Namibia IPP and Investment Market Framework Technical Assistance

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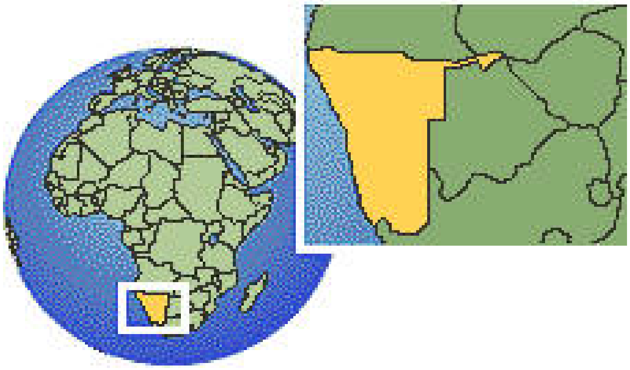
REGULATORY BARRIERS AND RISK MITIGATION



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ANNEX 8: REGULATORY BARRIERS RISK MITIGATION MEMORANDUM

MEMORANDUM

TO: ECB, CORE

FROM: PAUL SOTKIEWICZ

SUBJECT: REGULATORY BARRIERS/RISK MITIGATION FOR INDEPENDENT POWER PRODUCERS IN NAMIBIA

DATE: 10/4/2006

CC: DONALD HERTZMARK, VINOD SHRIVASTAVA

I have been asked by CORE to prepare a memo regarding regulatory barrier/risk mitigation for IPPs in Namibia to be presented and discussed in conjunction with the CORE/USTDA mission for the week of June 12-17. Some of the issues discussed below have been identified in the *Namibia IPP and Investment Framework Technical Assistance Inception Report* dated April 21, 2006, while others have not. The main purpose of the memo is to provide an overview that is as comprehensive as possible with the understanding that particularly detailed issues or questions in the Namibian context not addressed here will be addressed at a later date.

DEFINE A POLICY FOR IPPS IN AS MUCH DETAIL AS POSSIBLE BEFORE CONTRACTS ARE SIGNED

It is of the utmost importance for government or the electricity regulator, depending on country context, to attempt define in as great a detail as possible so as to minimize the uncertainty to both the IPP and off-taker about what is or is not acceptable. This principle seems simple, but a well defined policy that reduces uncertainty for all parties related to the IPP will likely reduce costs to the developer as well as the off-taker.

In the absence of a well-defined policy, the contracting arrangements between the IPP developer and the off-taker become more complex which may lead to a greater likelihood of contract incompleteness and socio-political unacceptability which often leads to contract renegotiations.

The main areas where it is crucial for policy to be well-defined are:

1) The acceptable level of IPP costs that will be allowed to be passed through to customers along with any incentive mechanisms to keep down the costs of the IPP while allowing a “reasonable return” on the developer’s investment. Implicit in any discussion of cost pass through is the idea of risk allocation and mitigation.

2) Part of whether costs are considered prudent or acceptable is the manner in which the deal is negotiated. In many regulatory frameworks competitive tendering is required to assure all costs are prudent. However recent examinations of competitive tendering processes seem to indicate negotiations between parties may result in better outcomes.

3) The way in which the services of the IPP will be priced to the off-taker and hence the effect on the costs that allowed to be passed through to regulated customers. In many instances take-or-pay provisions have forced off-takers to take the power when it is not needed in order to ensure the IPP recovers its costs. The other issue here is the rate design used for compensating the IPP with the two obvious choices being to recover all costs in the per MWh charges or to use a multi-part pricing mechanism to discerns between fixed costs (capacity, overhead) and variable costs (fuel, extraction, etc.).

4) With a determination of what costs will be passed through and how the IPP services will be priced, the next issue is how to allocate the costs associated with the IPP across customer classes. Again, there are various rate design methods possible, but some may work better than others. The allocation policy is crucial for acceptability for the customers of the off-taker and by extension to government.

5) Finally, an issue that comes up is the overall price level currently in existence at the time of the IPP's entrance into the market. There are two main areas of concern. The first is the idea that prices reflect revenue insufficient tariffs. Regardless of the state of IPPs, this is a situation that should be corrected to ensure the financial sustainability of the electric power sector. The second relates to revenue sufficient tariffs and the choice of how the capital base is to be computed for rates. Regulators have a role to play here with choices of the base by which prices are computed (historical costs or replacement costs generally) in order to signal to consumers the cost of producing power. This is especially true in cases where the existing capital stock has been fully amortized and the true costs of power in current prices are not reflected in rates. The issues of price level and revenue sufficiency are important for socio-political acceptability and important to signal to IPPs that they will be able to recover costs in the regulatory environment. However, it is not directly related financially to the IPP project itself. If the costs of the IPP appear to have adverse rate impacts on some classes of customers, that can be addressed through cost allocation and rate design.

PASS THROUGH OF IPP COSTS

Perhaps the biggest regulatory risk or issue faced by the IPP and off-taker is what costs will be allowed to be passed through to off-taker's customers. An automatic, full pass through of costs places all the risk on electricity consumers and provides no incentives for the IPP or off-taker to keep costs down, although the reduced risk, in theory, should reduce the cost of capital and therefore the total costs of the project. A full pass through should ideally only be considered if the regulator has the ability to review the contracts *ex ante* for reasonableness, and/or if the IPP and associated power purchase agreement can either be benchmarked in some fashion or if the contract was procured through a competitive tender (discussed below). It may also be possible to set up an incentive scheme that does not necessarily allow a full pass through of certain controllable costs such as fuel costs, for example.

The reason for *ex ante* review rather than an *ex post* review of costs is that after-the-fact reviews of costs create risk and uncertainty for the IPP and/or the off-taker in that what may have seemed reasonable and prudent before may later be determined to be neither reasonable nor prudent. Reviews before the fact create a sense of stability and knowledge that as long as the rules are followed costs will be recovered.

With respect to benchmarks, it would be helpful to have market-based benchmarks in functioning power markets. In the Namibian context, the closest thing to a power market is the bilateral trading that goes on within SAPP and the prices at which transactions occur are generally not publicly known (to my knowledge). This leaves administratively determined benchmarks as the remaining alternative. In the Namibian context, such a benchmark could consist of an estimate of natural gas costs from the Kudu project, plus an international benchmark of installed costs of a combined cycle natural gas facility of similar size. But even such an administratively determined benchmark has its problems. One is how to estimate the costs of gas from a field that is yet to be tapped. Another is how to differentiate country risk across countries in an international benchmarking study. And finally, how one might handle foreign exchange risk in the cost is not entirely clear. A cruder benchmark may be the cost of using a petroleum distillate fired combustion turbine or combined cycle unit with which there is much regional knowledge and experience. Such a benchmark would provide an upper bound on costs.

Finally, regulators in different parts of the world have made the determination that power or projects procured through a competitive tender process are by definition reasonable and prudent and are thus entitled to full cost pass through. The implication of using a competitive tender is discussed in greater detail below.

Even if a full pass through of costs is allowed under the best of circumstances, a full pass through provides little incentive to reduce costs and operate efficiently. Regulators, off-takers, and IPPs are potentially leaving money on the table for their respective constituents. If fuel costs are controllable, it makes little sense to place all the risk on consumers who have little ability to mitigate that risk. Why not provide a “benchmark”, perhaps changing to reflect changing fuel markets, that the IPP or off-taker could beat and thus keep some of the cost savings. Moreover, if fuel costs rise over the benchmark, then consumers are not fully exposed to the full increase. The same idea might apply to hedging foreign exchange risk where the IPP can increase its profits by hedging foreign exchange fluctuations.

References:

Beatriz Arizu, Luiz Maurer, and Bernard Tenenbaum, "Pass Through of Power Purchase Costs: Regulatory Challenges and International Practice" World Bank Energy Sector and Mining Board Discussion Paper No. 10, February 2004.
Tonci Bakovic, Bernard Tenenbaum, and Fiona Woolf, "Regulation by Contract: A New Way to Privatize Electricity Distribution?" World Bank Energy and Mining Sector Board Discussion Paper No.7, March 2003.

COMPETITIVE TENDERS VERSUS NEGOTIATIONS

Competitive tendering processes have been used by governments and private firms around the world to procure services in the belief that competition will invite many bidders which will result in lower prices for procurement of goods and services. Moreover, competitive tendering processes are also used to promote transparency and as a check against corrupt practices. Finally, a competitive tendering process helps offset some of the information asymmetries that may exist between the buyer and the seller of the good or service in question.

In spite of the advantages of competitive procurement, recent economic analyses of procurement practices in the private sector reveals that procurement is often done through the process of negotiation rather than competitive tenders and that this is more a rule than an exception in many industries. According to Tadelis and Bajari (2006),

> "In contrast, scholars and practitioners of engineering and construction management argue that the central problem in procurement is not that suppliers know so much more than procurers at the onset of the project, but that instead both procurers and suppliers share uncertainty about many important design changes that occur after the contract is signed and production begins. These changes are usually a consequence of design failures, unanticipated conditions, and changes in regulatory requirements." p. 3

And this is what an IPP project really at its heart, an engineering and construction project.

The choice of mechanism to use is a function of the complexity of and uncertainty surrounding the project to be undertaken. The trade-offs between the choices are the incentive to keep project costs down versus the incentive to adapt to changes and to share information between buyer and seller which keeps renegotiation costs down.

For projects, goods, or services that are relatively simple, a competitive tender process is preferable. For example, suppose there are multiple IPPs on the ground willing to supply power. The contracts for these are simple in that the buyer wants power (MWh) at a certain price. The complexities have already been encountered and dealt with at the development stage of the IPP. Note the implicit allusion to a fixed price for power in this example. However, if the project is complex and full of uncertainties, much like the Kudu project where there are two phases of development with the gas field and the power project, then it may be preferable to use negotiations rather than competitive tender. Finally, not all projects can be fit into the category of simple or complex. For projects that have "moderate complexity and uncertainty", the choice of procurement mechanisms may be dependent upon the number of available suppliers. If the number is small, then negotiations may be better, but if there is a large number of suppliers, then competitive tendering may be better. Unfortunately, what is a large number or a small number of suppliers is up for debate.

Finally, the choice about the method of compensation for the IPP developer (generically fixed price versus cost-plus), which has large implications for risk allocation between developer and off-taker, is also affected by the complexity and uncertainty surrounding the project.

First, for IPP or power purchase agreement (PPA) contracts that are not complex or filled with a great deal of uncertainty that cannot be anticipated, and performance (output) can be verified then a fixed price contract may be preferable. One could imagine a very simple contract where the IPP had already been built and the IPP had a long-term fuel contract. In this case a fixed price contract might be appropriate and would provide the IPP with incentives to keep its facility up and running efficiently. Second, if a project has a lot of uncertainty and complexity with changes likely throughout the life of the project, such as a Greenfield IPP project being built from the ground up, then a cost-plus price may be preferable.

In summary, projects that are simple with many potential suppliers could be procured by competitive tender at a fixed price. For projects that are complex or with few potential suppliers, then a negotiated contract may be preferable to avoid costly renegotiations and to even procure the project at a lower price. According to Bajari, Houghton, and Tadelis (2006), for highway construction contracts in the US, bidders for these complex and uncertain contracts increase their bids significantly to account for adaptations that are likely to occur and result in project renegotiation. The estimated adaptation cost figured into the bid is between 8% and 24% of the estimated project cost. For large projects, this would be a significant amount of money. How this result translates to IPPs in a developing country context is not entirely clear, but does confirm the intuition some have regarding the prices for IPPs in developing countries that account for risk and the possibility of renegotiation.

<u>References:</u>
Patrick Bajari, Stephanie Houghton, and Steve Tadelis, "Bidding for Incomplete Contracts: An Empirical Analysis", Working Paper, February 3, 2006.

Steve Tadelis and Patrick Bajari, "Incentives and Award Procedures: Competitive Tendering vs. Negotiations in Procurement", Working Paper, January 2006. Forthcoming in the *Handbook of Procurement*, Cambridge University Press, 2006.

PRICING IPP SERVICES
IPPs provide two main services. The first service is the capacity potential to produce power. This service may be especially important if the IPP is a thermal unit in a hydro-dominated power system as such systems are vulnerable to

drought. This first service can be thought of as a physical call option on the power that could be produced from the capacity. Another way of thinking of this first service is as an insurance policy against drought in a hydro-dominated system. The second service an IPP provides is the actual energy produced. It is useful to think about the services provided by the IPP when thinking about how to price its services.

As mentioned in the introduction, there are two main methods by which the IPPs services can be priced. Perhaps the most common pricing method is to price out the fixed, capital costs along with variable costs such as fuel in a single per MWh charge. Implicit in the per MWh charge, in practice, is that the IPP's output is contracted under take-or-pay provisions in order to ensure the IPP recovers its costs plus a rate of return on its investment. First, all-in per MWh charges are not economically efficient prices as they are based on more than just the marginal cost of producing power so that the fixed costs can be recovered. Second, the take-or-pay provisions add to the inefficiency as it forces the off-taker to take the power whether it needs it or not, and in system operation take-or-pay power often displaces cheaper sources of power. In short per MWh only charges with take-or-pay provisions is not efficient in an economic sense and is likely to raise overall costs to the off-taker and its consumers. Moreover, a take-or-pay pricing with per MWh charges do not explicitly recognize the two different services provides by IPPs.

The second pricing mechanism is a multi-part pricing mechanism, the simplest of which is two-parts. Multi-part prices are recognized as economically efficient pricing schemes where there are large fixed costs present than must be recovered. The first part of the price (capacity payment) recognizes the capacity call option/insurance service the IPP can provide. This price does not change with energy output and is designed to recover the fixed cost plus any rate of return for the IPP. Unlike the per MWh charge with take-or-pay provisions, the IPP need not run in order to recover its costs and rate of return. The second part of the price recovers the variable cost of operation when the IPP is required to run to provide energy. A two-part price for IPP services not only explicitly recognizes the two services provided by an IPP (or any other generator for that matter), but is also structured in such a way as to allow cost recovery without unduly raising costs to the off-taker and its customers by requiring to run the IPP inefficiently relative to other generators on the system.

There are two other operational and contractual issues that should be addressed for any IPP. One is the issue of availability and performance. The IPP, to actually provide the call option service, must actually be available to run when needed subject to scheduled maintenance outages. Consequently, reductions in agreed upon availability should result in reductions in the capacity payment to encourage efficient maintenance practices. Second, if the unit is unavailable when energy is needed, then their should be a clause for liquidated damages payable to the off-taker for emergency power it had to procure or for load it had to shed due to the unavailable energy from the IPP. The other issue is that of ancillary service provision from the IPP such as reserve service, frequency response, or voltage support. Terms and conditions for such services should be made explicit in the contract. For some services, such as some reserves, the capacity payment covers the cost of the IPP being there and ready to generate even though it is not operating. For other services such as frequency control, voltage support, or spinning reserves (unit is operating but only partly loaded), then the IPP should be compensated for its fuel and variable operation and maintenance cost associated with providing those services.

References:

Chao, Hung-po and Wilson, Robert, "Multi-Dimensional Procurement Auctions for Power Reserves: Robust Incentive-Compatible Scoring and Settlement Rules," *Journal of Regulatory Economics* 22:2 pp. 161-183, 2002.

O'Neill, Richard P., Sotkiewicz, Paul M., Hobbs, Benjamin F., Rothkopf, Michael H., and Stewart, Jr., William R., "Efficient Market-Clearing prices in Markets with Nonconvexities," *European Journal of Operational Research* 164, pp. 269-285, 2005.

Oren, Shmuel S., "Ensuring Generation Adequacy in Competitive Electricity Markets," *University of California Energy Institute Energy Policy and Economics Working Paper 007*, June 2003.

RATE DESIGN AND COST ALLOCATION

With the decisions made regarding pass through, procurement method, and IPP pricing, all that remains is the allocation of the IPP costs among the off-taker's customers. Clearly, there will be some groups that the regulator and government wishes to protect while there are other groups that are able to bear the cost burden of a new IPP. Rate design plays a crucial role in making the allocation decision. Just as we discussed with pricing out IPP services, the most efficient pricing mechanism for customers is to use multi-part prices which also allows for a more transparent way of allocating the fixed costs of the IPP (which account for the largest portion of costs) through fixed charges than through per MWh charges to final consumers. I have included two attachments to this memo on rate design, cost allocation, and cross-subsidies that are far more complete in its discussion than any short memo.

Attachments:

Paul M. Sotkiewicz, "Cross-Subsidies through Fixed Charges: Minimizing Electricity Consumption Distortions", PURC Working Paper January 2005.

Paul M. Sotkiewicz, "Cross-Subsidies in Rate Design: Why Multi-part Tariffs and Subsidies Through Fixed Charges Minimize Electricity Consumption Distortions ", PowerPoint Presentation, Revised May 17, 2006.

MOVING FORWARD

It is important to define to the fullest extent possible the regulatory policy that will be in place with respect to IPPs. Not all of the policies discussed in this memo are unique to addressing IPPs in the regulatory context such as the pricing of services, rate design, and the allocation of costs, but they are important in the context of IPPs in a developing country context. The actual activities of defining the rate design and allocating costs are very technical in nature, but the decision on who will be allocated costs is a more subjective exercise. And while there are attempts to try and avoid subjective decisions in the regulatory arena through the use of competitive tenders and delineating what costs are acceptable for pass through to consumers in advance, there is still a measure of subjectivity involved and decisions on the correct course may not be so clear in all cases as we can see with respect to new information emerging on competitive tenders versus negotiated contracts. In the final analysis, there is still a great deal of art that needs to go along with the technical science in regulating IPPs.