ELECTRIC POWER RESEARCH INSTITUTE

Energy Storage and Distributed Generation Technologies

Real Options Valuation/Benefit Case Studies

Technical Report

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Real Options Valuation/Benefit Case Studies

1010746

Final Report, March 2006

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This report describes research sponsored by the Electric Power Research Institute (EPRI).

The report is a corporate document that should be cited in the literature in the following manner:

Energy Storage and Distributed Generation Technologies: Real Options Valuation/Benefit Case Studies. EPRI, Palo Alto, CA: 2006. 1010746.

PRODUCT DESCRIPTION

The major elements of the electricity generation, transmission, and distribution system normally operate at a nominal fraction of their full capacity because the assets are designed for the most extreme operating conditions. For summer-peaking utilities, this capacity corresponds, more or less, with hot, humid days in the summer months when commercial and industrial electricity customers are themselves running at peak capacity. Utilities and other service providers delivering electricity have tremendous financial incentives to build flexibility into this system—by using processes and technologies designed to increase asset utilization while reliably producing and distributing electricity at the lowest possible cost. Economic evaluation tools and analysis techniques must be sophisticated enough to account for the complexity inherent in the new electricity value chain while giving managers the ability to fairly consider new technology investments in a re-regulated business environment. These tools and techniques will be used to make investments in a *hybridized* electricity grid comprised of basic, familiar, and proven assets integrated with specialized technologies designed to create new operating flexibility and efficiency benefits that can be shared with an increasing number of stakeholders, including electricity customers.

Results & Findings

This report builds on the foundation concepts created in an earlier report, *Energy Storage Technology Valuation Primer: Techniques for Financial Modeling* (EPRI report 1008810, 2004). The document uses advanced valuation techniques described in that report with actual data used by two utilities—New York Power Authority and Public Service Electric & Gas Company—making investments in distributed generation and energy storage *today*. This new report helps close the gap between the abstract, textbook approach to financial modeling (and its hypothetical examples) and the “real-world” by using that data to better understand how to value investments in new technologies. Each investment decision was modeled with traditional discounted cash flow methods and then with advanced valuation techniques, including Monte Carlo simulation and Real Options. The economic and strategic values in each investment alternative were quantified. Importantly, the value of managerial flexibility embedded in each investment could be calculated, leading to a more rigorous analysis of each investment alternative.

Challenges & Objective

Utilities considering energy storage or distributed generation technologies need tools and evaluation methods to assist them with decision-making. These decisions can be challenging because new energy storage and distributed generation technologies must often compete for scarce capital with projects using more familiar technologies that are perceived to have lower risk. The challenge is even greater where the regulatory environment has eliminated the integrated electric utility providing all three functions of generation, transmission, and distribution. As channel participants increase, extracting the value of system flexibility afforded by energy storage or distributed resources become more difficult. As such, the objective of this project is to give decision makers a tool to assist them with assessing candidate technology investments, particularly those with multiple beneficiaries (and, increasingly, multiple investors).

Applications, Values & Use

The techniques described in this report can be used by utilities considering investments in new technologies, in research and development (R&D) settings, or in any environment where technologies considered 'risky' must compete with familiar, incumbent technologies with proven track records. The process used enables an analyst or manager to build a case for strategic investments that will produce economic value in the future and to rely less on qualitative assessments of new technologies.

People who will benefit from this report are those interested in understanding the value of energy storage devices (e.g., batteries, ultra-capacitors, flywheels, compressed air energy storage plants) or distributed generation (e.g., fuel cells, micro-turbines, sterling engines, or reciprocating engine-generators), or both. Indeed, investments in both energy storage and distributed generation technologies are under consideration for both case study participants. Readers also should be those interested in how best to incorporate new technologies into the existing electric grid and how to fairly evaluate technology alternatives with different risk profiles.

EPRI Perspective

EPRI believes that the techniques used in this report offer members a way to critically assess new technology options like energy storage or distributed generation technologies. These techniques also allow analysts to use a quantitative methodology to support business decisions involving investments in *any* energy technology where uncertainties in both the technology (e.g., in cost and performance) and in the number and type of benefits exist.

Approach

The approach used in this report was to take the analysis techniques described in EPRI report 1008810 and apply them to actual investment decisions under consideration by two EPRI members contemplating investments in either energy storage, distributed generation, or both. EPRI members provided data, participated in developing refined models, and helped identify strategic values/benefits embedded in current investment opportunities. Results were shared periodically with the participating utilities and EPRI members during development of each model. This approach allowed insights and perspectives from those who have encountered similar investment decisions in the past to be incorporated into the final tool and results.

Keywords

Energy storage, Load leveling, Batteries, Power quality, Flywheels, Electrochemical capacitors
Compressed air energy storage (CAES), Distributed generation, Monte Carlo simulation
Real options, Decision science

ABSTRACT

Electric Utilities considering investments in advanced energy storage and distributed generation technologies used in transmission and distribution systems need valuation techniques that account for the different cost and benefit combinations resulting from new technologies and their different risk characteristics, especially for technologies in early commercialization stages.

This report shows how Monte Carlo simulation and Real Options analysis tools can be used to quantify strategic value and economic value in energy storage and distributed generation technology investments, using actual case data provided by two different utilities, New York Power Authority based in White Plains, N.Y., and Public Service Electric & Gas Company (PSE&G), based in Newark, N.J.

The report illustrates a structured valuation process that uses actual data from utility investment decisions and shows how an analyst may quantify the value of flexibility inherent in most typical investment decisions. The work builds on the foundation work provided in an earlier report, *Energy Storage Technology Valuation Primer: Techniques for Financial Modeling*, EPRI Report #1008810 published in December 2004, and shows how such models can be practically constructed using data and models provided by EPRI members.

ACKNOWLEDGMENTS

The case studies in this report were produced with assistance and guidance from John L. Del Monaco, Melvin L. Zwillenberg and Joe Lalier from PSE&G, and Yan Kishinevsky and Guy Sliker from New York Power Authority.

EPRI thanks these individuals for providing access to data used in energy storage and distributed generation investment decisions, and for providing insights and suggestions for refinements as the models were developed for the cases contained in this report.

High Energy Consulting received valuable guidance and contextual understanding of the history of the research and development and commercialization efforts for new electricity technologies from Dr. Robert Schainker, the EPRI project manager responsible for this report. Steve Eckroad from EPRI also provided insights and practical experience that were helpful for creating the energy storage technology maintenance and life models used in this report.

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1
INTRODUCTION

The case studies in this report provide details of investment decisions made by EPRI member utilities in energy storage technologies and distributed generation technologies. Each case begins with a spreadsheet model designed to compare investments in new technologies with competing investments in assets possessing long track records of use in transmission and distribution systems.

The cases build on the foundation material provided in a previous EPRI report, *Energy Storage Technology Valuation Primer: Techniques for Financial Modeling*, #1008810, and show how risk can be quantified and accounted for in the investment decision along with the strategic value in the investment opportunity—hidden value that is usually assessed only qualitatively in processes relying solely on discounted cash flow techniques.

Spreadsheets are invaluable for financial modeling, and enable us to make an estimate of the value of an investment opportunity; for example, spreadsheets can be used to make a projection of cash flows, an income statement, or a breakeven analysis. For the case studies included in this report, we'll create a spreadsheet for different energy storage and distributed generation investment opportunities, and we will use this *Deterministic Cash Flow Model* as the *starting place* for the valuation process shown in Figure 1-1, resulting in estimates for both strategic and economic value. The process will create a characterization of the risk in the investment opportunity.

The process used in this report is dynamic and allows for ongoing refinement as analysts and managers acquire better information about an investment opportunity. The process is flexible enough to allow the user to systematically apply judgment and critical thinking to the investment decision, while employing software designed for use in most modern personal computers and commonly used operating systems installed on these personal computers.

The iteration step shown in Figure 1-1 is used whenever opportunities exist to reduce the project risk in the investment decision—the risk under the control of the project team. This step illustrates that actions should be taken to reduce project risk when such efforts are justified, while systematically revealing the sources of market risk that will result in strategic value.

The process ends with the economic value and the strategic value estimates that are important for decision-making. The former category is well known and usually quantified using discounted cash flow techniques. The latter category is rarely known and is usually only assessed qualitatively in the absence of valuation techniques used in this report. Our objective is to show you how to quantify strategic value with real options and to confidently identify the sources of value enabling you to make better investment decisions, especially for new technologies.

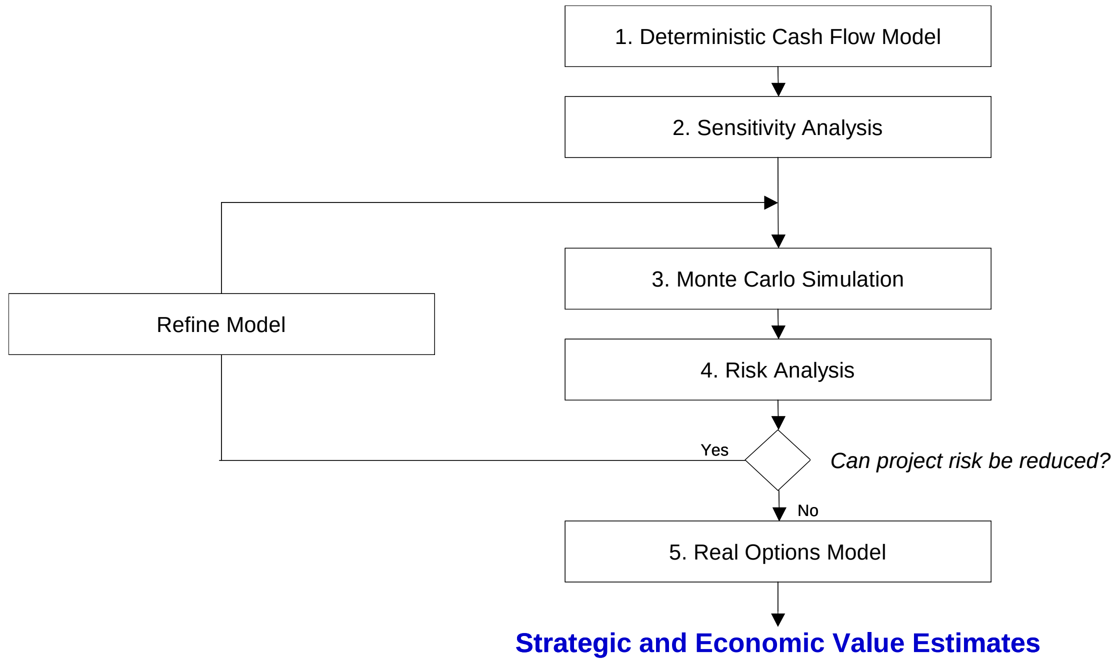

Figure 1-1
Valuation Process

The descriptions for each of the five steps are as follows:

1. **Deterministic Cash Flow Model.** Step 1 includes the creation of a basic spreadsheet model used to calculate the net present value of the investment opportunity. It is essentially a summary of all of the expected costs and benefits associated with the investment in energy storage or distributed generation facilities over a period of several years, known as the modeling period. All of the cash flows are discounted to today's present value, resulting in the net present value (NPV), of the investment opportunity. The model is known as a deterministic model because a group of input assumptions results in a *single* model output.[1]

2. **Sensitivity Analysis.** The second step of the process is used to begin to understand the relative importance of the different input variables in the model created in step 1. The model is exercised, by making small changes in the value of each input variable while holding all of the other input variables constant, noting the change in the output variable, NPV. This step is simple, yet important, as it highlights the input variables that deserve greater scrutiny. This step will also be useful for characterizing the risk in the investment opportunity. Usually, the output variable, in this case NPV, is highly sensitive to small changes made independently in just a handful of input variables. It is helpful to view these variables graphically or with data tables; the analyst will begin to understand how the model itself might be refined, by focusing on the input variables that matter the most.

[1] A deterministic model can also be used to produce a unique *set* of outputs, a group of outputs evaluated together. Because we are interested in modeling the strategic value in the investment opportunity by using real options, we will also need to model a second output, known as the *project cash inflows*, which is simply the present value of the benefits received by the investing company during the modeling period. As we will see later, it is the risk in the project cash inflows that largely determines the value of any options embedded in the investment opportunity.

3. **Monte Carlo Simulation.** In this step, a probability distribution is assumed for each of the important input variables. This step basically characterizes the risk in each of the input variables, drawing on the analyst's experience and empirical data where it is available. For some of the input variables, it will make sense to gather historical data to help with the task of estimating the range of possible values and the shapes of the distributions assumed for these values. A simulation of the valuation model output value(s) results from running a Monte Carlo software tool which essentially recalculates the spreadsheet thousands of times using input values varying over ranges selected by the analyst, in proportion to the assumed input distribution shapes. A histogram of the output results and statistical analysis will be used to quantify the risk in the investment opportunity.

4. **Risk Analysis.** The risk analysis step enables us to identify and analyze the risks that can be controlled (project-specific risks) and those that cannot be controlled (market risks). The former risk category should be minimized. The latter risk category will be used to shed light on where the strategic value in the investment opportunity might be found. Invariably, the modeling activities completed to this point will reveal model refinements that should be made immediately. In other words, there will be risk in some input variables that can be reduced immediately, by gathering historical data, or by modifying the deterministic model to more accurately represent the relationships in the opportunity. In short, what usually begins with a simple model grows in complexity where such complexity is warranted. This iterative step is shown in the *Refine Model* step shown after Step 4 in Figure 1-1.

5. **Real Options Model.** When the model is sufficiently refined, opportunities for managerial flexibility are identified and the investment opportunity is modeled as a Real Option. The current investment opportunity itself is either viewed as an option to make a larger investment in the future, or the current investment opportunity is modeled as an investment that can be delayed. In this stage, we'll quantify the strategic value resulting from managerial flexibility using real options and the economic value quantified with discounted cash flow analysis. We'll study the relationships between the two sources of value and identify the types of investments that may be warranted.

2
CASE 1 – NYPA SODIUM SULFUR BATTERY

Background

New York Power Authority (NYPA) is the largest state-owned electric power organization in the United States, with 17 generating facilities and over 1,400 miles of transmission lines. As a generation and transmission utility, NYPA serves numerous customer groups, including government agencies, rural electric cooperatives, municipal utilities, private utilities and neighboring states. NYPA finances projects through bond sales to investors and internal sources of cash, with bondholders paid through proceeds from operations.

NYPA is a national leader in energy efficiency and the development of clean energy technologies and electric vehicles. Its research and development activities include investments in new transmission technologies and energy storage systems. In 2005, NYPA began investigating the feasibility of installing a battery energy storage system for Long Island Bus Company, who purchases electricity from a distribution utility, Long Island Power Authority (LIPA). Long Island Bus Company is a subsidiary of New York Metropolitan Transportation Authority (MTA), an organization that also purchases electricity from NYPA directly.

The Long Island Bus Company currently has one of the most successful alternative fuel programs in the country, with more than 200 buses currently powered by natural gas. This large program required the installation of a natural gas fueling station at an existing bus depot. A pair of 600 hp electric compressors increases the pressure of the gas for bus fueling, and the installation of these compressors resulted in increased energy consumption and 1100 KW of additional electric demand. In addition, labor for the fueling station is provided by Long Island Bus Company 24 hours/day and requires three eight-hour labor shifts.

NYPA first proposed the idea of using a Sodium Sulfur (NAS) battery energy storage system to reduce the electricity charges associated with the fueling station by using electricity during off-peak periods to charge the batteries, and use the stored energy from the batteries during the peak periods when the energy and demand charges are the highest. This solution would also enable Long Island Bus Company to eliminate the labor associated with a third shift, since refueling operations would now be possible during periods where electricity costs were previously cost-prohibitive. The NAS project was sized to accommodate the fueling needs for up to 220 buses.

A deterministic model was prepared by NYPA to evaluate the costs and benefits associated with the NAS battery energy storage for peak shaving, and this model was used as the starting point for the case study. Throughout 2005, the model was refined several times and the risks were quantified using the process valuation process described in Chapter 1.

Step 1: Deterministic Cash Flow Model

NYPA first created a model of the electricity use, demand and cost for the Long Island Bus Company fueling station compressors using the current LIPA tariff and a spreadsheet. The primary cost elements of the current electricity rate tariff are summarized in Table 2-1.

Table 2-1
LIPA Electric Rate Tariff for Long Island Bus Company

LIPA Tariff	Rate	Energy ($/kWh)	Demand ($/kW/month)
I, off peak	Midnight-7am	$ 0.0440	$ 0.000
II, peak	June-Sept, Mon-Sat, 10am-10pm	$ 0.0762	$ 34.350
III, intermediate	All other times	$ 0.0737	$ 3.420

NYPA modeled two scenarios using the LIPA tariff: 1) the total annual electricity cost of using the natural gas fueling station compressors during peak periods without any energy storage benefits, and 2), the total annual electricity cost of using the compressors during peak periods with energy provided by a 1.2 MW NAS Battery System charged during off-peak periods. The modeled electricity usage, demand and cost totals for each of scenarios are shown in Table 2-2.[2] Detailed summaries for modeled electricity energy and demand costs for all rate schedule periods for each scenario are shown in Tables 2-3 and 2-4.

Table 2-2
Modeled Electricity Costs for 1.2 MW NAS Battery

Operating Scenario	Annual Electricity Energy Charges ($)	Annual Electricity Demand Charges ($)	Total Annual Electricity Costs ($)
1. Operating compressors during peak periods without the benefit of an energy storage system	$122,684	$47,880	$170,564
2. Operating compressors during peak periods with energy from 1.2 MW NAS battery storage system charged during off-peak periods	$157,718	$6,576	$164,294
Net Difference	**$35,035**	**($41,304)**	**($6,269)**

[2] NYPA actually modeled several other operating scenarios, including alternatives with different gas compressor operating profiles and summer-only operation for the NAS battery energy storage system. This case incorporates the operating scenario with the highest overall net economic benefit.

Table 2-3
Cost to Shift Peak Compressor Demand, No Battery Energy Storage System

LIPA Tariff	Rate	Energy ($/kWh)	Demand ($/kW/month)
I, off peak	Mid-7am	$ 0.0440	$ -
II, peak	Jun-Sep, Mon-Sat, 10a-10p	$ 0.0762	$ 34.350
III, intermediate	All other	$ 0.0739	$ 3.420

June/July/August/September

Weekday					
Time Period	**Tariff**	**Run Hours**	**Demand (kW)**	**Daily kWh**	**Energy Cost ($)**
Midnight to 7 AM	Off-Peak	6	1100	4,950	$ 217.80
7 AM to 10 AM	Int.	0	0	0	$ -
10 AM to 8 PM	Peak	0	0	0	$ -
8 PM to 10 PM	Peak	0	0	0	$ -
10 PM to Midnight	Int.	2	1100	1,650	$ 121.94
Daily Total		**8**		**6,600**	**$ 339.74**

Saturday					
Time Period	**Tariff**	**Run Hours**	**Demand (kW)**	**Daily kWh**	**Energy Cost ($)**
Midnight to 7 AM	Off-Peak	6	1100	4,950	$ 217.80
7 AM to 10 AM	Int.	0	0	0	$ -
10 AM to 8 PM	Peak	0	0	0	$ -
8 PM to 10 PM	Peak	0	0	0	$ -
10 PM to Midnight	Int.	2	1100	1,650	$ 121.94
Daily Total		**8**		**6,600**	**$ 339.74**

Sunday					
Time Period	**Tariff**	**Run Hours**	**Demand (kW)**	**Daily kWh**	**Energy Cost ($)**
Midnight to 7 AM	Off-Peak	6	1100	4,950	$ 217.80
7 AM to Midnight	Int.	1.3	1100	1,073	$ 79.26
Daily Total		**7.3**		**6,023**	**$ 297.06**

Table 2-3
Cost to Shift Peak Compressor Demand, No Battery Energy Storage System (Continued)

4-Month Summer Period Summary					
	Energy ($)	**Demand ($): Peak**	**Demand ($): Intermediate**	**4-Month Total kWh**	**4-Month Total**
Weekday Total	$ 29,605.48	$ -	$ 15,048.00	575,143	$ 44,653.48
Saturday Total	$ 5,921.10			115,029	$ 5,921.10
Sunday Total	$ 5,177.29			104,964	$ 5,177.29
4-Month Total	**$ 40,703.87**	**$ -**	**$ 15,048.00**	**795,135**	**$ 55,751.87**
				$/kWh	$ 0.0701

October to May (8-Months)

Weekdays					
Time Period	**Tariff**	**Run Hours**	**Demand (kW)**	**Daily kWh**	**Energy Cost ($)**
Midnight to 7 AM	Off-Peak	6	1200	5,400	$ 237.60
7 AM to Midnight	Int.	1.5	1200	1,350	$ 99.77
Daily Total		**7.5**		**6,750**	**$ 337.37**

Weekends					
Time Period	**Tariff**	**Run Hours**	**Demand (kW)**	**Daily kWh**	**Energy Cost ($)**
Midnight to 7 AM	Off-Peak	6	1200	5,400	$ 237.60
7 AM to Midnight	Int.	1.5	1200	1,350	$ 99.77
Daily Total		**7.5**		**6,750**	**$ 337.37**

8-Month Fall/Winter/Spring Period Summary					
	Energy ($)	**Demand ($): Peak**	**Demand ($): Intermediate**	**8-Month Total kWh**	**8-Month Total**
Weekday Total	$ 58,556.93	$ -	$ 32,832.00	$ 1,171,607.14	$ 91,388.93
Weekend Total	$ 23,422.77			$ 468,642.86	$ 23,422.77
8-Month Total	$ 81,979.70	$ -	$ 32,832.00	$ 1,640,250.00	$ 114,811.70
	$ 122,683.56		**$ 47,880.00**	**$/kWh**	**$ 0.0700**
			Total	**2,435,385**	**$ 170,563.56**

Table 2-4
Cost to Shift Peak Compressor Demand with 1.2 MW NAS Battery

LIPA Tariff	Rate	Energy ($/kWh)	Demand ($/kW/month)
I, off peak	Mid-7am	$ 0.0440	$ 0.000
II, peak	Jun-Sep, M-Sat, 10a-10p	$ 0.0762	$ 34.350
III, intermediate	All other	$ 0.0737	$ 3.420

June-September

Weekday								
Time Period	**Tariff**	**Compressor Hours**	**Compressor KW**	**Battery Run Hours**	**Charge Hours**	**Battery KW**	**Daily kWh**	**Energy Cost ($)**
Midnight to 7 AM	Off-Peak	1	1100	0.0	7.0	1,000	7,825	$ 344.30
7 AM to 10 AM	Int.	0	0	0.0	3.0	233	700	$ 51.58
10 AM to 8 PM	Peak	4	1100	4.0	4.0	92	368	$ 28.04
8 PM to 10 PM	Peak	2	1100	2.0	1.0	92	92	$ 7.01
10 PM to Midnight	Int.	1	1100	1.0	1.0	92	92	$ 6.78
Daily Total		**8**		**5.3**	**7.7**		**9,077**	**$ 437.72**

Saturday								
Time Period	**Tariff**	**Compressor Hours**	**Compressor KW**	**Battery Run Hours**	**Charge Hours**	**Battery KW**	**Daily kWh**	**Energy Cost ($)**
Midnight to 7 AM	Off-Peak	1	1100	0	7.0	1,000	7,825	$ 344.30
7 AM to 10 AM	Int.	0	0	0	3.0	233	700	$ 51.58
10 AM to 8 PM	Peak	4	1100	4	4.0	92	368	$ 28.04
8 PM to 10 PM	Peak	2	1100	2	1.0	92	92	$ 7.01
10 PM to Midnight	Int.	1	1100	1	1.0	92	92	$ 6.78
Daily Total		**8**		**5.3**	**7.7**		**9,077**	**$ 437.72**

Table 2-4
Cost to Shift Peak Compressor Demand with 1.2 MW NAS Battery (Continued)

Sunday								
Time Period	**Tariff**	**Compressor Hours**	**Compressor KW**	**Battery Run Hours**	**Charge Hours**	**Battery KW**	**Daily kWh**	**Energy Cost ($)**
Midnight to 7 AM	Off-Peak	1	1100	0	6.9	1,000	7,755	$ 341.22
7 AM to Midnight	Int.	6.3	1100	6.3	6.0	92	552	$ 40.68
Daily Total		**7.3**		**4.7**	**12.9**		**8,307**	**$ 381.90**

4-Month Summer Period Summary								
	Energy ($)	**Demand ($): Peak**	**Demand ($): Intermediate**				**4-Month Total kWh**	**4-Month Total**
Weekday Total	$ 38,143.74	$ -	$ 3,191.54				681,893	
Saturday Total	$ 7,628.75						158,197	
Sunday Total	$ 6,656.01						144,779	
4-Month Total	**$ 52,428.50**	**$ -**	**$ 3,191.54**				**984,869**	**$ 55,620.04**

October-May

Weekdays								
Time Period	**Tariff**	**Compressor Hours**	**Compressor KW**	**Battery Run Hours**	**Charge Hours**	**Battery KW**	**Daily kWh**	**Energy Cost ($)**
Midnight to 7 AM	Off-Peak	1	1200	0	7.0	1,000	7,900	$ 347.60
7 AM to Midnight	Int.	6.5	1200	5.8	6.0	92	1,155	$ 85.12
Daily Total		**7.5**		**4.4**	**13.0**		**9,055**	**$ 432.72**

Table 2-4
Cost to Shift Peak Compressor Demand with 1.2 MW NAS Battery (Continued)

Weekends								
Time Period	**Tariff**	**Compressor Hours**	**Compressor KW**	**Battery Run Hours**	**Charge Hours**	**Battery KW**	**Daily kWh**	**Energy Cost ($)**
Midnight to 7 AM	Off-Peak	1	1200	0.0	7.0	1,000	7,900	$ 347.60
7 AM to Midnight	Int.	6.5	1200	5.8	6.0	92	1,182	$ 87.11
Daily Total		**7.5**		**4.4**	**13.0**		**9,082**	**$ 434.71**

8-Month Fall/Winter/Spring Period Summary								
	Energy ($)	**Demand ($): Peak**	**Demand ($): Intermediate**				**8-Month Total kWh**	**8-Month Total**
Weekday Total	$ 75,108.44	$ -	$ 3,384.22				1,571,689	$ 75,108.44
Weekend Total	$ 30,181.53	$ -					630,550	$ 30,181.53
8-Month Total	**$ 105,289.97**	**$ -**	**$ 3,384.22**				**2,202,240**	**$ 108,674.19**
	$ 157,718.47		**$ 6,575.77**			**Total:**	**3,187,109**	**$ 164,294.23**

There exists a net economic benefit to using the battery energy storage system during peak periods, although in this case, the benefit is small relative to the total cost of the project. The project reduces annual demand charges by $41,304, but these savings are mostly offset by the increased energy needed to charge the batteries during off-peak periods. After subtracting this annual cost increase of $35,035, the net benefit associated with reduced total electricity cost is $6,239 annually.[3]

For this project, the peak shaving benefits alone are not enough to produce an attractive return on the investment (ROI). The main economic benefit from this project is expected to be the labor savings associated with the elimination of a third shift at Long Island Bus Company, a benefit estimated to be worth $220,000 annually. At one stage in the analysis, there was a belief that the distribution utility, LIPA, might also provide its customer with an incentive under a Peak Reduction Program, and this annual benefit was initially estimated at $500/KW, or, $50,000.[4]

The first cost-benefit model created by NYPA is shown in Table 2-5. In this model, NYPA proposes to finance the project for Long Island Bus Company over 12 years, at 3.00% interest. The project is estimated to cost $3,097,668, with nearly half of this cost, $1,500,000, to be reduced by other investments, primarily from the Department of Energy and the New York State Energy Research and Development Authority (NYSERDA). The net amount to be financed, $1,597,668, will result in an annualized cost of $158,703 for the installed equipment. NYPA initially estimates $10,000 for annual operations and maintenance (O&M) costs.

The net annual savings, $107,566, is simply the difference between the estimated annual benefits ($220,000 + $50,000 + $6,239) and the estimated annual costs ($158,703 + $10,000). Even without the assumed peak shaving incentive of $50,000, the project model shows positive cash flow. From this initial analysis, NYPA decides to proceed with project development. Note, however, the importance of the other investments: if the customer finances the *entire* project cost of $3,097,668, the annual financing cost rises to $307,705 and the project implementation results in negative cash flow, ($41,436) annually, or ($91,436) without the peak shaving incentive. It is doubtful that the Long Island Bus Company would accept a project with negative cash flow, unless there were other reasons for investing in the project.

The value of the project, even at this early stage in the analysis, is obviously sensitive to some of the input assumptions. There is risk in the project that we should try to characterize and quantify. Ultimately, we will want a good understanding of risks that are within our control

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[3] The numerical data in this report is taken directly from the inputs and outputs used in the actual computer programs used to model the opportunity and contain more significant digits than would be used in a management summary report. Management reports should ordinarily only include 2 or 3 significant digits, at most.

[4] This estimated benefit was later removed from the analysis, for a variety of reasons. LIPA's current *Peak Reduction Program* is designed for customers who can commit to "contracted demand" reduction on days when customer demand for electricity might exceed available supply. Participants in this program are using Standby Generators, shifts in production and non-essential equipment shutdowns to shed at least 50 KW on "critical days." Investors in energy storage systems used for peak shaving should not assume that there is no incentive available from the distribution utility (beyond reduced demand charges), however, and should investigate utility programs, particularly with service providers known to develop customized incentive programs for demand control.

(project risk or unique risk) and risks outside of the control of the project team (market risk or systemic risk), and can identify steps to reduce risk where this effort is worthwhile.

Table 2-5
Initial Cost-Benefit Model, 20 G50 NAS Batteries with EPS

Material	$2,465,428
Installation	$326,435
System engineering, project management	$54,203
Permit	$35,000
Subtotal System Costs, including: - Overall System Engineering - 2 x 600kVA PCS - 13.8k/400V, 1200kVA transformer - 1 x 100kVA aux. power distribution/combiner - 1 x 13.8kV breaker (exist enclosure) - 1 x 20 module NAS battery system, controls - 1 main controller - 1 lot installation, commission - 1 lot drawings, PE stamp civil, permits - 1 NAS battery permit estimate	**$2,881,066**
Extended Warranty, 3 Years	$116,602
Battery Disposal	$100,000
Total Cost (before other investments)	**$3,097,668**
NYSERDA investment	$1,000,000
Other Cost Sharing	$500,000
Total Financed	$1,597,668
Interest Rate	3.00%
Loan Term (years)	12
Monthly Payment	$13,225
Annual Capital Cost	$158,703
Annual O&M	$10,000
Annual Energy Cost Savings	$6,269
Annual Labor Cost Savings	$220,000
Credit for EPS @ $500/kW	$50,000
Total Annual Savings	**$107,566**

NYPA developed the deterministic model further by revising the input values based on new information, with the revised inputs shown in Table 2-6. Note that the project cost has increased by $856,477 to $3,954,145, the investments from other interested parties have been increased by $67,500, and the annual O&M costs have increased from $10,000 to $22,054. In addition, a new variable has been added: the annual degradation in energy storage system performance, a variable representing the expectation that battery modules may fail over the 12 year life of the equipment. In the initial model NYPA had assumed that the equipment capacity (for providing electricity for the gas compressors during peak periods) would decline by 2.0% annually.

Table 2-6
NYPA Sodium Sulfur Battery Financial Model, Revised Input Assumptions

Valuation Model Assumptions	Nominal Value	High Estimate	Low Estimate
Capital Cost (including design, installation, commissioning, project management)	**$3,954,145**	**$4,349,560**	**$3,558,731**
Other investments from NYSERDA/DOE:	$1,000,000	$1,100,000	$900,000
Investments from all other sources (EPRI, LIPA, other participating utilities)	**$567,500**	**$624,250**	**$510,750**
Annual O&M	**$22,054**	**$24,259**	**$19,849**
Battery Disposal Cost (assumed to occur at the end of the project life)	$100,000	$110,000	$90,000
Interest rate	3.0%	3.3%	2.7%
Reduction in demand charges	$41,304	$45,434	$37,174
Increase in energy costs (for recharging batteries)	$35,035	$38,539	$31,532
Reduction in fueling station labor charges	$220,000	$242,000	$198,000
Credit for EPS	$50,000	$55,000	$45,000
Project life (years)	12.0	12.0	12.0
Annual degradation in energy storage system performance	**2.0%**	**3.0%**	**1.0%**

The new and revised input values are highlighted in bold typeface in Table 2-6. Note that we are now calling these input values “nominal values,” which means that they are our most likely estimates for each of the input values. We’ve also added a “high estimate” and a “low estimate” for each of the input variables, representing the range that we initially expect *actual* input values to fall within. For each input variable, except for project life and annual degradation in system performance, we’ll start with an assumption that the nominal value is in the middle of a range with uncertainty of +/- 10%.[5] We’ll model the impact project life risk in a later model revision.

NYPA proposed a larger range for the assumed degradation in system performance, ranging from a low value of 1% to a high value of 3% to characterize how uncertain this value is at this stage of model development. NYPA further built in a safety factor into its calculations by assuming that only 1.0 MW of the battery capacity would be used to supply the gas compressors over the life of the project—not the full 1.2 MW installed. The inclusion of a *safety factor* is a

[5] The choice of a +/- 10% input uncertainty range is arbitrary, and was used to initiate a discussion to determine what the actual values might be. As we will see later, only a few of the input variables are really driving most of the risk in this project—these will be the variables where we will want to do a better job of estimating not only the ranges for the input values, but also the assumed probability distributions.

common way to deal with input variables characterized by uncertainty, and is often used as the basis for the claim that operating assumptions are conservative. In short, NYPA accounted for the risk of performance degradation by assuming that only 1.0 MW of capacity would be available over the 12-year assumed life of the equipment and not the entire 1.2 MW rated capacity.

Finally, we structure the deterministic model as a cash flow statement, with cash inflows (project benefits) on top and cash outflows (project costs) on the bottom. The cash flows are discounted to the present value using the assumed cost of capital of 3.00%.[6]

For simplicity, only the first five years of the cash flow projection are shown in the resulting output model shown Table 2-7. The system is not expected to produce any benefits after Year 12, and this is the year that the expected costs of battery disposal will be incurred. Note that the assumed degradation in system performance is reflected in the declining values for benefits associated with reduced demand charges and EPS peak-shaving credits from LIPA.

Table 2-7
NYPA Sodium Sulfur Battery Deterministic Model, Revised Input Assumptions

Year	0	1	2	3	4	5
Cash outflows						
Energy to charge NAS batteries		($35,035)	($35,035)	($35,035)	($35,035)	($35,035)
O & M		($22,054)	($22,054)	($22,054)	($22,054)	($22,054)
Battery disposal cost						
Project cost	($3,954,145)					
Total costs	**($3,954,145)**	**($57,089)**	**($57,089)**	**($57,089)**	**($57,089)**	**($57,089)**
Cash inflows						
Labor costs savings		$220,000	$220,000	$220,000	$220,000	$220,000
Reduction in demand charges		$41,304	$40,478	$39,668	$38,875	$38,097
Credit for EPS		$50,000	$49,000	$48,020	$47,060	$46,118
Construction other investments	$1,567,500					
Total benefits	**$1,567,500**	**$311,304**	**$309,478**	**$307,688**	**$305,935**	**$304,216**
Cash flow	**($2,386,645)**	**$254,215**	**$252,389**	**$250,599**	**$248,846**	**$247,127**
Present value of cash flow	($2,386,645)	$246,811	$237,901	$229,334	$221,096	$213,174
Net Present Value	**($12,090)**					

For this deterministic model, the resulting NPV is slightly negative: ($12,090), an amount that is quite small relative to the size of the total investment of $3,954,145. In fact, we can imagine that

[6] This project assumes 100% debt financing, using NYPA's proposed financing rate for LIPA.

only a very small change in one or more of the input variables would change this to a positive NPV project—the usual criteria for traditional discounted cash flow investment decisions.

Step 2: Sensitivity Analysis

A sensitivity analysis is performed to begin to understand the relative contributions of each of the input variables to the risk in the project and to prioritize the inputs so that analysis time is spent efficiently. Sensitivity analysis (a measure of the incremental change in the output for an incremental change in each of the inputs) captures one of the two dimensions of risk[7] and is easily accomplished by simply changing each of the input values by a small amount, say, 1%, and noting the incremental change in the output value, in this case, NPV. The results summarizing the sensitivity analysis for each of the 12 input variables are shown in Table 2-8.

Table 2-8
NYPA Sodium Sulfur Battery Sensitivity Analysis

Valuation Model Assumptions	Nominal Value	Recalculated NPV after 1% Increase in Input Value	% Change in NPV for 1% Increase in Input Value (Absolute Value)
Capital Cost	$3,954,145	($51,631)	327%
Reduction in fueling station labor	$220,000	$9,809	181%
Project life (years)	12	$7,077	159%
Other investments from NYSERDA/DOE	$1,000,000	($2,090)	83%
Other investments from all other sources	567,500	($6,415)	47%
Credit for EPS	$50,000	($7,593)	37%
Interest rate	3%	($16,144)	34%
Reduction in demand charges	$41,304	($8,376)	31%
Increase in energy costs (for recharging batteries)	$35,035	($15,573)	29%
Annual O&M	$22,054	($14,289)	18%
Annual degradation in system performance	2%	($12,912)	7%
Battery Disposal Cost	$100,000	($12,771)	6%
Nominal NPV	($12,090)		

Not surprisingly, the results show that the value of this project is most sensitive to the capital cost. This result is expected whenever a project has an NPV that is small relative to the capital cost, as this project has. The second most important input value is the annual reduction in fueling station labor, which stands to reason since this is far and away the dominant source of benefits from the project. The assumed project life has also emerged as an important driver of value and will be examined more closely as the model is further refined.

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[7] The other important dimension of risk is the *uncertainty* in each input variable, characterized by the range and assumed probability distribution for each input variable. This risk component will be addressed later.

A change of only 1% in any of these top three input values is enough to change the NPV of the project from negative to positive. This insight provides us with the rationale for model refinements and also helps to prioritize the inputs requiring a more rigorous assessment of risk. We can also see which input variables might be safely ignored during the analysis. The battery disposal cost estimate of $100,000 is a good example. A small error in the estimate of a nominal cost that will not be incurred for 12 years has a quite negligible effect on the project NPV. Obviously, we would be better off understanding the risks in the capital costs, the reduction in fueling station labor charges and the life of the battery energy storage system.

Step 3: Monte Carlo Simulation

A Monte Carlo simulation is run for the model, using the 12 input variables identified. For each of the 12 input variables a triangular distribution is initially assumed with ranges corresponding to the values summarized in Table 2-6. More representative distribution shapes will be used later.[8] The assumed distribution for one of the input variables, the capital cost, and the frequency distribution for the values randomly chosen during the Monte Carlo simulation, is shown in Figure 2-1. This distribution shows a nominal value of $3,954,145 +/- 10% and the shape of the assumed distribution is a symmetrical triangle. At this stage in the analysis, it does not really pay to try to estimate more complex distributions, (lognormal, binomial, Poisson, etc.) until we have a better idea of which inputs are driving the uncertainty in the model. The triangular distribution is ideal for preliminary analysis where limited data is available and reasonable estimates can be made for the maximum, minimum and most likely values.

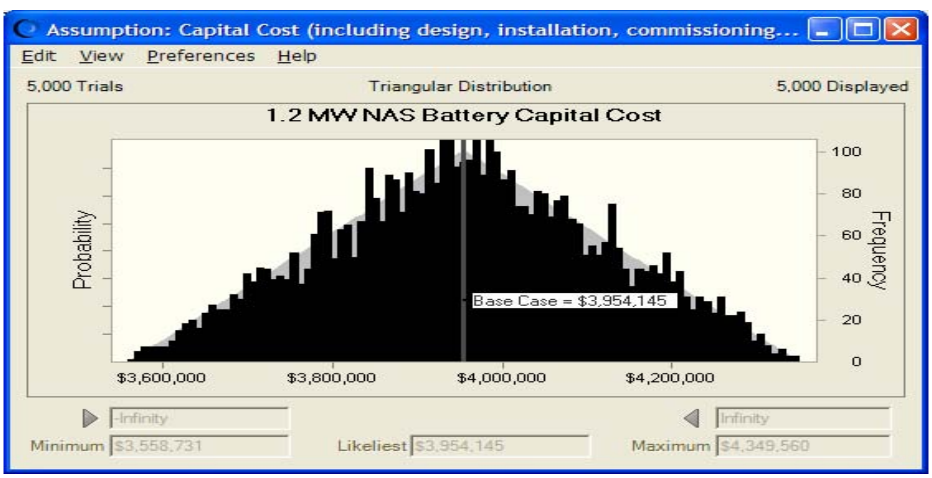


Figure 2-1
Probability Distribution, NAS Battery Capital Cost

8 Most Monte Carlo simulation tools allow numerous different input distribution shapes, including Gaussian, Lognormal, Weibull, Exponential, Uniform, and Binomial, for example. In the absence of better data, a symmetrical triangular distribution, with a nominal value at the center and boundaries representing the “best case” and “worst case” estimates are usually a reasonable starting place. As the model is refined, the input variables with the highest relative contribution to uncertainty will be modified with more representative assumed distribution shapes. For some variables, it will make sense to collect empirical or historical data and create custom distributions that more accurately represent the probabilities and input ranges that can be expected in the future.

The results of the simulation showing the range of possible values for the NPV are shown in Figure 2-2. The values corresponding to one and two standard deviations on either side of the base case NPV of ($12,090) are shown in Figure 2-3.

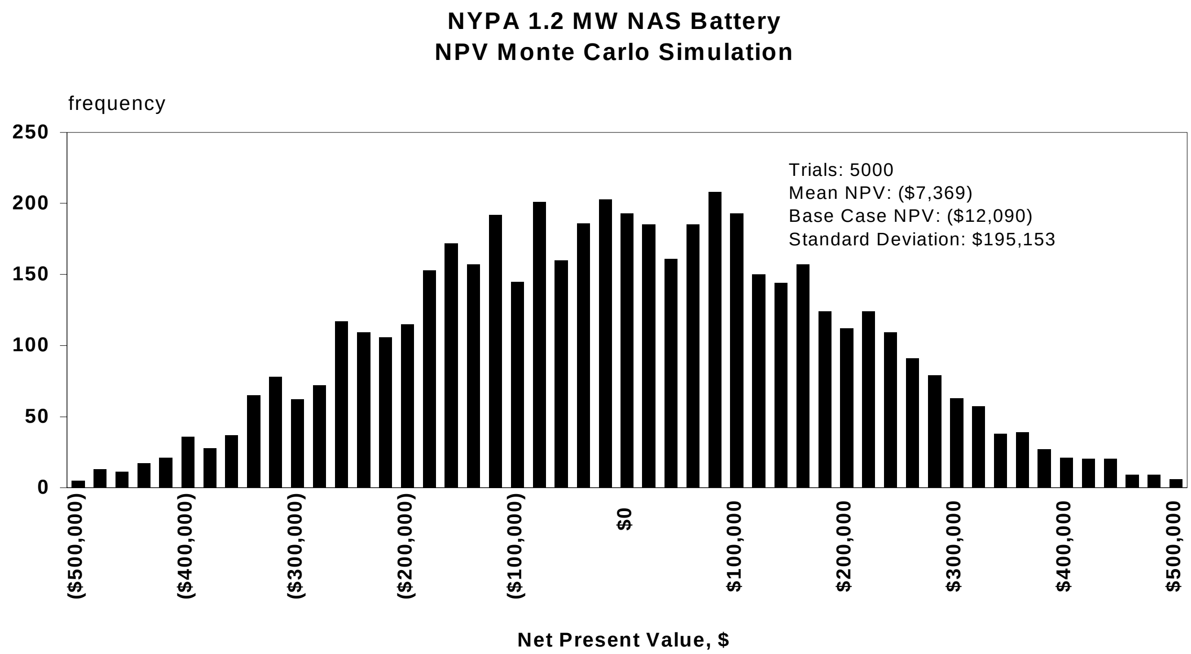


Figure 2-2
Monte Carlo Simulation, NYPA NAS Battery NPV

From these results, we can see that there is quite a large range of possible outcomes for this project, given the uncertainty assumed initially in each of the 12 input variables. The base case NPV of ($12,090) has a standard deviation of nearly $200,000. For a deterministic model, we can only really say that the NPV of this project is ($12,090), because a deterministic model has a single output associated with a single set of inputs. Following a Monte Carlo Simulation, we can say that the base case NPV is ($12,090) and that we believe, with 95% certainty[9], that the actual NPV will be between ($398,922) and $367,792. The shape of the distribution also leads us to conclude that we can be 47.20% certain that the NPV will be positive.

Do we have enough information to proceed with the investment? At this stage, the answer is “probably not.” Most of us would have difficulty justifying an investment of nearly $4 Million if we could only say that there was a 50-50 chance that the project would create positive value and that a loss of $400,000 was about as likely as a profit of $400,000. On the other hand, this might be the type of investment risk that is typical for early-stage investments in technologies without a long history of commercial applications.

[9] Two standard deviations will contain 95% of the data in the frequency distribution. If we wanted greater certainty, three standard deviations would contain 99% of the data.

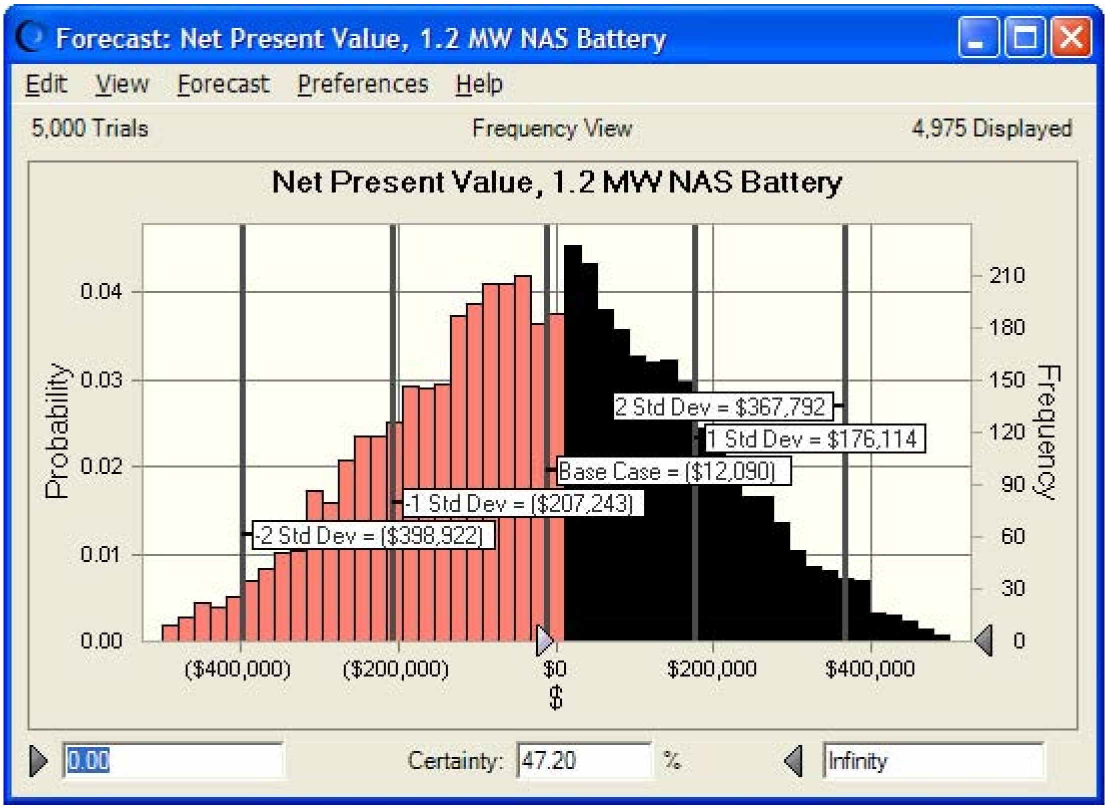


Figure 2-3
Monte Carlo Simulation, NYPA NAS Battery NPV, Standard Deviation

To further understand the risk in the NAS Battery investment opportunity, we'll model a second output: the present value of the project cash inflows. As we will see during the Real Options analysis, the risk in this output value is what drives the strategic value in the investment opportunity. This value corresponds with the cash flows coming back to the investor after the initial investment in the project is made. Referring back to Table 2-7, the project cash inflows are the cash flows *after* year 0, when the initial investment in the NAS battery project is to be made. In year 0, the present value of the cash flows is simply the difference between the installed project cost, ($3,954,145) and the assumed other investments, $1,567,500, which is ($2,386,645). The present value of the project cash flows after year 0 is $2,374,555. The difference between the net installed capital cost and the project cash inflows, obviously, is the NPV of ($12,090).

For real options analysis, we will need to understand the risk *and* the absolute value of the project cash inflows, as these are two of the fundamental inputs in the Black Scholes option pricing formula when this technique is used to model real options.

The Monte Carlo Simulation for the NAS Battery project cash inflows is shown in Figure 2-4. The first thing that you may observe is that there is quite a bit less risk in the project cash inflows than in the NPV distribution modeled earlier. The present value of the project cash inflows is $2,374,555, with a standard deviation of 4.1%.

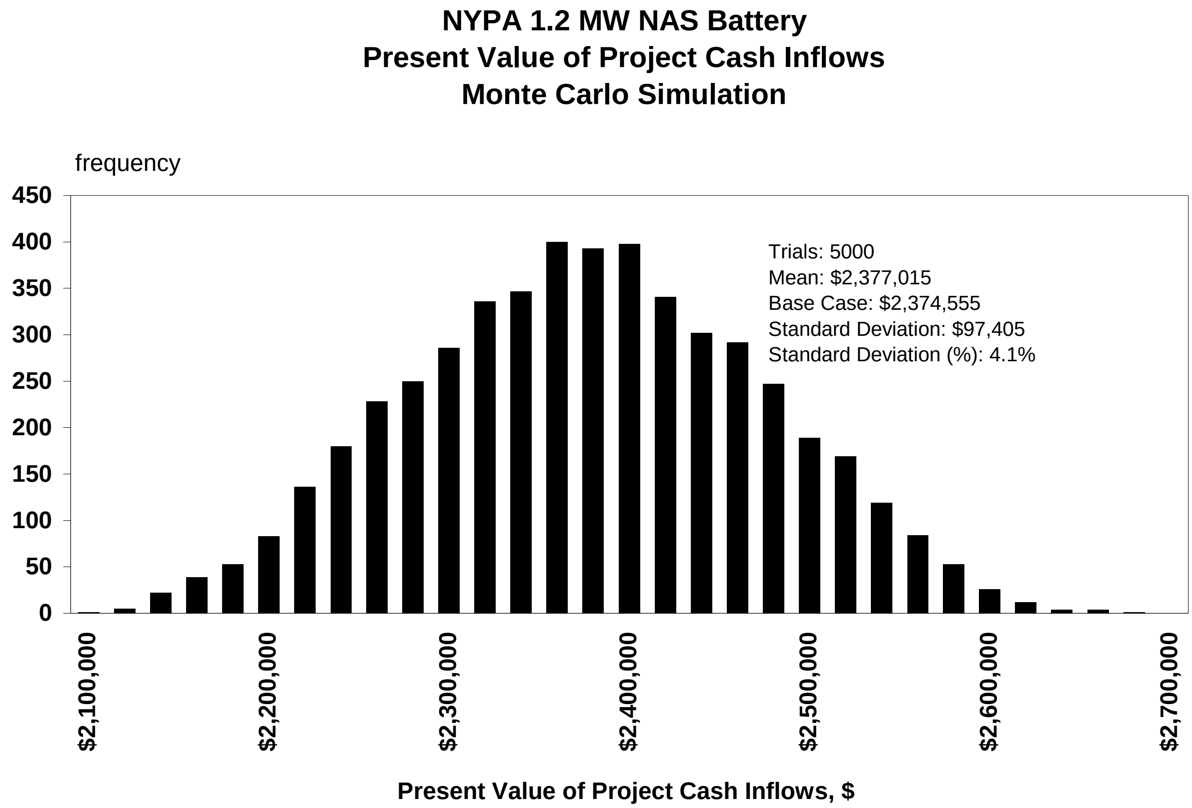


Figure 2-4
Monte Carlo Simulation, NYPA NAS Battery Project Cash Inflows

Figure 2-5 shows that we can say that the present value of the project cash inflows will be between $2,181,260 and $2,569,030 with 95% certainty.[10]

[10] A financial stock price analogy may prove helpful at this point. The investment in the 1.2 MW NAS battery, after subtracting the value of the other investments, is analogous to an investor buying 238,664 ½ shares of stock in ABC Company at the market price of $10.00 per share, for a total of investment of ($2,386,645). (Transaction costs are ignored). The investor has paid a fair amount for the ABC stock if the market price of $10.00 per share accurately represents the present value of the future cash flows produced by ABC Company. If the market price accurately represents the present value of the future cash flows, (this would be true in efficient markets), the present value of the future cash flows, discounted at the expected rate of return for stocks with similar risk, will be +$2,386,545 and the NPV of the transaction will be zero. If the stock is overpriced, and the actual value of 238,664 ½ shares of ABC stock as measured by the present value of the future cash flows is only +$2,374,555, or, $9.95/share, the net present value of the transaction would be ($12,090). The expected return for the stock is determined, in part, by the expected risk in the *future* cash flows. Past stock volatility is sometimes used as a proxy or guide for the expected future risk, and the investor in the ABC Company stock may have analyzed the company's daily stock prices for the past year and found them to vary between $9.59 to $10.41 for 68% of the time. If future volatility (or risk) were similar, this would correspond to a standard deviation of future cash inflows of 4.1%.

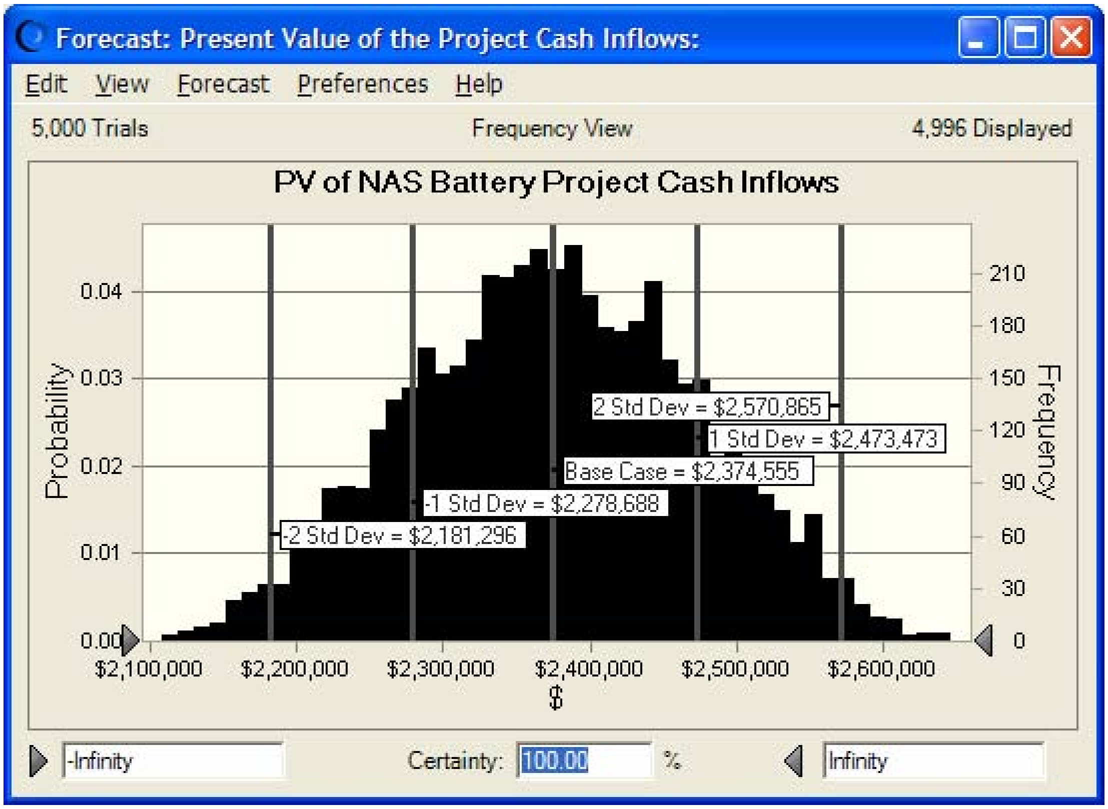


Figure 2-5
Standard Deviation of NYPA NAS Battery Project Cash Inflows

Step 4: Risk Analysis

Most of the risk associated with these project cash inflows is related to the uncertainty in the estimate for labor reduction associated with the elimination of a third shift at the fueling station. The risk in the output is dependent on the relative risk contributions from each of the model inputs. The risk contributed by each input is dependent on both the sensitivity *and* the assumed probability distribution for each of the model inputs.

The Monte Carlo simulation tool enables us to prioritize the model inputs in order of contribution to the risk in the model outputs. A simple way to see the contribution of each of the inputs to overall project risk is to rank the inputs by contribution to output statistical variance. When this exercise is completed for the project cash inflows, for example, (Figure 2-6) it is clear that the reduction in labor associated with the elimination of the third shift is by far the most dominant contributor to the risk in the project cash inflows output variable.

A similar ranking of input variables in order of contribution to the risk in the project NPV is shown in Figure 2-7. Here, we can clearly see that risk from the capital cost and the fueling station labor savings are the dominant drivers in overall risk in the overall project value.

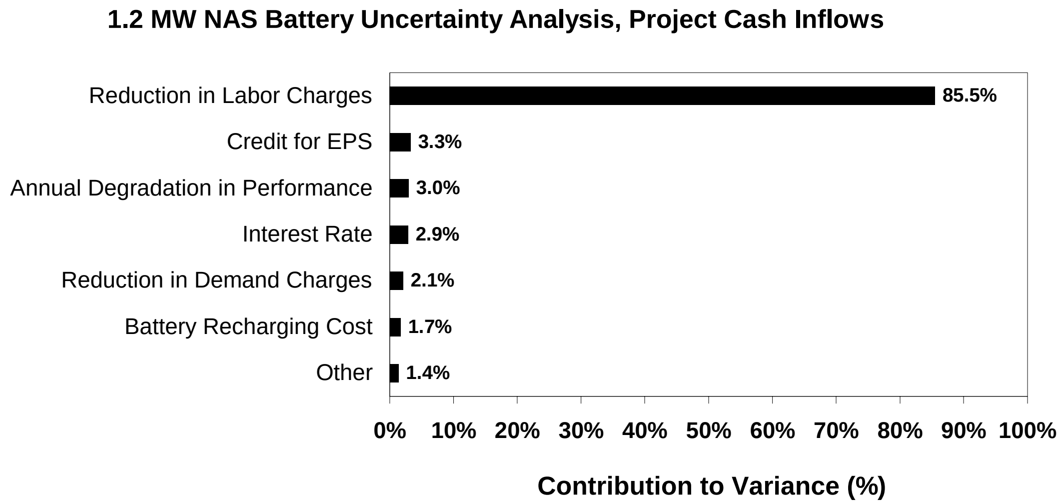


Figure 2-6
Uncertainty Analysis, NYPA NAS Battery, Project Cash Inflows

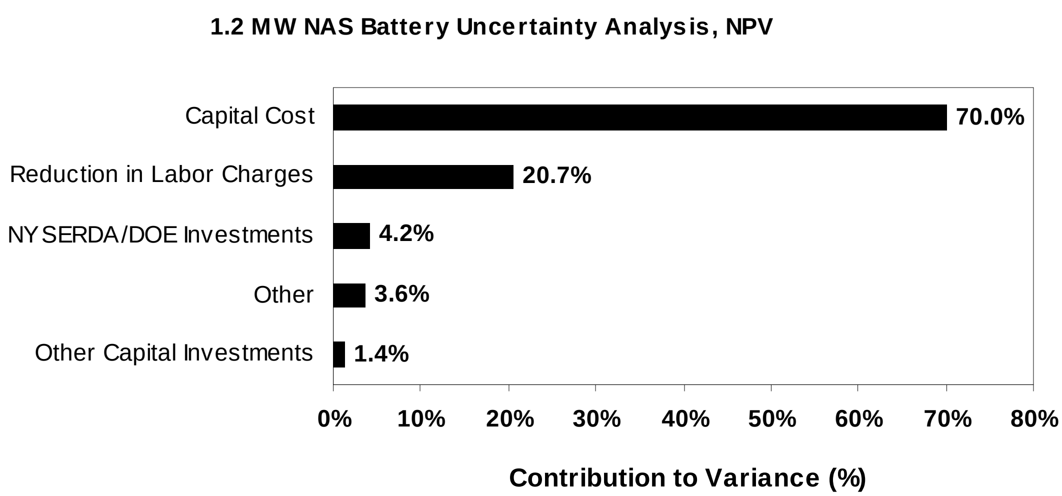


Figure 2-7
Uncertainty Analysis, NYPA NAS Battery, Project NPV

Model Refinement

Although the model is relatively basic at this stage, we now have a fair understanding of the value drivers and their relative contributions to overall project risk. NYPA further refined the model by reducing the risk in its estimates for three of the primary value drivers:

1. The installed costs for a 1.2 MW NAS Battery
2. The annual benefits associated with the reduction of labor at the LIPA fueling station
3. The useful life of the equipment

Focused attention in each of these areas and modifications of the algorithms used to calculate NPV should more accurately represent the risk in this project and enable us to confidently identify any real options embedded in the project so that strategic value can be calculated in addition to economic value.

We are now at the decision point in the flow chart illustrated in Figure 1-1 where the question is asked, *"Can project risk be reduced?"* The next section will provide an overview of a few of the ways that the model was revised to reduce project-specific risk.

Installed Costs for a 1.2 MW NAS Battery

NYPA reduced the risk in the estimate of the initial capital cost for designing, installing and commissioning a 1.2 MW NAS Battery by negotiating contract terms with a system integrator, ABB. This step followed a feasibility report and NYPA estimates for all project costs. The battery modules themselves, produced by NGK in Japan, comprise most of the project cost.

At the time that the valuation estimate was prepared for this case, the cost for the 1.2 MW/7.2 MWH NAS battery energy storage system was $4,100,000, a total that included a worst-case estimate of $200,000 for battery disposal to be included in the project price, and a worst-case estimate for construction contingency of $150,000.

The best-case scenario for the battery disposal cost is $0 and the best-case scenario for the construction contingency is also $0, although each of these cases is not believed to be likely. For the next iteration of the Monte Carlo simulation, NYPA used a nominal construction cost estimate of $3,825,000, which includes a $75,000 construction contingency, and a battery disposal cost of $100,000, to be included in the initial project contract. NYPA's objective is to ask the system integrator, ABB, to be responsible for the battery disposal costs and to commit to this cost today. This is another effective strategy for reducing project risk—to shift the risk to the supplier. Furthermore, a fixed price contract with a single system integrator is an effective way to control the risk of cost overruns. Because there may be unanticipated conditions or other circumstances at the job site, a nominal contingency is also established for the project, and totals an amount representing less than 2% of the project cost. Through these steps, a large portion of the project risk associated with the project cost has been reduced.

Reduction in Labor at the Long Island Bus Company Fueling Station

For the NYPA NAS battery project, the majority of the project benefits are attributable to issues that are under the control of the Long Island Bus Company. NYPA believes that the $220,000 estimate for annual labor reduction is a reliable number and that it only has the potential to grow along with the salary budget for the Long Island Bus Company. The last iteration of the model assumed constant labor savings over the life of the NAS Battery equipment. The next iteration will include an assumption that annual salary raises of 2.5% are the most likely rate to be used to escalate the annual value of labor savings. The anticipated inflation rate is used as a guide for assumed salary raises, and NYPA estimates a high estimate of 3.5% and a low estimate of 2.0%.

In addition to including an escalation rate for the labor savings associated with this project, we'll also reduce the uncertainty in the value of the estimated annual savings, from +/-10% to +/-2%.

With this change, the range used in the Monte Carlo Simulation will be $215,600 to $224,400. The nominal, or most likely value is unchanged at $220,000 in the first year.

Equipment Life

Our first model assumed that the equipment would have a useful life of 12 years, and after 12 years, all costs and benefits were assumed to end. In fact, our first deterministic model assumed that a cost of $100,000 would be incurred following the end of the 12th year for battery disposal costs. In the first deterministic model and the Monte Carlo Simulation, we did not assign any risk to project life—we simply assumed that the installed equipment would produce the desired benefits for 12 years.

In this next iteration, we'll analyze the effect of adding risk to the assumed life. This uncertainty will be modeled by creating an assumed probability distribution for a range of possible lives over which the equipment might reasonably be expected to perform. The number of years over which cash flows will be summed will thus become a variable in the Monte Carlo simulation—some iterations of the model will include more than 12 years of cash flows, some less. In the end, the probability distributions for our two model outputs, NPV and Project Cash Inflows, will reflect the changing assumptions for useful project life. NYPA believes that the installed system may last as few as 10 years or as many as 16 years. We'll assume a 5% probability for short system life and a 5% probability that the equipment can last as long as 16 years. The custom probability distribution assumed in the Monte Carlo model is shown in Figure 2-8.

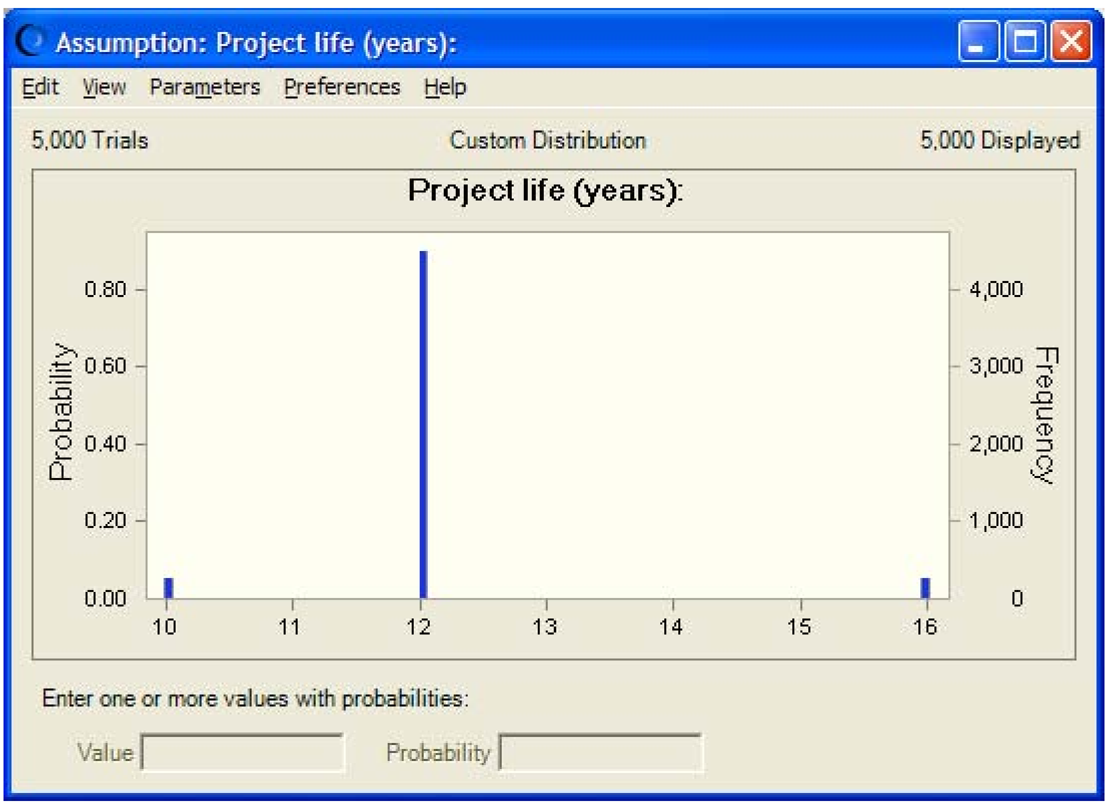


Figure 2-8
Assumed Probability Distribution for NAS Battery System Life

During the development of this part of the valuation model, it was observed that the life of the NAS battery *system* is dependent, in part, on battery module maintenance and the periodic replacements of failed modules. The initial valuation module simply assumed that the system performance would degrade at a more or less constant rate over the 12 year life of the system and that after 12 years, the system would fail to produce the peak-shaving benefits desired by Long Island Bus Company. In the current iteration of the model, we've incorporated data from 42 months of life testing at NGK to make an estimated probability distribution for battery module replacement frequency. We've assumed that two battery modules must be replaced whenever system performance falls below 90% of the system design capability (1.2 MW/7.2 MWH). This condition occurs whenever three battery cell "trains" have failed, an event that NGK data predicts will occur after 94 months of use—about 8 years of operation.[11] The range on the battery module replacement frequency is from 45 months (about 4 years) to 151 months (about 13 years). We'll assume, initially, that there is a 25% probability that the modules will need to be replaced every four years, a 50% probability that the frequency will be 8 years, and a 25% probability that the system will operate for 13 years without needing a battery module replacement. The assumed probability distribution for this input is shown in Figure 2-9.

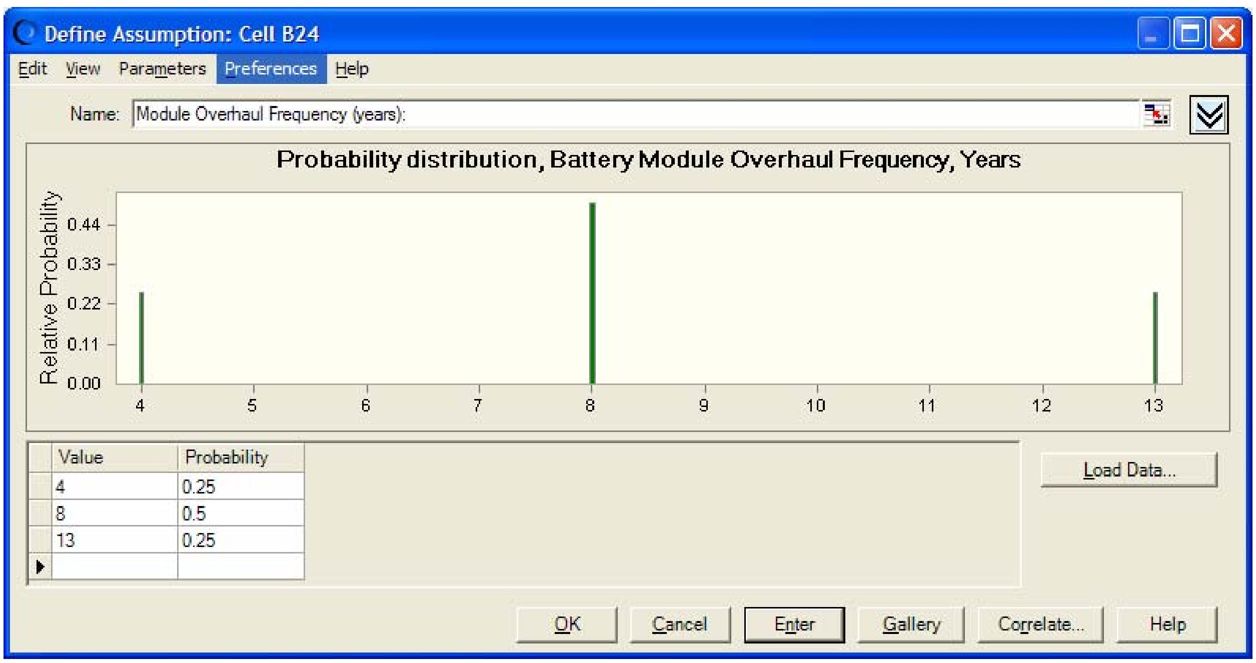


Figure 2-9
Assumed Probability Distribution for NAS Battery Module Replacement Frequency

[11] The battery module replacement frequency estimate is based on no preventive maintenance—two modules are simply replaced whenever three battery cell "trains" have failed. NGK also performed life testing assuming 3-year and 6-year maintenance intervals, where all failed cells would be replaced at regular intervals, regardless of system performance. In each of these cases, the battery module replacement frequency was not significantly different from the no-maintenance case modeled in the Monte Carlo simulation.

In addition, we've now accounted for the cost of the battery module replacement event: $130,000 for two replacement modules. In the absence of any better information, we'll assume a triangular distribution for this new input and will assign a range of +/- 10%.

The effort required to model the effects of battery maintenance, the costs and frequency of module replacement, and the impact on overall system life highlights one of the key drivers of uncertainty in the adoption of new energy storage technologies; that is, we simply do not know how long the equipment will last. We can guess, from the best available test data, but the fact remains that the number of years that we can expect benefits to accrue is an uncertain variable.

Other Model Revisions

A few other changes were made to the model developed initially, to account for the fact that costs and benefits are likely to change over the project life. We've added an assumption that accounts for increases in the cost of scheduled, preventive maintenance, with a nominal value of 3.0% annually, a worst case of 3.5%, and a best case of 2.0%, with a triangular distribution. This is the type of risk that might be mitigated through the negotiation of a multi-year, fixed price service agreement with the service provider.

We've also included the assumption that energy and demand charges will change each year. For each of these variables an escalation rate of 1.0% has been assumed, with a low estimate of 0.0% and a high estimate of 2.0%. Again, a triangular distribution has been assumed.

The risk in the assumed other investments from NYSERDA and the Department of Energy has been removed, as the estimated $1,000,000 in project assistance from these two sources is considered to be quite reliable. The assumed other investments from all other sources was increased to $800,000 +/-$100,000. The EPS credit has been set to zero in the valuation model to more accurately reflect the fact that the amount of this benefit, if any, is simply unknown. This input is left as a placeholder, to be filled at a future date if it is later found that peak shaving or load shifting incentives become available from LIPA, the distribution utility serving the customer.

Finally, a wider range of uncertainty was assigned to the interest rate input variable. This case was developed during a period with gradually rising interest rates and it was believed by NYPA that rates used to finance such a project could be as low as 1.25% or as high as 6.00%. The most likely rate of 3.00% was left unchanged.

The revised input assumptions are shown in Table 2-9. The input assumptions highlighted are those with a probability distribution assumed for the Monte Carlo simulation. All of these variables, with the exception of system life and battery module overhaul frequency, used triangular distributions. System life and module overhaul frequency used the discrete, custom probability distributions illustrated earlier.

Table 2-9
NYPA NAS Battery Financial Model, Input Assumptions, Second Revision

Valuation Model Assumptions	Nominal Value	High Estimate	Low Estimate
Capital Cost (includes $75,000 contingency)	$3,825,000	$3,900,000	$3,750,000
Other investments from NYSERDA/DOE	$1,000,000	$1,000,000	$1,000,000
Other investments from all other sources (EPRI, LIPA, other participating utilities)	$900,000	$800,000	$1,000,000
Scheduled service, preventive maintenance	$10,000	$22,000	$10,000
Assumed annual increase in maintenance labor costs	3.0%	3.5%	2.0%
Unscheduled maintenance, Spare parts and repair of modules	$130,000	$117,000	$143,000
Battery Disposal Cost (2005 dollars)	$100,000	$200,000	$0
Escalation rate in cost of modules	0.0%	5.0%	-5.0%
Interest rate	3.00%	6.00%	1.25%
Reduction in demand charges	$41,304	$41,717	$40,891
Annual increase in energy and demand charges	1.0%	2.0%	0.0%
Energy cost for recharging batteries in year 1	$35,035	$35,385	$34,685
Annual reduction in fueling station labor	$220,000	$224,400	$215,600
Assumed annual increase in bus company labor costs	2.5%	3.5%	2.0%
Credit for EPS	$0	$50,000	$0
System life (years)	12	16	10
Assumed Probability for system life	90%	5%	5%
Annual degradation in energy storage system performance	2.0%	3.0%	1.0%
Module Overhaul Frequency (years)	8	13	4
Assumed Probability for overhaul frequency	50%	25%	25%

Monte Carlo Modeling Results

For clarity, only the cash flows for the first eight years of the deterministic model are shown in Table 2-10. The model was actually run with 16 years of cash flow results, to account for the fact that the system life variable now includes a 25% probability that the system may last as long as 16 years. Note that the NPV for the project has now improved to $296,130 an amount that is $308,220 higher than the ($12,090) NPV calculated when the model was first run. This increase is largely attributable to the increase in investments from others, from $1,567,000 to $1,900,000.

Table 2-10
NYPA NAS Battery Cash Flow Model

Year	0	1	2	3	4	5	6	7	8
Cash outflows									
Energy to charge batteries		($35,035)	($35,385)	($35,739)	($36,096)	($36,457)	($36,822)	($37,190)	($37,562)
O & M		($10,000)	($10,300)	($10,609)	($10,927)	($11,255)	($11,593)	($11,941)	($12,299)
Battery module overhaul cost					$0				($130,000)
Battery disposal cost	($100,000)								
Project cost	($3,825,000)								
Total costs	($3,925,000)	($45,035)	($45,685)	($46,348)	($47,024)	($47,713)	($48,415)	($49,131)	($179,861)
Cash inflows									
Labor Savings		$220,000	$225,500	$231,138	$236,916	$242,839	$248,910	$255,133	$261,511
Reduction in Demand Charges		$41,304	$40,891	$40,482	$40,077	$39,677	$39,280	$38,887	$44,284
Credit for EPS		$0	$0	$0	$0	$0	$0	$0	$0
Construction subsidies	$1,900,000								
Total benefits	$1,900,000	$261,304	$266,391	$271,620	$276,993	$282,516	$288,190	$294,020	$305,795
Cash flow	($2,025,000)	$216,269	$220,706	$225,272	$229,970	$234,803	$239,775	$244,889	$125,934
Present value of cash flow	($2,025,000)	$209,970	$208,037	$206,156	$204,325	$202,543	$200,808	$199,117	$99,413
Cumulative PV of cash flow	($2,025,000)	($1,815,030)	($1,606,993)	($1,400,838)	($1,196,513)	($993,970)	($793,162)	($594,045)	($494,632)
Net Present Value	**$296,130**								
PV, Project Cash Inflows	**$2,321,130**								

The battery disposal cost is now shown in year 0 and the $100,000 base case value is assumed to be part of the initial contract price. Note also the new "battery module overhaul cost" line in the Cash Outflows portion of the model. In the base case, a $130,000 charge is shown in year 8, reflecting the most likely battery module replacement frequency. A charge of $0 is shown in year 4. During the Monte Carlo simulation, the model is currently set up so that 25% of the iterations will have a charge of $130,000 in year 4, 8 and 12. 50% of the iterations will show this charge appearing only in the eighth year[12], and 25% of the time, the charge will only be modeled during year 13. During the Monte Carlo simulation, the assumed cost for the battery module replacement will also change, to reflect the fact that there is some probability of cost reduction and some probability that costs will increase.

The other costs that we have made are evident in the model, including escalating costs for operations and maintenance and energy required to charge the batteries during off-peak periods. The value of the benefits attributable to a reduction in demand charges are escalated each year, to reflect an assumed 1.0% annual increase in demand charges. This increase is offset, however, by the assumption that system performance will degrade by 2.0% each year. The net effect is a 1% decline in the value of the demand savings benefits, until the year that failed battery modules are replaced (shown in year 8 in the model) when the value of the benefits is restored to a value reflecting the escalated demand charges. This model probably represents a more realistic operating strategy; instead of simply allowing system degradation to occur over the life of the

[12] It would not make sense to also include this charge in year 16, since this is the maximum life currently estimated for the NAS battery system.

equipment, battery modules will instead be replaced. In this case, they will be replaced when the system performance falls below the load shifting and energy production capabilities expected by the customer.

Finally, the assumed credit for EPS has been removed, but a line for this potential benefit has been left in the spreadsheet. After all of these changes, the present value of the project cash inflows is $2,321,130—an amount that is not significantly different from the $2,374,555 value calculated earlier. The risk in these cash inflows, however, has increased and deserves scrutiny.

In Figure 2-10, we can see the results of the Monte Carlo simulation for the project NPV. The standard deviation has increased by over $50,000, to $258,650. The mean value for this distribution, $206,464, is lower than the base case value (from the deterministic model) of $296,130, a result that is most likely attributable to the skewed distributions assumed for both battery module replacement frequency and overall system life.[13] Since our NPV has increased over the last run of this model, there is now a more than 80% probability that the project will have a positive NPV. The positive outcomes modeled in Figure 2-10 would give a typical investor a fair amount of confidence that the project returns will exceed the cost of capital.

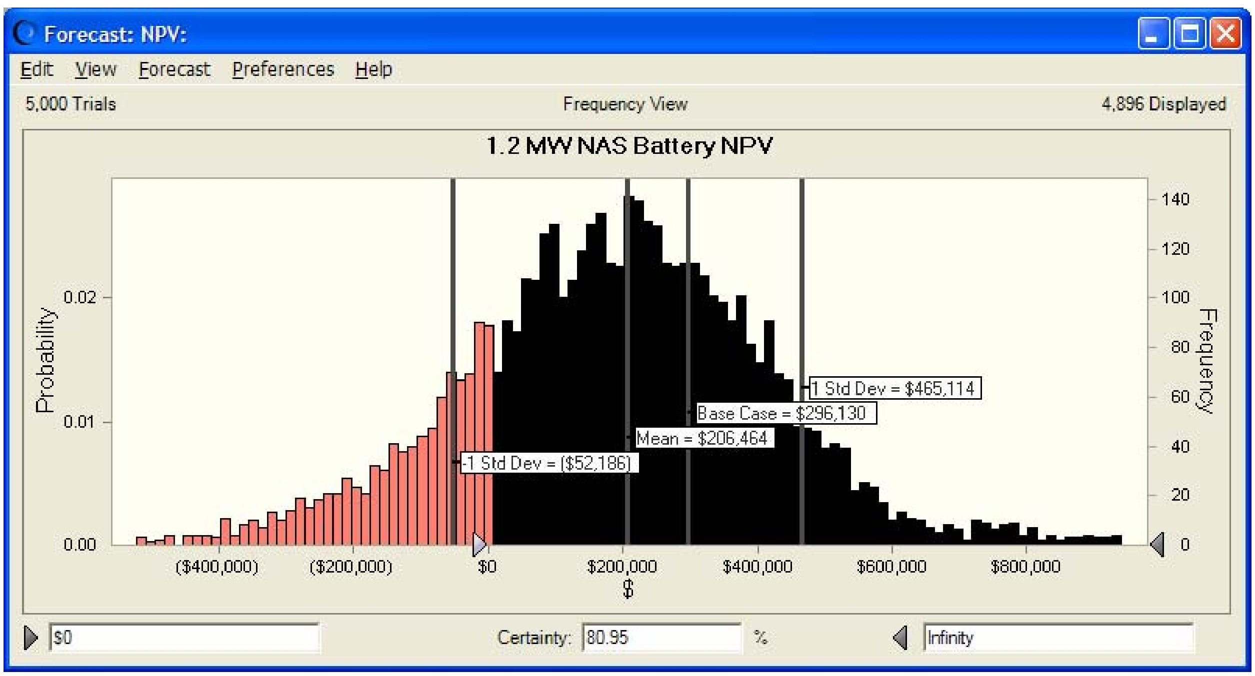


Figure 2-10
Revised Monte Carlo Simulation, NYPA NAS Battery NPV

Figure 2-11 shows the probability distribution for the project cash inflows for our revised model. The standard deviation has increased to $249,507, an amount that is about 11.2% of the mean value of $2,231,028. Recall that in our first Monte Carlo simulation, the standard deviation was

[13] If the probability distributions assumed for each of the input variables are symmetrical, the mean value for the output (NPV in this case) tends to be close to the base case value. If the output values are highly sensitive to small changes in input values, characterized themselves by skewed distributions, the output will also be skewed.

only 4.1%—an amount reflecting the fact that most of our input assumptions used symmetrical triangular distributions. The range for each of these distributions in the first simulation was simply calculated by adding and subtracting 10% to each of the nominal input values. In the current model, we have a more accurate estimate of the risk in the project cash inflows because our new model is more representative of the actual operating conditions NYPA will experience in the future.

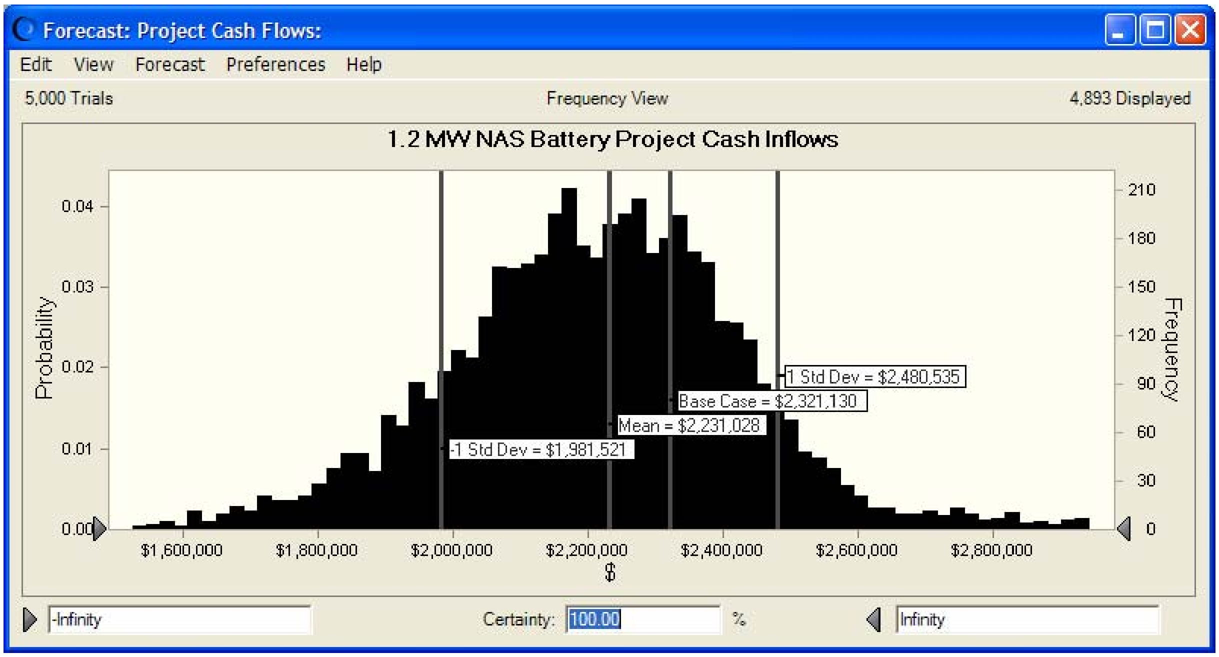


Figure 2-11
Revised Monte Carlo Simulation, NYPA NAS Battery Project Cash Inflows

What we have now is essentially a better estimate of the *risk* in this investment opportunity. The input values contributing most significantly to the risk in the NPV and the project cash inflows are shown in Figures 2-12 and 2-13 respectively.

From these diagrams, we can see that the risk contributions from the interest rate, the project life and the battery module overhaul frequency are contributing most of the risk to both the NPV and the project cash inflows, when ranked by contribution to variance. Recall that in our first simulation, the risk in the capital cost estimate and in the reduction in labor charges associated with the third shift at the fueling station were the main contributors to the risk in the project.

The capital cost and the reduced labor charges are examples of variables that are largely within the control of the investor, in this case the Long Island Bus Company. By the time this customer is signing a financing agreement, the term, the interest rate and the monthly payments to service the debt will be known and will have almost zero uncertainty, or risk.[14]

NYPA will be similarly motivated to reduce the risk in the capital cost and will insist on a fixed price contract with a single vendor, ABB, who will be responsible for almost all of the system integration. The remaining risk is represented by a relatively small contingency budget and that

[14] This is true for a fixed-rate financing agreement. A variable rate agreement would increase the risk in the project.

may or may not be used. Rigorous project management and cost control during the project installation and commissioning further reduces the risk in the capital cost variable.

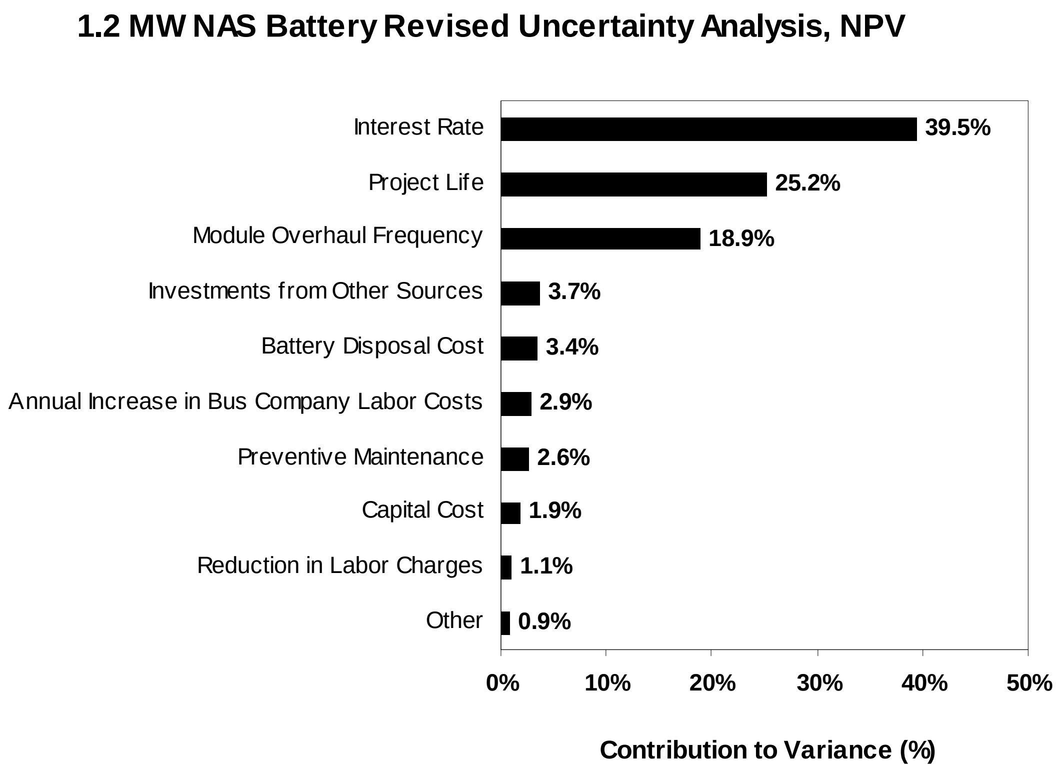


Figure 2-12
Revised Uncertainty Analysis, NYPA NAS Battery, Project NPV

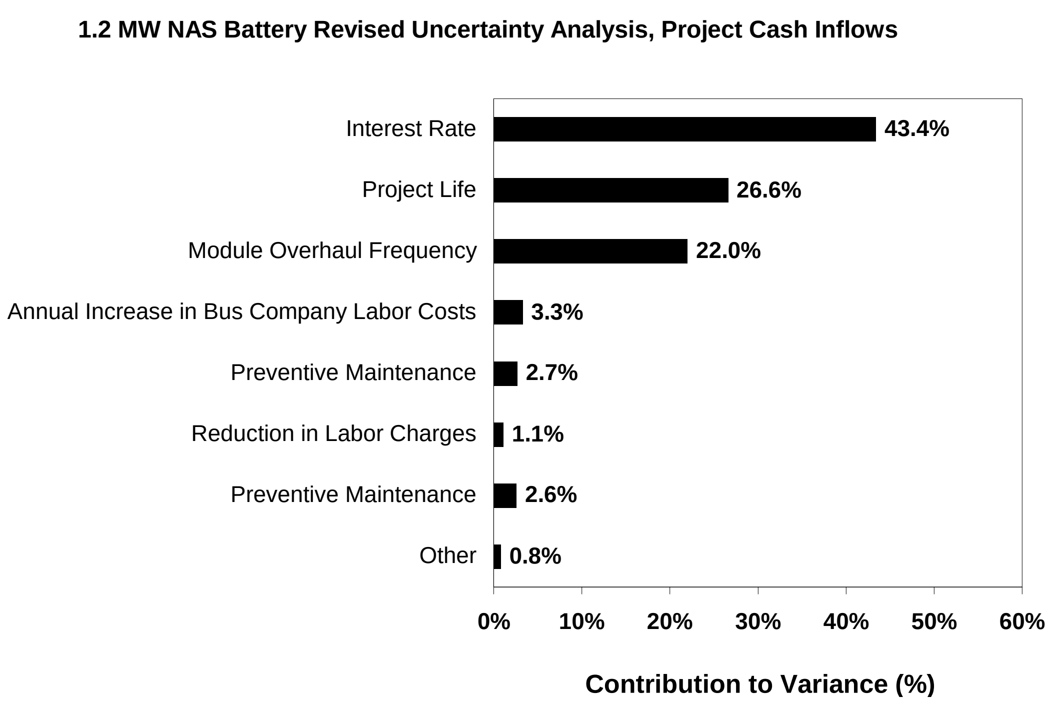


Figure 2-13
Revised Uncertainty Analysis, NYPA NAS Battery, Project Cash Inflows

Likewise, the benefits associated with reduced labor charges are completely within the control of the Long Island Bus Company. The staffing levels and salary levels are known with a high degree of certainty and can be predicted for years into the future. The customer also has over a decade of fueling station labor cost data to analyze and incorporate into the estimate of future benefits for this project.

The estimated project life and the battery module overhaul frequency, however, are not so easily controlled, and these variables contribute greatly to the overall risk in this project. For new energy technologies, one of the most difficult things to estimate is the useful life of the equipment. The overall project life estimate ranges from 10 years to 16 years in this current model, and may actually be longer, especially if maintenance and operating costs (driven by battery replacement cost and overhaul frequency, and costs of energy to recharge the batteries) can be kept under control. These input variables, and the uncertainty associated with them represent the *market risk* in the NAS battery technology investment, because they are not under the control of either the customer or NYPA, and there is very little that anyone besides NGK can do to reduce the risk associated with these variables. NYPA can attempt to transfer this risk to NGK or their system integrator, ABB, by entering into a performance contract with guarantees for system performance, but until such a contract exists, the risks associated with the project life and battery module replacement frequency are considered market risks.

This point is important, because the strategic value in the investment opportunity, which will be quantified in the next section, will largely be determined by market risk and not by project risk. Options have value because of uncertainty attributable to market risk—not the project risks that can be mitigated through disciplined project management, contract management and/or cost control.

Indeed, during the development of this case, a large part of the project risk was being mitigated by NYPA through direct negotiations with ABB and discussions with NGK about, among other things, battery module life and replacement frequencies resulting from different maintenance strategies. Discussions with Long Island Bus Company provided NYPA with the assurance that the labor savings associated with the elimination of a third shift at the fueling station were relatively certain.

The system life estimate is worth additional analysis as our range of possible values for this assumption is quite large. The sensitivity analysis showing the relationship between system life and NPV is shown in Figure 2-14.

Before proceeding to Step 5 in the valuation process, Real Options, one more input value adjustment seems necessary: the interest rate. At present, there is a large range estimated for this value and it is currently the biggest contributor to the uncertainty in the NPV and the project cash inflows. NYPA is proposing to finance this project for Long Island Bus Company and initially assumed an interest rate of 3.00%. The range of possible values that this input might take between now and the time that a financing agreement is in place now appears to be too large. Although interest rates were, in fact, rising during the development of this case, it is hard to imagine that NYPA would be offering its customer a rate of 5.00% or 6.00% for this project. In fact, the rate assumed appears to be a subsidized rate of sorts, as Long Island Bus Company is unlikely to find financing rates in this range if it shopped for a 12 year agreement in public markets. If the rate offered is too high, the project is no longer attractive to Long Island Bus Company. The project NPV actually turns negative at an interest rate of 5.3%.

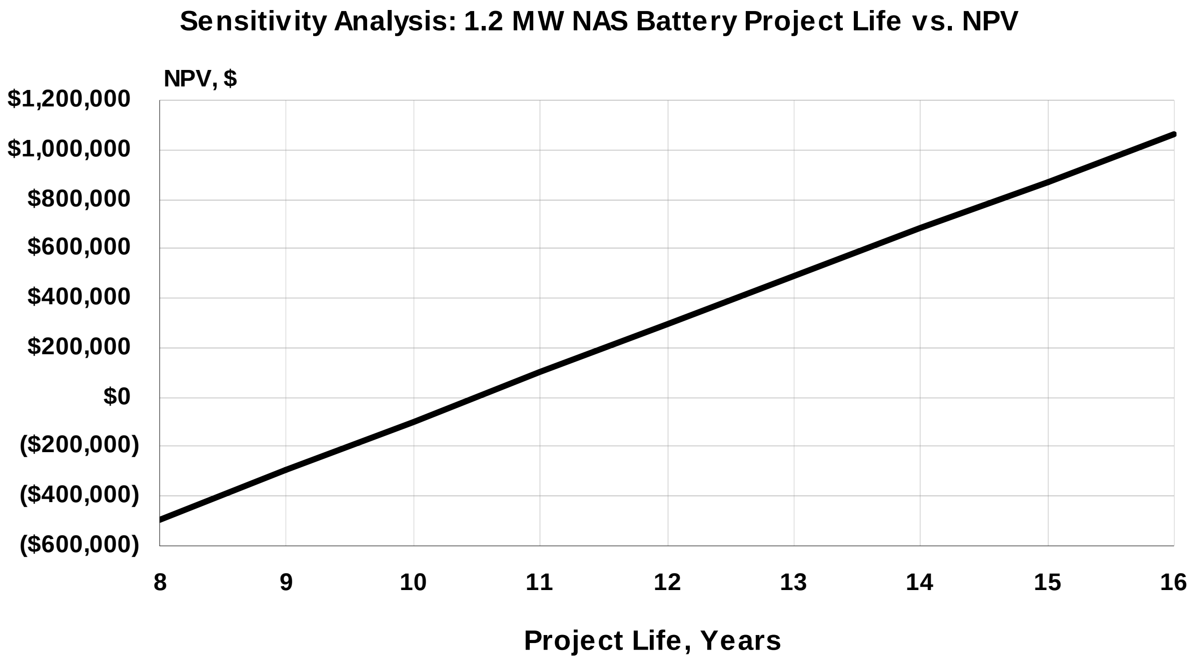


Figure 2-14
NYPA NAS Battery Sensitivity Analysis, System Life vs. NPV

In summary, the interest rate offered is within the control of NYPA and we should be able to reduce the uncertainty associated with this input variable. For the final iteration of the Monte Carlo model, the rate is assumed to be 3.00% with a low estimate of 2.00% and a high estimate of 4.00%. A triangular distribution is used again.

With this final change in the model, the interest rate drops to third in importance in the contribution to variance ranking for both the project NPV and the project cash inflow. The overall risk in the project is similarly reduced. The final Monte Carlo probability distributions for project NVP and project cash inflows are shown in Figures 2-15 and 2-16 respectively. The uncertainty analysis showing the contribution to variance rankings for each of these model outputs are shown in Figures 2-17 and 2-18.

The change in the estimated uncertainty associated with the interest rate also raised the probability that the project produces a positive NPV. The probability distribution for the NPV indicates that we have nearly an 89% probability that the project will produce a positive NPV.

For most investors, this is probably sufficient and the decision would be made to invest in the project. There is, however, some strategic value in this project that can be quantified using real options and we have identified most of the variables necessary for calculating this strategic value already.

In the final step of the valuation process, we'll quantify this value and we will also make an estimate of the value of at least one more option embedded in the NAS battery investment decision.

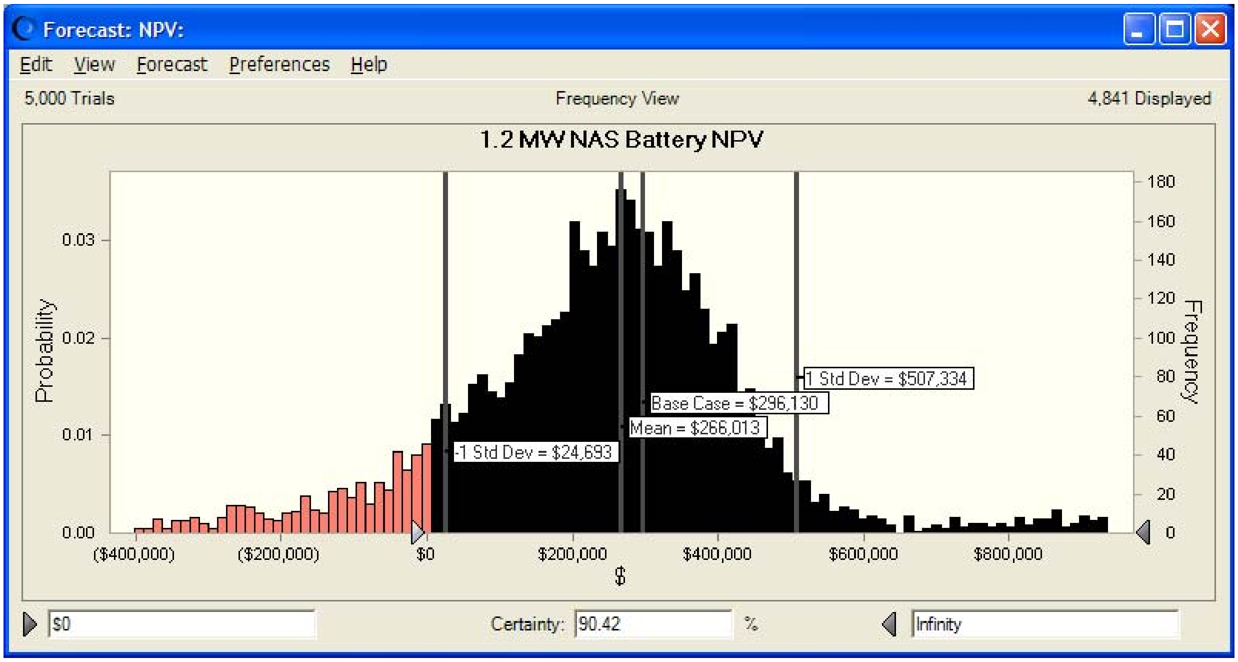


Figure 2-15
Final Monte Carlo Simulation, NYPA NAS Battery NPV

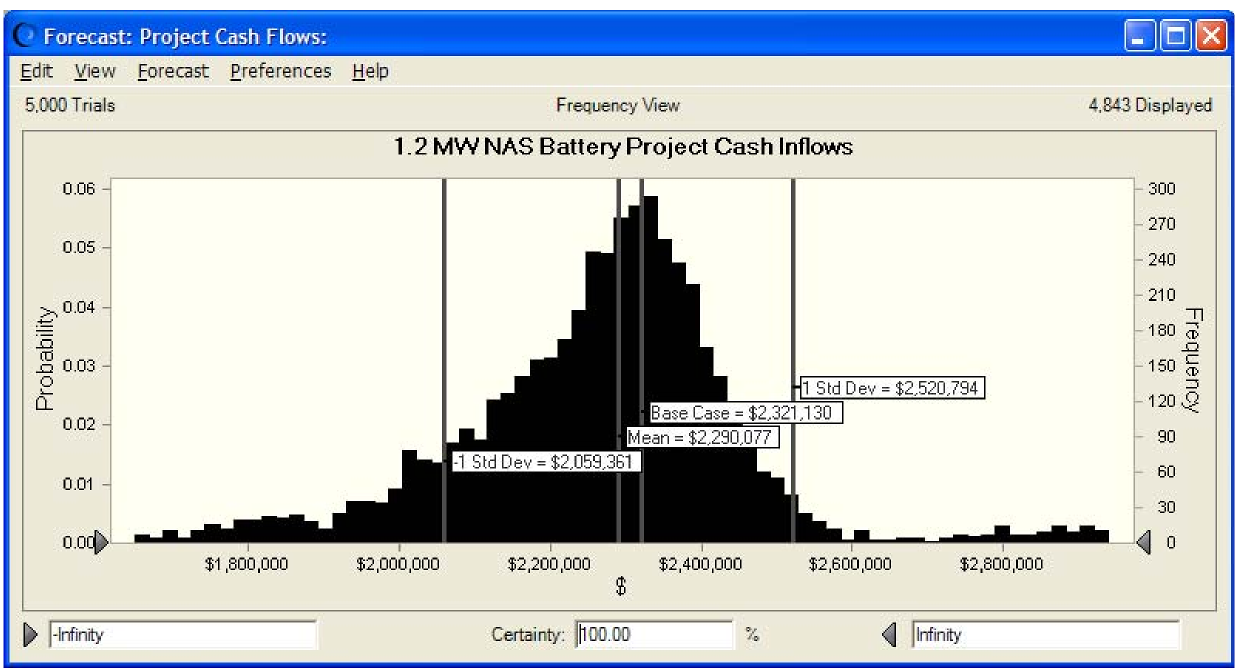


Figure 2-16
Final Monte Carlo Simulation, NYPA NAS Battery Project Cash Inflows

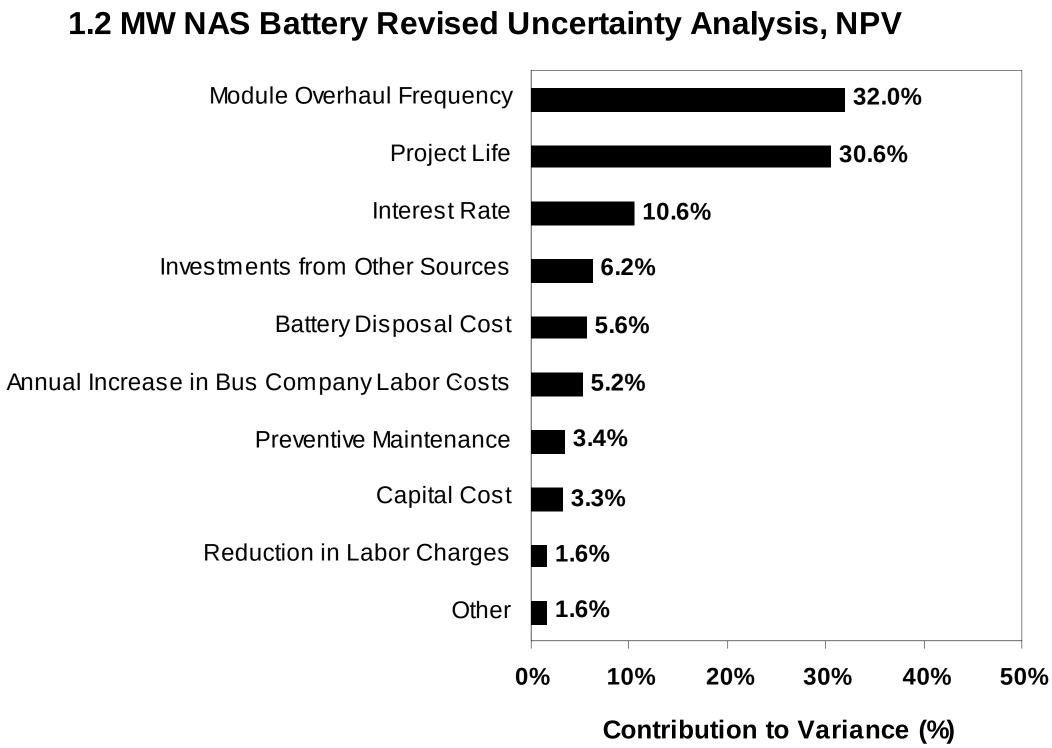


Figure 2-17
Final Uncertainty Analysis, NYPA NAS Battery, Project NPV

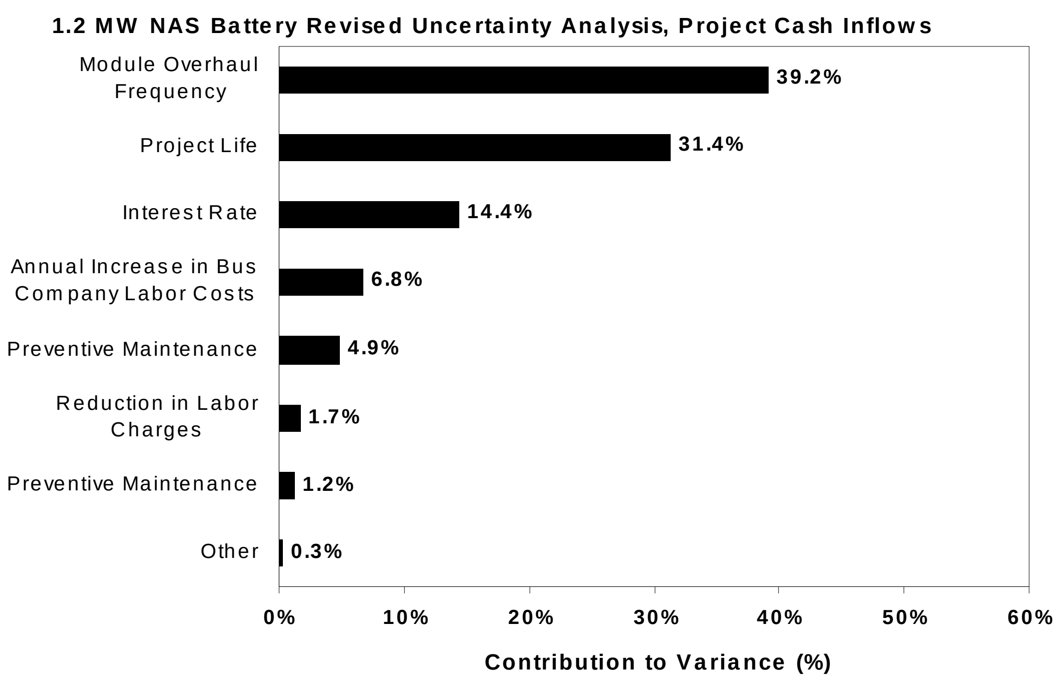


Figure 2-18
Final Uncertainty Analysis, NYPA NAS Battery, Project Cash Inflows

Step 5: Real Options

The use of real options to value the strategic benefits embedded in an investment opportunity can help investors understand the value of managerial flexibility. Additionally, options can help analysts understand the drivers of strategic value associated with market risk and the drivers of economic value associated with variables that can be controlled by the project team, the so-called project risks, sometimes known as unique risk. Viewing investment opportunities from the perspective of managerial flexibility also enables managers to seek ways to build flexibility into investment decisions and to seek sources of strategic value that can be used to supplement the economic value. This approach can be especially useful for estimating *today's* recommended investments in new energy storage technology investments where present costs are high relative to incumbent technologies, but where costs, over time, may fall.[15]

The Appendix includes a brief overview of the Black-Scholes option pricing equation used to estimate the value of financial options, an approach that can also be used with investments in real assets like energy storage technologies. In this section, we'll price one option "owned" by the customer, Long Island Bus Company, and one owned by NYPA.

Long Island Bus Company – Option to Delay Investment

The first option is technically owned by Long Island Bus Company, since they are the primary investor interested in purchasing a 1.2 MW NAS battery energy storage system, and they will also be the entity owning the benefits resulting from the investment, benefits largely comprised of labor savings associated with the third shift at a natural gas compressor fueling station.[16]

Long Island Bus Company has not yet made the investment in the 1.2 MW project, although they have been discussing the project with NYPA for several months. Technically, they still have the option to abandon the opportunity. There exists some possibility that this deal does not go through, and one can imagine the number of things that can change between now and the time that an investment decision must be made. Perhaps the interest rate that NYPA is able to offer contractually rises to 5% or more. ABB or NGK could abandon the opportunity. Although its not likely as of this writing, this possibility would likely result in an abandoned project, since NGK is really the only company that has anything close to a commercial offering in Sodium Sulfur battery technologies for utility use. Any event requiring a new, *clean slate* approach creates the possibility that Long Island Bus Company or other parties, like the Department of Energy or NYSERDA, lose interest. As we've seen previously, without investments from these other agencies, we really do not have an economically feasible project.

Another possibility is that the Bus Company may find that it is simply politically unwise to re-assign or lay off employees associated with the third shift at the natural gas fueling station. It

[15] Or, where benefits associated with the new energy storage technology investment may rise.

[16] Although NYPA is providing project management, construction management, financing and administration for the project, the majority of the economic benefits for this *particular* project will accrue to Long Island Bus Company. The second real options model will estimate the strategic value that NYPA can claim from this opportunity.

may be possible, in theory, to save $220,000 annually on labor, but we really don't know for sure how this project compares with other investment opportunities that the Long Island Bus Company is considering, and whether competing opportunities may be able to save money without reducing the size of the workforce.

There is also upside potential afforded by delaying the investment decision. A guarantee of system life might be negotiated, or a guaranteed maximum price for failed battery modules over the life of the agreement. Fueling station labor rates might rise faster than expected. More investments might be negotiated with other interested participants. In short, delaying the project also exposes Long Island Bus Company to possibilities that may increase economic value.

The reason for this discussion is that Long Island Bus Company currently owns the option but not the obligation to invest in the 1.2 MW NAS Battery project proposed by NYPA. Let's assume that this option will expire in one year. That is, the Bus Company can continue to work with NYPA to negotiate a contract document and a lease agreement, and all of the necessary services, and can delay the actual contract signing for one year. If they do, in fact, possess this option, then this option has strategic value that can be quantified using real options. If the option does not exist for one year, we can easily do a sensitivity analysis to show how the strategic value varies with the time to expiration of the option. The value of the option is dependent on six variables, several of which we have estimated already. The six variables (and their financial option equivalents) and the value of the option, including the economic and strategic components, are shown in Table 2-11.

Table 2-11
NYPA NAS Battery Real Option Inputs and Outputs

Inputs		
Real Option		**Financial Option Equivalent**
Present Value of the Project Cash Inflows:	**$2,290,077**	Stock Price ($):
Standard deviation of project cash inflows:	**10%**	Volatility (%):
Required investment:	**$2,025,000**	Exercise Price ($):
Length of time option is valid:	**1.0**	Time To Expiry (years):
Annual costs of keeping the option open:	**$50,000**	Dividends ($):
Risk free rate (Estimated from treasury yield curve, 12/10/05):	**4.30%**	Risk-free Interest Rate (%):
Outputs		
d_1:	1.4918	
$N(d_1)$:	0.9321	proportion of shares required to replicate a call option
d_2:	1.3918	
$N(d_2)$:	0.9180	probability the call option will be exercised on expiry
Value of the option:	**$307,809**	
Intrinsic Value:	**$265,077**	
Strategic Value:	**$42,732**	

Note that we've made an assumption that Long Island Bus Company must invest something between now and the date of expiration for this option to have any value. We've conservatively assumed that they will spend $50,000, mostly through such items as paying a manager assigned to negotiate a contract, participate in discussions with project stakeholders, evaluate any site-specific conditions that impact the project, and/or ensure that the benefits associated with the elimination of a third shift are actually possible.[17]

The option to delay the $2,025,000 investment ($3,925,000 minus assumed other investments of $1,900,000) is worth $299,760 to the Long Island Bus Company. This total is comprised primarily of economic value (known as *intrinsic* value in financial options), which is simply the net present value of the future project cash inflows if the option was exercised right now, $255,416. The strategic value is the *additional* value of flexibility, if the Long Island Bus Company is indeed able to delay this investment for a year without materially impacting the economic estimates for costs and benefits that we've made so far. This value is $44,344.

Figure 2-19 shows the project and its location on a payoff diagram, commonly used to show financial options. The intrinsic value line simply shows that the economic value is zero until the present value of the project cash flows equals the exercise price $2,025,000; above this point on the payoff diagram, the intrinsic value simply equals the NPV of the project. Values below $2,025,000 for the present value of the project cash flows would obviously result in a negative NPV project, where the value of the option is comprised of strategic value exclusively.

[17] The annual cost to keep a real option open is analogous to the dividends on a stock option. In a stock call option, the owner has the option to purchase the stock at a future date. The owner of such an option will not be paid dividends associated with that stock, and this is essentially an additional cost to owning the option instead of the underlying stock directly. The modified Black Scholes option pricing formula can be used to account for the impact of the annual cost of keeping a real option open prior to expiration, and this cost recognizes that when the option involves real assets, some amount of effort must be expended to ensure that the option can indeed be exercised.

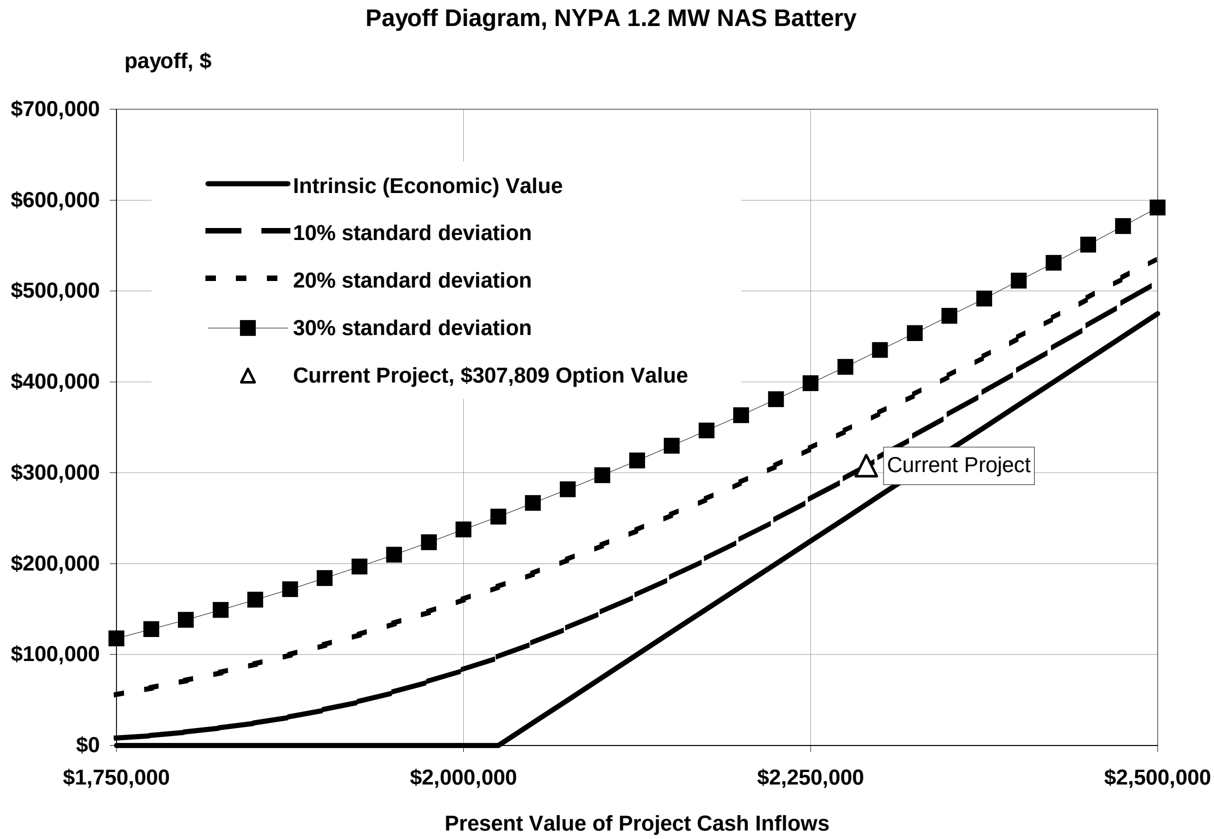


Figure 2-19
NYPA 1.2 MW NAS Battery Real Option Payoff Diagram

The other curves in the diagram show how the total value of the option, comprised of strategic and intrinsic value, varies for different standard deviation values. For an option that is this far *in the money*, the risk in the project cash flows is not a significant driver of strategic value. Indeed, in this example, the majority of the option value comes from the amount remaining after investing the $2,025,000 for one year at the risk-free rate of 4.30% and subtracting the cost of keeping the option open. If the investor truly owns the option, but not the obligation, to invest this sum one year from now, the candidate funds would be assumed to earn interest at the risk free rate. If the returns at the risk-free rate are on the same order of magnitude as the cost to keep the option open (the dividend) and no other significant sources of strategic value have been quantified, it then makes sense to exercise the option.

Figure 2-20 shows the relationship between economic value and strategic value for different values for the present value of the project cash flows. In general, when the strategic value is small relative to the economic value (in this example, the strategic value is 17% of the economic value), the option should be exercised.

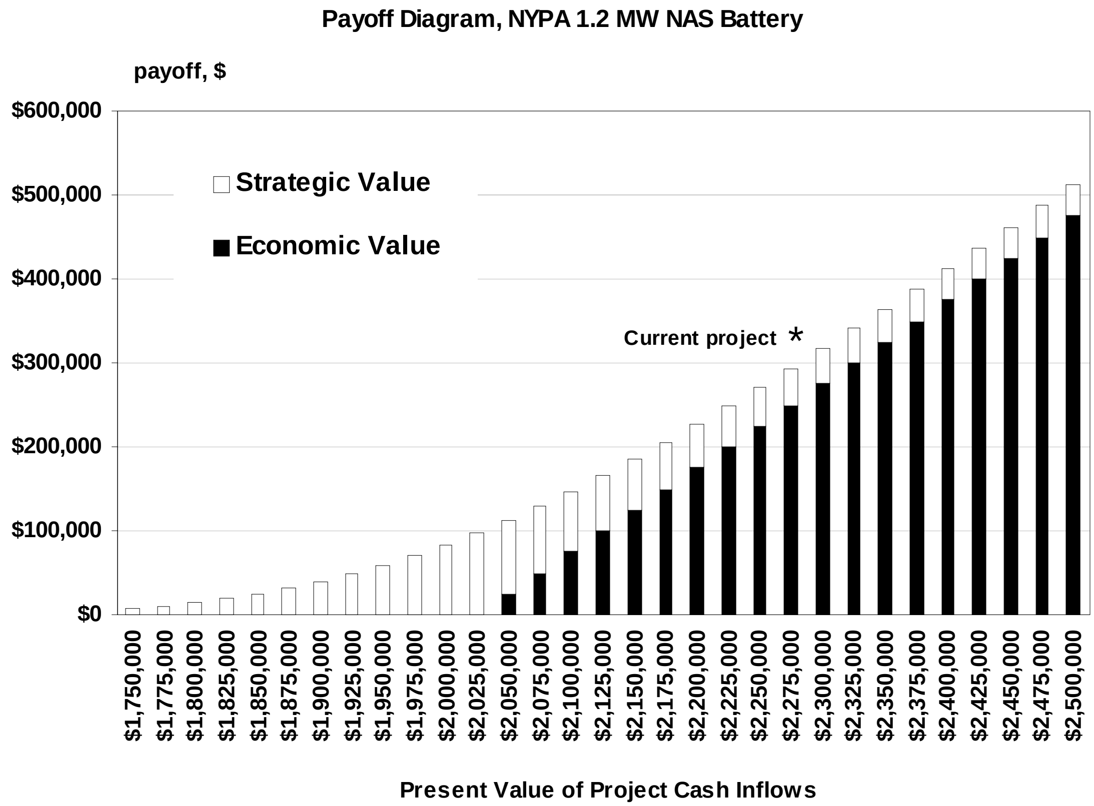


Figure 2-20
NYPA NAS Battery Payoff Diagram, Strategic vs. Economic Value

If delaying the project for a year produces a real risk that a key partner in the project changes their participation conditions (perhaps ABB would raise the project price, or insert a clause into a contract proposal stating that the proposed price is good for only 90 days, for example), then the value of the option obviously changes. It might be unrealistic to assume that a delay of one year will still enable Long Island Bus Company to exercise the option for the price we've modeled.

The strategic value component of this option value is most sensitive to the time to expiration, with a 1% change in this assumption resulting in more than a 10% change in the strategic value in the project. Figure 2-21 shows the sensitivity of all six real options model inputs and Figure 2-22 shows how the strategic value varies with the time to expiration input alone.

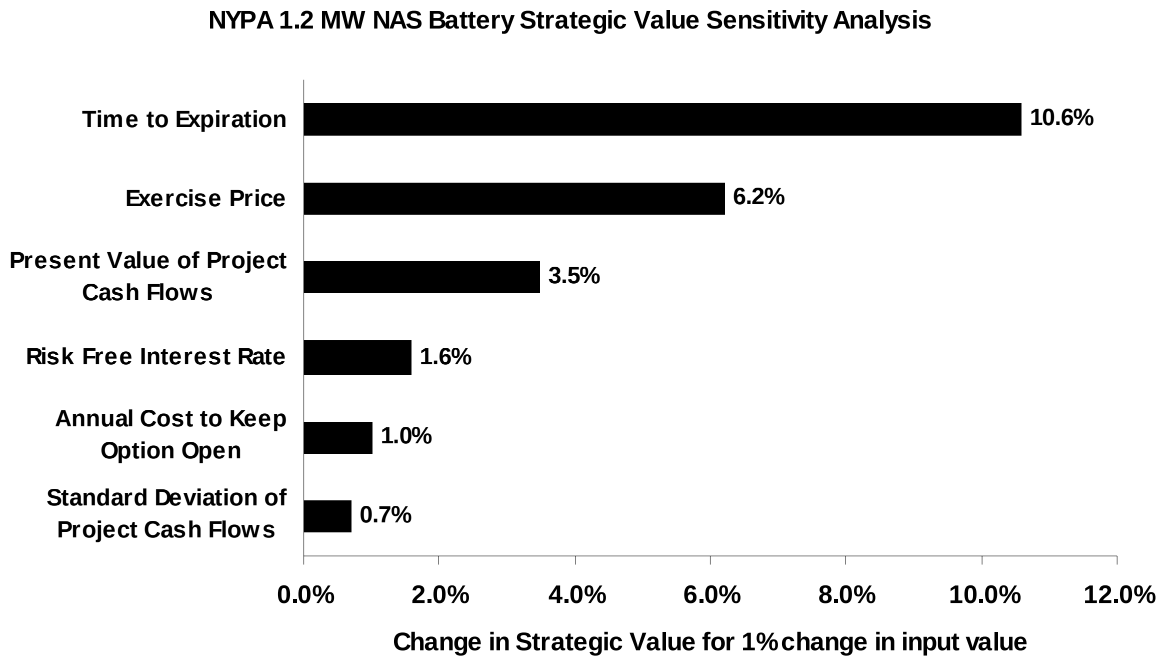


Figure 2-21
Sensitivity of Real Option Input Variables

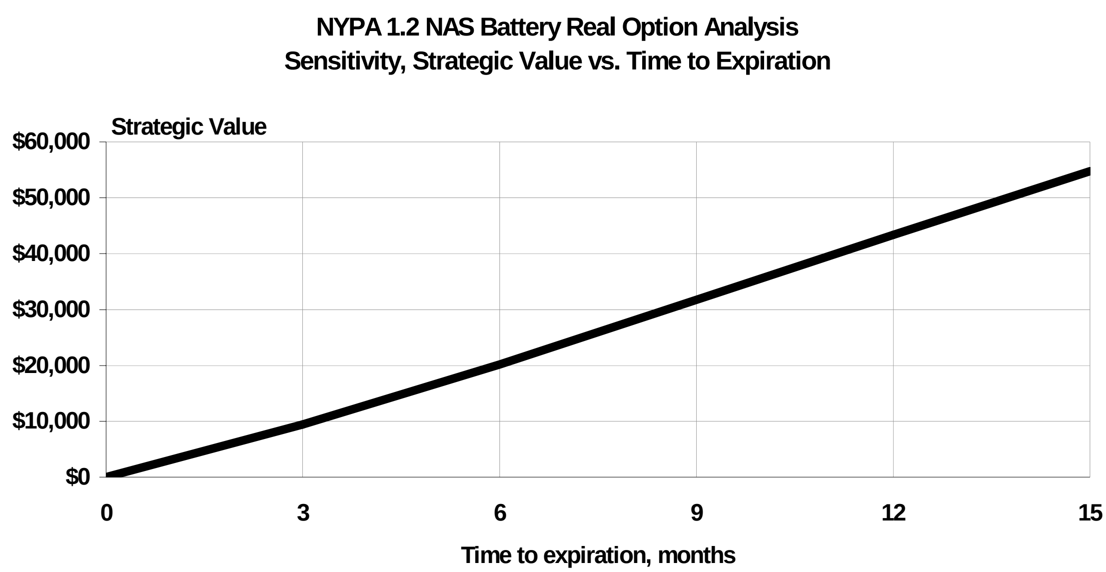


Figure 2-22
Time to Expiration vs. Strategic Value

For this project, the amount of money spent on the resources to keep the option open for a year are on the same order of magnitude of the strategic value itself—which means that the option should be exercised. There is simply not enough strategic benefit to delaying the decision.

The option analyzed is the option owned by the Long Island Bus Company. What about the option owned by NYPA? NYPA believes that a demonstration project like the 1.2 MW NAS Battery Energy Storage system for Long Island Bus Authority can provide them with the experience to apply this technology in the future, on the chance that costs fall to the level where the technology can compete with other alternatives without investments from other parties.

A second options analysis will be performed to make an estimate of the option value of the NAS Battery technology as an alternative to natural gas combustion turbines used for load control, under the assumption that this option may have value because of two major sources of uncertainty that are outside of the control of NYPA:

1. The price for natural gas
2. The cost for NAS Battery Energy Storage Systems

Obviously, there are other sources of uncertainty, but we'll focus on these two since they are largely outside of the control of NYPA and represent market risk—the type of risk that is associated with strategic value. Since the future values for these parameters are uncertain, (i.e., they are risky and are likely to contribute to the standard deviation of future project cash flows determined by their values) the modeling may reveal that there is strategic value in investing in the NAS demonstration project now—*beyond* the values already quantified. In other words, NYPA participation in the Long Island Bus Company project creates the option to make a larger investment in NAS technology in the future. This is an example of a *growth option*, where a large investment in the future is made possible, in part, because of a smaller investment made today. In other words, the investment that seems to be comprised mainly of economic value may also include strategic value if the experience gained by such an investment results in an option to make a much larger investment in the technology in the future.

Growth Option – 50 MW of NAS Batteries

NYPA is investing in understanding electricity storage technologies in part because it believes that storage has the possibility of being employed as a clean alternative to combustion-based peak-shaving technologies such as natural gas turbine generators in the future. At today's energy storage capital costs, this idea does not yet make economic sense (without contributions from other investment partners), but this does not mean that the idea does not have *strategic* value. Real options can be used to quantify this strategic value.

To frame the problem as a real option, we need to imagine a future application of electricity storage technologies such as the NAS battery, if capital costs were lower or if costs of the incumbent technology were higher. NYPA suggested that NAS might be employed as a peak shaving technology at some date in the future, and could be used as a substitute for natural gas-fired combustion turbine generators. Such an idea might also become attractive if natural gas costs continue to rise and if NAS battery costs fall as expected.

To structure the problem as a real option, it was assumed that NYPA would need to invest in 50 MW of peak-shaving capacity for its service area within five years, and that the most likely technology to be employed would be natural gas combustion turbines. Although a variety of load shifting and peak shaving technologies are available, including different pricing alternatives, the use of backup generators and load control devices such as remotely-controlled thermostats, it is not unreasonable to expect that some portion of the peak shaving needs would be filled through gas-fired distributed generation.[18] In New York City, new generation is often located within the city itself because of transmission bottlenecks and so there is also an increasing need to employ cleaner generation alternatives.

What would the *option* to install 50 MW of NAS batteries for peak shaving five years from now be worth *today*? To answer this question, we'll use the same five valuation steps used earlier, although in the interest of expedience and simplicity we'll skip over the sensitivity analysis and the risk analysis and will just look at the risk contributed by the price of natural gas and the estimated probability that NAS capital costs will fall. In all likelihood, these are going to be the major drivers of strategic value in this exercise—if natural gas costs continue to rise and continue to be volatile and there is some probability that NAS costs will fall materially, there will be some strategic value that we can quantify, to make an estimate of the amount of investment that can be justified today, over and above that investment already justified previously through economic value alone.

Deterministic Cash Flow Model – 50 MW of NAS vs. 50 MW of Gas Turbines

A deterministic cash flow model is prepared using the inputs summarized in Table 2-12. The two input variables that we will exercise in the Monte Carlo simulation, natural gas fuel cost and NAS capital cost, are highlighted.

A summary of the major cost elements comparing 50 MW investments in these two technologies is shown in Table 2-13. (Note that all figures are now shown in millions of dollars). Essentially, we are comparing a $40 M investment in 50 MW of gas turbines (50 MW X $800/MW) with $150 M investment in 50 MW of NAS batteries (50 MW X $3000/MW). Each technology produces roughly the same amount of energy and demand benefits each year, about $8.1M annually, but the NAS battery has lower total annual operating costs of $3.012 M vs. $3.478 M for the gas turbines.

[18] In 2002, NYPA installed over 400 MW of peak-shaving capacity using gas turbines in its service territory. We are assuming, conservatively, that it is not unreasonable to expect that 50 MW of additional capacity will be needed within five years, and that alternatives to this known investment need may have strategic value.

Table 2-12
50 MW NAS vs. Gas Turbine Inputs

Combustion Turbine Input Assumptions	
Assumption	**Nominal Value**
Distributed Generation Cost ($/KW):	$800
Distributed Generation Installed Capacity (KW):	50,000
Efficiency (%):	31%
Fixed O&M costs ($/KW/year):	$15
Variable O&M costs ($/kwh):	$0.015
Fuel costs ($/MMBTU):	**$12.00**
Cost of capital (%):	4%
Depreciation Life, Book (years):	20
Depreciation Method:	MACRS
Salvage Value:	$0
Capacity factor:	3.9%
Displaced electric power purchase costs:	$0.0762
Federal Tax Rate:	35%
State Tax Rate:	5%
Property Taxes and Insurance:	2%
Electric Power price escalation rate (%):	1.0%
O&M escalation rate (%):	1.5%
Fuel cost escalation rate (%):	2.0%
Property Tax and Insurance escalation rate (%):	2.0%
Demand Charges:	$34.35
Number of months demand charges are reduced:	4
Hours of operation per day:	4
Number of days distributed generation will be operating annually:	85
Annual energy production (kwh):	17,000,000
Annual fuel cost ($):	$2,483,859
NAS Energy Storage Input Assumptions	
Capital Cost ($/KW):	**$3,000**
Fixed O&M costs ($/KW/year):	$10
Battery Module Replacement Cost:	$65,000
Cost for recharging batteries ($/KW/year):	$35
Module overhaul frequency (years):	8
Energy and Demand Benefits ($/KW/year)	$41

Table 2-13
Cost Comparison, 50 MW NAS Batteries vs. Gas Turbines

(All Figures in $ Millions)

	Gas Turbines	NAS
Capital Cost, 50 MW, 2011:	($40)	($150)
Benefits		
Annual Energy and Demand Benefits	$8.1	$8.1
Costs		
Annual Fixed O&M	($0.750)	($0.500)
Annual Variable O&M/Battery Replacement	($0.328)	($0.812)
Annual Fuel/Battery Recharging Costs	($2.400)	($1.700)
Total Annual Costs	($3.478)	($3.012)
Simple Payback (Years)	**9**	**29**
Present Value (Combustion Turbine)	($1.7)	
Present Value (NAS Energy Storage)	($78.0)	
NPV, Combustion Turbine	**$76.3**	

The simple payback of 9 years for the natural gas distributed generation units vs. the 29 year payback for the NAS batteries seems to indicate an overwhelming advantage for the former technology using an economic assessment alone. Using discounted cash flow analysis, the 20-year present value of the gas turbines is ($1.7 M) and the present value of the NAS batteries is ($78.0 M). The difference between the two results, $76.3 M is the NPV of 50 MW of gas turbines, assuming that NAS is the technology used for comparison. Note, however, that we have assumed a gas cost of $12.00/MMBTU and a NAS capital cost of $3000/MW, which is about the price that NYPA will soon be paying for the Long Island Bus project. Since each of these inputs is uncertain there is managerial flexibility that has value if there is some probability that either or both values will change during the investment horizon of five years.

Monte Carlo Simulation

The value of the option to invest in 50 MW of NAS battery technology five years in the future will be driven by the possibility that NAS capital costs will fall significantly and the continuing increases in natural gas prices and *volatility*. As you may recall, the volatility in the values of input drivers associated with market risk (that is, the risks largely outside of the control of the project team) increases the risk in the project cash flows and thus are sources of strategic value.

For the Monte Carlo simulation, a $12.00/MMBTU value was used for natural gas and a *lognormal* distribution was assumed with a standard deviation of $5.00/MMBTU. To arrive at this estimated distribution, it was assumed that gas prices over the 25-year modeling period (five years before the investment will be made and 20 years of project life[19]) would be at least as volatile as gas prices have been in the U.S. for the last 25 years. This distribution used in the Monte Carlo simulation is shown in Figure 2-23 and the data for wellhead prices (which are lower than prices paid by utilities but have a price probability distribution that will be similar) is shown in Figure 2-24.[20]

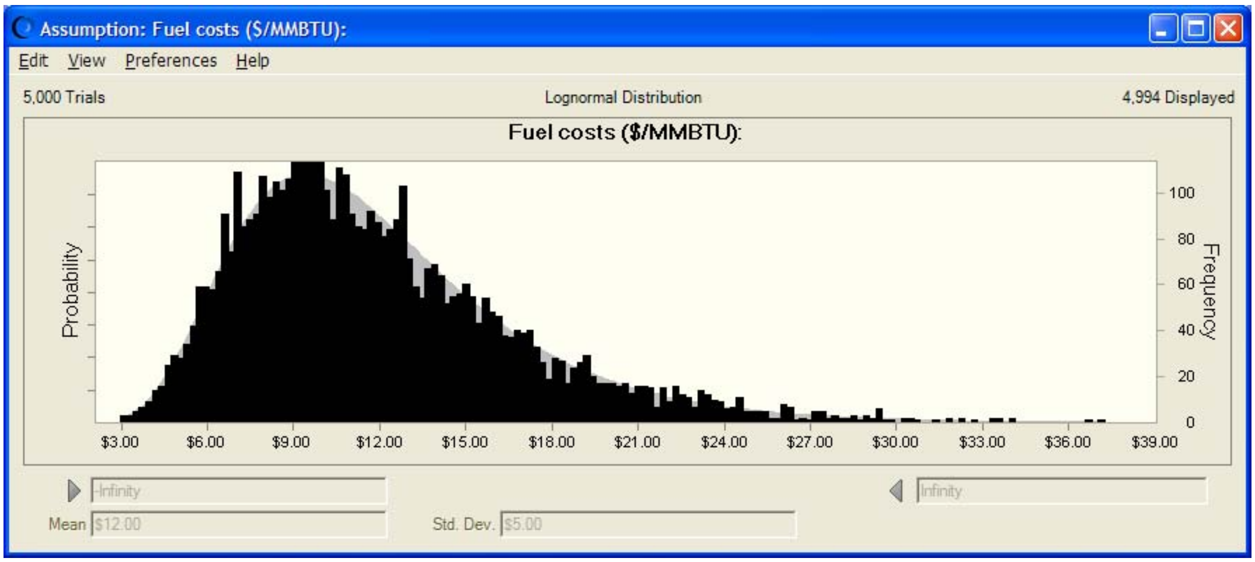


Figure 2-23
Probability Distribution, Natural Gas Prices

Note the similarities between the shapes in Figures 2-23 and 2-24. The lognormal distribution is ideal for datasets that cannot be negative and is often found in cost data and stock prices, for example. The 25-year natural gas price history shown in Figure 2-24 can be used as a proxy for the distribution shape for the gas prices used in the Monte Carlo simulation and as a means of estimating the standard deviation in annual gas prices. For the past 25 years, the standard deviation for gas prices has been about 40%. Since 1995, the standard deviation has been closer to 50%.

To account for the possibility that NAS battery technology costs may fall, NYPA assumed the following simple probability distribution: a 50% probability that costs will not fall at all but will remain the same for the next five years, and a 50% probability that costs will fall by 50%.

[19] For simplicity, it was also assumed that the NAS batteries sold five years from today will have a 20-year useful life, since customers will demand at least this expected life for a fully commercialized product.

[20] Energy Information Administration *Annual Energy Outlook 2006 (Early Release).*

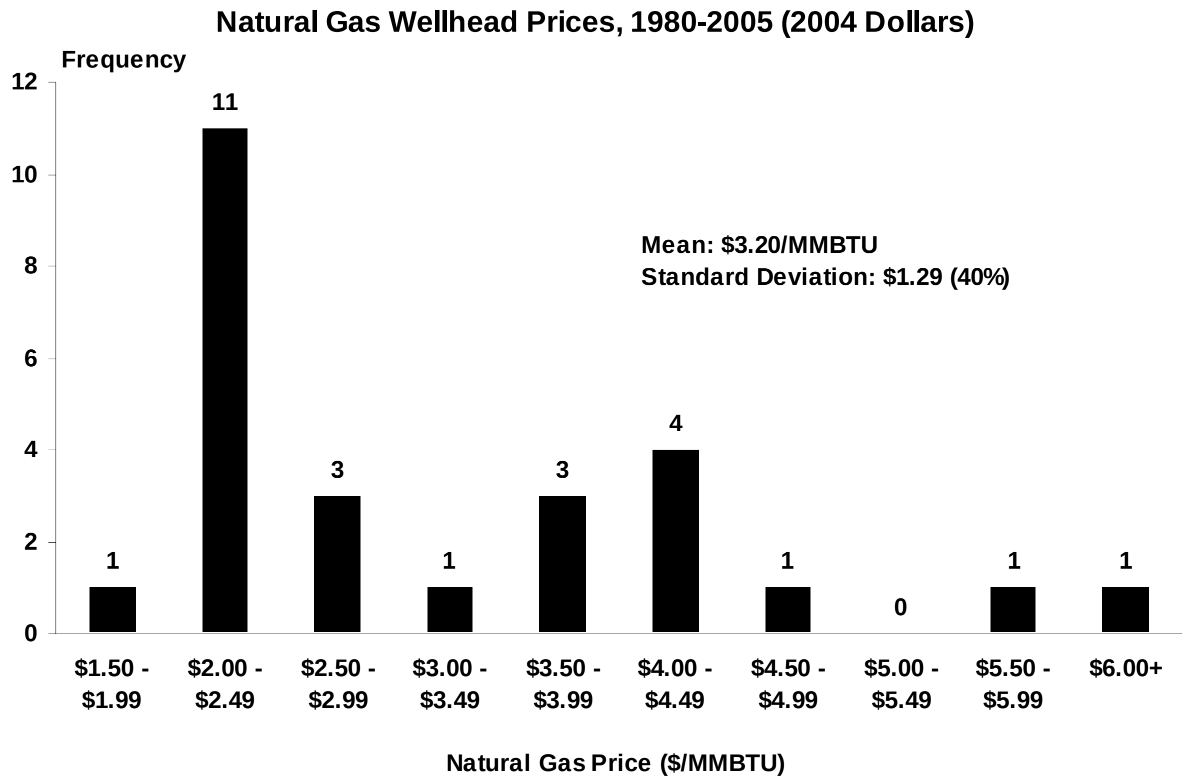


Figure 2-24
U.S. Natural Gas Prices, 1980-2005

This distribution is easily modeled in the Monte Carlo simulation software and is shown in Figure 2-25. This estimate is based on discussions with the manufacturer and expectations that commercialization efforts in the U.S. will result in significantly lower costs over the next five years.

To illustrate the sensitivity of these two input variables, the present values of the 50 MW gas turbine option and the 50 MW NAS battery option are about the same if the NAS battery costs are reduced by 50% and if natural gas prices double from $12.00/MMBTU to $24.00/MMBTU. *The possibility that these events could each occur simultaneously over the next five years is what gives the NAS alternative strategic value.* The probability of this kind of event does not have to be very large for the strategic value to be positive.

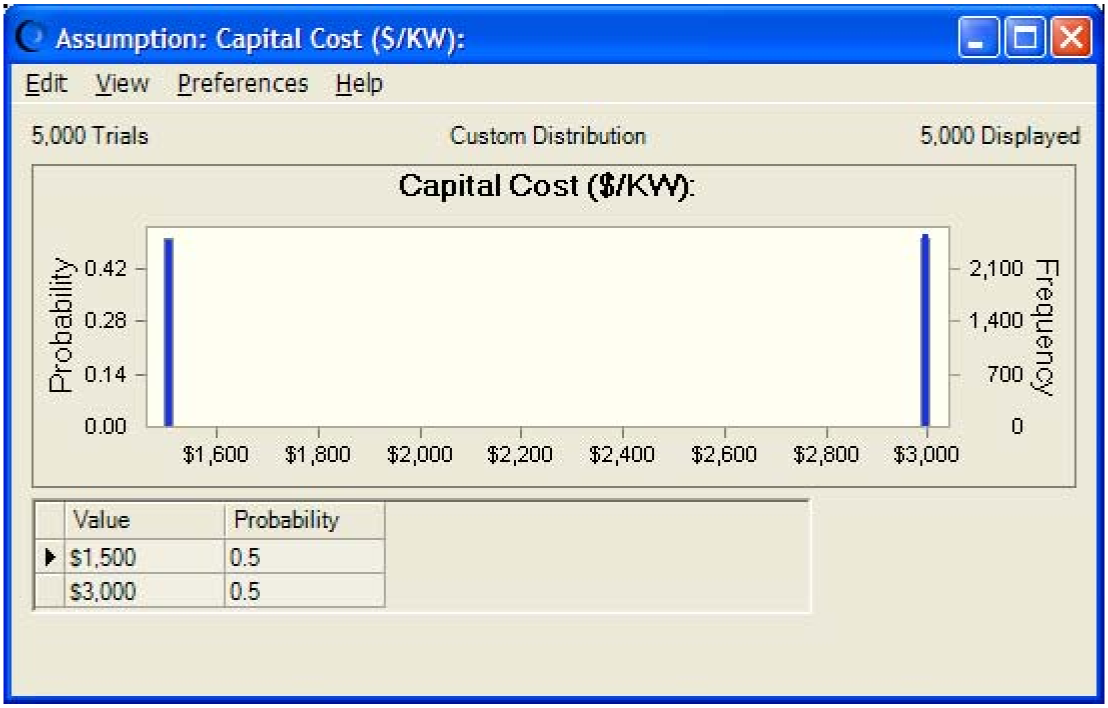


Figure 2-25
Assumed Distribution for NAS Battery Costs

A Monte Carlo Simulation was run and the probability for the NPV of the 50 MW NAS investment relative to the gas turbine investment alternative is shown in Figure 2-25. The two peaks result from the fact that we only have two estimates for NAS costs, $3000/KW and $1500/KW, and 50% of the 5000 simulations used one of these two values.

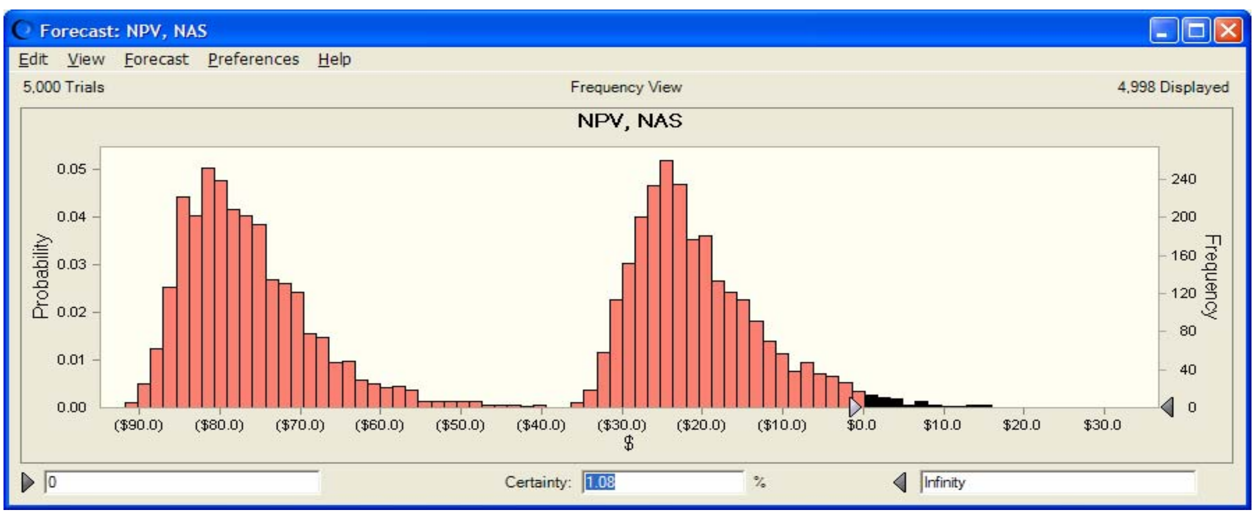


Figure 2-26
Monte Carlo Simulation, 50 MW NAS Relative to 50 MW Gas Turbines

Note that the vast majority of the scenarios show a negative NPV—*but not all of them.*

There are a small number of simulations, shown in black at the right side of the output, where the NPV of 50 MW of investment in NAS technology was *positive relative to gas turbines*. Although the probability of a positive NPV is small, it is large enough to suggest that there may be strategic value that we can quantify using real options.

Recall that it is the risk in the project cash inflows—those cash flows resulting from the project after that capital investment is made that largely determines the option value in the investment alternative. To calculate this, we simply looked at the present value of the cash flows resulting from an investment in 50 MW of NAS batteries for peak shaving five years in the future as one of the outputs in the Monte Carlo Simulation. The results are shown in Figure 2-27.

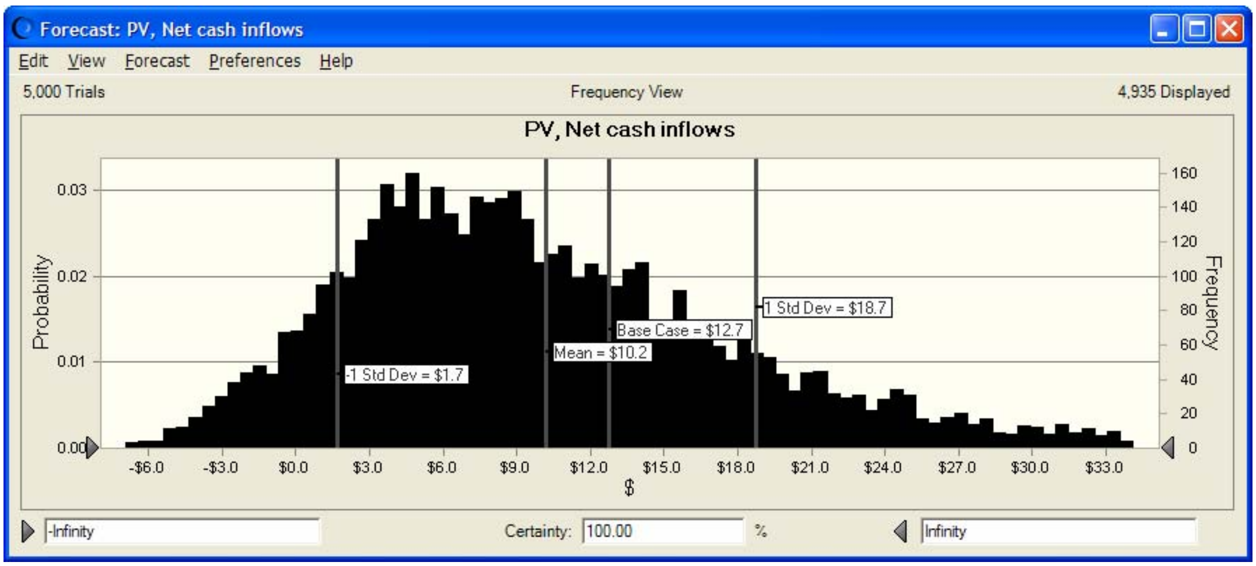


Figure 2-27
Present Value, Net Cash Inflows, 50 MW NAS Battery Relative to Gas Turbines

The present value of the project cost inflows was determined by calculating the difference between cash flows produced by the 50 MW NAS battery investment and the cash flows produced by a 50 MW gas turbine investment and discounting these to the present value. The base case (i.e., deterministic) value is $12.7 M. In the Monte Carlo simulation, the lower mean value of $10.2 M results from the fact that the gas price, a major driver of project value, is skewed to the left since we assumed a lognormal distribution. The feature shown in Figure 2-27 that will be a significant driver of real option value is the standard deviation of the project cash inflows, whose value of $8.5 M corresponds with a standard deviation of over 80%.

This high degree of market-specific risk coupled with a long time to expiration for the exercise of this option (5 years) should result in significant strategic value. Other sources of market-specific risk (the capital cost for natural-gas combustion turbine technology, for example) have, for simplicity, not been quantified, but this is an example of a factor that could increase the standard deviation of the project cash flows further.[21]

Real Options – 50 MW NAS Battery Investment

To calculate the value of the option to invest in 50 MW of NAS batteries for peak shaving five years from now using the Black-Scholes option pricing formula, we need just a few more variables: the exercise price and the estimated annual cost to maintain the option, a term known in financial options as the dividend. The rest of the variables, including the time until expiration, the stock price (the present value of the project cash inflows), the risk-free rate, and the volatility of the project cash flows have already been calculated.

The exercise price is the present value of the difference between the first year capital costs for the 50 MW NAS battery investment and the first year capital costs for the 50 MW gas turbines. The reason that we are using the difference between the two investment amounts is that we are assuming that *some* investment must be made and that the value of the alternative chosen will preclude (eliminate the need for) the investment in the second choice. The same approach was taken with the project cash flows in the earlier section.

To see how the exercise price is calculated, see the cash flow projections for each alternative in Figures 2-28 and 2-29 (only the first five years are shown for simplicity).

Year	2011	2012	2013	2014	2015
Income statement impacts					
Value of electricity produced		1,295,400	1,308,354	1,321,438	1,334,652
Value of avoided demand charges		6,870,000	6,870,000	6,870,000	6,870,000
Fixed O&M costs		(750,000)	(761,250)	(772,669)	(784,259)
Variable O&M costs		(255,000)	(258,825)	(262,707)	(266,648)
Fuel costs		(2,483,859)	(2,533,536)	(2,584,207)	(2,635,891)
Property Taxes and Insurance		(800,000)	(816,000)	(832,320)	(848,966)
Depreciation (20 year MACRS)	(1,500,000)	(2,887,600)	(2,670,800)	(2,470,800)	(2,285,200)
EBIT Impact	(1,500,000)	988,941	1,137,943	1,268,735	1,383,688
Less taxes	600,000	(395,577)	(455,177)	(507,494)	(553,475)
EBIAT	(900,000)	593,365	682,766	761,241	830,213
Plus depreciation	1,500,000	2,887,600	2,670,800	2,470,800	2,285,200
Cash flow from operations	600,000	3,480,965	3,353,566	3,232,041	3,115,413
Capital Investment	(40,000,000)				
Book value of asset sales					
Net cash flow	(39,400,000)	3,480,965	3,353,566	3,232,041	3,115,413
Present value of net cash flow (in each year)	(32,383,928)	2,751,057	2,548,434	2,361,621	2,188,848
Cumulative present value of net cash flows	**(32,383,928)**	(29,632,871)	(27,084,437)	(24,722,816)	(22,533,968)

Figure 2-28
50 MW Gas Turbine Cash Flows

[21] If the capital costs for natural gas distributed generation equipment rises, for example, the real option value would increase further.

In Figure 2-28, the capital investment shown in year 2011, five years from today, is $40 M, which is simply $800/MW X 50 MW. After subtracting the tax benefits from depreciation and discounting the result to the present value, the required investment is ($32.38 M). This is essentially today's value for the cash flow impact of the capital investment.

Year	2011	2012	2013	2014	2015
Income statement impacts					
Value of electricity produced		1,295,400	1,308,354	1,321,438	1,334,652
Value of avoided demand charges		6,870,000	6,870,000	6,870,000	6,870,000
Fixed O&M costs		(500,000)	(507,500)	(515,113)	(522,839)
Battery Module Replacement costs		0	0	0	0
Cost to recharge batteries		(1,750,000)	(1,785,000)	(1,820,700)	(1,857,114)
Property Taxes and Insurance		(3,000,000)	(3,060,000)	(3,121,200)	(3,183,624)
Depreciation (20 year MACRS)	(5,625,000)	(10,828,500)	(10,015,500)	(9,265,500)	(8,569,500)
EBIT Impact	(5,625,000)	(7,913,100)	(7,189,646)	(6,531,075)	(5,928,425)
Less taxes	2,250,000	3,165,240	2,875,858	2,612,430	2,371,370
EBIAT	(3,375,000)	(4,747,860)	(4,313,788)	(3,918,645)	(3,557,055)
Plus depreciation	5,625,000	10,828,500	10,015,500	9,265,500	8,569,500
Cash flow from operations	2,250,000	6,080,640	5,701,712	5,346,855	5,012,445
Capital Investment	(150,000,000)				
Book value of asset sales					
Net cash flow	(147,750,000)	6,080,640	5,701,712	5,346,855	5,012,445
Present value of net cash flow (in each year)	(121,439,730)	4,805,618	4,332,833	3,906,895	3,521,677
Cumulative present value of net cash flows	**(121,439,730)**	(116,634,112)	(112,301,279)	(108,394,384)	(104,872,707)

Figure 2-29
50 MW NAS Battery Cash Flows

The same approach is used to calculate the present value of the required investment for the 50 MW NAS battery alternative. In the model shown, the $150 M cost is simply the assumed unit cost of $3000/MW X 50 MW, with the depreciation tax benefits subtracted and discounted to the present value, resulting in a cash flow impact of ($121.44 M).

The exercise price used in the Black-Scholes option pricing model is simply the difference between the present value of the NAS alternative, ($121.44 M) and the gas turbine alternative ($32.38 M), which is $89.1 M.

The annual cost to keep the option open for five years is estimated to be $150,000. This accounts for the fact that NYPA must maintain some competence and experience with the NAS technology during the five-year holding period. This cost might include costs associated with pilot projects such as the Long Island Bus Company example described earlier, or with investments made in EPRI membership, or in other research and development activities.

The estimate of this cost reflects the cost that strategic value is not free—it must be maintained for the option to be exercised in the future. NYPA cannot simply suspend all investments associated with NAS technology if it believes that there is some chance that it might conceivably consider a 50 MW investment in five years that costs $89.1 M in today's dollars. Indeed, NYPA is making investments associated with keeping the electricity storage investment option today.

Finally, the risk free-rate will be the yield on a five-year treasury bond, 4.5%.

The six variables entered into the Black-Scholes option pricing formula are shown in Table 2-14.

Table 2-14
50 MW NAS Growth Option

All Values Shown are $ Millions		
Inputs		
Real Option		**Financial Option Equivalent**
Present Value of the Project Cash Inflows:	**$10.2**	Stock Price ($):
Standard deviation of project cash inflows:	**80%**	Volatility (%):
Required investment:	**$89.1**	Exercise Price ($):
Length of time option is valid:	**5**	Time To Expiry (years):
Annual costs of keeping the option open:	**$0.15**	Dividends ($):
Risk free rate (Estimated from 5 year treasury yield):	**4.5%**	Risk-free Interest Rate (%):
Outputs		
d_1:	-0.2325	
$N(d_1)$:	0.4081	proportion of shares required to replicate a call option
d_2:	-2.0214	
$N(d_2)$:	0.0216	probability the call option will be exercised on expiry
Value of the option:	**$2.3**	

The value of this growth option, using the variables shown, is $2.3 Million. What this means is that the option to invest $89.1 M in 50 MW of NAS battery capacity for peak shaving, instead of 50 MW of natural gas turbine generation five years from today, is worth $2.3 Million. When this investment is analyzed for economic value alone using a deterministic model, it is not obvious at all that any investment in NAS is warranted. In fact, the project cash flows are only estimated to be worth $12.7 M using the deterministic model, and $10.2 M using the mean from the Monte Carlo simulation. The difference between the NAS investment, ($89.1 M), and the project cash flows, $12.7 M, is ($76.3 M) and represents the NPV of the NAS alternative. The same result was attained earlier when we simply compared the present value of the cash flows associated with the gas turbine investment ($1.7 M) and the cash flows associated with the NAS battery investment ($78.0 M). The difference between these two present values is also ($76.3M).

The additional value comes from the fact that the cash flows are volatile and there is a long period for exercising this option. In fact, this option value is highly sensitive to the time to expiration and the volatility of the project cash flows, which we earlier determined was highly dependent on the volatility of gas prices.

Figure 2-30 shows the option payoff diagram for this investment opportunity and Table 2-15 shows how the strategic value varies for different combinations of project cash inflow values and volatilities. Table 2-15 is essentially a detailed look at the lower left hand corner of the option payoff diagram in Figure 2-30.

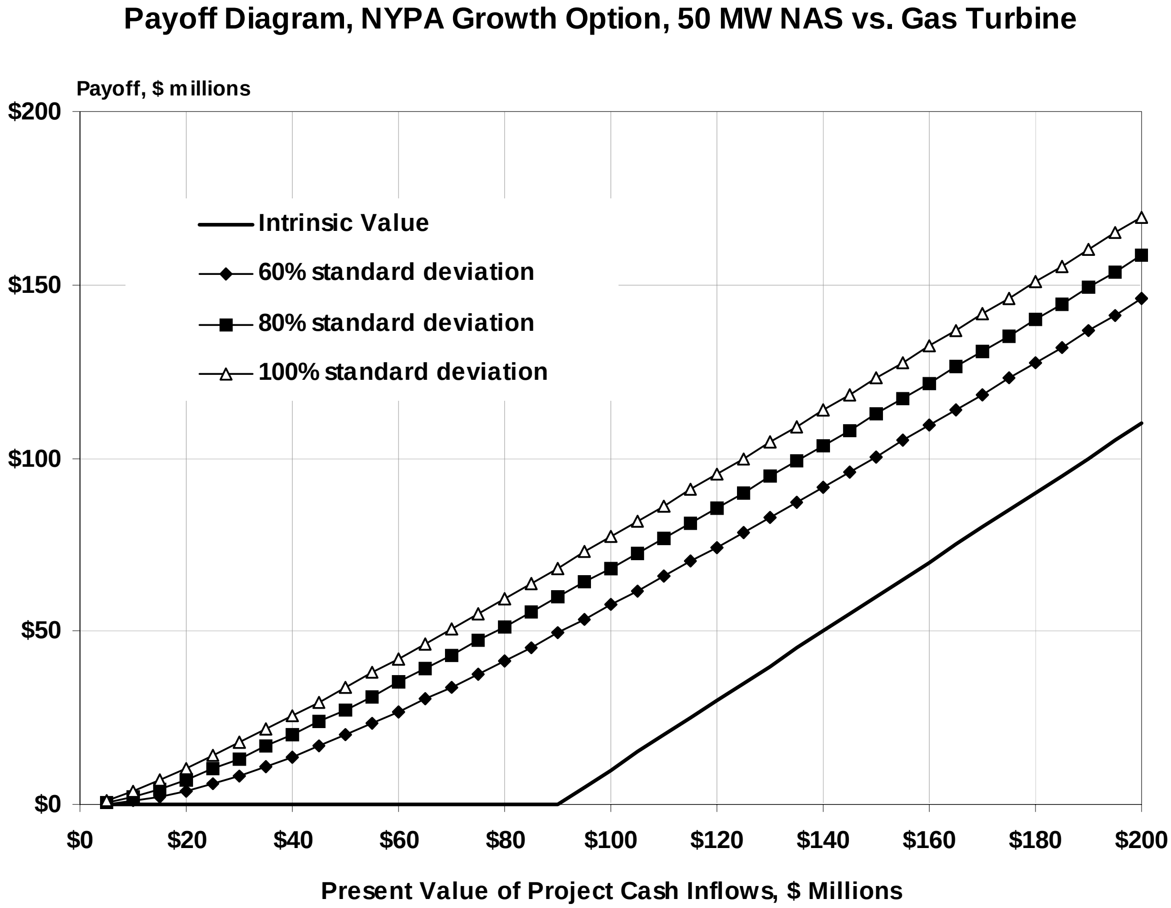


Figure 2-30
Option Payoff Diagram 50 MW NAS Battery Investment

Table 2-15
50 MW NAS Battery Option Values for Different Volatilities, Project Cash Flows

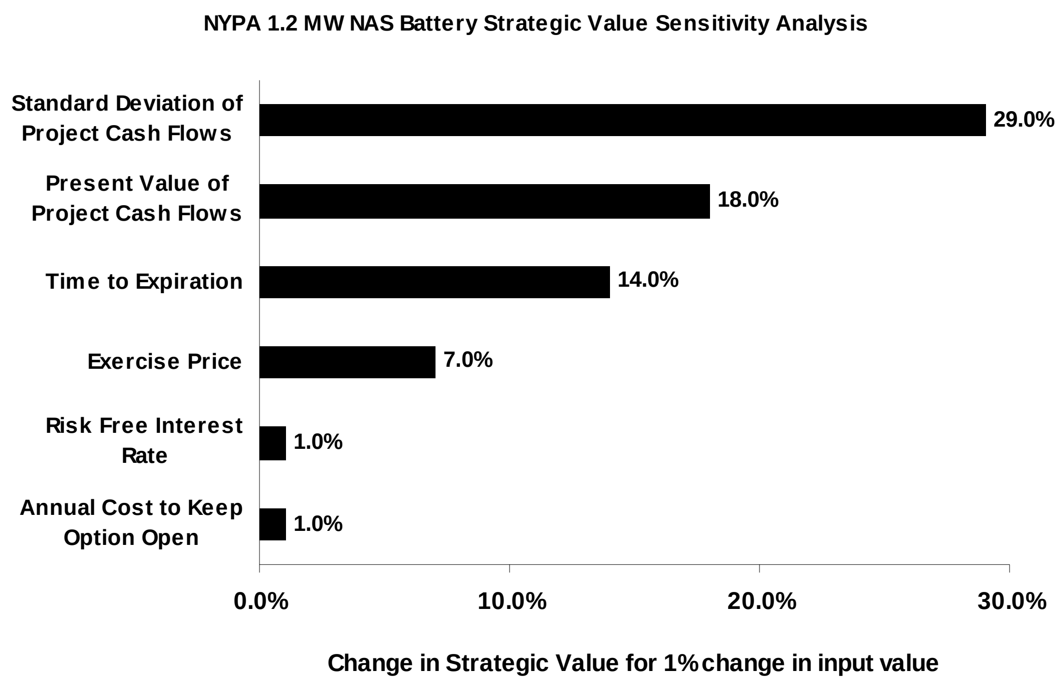
All Values Shown are $ Millions

		Uncertainty (standard deviation of project cash inflows)					
		50%	60%	70%	80%	90%	100%
Present Value of Project Cash Inflows	$5	$0.03	$0.13	$0.32	$0.59	$0.92	$1.29
	$10	$0.34	$0.82	$1.48	$2.25	$3.07	$3.89
	$15	$1.08	$2.07	$3.25	$4.51	$5.78	$6.99
	$20	$2.23	$3.78	$5.47	$7.18	$8.84	$10.39
	$25	$3.77	$5.86	$8.02	$10.13	$12.14	$14.00
	$30	$5.65	$8.24	$10.83	$13.31	$15.63	$17.75

Note the fact that this option is comprised entirely of strategic value, unlike the earlier option comprised mainly of economic value. To return to the financial options analogy, this investment is like a five-year stock call option with an exercise price of $89.10/share for a stock currently trading at only $10.20/share and paying a dividend of $0.15 annually. For this stock option, a prudent investor could invest $2.30/share for the right, but not the obligation, to buy the stock five years from now at $89.10. The option has value, in part, because there are five years in the holding period and the stock is volatile, with a standard deviation of stock prices expected to be 80%.

The data in Table 2-16 shows that the value of the option is highly sensitive to the volatility of the project cash flows. The next most sensitive factors are the value of the project cash flows and the time to expiration.

Table 2-16
Sensitivity Analysis, 50 MW NAS Battery Option Value



This option is only worth $950,000 if the time to expiration is only 3 years instead of 5 and the value is reduced to $350,000 for a 2-year holding period. This sensitivity to option holding period illustrates the importance of long-term planning and a judicious assessment of how long an option can really be expected to be valuable. If NYPA really must make a decision in 3 years instead of 5, the strategic value of other alternatives to gas turbines for peak shaving might prove superior. In this example, we see that the strategic value is not a trivial amount and that an investment in a project like the one described earlier for the Long Island Bus Company might even be warranted without investments from other parties (such as NYSERDA or DOE).

3
CASE 2 – PSE&G T&D UPGRADE DEFERRAL

Background

Public Service Electric & Gas Company (PSE&G) is a subsidiary of Public Service Enterprise Group, an energy and energy service company headquartered in New Jersey. PSE&G is the regulated utility Division, delivering gas service to 1.7 million customers and electric service to 2.1 million customers, in a 2600 square mile area of New Jersey where 70% of the population resides.

Like most distribution utilities, PSE&G must plan for load growth within its existing service territory, and make investments to upgrade existing transmission and distribution (T&D) assets to accommodate this growth. These investments have typically included line construction, substation upgrades, regulatory fees and right-of-way perfection expenses. In recent years, the company has been challenged by the New Jersey Board of Public Utilities to consider investments in distributed generation in its planning process, and began working with EPRI to model distributed generation investment alternatives.

In 2004, PSE&G worked with EPRI on a pilot version of the *DR Economic Screening Tool*, a spreadsheet software tool designed to model distributed generation investments and compare these with traditional T&D upgrade investments. This tool was used on a case study called the PSE&G Substation, and compared a traditional T&D upgrade investment with an alternative employing 5 MW natural gas combustion turbine distributed generation units to meet the growing load on a part of the distribution system where loads were expected to exceed capacity in 2005. PSE&G was interested in knowing if the deferral of a planned $20,000,000 investment in a 60 MVA upgrade to the portion of the distribution system served by a PSE&G Substation could be made possible through smaller investments in distributed generation units added to the system as the load grows.

Some of the results from the modeling of this investment opportunity are shown in Table 3-1. This modeling tool essentially calculates the value of T&D deferral and compares this with the estimated costs for distributed generation for multiple years. A summary of the Year 1 cash flows alone is shown in a different way in Table 3-2, grouping the costs and the benefits associated with the distributed generation project. To understand how this model works, it is useful to know that distributed generation is proposed to be used as a means of closing the gap between the existing system capacity, 359,000 kVA, and the existing peak load, which has grown by 1.1% from 367,000 kVA in Year 0 to 371,037 in Year 1. The DR Screening Tool allows the user to choose a “DR Increment Size” and for this model iteration, a 5000 KW gas combustion turbine was chosen for this input. Three of these units will be needed to fill the 12,037 kVA gap between system capacity and system peak load in Year 1.

Table 3-1
Sample Output from DR Screening Tool, PSE&G Substation Case

Existing System Capacity	359,000	kVA
Existing Peak Load	367,000	kVA

Year by Year Economics (in Year 0 $)	**0 (current)**	**Year 1**	**Year 2**	**Year 3**	**Year 4**
Peak system load	367,000	371,037	375,118	382,246	388,362
DR increment size	5,000				
Number of units installed that year	0	3	1	1	1
Total DR capacity (kW)		15,000	20,000	25,000	30,000
DR equipment cost		10,556,075	3,288,497	3,073,362	2,872,300
Fuel cost		758	968	2,424	2,661
Displaced electricity purchase		636	804	1,995	2,169
DR maintenance		186,572	289,442	367,070	447,094
DR property taxes and insurance		203,204	245,814	279,673	305,897
DR federal and state tax benefits		90,796	120,218	148,135	342,416
T&D payment		2,103,580	2,103,580	2,103,580	2,103,580
T&D maintenance		71,145	67,488	64,019	60,728
T&D property taxes and insurance		364,486	331,907	302,030	274,642
T&D federal and state tax benefits		785,047	716,095	651,160	589,967
Deferral Benefit					
The year by year PV of Deferring the T&D Investment		1,222,814	1,142,817	1,068,053	998,181
The DR Option					
NPV of installing DR		-9,632,361	-12,193,242	-14,697,588	-16,982,774

Table 3-2
PSE&G Substation Cash Flows, Year 1

	Year 1
Costs	
DR equipment cost	(10,556,075)
Fuel cost	(758)
DR maintenance	(186,572)
DR property taxes and insurance	(203,204)
Total Costs	(10,946,608)
Benefits	
Displaced electricity purchase	636
DR federal and state tax benefits	90,796
The year by year PV of Deferring the T&D Investment	1,222,814
Total Benefits	1,314,247
Present value of cash flows, year 1	**(9,632,361)**

The majority of the cost for the DR alternative in Year 1 is the capital cost for the gas turbine distributed generation units. Each 5000 KW unit is assumed to cost $3,765,000. Three units would thus cost $11,295,000, and this figure is discounted at an assumed capital cost of 7% to arrive at the Year 1 cash flow of $10,556,075. The present value of the DR alternative in Year 1 is ($9,632,361), and is simply the sum of the capital, fuel, maintenance, property taxes and insurance costs, and the benefits associated with the value of the electricity produced by the distributed generation units, the tax benefits associated with the capital investment, and the annual value of T&D deferral. In all 10 years modeled with the DR screening tool, the distributed generation alternative produced a negative NPV; at the end of 10 years, the cumulative NPV was ($36,809,162).

PSE&G modeled different growth rate assumptions and load shapes using the DR Economic Screening Tool and found that traditional T&D investments were superior to distributed generation investments under most sets of assumptions. As a result, no investment in distributed generation was made for the PSE&G Substation case. This is a common result when considering investment in alternative technologies—the NPV of the alternative (gas combustion turbines) is negative when compared with investments in incumbent technology alternatives (the traditional T&D upgrades), and therefore the decision is made not to invest in distributed generation.

PSE&G decided that there would be benefit to modeling the risk in this opportunity to see if *some* investment in distributed generation is warranted, even though the project NPV predicted by the deterministic model is negative. Further, PSE&G was interested in knowing if an investment in an energy storage technology as a T&D deferral strategy might also be warranted by such an analysis.

The valuation process illustrated in Chapter 1 was applied to the PSE&G Substation Case to model the risk in this investment opportunity and to determine if any quantifiable real options might reveal the strategic value that could be used to enhance the economic value determined through discounted cash flow analysis.

Step 1: Deterministic Cash Flow Model

The inputs used in the DR Economic Screening Tool for the PSE&G Substation case were used as a starting place to create a deterministic cash flow model that could later be used for sensitivity analysis, Monte Carlo modeling, uncertainty analysis and real options analysis. The approach chosen was to create a 20-year pro forma cash flow projection for each alternative technology under consideration, and to compare the net costs and benefits for each alternative to the traditional T&D upgrade investment. The traditional T&D upgrade is sometimes known as the *incumbent technology*.

The analysis started by evaluating distributed generation investments. Later, we'll see how investments in energy storage technologies compare.

The inputs used to model the investments in the traditional T&D upgrade are shown in Table 3-3 and the first several years of the cash flow projection are shown in Table 3-4.

Table 3-3
T&D Upgrade Deterministic Model Inputs

Assumption	Nominal Value
Transmission Upgrade Cost (1)	$20,000,000
Transmission Upgrade Incremental O&M costs ($ per year)	$75,000
Capacity of the new T&D Project (kVA)	60,000
Load Growth (%)	1.0%
Allowable System Capacity (kVA)	359,000
Existing Peak Load (kVA)	362,000
Planning period (years)	20
Lead time (years)	1
Cost of capital (%)	7%
Depreciation Life, Book (years)	40
Depreciation Method	SL
Salvage Value	$0
Federal Tax Rate	35%
State Tax Rate	5%
Property Taxes and Insurance	2%
O&M escalation rate (%)	1.5%
Property Tax and Insurance escalation rate (%)	2.0%
Growth rate assumed for terminal value (%)	2.0%

Table 3-4
T&D Upgrade Cash Flow Projection

Peak system load	362,000	365,620	369,276	372,969	376,699
Year	**0**	**1**	**2**	**3**	**4**
Income statement impacts					
Fixed O&M costs		(75,000)	(76,125)	(77,267)	(78,426)
Property Taxes and Insurance		(400,000)	(408,000)	(416,160)	(424,483)
Depreciation (straight line)		(500,000)	(500,000)	(500,000)	(500,000)
EBIT Impact		(975,000)	(984,125)	(993,427)	(1,002,909)
Less taxes		390,000	393,650	397,371	401,164
EBIAT		(585,000)	(590,475)	(596,056)	(601,745)
Plus depreciation		500,000	500,000	500,000	500,000
Cash flow from operations		(85,000)	(90,475)	(96,056)	(101,745)
Capital Investment	(20,000,000)				
Net cash flow	(20,000,000)	(85,000)	(90,475)	(96,056)	(101,745)
Present value of net cash flow (in each year)	(20,000,000)	(79,439)	(79,024)	(78,410)	(77,621)
Cumulative present value of net cash flows	(20,000,000)	(20,079,439)	(20,158,464)	(20,236,874)	(20,314,495)
PV, T&D Upgrade	**(21,371,423)**				

Note that our incumbent technology, the 60,000 kVA T&D upgrade, is largely comprised of a $20,000,000 capital cost and an assumed increase in annual O&M costs of $75,000. Escalating the various costs by the assumed amounts in Table 3-3 and discounting all cash flows to the present value results in a total project cost of ($21,371,423). In other words, the present value of all of the costs associated with the 60,000 kVA T&D upgrade over the 20-year modeling period is ($21,371,423).[22]

The model inputs used for the distributed generation investment alternative are shown in Table 3-5, and some comments are necessary for a few of these inputs highlighted in bold typeface.

Table 3-5
Distributed Generation Inputs

Assumption	Nominal Value
Distributed Generation Cos	$3,765,000
Distributed Generation Installed Capacity (KW)	5,000
Efficiency (%)	31%
Fixed O&M costs ($/KW/year)	$15
Variable O&M costs ($/kwh)	$0.015
Fuel costs ($/MMBTU)	**$6.00**
Cost of capital (%)	7%
Depreciation Life, Book (years)	20
Depreciation Method	SL
Salvage Value	$1,500,000
Capacity factor	**6.3%**
Displaced electric power purchase costs	$0.056
Federal Tax Rate	35%
State Tax Rate	5%
Property Taxes and Insurance	2%
Electric Power price escalation rate (%)	1.0%
O&M escalation rate (%)	1.5%
Fuel cost escalation rate (%)	2.0%
Property Tax and Insurance escalation rate (%)	2.0%
Load growth rate (%)	**1.0%**
Existing system capacity (kVA)	359,000
Existing peak load (kVA)	362,000

[22] For the moment, we are ignoring terminal value, that is, the value of the cash flows assumed to exist after the end of the 20-year modeling period. In a later iteration of the model, we'll explore ways to deal with the valuation of assets with useful lives that are longer than the modeling period. T&D assets are in this category. Although they may last for 40 years or more, our valuation models for all investment alternatives will be limited to 20 years for simplicity.

The fuel cost of $6.00/MMBTU applies to the fuel used by the distributed generation units during peak shaving periods. The model calculates the annual cost of natural gas used by the combustion turbine distributed generation units using this value.[23]

The capacity factor is a measure of how many hours per year the distributed generation equipment is running, as a percentage of the total available hours in the year. PSE&G initially estimated that the annual number of hours that the system would be operating at or near peak capacity of 359,000 kVA would be 550 hours. Dividing this total by the total number of hours in a year results in a capacity factor of 6.3%. As we will see later, this is a simplifying assumption that is probably sufficient for our initial modeling purposes, but it is an input that we will want to refine further to more accurately represent the operation of the units as more distributed generation units are installed on the system.

Finally, the load growth rate is an important measure of how fast the system load is expected to increase over the 20 years in the modeling period. The higher the load growth rate, the faster that the gap between existing system capacity and peak load grows, and the more distributed generation units will be needed to make up the difference. Recall that the distributed generation units are being used to defer the larger $20,000,000 investment in the T&D system upgrade; the higher the load grows, the greater the cost of T&D deferral.

Table 3-6 shows the first several years of the distributed generation cash flow projection, the present value of distributed generation costs over the 20-year modeling period, and the present value of the T&D upgrade costs calculated earlier.

The NPV of the distributed generation alternative, ($12,487,162), is simply the difference between the present value of the T&D upgrade costs and the present value of the distributed generation costs. Note that in the first four years, we will have added 4 natural gas combustion turbine distributed generation units to make up the difference between the existing system capacity and the peak load projected for that time—376,600 kVA.

Note also that the cost of fuel for the distributed generation equipment exceeds the value of the electricity produced in each year of the projection; this is due, in part, to the relatively low value of electricity purchases ($.056/kwh) that will be offset through the use of the distributed generation equipment. The electricity price is a fixed rate that PSE&G has negotiated with its suppliers. At $6.00/MMBTU for natural gas, and distributed generation equipment running at 31% efficiency, the value of the electricity produced is lower than the cost to produce it, even without accounting for operations and maintenance costs.

This observation led to key insight in the valuation of the distributed generation alternative: our capacity factor assumption deserves additional scrutiny, because if the equipment runs more than 550 hours per year, the NPV of the distributed generation alternative should be even lower. In summary, the more that the distributed generation equipment is used, the lower the NPV.

[23] The fuel price was originally assumed during 2004 when the DR economic screening tool was first used. By the time this case was written, fuel prices were over $15.00/MMBTU. A later iteration of this model will incorporate a natural gas pricing forecast to better represent the dynamic nature of this variable.

So, on the first pass, we have a negative NPV project using the deterministic cash flow model. The analysis thus far indicates that if we invest in distributed generation for the next 20 years to defer the T&D upgrade investment of $20,000,000, we will destroy on the order of $12.5 million in shareholder value—a prospect that is clearly not in the interest of either PSE&G or its shareholders.

Table 3-6
Distributed Generation Cash Flow Projection

Peak system load	362,000	365,620	369,276	372,969	376,699
DR increment size (KW)	5,000				
Total number of DR units installed	1	2	3	3	4
Total DR capacity	5,000	10,000	15,000	15,000	20,000
Year	**0**	**1**	**2**	**3**	**4**
Income statement impacts					
Value of electricity produced		309,053	468,215	472,897	636,835
Fixed O&M costs		(150,000)	(228,375)	(231,801)	(313,704)
Variable O&M costs		(82,782)	(126,036)	(127,926)	(173,127)
Fuel costs		(403,174)	(616,856)	(629,193)	(855,703)
Property Taxes and Insurance		(150,600)	(230,418)	(235,026)	(319,636)
Depreciation (straight line)		(226,500)	(339,750)	(339,750)	(453,000)
EBIT Impact		(704,003)	(1,073,220)	(1,090,799)	(1,478,334)
Less taxes		281,601	429,288	436,320	591,334
EBIAT		(422,402)	(643,932)	(654,480)	(887,001)
Plus depreciation		226,500	339,750	339,750	453,000
Cash flow from operations		(195,902)	(304,182)	(314,730)	(434,001)
Capital Investment	(3,765,000)	(3,518,692)	(3,288,497)	0	(2,872,300)
Book value of asset sales					
Net cash flow	(3,765,000)	(3,714,594)	(3,592,679)	(314,730)	(3,306,301)
Present value of net cash flow (in each year)	(3,765,000)	(3,471,583)	(3,137,985)	(256,913)	(2,522,361)
Cumulative present value of net cash flows	(3,765,000)	(7,236,583)	(10,374,568)	(10,631,481)	(13,153,842)
PV, Distributed Generation Alone	**(33,858,584)**				
PV, Transmission & Distribution Upgrade Alone	**(21,371,423)**				
NPV of Distributed Generation	**(12,487,162)**				

Before abandoning distributed generation or other investments in energy storage, however, we need to model the risk in this opportunity, and we will use this information in the real options analysis later.

We'll begin with a sensitivity analysis, to understand how the NPV is impacted by changes in input assumption values. Then, we'll incorporate a number of model revisions that were proposed by PSE&G during the creation of this case, and model the risk using the Monte Carlo simulation, before identifying any options embedded in this investment opportunity.

Step 2: Sensitivity Analysis

The model developed so far has nearly 40 inputs between the T&D upgrade inputs and the distributed generation inputs. For simplicity, the ten inputs most likely to need further analysis are used in a sensitivity analysis. We independently changed the value of each of these inputs by 1% and recorded the change in the NPV for the project. Figure 3-1 shows the percentage change in the NPV resulting from a 1% change in each of the input values.

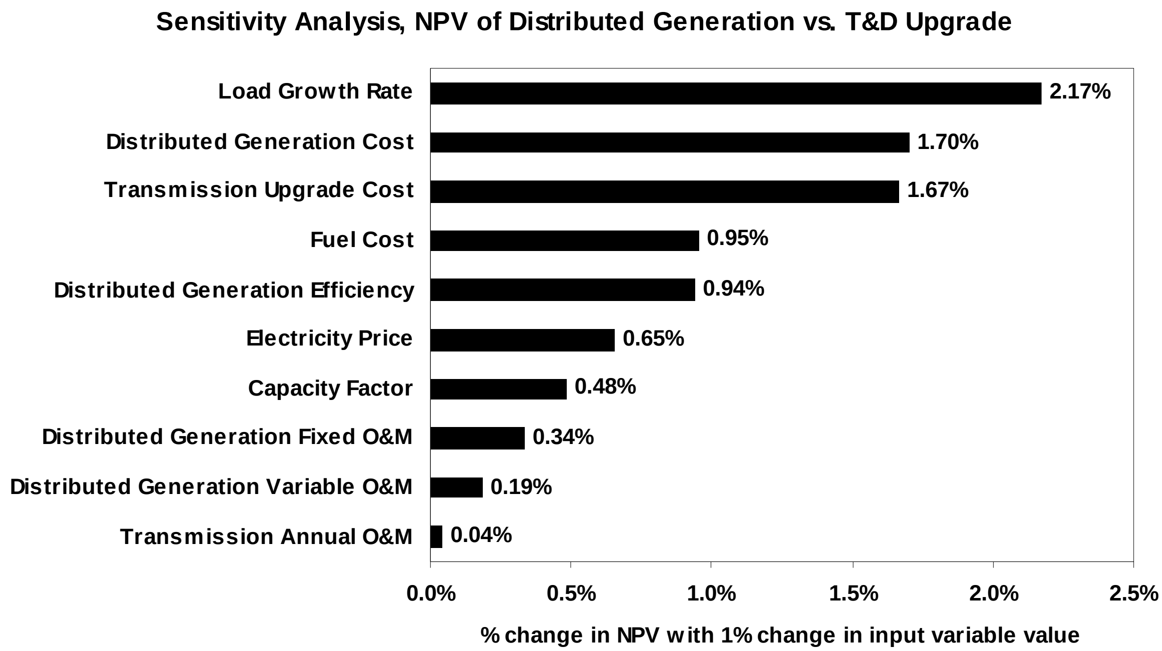


Figure 3-1
Sensitivity Analysis, NPV of Distributed Generation vs. T&D Upgrade

PSE&G had discovered through its use of the DR Economic Screening tool that the assumed load growth rate was likely to be a variable worth exercising. In addition, there is a wide range of possible values for the load growth that are likely to occur over the next 20 years, with a low estimate of 0.5% annually to a high estimate of 1.5% annually.[24]

Since the load growth assumption is so important, it is worthwhile to see how the NPV varies with changes in this assumption, along with changes to another important assumption, the capacity factor for the distributed generation equipment. The data table shown in Table 3-7 illustrates how the NPV changes with different assumptions for these two variables. The positive NPV cases are highlighted and the NPV for a combination of load growth and capacity factor for the current base case is highlighted in bold typeface.

Interestingly, there are a number of combinations of load growth and capacity factor where it makes economic sense for PSE&G to defer its planned $20,000,000 investment in a T&D upgrade for the PSE&G Substation, and to invest, instead, in 5,000 KW natural gas combustion turbines. If the equipment is used for a small number of hours each year, say, under 350 hours

[24] Recall that variables with a high range of uncertainty and high sensitivity with respect to the output for the model are those variables likely to contribute the most to the overall risk in the output.

annually[25], and annual load growth is 0.6% or less, it appears that distributed generation may be a superior economic alternative for deferring the investment in the T&D upgrade.

Table 3-7
Sensitivity Analysis Data Table, NPV vs. Load Growth Rate and Capacity Factor

		Load Growth Rate								
		0.0%	**0.2%**	**0.4%**	**0.6%**	**0.8%**	**1.0%**	**1.2%**	**1.4%**	**1.6%**
Capacity Factor	**0%**	16,996,300	12,241,778	7,841,608	3,192,540	(1,542,112)	(6,475,416)	(11,159,472)	(15,878,057)	(21,310,099)
	2%	16,765,663	11,671,279	6,954,340	1,976,500	(3,099,450)	(8,383,907)	(13,399,234)	(18,489,621)	(24,315,948)
	4%	16,535,026	11,100,779	6,067,071	760,461	(4,656,788)	(10,292,397)	(15,638,995)	(21,101,184)	(27,321,797)
	6%	16,304,389	10,530,279	5,179,803	(455,579)	(6,214,125)	**(12,200,888)**	(17,878,757)	(23,712,748)	(30,327,646)
	8%	16,073,752	9,959,779	4,292,535	(1,671,618)	(7,771,463)	(14,109,379)	(20,118,519)	(26,324,311)	(33,333,495)
	10%	15,843,115	9,389,279	3,405,266	(2,887,658)	(9,328,800)	(16,017,869)	(22,358,280)	(28,935,875)	(36,339,344)
	12%	15,612,478	8,818,780	2,517,998	(4,103,698)	(10,886,138)	(17,926,360)	(24,598,042)	(31,547,438)	(39,345,193)
	14%	15,381,841	8,248,280	1,630,730	(5,319,737)	(12,443,475)	(19,834,851)	(26,837,803)	(34,159,002)	(42,351,042)
	16%	15,151,204	7,677,780	743,462	(6,535,777)	(14,000,813)	(21,743,341)	(29,077,565)	(36,770,565)	(45,356,891)
	18%	14,920,566	7,107,280	(143,807)	(7,751,816)	(15,558,151)	(23,651,832)	(31,317,326)	(39,382,129)	(48,362,740)
	20%	14,689,929	6,536,780	(1,031,075)	(8,967,856)	(17,115,488)	(25,560,323)	(33,557,088)	(41,993,692)	(51,368,589)

The *possibility* that the NPV of an investment alternative may be positive hints at the existence of a real option embedded in the project.

Model Revisions

PSE&G made a number of refinements for the valuation model following the analysis performed to this point, and the changes were designed to reduce the unnecessary risk that results from the use of assumptions that are too simplistic or the use of algorithms that do not adequately represent real-world behavior. For example, the model currently utilizes a single input for distributed generation capacity factor. A more accurate model would treat this as a dependent variable instead of an independent variable.

In this section, we'll describe six revisions to the model that were made by PSE&G prior to beginning the Monte Carlo simulation stage of the valuation process.

These changes include:

1. Incorporating a natural gas price forecast
2. Modeling the electricity price as a function of natural gas costs
3. Creating an algorithm for capacity factor
4. Adding the terminal value to the NPV calculation
5. Accounting for the costs of project delay for T&D upgrade investments
6. Accounting for the possibility that multiple T&D upgrade investments may be necessary

The changes to the model will enable us to have greater confidence in the discounted cash flow results and to set the stage for the probability distribution estimates that will be required for the Monte Carlo simulation.

[25] 350 operating hours per year corresponds to a 4% capacity factor.

Natural Gas Price Forecast

The $6.00/MMBTU fuel price used by PSE&G to model the distributed generation investment opportunity using the EPRI DR Economic Screening tool was a good starting place in 2004. The average annual natural gas price in 2004 was $5.49/MMBTU at the wellhead, $6.09/MMBTU for gas used in electric power production, and $6.43/MMBTU for industrial users.[26] In 2005 and 2006, natural gas prices were significantly higher, and this input to the distributed generation case was revised.

PSE&G made its 20-year natural gas price forecast available for this case study, using estimated prices for the Henry Hub and an estimated price for transportation of the fuel. In addition, a band of uncertainty was also estimated for each of the 20 years, with a probability estimate for the high, low and nominal values. Discrete probability estimates were created for the high, low and nominal values and these will also be used in the later Monte Carlo simulation for this case. The cash flow model used in this case study was modified so that a different natural gas price forecast would be used for each of the twenty years of the projected cash flows for the distributed generation case, replacing the earlier assumption of a single gas cost estimate in the first year followed by an assumed annual cost escalation rate.

The gas price forecast incorporated into the distributed generation cash flow model is shown in Figure 3-2.

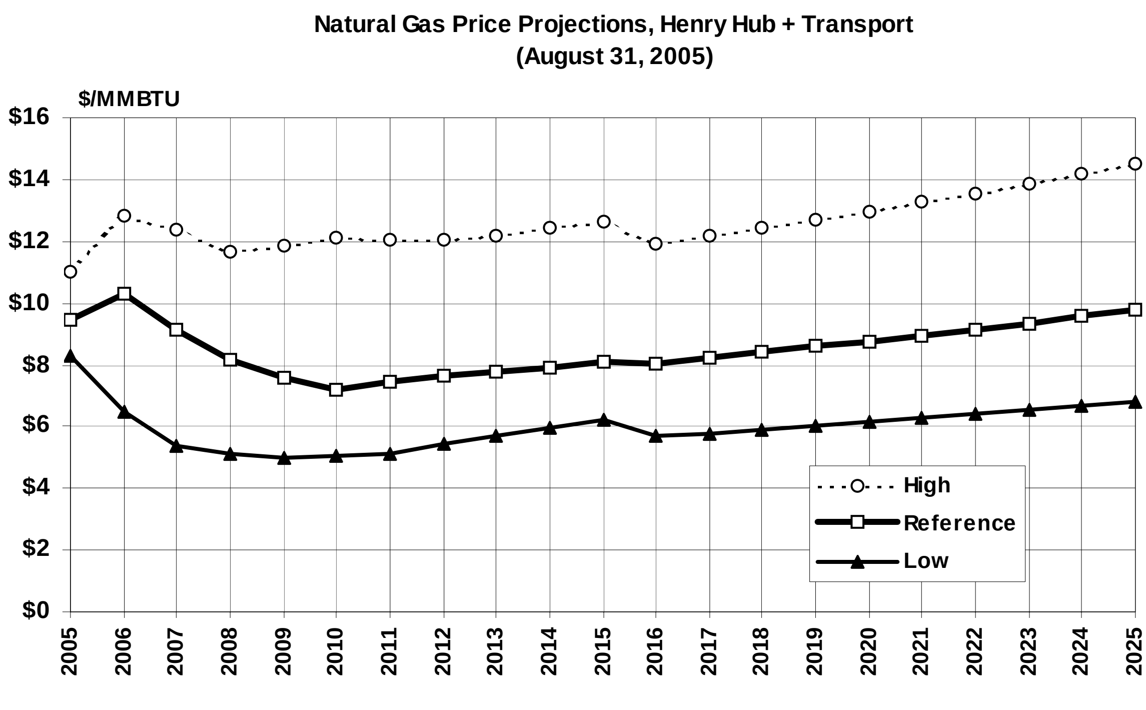


Figure 3-2
Natural Gas Price Forecast

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[26] U.S. Department of Energy, Energy Information Administration, *Natural Gas Monthly*, November 2005

Electricity Price Algorithm

The original version of the valuation model assumed a single unit price for the value of the electricity produced by the distributed generation units, escalated at a constant rate over the 20 years of the modeling period. A refinement of this algorithm relates the price used in calculating the value of the electricity produced by the distributed generation units to market prices for natural gas. Every year, PSE&G negotiates a three-year agreement to purchase electricity to fill 1/3 of its anticipated needs and every year, a new three-year electricity purchase agreement expires. The suppliers for the electricity base their pricing on their own three-year forecasts for natural gas. As a result, there is a relationship between electricity supplier expectations for natural gas prices and the prices offered for electricity under multi-year contracts.

An algorithm was designed to either increase or decrease electricity prices used to calculate the value of the electricity produced by the distributed generation units based on the natural gas forecast used earlier. For each year in the model, the three-year compound annual growth (or decline) rate in the forecast price of natural gas was annualized and applied to the electricity price from the preceding year to arrive at an electricity price forecast.

The electricity prices used in the revised model are shown in Figure 3-3.[27]

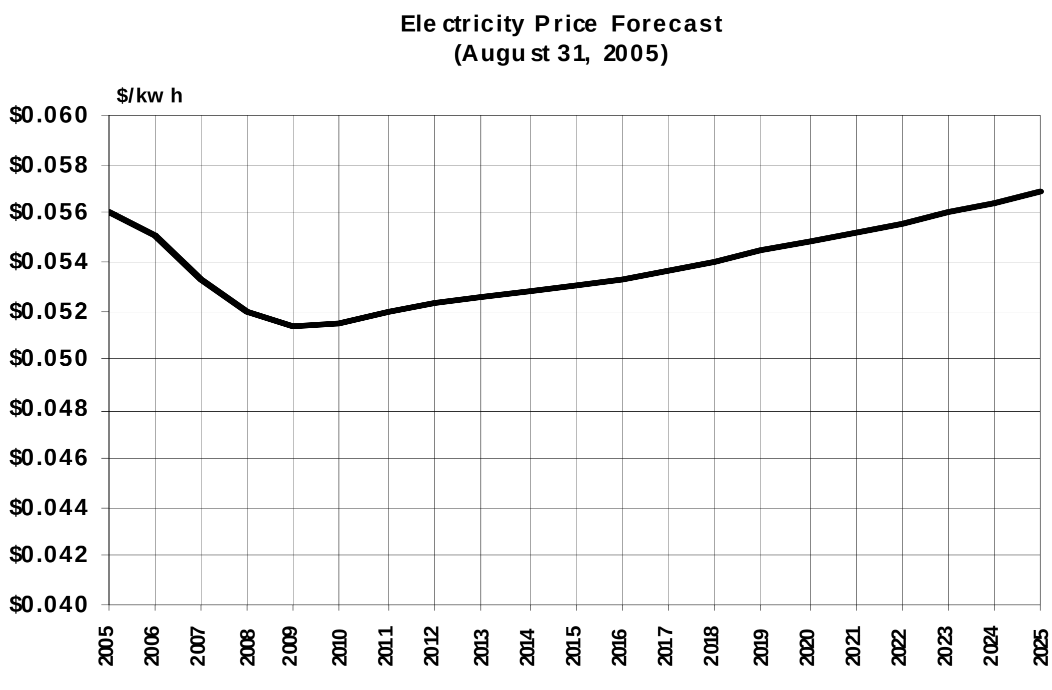

Figure 3-3
Electricity Price Forecast for Distributed Generation

[27] The volatility resulting from the impact of rising natural gas prices was highlighted in the February 10, 2006 announcement that PSE&G and three other New Jersey companies will pay 55% more for power to supply customers following the 2006 utility supply auction, according to the New Jersey Board of Public Utilities.

Capacity Factor Algorithm

The first model created for PSE&G assumed a constant capacity factor for all distributed generation units installed over the 20-year modeling period to be 6.3%, or about 550 hours per year. In reality, the fleet of distributed generation units will run a different number of hours each year, depending on the load profile for the distribution system. As the load increases over time, some distributed generation units will run more hours than others.

PSE&G provided a representative Load Duration Curve to assist with the creation of an algorithm to predict how many hours the fleet of distributed generation units will run for different system loads. Figure 3-4 shows a load duration curve for the PSE&G system for 2002, a year with a fairly hot summer. (2003 and 2004 were unusually cool years and so data used from this period would result in a low estimate of distributed generation capacity factor.) It was assumed that the PSE&G Substation part of the T&D system would have a load duration curve with a similar shape as shown in Figure 3-4.

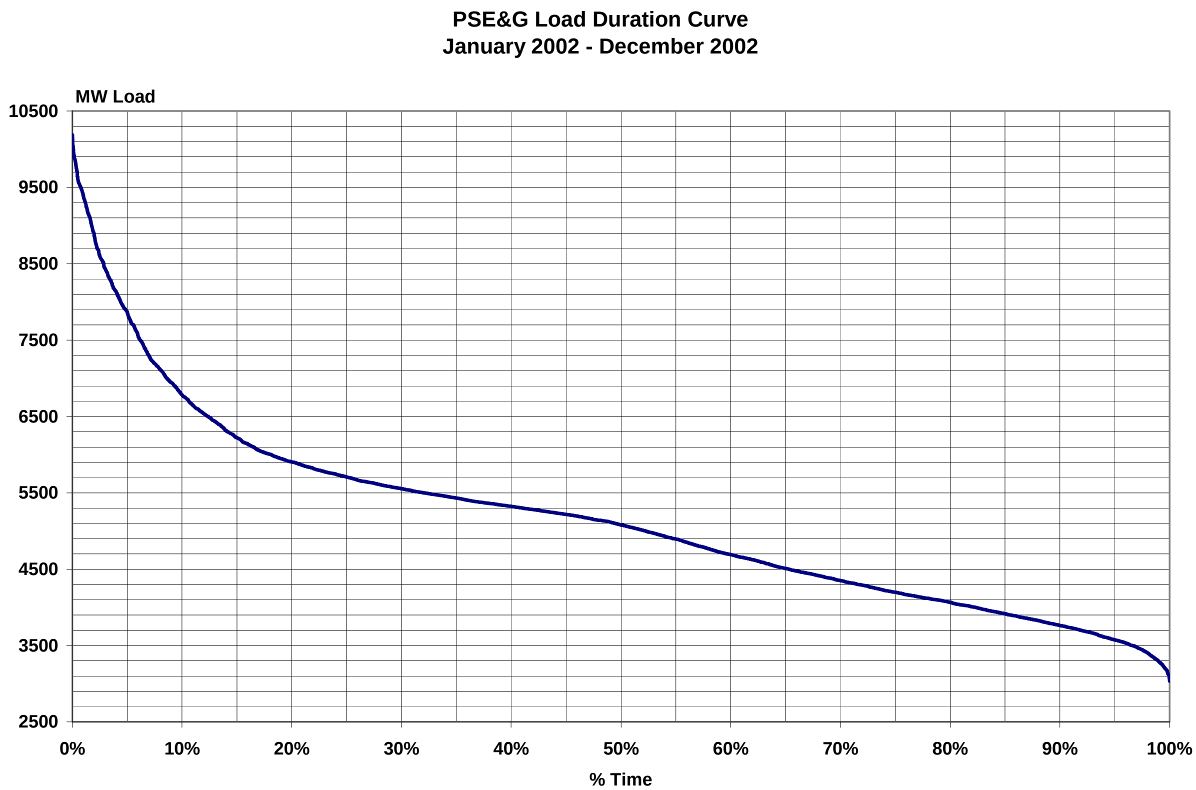

Figure 3-4
Load Duration Curve, Representative PSE&G Location

This information was used in a simulation designed to create an algorithm showing how many distributed generation units are in use and how many hours each are operating as the system load grows from 365,000 kVA to 500,000 kVA, and successively more distributed generation units are added to the fleet. An empirical relationship was developed from this simulation, showing the relationship between the system load and the average annual hours of operation for a fleet of 5000 KW natural gas combustion turbine distributed generation units. The relationship is shown in Figure 3-5.

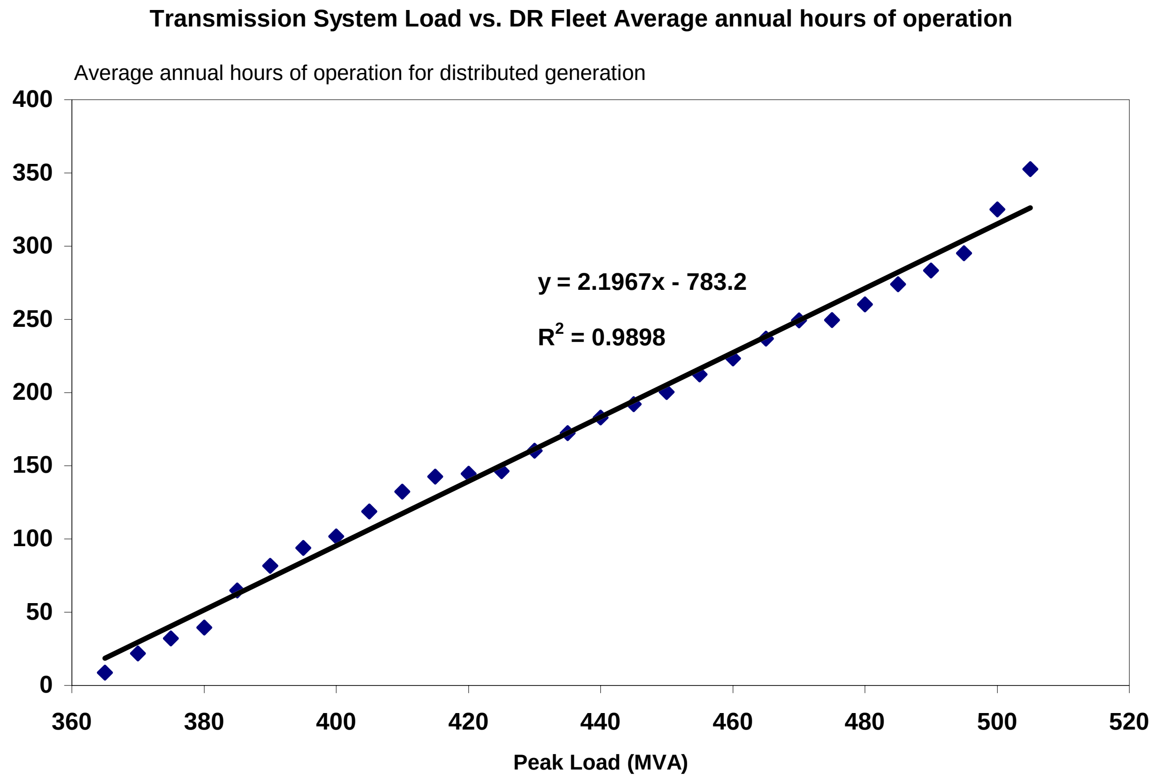

Figure 3-5
Distributed Generation Capacity Factor Algorithm

The model shows that the average annual hours of operation for the distributed generation fleet gradually rises as the peak load on the system increases. Linear regression was used to derive the formula for the relationship, and this equation was incorporated directly into the distributed generation cash flow model, making capacity factor an independent variable varying with peak load instead of a single dependent variable. Interestingly, even as the peak load increases to 500,000 kVA, the average annual hours of operation for the distributed generation units is only about 300 hours, corresponding with a capacity factor of 3.4%—less than the 6.3% originally assumed.

The result is that the NPV of the distributed generation alternative should improve as a result of this revised algorithm for calculating capacity factor, because the distributed generation units are running fewer hours per year, which as discussed earlier, produces fewer operating expenses.

Terminal Value

The first iteration of the cash flow model assumed that all cash flows after the end of the 20-year modeling period simply stopped. The NPV for the T&D upgrade alternative and the distributed generation investment alternative simply used the present value of the 20 years of cash flows included in the model. This simplification ignores the value of cash flows accruing after the end of the modeling period, and for some investments, this can be a significant omission.

A common way to account for present value of the cash flows following the end of the modeling period is to assume that the cash flows in the last period continue as a growing perpetuity. The value of the perpetuity is simply the cash flow in the last year of the model, divided by $(r-g)$, where r is the discount rate and g is the assumed growth rate of the cash flows following the end of the modeling period.

The present value of the result is simply added to the present value of the rest of the cash flows in the model. This method is appropriate for cash flows that are fairly steady and for assets that are maintained more or less indefinitely. (Many electric distribution assets are in this category).

The terminal value was added to the present value of the cash flows for both the T&D upgrade model and the distributed generation model.

Costs of Project Delay

The first iteration of the model assumed that the T&D upgrade project was installed and providing operational benefits within one year from the day that capital is committed for the project. In Table 3-4, the $20,000,000 capital investment is shown in Year 0, and the costs associated with the operation of the system are shown beginning in Year 1. Occasionally, the project may be delayed, for permitting reasons, for example. Sometimes public opposition, especially for undeveloped substation sites, can result in a project delay. For existing substation locations (such as the PSE&G Substation) with a planned expansion, permitting is not usually the cause of a project delay.

If the delay is expected to be one year or less, special emergency operating procedures are designed to reduce the risk during peak summer periods. If the delays are expected to be 2 years or more, PSE&G will install a temporary unit substation and a distribution feeder, and will make load transfers to relieve an overloaded substation. A common unit substation and feeder provides 8 MVA of capacity at a cost of $2,000,000. Usually, a location can be found for a unit substation that does not result in the need to reinforce 26 kV lines in the area, but on occasion, the required reinforcement of 26 kV lines can add $300,000 to the project cost. This scenario was considered to be a remote possibility and was not incorporated in the model.

On rare occasions, 8 MVA is not enough to provide for the necessary capacity and PSE&G will consider adding two temporary unit substations. This was also considered to be a remote possibility. The probability of a two-year project delay requiring the installation of a temporary unit substation and associated feeder is estimated to be 25%. The costs of project delay were estimated at $2,000,000 and this information along with the probability estimate of 25% was added to the input distributions used in the Monte Carlo simulation.

Multiple T&D Upgrades

After exercising the model, it was discovered that a 60 MVA T&D upgrade would not be sufficient for the 20-year modeling period under all load growth scenarios. Under the base case peak load growth rate assumption of 1.0%, a second 60 MVA T&D upgrade is needed by Year 16, when the peak load will have grown to 420,271 MVA, exceeding the system capacity of 419,000 MVA. (The current system capacity is 359,000 MVA; after the first 60 MVA T&D upgrade project, the new system capacity will be 419,000 MVA. Under a high peak load growth rate assumption of 1.5%, a *third* upgrade project is needed during the modeling period of 20 years.

The assumption that a single 60 MVA upgrade would be sufficient underestimates the true cost of the T&D upgrade alternative and decreases the NPV of the distributed generation alternative.

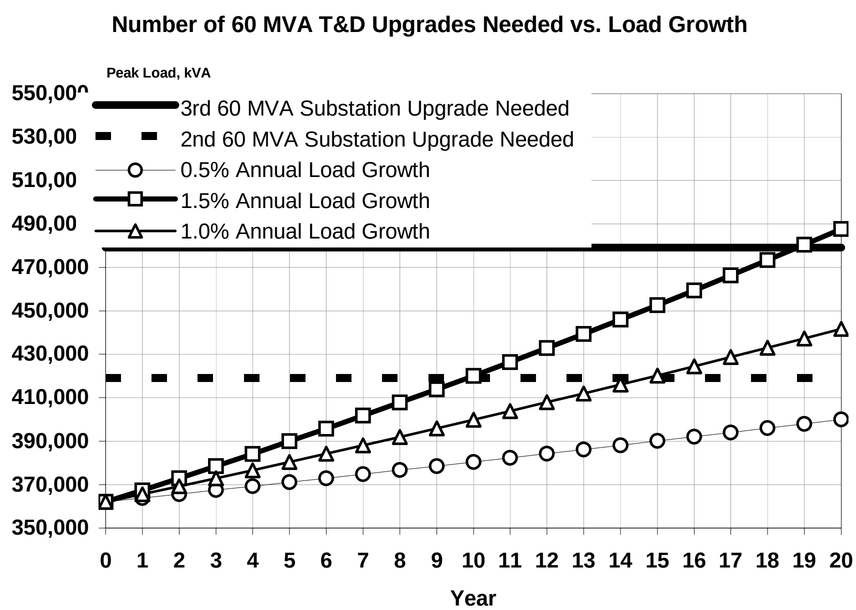

Figure 3-6
Load Growth vs. Number of T&D Upgrades Needed

On the next model iteration, described below, these costs will be included and the Monte Carlo simulation will account for the fact that some peak load growth scenarios will require multiple T&D upgrade investments.

Other Model Changes

The original model had no assumed costs for Land Costs/Rights of Way perfection. PSE&G suggests property costs average $2,000,000 and can vary from as little as $0, in the case where the land has been owned for a long time and sufficient existing space exists for the T&D upgrade, to as much as $4,000,000. A nominal value of $2,000,000 was entered into the model.

Finally, the cost escalation was assumed to be zero for the distributed generation equipment on the initial model. Although natural gas distributed generation is considered to be a mature technology, this does not necessarily mean that technology costs will not rise in the future. An escalation rate of 2.0% was assumed for this input, with a range from 1.0% to 3.0%.

Step 3: Monte Carlo Simulation

The revised inputs for the deterministic model and the ranges and distribution shapes assumed for the Monte Carlo simulation for the T&D upgrade inputs, and the distributed generation inputs are shown in Tables 3-8 and 3-9, respectively.

Table 3-8
Revised Inputs, T&D Upgrade

Assumption	Nominal Value	Low Estimate	High Estimate	Distribution Shape
Transmission Upgrade Cost:	$20,000,000	$18,000,000	$22,000,000	Triangular
Land/Right of Way perfection costs:	$2,000,000	$0	$4,000,000	Triangular
Transmission Upgrade Incremental O&M costs ($ per year):	$75,000	$67,500	$82,500	Triangular
Annual cost of a temporary substation ($/MVA):	$2,000,000			
Temporary substation size: (MVA):	8			
Capacity of the new T&D Project (kVA):	60,000			
Load Growth (%):	1.0%	0.5%	1.5%	Triangular
Allowable System Capacity (kVA):	359,000			
Existing Peak Load (kVA):	362,000			
Planning period (years):	20			
Delay time (years):	1	1	2	Custom
Probability:	75%		25%	
Cost of capital (%):	7.0%	6.3%	7.7%	Uniform
Depreciation Life, Book (years):	40			
Depreciation Method:	SL			
Salvage Value:	$0			
Federal Tax Rate:	35%			
State Tax Rate:	5%			
Property Taxes and Insurance:	2.00%	1.80%	2.20%	Triangular
Capital Cost escalation rate (%):	3.00%	2.70%	3.30%	Triangular
O&M escalation rate (%):	1.50%	1.35%	1.65%	Triangular
Property Tax and Insurance escalation rate (%):	2.00%	1.80%	2.20%	Triangular
Growth rate assumed for terminal value (%):	2.00%	1.80%	2.20%	Triangular

Table 3-9
Revised Inputs, Distributed Generation

Assumption	Nominal Value	Low Estimate	High Estimate	Distribution Shape
Distributed Generation Cost (5 MW):	$3,765,000	$3,388,500	$4,141,500	Triangular
Distributed Generation Installed Capacity (KW):	5,000			
Efficiency (%):	31.0%	27.9%	34.1%	Triangular
Fixed O&M costs ($/KW/year):	$15.00	$13.50	$16.50	Triangular
Variable O&M costs ($/kwh):	$0.0150	$0.0135	$0.0165	Triangular
Fuel costs ($/MMBTU):	$9.43	$8.27	$11.01	Custom
Cost of capital (%):	7.0%	6.3%	7.7%	Uniform
Depreciation Life, Book (years):	20			
Depreciation Method:	SL			
Salvage Value:	$1,500,000			
Capacity factor:	6.3%	0.0%	10.0%	Triangular
Displaced electric power purchase costs (2005):	$0.0560	$0.0560	$0.0560	Uniform
Federal Tax Rate:	35%			
State Tax Rate:	5%			
Property Taxes and Insurance (% of capital cost):	2.00%	1.80%	2.20%	Triangular
Electric Power price escalation rate (%):	3.00%	2.70%	3.30%	Triangular
O&M escalation rate (%):	3.00%	2.70%	3.30%	Triangular
Fuel cost escalation rate (%):	3.00%	2.70%	3.30%	Triangular
Property Tax and Insurance escalation rate (%):	0.00%	0.00%	0.00%	Triangular
Load growth rate (%):	1.00%	0.50%	1.50%	Triangular
Growth rate assumed for terminal value (%):	2.00%	1.80%	2.20%	Triangular
DR Capital cost escalation rate (%):	2.00%	1.00%	3.00%	Triangular
Year 1 gas cost ($/MMBTU):	$9.43	$8.27	$11.01	Custom
Probability:	45%	30%	25%	
Year 1 electricity price ($/KWH):	$0.056			
Existing system capacity (kVA):	359,000			
Existing peak load (kVA):	362,000			

The model inputs with high and low estimated values have been assigned an assumed probability distribution; in most cases, a triangular distribution was used with a range corresponding to the high and low estimates for the input value. The model inputs that are not highlighted are assumed to be constant.

The fuel costs used in the distributed generation cost model now have a separate value for each of the 20 years in the projection, with an assumed probability distribution for high, low and reference values. The Monte Carlo assumption for the first year fuel cost, for example, is illustrated in Figure 3-7, and shows a reference case of $9.43/MMBTU with a probability of 45%, a high case of $11.01/MMBTU with a probability of 25%, and a low case of $8.27, with an estimated probability of 30%. This data is identical to the data shown previously in Figure 3-2 and includes the assumed costs of transporting the gas from the Henry Hub. For the reference case, $1.20/MMBTU is assumed for transportation. For the high case, a $1.40/MMBTU transport cost is assumed, and for the low case, $1.00/MMBTU is assumed.

A custom probability distribution for each of the 20 years that a gas forecast was made by PSE&G was included in the Monte Carlo simulation.

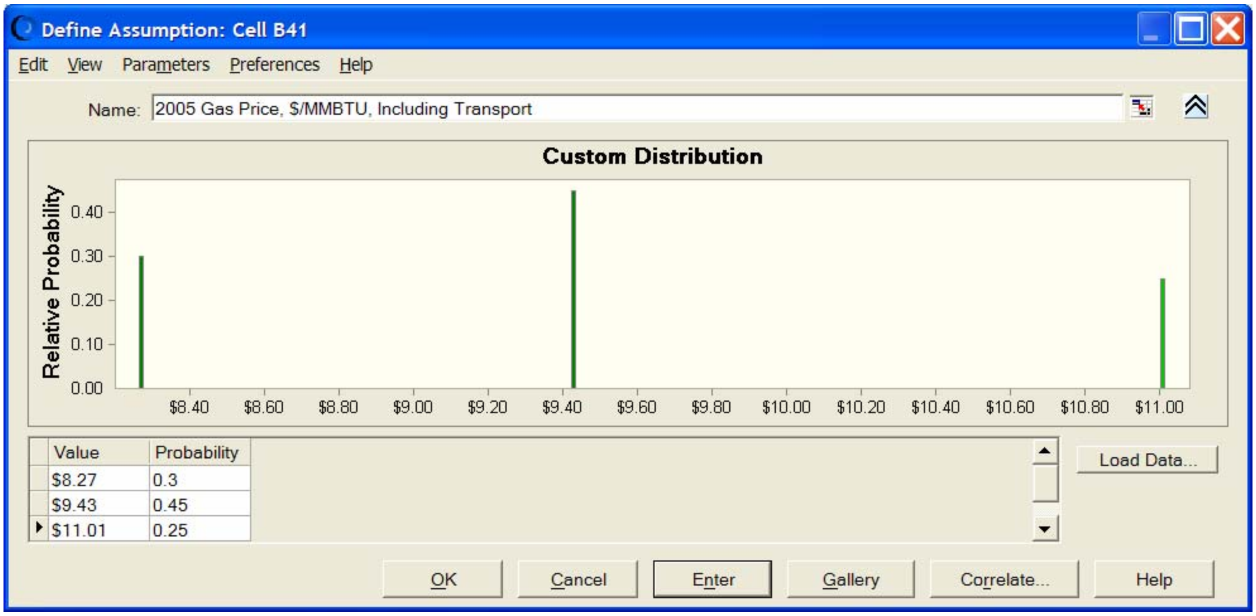

Figure 3-7
Probability Distribution Assumption, Year 1 Fuel Price

The base case cash flow projection for the T&D upgrade, using the revised set of assumptions, is shown in Table 3-10.

Table 3-10
Revised Cash Flow Projections, T&D Upgrade

Year	0	1	2	3	4
Income statement impacts					
Fixed O&M costs	0	(76,125)	(77,267)	(78,426)	(79,602)
Property Taxes and Insurance	0	(462,264)	(471,509)	(480,939)	(490,558)
Annual cost of temporary substation	0	0	0	0	0
Depreciation (straight line)	0	(566,500)	(566,500)	(566,500)	(566,500)
EBIT Impact	0	(1,104,889)	(1,115,276)	(1,125,865)	(1,136,661)
Less taxes	0	441,956	446,110	450,346	454,664
EBIAT	0	(662,933)	(669,166)	(675,519)	(681,996)
Plus depreciation	0	566,500	566,500	566,500	566,500
Cash flow from operations	0	(96,433)	(102,666)	(109,019)	(115,496)
Capital Investment	0	(22,660,000)	0	0	0
Net cash flow	0	(22,756,433)	(102,666)	(109,019)	(115,496)
Present value of net cash flow (in each year)	0	(21,267,695)	(89,672)	(88,992)	(88,112)
Cumulative present value of net cash flows	0	(21,267,695)	(21,357,367)	(21,446,359)	(21,534,471)
Present Value of T&D Project Costs	**(49,594,467)**				

The capital cost for the project is now incurred one year after the decision to invest is made, to account for a one-year project delay in the base case. 25% of the Monte Carlo simulations will include a two-year delay, and for these scenarios, the cash flow projection will look like the one shown in Table 3-11, which includes the $2,000,000 cost for a temporary unit substation and feeder in the year prior to the year that the T&D upgrade investment actually is incurred. Note that the after-tax impact of this expense is only $1,200,000, since this operating expense is deductible and is reduced by the reduction in state (5%) and federal (35%) taxes. This expense is reduced further, to $1,121,495 when it is discounted to the present value using the assumed capital cost of 7%.

Table 3-11
Revised T&D Upgrade Cash Flow Projection, with 2 Year Project Delay

Year	0	1	2	3	4
Income statement impacts					
Fixed O&M costs	0	0	(77,267)	(78,426)	(79,602)
Property Taxes and Insurance	0	0	(485,655)	(495,368)	(505,275)
Annual cost of temporary substation	0	(2,000,000)	0	0	0
Depreciation (straight line)	0	0	(583,495)	(583,495)	(583,495)
EBIT Impact	0	(2,000,000)	(1,146,416)	(1,157,289)	(1,168,372)
Less taxes	0	800,000	458,567	462,915	467,349
EBIAT	0	(1,200,000)	(687,850)	(694,373)	(701,023)
Plus depreciation	0	0	583,495	583,495	583,495
Cash flow from operations	0	(1,200,000)	(104,355)	(110,878)	(117,528)
Capital Investment	0	0	(23,339,800)	0	0
Net cash flow	0	(1,200,000)	(23,444,155)	(110,878)	(117,528)
Present value of net cash flow (in each year)	0	(1,121,495)	(20,477,033)	(90,510)	(89,662)
Cumulative present value of net cash flows	0	(1,121,495)	(21,598,528)	(21,689,038)	(21,778,700)

The present value of the T&D Upgrade costs is ($49,594,467), which includes the terminal value of ($14,440,723), in addition to the costs of a second 60 MVA T&D upgrade made in Year 16. This second 60 MVA T&D upgrade is assumed to have a nominal cost of ($35,303,542) because we’ve assumed a 3.0% annual escalation in T&D upgrade capital costs. When this total is discounted to the present value, the cost is ($12,124,318) in today’s dollars.

Because the terminal value is calculated with cash flows following the end of the 20-year modeling period that are assumed to grow in perpetuity, the ($49,594,467) present value of the T&D upgrade alternative is essentially the estimated cost of upgrading the T&D system with today's technologies indefinitely. For a fair comparison with competing technologies, a similar terminal value assumption was made.[28]

The distributed generation cash flow projection is shown in Table 3-12, with the difference between the two cash flow projections shown at the bottom of the table.

Table 3-12
Revised Distributed Generation Cash Flow Projection

Year	0	1	2	3	4
Income statement impacts					
Value of electricity produced		304,203	441,362	429,827	567,144
Fixed O&M costs		(150,000)	(231,750)	(238,703)	(327,818)
Variable O&M costs		(82,782)	(127,898)	(131,735)	(180,916)
Fuel costs		(692,787)	(923,269)	(822,475)	(1,015,999)
Property Taxes and Insurance		(150,600)	(225,900)	(225,900)	(301,200)
Depreciation (straight line)	0	(226,500)	(339,750)	(339,750)	(453,000)
EBIT Impact	0	(998,466)	(1,407,205)	(1,328,736)	(1,711,789)
Less taxes	0	399,386	562,882	531,494	684,716
EBIAT	0	(599,080)	(844,323)	(797,241)	(1,027,073)
Plus depreciation	0	226,500	339,750	339,750	453,000
Cash flow from operations	0	(372,580)	(504,573)	(457,491)	(574,073)
Capital Investment	(3,765,000)	(3,589,065)	(3,421,352)	0	(3,109,070)
Book value of asset sales					
Net cash flow	(3,765,000)	(3,961,645)	(3,925,925)	(457,491)	(3,683,144)
Present value of net cash flow (in each year)	(3,765,000)	(3,702,472)	(3,429,055)	(373,449)	(2,809,853)
Cumulative present value of net cash flows	(3,765,000)	(7,467,472)	(10,896,527)	(11,269,976)	(14,079,829)
Present value DG Investments	**(3,765,000)**	**(3,354,267)**	**(2,988,341)**	**0**	**(2,371,895)**
Cumulative PV of DG Investments	**(25,536,360)**				
PV, Distributed Generation Alone	**(57,040,281)**				
PV, Transmission & Distribution Upgrade Alone	**(49,594,467)**				
NPV of T&D Upgrade, Relative to Distributed Generation	**7,445,814**				

[28] The terminal value estimate highlights the difficulty of comparing investments with different useful lives, and is yet another reason why discounted cash flow techniques have shortcomings when applied with new technologies where the useful life may not be known with certainty. Although a typical T&D asset may have an accounting (or book) life of 40 years, many of these assets are essentially maintained indefinitely. Distributed generation assets, on the other hand, may have an accounting life of 20 years, but may also be maintained indefinitely, provided that parts and service capabilities are maintained and the continued maintenance of the asset compares favorably with the decision to replace it. The purpose of introducing terminal value into this case is to highlight the fact that asset lives often are longer than the modeling period used for valuation purposes, and we often have no choice but to try to estimate the value of the cash flows following the end of the modeling period. For many new businesses, including new, unproven distributed generation businesses, especially those with negative cash flows in the early years, the majority of the valuation estimate is in the terminal value.

The terminal value for the distributed generation case is ($17,369,979), which represents about 30% of the total present value of ($57,040,281).[29] The difference between the two cash flow projections is the NPV for the project. If we were calculating the NPV of distributed generation relative to the T&D upgrade, we would say that its NPV is negative, or ($7,445,814). The NPV of the T&D upgrade relative to the distributed generation investment case is $7,445,814. This NPV result assumes that *some* investment decision must be made. For simplicity, it is assumed that the best competing investment (to a T&D upgrade project) for meeting the project load growth for the customers served by the Bremer Substation is distributed generation; the NPV of the T&D upgrade investment is therefore the difference between the two competing cash flow alternatives.

As we will see shortly, a third alternative exists—to do nothing now, and to invest in the T&D upgrade later, an alternative which requires that we model the opportunity as a Real Option, to capture the strategic value included with this flexibility.

The Monte Carlo simulation will run our valuation model through 5000 iterations, changing the values of the input parameters highlighted in Tables 3-8 and 3-9 according to the probability distributions assumed for each value.

The Monte Carlo simulation for the project NPV for T&D upgrade investment relative to the distributed generation investment is shown in Figure 3-8. Note that the mean value for this distribution does not vary materially from the base case value of $7,445,814 calculated using the deterministic cash flow model. The range of outcomes is quite wide—there is about a 10% probability that this investment could be worth ($10,000,000). On the other hand, there is about a 20% probability that the project NPV is *positive* $20,000,000. The histogram in Figure 3-8 shows that there is about a 67% probability that the T&D upgrade investment relative to the distributed generation investment is greater than zero. That might be considered a good probability, but not a great one—the decision to invest $20,000,000 right now in a 60 MVA substation upgrade obviously has some uncertainty that should be further analyzed.

The picture becomes clearer when we separate the histogram shown in Figure 3-8 into two components—the cash flows associated with the T&D upgrade and the cash flows associated with the distributed generation investments. Figure 3-8 is, after all, the sum of these two models.

Figure 3-9 shows the distributed generation cash flows and Figure 3-10 shows the T&D upgrade cash flows.

[29] In the T&D upgrade case terminal value represented about 29% of the total present value of costs in the model.

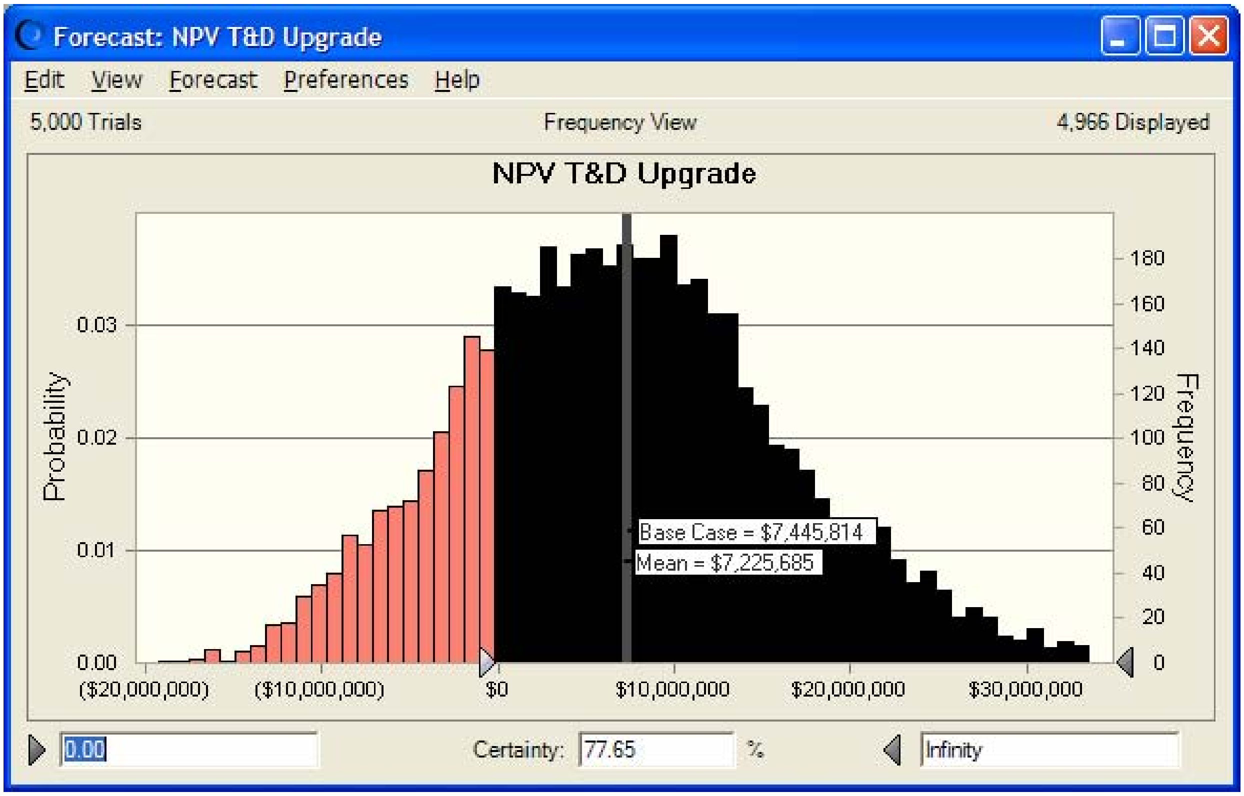

Figure 3-8
Monte Carlo Simulation, T&D Upgrade

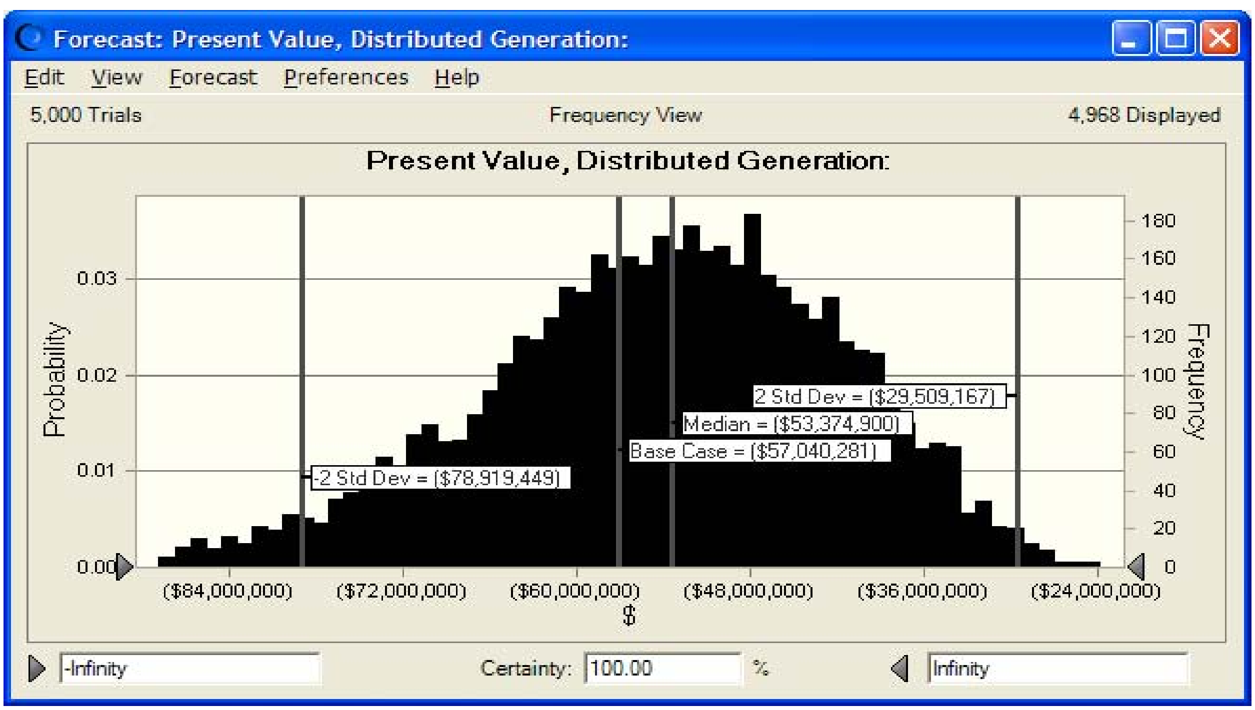

Figure 3-9
Monte Carlo Simulation, Distributed Generation Cash Flows

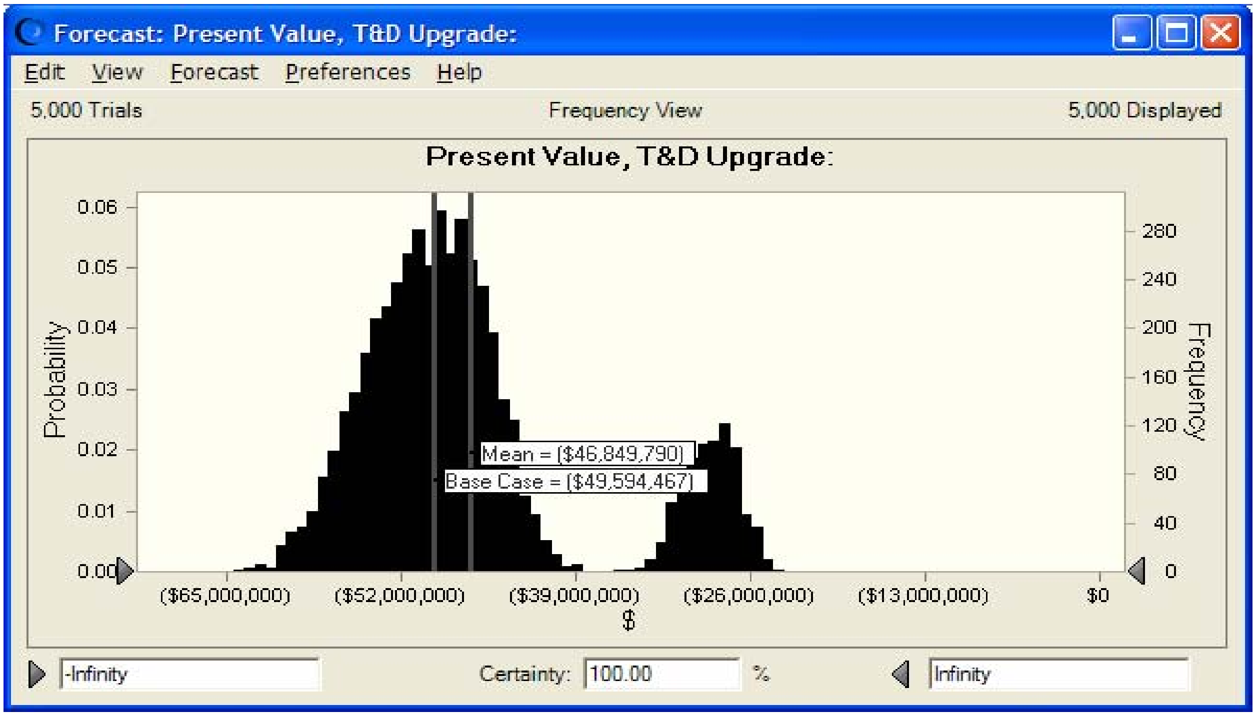

Figure 3-10
Monte Carlo Simulation, T&D Upgrade Cash Flows

The T&D Upgrade Cash Flows histogram is interesting, because it is not symmetrical, and the simulated costs appear to be converging around two distinctly different costs: ($50,000,000) and about ($26,000,000). The reason for this is that the low load growth scenarios (less than 0.8% per year) result in the need for a *single* 60 MVA T&D investment over the 20-year modeling period, while most of the remaining growth scenarios remaining load growth scenarios require a second 60 MVA T&D upgrade. In the highest load growth case of 1.5% per year, a third investment is necessary.

The risk in the load growth assumption is still the leading contributor to uncertainty in the model and the risk attributable to this input variable appears to have been exacerbated by the fact that more than one 60 MVA T&D upgrade may be necessary over the modeling period for a number of growth rate assumptions. This fact, more than any other, has narrowed the NPV difference between the distributed generation case and the T&D upgrade case.

Figure 3-11 shows the histogram for the project cash inflows from the T&D upgrade investment. As you will recall, it is the risk in these cash flows that will drive the value of any options embedded in the project. The standard deviation of these cash flows is about 30%, and this is the uncertainty will be a contributor to the strategic value calculated with real options later.

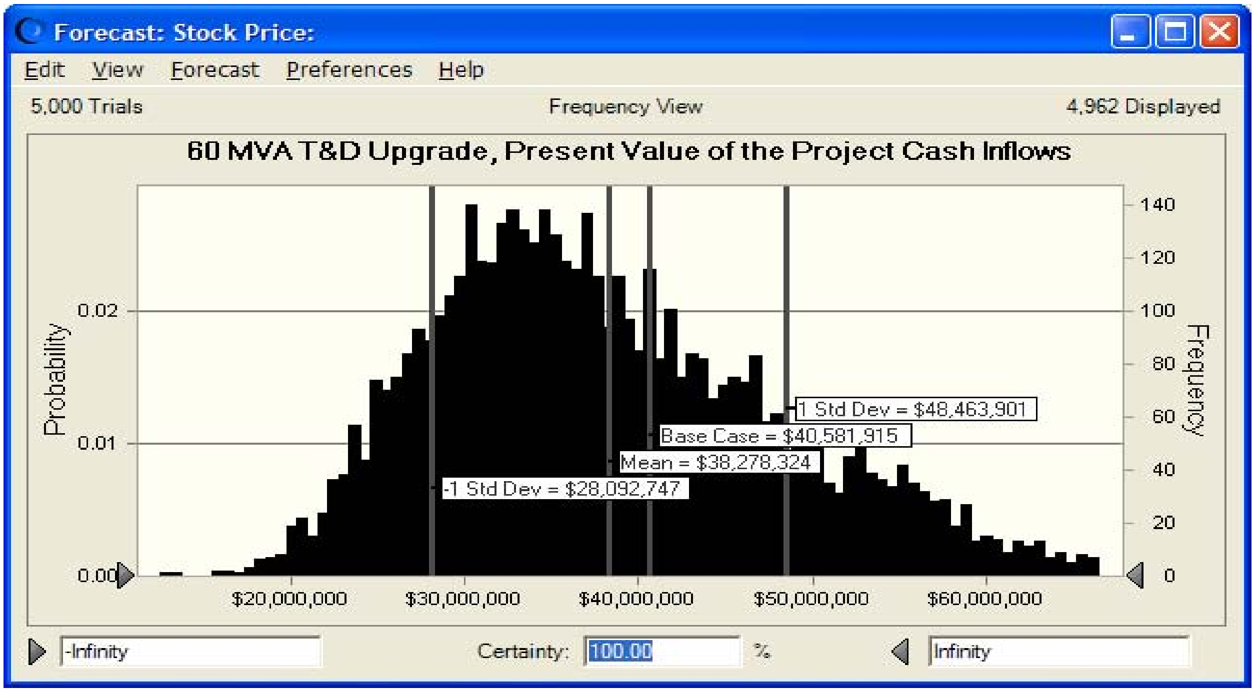

Figure 3-11
Monte Carlo Simulation, T&D Upgrade Project Cash Inflows

Step 4: Risk Analysis

Figure 3-12 shows the contributors to the uncertainty in the project cash flows. Clearly, the uncertainty in the assumed rate of load growth is contributing most of the risk to the project at this point. It is possible that the triangular distribution assumed is resulting in too much emphasis to the load growth values at the extreme ends of the probability distribution, and it is likely that a Normal, (i.e., Gaussian) distribution would be more representative of the growth rate assumptions going forward. Another way to model the risk attributable to this input variable is to recognize that the uncertainty for this variable is probably greater in the later years. In other words, the estimation of load growth is easier, and can be done with a probability distribution with a smaller range of possible values in the next few years; the opposite is true for dates in the distant future—we are less able to predict load growth rates 20 years from now and the estimate will have a much larger range of uncertainty associated with it.

A potential enhancement to the valuation model is to make a load growth forecast, similar to the forecast made for natural gas prices, and to estimate the high, low, and reference cases for all 20 years of the model. An analysis of past load growth rates in the PSE&G system may also be used to understand what kind of uncertainty (as measured by the standard deviation of load growth rates) has occurred in the past. Granted, the past is not a perfect predictor of the future; but given the contribution of the load growth estimate to the total uncertainty in the model, it is an exercise worth undertaking.

The reduction in uncertainty for this variable might also decrease the likelihood that more than one 60 MVA T&D upgrade investment will need to be made over the modeling period.

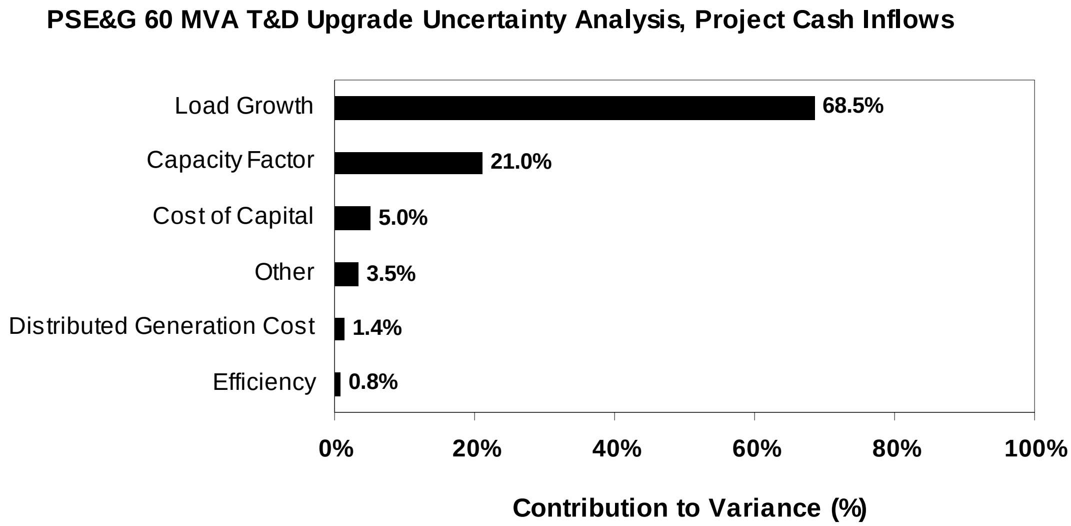

Figure 3-12
Uncertainty Analysis, T&D Project Cash Flows

Step 5: Real Options

A clear example of an option embedded in this project example is an option that PSE&G already owns and is aware of—the option to delay the investment in the 60 MVA T&D upgrade project. If PSE&G relied on deterministic cash flow models to make its investment decisions, the decision to invest the $20,000,000 in the T&D upgrade would have been made last year, when the peak load first exceeded the system capacity of 359,000 MVA. As of the writing of this case study, PSE&G has not yet committed the $20,000,000 to the upgrade, and is using a variety of measures to delay this investment further.

In the discussion about costs of project delay, PSE&G revealed of number of steps currently taken when a project is delayed for permitting reasons. These steps included planning for a first contingency by developing special operating procedures to ensure reliable electric delivery during peak summer periods when the risks are the greatest. The steps also included measures that would be taken if delays were expected to take two years or more—and these are the scenarios where temporary unit substations and distribution feeders would be employed. On some occasions, extra reinforcement is necessary, and represents an additional cost.

These same steps that might be used for unplanned delays can also be used for planned delays—and here we begin to see the value of managerial flexibility included in the PSE&G planning process. Joe Lalier from the PSE&G Distribution department said it best, when he observed, *"….the installation of unit substations in not just for unforeseen delays, but has been a part of our Planning Process for many years. We used units to delay major substation upgrades whenever we can, and it also 'buys time' to validate the expected load growth. Since the unit* *substations (can) get used elsewhere (after the delay period is over), it is a very attractive approach."*

In fact, permitting rarely delays an upgrade at an existing site, such as the Bremer Substation. In these cases, it makes sense to intentionally delay the project when deferral is economically beneficial. We can use real options to quantify the value of this T&D deferral, using the Black Scholes option pricing formula and the variables we've already discussed.

The option pricing inputs are shown in Table 3-13 and include the present value of the project cash inflows, $40,581,915. These are the cash flows resulting from the investment in the new T&D upgrade assets and are analogous to the stock price for a call option on a share of stock in a financial option. The volatility is the standard deviation of the project cash inflows simulated through the Monte Carlo model and shown in the histogram illustrated in Figure 3-11. The value we will use in the option pricing formula is 30%.

Table 3-13
Option to Delay 60 MVA T&D Investment by One Year

Inputs		
Real Option		**Financial Option Equivalent**
Present Value of the Project Cash Inflows:	$40,581,915	Stock Price ($)
Standard deviation of project cash inflows:	30%	Volatility (%)
Required investment:	$33,136,101	Exercise Price ($)
Length of time option is valid:	1.0	Time To Expiry (years)
Annual costs of keeping the option open:	$100,000	Dividends ($)
Risk free rate (Estimated from treasury yield curve, 12/10/05):	4.30%	Risk-free Interest Rate (%)
Outputs		
d_1:	0.9608	
$N(d_1)$:	0.8317	proportion of shares required to replicate a call option
d_2:	0.6608	
$N(d_2)$:	0.7456	probability the call option will be exercised on expiry
Value of the option:	**$10,000,475**	
Intrinsic Value:	**$7,445,814**	
Strategic Value:	**$2,554,661**	

The volatility in this example is driven primarily by the uncertainty associated with the load growth rate, although it is possible that this uncertainty could be reduced through a careful analysis of the factors impacting this variable in the area served by this substation in the future.

The exercise price for this option is the present value of the capital committed for the T&D upgrade project, and includes the present value of the first 60 MVA investment in Year 2 and the second investment in Year 16, a total of $33,136,101.[30] The time to expiration is conservatively estimated to be one year. PSE&G distribution engineering indicates that it is possible to delay large T&D investments even longer and a two-year delay is possible with careful planning.

[30] Technically, there are two investments here and the second 60 MVA T&D upgrade may also be deferred. In short, this is a compound option, where the purchase of the first option gives the investor the right but not the obligation to also invest in the second option to delay. To keep this case simple, we'll treat this as a single investment, valued as the sum of present values of both T&D upgrades. This approach will result in a conservative estimate of the value of the option, since the second option to delay will have additional strategic value.

The annual to cost keep the option open is the cost of maintaining the knowledge and expertise within the company to defer large T&D investments, and includes the costs of maintaining the competencies and processes necessary for transporting and installing temporary unit substations and feeders, reinforcing distribution lines, and implementing special operating procedures during peak periods when risks are highest. There is some amount of 'overhead' required for maintaining and managing a fleet of temporary unit substations and executing load transfers to protect overloaded substations. This input is conservatively estimated at $100,000 per year.

Finally, the risk free rate was derived from treasury bills with a similar maturity. The inputs are entered into the Black Scholes option pricing equations and the result shows that there is a significant amount of strategic value associated with the option to delay the 60 MVA T&D upgrade investment by one year, $2,554,661, an amount representing about ¼ of the total value of the option, which in this case is $10,000,475. The difference, $7,445,814, is the intrinsic or, economic value, which is simply the NPV of the project if the option was exercised right now.

Figure 3-13 shows the relationship between strategic value and economic value for different project cash inflow values and we can see from this illustration that this is an option that is "*in the money*", but where there is still sufficient incentive to delay exercising the option. The option to delay investment has value because we can decide at any time between now and the expiration of the option to make the T&D upgrade investment. This delay also enables PSE&G to 'validate the expected load growth.'

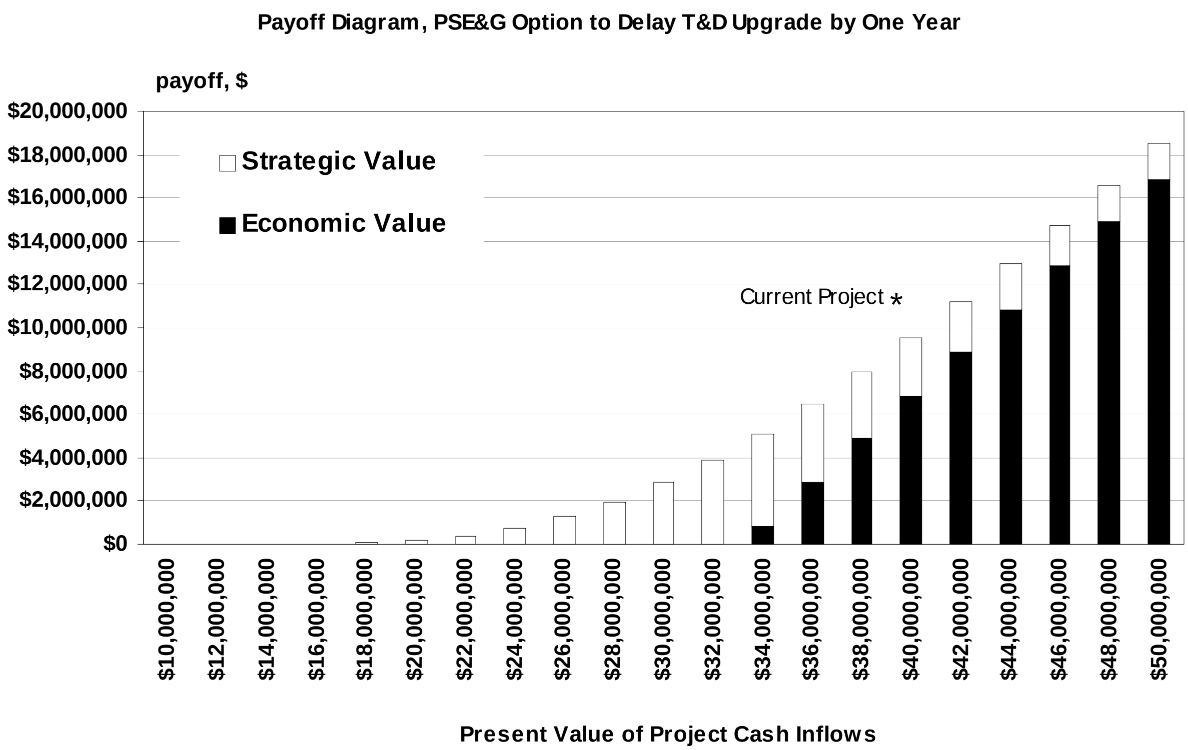

Figure 3-13
Option to Delay 60 MVA T&D Upgrade Investment, Economic vs. Strategic Value

If the load growth projections can be confirmed with greater accuracy, the risk in the project cash flows will be reduced, the strategic value relative to the economic value will decrease, and PSE&G will be in a better position to exercise the option. While the risk is high, however, the value of deferral is greater.

Figure 3-14 shows how the strategic value of the investment opportunity is affected by the risk in the project cash flows. Option values are shown for standard deviations ranging from 10% to 50%. A 50% standard deviation corresponds with an option to delay where nearly half of the value of the option is strategic value.

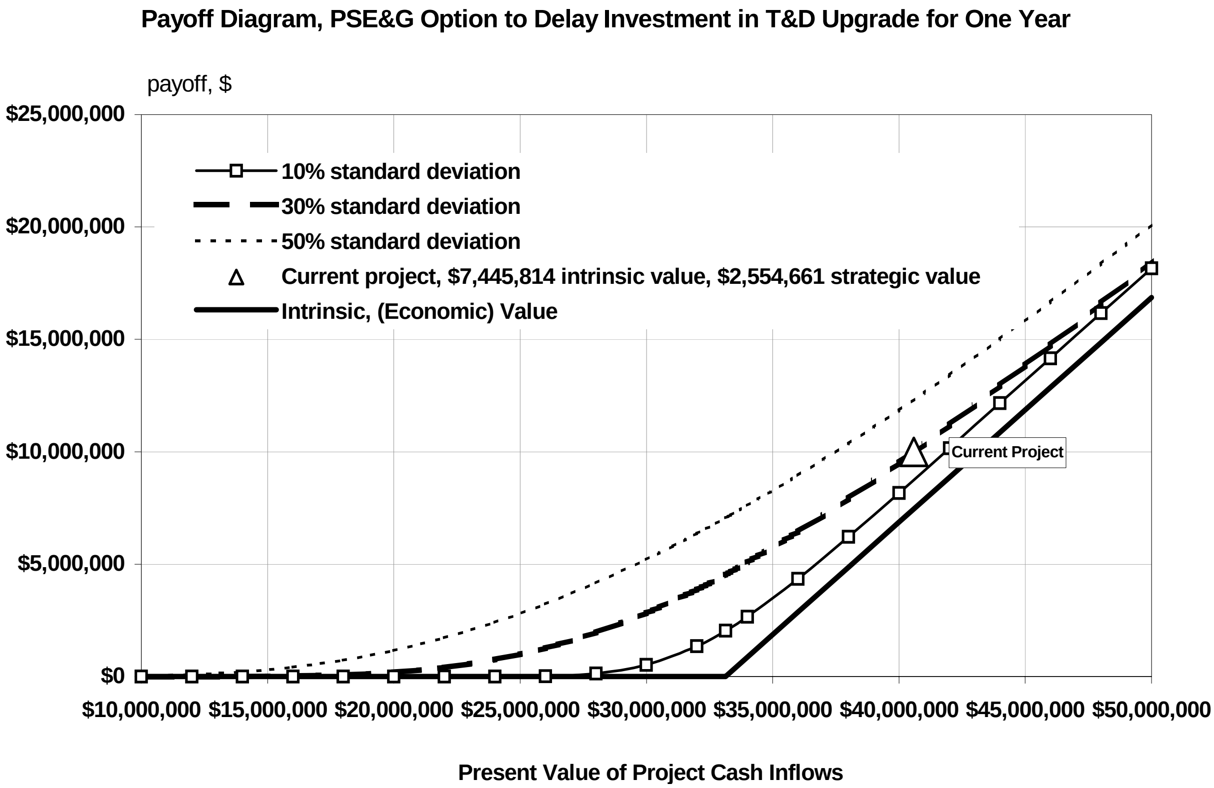

Figure 3-14
Option to Delay 60 MVA T&D Upgrade, Strategic Value vs. Standard Deviation

If PSE&G possesses the competencies and process knowledge to delay the 60 MVA T&D investment even longer, there is additional strategic value. If the expiration period is extended to two years, the strategic value rises to $4,741,643. At three years, the strategic value is $6,544,984. If a delay of two years is realistically achievable, it may actually benefit PSE&G to install a 5 MW gas turbine distributed generation unit, particularly if this investment can be associated with other growth options that other deferral investments cannot be associated with.

In other words, if PSE&G has some other reason to be interested in distributed generation investments, beyond their use in deferring traditional T&D upgrade investment, it may benefit PSE&G to invest a portion of its deferral investments into a distributed generation project.

Today, it appears that PSE&G has made the prudent decision to defer investment in T&D upgrade projects like the PSE&G Substation case. The $2,000,000 cost for moving and installing an 8 MVA temporary unit substation and feeder and the additional $300,000 potential costs of reinforcing 26 kV distribution lines are smart investments, especially if the result is two years of deferral of the 60 MVA T&D upgrade investment—because the strategic value of the option to delay is worth more than this cost.

This same approach can be used to value options in energy storage. PSE&G has made some preliminary investigations of energy storage technologies such as Sodium Sulfur (NAS) batteries and Vanadium Redox batteries that might also be used as alternatives to capital investments in T&D upgrades.

What this case illustrates is that these technology investments are competing not only with the T&D upgrade investments, but also with the technologies and processes used to defer these investments, such as temporary unit substations and other measures used to manage system operation during peak periods where system load exceeds system capacity. These processes are being used by PSE&G as there are already occasionally times during the summer when this condition exists.

In other words, PSE&G has already invested in the option to delay the both the 60 MVA upgrade at the PSE&G Substation *and* investments in what appears to be the next best alternative—using natural gas-fired distributed generation installed in smaller increments.

4
CONCLUDING REMARKS

Modeling the risk in investment opportunities and identifying sources of hidden strategic value through real options are effective ways to fairly consider distributed generation and energy storage technology investments that may become important components of the larger transmission and distribution system in the future. As the case studies have shown, the techniques are useful for comparing new technologies characterized by higher risk with familiar technologies possessing lower risk, long track records.

The process used in this report is dynamic, and the models described were modified many times to account for new information and a genuine desire by the participating utilities to ensure that models accurately represented the range of possible future states realistically. This section highlights a few of the major conclusions from the case studies and implications for future efforts in valuation of new energy storage and distributed generation technologies.

NYPA 1.2 NAS Battery Project Final Revisions

As this work on these case studies was concluding, NYPA provided the most current cost data to include in this report. The final cost data is summarized in Table 4-1. The capital cost estimate has increased, but now includes the assumption that battery disposal costs *and* decommissioning will be included in the project price. The inclusion of end-of-life cost estimates up-front is an effective way to transfer risks to the technology supplier, in this case NGK.

Another important change is that the number of partners expected to provide funds for the project has increased and the uncertainty associated with their expected contributions has been decreased. The 'co-funding subtotal' amount is $1,860,000 and is slightly less than the last estimate of $1,900,000, but the uncertainty used for the last model revision was +/- $100,000.

The most significant change affecting the valuation model is the proposed interest rate of 1.43%. This is the rate that NYPA intends to be offering to Long Island Bus Company (LIBC) to finance the project and it is a below-market rate that has the effect of increasing the economic value of the NAS battery project, and the present value of the project cash flows used in the real options pricing model.[31] The below-market rate provides LIBC with even greater incentive to invest in the project now. To illustrate the dynamics of the impact of these last revisions on one of the real

[31] The proposed interest rate and the assumption that Long Island Bus Company will employ 100% debt financing means that this rate is used as the discount rate to value the future cash flows resulting from the investment. The lower the discount rate, the higher the value of the future cash flows from reduced electricity costs and reduced labor costs associated with the elimination of the third shift at the fueling station.

options, the option to delay the project for one year, a comparison of the economic and strategic values between December 2005 and February 2006 is shown in Table 4-2.

Table 4-1
Cost Summary, NYPA/Long Island Bus Company 1 MW Battery Storage Project

Capital Cost Estimates	
Equipment (M)	
Batteries	$1,651,000
Power conversion system	$578,000
System integration	$186,000
subtotal 1	**$2,415,000**
Installation (L)	
Installation & commissioning	$837,000
Performance bond	$25,110
15% contingency (labor)	$125,550
subtotal 2	**$987,660**
Total M&L	**$3,402,660**
Other direct and indirect expenses	
NYPA Fees	
12.5% material and labor	$406,500
Interest During Construction	$24,329
subtotal 3	**$430,829**
Decommissioning & disposal (estimated)	$182,000
Total Capital Cost Estimates	**$4,015,489**
Co funding	
NYSERDA	$1,000,000
EPRI	$500,000
LIPA	$200,000
CEA	$25,000
APPA	$75,000
POCR	$60,000
Co funding subtotal	**$1,860,000**
Net Project Capital Cost	**$2,155,489**
Financing Assumptions	
Financing Interest Rate	1.43%
Financing Term (years)	12
Existing LIPA rate	SC 284

Table 4-2
NYPA NAS Battery Economic and Strategic Value, December 2005 and February 2006

Real Option Inputs			
	12/10/2005	**2/9/2006**	**change**
Present Value of the Project Cash Inflows	**$2,290,077**	**$2,521,113**	**$231,036**
Standard deviation of project cash inflows	**10%**	**10%**	**0%**
Required investment (exercise price)	**$2,025,000**	**$2,092,714**	**$67,714**
Length of time option is valid	**1.0**	**0.8**	**(0.2)**
Annual costs of keeping the option open	**$50,000**	**$50,000**	**$0**
Risk-free rate for U.S. Treasuries	**4.30%**	**4.66%**	**0.36%**
Outputs			
d_1	1.4918	2.3663	
$N(d_1)$	0.9321	0.9910	
d_2	1.3918	2.2769	
$N(d_2)$	0.9180	0.9886	
Total Project Value	**$307,809**	**$465,982**	**$158,172**
Intrinsic Value	**$265,077**	**$428,399**	**$163,322**
Strategic Value	**$42,732**	**$37,583**	**($5,150)**
Ratio of Intrinsic to Strategic Value	**6.20**	**11.40**	

The total project value has increased, but the strategic component has decreased, primarily because two months have passed and the expiration period was originally assumed to be one year. The volatility for the project cash flows is still 10% and the risk-free rate increased from 4.30% to 4.66%. Although the exercise price increased to $2,092,714[32], this increase was more than offset by the increase in the present value of the project cash inflows.

Note that the economic, or, intrinsic value in this project is now 11.4 times the strategic value represented by the option to delay the investment. In December, the ratio of intrinsic to strategic value was only 6.2. This ratio is an important measure that can be used to guide the decision to exercise the option to invest. For new technology investment alternatives with long option expiration periods, high volatility and negative net present values, the ratio will be zero. For alternatives with positive economic value, shorter option expiration periods and low volatility, the option should be exercised. In financial parlance, this is an option that is *deep in the money*.

[32] The exercise price was determined by assuming that half of the estimated $125,550 contingency labor cost will be used in this project and that all outcomes between $0 and $125,550 are equally likely. In the Monte Carlo simulation, this corresponds to a *uniform* distribution. The exercise price of $2,092,714 is thus $4,015,489 total capital cost less the $1,860,000 assumed co-funding amount and less half of the contingency labor, or, $62,775.

Growth Option – 50 MW Gas Turbines vs. 50 MW of NAS

The growth option discussed in the NYPA case showed how the volatility in natural gas prices and the probability that NAS capital costs may decrease affects the value of the option to use NAS as a peak-shaving technology strategy in the future. In the short term, natural gas prices have remained volatile and this is a variable that must be monitored closely to understand its impact on any options involving natural gas fired distributed generation. As you may recall, the growth option modeled for NYPA assumed a lognormal distribution with a nominal value of $12.00/MMBTU and a standard deviation of $5.00/MMBTU—a total reflecting the approximate shape of the annual U.S. natural gas price distribution for the past 25 years.

Between December 2005 and February 2006, spot prices for natural gas in the U.S. fell by almost 50%.[33] Is $12.00/MMBTU still a good assumption for the nominal value of natural gas prices going forward? If $10.00/MMBTU is believed to be a more realistic estimate for the price of natural gas, the value of the option to use 50 MW of NAS batteries instead of gas combustion turbine technology five years from now falls from $2.3 M to $2.0 M. For $8.00/MMBTU gas, the option value falls to $0.9 M.

It is the volatility *and* the absolute value of the natural gas price driving the value of this option, along with the time to expiration. The size of the future investment is also an important driver: suppose 100 MW instead of 50 MW would be a more realistic estimate of the required distributed generation or energy storage investment needed within five years. The strategic value represented by the growth option would similarly be doubled.

Finally, the NYPA case illustrates the important role that multiple investors can have in a demonstration project. Each of the co-funding participants listed in Table 4-1 is investing in an option and the lessons from the Long Island Bus Company project will be valuable to each participant for different reasons. In this case study, we've shown how $1-$2 million in option value can be quantified by identifying a growth option for NYPA. For each of the other participants investing in the NAS battery project, other options exist and can be similarly quantified. For some investors, such as the Long Island Bus Company, the value of the option is realized completely through direct investment in the demonstration project itself, and the value received is economic value (through reduced energy and labor costs). For others, such as NYPA, the value is strategic. For a distribution utility like LIPA, the value is probably a mix of economic and strategic—this utility may be able to defer an investment in a portion of its own distribution system (the option to delay investment) as a result of this project while realizing economic benefits from reduced electricity purchases during peak periods.

The case illustrates how it is common in the electricity industry today for multiple investors and multiple beneficiaries to be involved with a technology demonstration project. A well-conceived project will result in equitable splits of the rewards and costs and can represent an essential milestone in the commercialization of new energy storage or distributed generation technologies.

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[33] Spot prices at the Henry Hub were $15.40/MMBTU on December 13, 2005 and had fallen to $7.52/MMBTU by February 9, 2006.

PSE&G Options

The PSE&G case was originally conceived to determine if distributed generation or energy storage, installed in small, 5 MW increments, could be used as an effective means of deferring larger investments (60 MVA) in traditional transmission and distribution system assets. In this case study, the distributed generation alternative utilizing natural gas combustion turbine technology was considered as the best competing alternative and the model developed included a detailed assessment of this option.

Energy storage was also considered, including NAS and Vanadium Redox Batteries (VRB), and in these cases, neither technology was found to be economically viable relative to distributed generation, traditional T&D upgrades, or as a strategy for deferring T&D upgrades. The reason is because there was not a scenario that would produce a positive NPV case, given the best estimates for technology costs over the next five years.

To see why, consider the relative costs of the four technology alternatives. Each technology alternative was modeled using a 20-year pro forma cash flow projection, including a terminal value. The present value for each alternative is shown in Table 4-3.

Table 4-3
Present Value of PSE&G 60 MVA Upgrade Technology Alternatives

PSE&G Technology Alternative	Present Value ($ Millions)
Traditional T&D Upgrade	($49.6)
Natural Gas DG	($57.0)
VRB	($135.7)
NAS	($165.0)

As we showed before, the natural gas distributed generation option is a close second to the traditional 60 MVA T&D upgrade project. The storage options are much more costly—even when accounting for the possibility that costs may fall in the next five years. One VRB manufacture was asked for a probability distribution for VRB costs over the next five years, to see if there might be strategic value resulting from the possibility that VRB costs could be competitive with other alternatives over this time horizon.

The estimated probabilities and cost reductions over a five-year period received from the manufacturer are shown in Table 4-4, along with the NPV of the traditional T&D upgrade relative to the VRB alternative for all scenarios. Note that there is also a small probability, 5% , that costs will increase due to possible shortages in Vanadium, which would result in a 10% increase in cost. The model shows that even with the most aggressive assumptions for VRB costs reductions, the traditional T&D upgrade would produce superior economic value. The same is true for the NAS battery technology in this example.

Table 4-4
VRB Cost Probability Distribution

VRB Estimated Cost Change within 5 Years	Estimated Probability of VRB Cost Change within 5 Years	Cost for 5 MW Block ($ Millions)	Present Value for PSE&G 60 MVA Case	NPV of Traditional T&D Investment Relative to VRB
10%	5%	($16.7)	($147.5)	$97.9
0%	5%	($15.2)	($135.7)	$86.1
-10%	5%	($13.7)	($123.9)	$74.3
-20%	20%	($12.2)	($112.2)	$62.6
-30%	25%	($10.6)	($100.5)	$50.9
-40%	20%	($9.1)	($88.7)	$39.1
-50%	10%	($7.6)	($77.0)	$27.4
-60%	5%	($6.1)	($65.0)	$15.4
-70%	5%	($4.6)	($53.5)	$3.9

The point of this analysis is that energy storage (as an alternative to traditional T&D upgrade investments or distributed generation) does not make economic sense ***when deferral is the only benefit.*** There must be some other compelling reasons for using the technology for these alternatives to warrant further consideration. This case might actually look entirely different if reliability benefits had significant economic value, or if spinning reserve and power quality were also taken into account—or if electricity produced during peak periods were valued with real-time rates and not the negotiated wholesale rates used in this case.

The reason is that we have not one but two better options than storage in this particular case: distributed generation (which has value because of the possibility that natural gas costs may fall) and proven deferral alternatives that PSE&G is already employing today, including mobile substations, modified operating procedures during peak periods, and reinforcement of distribution lines near the affected substation.

PSE&G is better served by investigating further analysis into the distributed generation options that appear to be marginal today, that have the possibility of producing positive economic value in the future. As we learned earlier, there is strategic value to delaying the 60 MVA T&D upgrade investment that we quantified by using real options. Further efforts should be expended in understanding whether distributed generation can compete effectively with the current processes for deferring T&D upgrade investments. At the time of this writing, PSE&G had begun questioning whether a mobile or transportable distributed generation option would make even more economic sense for the case in question. This alternative would create a different set of economics that may be attractive—especially if a third party can be used to share the risk in such an option. Other utilities have already employed the idea of using mobile distributed generation as a temporary measure for operating T&D assets operating near capacity during some periods of the year. Perhaps this would also make economic and strategic sense for PSE&G as well.

This alternative comes with another option that has value—the option to move the asset to other parts of the distribution system as needs change. The flexibility inherent in a mobile distributed generation option is the type of value that can be quantified using real options. A rigorous assessment of this alternative may reveal that mobile distributed generation is competitive with mobile substations as another strategy for T&D upgrade deferral.

The mobile distributed generation alternative has the added advantage that no single project must bear the entire capital cost for the equipment—these costs can be spread out over all of the locations such equipment might be used over its lifetime. Within PSE&G, there is some precedent for this type of approach today. On rare occasions, diesel reciprocating engine generators are sometimes leased from a third party service provider to provide customer support during outages that are expected to be temporary. Although this alternative is only used for emergencies, there is some acquired experience that might be useful in evaluating whether other mobile strategies are economically feasible, and whether owning distributed generation assets would produce greater economic and strategic benefits to PSE&G if the equipment was owned directly instead of leased.

A final point should be made about real options resulting from the possibility that the costs of new technologies may fall. The probability distribution shown in Table 4-4 is a manufacturer's estimate. This is very different from what the investor (in this case, PSE&G) believes that the probability distribution may be. For the option to have value, the investor must believe that the cost reduction estimates are realistic and that the timeframe over which these projections are made is reasonable. These are some of the more difficult issues to determine in the objective evaluation of new technologies, and similar proxies and benchmarks for cost and performance data can be difficult to find.

In this example, PSE&G is relying, in part, on historical data on how other energy technologies have evolved during the commercialization phase. An analysis of the commercialization of other new energy technologies such as micro-turbines, fuel cells, photovoltaics and even wind turbines, including associated inverter and balance-of-plant technologies, can all be used to help in the assessment of the likely cost trajectory that a new technology might eventually take.

With the modeling techniques described in this report, we can create probability distributions and risk estimates that represent our best guesses about the future, supplement this information with facts and expert opinions from the marketplace, and transform this data into economic and strategic value estimates that can be used for prudent investment decisions.

5
GLOSSARY

ABB	Abbreviation for company formerly known as Asea Brown Boveri
DOE	Department of Energy
EIA	Energy Information Administration
EPS	Electric Peak Shaving
KVA	Kilo Volt Amperes
LIBC	Long Island Bus Company
LIPA	Long Island Power Authority
MMBTU	Million British Thermal Units
MVA	Mega Volt Amperes
MW	Mega Watts
NAS	Sodium Sulfur Battery, chemically known as NaS
NGK	Abbreviation for company formerly known as Nihon Gaishi Kaisha
NPV	Net Present Value
NYPA	New York Power Authority
NYSERDA	New York State Energy Research and Development Authority
O&M	Operations and Maintenance
PSE&G	Public Service Electric & Gas Company
ROI	Return on Investment
T&D	Transmission and Distribution
VRB	Vanadium Redox Battery, a flowing electrolyte battery technology

A

BLACK-SCHOLES OPTION PRICING FORMULA

For the valuation of projects that include options, the Black-Scholes option pricing formula is used. This closed-form equation, routinely used to value financial options (options to purchase or sell financial assets), can also be used to value options of real assets, such as electricity energy storage systems. The closed-form option pricing formula has six components[34], and is used by financial option traders (and employees who want to know what their stock options are worth) to determine the value of call options. Importantly, each of the six inputs in the financial option-pricing model has an analog when the formula is used to estimate the value of a real option. Presented in Equation A-1 is the Black-Scholes option-pricing equation, with inputs described for both financial options and real options,

$$V_{option} = Se^{-\delta t} \times N\left(d_1\right) - Xe^{-rt} \times N\left(d_2\right), \qquad \textbf{Equation A-1}$$

where $d_1 = \left\{\ln\left(S/X\right) + \left(r - \delta + \sigma^2/2\right)t\right\} / \sigma \times \sqrt{t}$, and

$$d_2 = d_1 - \sigma \times \sqrt{t}$$

For Financial Options,

V_{option}	=	The value of the call option, or, the price of the call option
S	=	The stock price
X	=	The exercise price
δ	=	The dividend amount
t	=	The time to expiration
r	=	The risk-free interest rate
σ	=	The volatility or standard deviation of the logarithm of the stock's returns
$N(d)$	=	The cumulative normal distribution function
$N(d_1)$	=	The proportion of shares required to replicate the call option

[34] Fisher Black and Myron Scholes derived the formula for pricing European call and put options for stocks that do not pay dividends, and received the Nobel Prize in Economics for their work in 1973. Robert Merton modified the formula in 1977 to include the valuation of stocks that pay dividends, and was the first to observe that the formula used to value financial options backed by securities could also be used to value real options, those options to invest in real assets producing a stream of cash flows.

$N(d_2)$ = The probability that the call option will be exercised on expiry

The derivation of the Black-Scholes option pricing formula is beyond the scope of this document and would require an understanding of stochastic processes. The formula and its components, however, are easily modeled using a spreadsheet software program, most of which have the necessary statistical functions used in the option pricing formula.

For real options, the formula is identical, but the inputs themselves have different, although analogous, meanings.

Here are the meanings of the inputs in the Black-Scholes pricing formula when they are used for real options:

V_{option}	=	The value of the real option
S	=	The present value of the cash flows associated with the underlying investment
X	=	The cost to invest in the technology at a future date
δ	=	The annual cost of maintaining the option (i.e., product development costs)
t	=	The time for which the option is valid
r	=	The risk-free interest rate
σ	=	The volatility, or, the standard deviation of the cash flows from the investment
N(d)	=	The cumulative normal distribution function
$N(d_1)$	=	The proportion of shares required to replicate the call option
$N(d_2)$	=	The probability that the call option will be exercised on expiry

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