low, ICAP combined with DADRP can make money under both high and medium revenue expectations, and remain at least marginal even under low revenue expectations. This profitability is very sensitive to acquisition costs, however. Medium to high revenues are required to produce positive NPVs when the acquisition cost gets to $30/kW, and even high revenues cannot salvage the high acquisition cost ($60/kW) scenario.

Evaluating DADRP as a Bidding Option

The economics of participation in the DADRP program depend on a wide range of complex factors. On the revenue side, the main factors are the characteristics of the customer demand and its flexibility, and the probabilistic characteristics of the day-ahead power and gas prices. On the cost side, the operational procedures that need to be put in place to facilitate participation are important. The costs of these procedures will be different for different types of participants and intermediaries.

In the section that follows, the revenue sides associated with load curtailment (discretionary load) and gas-driven on-site generation applications are explored. The cost side for the participants is highly variable, and depends upon whether the customer achieves a reduction in utility-served load by curtailing or by operating an on-site generator. (In analysis that follows, we will denote on-site generation as DG (for distributed generation)). In modeling the cost side for load curtailment, we assume that the customer includes its outage or lost revenue costs implicitly in setting the strike price at which it will curtail.

For the DG case, evaluating the economics of the investment requires comparing the option value with the full cost, which includes both capital cost and operating costs. We do not in this exploratory evaluation attempt to specify equipment costs and conduct a full investment analysis. Instead, we focus on generating the option value of the DG option (including operating costs), and leave it to another study to ascertain whether the net revenues would serve the debt on the DG system implied by our analysis.

Load Curtailment Option Value

Load curtailment involves reducing electricity usage in a given time period without causing demand to increase at another period. Activities like halting a production process without rescheduling, or reducing lighting or HVAC services are examples of curtailment. *Load shifting* occurs when the customer shifts usage from one period to another in response to either the effective marginal cost of electricity, or to some other inducement (such as those offered by the ICAP/SCR and DADRP programs). When loads are shifted, the costs incurred change dramatically, as they depend upon the cost of make-up power, rather than the outage cost incurred by foregoing a service electricity provides. Such an analysis is beyond the scope of the focus of this study, but deserves attention in subsequent analyses.

The Load Curtailment Options Model

The ability to curtail electricity usage can be viewed as the equivalent to owning a strip of options, one for each time period. An option is the right, but not the obligation, to undertake a market action. In this context, we assume that the customer has entered into a commodity service contract whereby it pays a usage that is not directly tied to the prevailing price, and that contract allows it to consume at any level and pattern it so chooses. The most straightforward example is service under POLR tariff rate comprised of demand and flat energy prices. Since it can vary usage at any time, with no penalty, the customer subscribes to DADRP whereby it may bid to curtail in the NYISO day-ahead market.

The bid involves specifying a quantity to be curtailed, the hours in which it would be curtailed, and the price required to undertake the curtailment. When its curtailment bid is accepted, the customer must either fulfill the curtailment obligation, or face a penalty for failure to do so. The penalty is equal to the real-time LBMP at the time of noncompliance times the level of noncompliance. Thus, the customer can consider itself as having stream of hourly options to curtail available to it. To evaluate that option, the analysis below used conventional options modeling techniques to generate the value of that option under various conditions and bidding strategies.

Option valuation techniques are appropriate for valuing load curtailment capability if the characteristics of the option conform to the models typically used in other markets. An option value is defined as the expected value or payoff where:

Payoff = max [(exercise price – strike price), 0].

The formula expresses the option payoff to be the maximum of 1) the difference between the price received if the option is exercised and the strike price, the amount paid for the option and 2) zero). Typically options are sold, in which case the second result is a loss; the option is never in the money (price never exceeds the strike price) and the net result is a loss in the amount of the option payment. In this application, the price is the amount the customer receives for curtailing, which under DADRP is the day-ahead market price. The strike price is the curtailment bid the DADRP participant submits as its curtailment bid price, which should be at least equal to the cost it would incur if it curtailed. Since customers do not have to pay any fee for the right to bid under DADRP, the option formulation is as specified above, where the outcome is zero if the bid is never accepted.

To value the option, the probabilistic nature of the hourly, day-ahead prices must be characterized as a distribution with known mean and variance. In this analysis, we adopt a somewhat simplistic representation of electricity prices, the Geometric Brownian Motion (GBM) distribution, a constant volatility model. In other words, dispersion in the distribution of hourly is constant over time. The primary reason for adopting the GBM model is that it allows us to use the Black-Scholes option valuation model to value the options. The Black-Scholes model is commonly used by commodity traders to establish a base value for an option, to permit a liquid market for trading the option. (See Appendix 7C for the details of the model.)

In this analysis, each time period in the future is viewed as a separate option and is valued as such. In other words, at each time period in the future the customer has the right but not the obligation to curtail. At each time period, there is a probability distribution of the day-ahead price for that period, and from this one can calculate:

- the probability that the price will be over the strike price (which is discussed below)
- the expected level of payoffs.

The option value of demand reduction flexibility then is the sum of the option values for all the time periods. While the NYISO day-ahead market trades on hourly transactions, for reasons described below the instant analysis employs a longer time period.

To value the option to curtail, one of the key parameters is the strike price at which the option is exercised - the price at which the DADRP participant is willing to curtail if its offer is accepted. When power is curtailed, the customer suffers a reduced level of service, such as reduced lighting of HVAC services levels in commercial buildings or reduced enterprise revenue because of reduced production, which would be typical of industrial facilities. The monetary value associated that represents the reduced service is embodied in the strike price. Customers should consider all the cost associated with the curtailment and then bid at least that amount.

The cost incurred by customers when service is curtailed is called outage costs. Studies conducted to measure outage costs report values ranging for zero to over $100/kWh. Low outage costs are associated with customers that were easily able to withstand the inconvenience. Residential customers that are not home when the power goes off for a short time only face the nuisance of resetting clocks. Some industrial processes can shut down quickly for short periods with little cost, air-processing facilities being a prime example. Very high outage costs come about when the outage wreaks havoc with the facility, or safety is compromised. Other constraints on a facility also affect outage cost. The duration of the outage can affect outage cost dramatically. Outages that are very short generally result in lower damage costs. But outages of a duration that conforms to business practices also have lower costs, even if they run several hours. That's because it allows the customer to rearrange its operations in a cost-minimizing manner. For example, a two-hour outage might force the customer to pay overtime to meet the day's output requirement. But, if the outage is scheduled for all afternoon, then the customer may be able to alter shift assignments such that additional labor costs are negligible.

A detailed specification of outage costs is beyond the scope of this analysis. However, we are compelled to demonstrate the impact of outage costs on DADRP option value. Therefore, we provide the option values associated with different strike price (outage cost) levels.

Assumptions

Specifying the option model requires six different parameters, each representing some aspect of the customer's cost or market volatility, as follows:

Forward Price Curves: Forward curves are typically developed using the forward prices of power traded in liquid markets. Typically, beyond 18 months the markets are not very liquid—at that point a more robust forecasting model is required, such as a production cost simulation. For this study, we used price simulations by Energy information Agency (EIA) Annual Energy Outlook (AEO) 2002. The standard data sets that are published do not have the on-peak off-peak prices by month. EIA provided us with more detailed results from which we derived the forward curve of on-peak prices. The AEO 2002 forecast of on-peak prices in the New York region are presented in Appendix G.1.1.

Volatilities: Volatilities are typically derived from the prices of options. However, when such prices are not available and/or markets are not liquid, an alternative is to analyze historical prices to characterize the volatilities of future prices. Historical power prices are analyzed to determine the level of volatility for New York as described in Appendix G.1.2. Based on that analysis, we use a Black-Scholes volatility parameter value of 90% for the calculation of the option values.

Strike Price: This is the price at which the customer is willing to undertake a curtailment. as discussed above. For this analysis we used strike prices in the range from $100/MWh to $500/MWh.

Curtailment duration constraints affect the acceptable frequency and duration of curtailments. Different organizations have different constraints on how many hours they can curtail, how much notice they need, and how frequently they can do it. DADRP protocols establish the notice (a day ahead) and frequency (hourly) of pricing periods. If those are not acceptable, then the customers will not participate. DADRP also allows customers to submit blocked bids that require the curtailment be of a specified length, say four consecutive hours. This prevents avoids a sequence of individual curtailment hours that are separated by one or more non-curtailment hours. Many customers report that such curtailments are the most costly to endure. (Which is why the blocking provision was enacted.) To characterize block bidding, this analysis assumes that bids are submitted for blocks of on-peak hours that accommodate the customer's situation. In addition we specify alternative levels of the monthly maximum hours of curtailment of 20 to 200 hours as a proxy for customers' tolerance or the total number of curtailment it is exposed to.

Interest rate: For option value calculations one needs to use risk-free interest rates. Considering that the forward curves we are using are in real terms (2000 dollars), we need to use risk free real interest rates. The Treasury Yield Curve indicates that the interest rates are about 1.5% for one-year maturity, and about 3% for 5-year maturity. Deducting the inflation rate we used an interest rate of 1%.

Time frame: As described the option value is calculated for the on-peak hours of each month for a five-year period. This approach gives a lower bound to the option value since it corresponds to a flexibility level where the customer accepts the average on-peak price for its curtailment. Customers that can turn equipment on and off every hour can generate greater value for that enhanced optionality than our results produce.

Curtailment Option Value Simulation Results

The results for option values for curtailment are presented in Table 7-6.. A curtailment level of 200 hours corresponds to a customer with a very high level of flexibility; the customer can curtail about 10 hours each of the 20 weekdays of the month. Table 7-6 shows that for a customer with that level of flexibility, and a strike price of $0.10/kWh, the revenue generated from participating in the day-ahead market will be $139,000 for the 5-year period. This value reduces to $42,000 for a strike price of $0.50/kWh.[7]

The strike price is assumed to reflect the bidder's entire variable operating expenses and/or revenue losses. The option value calculated can also be adjusted to account for the initial investment (e.g. in control equipment installed to facilitate the curtailment) needed to enable participation, and the NPV of any operating expenses. (See *Inclusion of DADRP in the CSP Business Case*, above.)

Table 7-6. Option Value of Curtailment for 5 Years of Operation (thousand $/MW)

Monthly Limit (hours)	Strike Price ($/kWh)				
	0.10	0.20	0.30	0.40	0.50
20	14	9	6	5	4
100	70	44	32	25	21
200	139	87	64	50	42

Assumptions: Price volatility of on-peak power = 90%
Risk-free real interest rate = 1%
All prices in year 2000 dollars.

[7] Even though the higher strike price produces more revenue for each hour in which these loads are scheduled, the number of hours scheduled falls proportionally greater and as a result total revenue declines.

Distributed Generation Option Value

The DG units considered in this section are assumed to be fueled by natural gas. (We have not considered diesel generators since they do not currently qualify to participate to the DADRP program.)

DG Model

Owning a natural gas generator is equivalent to owning a strip of spread options, one for each time period. Option value is the expected value of payoff where

Payoff = max [power price - (HR*gas price + variable O&M), 0]

The above expression can also be separated into marginal revenue (MR) and marginal cost (MC). Power price is MR, and the term in parentheses is MC. Whenever the MR exceeds MC, generators are run (provided there are no other operational constraints).

To value the option, the probabilistic nature of the power prices and gas prices needs to be characterized. In this preliminary work, we used rather a simplistic model where the spread (power price – HR*gas price) is assumed to be distributed normally. Volatility is not the standard Black-Scholes volatility; it is the absolute volatility of the spread (see Appendix 7.B for the details of the model).

Every time period is a separate option. Total value of the generation optionality is the sum of these option values throughout the lifetime of the equipment. As was invoked above, the value is determined for a five-year period, which is shorter than the typical lifetime of natural gas driven generators. However, the uncertainty in price forecasts beyond years militates using an abbreviated lifetime to evaluate the investment.

The strike price is mainly the variable operating costs for running the equipment. The other important factor in valuing the distributed generation option is the Heat Rate (HR) of the equipment.

The fixed O&M is not part of the strike price. Such costs are bundled with the investment costs and compared to the option value in order to qualify the technology as economic or not.

DG Assumptions

The important differences in this model are with regard to the specification of the forward curve and volatility, how strike prices are set, and constraints on curtailment bidding imposed by environmental regulations. These are described below.

Forward Curve: Gas forward curve is from taken from the 2002 New York State Energy Plan and is presented in Appendix G.1.1. The model uses monthly values but the gas price data is annual. If and when a forecast of monthly-prices is available, that needs to replace the numbers used here.

Volatility: The absolute volatility of power-gas price spread is developed from historical price data in Appendix G.1.2. In this analysis an annualized value of $80/MWh is used.

Strike Prices (Variable O&M): Typical values for variable O&M costs for gas driven technologies are around $7/MWh. We present results for values close to this number.

Heat Rate (HR): A heat rate of 11400 Btu/kWh is assumed. This corresponds to 30% efficiency that is representative of the more efficient micro-turbines.

Customer constraints on frequency and duration of DG operation: Different organizations have different constraints on how many hours they can run generators, and how frequently they can do it usually depending on environmental regulations. In this study, we evaluated monthly maximum hours of generation at intervals between 20 to 200 hours as a proxy for environmental and other constraints.

Interest rate: As was the case above, we used a real interest rate of 1%.

Time frame: The values given in the results section are the sum of the monthly peak period option values for 5 years of operation.

DG Option Simulation Results

The option values simulated for gas-driven distributed generation are presented in Table 7.3.2. The values are comparable to the costs of installing some classes of gas driven technologies (such as micro-turbines). These results indicate that, where constraints permit operating close to 200 hours/month, natural-gas driven technologies such as micro-turbines may be feasible. The revenues generated would still not support fuel cell technologies at current technology costs.

Table 7-7. Option Value of Gas Driven Distributed Generation for 5 Years

of Operation (thousand $/MW)			
Monthly DG Dispatch Limit (hours)	**Variable O&M ($/MWh)**		
	4	**7**	**10**
20	**52**	**51**	**49**
100	**262**	**254**	**246**
200	**524**	**507**	**491**

Assumptions: (a) Spread volatility (absolute) $80/MWh; (b) Risk-free real interest rate = 1%; (c) Prices in Year 2000 dollars; (d) Heat Rate = 11,400

Future Work

Improvements in ICAP/EDRP modeling: In the preceding sections we evaluated the ICAP/EDRP opportunities using historical event data. ICAP/EDRP events are mainly driven by the level of reserves. Ideally we would look at historical reserve data and also historical events and come up with a probabilistic model for the ICAP/EDRP occurrences. Since in these programs the payment to the customers is also a function of the real-time prices, we need to model the real-time LBMPs together with the events with the appropriate correlation. The valuation model can be constructed as a Monte-Carlo simulation model. Events and prices are generated using the event process and the results for a large number of simulations constitute the output of the model. The mean value of the cash flow is the forecasted value of participation.

Required Improvements in DADRP Modeling: The forward curves and volatilities used in this model need to be improved to put this analysis in line with what the more sophisticated companies are doing in the market. Forward curves used here may not be in line with the traded forward prices.

In reality, volatilities are not constant as assumed here, thus rendering the results of the Black-Scholes model speculative. Models need to be developed to reflect the seasonality of volatility. Also, the volatilities need to be in line with the prices of traded options. Also, the introduction of hourly volatilities will better estimate the true value of hourly flexibility, and evaluate alternative curtailment strategies.

Mo*deling displacement together with curtailment (discretionary load) and DG:* In this report we covered curtailment and DG. Another important type of demand response is displacement where the customer shifts the time of energy use without reducing the overall volume. To value this type of response one needs to model the power-price spread between on-peak and off-peak.

Modeling Intermediaries: The value added by intermediaries can be modeled, and in some cases quantified. For example, the addition of controls leads to greater hourly flexibility and therefore increases the option value. Other entities can provide risk management services that complement a curtailment strategy and produce greater profits.

Customer Modeling: The customer constraints will have a great influence on the value once the hourly valuation is introduced. Many organizations have complex operational constraints and they may use optimization techniques to extract the most value given their constraints. Similar optimization techniques need to be utilized in the valuation model.

Table 7-1A Subscribed and actual performance by 2002 NYSERDA PON participants

Summer 2002 Events Only & NYSERDA 2002				
	All EDRP Subscribers			
	Overall Total Number of EDRP Subscribers	Total Pledged Hourly MW Reduction	Total Average Hourly MWH Performance	Wgt. Performance Ratio
Non-NYSERDA	1,407	1,254.7	552.6	0.44
Peak-Load Only	118	31.5	1.5	0.05
Enabl. Tech Only	183	186.7	110.3	0.59
Both	3	5.5	4.5	0.81
Totals	**1,711**	**1,478.3**	**668.8**	

	Subset of All EDRP Subscribers with positive EDRP Performance							
	Number of Customers	% of Total Analyzed	Total Pledged Hourly MW Reduction	% of Total Analyzed	Total Average Hourly MWH Performance	Wgt. Performance Ratio	Total Summer 2001 MW Performance	Total Summer 2002 Program NYISO Payments
Non-NYSERDA	1,168	83%	1,071.5	85%	552.6	0.51	5,448.8	$2,724,381
Peak-Load Only	18	15%	5.6	18%	1.5	0.27	14.9	$7,474
Enabl. Tech Only	128	70%	169.4	91%	110.3	0.65	1,102.9	$551,440
Both	3	100%	5.5	100%	4.5	0.81	44.7	$22,329
Totals	**1,317**	**77%**	**1,252.0**	**85%**	**668.8**		**6,611.2**	**$3,305,622**

Table 7-1B Subscribed and actual performance by NYSERDA PON participants who re-enrolled from 2001 or enrolled in Summer 2002

	All EDRP Subscribers			
	Overall Total Number of EDRP Subscribers	Total Pledged Hourly MW Reduction	Total Average Hourly MWH Performance	Wgt. Performance Ratio
Non-NYSERDA	1,370	1,168.4	493.2	0.42
Peak-Load Only	146	102.5	51.9	0.51
Enabl. Tech Only	185	187.8	110.9	0.59
Both	10	19.7	12.8	0.65
Totals	**1,711**	**1,478.3**	**668.8**	

	Subset of All EDRP Subscribers with positive EDRP Performance - Cumulative							
	Number of Customers	% of Total Analyzed	Total Pledged Hourly MW Reduction	% of Total Analyzed	Total Average Hourly MWH Performance	Wgt. Performance Ratio	Total Summer 2001 MW Performance	Total Summer 2002 Program NYISO Payments
Non-NYSERDA	1,138	83%	988.6	85%	493.2	0.50	4,855.0	$2,427,479
Peak-Load Only	40	27%	73.4	72%	51.9	0.71	518.8	$259,377
Enabl. Tech Only	130	70%	170.5	91%	110.9	0.65	1,109.3	$554,673
Both	9	90%	19.5	99%	12.8	0.66	128.2	$64,093
Totals	**1,317**	**77%**	**1,252.0**	**85%**	**668.8**		**6,611.2**	**$3,305,622**

Appendix 7B – Market Maker Survey Instrument

BACKGROUND

Neenan Associates has been asked by New York State Energy Research and Development Authority (NYSERDA) to help it develop programs to promote participation in demand response programs. The survey that follows was designed to collect information on the relative preferences for alternative NYSERDA programs by entities, like yourself, that are or might provide demand response program services.

NYSERDA administers the New York State electric system benefits fund to promote economic growth in the state through the wise and effective use of electricity. These programs include investments in conservation devices, alternative generating technologies, and more recently in promoting demand response program participation. NYSERDA's focus in the past two years has been on increasing participation in the demand response programs implemented by the New York Independent System Operator (NYISO).

NYSERDA desires to understand how demand response contributes to the business goals of firms that are either currently involved in implementing such programs in New York, or that are or might be considering involvement in the near future. More specifically, NYSERDA desires to identify and characterize the factors that these entities indicate are critical to their sustained involvement in demand response programs in New York so it can better tailor its programs to these needs.

Neenan Associates will treat all information provided by respondents as strictly confidential, including the identity of the respondents. The information received will be used in summary form, or as non-attributed specific responses, to advise NYSERDA on how it can design programs that are attractive to a variety of demand response providers.

Please complete the attached survey and return it to:

Bernie Neenan

Neenan Associates

Tel. 315.478.9974
Fax 315.478.9982

Email bneenan@bneenan.com

If you'd like to complete the survey over the phone, or discuss the survey and NYSERDA programs further, please call Bernie Neenan at the number provided above.

Thanks for taking time to help NYSERDA design effective demand response programs.

Survey respondent (individual): ______________________________

Entity (business)________________________________Date__________

Phone # ______________ email ______________________________

INFORMATION YOU PROVIDE WIL BE HELD CONFIDENTIAL AND CONVEYED IN SUMMARY FORM OR WITHOUT ATTRIBUTION TO THE RESPONDANT

Section 1.0 Business Characterization

Q 1.1. Which of the following best describes your primary business activity (check one)?

☐ **Regulated (POLR) commodity provider**

☐ **Competitive commodity provider**

☐ **Curtailment service provider (no commodity or wires services)**

☐ **Electricity wholesale trading and financial services**

☐ **Information technology equipment/service provider**

☐ **Controls technology equipment/service provider**

☐ **Performance ESCO**

☐ **Other (Please specify)__________________________________**

2002 NYISO PRL Evaluation

Q 1.2. What hurdle rate does your firm require for investments in new business lines?

☐ **ROI (%) ____________percent**

☐ **Payback ____________years**

Q 1.3. Which of the following best describes how you see demand response contributing to your business objectives (check one)?

☐ **Specialize in demand response, as a curtailment service provider**

☐ **Complement to commodity service business**

☐ **Complement to wires services business**

☐ **Complement to control technologies business**

☐ **Complement to information technologies business**

☐ **Other (Please specify)_____________________________________**

Q 1.4. What do you see as the primary barriers to achieving your goal with regard to demand response (list in order of importance)?

1st.____
____
____

2nd.____
____
___

3rd.____
____
___

Q 1.5 Should regulators or state policy makers direct public benefit funds to promote demand response? Please elaborate on your choice.

Yes.____

No.____

Q 1.6 Which of the following best describes you view on how demand response programs should be administered (please check one)?

- ☐ **ISOs should design and administer demand response programs directly to retail customers**
- ☐ **ISOs should offer demand response programs but only through POLR and competitive retailers**
- ☐ **ISOs should not be involved in demand response programs that should be left to competitive entities**

Please provide comments to support your choice

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Section 2.0. Experience with Demand Response Programs

Q 2.1. Was your firm involved with the designing or implementing load management programs *prior to 1998*? If so, please indicate your involvement for those you indicate yes in the adjacent columns.

Load Control Program Involvement Prior to 1998						
Yes or no	**Sector**	**Type (see key)**	**State**	**Design (see key)**	**Implement-ation (see key)**	**Enabling Technology (see key)**
	Residential					
	Commercial					
	Industrial					

Key for Type (select the one that best describes the program):

Utility sponsored **DLC** = direct load control

Utility sponsored **LC** = Load curtailment

Utility sponsored **RTP** = Real-time pricing

Other = O (describe) ___________________

Key for Design - includes setting program features and preparing and filing tariffs of other authorizations.

Key for Implementation - recruitment of participants, billing and other customer services.

Key for Enabling Technology - supplying and/or installing meters, meter reading and visualization equipment, load control technologies

Q 2.2. Which of the following best describes why you implemented a demand response program?

☐ **Avoid peak capacity investment**

☐ **Prevent uneconomic bypass/cogeneration investments**

☐ **Load profile reshaping**

☐ **Promote expanded electricity usage**

☐ **Other (specify) ____**

Q 2.3. What was the highest level of participation you realized?

Sector	Number of Participants	Curtailable MW
Residential		
Commercial		
Industrial		

Q 2.4. Is the program (are the programs) still in operation?

☐ **YES**

☐ NO - why was it (were they) eliminated?

____

Q 2.5. Was your firm involved with ISO-based load management program *outside of New York State? If so, please* Indicate your involvement for those you indicate yes.

Involvement in ISO Program in CA, TX, PJM or ISO-NE						
Yes or no	**Sector**	**Type (see key)**	**State**	**Design**	**Implement-ation**	**Enabling Technology**
	Residential					
	Commercial					
	Industrial					

Key for Type (select the one that best describes the program):

ISO sponsored capacity program = **ICAP**

ISO sponsored emergency program = **Emergency**

ISO sponsored energy bid or load following program = Energy

Key for Design - includes setting program features and preparing and filing tariffs of other authorizations.

Key for Implementation - recruitment of participants, billing and other customer services.

Key for Enabling Technology - supplying and/or installing meters, meter reading and visualization equipment, load control technologies

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Q 2.6. What was the highest level of participation you realized in that ISO-based program?

Program Type	Number of Participants	Curtailable MW
ICAP		
Emergency		
Energy		

Q 2.7. Has your firm been involved with price-responsive load programs implemented by NYISO ? *If so, please* Indicate your involvement for those you indicate yes.

Involvement with NYISO-based Programs						
Yes or no	Sector	Type (see key)	State	Design	Implement-ation	Enabling Technology
	Residential					
	Commercial					
	Industrial					

Key for Type (select the one that best describes the program):

ISO sponsored capacity program= **ICAP**

ISO sponsored emergency program = **Emergency**

ISO sponsored energy bid or load following program = **Energy**

Section 3.0. Relative Preferences for Alternative Program Initiatives

NYSERDA funds program initiatives through Program Opportunity Notices (PONs). It currently is evaluating the effectiveness, in attracting the participation of firms like yours, of PON initiatives directed at the various stages of the demand response business structure.

In the table below, please rank the value to your business of funding directed at each of the listed PON Initiatives. A score of 1 indicates little or no value to your business model, and value of 6 indicates a very high value. If there is a specific activity listed in the examples, or that you have identified, that stand outs as being especially useful to you, please so indicate in the Comments column.

Table 1. Alternative Programs to Support Demand Response

Stage	PON Initiative	Examples	Value 1-6: 1 (low), (high)	Comments (add'l space at the end of the document)
1	General Concept Promotion and Education	• Generic brochures • Briefings, workshops • Testimonials, Case Studies		
2	Individual customer Assessment and Training	• Self-administered workbook • Tailored, on-site audit • Web-based, interactive audit		
3	Marketing and Subscription	• Sales goals incentives • Sales materials budget		
4	Essential Technology	• Meter acquisition • Meter installation • Meter reading		
5	Enabling Technology	• Event Communications • Meter gateway • Web-based meter access		
6	Program Administration	• Billing systems or services		
7	Performance Benefits	• Augment NYISO payment levels • Guaranteed # curtailment opportunities each year • Cover noncompliance penalties		
8	Other-specify			
9	Other-specify			

Section 4.0. Relative Preferences for Alternative Program Initiatives

In the table below, for each Stage and PON initiative, please indicate the Percentage Funding you would like to see devoted to the indicated PON Initiative.

Table 2. Allocation of PON Funding to Best Promote Demand Response for Your Business Model

Stage	PON Initiative	Percentage Funding PON Initiative	Comments
1	General Promotion and Education		
2	Individual customer Assessment and consulting		
3	Marketing and Subscription		
4	Essential technology		
5	Enabling technology		
6	Program Administration		
7	Augment Performance Benefits		
8	Other-specify		
9	Other- specify		
	TOTAL	100%	

Section 5. Comments

Q. 5.1 Do you have additional comments or recommendations you would like brought to NYSERDA's attention? If so, please write them out in the space below. Comments and suggestions will be conveyed to NYSERDA and others without attribution.

Comments and suggestions

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Thanks again for taking time to help NYSERDA design effective demand response programs.

Appendix 7C: Business Case Models

Energy Price Modeling

<u>Forward Prices</u>

<u>*Forecast of Power Prices*</u>

The power price forward view was developed using results from AEO2002, which and are shown in Fig. 7-7.

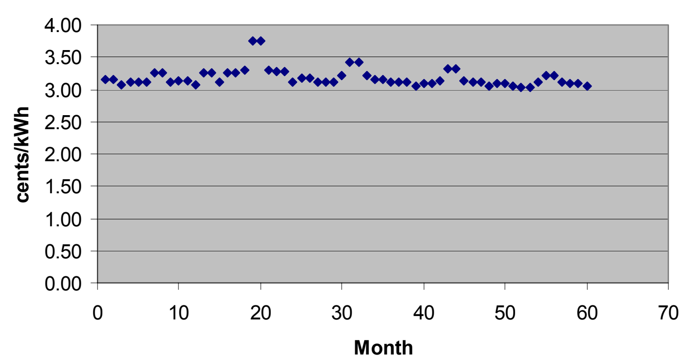


Fig. 7-7 Power Forward Curve

<u>*Forecast of Natural-gas Prices*</u>

Gas price forward view is derived from the 2002 New York State Energy Plan and is shown in Fig. 7-8.

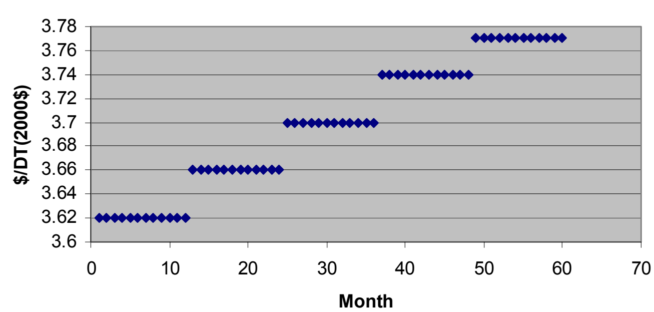


Fig. 7-8 Gas Forward Curve

<u>Price Modeling</u>

<u>*Analysis of Historical Prices:*</u>
<u>*Determination of Power Price Volatility*</u>

We compiled and analyzed the historical day-ahead prices for NYISO. Fig. 7-9 shows the day-ahead prices. Fig. 7-10 shows the level and seasonal nature of price volatility that needs to be represented the price model. The volatilities shown in this figure are the standard deviations of daily price returns. For each day the daily price return is:

$$\text{SD of Returns} = \{[\text{price}(t+1)-\text{price}(t)]/\text{price}(t)\}.$$

$$= \{\ln(\text{price}(t+1)/\text{price}(t)\}$$

The standard deviation of such returns for days from 15 days before to 15 days after gives the 30-day rolling price volatility.

Black-Scholes model assumes that the volatility is constant over time. The figure in this page clearly shows that the volatility does not stay constant over time; it exhibits as distinct seasonal pattern and perhaps a subtler day-type pattern. However, it appears that the level of the volatilities in spring and summer months have been coming down, and during calmer seasons the volatilities have been around 90%. Based on this chart we used a longer-term volatility of 90%. This gives a conservative value for the options considered. Higher volatilities generate higher option values.

Fig. 7-9 Historical Day-Ahead On-Peak Prices for Power

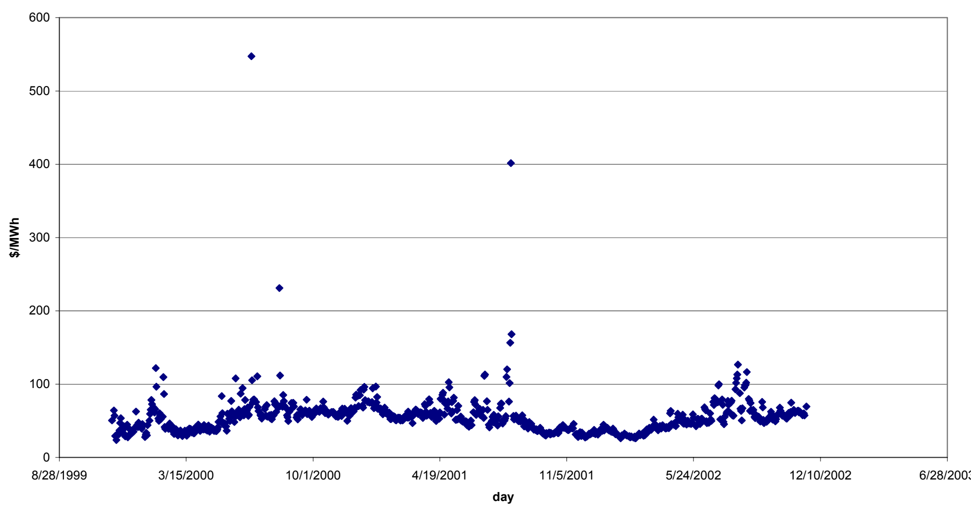


Fig. 7-10 30-day Rolling Annualized On-Peak Volitility for Power

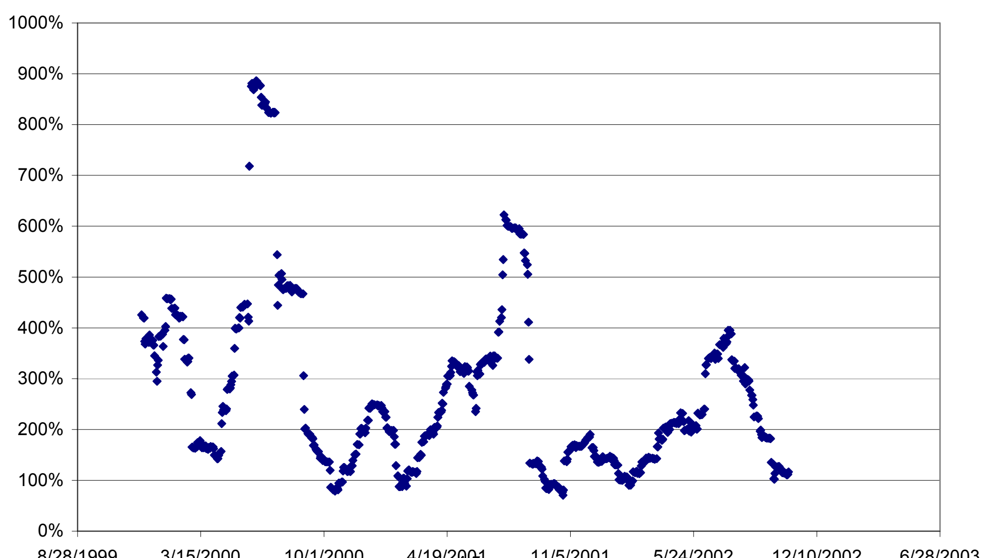


Fig. 7-11 shows the historical gas prices in the New York area.

In some modeling approaches, we use the distribution of the spread between power and gas prices directly. Fig. 7-12 shows the historical spread values.

Fig. 7-11 Historical Gas_Daily Natural Gas Price Index (Transco Zone 6, NY)

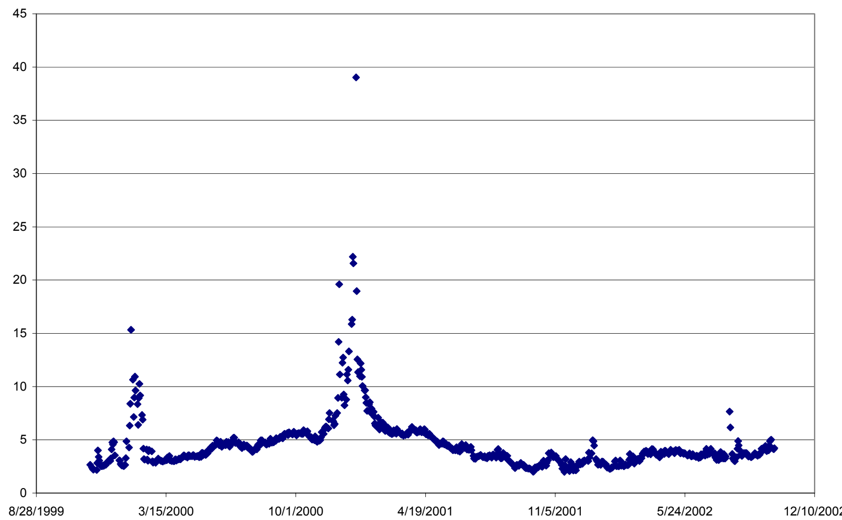


Fig. 7-12 Historical Spread between Power and Gas Prices

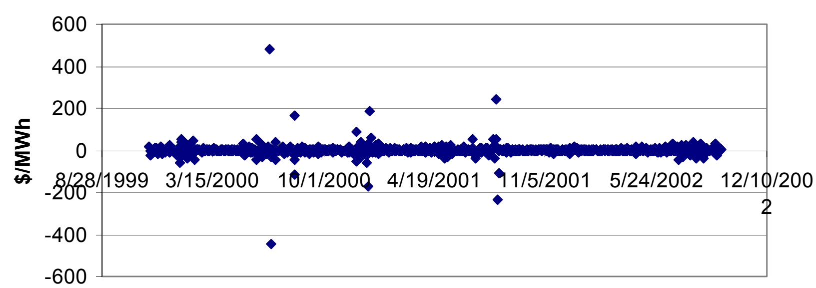
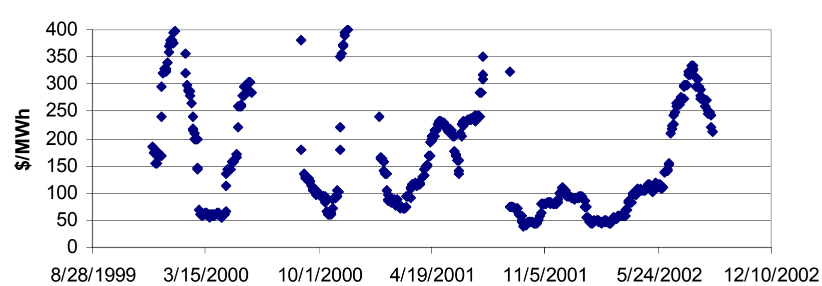


Fig. 7-13 shows the volatility of the spread. It is the absolute volatility of the spread. In other words, it is the standard deviation of [spread(t+1) – spread(t)].

Fig. 7-13 30-day Rolling Annualized Absolute Volatility of Spread



Option Pricing Models

Load Curtailment Options Model

$$Option\ Value_t = e^{-rt}[P_t\ N(d) + Strike\ N(d - \sigma\sqrt{t})]$$

$$d = \frac{\ln(P_t / Strike) + 0.5\ \sigma^2\ t}{\sigma\sqrt{t}}$$

$$P_t = forward\ \ price\ of\ \ power$$

$$r = risk\ \ free\ discount\ rate$$

$$\sigma = Black - Scholes\ volatility$$

$$Strike = strike\ price$$

$$N(.) = normal\ distribution\ \ function$$

Distributed Generation Options Model

$$Option\ Value_t = e^{-rt}[(P_t - HR * G_t - Strike)N(d) + \sigma\sqrt{t}\ n(d)]$$

$$d = \frac{P_t - HR * G_t - Strike}{\sigma\sqrt{t}}$$

$$P_t = forward\ \ price\ of\ \ power$$

$$G_t = forward\ \ price\ of\ \ gas$$

$$HR = heat\ rate$$

$$r = risk\ \ free\ discount\ rate$$

$$\sigma = absolute\ volatility$$

$$Strike = \mathrm{var}iable\ O\ \&\ M$$

$$N(.) = normal\ distribution\ \ function$$

$$n(.) = normal\ density\ \ function$$