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Efficient frontiers for electricity procurement by an LDC with multiple purchase options

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Abstract

In meeting its retail sales obligations, management of a local distribution company (LDC) must determine the extent to which it should rely on spot markets, forward contracts, and the increasingly popular long-term tolling agreements under which it pays a fee to reserve generator capacity. We address these issues by solving a mathematical programming model to derive the efficient frontier that summarizes the optimal tradeoffs available to the LDC between procurement risk and expected cost. To illustrate the approach, we estimate the expected procurement costs and associated variances that proxy for risk through a spot-price regression for the spot-purchase alternative and a variable-cost regression for the tolling-agreement alternative. The estimated regressions yield the estimates required to determine the efficient frontier. We develop several such frontiers under alternative assumptions as to the forward-contract price and the tolling agreement's capacity payment, and discuss the implications of our results for LDC management.

Keywords: Efficient frontier; Cross hedging; Forward contracts; Tolling agreements; Partial-adjustment model

1. Introduction

A concomitant of deregulation and related market reforms in the electricity industry in the United States has been the emergence of wholesale electricity spot markets for which highly volatile prices that are at best amenable to imperfect forecasts are the norm. The price volatility and forecast imperfection have two principal sources: (1) the random demand surges that the buyers, notably local distribution companies (LDCs) that must procure electricity to meet customer demand in real time, have to deal with in the face of the generators' upward-sloping electricity supply curve; and (2) random capacity shortages due to unexpected generation or transmission outages that shift the supply curve upwards along a downward-sloping and inelastic electricity demand curve [1–3]. Analogous random changes in the price of natural gas, which is both an input into the electricity generation process as well as a competitive energy source, can further exacerbate the electricity spot-price volatility [4,5]. If unmitigated, such price volatility can financially ruin an LDC with its obligation to serve at regulated rates unresponsive to wholesale spot market prices. A dramatic case in point is the April 6, 2001 bankruptcy of Pacific Gas and Electric

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Company (PG&E), one of the largest LDCs in the United States [6–10]. Both state and federal governments now endorse the important role of risk management in the energy business [11,12].

Recent analyses of an LDC's management of electricity-procurement cost and risk have focused on two procurement alternatives: spot-market purchases and fixed-price forward-contract purchases [13–15]. The latter facilitate risk management and mitigate potential market-power abuses by generators, because they reduce an LDC's dependence on the spot markets [16]. LDC management, however, may be reluctant to enter into a long-term forward contract if the LDC's regulator—and the industry remains subject to partial regulation—can engage in an after-the-fact prudence review that might result in full cost recovery being disallowed [9,17].

To be sure, legislative actions can minimize the need for and use of after-the-fact prudence reviews. For example, California Assembly Bill (AB) 57 that became law on September 25, 2002 directs "the Public Utilities Commission ... to review each electrical corporation's procurement plan in a manner that assures creation of a diversified procurement portfolio, assures just and reasonable electricity rates, provides certainty to the electrical corporation in order to enhance its financial stability and creditworthiness, and eliminates the need, with certain exceptions, for after-the-fact reasonableness reviews of an electrical corporation's prospective electricity procurement performed consistent with an approved procurement plan" (Section 1(c)).

On October 24, 2002, the California Public Utilities Commission (CPUC) issued Decision 02-10-062, which implements AB57. The Decision requires the three large utilities, PG&E, Southern California Edison (SCE) and San Diego Gas and Electric (SDGE), to submit procurement plans for the CPUC's approval. A critical element of such plans is the choice among alternative electricity-procurement options. That is, in meeting its down-the-road electricity requirements: to what extent should the LDC rely on spot markets? To what extent should it rely on forward contracts? And to what extent should it rely on the increasingly popular long-term tolling agreements under which the LDC pays a generator a fee to, in effect, reserve some of the generator's capacity?

We address these issues by first solving the mathematical programming model from which one derives the efficient frontier that summarizes the optimal tradeoffs available to LDC management between procurement risk and expected cost, when it can diversify its electricity purchases through electricity spot markets, fixed-price forward contracts, and tolling agreements. We then put empirical meat on these theoretical bones via an application in which we estimate expected procurement costs and the associated variances that proxy for risk. The estimation entails a spot-price regression for the spot-purchase alternative and a variable-cost regression for the tolling-agreement alternative. The estimated regressions yield the parameter estimates required to determine the efficient frontier. We develop several such frontiers under alternative assumptions as to the forward-contract price and the tolling agreement's capacity payment, and discuss the implications of our results for LDC management.

2. The efficient frontier

Consider an LDC that requires a flat power block of a given megawatt (MW) size to be delivered at 100%, 24 h a day, 7 days a week. The LDC has three procurement alternatives for buying the base-load power that will enable it to meet its resale obligation of serving its retail end-users:

(1) Spot-market purchases from a local hub, such as Mid-Columbia (Mid-C) in the state of Washington. Complete reliance on this alternative, however, exposes the LDC to the risk entailed in potentially volatile spot prices.
(2) A fixed-price forward contract offered by a generator such as Calpine or by a marketer/trader such as Morgan Stanley. The contract obligates the seller to physically deliver, and the LDC to accept, power at a fixed price. Relatively less risk verse than the buyer, the seller absorbs the spot-price risk and may charge the LDC a risk premium to ensure the forward contract's profitability [18,19].
(3) A tolling agreement offered by a generator. The agreement gives the LDC the right, but not the obligation, to dispatch a generation unit specified by the agreement. The LDC pays the generator a fixed per kilowatt (kW) payment for having the capacity available at an agreed fuel conversion rate (i.e., the heat rate in British thermal units (Btu) per kilowatt-hour (kWh)). The LDC supplies the fuel used by the generator, typically natural gas, and absorbs the fuel price risk. Since a generation unit's non-fuel variable cost is negligible, the LDC's least-cost operating decision is to dispatch the leased capacity whenever the per megawatt hour (MWh) fuel cost is less than the electricity spot price in $/MWh. The payment per kW is therefore the call-option value of a one kW capacity with a specific heat rate [20,21]. The capacity payment is equivalent to a fixed MWh payment for each MWh obtained by the LDC, irrespective of whether that MWh comes from the generator or the spot market. Specifically, the capacity charge per MWh is the capacity payment per kW-month multiplied by 1000 and divided by the number of hours (e.g., 744 for January) in the month. Least-cost dispatch decisions by the LDC always result in a variable cost per MWh that is lower and less volatile than the spot price, except under the highly unlikely scenario in which the spot price never exceeds the per MWh fuel cost of the tolling agreement.

Denote the average cost and variance per MWh of spot-market purchases by μ_1 and σ_1^2, respectively, with μ_2 and σ_2^2, and μ_3 and σ_3^2, denoting the average costs and variances