

Rationale for Cost-Based Short-Term Market and Day-Ahead Forward Market for the Wholesale Electricity Spot Market (WESM)

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Introduction

This memorandum describes the rationale for two possible changes to the Wholesale Electricity Spot Market (WESM) rules that will improve the efficiency of the market and limit the risk of significant harm to consumers from the exercise of unilateral market power. The first is a switch from a bid-based to a cost-based short-term energy and reserve market. This approach has been used to transition to an eventual bid-based market in industrialized countries and is a permanent feature of the short-term market in virtually all Latin American countries. The second is a formal day-ahead forward market rather than a four-hour-ahead spot market. Virtually all locational marginal pricing (LMP) markets use a formal day-ahead market where suppliers submit bids for all 24 hours of the following day which the market operator then uses to set prices and generation unit-level schedules for all 24 hours of the following day.

Cost-Based Short-Term Market

One lesson from electricity supply industry (ESI) reform in Latin American Countries (LACs) that has attracted little notice outside of the region is the use of cost-based dispatch and pricing in short-term energy and reserve markets. Virtually all of the LACs operate their short-term electricity market using generation unit-level variable cost estimates approved by the regulator. Chile, the first country to reform in Latin America in the early 1980s, has a cost-based dispatch for its short-term energy market. Currently, Brazil, Peru, Argentina as well as a number of other countries in Central and South America use a cost-based dispatch for their short-term electricity market. In Chile, this policy was adopted in order to focus the market design process on what is generally thought to be the major source of benefits of a wholesale electricity market, the formation of market for long-term energy supply contracts electricity retailers and large customers. The success of Chile in attracting sufficient private investment in generation units to meet its rapidly growing demand for electricity over the past 20 years is evidence of the success of this approach to electricity market design.

In any restructured ESI, a short-term market is necessary to manage imbalances between forward market obligations and actual consumption and production. Because electricity demand can be accurately forecasted far in advance of delivery, there is little need for any net energy to be traded in these short-term markets. In fact, all of the countries with cost-based short-term energy markets electricity retailers are mandated by the regulator to have 100% of their actual retail load obligations covered by long-term contracts.

To operate a cost-based market, all suppliers are required to submit to the market operator and regulator the characteristics of their generation units—heat rates (for fossil

fuel units), the variable operating and maintenance costs, and other demonstrable variable costs such as emissions costs. Fossil fuel suppliers are also required to submit information on their input fuel costs—typically the fuel supply contract associated with the generation unit. This information is used by the market operator to compute a variable cost for the generation unit—the sum of the heat rate times the fuel price plus the variable operating and maintenance cost and other demonstrable variable costs. The methodology used and the inputs provided by the supplier must be approved by the regulator before they can be used by the market operator. This certified generation unit-level variable cost information is then used by the market operator as willingness to supply bid of the supplier in the pricing and dispatch process.

One complication with a cost-based market occurs in a market with hydroelectric generation units that have significant storage capacity. For run-of-the-river hydroelectricity units the fuel component of the unit's variable cost is entered in as zero in the dispatch process when these units are able to operate. For hydroelectric units with significant storage capacity the system operator typically solves a discrete dynamic programming problem using the variable costs of the fossil fuel units and a forecast of the system demand over a long-time horizon (six to eight-teen months) to compute the opportunity cost of water for these units. This opportunity cost then becomes the analogue to the fuel cost in variable cost that enters the short term energy market for the hydroelectric units with significant storage capacity.

Although the short-term market is dispatched using on these variable costs, all unit owners are paid the LMP or market-clearing price in the case non-LMP markets that results from the price-setting process. This implies that each generation unit producing electricity during the hour is paid the increase in the minimized value of the total cost of meeting system demand (using these unit-level variable costs) at all locations in the network associated with one unit increase in the demand for electricity at that location.

Bid-based dispatch and pricing short-term energy markets have two obvious disadvantages. The first is system-wide market power, which is the ability to raise the system-wide price by bidding a willingness to supply curve that exceeds a unit's marginal cost curve at the level of output from the unit that the firm expects to sell in the market. The second problem is local market power, which occurs when a generation unit or set of units are the only ones able to meet a local energy need because of transmission constraints into this geographic area. Under both of these circumstances, unless the market operator can mitigate the bids of these suppliers, prices in a bid-based market can be expected to be substantially in excess of the marginal cost of the highest cost unit operating in the market for the case of system-wide market power, and in a smaller geographic area for the case of local market power.

A cost-based short-term market has a number of advantages for a developing country reforming its ESI. First, it allows the country to avoid the enormous expense of setting up a bid-based dispatch and pricing process. The dispatch algorithm used under the former regime can continue to be used with the only difference being that market operator now also uses it to set the prices each generation unit receives. The cost-based

approach also allows the ISO to avoid the time and expense of formulating a local market power mitigation mechanism, which is essential component of a bid-based ESI and is particularly important in country that does not have a transmission network that can support a competitive wholesale market, as appears to be the case in the Philippines.

Cost-based markets have an additional advantage that reinforces the goal of fostering active forward markets for energy. Assuming that the regulator publicly releases data on the operation of the market, suppliers and prospective new entrants will have a much easier time forecasting spot electricity prices in a cost-based market versus a bid-based market, because they will not have to forecast the ability of suppliers to exercise market power through their bids into the spot market. Although it is extremely difficult to forecast the ability of suppliers to exercise market power by bidding into the spot market, as the California and New Zealand markets vividly demonstrate, the ability of suppliers to exercise unilateral market power is a major determinant of the mean and variance of prices in short-term electricity markets. A cost-based market eliminates the variation in spot electricity prices that occurs from suppliers bidding to raise or lower these prices. This should reduce the cost of suppliers and load-serving entities signing forward contracts, because both sides will have less uncertainty about the time path of spot prices over the duration of the contract. Both parties can compute forecasts of future spot prices using the publicly available market outcomes data along with the cost-based dispatch algorithm.

Although suppliers are constrained to bid their regulated costs in a cost-based market, this does not eliminate the incentive or ability of privately owned suppliers to exercise market power. These attempts to exercise market power simply take a different form. Specifically, suppliers can now be expected to attempt to raise their regulated costs of production that enter the dispatch process or to declare outages from their lower cost units. Consequently, a necessary pre-condition for a cost-based market is that the regulator must have in place a mechanism for determining whether the production costs a supplier reports have been prudently incurred. In addition, the regulator must keep detailed records on unit outages and track these relative to historical and international benchmarks.

Cost-based electricity markets have the increased regulatory burden associated with setting a standard for prudently incurred input costs for each generation unit. To set these regulated costs of production, the regulator must also engage in more extensive data collection and analysis of market performance for input fuels and other inputs to the electricity production process. Bid-based dispatch markets have the problems with system-wide and local market power discussed above. A cost-based market mechanism has also been used in the PJM market in the United States during its initial year of operation as an LMP market in 1998. There is a high risk of market design flaws in the initial stages of operation of any short-term energy market. Starting with a cost-based market and transitioning to a bid-based market limits this risk. The potential benefits of bid-based dispatch and pricing and the huge uncertainty associated with these benefits in an ESI with a less-than-ideal transmission network and nascent regulatory framework

makes cost-based dispatch even more attractive in spite of the regulatory challenges associated with determining each unit's cost of production.

Day-Ahead Forward Market

The major source of benefits to suppliers and the system operator from an LMP market comes from the fact that all relevant operating and reliability constraints are accounted for in the pricing process. Suppliers can benefit from the fact that their unit will be less likely to be asked to move in a physically infeasible manner or to produce electricity across the hours of the day in a manner that significantly increases the expense of operating their unit. The system operator also has the potential to obtain a dispatch that involves less real-time reliability problems. This dispatch can significantly reduce the cost of real-time system operation because there is less need to operate expensive quick-start units in the real-time market and less need to hold generation reserves.

A day-ahead forward market is essential to realizing all of the above benefits of an LMP market. A day-ahead forward market, with a real-time imbalance market is present in all US markets that use LMP. The PJM market began operation without a day-ahead market, but it quickly realized the benefits of such a market and quickly implemented one. A day-ahead forward market typically requires all market participants to submit their supply and demand bids for all 24 hours of the following day before noon of the day of actual operation. The market operator then solves for the optimal dispatch for all 24 hours of the following day, often using a 2 to 3 day dispatch horizon. This process yields hourly schedules for all generation units in the system and hourly LMPs for each of these locations for all 24 hours of the following day. These generation and load schedules are financial binding and typically issued by the mid-afternoon of the day before. This enables generation unit owners sufficient advance notice to meet their generation unit-level hourly schedules for the following day. A real-time or imbalance market then operates the following day. In this market, suppliers and loads purchase and sell energy relative to these day-ahead schedules on an hourly basis.

There are a number of benefits of a day-ahead forward market. First, owners of long-start generation units can schedule these units to supply energy the following day in a more cost-effective manner. Second, generation unit owners can specify ramping constraints and other operating constraints on their units that can be honored and priced in the day-ahead market. Third, the day-ahead scheduling process allows the system operator to optimize the system choosing the hourly operating level of all units during all hours of the following day, rather than simply for a single hour at a time as is contemplated under the current 4-hour-ahead market. Assuming that the same hourly bids are submitted under current WESM design and day-ahead market design, the total as-bid costs for the day-ahead market will be lower than the total daily costs for the 24 distinct 4-hour-ahead markets. This logic implies that the day-ahead market provides greater opportunities for the system operator to optimize the dispatch of generation units to benefit: (1) producers with lower operating costs, (2) consumers with lower day-ahead market prices and (3) the system operator with less real-time reliability problems than the 4-hour-ahead market.

A day-ahead market also limits the opportunities suppliers have to exercise unilateral market power through their bids relative to the case of 24 distinct 4-hour-ahead markets. First, the system operator is able to look at the bids for all 24 hours of the following day to find the least-cost dispatch versus only looking at the bids for a single hour. This longer time horizon between sale and production of the energy increases the competitiveness of the day-ahead market. In addition, the longer time commitment possible under the day-ahead market (24 hours) versus the 24 distinct 4-hour-ahead markets (one hour) implies the suppliers will compete more aggressively to sell energy in the day-ahead market relative to the 4-hour-ahead market. In the US LMP markets, day-ahead prices are substantially less volatile than the real-time market prices because of this increased competition to supply energy on a day-ahead basis.

There are also substantial reliability benefits to a day-ahead market. The market operator can impose the reliability and grid operation constraints for all of the hours of the following day in the day-ahead dispatch. This can reduce the need for operating reserves and reduce the use of expensive quick-start units in real-time. A lower demand for operating reserves reduces total operating reserve costs and the price that the system operator must pay for operating reserves, both which will benefit consumers with lower wholesale electricity costs.

Because it yields a less volatile hourly price, a day-ahead market can reduce the cost to suppliers and retailers to signing forward contracts. The vast majority of long-term contracts in all markets around the world that have a day-ahead and real-time markets clear against the day-ahead market price rather than the real-time market price. In California, a major motivation for the current market redesign process is the implementation of a formal day-ahead price-setting process to facilitate forward contracting and capture the benefits of more efficient generation unit scheduling and real-time system operation made possible by a day-ahead LMP market.