Product Design for Colombia's Regulated Market[1]

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1 Summary

This paper presents a product design for Colombia's regulated market (MOR), which is scheduled to began in 2008. The regulated market consists of residential and other small customers. Currently, regulated customers represent 69% of the total load. Sequel papers will present a proposed auction design and transition to MOR.

I propose a market based on a single load-following product in which each supplier bids to serve its desired share of the Colombia regulated load. Thus, a supplier that wins a 10% share at auction has an obligation to serve 10% of the actual regulated load in every hour of the commitment period. The supplier is paid the MOR clearing price for every MWh of energy supplied. Deviations between the supplier's hourly supply and obligation are settled at the spot energy price or the scarcity price, whichever is lower. The spot settlement price is capped at the scarcity price, since the firm energy market provides price coverage for prices above the scarcity price (about $260/kWh in January 2007 Colombian pesos).

One-hundred percent of regulated load is purchased on behalf of the regulated customers in a sequence of auctions. Thus, MOR together with the firm energy market provides 100% price coverage for all regulated customers. MOR provides price coverage from zero to the scarcity price, and the firm energy market provides price coverage above the scarcity price. This accomplishes two things: 1) it provides rate stability for regulated customers, and 2) it provides revenue stability for suppliers. The result is reduced risk for both sides of the market.

The market is mandatory for regulated customers, but voluntary for suppliers. Mandatory participation on the demand side motivates robust participation on the supply side.

Although only a single product is proposed, the approach readily accommodates multiple customer classes, as needed. Such an extension is desirable if there are significant cost differences in serving different customer classes, say because of different load shapes. However, I find that the cost differences across customers are small, and therefore a single product is best. This will simplify the market, while enhancing liquidity and competition.

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The energy-share product enables load to be fully covered with a single product. For a supplier, the load-following product is natural, since in aggregate suppliers *must* follow load. A supplier is able to manage its exposure to the spot energy price through its portfolio of resources and its portfolio of nonregulated energy contracts. Even for a small supplier without a portfolio of resources or energy contracts, the risk from spot-price exposure is modest.

The proposed product does an excellent job of rate stability. Regulated load is fully hedged from the spot price. This makes sense for customers without hourly meters and demand management systems. However, for large nonregulated customers hourly meters should be required and demand response should be encouraged. The proposal can accommodate participation of such customers by introducing additional products that are based on expected load, rather than actual load. The actual load contract (pay as demand) is based on the customer's actual load in each and every hour of the commitment period. In contrast, the expected load contract is based on the customer's expected load in each and every hour of the commitment period as estimated from its historical load shape and estimated growth over the period.

The expected-load contract hedges price risk, yet still exposes the customer to the spot price on the margin, motivating demand response. Thus, the proposal can be extended to handle nonregulated demand, and in the future, regulated customers capable of demand response.

There are a number of possible choices for the timing and frequency of auctions, and the duration of contracts. These three elements can be adjusted to manage price and credit risk, while minimizing transaction costs. I present several alternatives. I recommend quarterly auctions of 2-year contracts, which are rolling on an annual basis. The use of 2-year contracts is consistent with the most common contract in the bilateral market. More importantly, the approach is simple and yet provides broad time diversification, shielding customers from transient events. One-eighth of regulated load is purchased in each auction. At any one time, two products are active and the customer rate reflects the average of eight auctions equally spaced over a two-year period. Even the auction with the shortest planning period occurs five months before the start of the contract. This means that the auction price will be set before there is much resolution of how severe conditions will be in the following dry season. I believe that this structure strikes the right balance between risk reduction and guarantee cost.

The proposed product complements the other key elements of the Colombian market: the spot energy market and the firm energy market. Combined, MOR and the firm energy market fully cover load. Not only does this reduce risk for both sides of the market, it puts suppliers in a nearly balanced position in the spot energy market. As a result, incentives to exercise market power are greatly mitigated in the spot market.

My next paper will propose an auction design. Once the auction design is specified, I will be in a better position to evaluate the essential objective of efficient price formation.

2 Introduction

As in most electricity markets, the vast majority of Colombia's energy is settled according to energy contracts with terms that are much longer than the hourly spot market. Energy contracts often have durations of one or two years, and sometimes more. These energy contracts benefit both supply and demand. Both sides of the market are able to lock in a price, and thereby reduce price risk from the more volatile spot market.

Unfortunately, the existing energy contracting market has high transaction costs, as a result of non-standard contracts, poor price formation, localized contracting, lack of transparency, and other factors. Evidence of a problem is seen in the frequent occurrence of higher contract prices for regulated customers compared with nonregulated customers, which is unexplained by load shapes, credit risks, and other factors.

CREG has proposed an organized regulated market (MOR) to address these problems. The goal of MOR is to promote efficient price formation in an energy contract market for regulated customers, both residential and small commercial. The market should dramatically lower transaction costs as a result of standard contracts and robust price formation in a transparent, national market.

This paper proposes a product definition for such a market. Product design is the critical first step in the design of any market. It defines what is being traded. Good product design can play an important role in reducing complexity and increasing liquidity in the market.

The paper is organized as follows. First, I discuss the purpose of the market. Then I consider elements of the Colombia electricity market that are relevant to product design. Next, I argue for an especially simple product design. I then examine other features of the product, such as the timing and frequency of purchase, and the duration of commitment. Finally, I respond to common questions from industry.

Many important issues are beyond the scope of this initial study. The details of auction design will be addressed in a subsequent paper, as will important transition issues and more detailed analysis of the integrated product and auction design. Critical issues of qualification and credit requirements, as well as other contractual arrangements will be addressed elsewhere. Finally, the focus is on the regulated customers, although I will provide some preliminary discussion of how the nonregulated customers may participate in a centralized market.

3 Purpose of the market

Many objectives must be considered in the design of MOR. These can be grouped into seven interrelated categories: efficient price formation, transparency, neutrality, risk management, liquidity, simplicity, and consistency.

- *Efficient price formation*. The market should produce reliable price signals based on market fundamentals. It should enhance competition and mitigate market structure problems. It should produce market-based rates for regulated customers.
- *Transparency*. The market should be highly transparent. Offers should be comparable. It should be clear why one supplier offer is accepted and another rejected. It should result in prompt regulatory review and approval, and encourage regulatory certainty.
- *Neutrality*. All suppliers should be treated equally, and all demanders should be treated equally.
- *Risk management*. It should reduce risks for both supply and demand by providing rate stability, yet be responsive to long-run market fundamentals. The market should shield participants from short-term transient events, and address counterparty risk.
- *Liquidity*. The market should promote a secondary market, including a liquid market for the primary product, as well as derivative products of both longer and shorter term.

- *Simplicity*. The market should be simple for participants, for the system operator, and for the regulator.
- *Consistency*. The market should be consistent with the other key elements of the Colombia setting. The most important of these are the spot energy market and the firm energy market. It also should be consistent with, or improve upon, the best-practice in other electricity markets.

Fortunately, these objectives are largely complementary with one another. Hence, it is possible to design the market to satisfy all of these objectives.

4 The Colombia setting

Colombia has a hydro-dominated electricity market. Roughly 80% of its energy comes from hydro resources, 67% of its capacity, and 50% of its firm energy—energy in an exceptionally dry period.

The cornerstones of the wholesale electricity market in Colombia are the spot energy market and the firm energy market. The spot energy market is a single-zone hourly market that determines the spot energy price in every hour as well as the efficient dispatch of resources. Supplier offers are submitted one day ahead of dispatch. The firm energy market is a long-term market to assure that there will be sufficient energy resources, even in an exceptionally dry period. The firm energy market pays suppliers a reliability charge per MWh of firm energy provided. Suppliers have an obligation to supply energy at prices above a scarcity price. Hence, the firm energy market provides price coverage for all prices above the scarcity price.[3] MOR is intended to provide the residual price coverage for prices from $0 up to the scarcity price, which currently is about $260/kWh in January 2007 Colombian pesos (US$125/MWh).

As is true of all electricity markets, the wholesale market in Colombia is not perfectly competitive. The largest-four companies provide about two-thirds of both the capacity and firm energy. Market shares of firm energy are shown in Table 1.

[3] The scarcity price is established by CREG and updated monthly based on the variation of the Fuel Price Index (the New York Harbor Residual Fuel Oil 1% Sulfur LP Spot Price). It has a double purpose. On the one hand, it indicates the time when the different generation units or plants will be required to fulfill their firm energy obligations, which happens when the spot price exceeds the scarcity price, and on the other hand, it is the price at which this energy will be paid.

Table 1. Company firm energy shares and market concentration

Company	ENFICC Declared (GWh)			Market	
	Hydro	Thermal	Total	share	HHI
Emgesa	10,419	2,373	12,792	21%	455
Epm	8,523	3,295	11,818	20%	388
Corelca		9,873	9,873	16%	271
Isagen	5,099	2,327	7,426	12%	153
Epsa	1,487	1,655	3,142	5%	27
AES Chivor	2,925		2,925	5%	24
Gensa	57	2,594	2,651	4%	20
Termoflores		2,189	2,189	4%	13
Termoemcali		1,533	1,533	3%	7
Merielectrica		1,404	1,404	2%	5
Termotasajero		1,349	1,349	2%	5
Termocandelaria		1,062	1,062	2%	3
Proelectrica		708	708	1%	1
Menores	689		689	1%	1
Urra S.A	438		438	1%	1
Total	29,637	30,363	60,000	100%	1,374

I calculate the Herfindahl-Hirschman Index, HHI, for firm energy. HHI is a commonly accepted measure of market concentration. The firm energy HHI is 1,374. Thus, the Colombian electricity market is moderately concentrated.[4]

These numbers are consistent with most electricity markets in the U.S. and elsewhere. Moderate concentration means that the market design should recognize the potential for market power and attempt to mitigate its abuse.

The market concentration picture would be much worse if transmission was inadequate to support a single-zone system. To maintain consistency with the spot market and firm energy market, I only consider a single-zone energy contract market. However, this does not preclude the possibility of multiple customer classes. The essential element is that all suppliers can compete for any of the customer classes, regardless of the supplier's location.

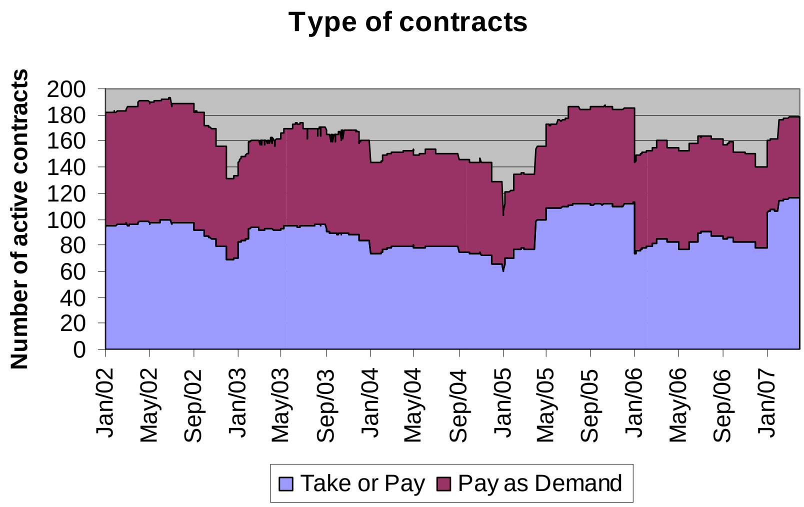
5 Product definition: energy share of regulated load

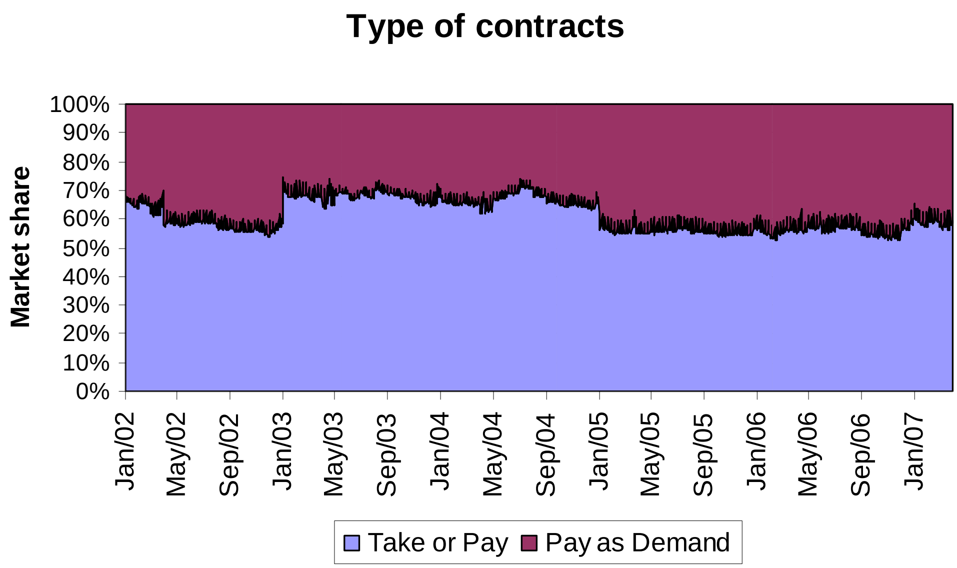
I propose a market based on a single load-following product in which each supplier bids to serve its desired share of the Colombia regulated load. Thus, a supplier that wins a 10% share at auction has an obligation to serve 10% of the actual regulated load in every hour of the commitment period. The supplier is paid the MOR clearing price for every MWh of energy supplied. Deviations between its hourly obligation and its supply are settled at the spot energy

[4] The U.S. Department of Justice and the FERC, for example, use the HHI for evaluating mergers. A market with an HHI less than 1,000 is considered to be competitive, one with an HHI between 1,000 and 1,800 is considered to be moderately concentrated, and one with an HHI of 1,800 or greater is considered to be highly concentrated. To compute the HHI, one sums the squares of the sellers' market shares. The HHI can range from a minimum of close to 0 to a maximum of 10,000. An HHI approaching zero would indicate near-perfect competition, with many thousands of sellers with negligible market shares. An HHI of 10,000 indicates the existence of a single firm with 100% market share.

price or the scarcity price, whichever is lower. The spot settlement price is capped at the scarcity price, since the firm energy market provides price coverage for prices above the scarcity price.

Thus, the product is a version of the familiar pay-as-demand contract. The figures below show that pay-as-demand is a significant contract form both in number and energy share.





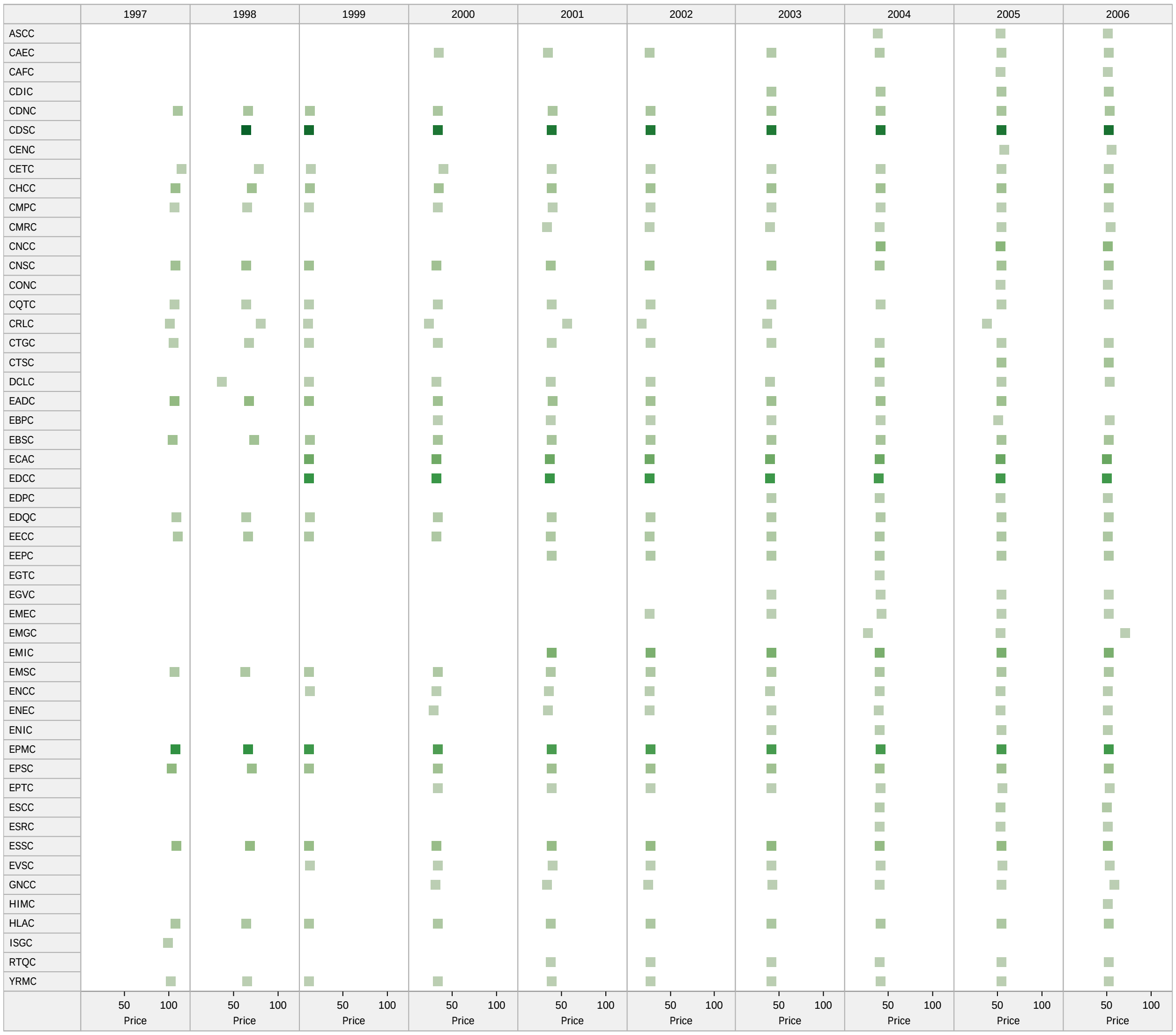
The regulated load is the aggregate load in the regulated market, including all 44 Load Serving Entities (LSEs) in Colombia. There are three alternative ways to handle contractual arrangements. In the first, a clearinghouse is established to manage the contracting. The clearinghouse would be the supplier's counterparty in the contract signed after the auction. In the second, as in the spot market, there is a master agreement, and a special scheme of guaranties, thus avoiding the need for a clearing house. In the third, the bundled product is purchased at auction, but the individual LSEs would be the supplier's counterparty. Thus, at the conclusion of the auction, each winning supplier would sign 44 contracts, one with each LSE for the share of load won in the auction. Which approach is better depends on legal matters that are beyond the scope of this study. In both cases, there is a single standard contract form and the auction mechanics are identical.

One-hundred percent of regulated load is purchased on behalf of the regulated customers in a sequence of auctions. Thus, MOR together with the firm energy market provides 100% price coverage for all regulated customers. MOR provides price coverage from zero to the scarcity price, and the firm energy market provides price coverage above the scarcity price.

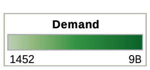
The market is mandatory for the LSEs, but voluntary for the suppliers. The reason for this distinction is simple. Mandatory participation by the LSEs provides regulatory certainty that benefits rate payers. Suppliers know that a large quantity of energy will be purchased and this motivates their participation. Some suppliers, especially small niche companies, may prefer to specialize in servicing the nonregulated market. Hence, participation on the supply-side is voluntary.

The approach readily accommodates multiple customer classes. This would be appropriate if different customer classes have substantially different costs. However, there is little variation in costs across the LSEs. This is seen in the figure below which shows average cost for each LSE for each of the last 10 years. Therefore, I recommend a single customer class for all regulated load.

Average cost ($/kWh) by LSE and Year



Price for each LSE broken down by Year. Color shows details about Demand. The data is filtered on Days, which ranges from 350 to 366.



The approach also eliminates all the problems of LSE purchase from its affiliate. The LSE cannot favor its affiliate, since all suppliers compete on the same basis for all regulated load. The procurement process is transparent, nondiscriminatory, and clearly defined. It is administered by an independent third-party.

5.1 Comparison with CREG's initial proposal

The "energy share" product definition is a major simplification from CREG's initial proposal, which involved two time-of-day products that did not fully cover load and therefore required a second market to cover the residual. There are numerous advantages to the simpler approach.

- *Improved liquidity*. A single standard product improves liquidity. This in turn promotes a stronger secondary market, both for the product and for derivatives of the product, such as monthly slices or long-term strips.
- *Enhanced competition*. Competition is enhanced, since all suppliers are competing for the same liquid product.
- *Reduced risk*. By providing 100% price coverage in combination with the firm energy market, regulated customers are fully hedged from spot price volatility. Suppliers too are able to sell forward, thus avoiding spot price volatility. Both sides of the market can further reduce exposure to transient events through the timing of purchase and sale, as discussed below. Finally, the aggregate regulated load is better understood and less volatile than less aggregated products.

One other area where I amend CREG's initial proposal is in the timing and frequency of auctions. As I discuss below, I recommend a greater frequency of auctions and a long-term commitment. The motivation for these changes is to further reduce supplier and customer risk from transient events.

In many other respects the proposal here is the same as CREG's initial proposal. Most importantly, there is a single centralized market with a standard contract. The product is bundled across all LSEs, rather than LSE specific. These features are essential to reducing transaction costs, improving liquidity, and enhancing competition.

6 Further issues

I now discuss a number of further issues.

6.1 Cross-subsidies

Different customers have different load shapes, both over the day and over the year. To the extent that these differences result in large cost differences, then it may be inappropriate to bundle the customers together into a single class. Fortunately, the cost differences across LSEs are small, as seen in the figure above showing the average cost of each LSE. Thus, it is appropriate to have a single customer class.

I estimated the cost differences from historical data over the last ten years. This likely overstates the cost differences. The reason is that recent market improvements, such as the firm energy market and the proposed MOR, will likely flatten prices over the day. Hence, the cost difference from different load shapes will be reduced. The recent market innovations are likely to flatten prices over the day, because 1) prices will be capped at the scarcity price, and 2) incentives for spot market manipulation will be greatly reduced. This should tend to flatten prices over the day, consistent with a competitive hydro system with ample capacity.

6.2 Load-following obligation is not ideal for all generators

In aggregate, generators must follow load, so load-following contracts are natural. They also allow full coverage of load with a single, simple product. However, some suppliers may not wish to follow load. For example, a low-marginal-cost baseload plant may prefer horizontal energy blocks (24-7 take-or-pay energy). MOR's use of load-following contracts would not prevent such a supplier from adopting such a contract—it would simple require the supplier to look for such a contract among the nonregulated customers or among other suppliers. In addition, the supplier with the baseload plant likely has other plants, such as hydro or peakers, which enables the supplier to follow load with its portfolio of resources. Indeed, a supplier typically invests in a portfolio of resources that allows it to follow load, again for the simple reason that that is what suppliers *must* do in aggregate. For such a supplier, the load-following contract is not a problem.

For a supplier without a balanced portfolio of plants capable of following load, the energy share product is still not much of a problem. It just means that in some hours the generator will over-perform and in some hours it will under-perform. As a result, it will receive a net reward or penalty, based on its aggregate performance. Aside from issues of market power, the load-following obligation does not distort at all the supplier's bidding incentives in the spot energy market or its dispatch. For example, a hydro resource with limited water will want to bid to supply in the highest priced hours, irrespective of the load-following obligation; a low-cost baseload resource will want to supply 24-7, irrespective of its obligation.

The consequence of a poorly balanced portfolio for a supplier is simply slightly greater risk, because its obligation will not match its output. There will be greater exposure to the spot price and greater risk. Importantly, there is no distortion to the bids or the dispatch, aside from issues of market power.

An example will help clarify the implications of an obligation/resource mismatch. I keep the example especially simple to convey the idea—it readily generalizes to realistic cases.

Assume there is no risk in the market as everyone knows future load precisely, generators never break down, and both the spot market and MOR are competitive. Assume load is 90 MW for 80% of the time, and 140 MW for the remaining 20%, so the average load is 100 MW. Assume the baseload marginal cost is $20 and peaker marginal cost is $100.

With competitive entry there is 90 MW of baseload and 50 MW of peaker. The spot market prices equal the marginal cost of the marginal resource: $20 80% of the time and $100 20% of the time. Thus, the time-average spot price is .8 (20) + .2 (100) = $36. The load-weighted average spot price is [.8 (90)(20) + .2 (140)(100)]/100 = $42.40. Hence, the competitive auction price is $42.40, the expectation of the spot price (load weighted).

The 90-MW baseload plant sells 90% of load, which is 81 MW off peak and 126 MW on peak. It will overproduce by 9 MW 80% of the time and under-produce by 36 MW 20% of the time. Its net deviation payment is

.8 (9)($20) – 0.2 (36)($100) = – $576, or – $6.40/MWh.

Thus, the plant's payment is $42.40 – $6.40 = $36/MWh, which is exactly what the baseload unit would earn in a competitive spot market, generating 90 MW in every hour. The baseload plant is indifferent between selling in MOR or supplying in the spot market. It makes a profit of $16/MWh, which contributes to its fixed cost. The residual fixed cost is covered in the firm energy market.

Now consider the 50-MW peaker plant, which sells the remaining 10% of the load, which is 9 MW off peak and 14 MW on peak. It will under-produce by 9 MW 80% of the time and overproduce by 36 MW 20% of the time. Its net deviation payment is:

– .8 (9)($20) + 0.2 (36)($100) = + $576, or + $57.60/MWh.

Thus, the peaker's payment is \$42.40 + \$57.60 = \$100/MWh, exactly what it would earn if it instead sold its output in the spot market. The peaker is also indifferent between selling in MOR or supplying in the spot market. Either way its payment just covers its variable cost. Its fixed cost is recovered in the firm energy market.

This example demonstrates that the load-following obligation does not distort the mix of plants, aside from issues of risk and market power.

Based on my analysis of risk in the firm energy market (Cramton et al. 2006), I tentatively conclude that the risk issue should not be a concern here. Companies can manage risk through 1) a portfolio of resources, and 2) a portfolio of nonregulated contracts, and even when the company lacks a portfolio, the spot price risk is modest. Moreover, the risk from obligation/resource mismatch should be less important in the future, as prices over the day will tend to flatten, as a result of the recent and proposed market innovations.

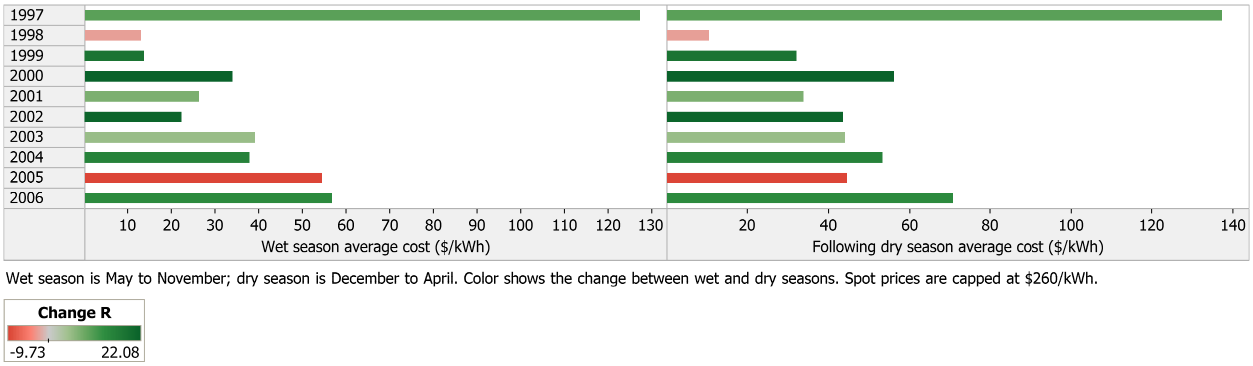
6.3 Is the price signal to the customer strong enough?

The proposal earns high marks for rate stability. The customer sees a flat price. The rate reflects long-term fundamentals and possibly differences in customer classes as discussed above. In addition, the rate can reflect seasonal factors. If costs, as reflected in expected spot prices, differ on a regular basis by season, then it may make sense to introduce a seasonal factor, which scales prices up in the dry season and down in the wet season. Such an extension is easily introduced.

Seasonal factors often are used in the U.S. to scale customer rates to better reflect long-run costs. Rates are scaled up in the three summer months (peak season), and down in the nine winter months (off-peak season). For example, in New Jersey, the summer factor is about 1.15 and the winter factor is about 0.95. Hence, customers pay 15% extra in the summer time and 5% less in the nine summer months. These factors are determined from long-run cost differences in the two seasons. Such a rate design is more efficient than a single flat rate throughout the year. Even with monthly meter reading, customer demand is able to respond to the higher rates in the high-cost season (summer).

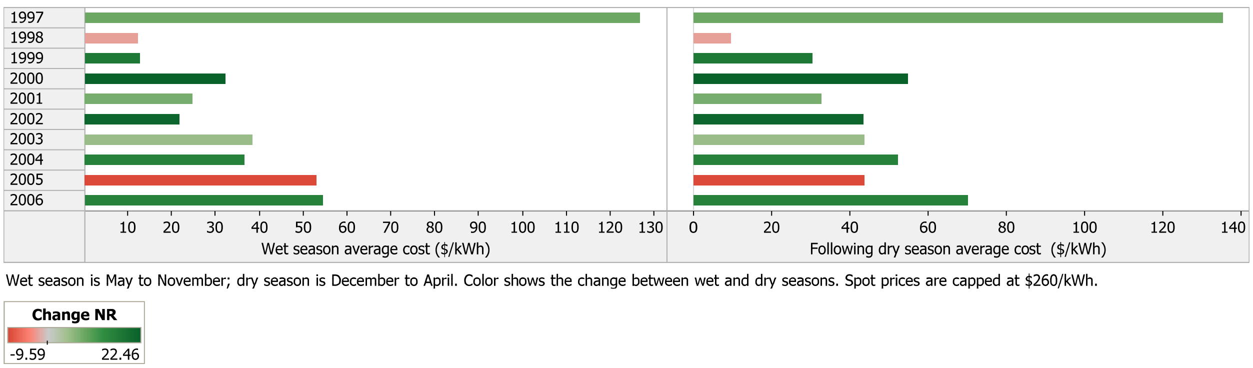
I have studied expected cost, based on the spot energy price, during the wet and dry seasons over the last ten years. For regulated customers, I find that there is a 19% difference in expected cost between the dry season (December to April) and the wet season (May to November). This implies seasonal factors of .92 in the wet season and 1.11 in the dry season. The figures below show the average cost in the wet and dry seasons in each of the last ten years for both the regulated and nonregulated load. Color shows the change from wet to dry season: dark green indicates a large increase in cost from wet to dry; orange indicates a large decrease in cost.

Average cost in wet and dry seasons, regulated market



Wet season is May to November; dry season is December to April. Color shows the change between wet and dry seasons. Spot prices are capped at $260/kWh.

Average cost in wet and dry seasons, non-regulated market



Wet season is May to November; dry season is December to April. Color shows the change between wet and dry seasons. Spot prices are capped at $260/kWh.

The justification for seasonal factors is much weaker in Colombia than in the U.S. In the U.S., the actual cost in the summer is nearly always higher than in the winter; hence, charging a price that better reflects expected costs will also better reflect actual costs. In Colombia, high prices in the dry season are rare, since it is only in exceptional dry seasons that water is scarce. Thus, charging a higher price in all dry seasons may in fact elicit the wrong demand response. A further issue with seasonal factors is that they adversely impact a customer's cash flow—many customers prefer to pay a roughly constant amount in each month. Cash flow especially is important in Colombia where the vast majority of residential customers are poor. For these reasons, I recommend against the use of seasonal factors.

The problem with a flat rate is that it eliminates any incentive for demand response during periods with a high spot price. Short-term transient spikes are neither seen nor felt by the customer. This is appropriate for small customers today. Since these customers do not have an hourly meter, it makes little sense to expose them to the spot price: the customer's short-term demand response cannot be measured, and therefore cannot be rewarded.

However, the world is changing. It is inevitable that over the next twenty years that low-cost hourly meters will be available at the residential level in Colombia (California already has these meters in place). In addition, customers will have demand management systems that can make effective use of the hourly price signals. It would be nice if today's MOR is able to handle such future innovations. Fortunately, the answer is that it can. All that is required is a simple change in the standard contract. Rather than have the contract follow *actual* load, it follows *expected* load for the customer class. In this way, load is still fully hedged with respect to its expected purchase, but deviations from the expected purchase are settled at the spot price. The customer sees and feels the spot price *on the margin,* motivating demand response, but its exposure to the spot price is limited to the difference between its actual and expected load.

Once hourly meters are installed and demand management systems are available at the residential level, it will make sense to switch to expected-load energy contracts. Until that time, the actual-load energy contracts are best.

6.4 Regulated demand participation

Under the proposal the LSEs must purchase 100% of regulated load in the MOR auction. That is, on the demand side, the auction is mandatory.

Related markets in the U.S. typically allow regulated customers to switch out of the regulated market. This option is called “retail choice.” Retail choice has been a failure throughout the U.S. It has led to complex rules and gaming behavior by both customers and retail providers. To my knowledge there are not any instances of a successful retail choice program. Perhaps the most successful are the ones that have done no harm, such as in Illinois, where retail choice has been available for five years and yet there has not even been a single company to apply to offer the retail service in competition with the utility.

Given the U.S. experience, I recommend against a retail choice program at this time. If one is introduced, the rules for switching out of and into the regulated market will need to be developed with care to avoid the gaming problems seen in the U.S. markets. Choice, to the extent it is exercised, should be exercised directly by the customer, rather than the LSE.

Another issue is the boundary between the regulated and nonregulated customers. It will make sense to examine both how the boundary is defined and how it evolves over time. My view is that regulated customers should be identified primarily by size (average energy use). Small, less sophisticated, customers should be regulated, and large, more sophisticated, customers should be nonregulated. Near the boundary, there may be some sophisticated regulated customers. It may make sense to allow these customers to choose whether to participate as a regulated or nonregulated customer, subject to switching restrictions.

It may make sense for large regulated customers to participate actively in the auction to provide some demand response in the regulated market. This mitigates supplier market power, and is easily accommodated by accepting demand curves from large regulated customers two weeks before the auction. The auctioneer then forms the aggregate demand for regulated load, which is what is purchased in the auction. Large customers participating in this way may purchase less than 100% of their load in the auctions.

Presumably, a large sophisticated buyer would reduce demand at high prices and take some chances on the spot market or a subsequent auction. This is a good thing if such participation decisions are made directly by the customer, rather than the LSE or a regulator. I believe it would be counterproductive for the LSE or regulator to attempt to act in a sophisticated way on behalf of the customer. Any demand response decision of the LSE or regulator inevitably would be second-guessed.

Over time, I would anticipate that the boundary shift toward more nonregulated customers, as the economics of demand response systems become more attractive.

6.5 Nonregulated demand participation

My initial thinking was that large customers should be excluded from MOR. These customers can take care of themselves, just as they have in the past. This simple approach avoids cross-subsidies to large customers with undesirable load shapes and/or poor credit. Such customers would readily enter MOR, and increase rates for regulated customers.

However, a better alternative is to expand the centralized market to include both regulated and unregulated customers. The regulated customers participate as described above, and the nonregulated participate as separate customer classes. Nonregulated customers would be grouped into one or more standard customer classes, based on load shape. Credit issues would be addressed with guarantees. Each customer class would be a separate product in the auction. Alternatively and preferably, a single product may be used that is properly indexed for load shape.

The auction for nonregulated load would occur simultaneously with the auction for regulated load, and indeed promote supplier substitution across the two products.

The standard contract for nonregulated customers would differ in two important respects from the regulated customer contract. First, credit and guarantee issues would be dealt with differently. Second, the contract would be an expected-load energy contract, rather than a actual-load energy contract, and hourly meters would be required. Nonregulated customers, then, would be hedged for their expected load, but would be exposed to the spot price on the margin. This motivates demand response and the acquisition of demand management systems.

Participation by nonregulated customers would be voluntary. These customers would apply two months before the auction. One week before the auction, each qualified customer would specify a demand curve—the quantity it desires to buy at various prices. Before the auction, the aggregate demand for each customer class would be revealed together with the aggregate load shape for the customer class.

Allowing the nonregulated demand to participate in this way has many advantages. First, it lets the nonregulated demand take advantage of the centralized market and standard contracts without harming the regulated customers. Second, it motivates demand response and demand management by the large customers. This will provide immediate benefits, and in addition, establish a path for subsequent innovation by residential customers over the next decades.

As I will describe in the sequel paper, the auction design can also be adapted to accommodate the nonregulated customers. Regulated customers benefit from the voluntary participation of nonregulated demand. In particular, the nonregulated demand response helps mitigate supplier market power in the centralized market.

6.6 Qualification and credit

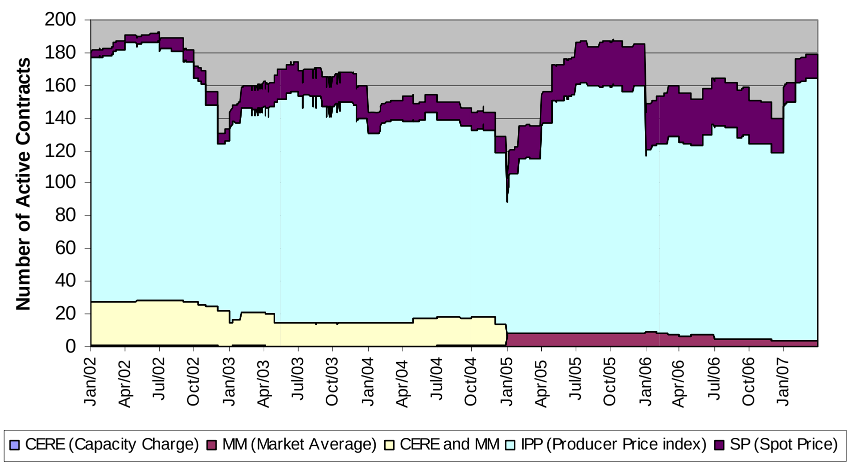
Qualification and credit issues are beyond the scope of this study. They are, however, crucial to the success of the market. They also are interrelated with the product design. For example, contracts of longer duration would require larger guarantees. Thus, the choice of a longer-term contract needs to reflect the tradeoff between reduced price risk and the cost of a larger guarantee.

Guarantees should be kept as small as possible and still satisfy a high level of security. For suppliers, it is possible to reduce the size of the guarantee to the extent the energy contract is backed with physical resources and firm fuel. It is important to take advantage of these factors in setting guarantee levels. Otherwise, guarantees might be so high so as to discourage participation from new entrants. These new entrants are important in promoting both competition and innovation.

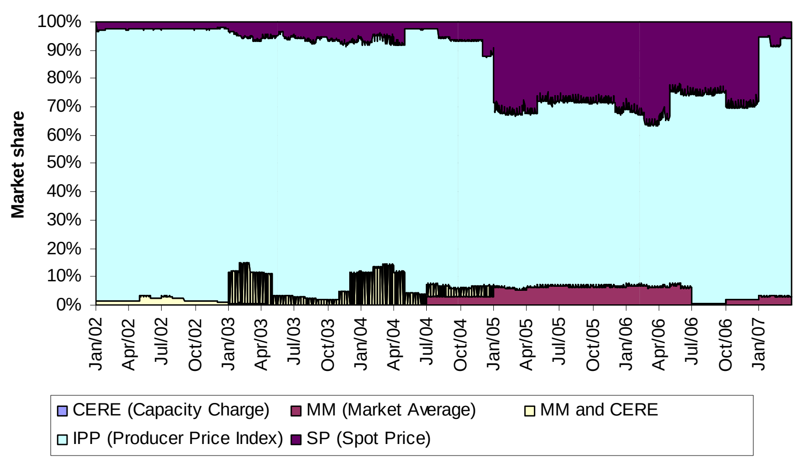
6.7 Price index

To limit inflation risk, I recommend that for multi-year commitments that the price be indexed for inflation. I recommend the Colombian Producers' Price Index (IPP). This is consistent with the majority of existing contracts, as shown in the two figures below.

Number of active contracts by price index



Market share (energy basis) of active contracts by price index



6.8 Lot size

I recommend a small lot size, say 0.1% of regulated load—about 6 MW. This gives suppliers great flexibility in expressing quantity. In France, the lot size is 1 MW. New Jersey has a large lot size, about 100 MW. I see no advantage to this large lot size.

7 Planning, commitment, and frequency

The final elements I address in this report are the timing and frequency of the auctions, as well as the duration of the contracts. As will become clear, these elements are best discussed together, since they are closely intertwined. First some definitions:

- *Planning period* is the time between the auction and the beginning of the commitment period. It gives the supplier the opportunity to make adjustments to its resources and other contract positions in order to be ready for its obligation. It also impacts how much uncertainty is resolved before the commitment begins, and thus has implications for risk. Longer planning periods increase price stability by removing more transient events from the price. However, guarantees must be held longer to manage credit risk.
- *Commitment period* is the contract duration—the time between the beginning and end of the commitment. The commitment period also impacts risk. As with longer planning periods, longer commitment periods increase price stability by removing more transient events from the price. Longer commitment periods also allow suppliers to secure financing and make longer term fuel commitments. However, guarantees must be larger to manage credit risk.
- *Frequency* is how often auctions are conducted. Frequency also impacts risk. More frequent auctions tends to reduce risk, since less volume is purchased at any one time. However, transaction costs increase with the frequency of auctions.

An important goal of the design is to use these three instruments to manage price risk and credit risk, while minimizing transaction costs. This is as much art as science. There are many possibilities that will work well. I now consider six reasonable options, and discuss the advantages and disadvantages of each. The six options are grouped into four broad categories:

1. Single auction for a single commitment period
2. Multiple auctions for a single commitment period with multiple planning lengths
3. Rolling auctions with a single commitment length and a single planning length
4. Rolling auctions with multiple commitment lengths

Each option is presented in its steady-state form, assuming the approach has been used for a long time. Typically, there needs to be a transition period of one or more years in which the schedule of auctions and the volumes are adjusted to reflect the situation at the start. This will be addressed in a third paper.

The six options are presented assuming contracts follow the calendar year, but this may be some alternative “power year.” It makes little difference in the discussion below.

7.1 Single auction for a single commitment period

The simplest option is a single auction for a single commitment period. An annual version is shown below.

Option 1. Annual auction for 1-year commitment (6-month planning period)

Auction date	Yr	Energy commitment			Planning
		2009	2010	2011	Months
Year	Qtr	1 2 3 4	1 2 3 4	1 2 3 4	ahead
2008	1				
	2		One product at any one time.		
	3	100%			6
	4				
2009	1				
	2				
	3		100%		6
	4				
2010	1				
	2				
	3			100%	6
	4				

With this option there is a single product at any one time. The advantage is simplicity. Suppliers do not need to decide when to sell—there is only one opportunity. The disadvantage is that 100% of regulated load for an entire year is purchased at one time. This increases risk, since the rate will reflect the market fundamentals at a particular instant, rather than an average of market fundamentals over time.

Many market participants voiced concern with such an approach. I agree—there are too many eggs in one basket.

7.2 Multiple auctions for a single commitment period with multiple planning lengths

The second option addresses the difficulty of the first. Multiple auctions are held for the single commitment period. An example with quarterly auctions is shown in Option 2.

Option 2. Quarterly auction for 1-year commitment with variable planning lengths

Auction date	Yr	Energy commitment			Planning
		2009	2010	2011	Months
Year	Qtr	1 2 3 4	1 2 3 4	1 2 3 4	ahead
2008	1	1/4			12
	2	1/4	One product at any one time.		9
	3	1/4			6
	4	1/4			3
2009	1		1/4		12
	2		1/4		9
	3		1/4		6
	4		1/4		3
2010	1			1/4	12
	2			1/4	9
	3			1/4	6
	4			1/4	3

In this option, the annual load is purchased over four quarterly auctions. Each auction procures one-quarter (25%) of the load. There is still only a single product at any one time, but the customer rate reflects the average of four prices from four different auctions taking place over the entire year. This provides the time diversification absent in the first approach.

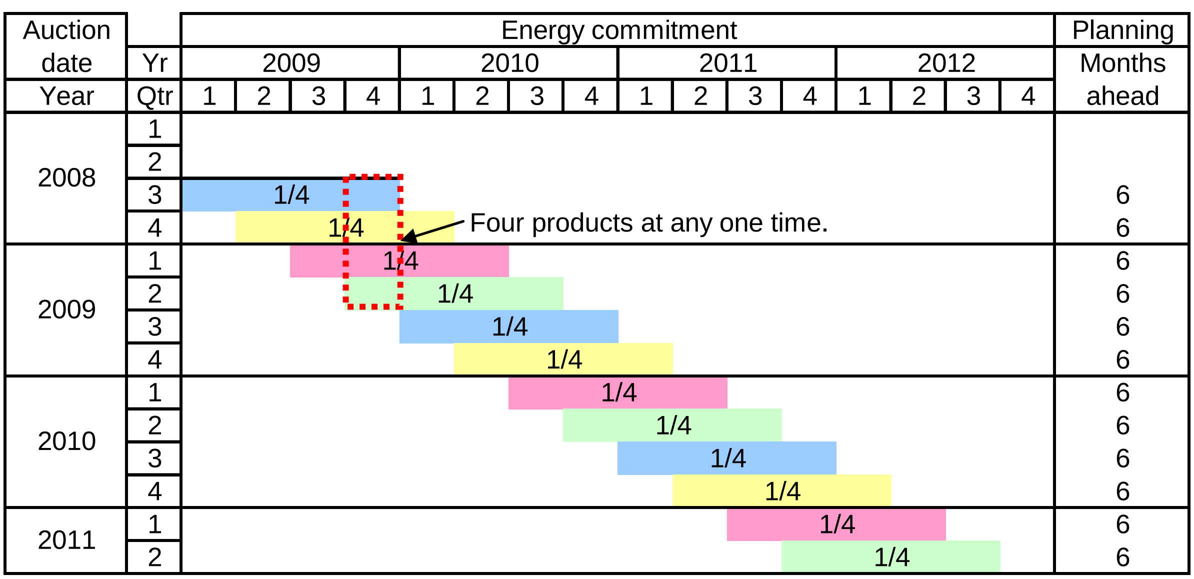
To accommodate this option, the planning period must differ with each auction, starting for example with 12 months for the first and down to 3 months for the last. I view this as an advantage, since it will accommodate the different planning needs of different suppliers. Also the conditional distribution of spot prices likely varies in important ways, depending on the length of the planning period, so different planning lengths provides further diversification.

The only difficulty with multiple auctions for the same commitment period is that the supplier must decide when to sell. The same product is sold at four different times. This may make the supplier's problem more difficult, but it does give the supplier greater flexibility in contracting throughout the year, which should improve the supplier's ability to manage risk. One simple strategy, which would work well for many suppliers, would be to sell one-quarter of its intended annual total in each of the four auctions.

7.3 Rolling auctions with a single commitment and planning length

A variation of the second option is to have rolling auctions. This allows a fixed planning period, but expands the number of products. Option 3 has rolling quarterly auctions with a one-year commitment. Like in Option 2, one-quarter of the load is purchased in each auction, and each auction is for just a single product.

Option 3. Rolling quarterly auction for 1-year commitment with 6-month planning length

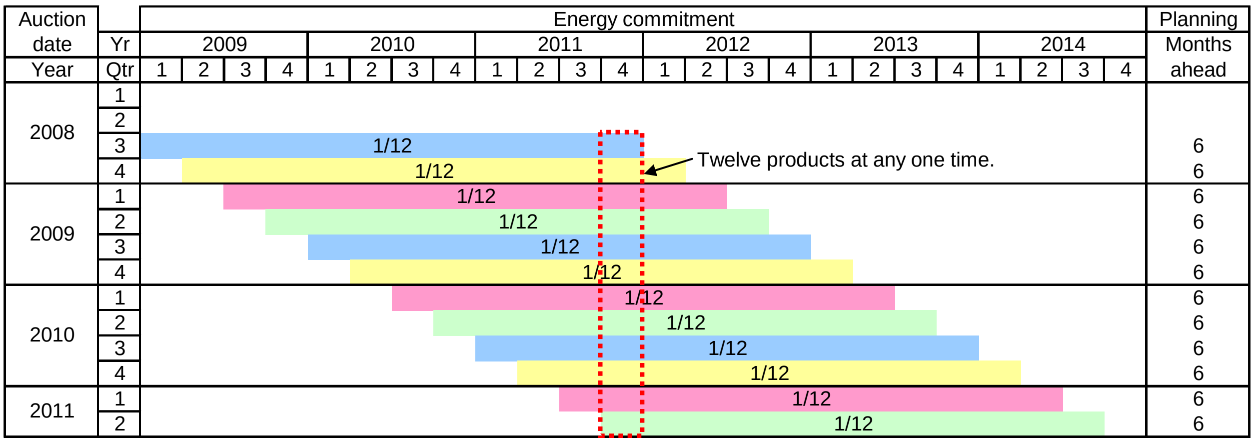


Option 3 provides time diversification—the customer rate at any time is based on the average of four distinct auction prices. The difference is that the year's load is covered with four products, rather than one. This may reduce liquidity, since there are many more products. However, the products are closely related, so I do not believe that liquidity is a major issue. Indeed, the rolling product structure gives suppliers an easy way to manage quantity variation over the year by adjusting its quantities for the quarterly products. Thus, there may be less need to rely on derivative products.

Both option 2 and 3 are sensible.

Option 4 is another variation: rolling quarterly auctions with a 3-year commitment. With the longer duration and the same frequency, there is now even greater time diversification. The customer rate is the average of twelve prices over a three-year period. The downside is that there now are 12 products covering load at any one time. Also the 3-year commitment may be well-suited for some, but may not be best for everyone.

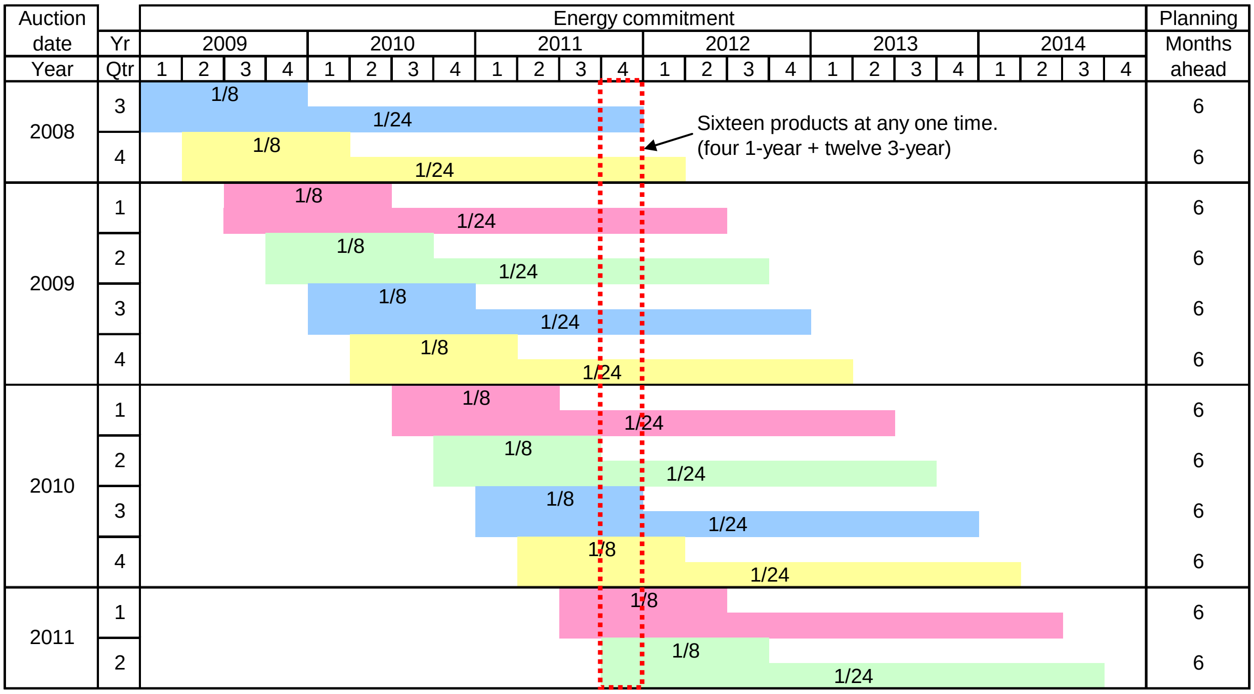
Option 4. Rolling quarterly auction for 3-year commitment with 6-month planning length



7.4 *Rolling auctions with multiple commitment lengths*

Option 5 introduces the flexibility of multiple commitment lengths.

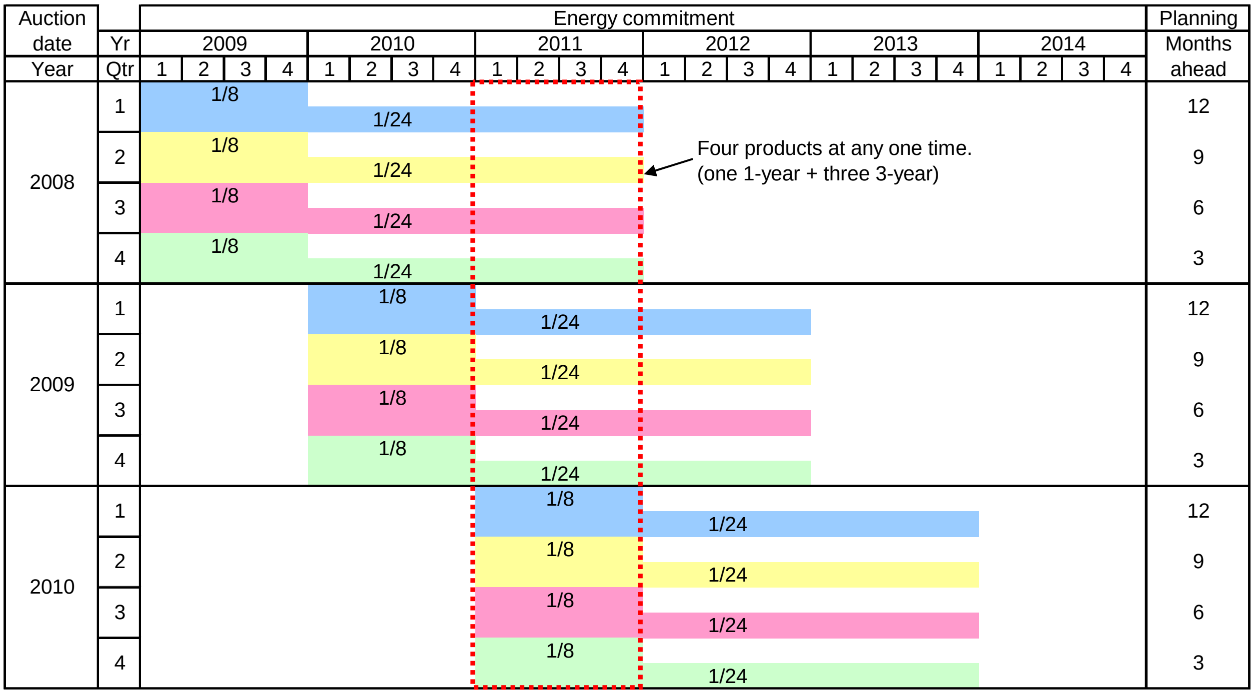
Option 5. Rolling quarterly auction for 1-year and 3-year commitments (6-month planning length)



Each quarterly auction now procures two products: a 1-year product ($1/8^{th}$ of load) and a 3-year product ($1/24^{th}$ of load over three years). The customer rate is the average of sixteen prices. This example splits the purchase 50-50 between 1-year and 3-year. Of course, any other split is possible. The best choice is the split that enables the market participants to best manage price and credit risk, and minimize transaction costs.

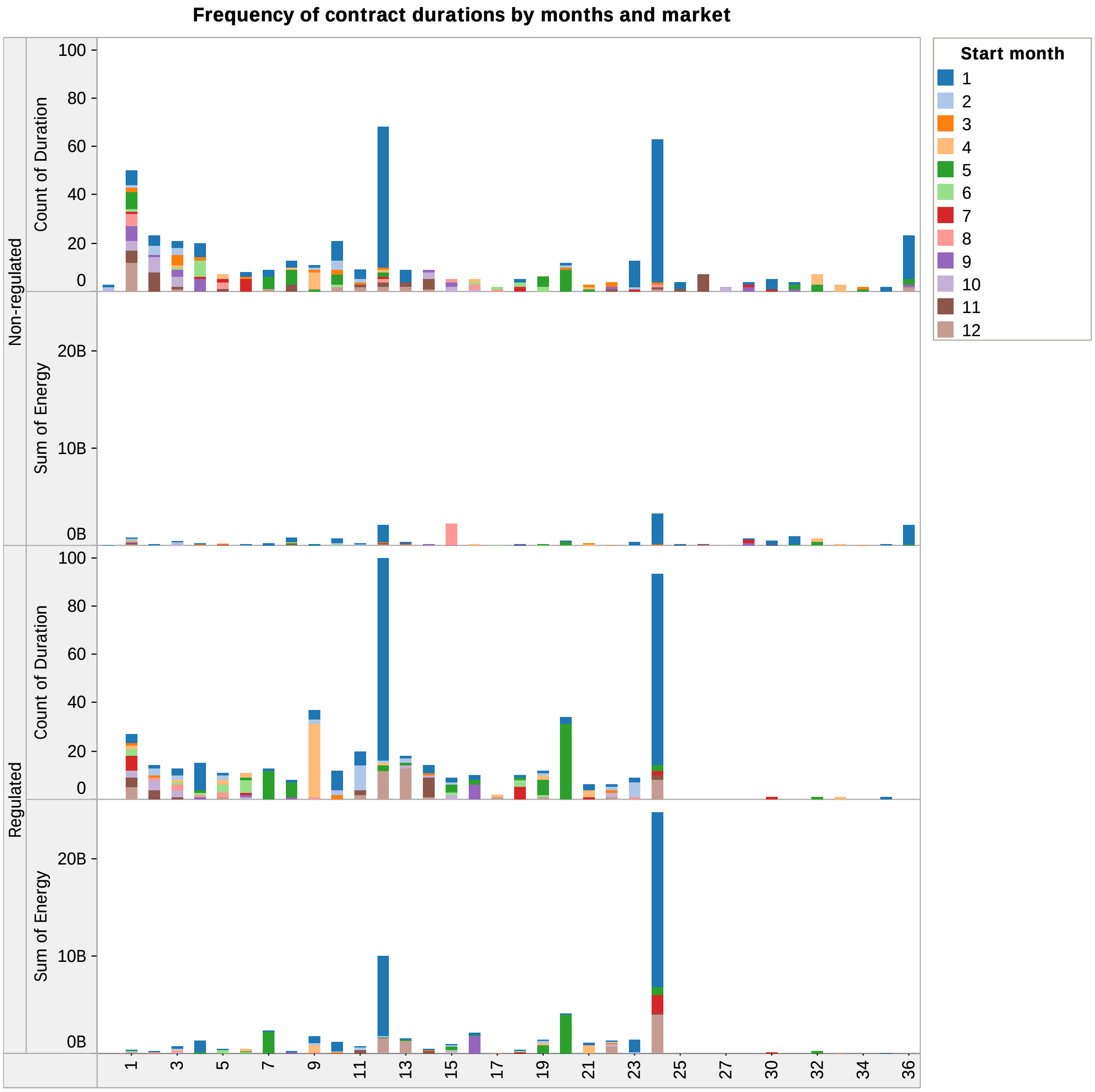
Finally, Option 6 reduces the number of products by having each quarterly auction sell the same two products. Thus there are four products at any one time, a 1-year product and three 3-year products. The customer rate is still the average of sixteen numbers from twelve different auctions, so the same time diversification is achieved.

Option 6. Quarterly auction for 1-year and rolling 3-year commitments (variable planning length)



7.5 Recommendation

It is instructive to look at the existing contract data to get a sense of historical contract durations and also the timing of contracts. The figure below shows the number of contracts for each contract duration, as well as the quantity of energy contracted with each duration. Durations greater than 3 years are rare and have been omitted. The top-two panels show the results for the nonregulated market and the bottom-two show the regulated market. The color indicates the start month of the contract.



Count of Duration and sum of Energy for each Duration broken down by Market. Color shows details about Start month. The view is filtered on Duration of 3 years or less.

There are several things to note. First, the most common contract durations are one-year and two-year contracts. In energy terms for the regulated market, two-year contracts dominate. The vast majority of one and two year contracts start in January, following the calendar year.

After studying the various options, the tradeoffs involved, and the historical contracts, I recommend quarterly auctions of 2-year contracts, rolling on an annual basis, as shown below. With this approach there are two products active at any one time. The customer rate is based on eight auctions equally spaced over a two-year period. One-eighth of regulated load is purchased in each auction. Even the final auction of each year has a planning period of five months. This means the auction takes place in August, before much information has been resolved about the severity of the following dry season. Importantly, information about the firm energy auction, both price and quantities, for the commitment years has been resolved at the time of the MOR auction.

Recommended planning, commitment, and frequency

Auction		Energy commitment												Planning
date	Yr	2009				2010				2011				Months
Year	Qtr	1	2	3	4	1	2	3	4	1	2	3	4	ahead
2008	1	1/8								2 products, 8 prices at any one time.				14
	2	1/8												11
	3	1/8												8
	4	1/8												5
2009	1					1/8								14
	2					1/8								11
	3					1/8								8
	4					1/8								5

8 International experience

The approach proposed here for product design is consistent with best-practice in the U.S. and elsewhere. Indeed, it improves upon it in important respects. All of the markets of which I am aware use a load-following product similar to what I have proposed. The product has worked well. Informal secondary markets appeared both before and after the auctions, enabling suppliers to balance positions in response to changed circumstance.

The worst approach I am familiar with is in my own state of Maryland.[5] Maryland procured multiple years of load all at a single time through an RFP process organized by each EDC. As fate would have it, the time of purchase coincided with the peak of a large gas price rise. As a result, the Maryland process resulted in large rate increases for residential customers. This problem is avoided in the five acceptable options described above.

New Jersey has had the longest and most successful procurement program.[6] The program has procured energy for regulated customers for five years, since 2002, through an annual auction. Initially, contracts were for one year, but after the first auction, 3-year contracts were introduced. In the second year (2003), 67% were 1-year contracts and 33% were 3-year contracts; in 2004, the split between 1-year and 3-year was 50-50. Now 100% of load is purchased in rolling 3-year contracts. The one complaint I hear from participants is that it would be better to have more frequent auctions. It is partly for this reason that I am recommending quarterly auctions.

Despite the fact that the New Jersey market is highly concentrated—the largest supplier has about 50% of the capacity—prices have been remarkably competitive. Part of the answer is that substantial imports are possible from outside New Jersey. As of now, market power appears to remain an unrealized concern.

[5] See http://www.psc.state.md.us/psc/electric/SOSRFP.htm.

[6] See http://www.bgs-auction.com/.

Illinois adopted a program nearly identical to New Jersey for its two largest LSEs.[7] So far, they have had only a single auction. The auction outcome appeared to be competitive, despite a market structure that is worse than in Colombia. Unfortunately, like Maryland, the first auction was held at a time of high gas prices, so rates increased, causing some political problems. However, the problems were modest compared with the fire-storm created in Maryland.

In France, my colleagues and I have been conducting large "virtual power plant" auctions for EDF as part of EDF's virtual divestiture program to address market power issues.[8] These are auctions to *sell* energy, rather than *buy*, but the experience is still relevant. These auctions are quarterly and involve multiple durations. The quarterly auctions have performed well compared with industry benchmarks.

Spain has recently announced that it will be conducting quarterly energy auctions for regulated customers.[9] The first auction is scheduled for June 2007. A descending clock auction will be used.

It is my view that the product design presented here is consistent with, and indeed improves upon, the best practices elsewhere.

9 Responses to common questions from industry

In this section, I discuss a number of comments and questions from industry.

How will the aggregate demand curve be defined? Will it be obtained as the sum of all the demand purchased by the LSEs in the auction?

MOR aggregate demand is equal to 100% of regulated load. Any particular MOR auction will procure some fraction, typically 12.5%, of the regulated load. The amount of energy that is purchased as a result of the MOR auction will vary from hour-to-hour, since it is a load-following product. Regulated load is readily estimated. Hourly estimates of regulated and nonregulated load will be made available to bidders before each auction.

Are LSEs allowed to purchase energy in the auction that is not required for final customers? If the answer is yes, will the aggregate demand curve be obtained exclusively from the sum of the demand of the regulated costumers?

LSEs are passive participants in the MOR auction; that is, the quantity that each LSE purchases in the MOR auction is determined from the demand curve as established by CREG before the auction. LSEs can participate on either the buy or sell side in the auction for nonregulated energy contracts. Such participation will be described in the auction design paper.

Because 100% of the demand will be procured in the MOR auction, the LSE will not be required to purchase energy in the spot market for regulated customers. Is that correct?

Yes, typically the LSE will purchase 100% of its need for regulated customers in MOR. However, as is described in the auction design paper, it is possible that due to a lack of

[7] See http://www.illinois-auction.com/index.cfm?fa=hm.home.

[8] See http://www.edf.com/345i/Home-fr/Capacity-auctions.html.

[9] See http://www.subasta-cesur.eu/Auction.asp?selectedTab=announcements&language=english.

competitive supply offers in the final quarterly auction less than 100% of the load would be procured in MOR. In this case, the remainder will be purchased in monthly secondary auctions. It is possible that some small quantity is purchased in the spot market, but this would only occur from a lack of supply offers in both the quarterly auctions and the secondary auctions.

We understand that the agents in the secondary market will be limited to suppliers, as long as the LSEs will not have to trade any energy in this market. Is that true?

Yes, that is true, except for the unusual circumstance described above. However, an LSE serving nonregulated customers may participate in the secondary market for nonregulated load on behalf of these nonregulated customers.

The proposal is not favorable for the supply side, because all the risk is assigned to it. As a consequence, the implementation of a secondary market is suggested.

For a supplier with the ability to generate electricity (a working generator with a fuel contract), MOR reduces a supplier's risk, since the supplier is able to lock in a long-term price and have less exposure to the volatile spot market. Nonetheless, I agree that the auction design should include a secondary market. This will be described in the auction design paper.

Is it correct that the regulated demand will be passive in the auction? Will there be competitive bidding only on the part of the generators (sellers)?

Yes. For the regulated demand, the buy side is passive. Only the suppliers bid. However, for the nonregulated market, both the demand and supply sides are active.

The secondary market that may appear as a consequence of the auction will include participation of LSEs or only of generators?

As described above, typically only the generators will participate in the secondary market for regulated demand. An exception may occur in the unusual case of insufficient competitive supply offers in the final quarterly auction. In this case, the residual regulated demand is purchased in the organized secondary market. This is described in detail in the auction design paper.

Is it possible that the LSEs, on behalf of the demand, to give up in an auction? Is it convenient to have a reserve price for the auction?

Yes, although the target demand in each auction is 12.5% of regulated load, a smaller amount may be purchased if there are insufficient competitive supply offers. The quantity that is purchased in every auction is determined from the intersection of the demand curve, determined by CREG in advance of the auction, and the generators aggregate supply curve as bid in the descending clock auction. The demand curve serves as the reserve price in the auction.

What will happen if there is not enough quantity offered in the auction? Is it possible to assign obligations, even if the auction does not have enough competition? In that case, will the residual demand be exposed to the spot prices? If the answer to the previous question is yes, can those prices be passed through to the customers. Is it possible to include the residual demand in the following auction?

If there is insufficient quantity offered in the auction, then less will be procured in the particular auction, and more in subsequent auctions. This issue will be addressed in the auction design paper. It is not possible to assign obligations in the event of insufficient supply, rather we simple postpone the assignment to a later auction or possibly even the spot market. Wherever the assignment is made—a primary auction, a secondary auction, or the spot market—the price is passed through to the customer.

Regarding the 2-year commitment period, it is suggested to include also a product with a 1-year commitment in order to improve risk management.

This is something I have considered and will consider more fully. Based on my experience with other markets, I believe it will suffice to include the one-year product in the secondary market. In particular in each monthly secondary auction, generators can buy and sell the one-year product.

In relation to the auction for nonregulated customers, the participating agents should be who define the products according to their own needs.

I agree that for nonregulated customers, market participants should be able to trade whatever products they wish; that is, the bilateral market has no restrictions on contracts for nonregulated customers. However, to minimize transactions costs, reduce risk, and improve liquidity, it makes sense to define a standard product for nonregulated customers. Generators and nonregulated customers that do not want to take advantage of the standard product are free to transact on whatever terms they find mutually desirable.

Efficient price formation requires active participation of the buyers, so the price should not be defined completely by the sellers. For that reason a double auction should be analyzed.

This point will be addressed in the auction design paper.

Buying in a single mechanism (MOR) reduces the liquidity of the products and the participation in other alternative markets.

It is true that to the extent that MOR is highly efficient, then the quantity traded in secondary markets will be less. However, this is not a reason to construct an inefficient auction. Moreover, experience over many decades and in many countries has consistently confirmed that the development of standardized products allocated in efficient auctions promotes secondary markets and market liquidity.

Given that supplier participation is voluntary, is it possible that in one of the eight auctions, some sellers will not participate, generating inefficiencies in the price formation.

Yes. It is a possibility. This issue is addressed in the auction design paper.

What would happen with deviations in projected demand?

This is not an issue in MOR. Since what is auctioned is a percentage of the realized load on an hour-by-hour basis throughout the commitment period, any deviation from projections is the responsibility of the supplier. This puts a little bit of risk on the supplier, which it must account for in its bid. Fortunately, the additional risk is not large. Aggregate regulated load is well understood and readily estimated. Estimating aggregate load to within say 2% is not difficult. This issue is addressed in the auction design paper.

What would happen when a new LSE enters the market? How can it purchase its requirements?

Restructuring of LSEs is beyond the scope of this paper. Nonetheless, in the event of a restructuring, the obligations and payments would simply move with the customers. If the customers of LSE A are shifted to LSE B, then the obligations to LSE A customers would simply shift to LSE B.

There is a five month planning period in the last quarterly auction. This is considered too short and risky.

Keep in mind that only 12.5% of load is being procured in this final auction; 87.5% of load is being procured well in advance of the final auction. In the New Jersey BGS auction, 33.3% of load is procured less than four months before the start of the commitment. In the context of Colombia's hydro-dominated system, I recommend a longer planning period. I will revisit whether 5-months ahead for the final 12.5% of load is too short.

Bearing in mind the energy variability of hydropower plants, a couple of agents have proposed to analyze the possibility to allow offers with different percentages of the aggregate demand each month without changing the price and commitment period.

My view is that a supplier with a hydro plant having lower expected supply in the dry season has several methods of managing the risk: 1) the supplier can have a diversified portfolio of resources that enables the supplier to better follow load in both dry and wet seasons, 2) the supplier can sell less in MOR contracts and sell more to nonregulated customers during the wet season, 3) the supplier can have a bilateral contract with another supplier to supply any obligation in the dry season that the supplier may not be able to handle with its own resources, and 4) the supplier can simply purchase in a secondary auction or the spot market the extra energy it needs in the dry season.

Given that MOR will facilitate the secondary market with monthly secondary auctions, I think that the methods above will be sufficient to let the resource owner effectively manage the risk of a load-following obligation. The alternative would be to introduce more complex products, but I do not think that that is advisable. It is not possible for suppliers to simply pick the months in which they would like to supply more. All suppliers would then pick the months in which the expected spot price is lowest. This would only work if multiple products were defined, which reduces liquidity and adds complexity.

The agents who act as a suppliers should be limited to generators in order to avoid intermediation costs.

Generators are free to participate directly in MOR and I suspect that nearly all will. One incentive for the generator participating directly is to avoid intermediation costs. However, there may be cases where the intermediary adds value that exceeds its intermediation cost. In this case, generators should be free to use an intermediary. Intermediaries often play an important role in markets by improving market liquidity and risk management.

There has been a misunderstanding about the lot size. You have recommended a lot size in the following terms: "say 0.1% of regulated load (6 MW)." This expression has been interpreted as a fixed quantity (6 MW) instead of a percentage of the demand. It will be desirable to clarify this issue.

You are right. The lot size is not fixed, but rather is a percentage of regulated load, such as 0.1%. Today, 0.1% is approximately 6 MW on average. The hour-by-hour obligation is based on the percentage of load, so that in one hour 0.1% may be 10 MW and in another it may be 4 MW, and indeed on average the obligation may differ from 6 MW depending on whether load growth is more or less than expected. My mention of 6 MW was simply as a means to provide a rough estimate of the average hourly obligation associated with 0.1% of regulated load. Before the auction, detailed estimates of hourly load will be provided to bidders. However, even these detailed estimates are still only estimates. The bidders must recognize that actual load may be more or less than the estimate in any hour, and that their obligation is based on the actual load realization on an hour-by-hour basis.

It will be necessary to establish a methodology to estimate the projected demand.

Yes. It will be helpful to estimate the projected demand. For MOR this is useful to the bidders in understanding their likely obligations. This information is provided to bidders in advance of the auction. However, for regulated load, the supplier's obligation is based on a percentage of actual hour-by-hour load. Thus, for settlement, all that matters is the actual load and what the supplier provided. Any deviation between the obligation and the supply in any hour is settled at the spot price. Hourly demand estimates are helpful in planning, but do not impact obligations or settlement for regulated load.

In contrast, for nonregulated customers, estimating hourly load is essential for both planning and settlement, since for nonregulated load the obligation is based on the estimated hourly load, rather than the actual. Hence, for nonregulated load, the estimates of nonregulated load are of primary importance. These estimates are fully disclosed before each auction.

10 Conclusion

MOR promises to reduce transaction costs and enhance competition for regulated customers. I have proposed a product design that—together with an effective auction design—will achieve all of the main objectives of the market.

Most importantly, the market is based upon a single load-following product. Suppliers bid to supply a share of the regulated load—aggregated across all LSEs. This simple approach enhances liquidity and competition, since all suppliers are competing for and trading in the same basic product.

Since regulated customers are procuring 100% of the regulated load, customers are fully-hedged from the spot price. Similarly, suppliers are able to lock in a long-term price to stabilize their revenues.

Several options were discussed for the timing and frequency of auctions, and the duration of contracts. Careful selection of these three parameters will enable both suppliers and regulated customers to best manage price and credit risks and minimize transaction costs. To this end, I recommend quarterly auctions of 2-year contracts, rolling on an annual basis. This approach is simple and yet provides substantial time diversification.

I also recommend that the approach be extended to accommodate participation by nonregulated customers to further take advantage of the centralized market and foster demand response.

The product is fully consistent with, and indeed complementary to, the other key elements in the Colombian market: the spot energy market and the firm energy market. The firm energy market together with MOR put suppliers in a nearly balanced position in the spot market. Not only does this reduce risk for both sides of the market, it greatly mitigates incentives to exercise market power in the spot market. Thus, I anticipate that MOR will not only solve problems in the contracting market, but will improve the performance of the spot energy market. Both the electricity industry and its customers will benefit from MOR.

Efficient price formation is one of the most important objectives of MOR. Price formation depends on both the product design and the auction design. This will be the subject of my next paper.

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