POWER SECTOR REFORM IN BRAZIL – SOME ISSUES

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PREFACE

The Inter-American Development Bank (IDB) retained our consultant services to help the Government of Brazil oversee the recommendations of some of the working groups in charge of developing the new Brazilian wholesale electricity market structure and rules seeking to ensure cost-efficient and reliable system expansion.

We traveled to Rio and Brasilia and participated in discussion meetings on September 23-25 and November 17-18, 2002 with IDB staff and the Brazilian team in charge of developing alternatives to the existing Wholesale Electricity Market. Among the participants in these meetings were

Francisco Gomide, Brazilian Minister of Mines and Energy;

Jaime Millán, representative of the IDB;

Brazilian consultants Mario Pereira and José Rosemblat, PSR Inc; and

Independent consultants Nils-Henrik von der Fehr and Frank A.Wolak.

On the basis of the presentations and discussions in these meetings - as well as background information contained in written materials provided to us (see the reference list below) - we were given the task of writing a summary report containing our conclusions and recommendations. Within the constraints of our mission the summary must be limited to a relatively short discussion of some of the main issues raised in the meetings. Hence the present report is not meant as a comprehensive account of the current discussion on power sector reforms in Brazil, or as an in-depth analysis of the various issues raised.

Oslo/Stanford, January 3, 2003

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INTRODUCTION

This report addresses four major challenges to the ongoing power sector reform process in Brazil. The first is how to provide the economic signals to private investors to guarantee adequate new capacity at least cost to support Brazil's future economic growth. The second is how to manage the risk of shortages associated with uncertain water availability given the existing mix of generating capacity in Brazil. The third is how to prevent distribution companies owning existing generation or planning to construct new generation units from including excessive profits into the prices they charge to their captive customers. The final issue is how to design mechanisms for final demand to become a more active participant in the wholesale market.

This report provides our recommendations for addressing these challenges. It proceeds as follows. For each topic, we first describe the outstanding issues. This serves two purposes: (1) it states our understanding of the problem, and (2) it provides context for our subsequent recommendations. Following this characterization of the problems, we then provide recommended solutions along with the rationale underlying our recommendation. After we repeat this process for each issue, we discuss any problems that might arise with coordinating our recommended solutions to each of the issues raised.

PROVIDING ENERGY ADEQUACY AT LEAST COST

There are number of challenges to Brazil attaining energy adequacy at least cost that are common to most developing countries, and number of challenges unique to Brazil. Those common to most all developing countries are: (1) a regulatory process with limited ability to enforce its decisions, (2) foreign exchange-rate risk for new fossil fuel-based entry because retail electricity is priced in terms of the domestic currency but input fossil fuels are purchased at international dollar-denominated prices, and (3) average wholesale electricity prices below the average cost of a new combined-cycle gas turbine (CCGT) facility. These conditions are not conducive to attracting new entry, even if there is a growing demand for electricity. Unless new entrants expect to receive prices that are sufficient to compensate them for their investment in a new CCGT facility, they will not invest. To the extent that new entrants lack faith in the integrity and stability of the regulatory regime, they will demand a risk premium on any output price they agree to or an explicit guarantee from the government in order to undertake new investment. We provide recommendations for eliminating these market conditions that are likely to create future energy shortfalls in Brazil.

Attracting new investment is made even more difficult by a number of factors unique to Brazil. Roughly 95% of the electricity consumed annually is produced by hydroelectric facilities. Consequently, even very efficient fossil-fuel units can be uneconomic to operate for extended periods of time when water is plentiful. The energy reallocation mechanism (MRE) used to compensate hydro plants for their annual energy production creates regulatory uncertainty about how new hydroelectric and fossil fuel units will be compensated for their output. Rather than being paid for their actual output during a given hour at the market clearing price for that hour, the MRE pays hydroelectric plants owners a pre-determined share of total hydroelectric revenues during that hour. Consequently, a new entrant has a strong incentive to construct facilities that the MRE mechanism pays the greatest revenues per dollar invested, rather than a facility that results in the greatest increase in overall system reliability. A mechanism that pays generation unit owners based on their actual output each hour would have a greater likelihood of providing the necessary incentives for new entrants to construct facilities that produce the most output during the hours when market prices are the highest, which therefore implies a greater increase in system reliability. Finally, Brazil uses an extremely low, relative to other wholesale electricity markets around the world, cost of deficit to determine how much water the National System Operator (ONS) uses to produce electricity each hour of the day. This figure does not reflect the full social cost of electricity shortages and therefore results in wholesale electricity prices that are too low to pay for the new investment necessary to serve the demand growth brought about by these prices.

REGULATORY CHALLENGES

The challenges common to most all developing countries must be solved in the same manner they are dealt with in other countries. Establishing a regulatory process that is able to withstand political and judicial review of its decisions takes time. In this regard it is important to bear in mind that in the United States, for example, regulatory oversight of the electricity industry at both federal and state level has been in place for more than 70 years. This regulatory structure has been subject to several major legal and political challenges to its authority over this time period. The most recent legal challenges are the events in the California electricity supply industry during the period June 2000 to June 2001 and the bankruptcy of Enron. Historically, these legal and political challenges and the subsequent response of the courts and the political process have caused the regulatory process to adapt to conditions in the industry. This process of continuous improvement in the US regulatory process is far from over.

The lesson for Brazil from the US experience is to accept the fact that establishing the political and legal credibility of a regulatory process takes time. It is unrealistic to expect that Brazil can immediately impose the same regulatory structure that exists in the US – or indeed in other developed countries – and achieve the same results. For example, being able to set regulated retail electricity prices that provide strong incentives for load-serving entities (LSEs) to procure wholesale power at least cost is an extremely difficult task. The legal and political process must have substantial confidence in the ability of the regulatory body to determine the least-cost mode of production in order to sanction the retail prices it sets. Thus, it is perhaps unrealistic to assume for the near future that the Brazilian regulatory body, ANEEL, will be able to determine and enforce retail prices that provide strong incentives for least-cost production. For the same reason, it is also unrealistic to expect that ANEEL can set the maximum price for wholesale power that it will allow retailers to pass through to final consumers in a manner that provides strong incentives for generation unit owners to sell their electricity to LSEs at the lowest price possible.

Rather than focus its regulatory efforts on determining the lowest possible retail price or wholesale price, formidable challenges even to the regulatory process in countries with long experience with tackling such issues, ANEEL should focus its efforts on enforcing the rules of the Brazilian electricity market and changing those rules that reduce market efficiency. As we discuss below, there are several market rule changes that will eliminate the conditions in the market described above that discourage new investment. The two most promising changes for attracting the appropriate quantity and mix of new investment to Brazil are: (1) increasing the cost of deficit entering the algorithm used by the ONS to set spot prices and dispatch hydroelectric and fossil-fuel generation units, and (2) phasing out the Energy Reallocation Mechanism used to compensate hydroelectric facilities.

One proposal under consideration for ensuring long-term energy adequacy would create a separate market for new capacity that load-serving entities are required to purchase from each year. Specifically, all LSEs would be required to purchase five percent of last year's demand in new capacity each year. The creation of a separate market for new capacity does solve the problem of attracting new combined-cycle gas turbine (CCGT) facilities or new hydroelectric facilities to the Brazilian market at a time when current wholesale prices are significantly less than the long-run average cost of a CCGT facility. However, we have serious concerns about the cost-effectiveness of this proposed method for meeting Brazil's demand growth. This requirement has a number of unattractive features that we describe below that cause us to recommend against its implementation.

Another proposal is to introduce a single-buyer model. Under this model a single entity would be responsible for planning and purchasing new generation capacity. This model has the potential benefit of allowing for coordinated system expansion, taking into account the need for a balanced growth of generation and transmission capacity. However, the single buyer model also creates considerable regulatory challenges, challenges that may well be too large to be handled by a relatively new and inexperienced regulator. As we discuss below, centralizing capacity decisions runs the risk of seriously biasing investment decisions as well as raising capacity costs above competitive levels.

LONG-RUN PRICE SIGNALS

The current Brazilian wholesale market rules differ significantly from those in wholesale markets in most developed countries along two dimensions. First, these wholesale markets use bids to determine which generation units are dispatched and at what level. In Brazil, all fossil-fuel generation unit owners first submit production cost data to ONS. Using this data, ONS solves a stochastic dynamic programming model to determine how much hydroelectric production is required in each hour and from what generation units this energy should be supplied, with the remaining energy consumed in the hour supplied from non-hydroelectric generation units. Second, although all other generation unit owners are paid for their actual production, hydroelectric facilities are paid for their share of total hydroelectric energy production based on their share of the total assured energy certificates (CEA) issued by ANEEL. This payment scheme eliminates many of the incentives generation unit owners may have to ignore the system operator's real-time dispatch instructions. Generation unit owners are not paid for their actual production during the hour, but for their CEA-weighted share of total hydroelectric energy production.

A key input to the stochastic dynamic programming model used by ONS is the cost of deficit parameter. As we discuss below, the cost of deficit parameter for the Brazil is substantially less than the value set for markets in Australia, England and Wales and the US. Although customer-level surveys of willingness to curtail may support this value as the cost of a shortage, this figure fails to recognize the enormous political cost associated with substantial supply shortfalls and the cascading losses in economic activity that result from involuntary electricity curtailments. The political fallout in Columbia, Chile and other Latin American countries that resulted from electricity shortages implies a social cost of electricity shortages that is orders of magnitude greater than the value currently used in Brazil. The experience of California during the rolling blackouts that occurred periodically from January to May 2001 indicates that the lost economic output associated with involuntary electricity demand curtailments to many industrial and commercial customers implies a cost of deficit to these customers far above the current cost of deficit in Brazil. The lost economic output due to an involuntarily curtailment of electricity led to additional losses in economic output from the sectors that used the output of this sector as an input to its production process. Brazil has a number of industrial and commercial customers where similar cascading costs of shortages would occur. Consequently, in order to improve system reliability and stimulate the appropriate magnitude and mix of new generation capacity, Brazil should adopt a cost of deficit more in line with those in Australia, England and Wales and the US. In addition, the mechanisms described below for involving final demand in the wholesale market should be adopted so that those customers voluntarily willing to curtail their demand at prices below this new cost of deficit are able to achieve the maximum benefits from doing so. If these mechanisms for involving final demand in the wholesale market are adopted then it makes even less sense to keep the cost of deficit used in the ONS dispatch process at its current level because customers have the ability to curtail their consumption voluntarily if prices rise above their own private cost of deficit during a given hour. Managing potential energy shortfalls without active demand-side participation is extremely expensive, and unnecessarily so, particularly in a country like Brazil. Most of the wholesale price variation is due to differences in water availability across seasons of the year or across years, rather than within the day, week or month. Consequently, there is little need for sophisticated and expensive hourly metering technology in order to involve final demand in the wholesale market. There are also much larger differences in willingness to pay for electricity across customer classes in Brazil relative to developed countries. These facts suggest that using price signals to final demand to manage potential water shortages in Brazil is considerably less expensive than constructing new capacity.

The Energy Reallocation Mechanism (MRE) introduces a number of distortions into the new investment decision-making process. First, because hydroelectric generation unit owners are not paid for their actual hourly output, there is little incentive for a new hydroelectric entrant to construct a facility that yields the greatest benefits to system reliability. In contrast, a new fossil fuel generation entrant bears all of the risk associated with not being dispatched by ONS if it is uneconomic at the current market price or unable to produce because of transmission congestion. For this reason, a new entrant that constructs hydroelectric capacity is hedged against both of these risks by the MRE. Thus, the presence of the MRE introduces a bias against constructing fossil-fuel facilities. The existence of the MRE also has the potential to bias a new hydroelectric entrant's choice of location and plant capacity. A new entrant will chose the plant's location and capacity to maximize the profits it expects to earn from entering, given the administrative process used to allocate assured energy certificates (CEAs). It is very unlikely that this administrative process will cause the new entrant to choose a location and capacity that maximizes system reliability. Because the MRE provides the new hydroelectric entrant with a costless hedge against all energy production risk, a new entrant has little incentive to build a plant that produces the greatest amount of output during the highest priced hours of the year. Consequently, under the MRE, Brazil faces a significant risk of an unnecessarily costly mix of new generation investments in terms of the choice of technology and location.

The proposed mandatory annual auction for new capacity has a number of shortcomings that strongly recommend against its implementation. First, a requirement to purchase some fixed percentage of last year's demand in new capacity is almost certain not to meet actual demand growth. Moreover, there is a strong incentive for the political process to set the required amount of new capacity purchases too high to minimize the risk of future shortages. The requirement to purchase a fixed percentage of last year's demand would very likely lead to the following sequence of events. Purchasing too much new capacity will cause the price paid for supply from existing generating capacity to remain low. This will allow load-serving entities to continue to pay artificially low prices for electricity from existing sources of supply, even though they are paying substantially higher prices for energy from new sources of supply. As long as the amount of new capacity is substantially less than the amount of existing capacity, it is total cost minimizing from the perspective of final demand to pay for more new capacity in order to keep the price of electricity from existing capacity low. However, this artificially low average price of electricity encourages over-consumption of electricity, which requires even greater very expensive (relative to the spot price of electricity) investments in new capacity to maintain these low average prices. In other words, the potential surplus from older, more efficient hydro facilities is being used to keep prices artificially low and to subsidize new and more costly capacity. Instead of raising an economic surplus in the form of a 'resource rent' on the plentiful and cheap hydro resources, this surplus is dissipated on over-consumption of costly energy.

Clearly, a superior strategy is a single price for electricity regardless of its source, not two prices of electricity — one for supply from existing capacity and one for supply from new capacity. The price of supply from existing capacity should also be the price paid for supply from new capacity. Paying the same price for supply from both existing and new capacity will avoid over-investment in unnecessarily expensive new capacity and over-consumption of electricity brought about by average wholesale electricity prices initially kept artificially low by the two-price strategy made possible by a mandatory annual auction for new capacity. As is the case for all homogeneous product markets, new entry should occur when the price paid to all suppliers is sufficient for the entrant to recover their operating costs plus an adequate return on investment. A unified price for electricity that reflects the cost of marginal capacity would induce an economic surplus on infra-marginal capacity. This resource rent would – under a system of either government ownership or a designated tax system – accrue to the government and could be used for whatever purpose it sees fit; there is absolutely no reason that this surplus must be used to subsidize electricity consumption, as would be the case under the two-price system discussed above.

The single-buyer model shares many of the deficiencies associated with a politically determined fixed and mandatory capacity expansion. Centralizing capacity decisions means entrusting a single entity with the responsibility for making crucial industry decisions; if it gets it right, then all is fine – if not, there is no one to take corrective measures. Moreover, the agency responsible for planning and purchasing new capacity will be subject to considerable pressure – political as well as economic. So long as the single buyer is able to pass on to others (retailers and end consumers) the cost of new capacity, there will be a strong temptation to yield to pressure for over-investment; thereby the agency also insures itself against any blame for eventual capacity shortages. Given the problems that Brazil has had with setting a maximum price that retailers can pass through to their consumers, there would seem to be little hope that the regulator would be able to set a reasonable maximum price of power that the single buyer can pass on to retailers which would put an effective limit on purchasing costs. Consequently, there would be little incentive to either limit capacity or to control the cost at which this capacity is obtained. In short, the single-buyer model suffers from the fundamental problems of high costs and low efficiency that plagued the old state-owned monopolies.

We believe that there is much greater hope of controlling costs and ensuring adequate levels of capacity expansion if such decisions are decentralized and subjected to competitive forces. By allowing consumers (or retailers on their behalf) to manage supply risks, and by placing the economic risk of new investment with generators, investment decisions are more likely to guarantee cost efficiency with respect to both capacity expansion and capacity mix. Admittedly, decentralizing capacity decisions does not circumvent the regulatory problem entirely; in particular, it requires close supervision of the network in order to ensure sensible localization of new generation capacity and a balance between generation and network investments. However, this regulatory problem is unavoidable and some form of system planning is required under any regulatory regime.

EFFICIENT ALLOCATION WATER FOR ELECTRICITY PRODUCTION

The second challenge associated with the ongoing re-structuring process is how manage the water availability risk given the existing mix of generation capacity in Brazil. The major proposal under consideration to address this issue is to allow generation unit owners to bid their willingness to supply water to produce electricity. Currently, ONS inputs the operating cost curves of the fossil-fuel generation units and a cost of deficit into a stochastic dynamic programming model to determine the amount of energy produced by each generating unit during each hour of the day. The proposal would allow hydroelectric unit owners to bid a willingness to supply water on a daily basis. The amount of water sold as electricity each hour would then be determined based on the aggregate willingness of hydroelectric plant owners to sell water.

The argument in favor of allowing hydroelectric generation unit owners to bid their willingness to supply water is that by giving them an opportunity to manage their own risk of water shortages, it will be easier for the Brazilian government to penalize individual generation unit owners for water shortages. The current Energy Reallocation Mechanism (MRE), by effectively treating generators as a single entity, creates a 'systemic risk' in the sense that all generators, in the event of a shortage, find themselves in exactly the same position. This, it is argued, reduces the incentive of individual generators to take actions to reduce risk, as they expect the government to bail the industry out when everyone is in the same dire circumstances. This is believed to be one reason why the industry did not provide serious opposition to the policy of ONS of depleting water reservoirs that eventually lead to the 2001 shortages. In other words, centralized dispatch, combined with a collectivist system of risk sharing, is thought to create a system failure that was largely responsible for the recent crisis.

However, the potential downside, in terms of opportunities to exercise market power, associated with allowing firms to bid their willingness to supply in a spot electricity market are substantial. Particularly, given the difficulties with regulatory oversight in the Brazilian market, we believe that it is unadvisable and largely unnecessary to allow a bid-based spot market. Instead, the reform process should focus on providing all market participants maximum flexibility to manage the risk associated with the current ONS dispatch process. Specifically, the cost of deficit should reflect the full social cost of supply shortfalls. This will provide both generation unit owners and LSEs with strong incentives to hedge against the potential high prices that could arise during periods of water scarcity. The ONS dispatch process should be made as transparent as possible to all market participants so that they are able to estimate the likelihood of future water shortfalls and take the forward financial positions necessary to hedge these future spot price risks. As discussed below, the evidence from wholesale electricity markets around the world is that the major benefits from electricity industry re-structuring occur as the result of the formation of robust medium-term and long-term forward markets for electricity. Short-term markets are primarily used to maintain system balance and manage transmission congestion, and as a result are extremely susceptible to the exercise of unilateral market power. One way to avoid this downside of short-term spot markets is to dispatch generation based on filed costs.

In order to provide the strongest possible incentives for efficient water management, the MRE should be phased out. The MRE completely divorces what a hydroelectric generation unit owner is paid from virtually all of the actions it might take. A hydroelectric generation unit owner is paid its share of total system-wide hydroelectric production during that hour, based on its ownership share of the total amount of assured energy certificate (CEA) capacity in Brazil. About the only way a firm may be able to influence the prices it receives by its behavior is through its outage declaration decisions. By declaring some of its hydro or fossil-fuel units out of service a firm may be able to impact market prices. However, unless the firm decides to use its outage declarations in this manner, it has little incentive to do anything but be a passive recipient of a fixed share of total hydroelectric revenues each hour.

The Energy Reallocation Mechanism (MRE) is also a double-edged sword in terms of the incentives it provides for generation-unit owner behavior. Under this scheme hydroelectric generation-unit owners are paid the hourly price times a quantity of output equal to their participation factor times the system-wide hydroelectric production for that hour regardless of how much energy, if any, their plant produces in that hour. This participation factor is that unit's share of the total amount of assured energy certificates (CEAs) on a system-wide basis. The MRE was designed to pool the revenue risk hydroelectric unit owners faced by being paid for the actual output of their unit during each hour. The ONS dispatch algorithm often does not dispatch a unit for an extended period of time, so the firm would face a significant risk of having no revenue stream if it were paid only for its actual hourly output. However, the revenue risk spread across generation unit owners by the MRE could also be managed through voluntary risk-sharing arrangements negotiated between hydroelectric and fossil-fuel generation unit owners. The MRE simply imposes a feasible, but certainly not the optimal, risk-sharing mechanism between all generation unit owners. Another shortcoming of the MRE is that it excludes fossil-fuel unit owners from the revenue risk-sharing mechanism. Consequently, although this risk-sharing mechanism is superior to one that requires hydroelectric capacity owners to be paid for their actual hourly production of electricity, there are many other revenue risk-sharing mechanisms with superior efficiency properties.

Admittedly, the MRE provides one solution to the problem of 'externalities' between generation units located on the same river, or 'cascade'. The pattern of operation of a particular generation unit influences the effectiveness of other units located further downstream on the same river. As we understand it, the MRE was originally devised to deal with this problem, by divorcing a unit's revenue streams from its actual operation and by allocating 'fair' shares of the overall revenues between generation units on the same river cascade. Under centralized dispatch the short-run operational problem of how to dispatch units on a cascade efficiently is effectively dealt with. What remains, therefore, is to allocate revenue to reflect the overall benefit created by individual parts of the system accurately and to provide efficient investment incentives. This could be done by a gradual phasing out the MRE, which would keep MRE schemes for individual river basins, while letting payments to individual generators depend on actual output on the particular river or cascade. However, although some of externality problem in cascades main remain in this scheme, we believe there are fixes that will eventually turn out to be both more effective and desirable, based on some type of freely negotiated agreements between generators.

COSTS AND BENEFITS OF BID-BASED DISPATCH

In order to give generation unit owners the opportunity to manage their spot market price risk, the MRE process should therefore be phased out and replaced with a default payment mechanism equal to the hourly spot price set by the ONS dispatch process times that unit's actual hourly output for all generation unit owners. All generation firms should be allowed to enter into hedging arrangements with other generation unit owners and load serving entities. Because all hydroelectric generators know that there is a likelihood of a sustained period of time when the ONS dispatches very little output from their units, they would have a strong incentive to enter into revenue risk-sharing arrangements with long duration with other market participants. Those generation unit owners that believe their water will be used more rapidly than they would like by the ONS dispatch process can enter into forward financial contracts which effectively transfer energy from the current period to future periods. This strategy for allowing generation unit owners to manage spot price risk has the attractive feature that firms would be unable to withhold energy from the spot market either by bidding very high prices or refusing to sell energy at any price in order to raise the spot electricity prices. They would only be able to engage in forward financial hedges against the revenue risk they face because their units are dispatched using the fossil-fuel unit operating costs and the cost of deficit parameter.

The key to this mechanism delivering superior market outcomes relative a market with the MRE in place and hydroelectric suppliers bidding their willingness to supply water is the transparency of the ONS dispatch process to all market participants. In particular, firms need to understand how their unit and all other units in the system would be dispatched and how market prices would be set for all possible system conditions. Under this scheme, firms would no longer be passive recipients of their CEA-weighted share of total hourly hydroelectric revenues. They would be price-takers in the energy market with strong incentives to keep their plants available in case this capacity is needed by

ONS. These units could be the only plants available to supply energy during this period of high spot prices. Without the MRE, firms would be compensated for both their actual spot market sales and the forward market positions they take to hedge their spot market revenue risk. Firms would still be largely unable to take unilateral actions to influence spot electricity prices or the amount of energy produced by their unit each hour because both these variables would still be determined by the ONS dispatch process. They would, however, be able to take positions in the forward market that maximize their expected profits given the best information they have about future system conditions and the likely impact these conditions will have on how the ONS dispatch process operates their units and prices electricity in the spot market. They would also have strong incentives to produce as much energy as ONS demands from their units during hours when the spot price is extremely high, because rather than being paid for the CEA-weighted average of hourly hydroelectric revenues, they would be paid for their actual hourly production times the hourly spot price.

A regime with the MRE in place provides little incentive for hydroelectric generation owners to maximize the amount of energy they produce from their units during the hours when the price of energy is highest. These firms only have an incentive to engage in activities that increase the size of their participation factor or avoid actions that reduce their participation factor. A cost-based dispatch process as discussed in the previous paragraph, where generation unit owners are also paid the spot price for their hourly output but are free to hedge this revenue risk, is an intermediate solution to the limited incentives for more efficient operation provided by the MRE mechanism that does not have the significant downside risk of a bid-based spot market.

As the experience with the California electricity market during the period June 2000 to June 2001 has demonstrated, the unilateral exercise of market power in a bid-based spot market can result in enormous transfers of wealth from consumers to producers in a relatively short time. Moreover, as the current refund proceedings at the United States Federal Energy Regulatory Commission have demonstrated, it is extremely difficult to undo these transfers once they have been made. For this reason, the intermediate solution of paying firms for their hourly output at the hourly spot price, but not allowing them to submit willingness to supply bids that set market prices, provide incentives for firms to make their units available during high-priced hours without allowing firms the opportunity to use their bids to attempt to raise spot prices.

While we are not opposed to Brazil eventually adopting a bid-based spot market, we are not convinced that this change in market rules will be a significant source of economic efficiency gains. So long as the cost of deficit is set so that wholesale prices will increase enough to cause fossil fuel units to be dispatched with sufficient frequency to prevent water shortages, there is little need for a bid-based spot market dispatch. Moreover, if the ONS dispatch process is based on publicly available information, then generation unit owners will be able to take forward market positions to hedge the spot price risk associated with this dispatch process, without the enormous potential downside created by allowing firms to bid their willingness to supply water.

It has been argued that by allowing firms the opportunity to manage their allocation of hydroelectric energy through willingness-to-supply water bids, unit owners would be less likely to blame the ONS dispatch process should water shortages subsequently occur. The argument is that because hydroelectric unit owners have the ability to express their individual value of water through their willingness-to-supply bids, they would be less inclined to blame ONS for future water shortages. It is important to emphasize that under the proposed mechanism for allowing firms to bid their water availability unit owners are still not free to operate their units as they see fit. This lack of operational freedom would seem to give them a very convenient mechanism for blaming shortages of water to the ONS dispatch process.

Under our recommended cost-based dispatch with a forward market to hedge spot price risk, unit owners would have extremely strong incentives to monitor the ONS dispatch process to ensure that the least-cost dispatch is occurring during each hour. They would also be free to take forward market positions that hedge their own plant-level or unit-level water availability risk. If water shortages subsequently occurred, those firms that bet on this outcome would argue in favor of requiring those entities on the other side of these financial commitments to honor their obligations. A well-defined process for generation asset transfer should be specified in advance as a method for honoring these financial commitments. Consequently, the existing ONS dispatch process need not be pre-disposed to system-wide shortages of water. An active forward market for hedging spot market price risk with well-defined liquidation rules for generation unit owners unable to meet their forward market obligations should go a long way towards solving the problem of market participants blaming the ONS for water shortages. Market participants have an option for taking a financial position to hedge the risk associated with an expected shortfall in their water availability as a result of the ONS dispatch process and will have a strong incentive to demand compensation when this event occurs.

SUPPLY SECURITY, RATIONING AND THE SOCIAL COST OF DEFICIT

As noted above, we believe that the market reform process should focus of refining the ONS cost-based dispatch protocols to ensure that it does not result in the inefficient use of Brazil's hydroelectric resources. A first step in this process is to increase the 'cost of deficit' parameter in the ONS dispatch stochastic dynamic program. The value for 2002 of 350 R$/MWh is orders of magnitudes lower than similar numbers used in other markets. For example, in the England and Wales electricity market, the 'value of lost load' under the former electricity pool market structure was more than £2500/MWh. In the Australian electricity market, the value of lost load is currently AU$10,000/MWh. Converting these two value of lost load figures to R$/MWh using current exchange rates yields values in the range of R$16,000/MWh for the England and Wales market and R$22,000/MWh for the Australian electricity market. Multiplying these figures by 0.5 to account for the current under-valuation of the Real yields a figure on the order of R$8000/MWh and R$11,000/MWh for the cost of deficit parameter. While we recognize that these are magnitudes were primarily determined by administrative processes, these values implicitly determine a market-wide willingness to tolerate energy shortfalls. For example, initially the Australian electricity market set the value of lost load at AU$5,000/MWh. As a result of growing concern that there were not enough peaking power plants in the Australian market to achieve the government's desired level of reliability of supply, the value of lost load was increased to AU$10,000/MWh, with an implicit promise to raise it to AU$20,000/MWh if sufficient peaking capacity did not materialize. This logic underscores the core of our argument for a substantial increase in the cost of the deficit parameter for Brazil. A cost of deficit for Brazil in line with these figures would make it very unlikely that the pattern of spot prices and water storage documented in Charts 4.4 and Charts 4.5 of the Progress Report Number 2 of the Committee to Revitalize the Brazilian Power Sector Model would occur in the future.[1]

Unless the cost of deficit parameter is increased to reflect the social cost of electricity supply shortfalls, the ONS dispatch process will continue undervalue the cost of shortages. This has the obvious benefit to consumers of low prices during periods when water is plentiful, but the very large potential cost that shortages become very likely during sustained dry periods. There is no escaping the basic reality of ensuring a high level reliability of supply — higher average spot prices ensure a higher level of system reliability. Setting a more realistic social cost of deficit parameter guarantees a higher level of system reliability. Involving final demand in the wholesale market allows each

[1] See Committee to Revitalize the Brazilian Power Sector Model (2002).

customer to decide how much to consume during high price periods and therefore manage the risk of supply shortfalls without resorting to rationing.

With a more realistic cost of deficit parameter, market prices would rise to the levels necessary to cause fossil-fuel units to operate to conserve water as the risk of rationing rises. This avoids building into the ONS dispatch process an arbitrary cost of deficit function, where the cost of deficit parameter rises as the amount water available falls. This sort of function still has the potential to fall prey to the same problem as a low cost of deficit parameter. If the function sets the cost of deficit parameter too low at high water levels, or not high enough at intermediate water levels, the same sort of problem as occurred during 2001 with relatively low prices and declining water levels could occur, even though the cost of deficit parameter is extremely high at low water levels. This is because by the time the water level falls to the level necessary to trigger a very high cost of deficit value, it may already be too late to prevent a water shortfall and subsequent period of rationing. Setting a fixed social cost of deficit parameter in line with those in other markets around the world will cause prices to rise to levels early enough in a sustained period of low water levels to prevent rationing.

Implicit in setting a substantially higher cost of deficit parameter is a commitment to allow substantially higher prices as the risk of rationing increases. With a value for the cost of deficit parameter in the $R10,000/MWh range, if a sustained period of low and declining water availability occurs, this would trigger price increases that encourage conservation (assuming that these price increases were passed through to consumers), rather than set prices so low that water levels continue to fall until rationing eventually occurs. This commitment to a higher cost of deficit parameter would also provide a long-term price signal for new investment in both fossil fuel and hydroelectric facilities.

Brazil's experience with rationing and California's experience with rolling blackouts have demonstrated that the total economic cost of electricity supply interruptions are significantly in excess of the direct willingness of consumers to be curtailed. Consequently, a superior strategy for managing potential supply shortfalls is to allow individual consumers to decide not to purchase at the prevailing market price rather than curtail their consumption involuntarily as is the case with rationing or rolling blackouts. The only way for Brazil to avoid rationing in the future is to ensure that as water levels begin to fall, market prices rise to levels high enough to make it economic to operate fossil fuel facilities more intensively. There are a variety of ways to accomplish this, but the most straightforward and internally consistent mechanism is to recognize explicitly in the cost of deficit parameter an extremely high social cost of rationing.

Although our recommendation to continue to use the ONS dispatch algorithm with a more plausible cost of deficit value may seem counter to relying on market mechanisms to set the prices generators receive for their electricity, we believe it is the most prudent way for Brazil to move forward with further industry re-structuring during a period of considerable macroeconomic and regulatory uncertainty. Another lesson from re-structuring processes around the world is that the major challenge associated with forming a wholesale market for electricity is preventing exercise of market power in the short-term or spot market. Few if any spot electricity markets experience persistent periods with little exercise of market power. The physical characteristics of electricity make it extremely susceptible to the exercise of market power in the spot market. Moreover, the larger the quantity of energy actually sold in this market and the larger is the largest firm selling in this market, the greater is the risk of significant spot market power.

In contrast, it is very difficult to exercise significant market power in forward markets for electricity, particularly if the time horizon to delivery of the electricity is greater than the time necessary to build new transmission or generating facilities. For the case of an electrical system dominated by hydroelectricity this time horizon is could be as short as a single annual water cycle or as long as a number of years. At these time horizons in advance of delivery, the physical characteristics of the transmission network and the operating constraints of generating units do not play nearly as important a role in determining the price consumers must pay for electricity. As time to delivery nears, conditions in the transmission network become apparent and the operating characteristics of generation units constrain their ability to respond to fluctuations in demand. For example, for large fossil-fuel or nuclear facilities, no matter how high the real-time price is, if a unit has not been started up almost two days before the hour under consideration, it cannot supply energy in the real-time market. Conversely, if this generation-unit owner received a generous price in the short-term forward market beyond two days in advance, if would start up and operate in real time. This discussion illustrates the general point that designing a spot market that limits the opportunities generation-unit owners have to exercise market power is significantly more difficult than designing even a short-term forward market for energy. A concrete illustration of this point comes from all of the wholesale markets currently operating around the world. Very short-term forward markets and real-time markets experience enormous price volatility, whereas longer-term forward market beyond a year in advance of delivery experience significantly less price volatility. Specifically, the wholesale markets in the eastern US periodically have spot prices that are on the order $1000/MWh, however prices even on the short-term, say week-ahead, forward market rarely exceed $150/MWh. Admittedly, the price-volatility problem may be less in a hydro-dominated system, at least in the very short term (day-to-day or week-to-week), but – as the Nordic experience suggests – even in such systems prices may fluctuate considerably over relatively short periods (month-to-month or season-to-season).

Because of the extreme susceptibility of even very well-designed and regulated bid-based spot markets to the exercise of market power, maintaining the current ONS dispatch algorithm and focusing the re-structuring process on the development of robust long, medium and short-term forward markets for energy is our preferred path to long-term energy adequacy at least cost for Brazil. This goal of ensuing adequate capacity at least cost is complicated by recent legal constraints requiring all state-owned generators to sell their energy through an auction, many province-owned generators to sell through an open, transparent mechanism, and distribution companies to purchase their energy requirements through an auction mechanism. An additional complication with getting new hydroelectric capacity constructed is the fact that a firm must have a hydro concession license to construct a new hydroelectric plant. However, the firm would also like to know the price at which it can sell the energy produced from the proposed unit before it enters the auction for the hydro concession. All of these complications argue in favor of the development of forward energy markets with forward financial commitments to supply electricity backed by actual physical generation resources at shorter time horizons to delivery and pure forward financial commitments to supply electricity at longer time horizons to delivery.

Real-time imbalances relative to these forward market commitments can be cleared against spot prices set through the ONS dispatch process. Viewed from this perspective, the fact that generation unit owners can take very few actions to move real-time prices enhances the willingness of generation-unit owners and LSEs to enter into forward commitments cleared against these prices. This increased willingness to contract occurs because these forward contracts will be viewed by generation-unit owners as providing insurance against spot price risk that they have little ability to impact. This is different from the case of bid-based spot electricity markets, where generation-unit owners are limiting their ability to impact spot electricity prices by selling forward market commitments. Because both generation-unit owners and load-serving entities have little ability to move real-time prices through their unilateral actions under the current ONS dispatch protocols, both will have strong incentives to enter into forward contracts to hedge this real-time price risk. Moreover, to the extent that the ONS dispatch process is made more transparent to market participants, this will further enhance their willingness to engage in forward financial obligations cleared against this price-setting process.

AUCTION MARKETS AND SETTING RETAILER REVENUE REQUIREMENTS

There are a many instances in the US and elsewhere where formal auction mechanisms have been successfully used to buy or sell items such as spectrum bands used to provide wireless telephony, natural resource mining rights, and many of other diverse products. Buying and selling forward financial commitments to deliver electricity to specific geographic regions in Brazil does not have any unique features that make it fundamentally different from any of the products that have been sold using auction mechanisms. The difference between electricity and other goods is greatest in real-time market. Here transmission capacity constraints, operating constraints on generating units, and other constraints associated with ensuring real-time energy balance at all locations in the transmission network can present many opportunities for generation unit owners to exercise significant market power in a bid-based electricity market. In contrast, forward financial commitments to deliver electricity a year or even a month in advance give the seller sufficient advance notice so many of the physical realities of real-time system operation can be planned for and are therefore not priced in a generation unit owner's bid to supply this electricity. In a system dominated by hydro – with extremely short ramp-up times/costs and with typically massive installed capacity –the opportunities for exercising market power are limited in the very short run. In such systems market power is typically exercised by inter-temporal price discrimination, whereby water (energy) is moved from periods in which demand is more inelastic to periods in which demand is more elastic (season-to-season, year-to-year).

Auctions for forward financial commitments to supply electricity to specific geographic areas could be operated similar to how the US Federal Communications Commission (FCC) operated its spectrum auctions. In the case of the FCC auctions, bidders competed in a simultaneous multi-round auction to purchase spectrum to provide wireless telecommunications services for pre-specified geographic regions of the US. Each round of the auction, suppliers could bid on spectrum blocks in any number of geographic regions. The auction ended when there were no buyers willing to submit higher bids on any of the spectrum blocks in any geographic area. Other market rules include, most notably, bidder activity rules that limit how much a bidder can bid in later rounds of the auction depending on the bids he or she submitted in earlier rounds.

Other modifications of these basic auction rules that limit the ability of suppliers to exercise market power in auction markets include limiting the form of supply bids submitted. For example, several of these auction mechanisms only allow suppliers to change the quantity they are willing to sell each round of the auction and demanders to alter the amount they are willing to purchase each round, with the auctioneer adjusting the market price according to some function of the difference between total supply and total demand at the price set by the previous round of bidding. A simple auction structure with these supply and demand quantity bids would proceed as follows. The auction could start at some minimum price. Demanders would submit their quantity demanded at this price subject to the activity rule that they could only decrease the amount they are willing to purchase at higher prices in subsequent rounds. Suppliers would also submit their quantity supplied at this price subject to constraint that they cannot decrease the total amount they are willing to sell in subsequent rounds. The auction would terminate when the amount suppliers are willing to sell at the price set at the beginning of the round exceeds the amount demanders are willing purchase. For the case of the Brazilian electricity market, the minimum starting price for the auction could be set at the average embedded cost of its hydroelectricity facilities.

The basic auction would be operated on an annual basis, with supplemental auctions on a monthly basis throughout the year. State-owned generators would be required to sell some pre-specified fraction of their available energy through these auctions on an annual basis. To the extent it is legally possible, provincial generators would also be required to sell a pre-specified fraction of their available energy in these auctions. These requirements could be enforced through a penalty mechanism administered by ANEEL. For example, suppose the requirement was for each firm to sell 80 percent of its available energy on an annual basis through these auctions for next two years, 70 percent in years 2 to 4 in the future, and 50 percent in years 4-6 in the future. ANEEL would monitor transactions in this market to verify that each firm had this total quantity of energy outstanding in forward financial contracts at pre-specified dates during the year. Firms that failed to meet this requirement would be required to pay a penalty per MWh they are below this requirement.

Load-serving entities (LSEs) would have a corresponding requirement to purchase some fraction of their energy requirements from these auctions over the next six years. Figure 1 gives a sample time path of these forward energy requirements. Let Q_F denote a forecast prepared by ONS of that LSE's demand for coming year. The LSE would then be required to have purchased at least f_1*Q_F MWhs of energy from these auctions for the coming year (t=0 to t=1), f_2*Q_F MWhs of energy during the following year (t=1 to t=2). The required quantities that must be purchased for delivery in years 3 to 6 are the value of f_i for that year times Q_F. These forward contract requirements on LSEs could be enforced through a penalty scheme administered by ANEEL using a similar scheme to the one proposed above for the suppliers.

These forward contracting requirements would move forward in time according to the same pattern given Figure 1. For example, suppose that at some start date the LSE had met the forward contracting requirements for the coming six years given the forecast value of its demand for the coming year. Then at the end of the first year, period t=0 to t=1 would be reset to the following year and ONS would provide the LSE with a value of Q_F for this year. This value of Q_F and the fractions given in Figure 1 would then set the forward contracting requirements for this LSE for the next six years. Forward market requirements for LSEs for a six-year time horizon could be updated each year in this manner using any pattern of f_i for the coming six years.

To allow new entrants to obtain the funding necessary to undertake investments in new generation capacity and participate in the auctions for concessions at new hydroelectric sites, different delivery requirements could be placed on forward contracts with longer times to delivery. For example, in order to sell a forward contract for delivery in the next three years, ANEEL and ONS could require that the seller show that this financial commitment is backed up by a generating facility capable of delivering this amount of energy. If the MRE is retained (something that is largely unnecessary with this auction mechanism), this requirement to demonstrate physical deliverability could be enforced by the requirement that a generation unit owner cannot sell more energy than the total amount of hydroelectric energy certificates that it owns plus the quantity of energy that ONS determined it can reliably produce on an annual basis from the other non-hydroelectric generation units that it owns. ONS would continue to dispatch the system, but hydroelectric generators would be paid for their hourly output according their actual hourly production. To the extent that their hourly production deviated significantly from their forward market obligations, they would purchase the shortfall from the spot market at the hourly spot price as is the case in all other electricity markets operating in other countries around the world.

Forward contracts for delivery 4 to 6 years into the future can be purely financial commitments, in the sense that there is no requirement to demonstrate physical deliverability of the electricity in order to sell the product. However, there is a requirement to convert this financial commitment to one that is backed by a physical resource if the time to delivery for an outstanding contract is 3 years or less. This would first involve showing an existing plant or a new plant under construction that can provide the energy sold. For new plants, there would be additional stages of validation to ensure the plant will actually be able to produce the energy sold by the delivery date. This process would be overseen by ANEEL, which should also have the authority to impose penalties for failure to meet the various deadlines for project completion. In addition, ANEEL could also require a new plant to place money in an escrow account at the start of the project to make sure that the company can pay any penalties. Consequently, if a supplier sells a commitment to a given quantity of energy to be delivered 5 years in the future to a specific geographic region of Brazil, and if the supplier does not sell this commitment in a future auction within the following two years, it has to demonstrate to ANEEL and ONS that it has the physical capacity to actually provide electricity to that location within 3 years according to a process overseen by these two entities. This flexibility for purely financial trading of forward commitments 4 to 6 years in the future will provide new entrants with the freedom to sell forward energy commitments that have the option to turn into physical commitments. With such a forward financial commitment we would expect that a supplier could then attempt to purchase a license for a new hydroelectric facility or finance a new fossil-fuel facility. If they are unable to get the new capacity started within 2 to 3 years of selling the forward financial commitment, then the supplier has the option to sell this obligation back in a subsequent annual or monthly auction. However, assuming the buyer of the original contract never sells his financial obligation to consume energy, he or she is still guaranteed delivery of energy at the contract price in the initial contract.

There are many different ways that these auctions could be structured depending on how much flexibility the auction designer would like to give to generation-unit owners and load-serving entities to express their willingness to supply and demand electricity over the next 6 years. All generation firms could be allowed to bid very flexible price-quantity pairs of energy over the six-year time horizon. The retailers could then submit willingness to purchase price-quantity pairs over this same horizon and market-clearing prices and quantities or pay-as bid prices and quantities at each location could be determined by maximizing the sum of producer and consumer surplus over all geographic regions and time periods. Such an extremely high-dimensional strategy space for generation unit owners and LSEs provides these entities with the maximum flexibility to express their costs and willingness consume in the bids they submit. However, this high-dimensional strategy space also has the downside that it provides each generation unit owner with a large number of bid parameters to use to attempt to raise market prices.

If the auction designer is concerned that this flexibility would provide too many opportunities for generation unit owners to exercise market power in this auction, a version of the simultaneous multi-round auction described above could be implemented. This auction design is at the opposite extreme in terms of allowing very little flexibility in the bids that suppliers and demanders can submit and how their bid quantities can change across each round of the auction. Here the downside is that this lack of flexibility may not allow suppliers sufficient freedom to express their true cost of supplying power at each location.

There are number of details of this auction mechanism that must be clarified before it can be implemented, but the basic idea of setting minimum annual sales quantities for federal and provincial suppliers and minimum annual purchase quantities for LSEs, both for the next six years, should be a part of any auction design. The purely financial nature of distant year contracts and physical backing requirement of near-to-delivery contracts is a second feature of any auction mechanism. As discussed above, as the time until delivery becomes smaller, a supplier would have to firm up the deliverability of the energy. Finally, some penalty mechanism enforcing the minimum sales requirements on suppliers and minimum purchase requirements on LSEs should also be included any auction design.

RETAIL-PRICE REGULATION

These forward market auctions could also be used to set the wholesale market revenue requirements for electricity retailers. Each year's auction market purchases would be used to set a portion of the retailer's annual wholesale market revenue requirements. For example, suppose the retailer purchased 500 MWh in year 0 for delivery in year 3 at a price of $20/MWh, 200 MWh in year 1 for delivery in year 3 at a price of $30/MWh and 100 MWh in year 2 for delivery in year 3 at a price of $10/MWh. Assuming that 800 MWh is ANEEL's forecast of that LSE's demand in year 3, the total amount of revenue that this retailer would be permitted to recover from its customers for wholesale electricity purchases in year 3, would be equal to (500 MWh)*($20/MWh) + (200 MWh) * ($30/MWh) + (100 MWh)*($10/MWh) = $17,000. The LSE should be permitted to offer any number of tariffs to final consumers that they could choose among on voluntary basis. However, any retail revenues to cover wholesale energy purchases to serve final consumers in excess of this magnitude would be returned to these customers in a lump sum payment. However, if as a result of energy trading activity or innovative retail tariffs the firm was able to reduce its wholesale energy purchase costs below this level, it would be able to keep 100% of the cost reductions in higher profits. Conversely, if these trading activities increased total wholesale energy purchase costs beyond this level, then the firm would be required to make up the difference in reduced payments to its shareholders.

Alternatively, ANEEL could set the LSE's average wholesale price equal to its portfolio average forward contract costs for the coming year. In this case, the average wholesale price implicit in the retail tariffs would be equal to $21.25/MWh = $17,000/800 MWh. This mechanism may provide incentives for the retailer to increase it sales, because its average wholesale price is fixed, but not its total wholesale revenues. Depending on the values set for the f_1 given in Figure 1, this mechanism could set wholesale revenue requirements too high or too low. If f_1 is set too low and the LSE has not purchased enough forward contracts to hedge the price risk associated with its spot market purchases, it could be exposed to a potentially very large spot market obligation to meet its contractual obligations to retail customers. However, setting f_1 too high creates the potential for the opposite problem. By requiring the firm to purchase too much energy at too high a price, the LSE's retail price will be set too high. Consequently, in setting the value of f_i for each year, ANEEL must balance these two competing goals. However, one point seems clear from this discussion, setting $f_1 = 1$, or requiring 100% of expected load to be hedged on a year-ahead basis seems to err on the side of setting prices too high. On the other hand, because Brazil is a hydro-based electricity system and water availability does not increase in response to higher spot prices of electricity, a sustained shortfall in water could very easily completely bankrupt retailers required to sell at a fixed price. For this reason, the value of $f_1 = 1$ should certainly be above 0.95.

PREVENTING SELF-DEALING BY DISTRIBUTION COMPANIES/RETAILERS

The Brazilian market does not envision vertical separation of distribution from generation. ANEEL is also currently unable to set retail rates that prevent self-dealing without being subject to legal and political protest by the LSEs. As a consequence, the cost to consumers of self-dealing between LSEs and their generation affiliates has grown over time.

The mechanisms for setting the retailer's wholesale market revenues or average wholesale price proposed above can help to solve this problem. For example, the portfolio average wholesale price at which the distribution company purchases its forward contract requirements could set the firm's wholesale energy price portion of its average retail rate. Any retail rate set by the regulator should give the firm the opportunity to recover this average auction price times the total quantity of energy actually sold to its customers. The distribution company should then be given the opportunity to manage its wholesale energy risk subject to this revenue requirement. For example, if it would like to sell some of its forward contract coverage for the coming year, because it believes its actual load is less than the forecast load, it should be allowed to do so. Moreover, if it finds that paying load to consume less costs less than buying the electricity, then it should be allowed to do this as well. However, the regulatory process should not change the firm's retail rates in response to any of these actions during the year the rates are in effect.

ENCOURAGING ACTIVE DEMAND-SIDE PARTICIPATION

The experience of Brazil during the rationing period has shown that a considerable amount of demand response exists. However, as far as we can see, how to best involve final demand in the market has not received much attention.

A straightforward way to involve consumers in the Brazilian market would be to allow retail tariffs to reflect system conditions. Because Brazil is a hydro-based system, there is very little wholesale price volatility within the day. Consequently, there is little need for sophisticated metering technology to record hourly consumption, in order to charge consumers according to the conditions in the wholesale market. Instead, the Brazilian regulator should consider setting tariffs that have a fixed per unit component that does not vary with system conditions, but any consumption beyond this level is charged at the monthly average wholesale price. In this way, all consumers could share in the cost of managing the amount of water available to produce electricity each year.

Moreover, free customers, those able to choose their supplier (or purchase directly from the wholesale market), should be treated just like generation units selling in the wholesale market. Specifically, the default price they pay for energy should be the hourly wholesale price, unless they arrange a forward contract with some distribution company or generation company. Allowing free consumers to return to the default customer rate at their discretion provides them with a hedge against spot price risk and the risk of curtailment that, in effect, means unnecessarily subsidizing these customers.

In the following we discuss in some detail various issues associated with the question of how to organize demand-side participation, including

- the underlying economic rationale;
- allocation of rights and responsibilities between consumers and other market participants;
- transactions costs; and
- legal, political and other constraints.

We end by outlining a few suggestions for reform adjustments designed to increase demand-side participation in the Brazilian market.

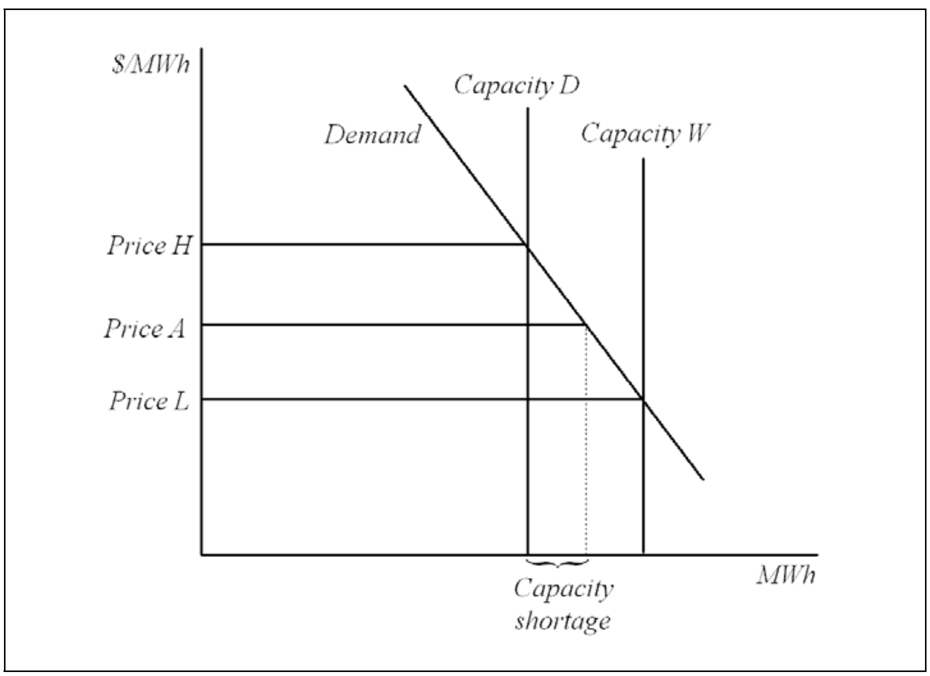
THE SIMPLE ECONOMICS OF DEMAND-SIDE PARTICIPATION

If there were no variation in demand and supply the optimal solution would simply be to build enough capacity to ensure that, at prevailing prices, all demand could be served. Given that demand and supply inevitably vary over time, sometimes in an unpredictable manner, this is not possible; there is always some likelihood that available capacity will be insufficient to meet demand.

Figure 1 illustrates this idea. The horizontal axis measures the volume of output (in MWh), while the vertical axis measures the price of output (in $/MWh). Output capacity is given, independently of price, but depends on underlying technological factors; in the figure, two capacity levels are illustrated (for a 'wet' and a 'dry' period, respectively). Demand, however, depends on price; the lower is the price, the greater is demand.

Consider first a case in which price remain fixed over time, independently of the underlying market conditions. For example, if price A prevails, the system will be in a situation of either excess demand or excess supply, depending upon the state of supply. In particular, in event D, the installed capacity will be insufficient to satisfy demand.

Alternatively, price may fluctuate according to market conditions. For example, in the event that capacity is D price is set at H, while if capacity is W price is set at L. In this case, demand and supply balances at all times; in particular, there is never any capacity shortage.



• *Figure 1: Capacity shortage*

Given available capacity, there are in principle two ways of eliminating a shortage: either price must be increased so as to choke off demand, or demand must be rationed. The effectiveness of the price measure depends on the responsiveness of demand to price changes. In the short run, the price elasticity of demand is typically very small. In the longer run, however, demand will respond much more elastically to price changes. The character of the supply security issue is, therefore, quite dependent on the time frame.

In the short run – within the day or hour – a capacity shortage may result from a shock on the demand side, resulting in an unusual peak in demand. More commonly, however, capacity shortages occur as a result of supply shocks. Such a shock may be due to a reduction in generation capacity, caused, for example, by a plant outage. Alternatively, failures in the transmission system, that reduce the ability to transport power from generation to consumption sites, may make it impossible to satisfy all of demand.

In the short run, capacity shortages have historically been dealt with by rationing. In principle, one could envisage a real-time market in which price reacted continuously to shifts in demand and supply. Modern telecommunications and metering equipment, and price sensitive controls installed at power-consuming devices, would ensure sufficiently rapid responses to shifting market conditions so as to achieve electrical equilibrium at all times. Electricity markets should – and probably will – move in this direction.[2] Even so, demand and supply shocks can occur so rapidly – and are so large – that serious imbalances eventually will occur. Consequently, some sort of rationing scheme must be in place to avoid such imbalances leading to out-of-bound frequencies ('brownout') or, in the worst case, a physical breakdown of the system ('blackout').

Fortunately, in a hydro-based system such as Brazil, there is rarely inadequate generating capacity to meet demand within a given hour of the day. Supply shortfalls in hydro-based systems take the form of energy shortfalls, where there is inadequate water to serve all demand over a given period of time, not inadequate generation capacity to meet demand peaks. A system with a considerable share of hydro-based generation output will tend to vary between wet and dry periods. In particular, extreme events, leading to long spells of low precipitation, may severely reduce the system's ability to produce energy. Similarly, demand may fluctuate over time in response to changes in outside temperature or other factors.

The scope for curtailing demand by means of price is therefore much larger in hydro-based systems. Energy shortages seldom occur suddenly and may often be foreseen well in advance. Consequently, prices can be adjusted before the actual event. Demand will generally be more responsive to higher prices when these prevail over a longer period of time. As a result, energy shortages are in principle avoidable, so long as prices are allowed to adjust sufficiently in line with underlying changes in supply and demand.

The sort of price changes that will be necessary to avoid energy shortages may however be quite large. During extremely low water conditions prices may have to rise to unprecedented heights in order to curtail demand to the level of available energy capacity. However, the bottom line is that when there is insufficient energy to meet demand at the prevailing retail price, demand must be reduced either voluntarily in the form of higher prices or involuntarily in the form random rationing. These high prices can impose significant hardship on consumers who pay for their entire consumption at these prices. However, it is hard to imagine that a rational consumer, faced with such a choice, would take such a risk.

Typically consumers would want to protect themselves against the potential for paying extremely high prices for all of their demand. This can be accomplished by entering into long-term contracts for a substantial fraction of their expected annual demand at a fixed prices and purchase their remaining consumption at the hourly spot price. In this way, consumers can take on an acceptable

[2] For arguments supporting such a development, see for example Borenstein (2001a, b).

level of spot price risk and shift their consumption in response hourly prices. Even though consumers are protected from high spot prices as a result of this forward contract, they still have strong incentives to reduce their demand beyond their forward contract quantity. To understand this incentive, consider the following example. Suppose a consumer purchased the right to buy 50 MWh at a price of $20/MWh. If the spot price rises to $200/MWh, this customer must pay $200/MWh for any consumption beyond 50 MWh. However, for consumption less than 50 MWh, this customer receives a refund on his monthly bill of $180/MWh for each MWh not consumed, because this customer has an extremely valuable right to buy 50 MWh of a product worth $200/MWh at a price of $20/MWh. Through this sort of hedging behavior, customers can take on an acceptable level spot price risk and earn substantial revenues from reducing their consumption in response to high spot prices. In this example, a customer could earn $9,000 = ($180/MWh) * (50 MWh) by not consuming any electricity in that month. As the spot price of electricity rises, the potential revenues earned by customers with fixed price forward commitments who forego consumption can be substantial.

Although one might think that setting high spot electricity prices is politically unacceptable, this is unlikely to be the case if there are a substantial number of customers with the right to purchase a fixed amount of MWh at a fixed price. These customers will argue for the right to profit from their apparent skill in hedging spot price risk. Consider the case of business and leisure air travelers. Business travelers tend to pay higher prices because of their inelastic demand. However, leisure travelers do not complain about the high prices paid by business travelers. They instead attribute the lower prices they pay for travel to their greater flexibility in terms of when they travel. Consequently, it is possible to allow all customers the *ex ante* opportunity to select the amount of spot price and quantity risk they wish to bear. In this way, no consumers will be harmed on an *ex ante* basis by high spot prices, because all customers have the right purchase a hedge against all but a very small amount of spot price risk. Industries highly dependent on electricity will therefore have a stronger incentive to hedge spot price risk. However, it is important to emphasize that there is no need for customers to be harmed by high spot prices and little need to resort to rationing to meet energy shortfalls, which is an extremely inefficient form of implementing a demand reduction. Clearly, overall cost to society associated with rationing is always higher than cost to society associated with using spot electricity prices to reduce demand. Under a rationing scheme customers with a high willingness to pay are curtailed with the same probability as customers with a low willingness to pay. Using spot prices to reduce demand guarantees that customers with the lowest willingness to pay will be the first to be curtailed.

The key to the successful use of demand-side participation to manage energy shortfalls is that no consumers are given complete hedges against spot price risk without paying the full cost of providing such a hedge. The cost of guaranteeing a fixed wholesale price for any quantity of consumption a final customer might choose is extremely expensive. Evidence from such full requirements default provider auctions in the US have yielded prices more than twice the average annual wholesale price. Unless a customer is willing to pay the fixed price necessary for some generation unit owner to be willing to make this full-requirements guarantee, then he or she must face some residual spot price risk. The regulator can set a fixed price full-requirements price below this level, but unless a retailer is able to procure the necessary wholesale market commitments at low enough prices to meet this fixed price commitment, implicit in such a requirement is probability that the retailer must default on this obligation. This is precisely the circumstance that existed in the California market. The California Public Utilities Commission and the LSEs negotiated a fixed price, full-requirements commitment California LSEs had to final customers. This commitment had a certain probability of default. Unfortunately, wholesale market conditions occurred which caused this default to occur. Had the promise to final consumers not been full-requirements at a fixed price, but a certain quantity of energy at a fixed price, the California electricity crisis could have been managed by offering customers the option to sell back their fixed-price quantity commitments at the current spot price.

The lesson from the California electricity crisis and the full-requirements default provider auctions in the US are that such full-requirements contracts are extremely expensive to provide. Few consumers would voluntarily elect to buy such contracts if offered the option to take on some spot price risk.

CONSUMER RIGHTS

In Brazil, so-called 'free consumers' are able to choose their suppliers freely (incl. taking their supplies directly from the wholesale market). This group is quite small, consisting of those with peak consumption above 3 MW and/or connections at a voltage level higher than 69 kV (starting from July 2003 ANEEL can reduce these capacity and voltage requirements).[3] The vast majority – the so-called 'captive consumers' – must take their supplies from their distribution company. Prices to captive consumers are (implicitly) regulated by the so-called Valor Normativo – or normative value – VN. The VN is a cap on the energy cost negotiated in a bilateral contract that a distribution utility can pass through to consumers.[4] The VN is set by ANEEL.

While the VN regulation does provide captive consumers with price protection, the actual extent of this protection would seem to be at the discretion of the regulatory authorities (ANEEL). In particular, the regulatory regime does not seem to rule out changes in pricing structure. During the 2001-2002 rationing event the government introduced a set of bonuses and penalties that in effect raised the price to consumers when their consumption exceeded a certain (individually set) threshold. Also, the current regime does not seem to preclude time-varying prices (at least as long as the average stays below the VN).

The regulatory regime does not give consumers – whether free or captive – the right to choose their level of supply security. Rationing of consumers will be carried out by so-called 'technical criteria', which do not take into account the contractual position of individual consumers. This means that a consumer is not able to protect himself or herself against a rationing event by entering into a contract with his or her supplier (or the system operator, for that matter).

In other words, while there is no way for market participants to contractually allocate quantity risks among market participants, the current regulatory regime does seem to provide for contracts with varying degrees of price hedging for captive consumers. For instance, it does seem possible for suppliers to offer contracts with different extents of price variability, so long as they do not violate the VN constraint. Furthermore, the regulator would seem to have the opportunity for regulating the price structure of contracts directly, if he so wished.

Free consumers should not be given the option to a full requirements hedge against spot price risk that is guaranteed by the Brazilian government. Free consumers should be treated the same way as generation unit owners. Their default price should be the hourly spot price of electricity. Unless they sign a forward contract, this should be the price they pay for all energy they consume. Suppose a free consumer has an hourly demand for electricity equal $D(p)$, where p is the hourly spot price of electricity. Let $SN(p) = D(0) – D(p)$, where $D(0)$ is this customers demand for electricity at a price of zero. Viewed from this perspective, a free consumer with no ability to impact the spot price is no different from a generation unit owner with no ability to impact the spot price with a marginal cost function equal to $SN(p)$. For this reason, free consumers should be treated exactly the same way as a

[3] It is not clear whether free consumers have the option of being captive; in particular, it is not clear on what conditions a free consumer can return to a default supplier. As we understand it, free consumers can choose a default at their discretion.

[4] We are unclear on how the VN mechanism treats energy not obtained in bilateral contracts (say, from the wholesale market).

generation unit owner. Unless they purchase hedge contracts, they should be subject to all spot price risk.

Captive consumers create a different problem. Here the issue is making sure that if these consumers have a fixed-price, full-requirements contracts, this contractual obligation is prudentially hedged by the load-serving entities, and there is not an implicit default probability in this contract. As discussed above, a superior solution is to allow fixed and variable price commitments between LSEs and final demand with fixed contractual commitments, and not full-requirements commitments. If full-requirements, fixed-price commitments are made available, ANEEL must guarantee that they are fully hedged by the LSE offering this service.

SUPPLIER RESPONSIBILITIES

Distribution companies are obliged to serve all of the demand by captive consumers at regulated prices. They are also required to cover 85% all 'captive load' by long-term contracts with a minimum duration of two years.[5] Should rationing occur, distribution companies and energy traders will not be held responsible for the supply of their individual customers. In other words, rationing of any consumer will be carried out by technical criteria that do not take into account how well (or poorly) this consumer is covered by contracts. As noted above, rather than have rationing as the end-game when there is a supply shortfall, ANEEL should re-structure contractual obligations between LSEs and the final demand, so that final consumers bear some portion of the risk outages, preferably through fixed-price, fixed-quantity contracts between LSEs and final demand, instead of full-requirements fixed-price contracts that have the distinct possibility of rationing.

TRANSACTION COSTS

The extent of contractual flexibility is to a large extent limited by costs associated with metering electricity consumption. However, given the large share of hydro-based generation, and the associated large power capacity, there is in the foreseeable future little need for demand-side flexibility in the very short run (hour-to-hour and day-to-day). Instead, demand flexibility should be encouraged over the medium and longer term (season-to-season and year-to-year). From a practical point of view, this considerably simplifies matters, as there is no need for real-time (hourly) measuring of consumption patterns. On the contrary, monthly or quarterly (or even yearly) metering of energy consumption may be sufficient to allow for contractual designs that encourage sufficient demand flexibility to share the risk of energy shortfalls between suppliers and final consumers.

Allowing parties to contract freely has the advantage that contractual terms will tend to reflect underlying needs of individual agents (duration, risk hedging etc.). However, allowing contractual freedom may increase overall transactions costs (associated with finding trading partners, negotiating terms, ensuring adherence to contractual obligations and so), especially in an immature market where individual parties have little or no experience with negotiating such contracts. In particular, contractual discretion may allow parties with market power to engage in anti-competitive practices (such as price discrimination). There are good reasons, therefore, to regulate contractual terms, at least in an initial period, until the market matures.

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5 Up till now all load has been covered by the 'Contratos Iniciais', or Initial Contracts. These are compulsory bilateral contracts for energy designed to smooth the transition process from the old to the new regulatory regime. They apply to all producers and distributors and increase every year so as to cover essentially all existing and projected loads up to year 2001. The contractual volume requirements (in GWh) remain the same in 2001 and 2002. Starting in 2003, the Initial Contracts are reduced by 25% and will be completely extinguished by the end of 2006.

One way of introducing such regulations would be to lay down a set of principles that all contracts must satisfy. These could include rules about non-discrimination, price caps, individual responsibilities, conflict resolution and so on. While such principles would ensure the reasonableness of overall contractual terms, they would still leave parties with a certain freedom to agree on the specifics of their contracts.

An alternative route is to introduce a default contract, by which the parties are bound unless they agree to change the terms. The default contract would be complete, in that it specifies in detail all relevant terms, and hence would alleviate the parties of the need to enter into explicit negotiations about contractual details.

The two approaches may of course be combined. This could be done by having a default contract and at the same time lay down rules about the extent to which the parties could deviate from the default terms. Alternatively, the default contract could be incomplete – only covering certain aspects of the trade – requiring the parties to negotiate their own terms for the remaining aspects. Regardless of the strategy followed, this contract should ultimately specify all the payments between the LSE and final consumer under all foreseeable contingencies. In addition, full requirements contracts should not be offered by LSEs unless ANEEL can verify that that the LSE has taken the necessary actions in the forward market to guarantee it will be honored.

LEGAL, POLITICAL AND OTHER CONSTRAINTS

While the supply security issue is important in its own right, it also has wider implications. The recent rationing events in California and Brazil remind us that, whatever the reasons for disruptions, the government will be held accountable for ensuring continuity of supply and failing in its task could lead to its downfall. There is, therefore, a temptation to maintain a strong grip on the industry, even when there are good arguments, economic and other, favoring deregulation and privatization. Providing solutions to the supply security problem is consequently crucial, not only for the acceptance of regulatory reforms, but for their sustainability also.

While the handling of the Brazilian supply crisis seems to have been quite successful, not leading to major political upheavals we would nevertheless expect there to be a strong political will to avoid a similar situation occurring again. On the one hand, this should provide for a willingness to consider seriously measures designed to increase supply security, including more active demand-side participation. On the other hand, creating a situation of strongly fluctuating energy costs – even if this could be shown to reduce the need for costly investment and hence increase the overall efficiency of the system – might be considered too costly, politically speaking. However, as noted above, by offering final consumers the option to hedge the vast majority of this spot price risk, the political difficulties associated with passing through spot prices to final consumers can be minimized, because there will customers that receive substantial benefits and customers that are penalized, but all customers had the *ex ante* opportunity to take the necessary precautions against the eventuality of a period of high spot prices.

Such concerns are not unique to Brazil, or even to Latin-America. All over the world governments worry about the implications of exposing consumers to actual electricity market conditions. We believe that some of these worries are exaggerated, in the sense that as consumers learn to adopt to their new situation (which will, in fact, not be much different from what they experience for most other goods, including other energy products) they will gradually accept that in this market fluctuating prices is the order of the day. For example, the experience from the Nordic countries – where retail prices tend to vary quite considerably over the season and from year to year

– the general public seems to have accommodated well to the more open and volatile market.[6]

Nevertheless, it may well be advisable to choose a gradual approach to demand-side participation. Firstly, most consumers would presumably welcome the opportunity to learn about how the market works before being required to participate actively, rather than being thrown right into a new market place. In particular, ANEEL can set initial standards for the maximum amount of spot price that a final consumer can take on. For example, it can impose a requirement that all regulated consumers must purchase at least 90% of last year's monthly energy demand in a fixed-price and fixed-quantity annual forward contract. Given that most consumers will probably have fairly similar preferences about what sort of contracts they would want to enter into (regarding risk hedging, duration etc.) the cost of regulating contractual terms – thereby limiting consumers contractual freedom – probably does not involve very great costs. As the market matures, one may want to increase consumers' contractual freedom, either by allowing more consumers to become 'free' or by easing restrictions on default contracts.

Apart from constraints of such a political nature, we are not aware of other constraints – legal, social or other – that would preclude more demand-side participation in the electricity market.

CONSUMER CHOICE

Allowing consumers a choice may be considered a benefit as such, but it also has the potential for improving efficiency, by letting consumers adjust to their actual needs and by encouraging suppliers to offer products that are tailored to their customers' needs. However, unless consumers are exposed to the actual consequences of their actions, individuals' choices may impose costs on other participants in the market.

Consider for example a case in which consumers can choose between two types of contracts, a fixed-price and a variable-price contract, respectively. Under both types of contracts consumers can take as much power as they want, but whereas the fixed-price contract offers power at a given price, the variable-price contract relates the price to actual market conditions, say to the wholesale price. Since the variable-price contract subjects consumers to risk, and also reduces the need for ensuring costly supplies in times of tight market conditions, such a contract will typically be sold at a premium; that is, the average (or expected) cost of electricity under such a contract will typically be less than under a fixed-price contract.

However, if consumers can switch back and forth between contract types the real difference between these contracts may be less than first envisioned. In particular, a consumer would want to hold a variable-price contract whenever the electricity price under this contract is below that of the fixed-price contract, and *vice versa*. Consequently, if consumers can switch contract at short notice, the fixed-price contract price will in effect put a ceiling on the price that consumers face. Moreover, such behavior will shift risk from consumers to suppliers and necessitate larger supplies in times of tight market conditions (when high variable prices would otherwise have encouraged consumers to reduce their demand).

Such behavior may not constitute a problem so long as buyers and sellers are free to negotiate contractual terms. Then consumers may well be given the opportunity to switch between contracts, but only at a cost; in particular, the duration of each type of contract, as well as the terms on which a contract can be terminated, will typically be subject to negotiations.

[6] Obviously, rising prices always make headlines – and people complain – but after the initial scare following the first dramatic price increase after deregulation, there is now no serious debate about tampering with market prices.

If the parties are not free to negotiate their own terms, however, matters are very different. For example, if regulations stipulate the fixed-price contract as a default, to which all consumers have the possibility to switch at their discretion, the resulting behavior basically shifts the entire risk to suppliers. The recent experience in California demonstrates what detrimental effects such regulations can have on the financial stability of the suppliers (distribution companies) in particular, and the electricity supply industry in general.

It is important therefore – to the extent that contractual terms are defined by government regulations – that these terms provide agents with incentives to behave such as not to shift costs and risks unduly between parties. Notice that this concern is relevant, not only for so-called 'free consumers' (i.e. consumers who are free to choose their supplier), but for any consumer that is provided with contractual freedom. In particular, if consumers are given the opportunity to choose between contracts that provide more or less exposure to price variability one should consider limiting their opportunities for reversing contractual choices.

ELASTICITY OF DEMAND

The recent rationing event suggests that in Brazil demand flexibility may be considerable. Consumption records from June to December 2001 showed a 20% load reduction, compared with the previous year. If one takes into account that new customers entered the market, actual savings per consumer were event greater than suggested by these numbers. However, the rationing intervention was clearly a unique event, and the reduction in consumption was clearly motivated not only by price increases (i.e., the bonuses and penalties that were introduced) but also by other concerns. This is evident, for example, by what happened in the South region, which was not forced to ration, but which nevertheless participated in the load reduction effort, as a result of appeals in the media. It is unclear, therefore, whether a similar response could be achieved under more normal circumstances.

Evidence from studies around the world suggests that electricity demand may in fact be fairly inelastic, at least in the short run. Admittedly, results tend to vary considerably, depending on the type of data used and the statistical techniques employed. However, it is not uncommon to find estimates of the demand elasticity at 0.2 or lower, implying that demand would fall by a modest 2% following a price increase of 10%.

It may be, therefore, that one will have to introduce fairly strong price signals in order to achieve substantial responses on the demand side. Furthermore, the demand response will probably depend on exactly how price signals are designed and the extent of publicity that these signals receive. For example, consumers may react differently if the price on their entire load varies than if only a marginal part of their load is exposed to price variation. They may also react differently to a penalty on demand increases as compared to a bonus on demand reductions. And, of course, consumers' awareness – and hence their response – will to a large extent depend on the public (media) interest in electricity prices.

PROPOSALS FOR INCREASING DEMAND PARTICIPATION

On the basis of the above discussion, we base our recommendations on the following assumptions:

- There are good economic reasons to introduce more active demand-side participation, in order to increase demand flexibility and hence reduce the need for costly investment in new generation capacity.

- There are no constraints – political, legal or other – that preclude wider demand-side participation in the electricity market. There may be a need for changes in certain regulations, but these can – at least in principle – be achieved within the current regulatory framework.

- There is, at least in the foreseeable future, a need for protecting consumers – especially those on low incomes – against strongly fluctuating electricity bills. Contractual design must therefore combine the need for providing price signals with a considerable degree of hedging against price risks.

- In order to limit transaction costs, default contracts should be simple and not depend on sophisticated metering or settlement procedures.

Default contracts: A straightforward way to involve consumers in the Brazilian market is to allow retail tariffs to reflect system conditions. Because Brazil is a hydro-based system, there is very little wholesale-price volatility within the day. Consequently, there is little need for sophisticated metering technology to record hourly consumption, in order to charge consumers according to conditions in the wholesale market. Instead, the regulator should consider setting a default tariff that have a fixed per unit component that does not vary with system conditions, but any consumption beyond this level is charged at a price depending on the wholesale price (say, a monthly average). In this way, all consumers could share in the cost of managing the amount of water available to produce electricity each year.

Contract flexibility: Some consumers may be willing to bear a higher risk than what would be offered in the default contracts. Such consumers could be given the opportunity to choose other types of contracts with more price variability, as this would further increase demand flexibility. It may not be necessary to actually provide regulations for such contracts. It may be more efficient, at least as long as transactions costs are not too high, to provide distributors/suppliers with incentives to enter into such contracts and then leave it to the parties to freely negotiate contractual terms.

In order to provide suppliers with incentives to offer such contracts, they should be allowed to keep (at least some of) the efficiency gain. This would be the case under price-cap regulation, as long as the cap covers that load that is negotiated at flexible prices, as any savings on wholesale procurement costs would remain with the supplier.

Some consumers may also want a higher degree of hedging that what is offered in the default contracts. Such demands do not in themselves involve any efficiency problems, but they do require consistent regulation on other elements. Firstly, since increased hedging typically involves the muting of market signals (unless the contracts are purely financial) and so leads to less demand flexibility, the cost of the additional generation capacity needed to cover demand should be born by the parties to the contract. This would require that either the consumer or the supplier be required to enter into contracts for the needed capacity (energy). One way of doing so would be to relate the contractual coverage on suppliers to the load under fixed-price contracts.

CONCLUDING COMMENTS

The primary goal of the reform process is ensuring sufficient capacity/investment to serve reliably Brazil's growing economy. Consequently, the market design process should focus on the development of a market for new capacity, rather than a spot market for electricity. Clearly, a mechanism for dispatching units in real-time that is transparent and stable is extremely important, and we have provided a number of recommendations for improving this process. International experience has shown that bid-based spot markets are very susceptible to market power problems. In addition, particularly for a country with a rapidly growing demand, the major source of benefits from re-structuring is not likely to be the result of spot prices signals, but instead better decisions about where, when and what technology to use to meet future demand growth. A first step towards developing an active forward market is to require buyers of electricity (consumers, or retailers on their behalf) to enter into long-term contracts with duration sufficiently long to provide the necessary financial guarantees to new entrants to cause them to build new capacity to meet Brazil incremental energy requirements at least cost. To ensure deliverability of this new generation capacity at definite date in the future, sellers of long-term electricity contracts should be required to back these new investments with commitments to produce electricity from these units according to a pre-specified timetable. To limit the transactions costs load-serving entities must pay to hedge their retail energy obligations and limit the opportunities for generation unit owners to exercise market power, long-term contracts should be standardized and traded in auction markets that are open infrequently, specifically yearly auctions with monthly supplemental auctions. The auction prices can then be used to set maximum retail prices that load-serving entities are allowed to recover from their customers. To stimulate more efficient utilization of existing generation capacity consumer participation in the wholesale market should be encouraged. Because of the dominance of hydroelectricity in the Brazilian system the technological cost of doing this is substantial less than in a fossil-fuel based system, because large price differences occur primarily across seasons of the year or across years, rather than across hours within the day. Consequently, there is little need for sophisticated metering and billing systems to implement a substantial demand-side participation program in Brazil relative to countries with fossil-fuel based systems.

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Figure 1: Pattern of Forward Contracting Requirements for a Load-Serving Entity for a Six-Year Time Horizon