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REAL OPTION VALUATION

of Distributed Generation Interconnection

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Executive Summary

Electricity restructuring, unprecedented demand for capacity, and technological advances have made distributed generation (DG) an increasingly viable answer to customer power requirements. DG refers to small-scale electric capacity near the receiving load. Such energy solutions could be attractive to end-users who demand independent, clean, low-cost, and reliable power.

A key question that DG installers will need to answer is whether they should remain interconnected to the distribution grid. These customers might argue that, since DG installation will reduce power purchases delivered by the utility, their interconnection fees should fall. However, this overlooks the added value coming from their ability to use this interconnection in desirable situations, which could have significant value. If the value of the interconnection for a given agreement length is greater than the interconnection fees charged by the utility distribution company (UDC), then the customer will remain interconnected.

An interconnected DG customer has the right, but not the obligation, to use the distribution grid. In deciding whether to remain connected to the grid, DG installers need a valuation technique that incorporates this flexibility and uncertainty. *Real-options theory* gives the necessary tools to tackle this problem. This method values investment decisions as if they were financial option contracts written on real assets. Since options grant rights without obligations, they must have financial value. The value of a DG customer's interconnection is comprised of a portfolio of real options. These options include:

- The option to sell excess power back to the grid.
- The option to buy supplementary power beyond on-site DG capacity.
- The option to buy backup power using standby contracts or spot markets.
- The option to come back, as a full requirements customer, to the utility or a third-party supplier.
- The option to perform wheeling transactions (wholesale or retail) using the grid.
- The option to trade derivatives that require physical delivery.
- The option to arbitrage gas and electricity markets by trading the "spark spread."
- The option to sell grid benefits such as reduction of spinning reserves, congestion relief, and deferral of transmission and distribution investments.
- The option to procure grid-based power quality and reliability services such as voltage support, reduction of low-frequency harmonics, and other ancillary services.

The value of these options depends upon the underlying price variables, the volatility of the underlying asset price, the risk-free interest rate, and the length of the interconnection agreement. Furthermore, depending on the customer's system interface with the utility grid, some of these options may not be exercisable. For example, a customer may not be able to operate his DG equipment and use the grid in parallel.

Determination of the value of a DG customer's grid interconnection can have an impact on some of the policy considerations that need to be addressed by regulators. Some of these considerations include:

- Should grid-side benefits be monetized?
- Should standby charges be included in the interconnection fees?
- Should interconnection fees depend on the customer's system interface?
- Should precise standards be adopted for the interconnection?
- Do DG-related stranded costs exist and, if so, should they be recoverable?

In general, higher interconnection rates may be justified in situations where the customer has additional options available and where the utility can demonstrate that providing these options has increased the costs for the utility. The particulars of this procedure depend on the regulatory mechanism chosen.

The valuation of a DG customer's interconnection also helps to ensure that price signals are consistent with market mechanisms adopted in a competitive electricity industry. As an element of UDC investment planning, one could estimate the price elasticity of demand for DG interconnection by combining market research with an interconnection valuation. While the specific market structures put in place will impact the numbers resulting from these analyses, the fundamental principles laid out in this paper will be useful independent of these details.

The valuation approach advocated in this paper should lead to improved interconnection decisions for DG customers by reflecting the full economic impact of customer, as well as grid side, costs and benefits. Compared to customer decisions that ignore the full real-option value of the interconnection, this could lead to improved power quality and reliability for DG customers and could avoid uneconomic disconnection of DG. Moreover, it avoids fragmentation of the power grid that could result in a stranded-cost spiral, causing distribution rate increases for remaining non-DG customers. Finally, preserving economic DG interconnections could contribute to a reduction of local market power problems.

The proposed framework could also substantially improve utilities', regulators', policy makers' and equipment vendors' understanding of a DG customer's interconnection decision processes. This should improve distribution planning forecasts of the number of interconnected DG customers and long-term forecasts of distribution system loads. Greater insight into the decision logic of DG customers should lead to improved investment decisions for distribution and transmission grid extensions, as well as better rate structures for interconnection fees and distribution and transmission wheeling. Improved understanding of system control, transmission, ISO, and RTO issues posed by DG interconnection could also provide useful input information for power exchanges designing local and regional power markets.

Finally, determination of the real option value of DG interconnection generates input information for strategy development of power marketers and ESCOs, as well as for vendors of DG equipment, equipment for microgrids, power quality equipment, and distribution and transmission equipment. A summary of these potential applications is given in the table below.

Table 1: Potential applications of DG-related real-option valuation.

H High level of interest M Moderate level of interest L Relatively low level of interest	*DG Customers*	*UDCs*	*TransCo & GenCo*	*RTOs, ISOs, PX*	*Regulators*	*Vendors*
DG interconnection decisions	H	H	M	M	M	H
DG customers' power quality and reliability	H	H	H	H	M	M
Avoidance of uneconomic grid fragmentation	L	H	M	M	H	L
Improved power quality in distribution grids	L	H	M	M	H	L
Avoidance of stranded cost and distribution rate spiral	M	H	H	H	H	L
Local market power mitigation	M	H	H	H	H	L
Estimation of price elasticity of DG interconnection	L	H	M	M	H	M
Distribution planning forecasts of DG interconnections	L	H	M	M	L	L
Long-term distribution system load forecasting	L	H	H	H	M	L
Distribution and transmission grid investment decisions	L	H	H	M	M	L
Rate design for interconnection and distribution wheeling	H	H	M	M	H	L
Local and regional power market design	M	H	H	H	H	M
Strategy development of power marketers and ESCOs	M	H	H	H	M	L
DG related system control, transmission, and RTO issues	L	M	M	H	M	M
Strategy development of DG related equipment vendors	L	M	M	M	L	H

Part I ❖ Introduction

This paper proposes a framework for valuing a distributed generation (DG) customer's grid interconnection. This issue is very timely, as efficient new technologies are prompting increasing numbers of customers to consider on-site generation solutions. The customer's decision to preserve his interconnection depends on the value of having the right to use this physical infrastructure for a variety of purposes. If the expected benefit from having these rights outweighs the fees charged by the utility distribution company (UDC), the customer will remain interconnected.

As restructuring continues, market variables will increasingly influence the grid interconnection decision. However, traditional valuation methods, relying on discounted cash flows, fail to incorporate the uncertainty and flexibility present in these types of situations. *Real-options theory* can solve this problem. This theory has its origins in capital market derivative pricing. The analogy between customer choices and financial option contracts is exploited to value these opportunities.

After giving the necessary background material, this paper identifies the options available to an interconnected DG customer and looks at the factors that influence the value of these options. Since part of this decision will be governed by the manner in which the interconnection rates are eventually structured, the paper concludes with policy considerations related to the valuation problem. These policy considerations relate to grid-side benefit monetization, standby charges, system interfaces, interconnection standardization, and stranded cost assessment.

Part 2 ❖ The DG Interconnection Issue

The DG model for supply differs significantly from the central-plant model for generation, transmission, and distribution. Namely, DG operators can deliver power to on-site loads without the use of transmission and distribution services. Alternatively, a DG installation that is interconnected to the grid can provide power to end-users directly at the distribution level, thereby avoiding large transmission losses. Many customers will find this flexibility enticing when choosing their energy solutions. End-users seeking independence from their serving utility, environmentally conscious consumers looking for low-emission generation technologies, and customers demanding enhanced power quality represent just a subset of those who are likely to be interested in installing DG units. Finally, as technologies evolve, DG may offer customers significant cost reductions over energy delivered from the grid.

The use of DG for on-site power is not a particularly new idea. In fact, devices such as reciprocating engines and gas turbines have been around for several years. Further, public safety institutions needing ultra-reliable electric supplies, such as hospitals, have long had emergency generators on site for use during utility service interruptions. However, the restructuring of utilities, the emergence of efficient new technologies (fuel cells, microturbines, and photovoltaics), and unprecedented capacity requirements have brought this issue to the forefront and suggested inventive new realms of application. Moreover, in capacity constrained markets, some of the on-site, emergency generators are now being dispatched to meet peak demand.

The decision of whether or not to remain interconnected to the distribution system is a question of the end-user's needs and the economic viability of the situation. Customers with sufficient installed DG capacity to cover their full load might argue that they should be immune from paying interconnection fees unless they are explicitly using their serving utilities' equipment. This ignores the value arising from their ability to use the interconnection in advantageous situations. The customer has the right, but not the obligation, to use the grid in these cases. Furthermore, the situations in which he chooses to do so are subject to great uncertainty. This naturally suggests a strong link to option-pricing theory. For the benefit of the reader who is unfamiliar with this topic, a cursory presentation is given in the next section.

Part 3 ❖ The Real Option Valuation Approach

3.1 Financial Options

Option-pricing theory developed as a method for valuing contingent claims in capital markets. Nevertheless, it can be an effective tool in assisting a firm's economic decisionmaking. There are two basic types of financial options—call options and put options. A call option is a contract that grants its owner the right, but not the obligation, to purchase an asset for a fixed price on or before a specified date. Similarly, a put option is a contract that grants its owner the right, but not the obligation, to sell an asset for a fixed price on or before a specified date. The fixed price in these contracts is known as the strike or exercise price, whereas the specified date is known as expiration or maturity. An option is said to be "out-of-the-money" if exercising it immediately would result in a financial loss. Similarly, an option is said to be "in-the-money" if exercising it immediately would result in a financial gain. American options can be exercised at any time prior to maturity. European options can be exercised only at maturity. The asset under consideration is commonly referred to as the underlying asset, since the value of the option is contingent upon the price of this asset. This further explains the origin of the term "contingent claim," which is simply a synonym for financial option. In recent years, options with increasingly more complicated features have appeared. These are sometimes referred to as "exotic" options,[1] while standard call and put options are referred to as "vanilla" options.

The purchaser of an option has contract rights without obligations. Such a contract has positive value, as reflected in the purchase price, which is known as the option premium. The goal of option pricing theory is to determine the "fair" option premium for a given underlying asset, strike price, and maturity. It is not immediately obvious whether a fair market price should even exist. Indeed, although option contracts have been traded privately for a long time, no analytically consistent framework for valuing them existed until 1973, when economists Fischer Black, Robert Merton, and Myron Scholes published groundbreaking papers on option pricing.

The revolutionary breakthrough of Black, Merton, and Scholes was their recognition that an investor could form a portfolio of risky assets that had a cumulative rate of return that was riskless.[2] This is accomplished by allowing the portfolio to consist of a single European option and an appropriate amount of the underlying asset that offsets the total risk. Thus, one can use an option and its underlying asset, say a stock, to replicate the price behavior of a riskless asset, say treasury bonds. The argument can be turned around so that

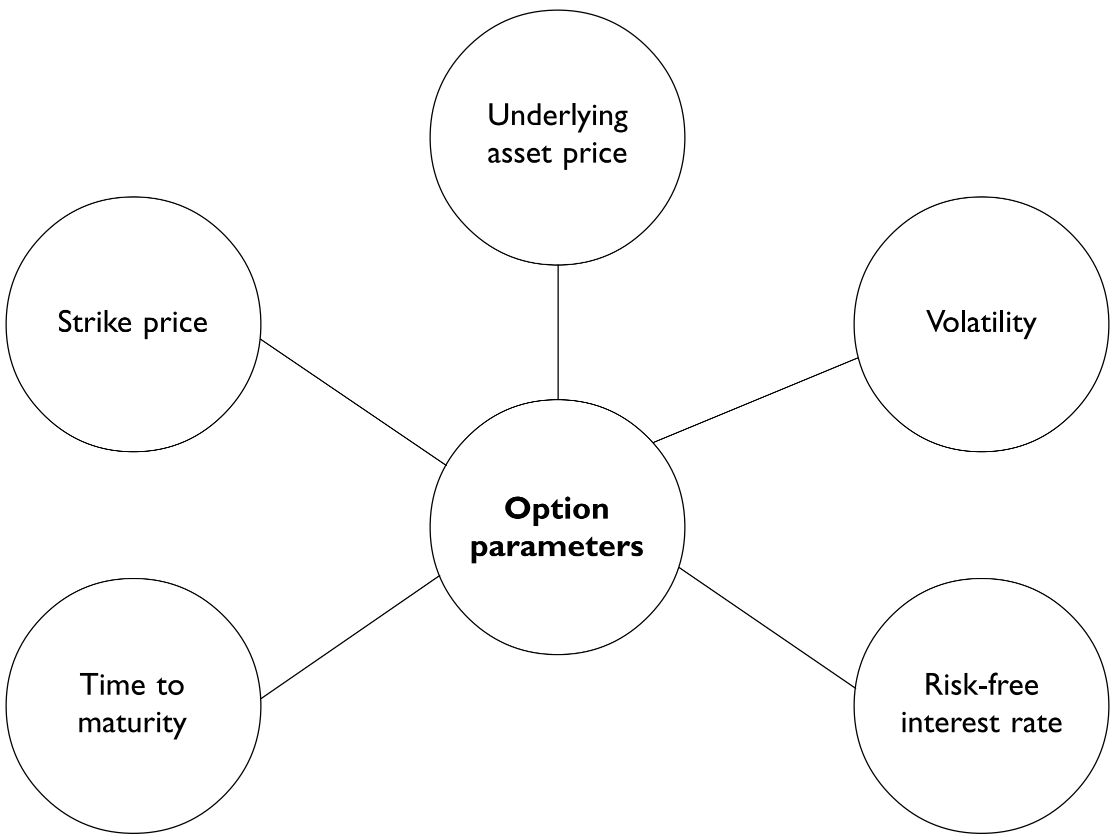
1 For a survey of exotic options and their features, see Chapter 18 of J. Hull, *Options, Futures, & Other Derivatives* (Upper Saddle River, NJ: Prentice Hall, 2000).

2 Actually, the portfolio is only riskless over short time intervals and needs to be continually readjusted to remain risk-free. This procedure is referred to as dynamic hedging.

one can use the underlying asset and riskless asset to replicate the price behavior of an option. The ratio of the underlying asset to the riskless asset in this portfolio depends on the volatility of the underlying asset price, the risk-free rate of return, the price of the underlying asset, the strike price, and the amount of time remaining until expiration.[3] Thus, knowledge of these parameters allows one to determine the theoretical value for the price of the option (see Figure 1). This price is unique, since any other value would enable an investor to lock in riskless profits by taking appropriate positions in the assets. It is in this sense that we refer to a fair premium for the option.

This analysis is based upon an idealized mathematical model that treats only simple European options. However, the observed market prices of options on a large class of underlying assets have been shown to be in remarkable accord with their theoretical values. Furthermore, strides in financial engineering have made it possible to value a wide variety of options with more complicated features.

Figure 1. Parameters that affect the value of an option.



3 The effects of dividends and storage costs are ignored for the purposes of this paper.

3.2 Real Options and Decisionmaking under Uncertainty

The application of option-pricing theory to capital budgeting decisions is a relatively new phenomenon. The most popular approach to investment decisions, net present valuation (NPV), often gives results that conflict with actual management decisions. The basic idea behind NPV is to determine the cash flows over the life of a project and discount them by the weighted average cost of capital. If this value is positive, then the firm should proceed with the project, otherwise it should choose not to invest. The problem is not NPV's validity as a theory, but rather that NPV is frequently applied without careful consideration of the assumptions on which it is based. NPV analyses assume that either a decision is reversible or, if the decision is irreversible, that it is a now or never opportunity. The bulk of decisions that a firm faces do not fall under these restrictions. In particular, NPV fails to capture the uncertainty and flexibility that often underlie decisionmaking in a corporate environment. NPV calculations ignore an investor's ability to modify his behavior in response to incoming information. Therefore, NPV often undervalues these situations.

Option-pricing theory may be a sensible way of handling capital budgeting problems involving flexibility and uncertainty. After all, the decision to make an initial cash outlay (the option premium) in return for the right to make a later purchase (receiving the underlying asset in return for the strike price) is a typical business decision. This alternative approach to corporate investment decisions is known as real-options theory, owing its name to the fact that the claims being made are on real, rather than financial, assets. Figure 2 illustrates the price drivers for real options and compares them with their financial-option cousins.

Although the idea of using option-pricing theory to value contingent claims on real assets was suggested shortly after the original Black-Scholes-Merton analysis,[4] enough complications remained to keep many skeptical of the validity of this approach. One of the fundamental difficulties was in the construction of the riskless portfolio. Since most real assets are not traded quantities, the arbitrage arguments that led to unique option prices do

Figure 2: Analogies between real and financial option parameters.

Option Parameter	*Financial Option*	*Real Option*
Underlying asset price	Stock or other asset price	Cash flow from project
Strike price	Strike price of the option	Fixed costs
Volatility	Volatility of asset price	Volatility of cash flows
Risk-free interest rate	Risk-free interest rate	Risk-free interest rate
Time to maturity	Time to expiration of the option	Time to expiration of investment

4 See, for instance, S. Myers, "Determinants of Corporate Borrowing," *Journal of Financial Economics* 5 no. 2 (1977), pp. 147–75.

not appear to apply. Nonetheless, a number of authors have recently claimed that real options can be valued similarly to financial options.[5] They maintain that even though these assets may not be formally traded, capital budgeting is concerned with determining the value of the projected cash flows that would result if these assets were traded. In other words, they argue that this approach accurately reflects the additional firm market value arising from the presence of these options. As a result, real-option valuation is gaining popularity, as an increasing number of corporate managers realize that this approach leads to better investment decisions.[6]

5 See, for instance, E. Kasanen and L. Trigeorgis, "A Market Utility Approach to Investment Valuation," *European Journal of Operational Research* 74, no. 2 (1994), pp. 294–309.

6 The mining of ore, the development of natural gas fields, and research and development in the pharmaceutical industry are just a few cases where real-options theory has been fruitfully applied. For a survey of applications, see Chapter 11 of L. Trigeorgis, *Real Options: Managerial Flexibility and Strategy in Resource Allocation* (Cambridge, MA: MIT Press, 1997).

Part 4 ✥ Framework for Valuing DG Interconnection

Real-options theory can lead to improved corporate decisions when flexibility and uncertainty play a significant role. The choice of whether a DG customer should remain interconnected to the distribution grid meets these criteria. The potential value-added uses of the interconnection are multifarious and evolve randomly in time. However, the types of problems that real-options theory is typically applied to are slightly different than the DG interconnection problem at hand.

The standard example of real-options theory applied to the electricity industry is in aiding the choice of whether to increase generation assets. A utility trying to decide if it should build a new facility now, or pay a fee that grants the right to wait and see if construction is economically wise as new information arrives, is actually buying an "option to defer." Having the ability to wait to exercise this option has significant value. In the absence of knowledge of real-options theory (or in cases where uncertainty is believed to be negligible), a utility might find that NPV is an adequate guide for making capital budgeting decisions.

On the other hand, a DG customer who chooses to be interconnected to the distribution grid has opened up a multitude of new opportunities. These opportunities *are* real options. The NPV approach is not applicable because it ignores the uncertain and dynamic situations the DG customer is likely to encounter. Moreover, NPV is likely to exclude many of these opportunities, since these uses for the grid may appear unattractive at the beginning of the planning horizon. Therefore, not only is real-options theory a potentially useful way of analyzing a customer's decision whether to retain his grid interconnection, it is superior to the NPV methods currently in use.

The options embedded in a DG interconnection generally fall into two broad categories: the option to buy and sell electricity to and from the grid, and the option to buy and sell grid services to and from a UDC. Examples of the first category include:

- The option to sell excess power back to the grid.
- The option to buy supplementary power beyond on-site DG capacity.
- The option to buy backup power using standby contracts or spot markets.
- The option to come back, as a full requirements customer, to the utility or a third-party supplier.
- The option to perform wheeling transactions (wholesale or retail) using the grid.
- The option to trade derivatives that require physical delivery.
- The option to arbitrage gas and electricity markets by trading the "spark spread."

Examples of the latter include:

- The option to sell grid benefits such as reduction of spinning reserves, congestion relief, and deferral of transmission and distribution investments.
- The option to procure grid-based power quality and reliability services such as voltage support, reduction of low-frequency harmonics, and other ancillary services.

This paper explains the applicability of real-options theory to the topic of interconnection valuation. Detailed mathematical computations are not presented, even though this analysis is based upon well-developed quantitative models. The results of a full-blown analysis depend on the details of the customer and industry structure assumed. While we have found the modeling process tractable, numerical results for customers' interconnection values are saved for later presentation. Instead, this paper focuses on the key price drivers for the options embedded in a DG customer's interconnection. It examines combinations (portfolios) of these options to see which ones are available in the presence of different system interfaces and which options can be exercised on a given maturity date. This analysis concludes with a discussion of policy implications one could derive using real-options theory.

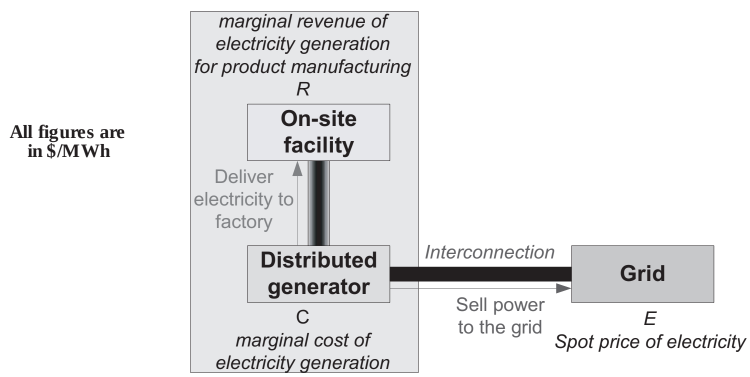
Part 5 ❖ Analysis of Individual Real Options

5.1 Sellback Option

Consider first the option to sell excess power back to the distribution grid. There are many circumstances in which a DG customer may wish to exercise this option. Essentially, the DG operator will choose to sell electricity back to the grid whenever his profits from doing so are larger than the profits otherwise obtained by using the electricity for on-site purposes (see Figure 3). The option payoff is merely the difference between these two profits, provided this difference is positive, otherwise the payoff is zero.[7]

Let E denote the spot price of electricity, R the marginal revenue of electricity generation for manufacturing the firm's product, net of all other costs of producing the product, and C the marginal cost of electricity generation. The quantities E, R, and C are

Figure 3: Exercise decision for the sellback option.



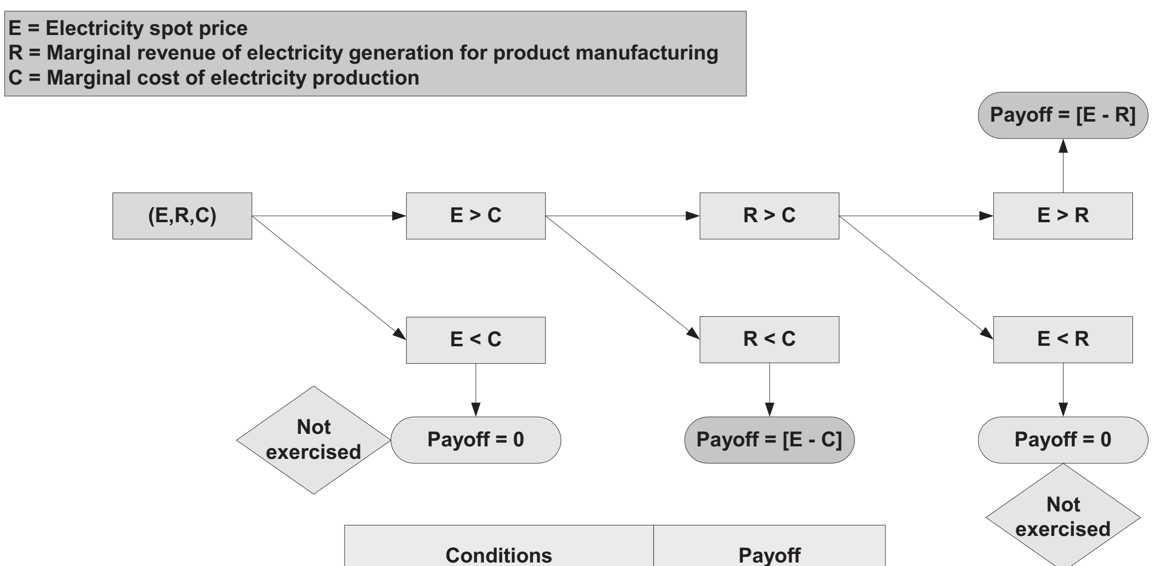
	Strategy:	*Deliver electricity to factory*		*Sell power to the grid*	*Option payoff*
	Profits:	R - C		E - C	$[[E - C]^+ - [R - C]^+]^+$
First case:	E = 130 C = 15 R = 30	15	Exercise option →	115	100
Second case:	E = 15 C = 15 R = 30	15	← Do not exercise option	0	0

7 The superscript "plusses" in the figure indicate the action of taking the positive part of the quantity in brackets. Thus, [X]+ is equal to X if X > 0 and zero otherwise.

measured in the same units.[8] In terms of these quantities, the marginal profit from selling electricity back to the grid is the difference between the electricity spot price (E) and the marginal cost of electricity generation (C), if this value is positive, otherwise this marginal profit is zero. On the other hand, the marginal profit from using the DG operator's capacity to produce the firm's product is given by the difference between the marginal revenue of production (R) and the marginal cost of electricity generation (C), if this value is positive, otherwise this marginal profit is zero.

Figure 4 indicates the resulting profits for different values of the quantities E, R, and C. By looking at the payoff table, it is clear that the payoff described above can be rewritten as the difference between E and the maximum of R and C, provided this difference is

Figure 4: Payoff analysis from the sellback option.



Conditions			Payoff
E > C	C > R	E > R	E - C
E > C	C > R	E < R	not possible
E > C	C < R	E > R	E - R
E > C	C < R	E < R	0
E < C	C > R	E > R	0
E < C	C > R	E < R	0
E < C	C < R	E > R	not possible
E < C	C < R	E < R	0

8 A firm usually thinks of its marginal quantities in terms of an additional unit of manufactured product. Hence, if one measures E in units of $/MWh, then R is the marginal revenue (in dollars) resulting from additional production processes that use 1 MWh of electricity. In general, this is not equivalent to the marginal revenue of production in $/(unit of manufactured product) multiplied by the ratio of the amount of manufactured product produced per MWh. However, if the marginal cost curves are flat over the range of interest, then this distinction is immaterial.

positive, otherwise the payoff is zero. If we assume R and C are constant over the range of interest, this is just a simple call option with the electricity spot price as the underlying asset price, and the maximum of the marginal revenue of production and the marginal cost of electricity generation as the strike price. If we assume that the marginal revenue (R) and marginal cost (C) have some functional form, then the value of the option is just a weighted average of a portfolio of options with a strike price that varies as a function of facility output.

5.2 Supplementary Power Option

A DG customer may wish to purchase power from the grid when his electricity requirements for production exceed his on-site generating capacity. Under normal circumstances, he will choose to buy supplementary power whenever his marginal revenue of production (R) is greater than the price at which he buys the supplementary power (P). One possibility for the value of P is the spot price of electricity (E), especially if the demand for supplementary power is unanticipated. However, P is more likely to be inferred from the customer's price exposure due to positions in over-the-counter (OTC) option contracts. In this case, one needs to include the effects of the interest-adjusted premium (I) and the strike price (X) of the OTC contract.

These conditions imply that the payoff of the supplementary power option equals the difference between the marginal revenue of production (R) and the price at which power is purchased (P), if this value is positive, otherwise this payoff is zero. Consider first the case in which the customer declines to purchase an OTC option contract and needs to go to the spot market for supplementary power. If we assume that the marginal revenue of production (R) is constant over the range of interest, this becomes a simple put option with the spot price (E) as the underlying asset price and R as the strike price. A more detailed analysis can be carried out by assuming some functional (or stochastic) form for the marginal revenue of production.

The case in which the customer enters into an OTC contract to purchase power is more complicated. The "price at which power is purchased" (P) is the minimum of either the sum of the interest-adjusted premium (I) and the strike price of the OTC contract (K), or the sum of the interest-adjusted premium (I) and the realized value (V) of not exercising the OTC contract. In turn, the realized value (V) is the difference between the spot price (E) and the remaining value of the unexercised OTC contract (O).[9] The term involving the strike price arises from situations in which prevailing market prices are high, making early exercise of the OTC contract economically sensible. Note that, other than requiring that the spot price be greater than the strike price, this term does not depend on the magnitude of the spot price

9 The quantities E and O should be measured in the same units, since we are taking their difference. However, in electricity markets E is usually measured in \$/MWh, whereas O is usually measured in \$. This causes no problems, as long as one is careful in scaling the notionals to make sure we are comparing "apples with apples."

when supplementary power is needed. This is because the customer requires the electricity and is merely choosing between the spot and option markets, depending on the economics of the situation. He cannot realize additional profit from increased spot prices without taking an offsetting position. However, this value is present in the absence of the interconnection and should not be included here.

The term involving the realized value (V) describes cases where buying in the spot market and holding on to the OTC option contract is preferable. The residual value of the OTC option contract (O) needs to be included; otherwise, the DG installer would systematically undervalue the supplementary power option.

To represent a supplementary power option, the payoff has to include information regarding when the customer requires additional power from the grid. This can be incorporated into the analysis by scaling the payoff by a probabilistic factor; that is, by weighting the payoff of the supplementary power option so that it has full value at random times (the moments where additional power is required) and has zero value otherwise. If this were not taken into account, the option would be greatly overvalued.

5.3 Backup Option

Unplanned generation outages are an unfortunate fact of life. Additionally, owners of generation equipment have to take their facilities off-line periodically for routine maintenance and overhauls. These scenarios also apply to DG customers. Therefore, the option to buy backup power is likely to have considerable value to an interconnected DG operator.

The backup option has a structure that is nearly identical to that of the supplementary power option. Namely, the payoff equals the difference between the marginal revenue of production (R) and the purchase price of backup electricity (P). Furthermore, the values for P are determined in the same manner as for the supplementary power option, but with three key modifications that lead to different values for the backup option. First, backup power and supplementary power are, in general, required at different times. Therefore, the probability weighting that needs to be incorporated into the payoffs has to be adjusted accordingly. Second, the notional value is usually much larger in the case of the supplementary power option. This is because, although supplementary power is typically a fraction of base power, it is usually delivered over a much longer period of time. Third, because of non-monetary outage costs, a DG customer may exercise the backup option in cases that result in financial losses. For example, a firm that manufactures a product bears reputational risk. Thus, strict economic exercise ignores the value that comes from uninterrupted delivery (even if at a short-term loss) of a firm's product to its customers. Also, certain industries are prone to major losses due to their inability to resume production immediately after losing power. An example of this is high-tech industries that require robotic assembly lines to be black started. A particularly simple way of handling this problem is to increase the marginal revenue by some fixed percentage that takes "non-financial" exercise (that is, exercising an out-of-the-money option) into account.

5.4 Comeback Option

One of the primary reasons that a DG customer initially invests in his equipment is because he assumes superior overall economics for on-site generation. However, a DG customer may discover that there are times when the economics are not as favorable as he thought. In these instances, he may decide to temporarily reinstate the utility as his electricity supplier. Of course, the value for a customer to come back to the utility in the short-term is partially contained in the backup and supplementary power options. A plausible "comeback" scenario, in the medium term, is a customer who finds it more economical to buy his power from the grid due to high seasonal fuel costs. The utility's costs are likely to be distributed over a wide range of generation technologies, making them less sensitive to price disruptions in a single market. In the long term, a customer may merely find that his investment was a mistake and that he will not operate his DG equipment. In this case, not only can the customer realize value by exercising the comeback option, but he can also sell his DG assets. Since selling these assets would not be possible in the absence of the interconnection, this component should be included into the long-term comeback option.

The short-term comeback option is exercised when the cost of on-site generation (C) is greater than the retail price charged by the utility for electricity (U). The payoff is equal to the difference between C and U, if positive, otherwise the payoff is zero. Practically speaking, it only makes sense to exercise this option if this difference is sustained over non-negligible time intervals. In other words, an operator of a real DG facility would not switch back and forth between DG and utility power unless it was expected to be profitable over an economically reasonable period. This can be incorporated into the payoff by increasing the utility's retail price (U) by a "penalty" amount that reflects the switching costs. The medium-term comeback option is similar to the short-term case, except that it carries a larger notional value.

The long-term case needs to be treated slightly differently. This option is really just an option to sell generation assets. Let G be the resale value of the customer's DG assets, C the cost of on-site generation, and E the spot price of electricity. The payoff of the long-term comeback option is the difference between G and a portfolio of option positions (L), if this difference is positive, otherwise the payoff is zero. The portfolio, L, consists of one European option for every observation date (D), until maturity of the comeback option. These observation dates are the moments when the customer would have resumed use of his DG capacity, had he not sold his generation assets. The dates (D) define the maturities of the options in the portfolio. The payoffs of the options in the portfolio are all given by the difference between the electricity spot price (E) and the cost of on-site generation (C), if this value is positive, otherwise the payoff is zero. The portfolio, L, represents the "expected" opportunity cost to the customer when selling his DG assets. The overall structure now reveals that the long-term comeback option is an American put option on a portfolio of European call options.

5.5 Wheeling Option

When treating the sellback option above, we assumed that the excess electricity was sold in the spot market. This situation is convenient, since the DG customer can exercise this option depending on his current needs. Some restructured markets may allow for direct retail sales by the DG facility, and the DG installer may also want to enter into wheeling arrangements.

The payoff for the option to execute wheeling transactions has a similar structure to the sellback option, with the exception that the spot price is replaced by "the price at which electricity is sold" (S). Exercising the wheeling option means that a wheeling contract has been entered into. The value of S depends on whether the wheeling transaction has been arranged through an option or forward contract. In the case of a forward contract, S is simply the delivery price of electricity. For an option, S is given by the maximum of two quantities, S1 and S2. S1 is the difference between the strike price (X) of the option contract and the interest-adjusted premium (I) paid to enter the contract. S2 is the present value of the contract (O), plus the marginal cost of on-site generation (C), minus the interest-adjusted premium (I). From the customer's point of view, the choice of S1 versus S2 represents the decision of whether or not to exercise the wheeling contract.

5.6 Spark Spread Option

A DG customer that is interconnected to the utility grid has the potential to perform cross-market arbitrage. In particular, a customer with gas-fired turbines can exploit price discrepancies between gas and electricity markets.

The payoff of this option is given by the difference between the electricity spot price (E) and the natural gas spot price (G), if this difference is positive, otherwise the payoff is zero. Of course, G is usually measured in $/Btus. However, this can always be converted into $/MWh using the implied heat rate. For simplicity, we define G to be measured in $/MWh, implicitly assuming that the heat rate has been used to perform this translation. Whether this is a put or a call option is difficult to determine, since E and G are both necessarily random quantities. The situation is analogous to an investor who buys an option to exchange one foreign currency for another, neither of which being his domestic currency.

Alternatively, the customer could attempt to realize these gains by locking in either the electricity or gas price through futures or options contracts. The payoff would need to be modified by replacing E and G with the sale or purchase price (P) implied by these contracts. This extension is similar to the way in which the spot price gets modified when going from the sellback option to the wheeling option.

5.7 Grid Services Options

The types of ancillary services that can be bought from and sold to the grid are numerous. However, they can be treated in a unified manner for valuation purposes. After all, a DG customer that buys grid services (or a certain level of power quality) from a utility is paying a fee in exchange for the ability to avoid investments that would provide these services on-site. Therefore, the payoff of the option to "buy a specific grid service" has a payoff given by the difference between the saved investment cost and the amount charged by the utility for this service, if this value is positive, otherwise the payoff is zero. The total value of being able to purchase all the services is just a portfolio of the options on individual services. Of course, the particular strike prices and underlying asset prices will vary depending on the service considered. However, the valuation approach will be the same in all cases. Similarly, the payoff of the option to "sell a specific grid service" has a payoff given by the difference between the amount the customer receives for the service and the opportunity cost incurred (if any) by selling it, if this value is positive, otherwise the payoff is zero. Again, the total value of all services that can be sold to the UDC is just given by a portfolio of options on individual grid services.

Part 6 ✥ Cumulative Effects and Economic Conclusions

In section 5, we described the payoffs for several of the real options available to an interconnected DG customer. In principle, knowledge of these payoffs allows the customer to value each real option. The cumulative value of the interconnection can then be determined by considering a portfolio of these real options. The interconnection value depends on the fundamental value drivers of the individual options, the individual options available to the customer over the interconnection horizon, the constraints on when the individual options can be exercised, and the interactions between the individual options. Comparing the real-option value of the interconnection with the price charged by the UDC for interconnection fees enables the customer to decide whether he should remain interconnected. It should also help regulators determine whether proposed interconnection fee structures are fair to all involved parties.

6.1 Value Drivers

The value of a financial option is affected by the following price drivers: the price of the underlying asset, the strike price, the volatility of the underlying asset price, the amount of time to maturity, and the risk-free interest rate.[10] These quantities, with appropriate interpretations, are also the price drivers for real options.

For the DG interconnection option, it is not always easy to disentangle the strike prices from the underlying asset prices. For instance, some of the individual put options resemble call options and vice versa. The reason is that, for these options, the strike price is random and the price of the underlying asset remains fixed. This is the reverse of what is usually encountered for simple options. This problem could be avoided through careful definitions of these prices. However, it is more natural in this context to consider an option as the right to exchange one asset for another. Therefore, any variable appearing in the payoff is treated as being the price of an asset that affects the value of that particular option. All other things being equal, increasing the value of any variable in the payoff that represents a quantity that is received increases the value of the option. Similarly, increasing any variable that represents a quantity that is paid out decreases the value of the option, again assuming all other variables are fixed. For instance, as the value of the spot price of electricity *increases* (E), the value of the sellback option *increases*. However, as the marginal revenue of production *increases* (R), the value of the sellback option *decreases*.

Intuitively, volatility is supposed to represent dispersion in price behavior. The (annualized) volatility of a price variable is defined as the standard deviation of returns on

10 The effect of quantities analogous to storage costs and dividends are ignored for the purposes of this paper.

that variable. All other things being equal, increasing the volatility of *any* price variable increases the value of an option dependent on that price variable. This is true whether this variable is received or paid out. The reason is that increased volatilities lead to increased chances that the option will be deep in-the-money at maturity. For example, in the case of the comeback option, *increased* volatility in the resale value of DG assets (G) *or* the electricity spot price (E) leads to *increased* option value.

The amount of time until maturity is just the time from the present until the interconnection agreement expires. For European options, which dominate the interconnection option, it is not obvious whether increasing the time to maturity increases or decreases the individual option values. However, increasing the maturity does add more options to the portfolio, since more exercise times are available (see Section 6.3). If the options added to the portfolio have sufficient value, then increasing the time to maturity will increase the value of the interconnection. For an American option, such as the long-term comeback option, *increasing* the time to maturity *increases* its value because an option with a greater time to expiration has more exercise opportunities. For example, in an uncertain market, there is a better chance of making an optimal sale on DG assets if given a longer time to sell them.

The risk-free interest rate affects the individual options in a more subtle way. As interest rates increase, price variables tend to increase. However, this behavior leads to increased option values when influencing variables representing positive cash flows and decreased option values when influencing variables representing negative cash flows. On the other hand, the interest rate also has an effect on the “present-value” of the option. Clearly, an increase in the interest rate decreases the present value of cash flows. Therefore, increasing the interest rate decreases the value of any option with a payoff whose randomness comes entirely from price variables that are paid out. It can also be shown that the effect on the discount factor is small compared to the effect on prices when interest rates are increased. Thus, increasing the interest rate increases the value of any option with a payoff whose randomness comes entirely from price variables that are received. Cases in which randomness comes from both types of variables have to be treated on an individual basis. Fortunately, most of the options encountered in the interconnection problem can be treated without this complication, since one of the variables will tend to be dominant. For instance, in the backup option, the marginal revenue of production (R) can be assumed to be constant relative to the stochastic purchase price of electricity (P). Therefore, *increasing* the interest rate leads to a *decreased* value for the backup option.

6.2 System Interfaces

The options that are available to a DG customer differ depending on the details of his interconnection arrangement and system interface. This paper restricts attention to three possible cases to illustrate this idea. The first situation assumes the DG customer is interconnected, but can only use the interconnection by automatic transfer. He is not able to operate his DG equipment and utilize the grid simultaneously. The second situation assumes the customer is interconnected, but cannot export power to the distribution grid. He can receive grid power and operate his equipment in parallel. The third situation assumes that the customer can utilize bi-directional power whenever it is required.

In the first case, the customer has the ability to exercise the sellback, backup, comeback, wheeling, and spark spread options. He also has the ability to exercise both classes of grid services options. He cannot exercise the supplementary power option, since that would require the ability to deliver on-site and grid power in parallel. Therefore, a DG customer with this interface will ascribe a lower value to his interconnection than if the entire portfolio of options were available to him. Of course, this assumes that the value of the supplementary power option would be non-negligible to this customer. The validity of this assumption depends on the customer's industry.

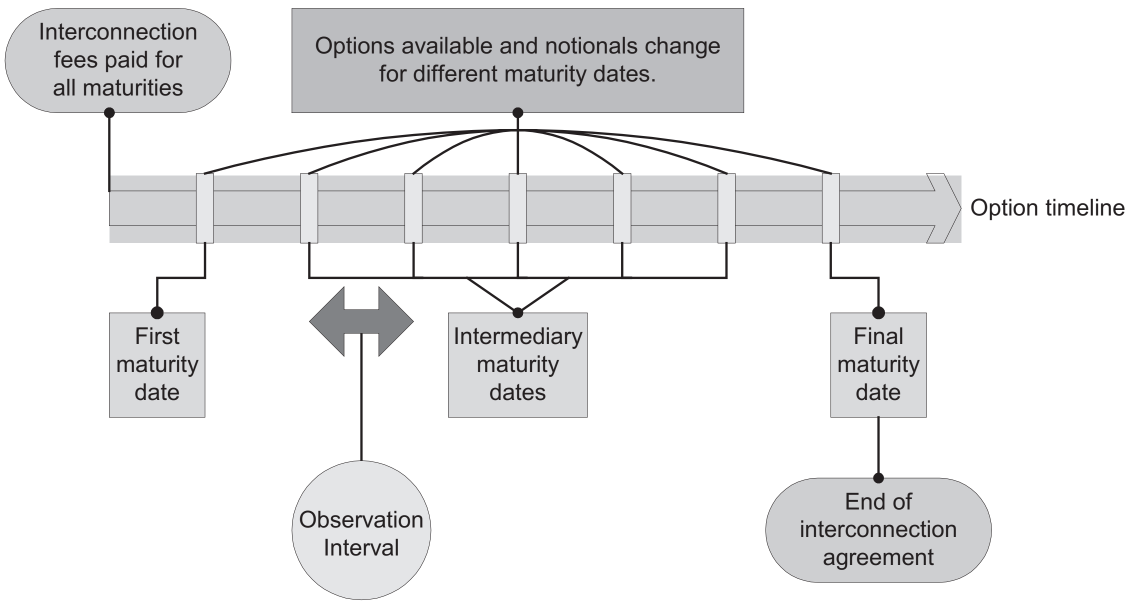
In the second case, the customer has the ability to exercise the backup, supplementary power, and comeback options. He also has the ability to exercise the option to buy grid services. He cannot exercise the sellback, wheeling, or spark spread options, since he does not have the physical infrastructure to deliver power to the grid. For the same reason, he cannot exercise the option to sell grid services. Therefore, this interface could lead to significantly reduced value than if the customer could exercise the full set of options discussed above. Therefore, the price that this customer is willing to pay to be interconnected may be significantly smaller than a customer with the third setup.

In the final case, the customer can exercise all of the options considered in the previous section. This could result in a relatively large real-option value for the interconnection. In turn, this could prompt the utility to propose that regulators institute large interconnection fees or sophisticated rate schedules for the services that DG customers buy from and sell to the utility. A customer in this position may find it economically desirable to enter into customized interconnection arrangements that give him the right to use his interconnection only for certain services. From a valuation point of view, ignoring infrastructure costs, this is equivalent to modifying a full-blown system interface into a tailored configuration.

6.3 Portfolio Maturity Structure

The maturity structure of the interconnection portfolio imposes further constraints on a customer's ability to exercise certain options. At any given exercise time, the customer can either choose to exercise the individual options, and realize the associated gains, or let it expire worthless. However, depending on the customer's desire and ability to take advantage of these opportunities, a very large number of exercise times could exist. That is, for any given option, say the sellback case, the customer really has a large number of European options differing only in their maturity dates. The maturities of these options range from the present until the end of the interconnection agreement in steps of some observation interval (see Figure 5). This observation interval represents the frequency with which the customer compares market data with his on-site situation to determine whether he should exercise individual options.

Figure 5. The maturity structure of the portfolio of DG options.



A further complication results from the notional sizes involved in the individual options. For example, if a customer exercises an option to sell 10 MWh back to the grid, then he needs to generate (for instance) an additional megawatt for a period of ten hours. Therefore, he cannot exercise additional sellback options (or, alternatively, wheeling or spark spread options) that utilize this megawatt of capacity over the delivery window. The point is that capacity constraints affect notional sizes and, therefore, the real options available to a DG customer. This information can be incorporated into the payoff to prevent the option from being systematically overvalued.

Finally, certain options cannot be exercised simultaneously. For instance, a sellback option cannot be exercised at the same time as a backup option. This is because, by definition, a backup option is only exercised when the customer's DG facility is not operating. Certainly, this eliminates the opportunity to sell power back to the grid at these moments. Again, this effect can be included into the option payoff to prevent overvaluation.

Part 7 ❖ Policy Considerations

The preceding analysis focused on the value of a DG customer's interconnection to the utility grid. However, the *values* (option premiums) determined by this approach are not the *prices* that will be charged by the UDCs for interconnection, which will be determined by regulation. The rate structure will reflect the utility's costs, and not the DG installer's value. However, this does not mean that the issues with which regulators will grapple are independent of the value of the interconnection to the DG customer. In particular, utilities could make the case that they should be compensated for the costs caused by serving interconnected DG customers. Regulators will need to determine whether such cost recoveries are justifiable.

7.1 Monetization of Grid-side Benefits

There has been considerable debate over whether benefits of DG to the utility should be monetized. Some argue that these benefits may be negligible and difficult to quantify, since they depend critically on the amount of interconnected DG capacity available to the utility. The real-options analysis presented in this paper shows that the value to the DG customer of the option to sell services to the grid can be significant in situations where the underlying variables are subject to large uncertainties. In cases where the utility has a high demand for these services, this option has a high value to the customer. The real-options approach, therefore, suggests that the ability of the DG customer to sell these benefits should result in an increase in interconnection fees to account for the customer's right to exercise these options.

7.2 Standby Charges

As shown in our analysis, the backup option embedded in the interconnection could have considerable value to customers who demand uninterrupted power. This option should not be confused with the DG installer's options to purchase backup or standby energy from a generator. The interconnection-based backup option gives the right to buy these generation-based backup options. The factors that determine the value of the interconnection-based backup option are the marginal revenue of production, the purchase price of electricity (spot transactions or contracts), the probability that standby services will be needed, and the incurred losses resulting from power interruptions. The customer's ability to exercise this option to take standby distribution exists for all interconnection system interfaces considered, and the utility's costs for providing standby distribution service are independent of whether standby power was used (i.e., whether the option was exercised). These capacity costs are invariant to the actual power flows, and should be recovered by utilities. Such a fee would represent the "backup" contribution to the option premium.

Utilities incur variable standby distribution costs when the DG customer demands backup power. In addition to the fixed costs discussed above, the DG customer, in exercising the distribution-based and generation-based options, should pay the variable costs incurred by the utility. This scenario assumes that the customer is interconnected and therefore this cost recovery should be handled in the same manner as for non-DG customers using grid services. That is, these variable costs of generation should not be incorporated into a DG customer's invariant, monthly interconnection fees.

7.3 System Interfaces

The options available to a DG customer depend on the details of his system interface. This can greatly affect the value of the interconnection to the utility grid. As a result, customers with different interfaces (and, therefore, a different portfolio of real options) would be willing to pay different amounts to remain interconnected. A customer with a bi-directional interface has the full portfolio of options available to him. All other things being equal, this configuration has a higher value than its alternatives. However, this does not mean that the utility should be automatically justified in proposing increased interconnection fees in accordance with an increase in customer value. As a regulated business, the utility should not be able to realize additional gains, unless it can demonstrate that it incurs increased costs for more complicated system interfaces. This is a possibility, since a more sophisticated configuration could require higher investment and maintenance costs. However, a utility is able to realize a variety of benefits that probably outweigh these costs. For example, a configuration that enables the DG customer to export power to the grid can alleviate congestion constraints occurring within regions of the grid. This configuration may allow the utility to defer some its distribution and transmission investments. Furthermore, an interface with more embedded options implies, all other things being equal, that the interconnection will be used more frequently. Therefore, DG poses less of a threat to the utility, since it is "less isolated" from the grid. In effect, these DG operators represent a significant customer base for the UDC.

7.4 Interconnection Standardization

The incorporation of precise standards for interconnection could have several potential benefits to the customer. A widely-adopted standard is likely to present a customer with more options, on average, than he would have in a customized configuration. Depending on his ability to exercise these options, a customer may be willing to pay larger interconnection fees. A utility, on the other hand, would need to make additional investments to promote and implement these standards. After all, a utility's primary concern would be in preserving the safety, reliability, and overall integrity of the grid. Therefore, an additional component should be included into the interconnection fee that covers the utility's costs to adopt these standards. The customer would view this portion of the fee as an additional premium for the options that he has just "purchased."

7.5 Stranded Costs

In principle, the emergence of DG could lead to stranded costs for which utilities should be compensated. The stranded investments could include generation, transmission, and distribution assets associated with serving the customer prior to his transition to DG. However, a real-options analysis suggests that these investments may not be stranded after all. For example, a customer who exercises the option to come back to the utility is using the utility's assets. Furthermore, once he returns to the utility he will be using these assets at originally-anticipated levels. A customer that exercises individual options is also using these assets, even if at lower levels than if the utility was his primary electricity provider. Even without exercising these options, the analysis suggests the DG customer is benefiting from the value of holding the portfolio of options the interconnection provides. If regulators recognize the real-option value of DG interconnection and permit utilities the cost of interconnection, this paper suggests that few of these assets will ever be stranded.

Part 8 ✧ Conclusions

In this paper, real-options theory has been used to demonstrate that remaining interconnected to the distribution grid can have considerable value to a DG customer. Some of the options that the customer can exercise include:

- Selling excess power in the spot market.
- Buying supplementary power beyond on-site DG capacity.
- Buying backup power using standby contracts.
- Returning full-time to the utility and selling his DG assets.
- Entering into wheeling contracts.
- Arbitraging the spark spread between gas and electricity markets.
- Buying and selling grid services.

The values of these options are driven by variables such as spot prices, marginal generation costs, marginal production revenues, volatility, interest rates, and maturity structure.

The portfolio of options that a customer holds is influenced by the system interface chosen. For instance, a customer that has the ability to export power has a whole class of options to sell electricity that he would not have otherwise. A customer's portfolio also changes through time, depending on his ability to exercise particular options. For example, during an on-site outage, the customer cannot exercise a sellback option.

The value of interconnection to the grid customer leads to rate policy implications. In general, it may be justifiable to increase a customer's interconnection rates in the presence of an increased number of options. These increases could change the allocation of recoverable costs among different groups of customers.

A key function in a restructured environment is coordinating the interface of DG with the existing utility infrastructure. In particular, the price signals that are sent need to be compatible with the market mechanisms in place. The analysis presented in this paper gives a more consistent approach to this issue than traditional regulatory rate setting.

Our analysis can also be useful in estimating the price elasticity of demand for DG interconnection. By separating different customers into groups that specify how much a customer is willing to pay for his interconnection, one can calculate the sensitivity of the number of DG customers that remain connected with respect to interconnection rates. An estimation of this quantity would give utilities and regulators a measure of the leeway available in setting optimal rates for interconnection.

Real-option valuation of DG interconnection can provide important information for a utility's investment decisions for distribution system upgrades. A utility investment in distribution or transmission equipment can affect the value of a customer's interconnection in a variety of ways. It affords the customer the ability to export more power back to the grid, since local transmission constraints will have been reduced. On the other hand, the clearing of bottlenecks reduces the local demand for the DG customer's power, resulting in lower realized prices.

The value of a DG customer's interconnection is a function of the structure of the industry. The analysis set forth in this paper has not explicitly assumed a particular structure in order to make our economic arguments independent of this feature. Of course, a further study that has the goal of determining a numerical dollar value for the interconnection would have to take this issue into account. Given the rapid changes occurring due to industry restructuring, this could have a significant effect on the value of a DG customer's interconnection. Coupling the qualitative analysis in this paper with a more mathematical treatment that incorporates these details can give thorough insight into these issues.