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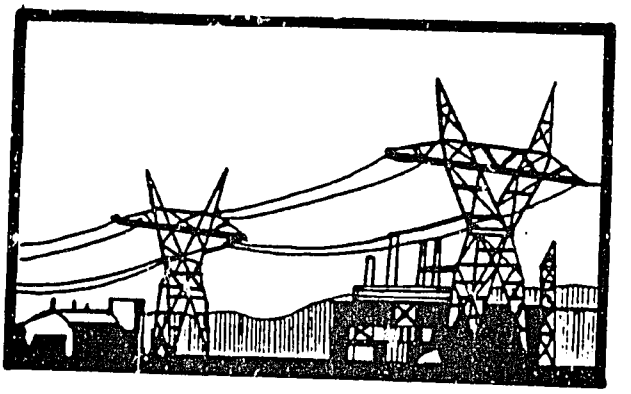

# PRIVATE POWER GENERATION THROUGH BUILD-OPERATE-TRANSFER

Manila Hilton
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OEA - USAID - TTEM - PCCI

# The Build-Operate-Transfer (BOT) Concept

presented at

Seminar on Private Power Generation Through
Build-Operate-Transfer

Manila, October 5, 1988

by

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# The Build-Operate-Transfer (BOT) Concept

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At the opening of a seminar on BOT, it seems appropriate first to say what BOT is.

BOT stands for Build-Operate-Transfer, and is used as a shorthand to describe the commercial structure of new infrastructure projects being executed under private sector ownership and financing. There are many variants of the model, but they all involve the establishment of a new private sector company as a vehicle for project ownership, financing, construction, and operation for a defined period of time.

We can see the typical BOT contractual structure in Figure 1.

Here you see the New Project Company in the center, the contractual agreements -- in the boxes -- and all the parties to the project -- in the ovals.

First, let's look at the shareholders, down at six o'clock. The new BOT project company typically has a majority private sector ownership, and a minority ownership by the host government, with the financial commitments and ownership rights spelled out in a Shareholders Agreement. The private ownership is provided mainly by the Project Sponsors, who in turn tend to be private international companies having a commercial interest in the construction and/or operation of the project -- such as construction contractors, equipment suppliers and fuel suppliers. In the case of a power generating project, the host government ownership position might be through the state power agency or fuel supply agency (if the project is to be based upon domestic fuel), or it might be through a government-owned financial institution, or a combination of such agencies. Since the capital requirements are large, there is usually also the need to attract portfolio investors, such as international financial institutions, to participate in the ownership structure.

Attracting a sufficient amount of equity is one of the key issues and challenges of BOT, and participation of the financial institutions imposes a tight discipline on both the contractual integrity and the risk-reward allocation built into the contractual arrangements.

The loan financing -- at 3 o'clock -- is provided by some combination of export credits, suppliers credits, commercial bank loans and institutional loans. A key feature and attraction of the BOT model is that the loans are made to the new project company, not to the national government or state utility. And from that arises another principal issue -- the loan security structure. This usually involves an escrowing arrangement -- shown at 2 o'clock -- under which the project revenues from the sale of electricity flow through an agent for the lenders, who accrues the debt service payment and captures the remaining cash generation in the early years for loan reserves as security for future revenue shortfalls. As we will see, a contingency financing arrangement provided by a Government financial institution -- shown at 10 o'clock -- is also typically required for a limited time to support the Project Company's loan service obligations. You'll hear more about the critical how and why of the credit structure later on today.

Three other major pieces of this BOT jigsaw puzzle are the construction contract -- at 9 o'clock, the plant operations contract -- at 7 o'clock, and the company management contract -- at 5 o'clock. The Project Sponsors are normally parties to these agreements, and the terms are geared to ensuring the delivery of a working plant on budget and schedule, and its uninterrupted operation at a high level of availability and efficient energy conversion.

Finally, in the case of power generating projects, there are three more key contractual documents -- an umbrella agreement which may be called a project implementation agreement, a power sales agreement, and a fuel supply agreement. The parties are, on the one hand, the project company, and on the other, the host government through its respective agencies. Or, if based upon imported fuel, the fuel supplier would typically be one or more private companies who may be part of the project sponsor group and participate as a shareholder as well.

The project implementation agreement -- at 1 o'clock -- is the first to be negotiated between the Government and the Project sponsors, and serves as a summary of all the key contractual undertakings. It sets out the agreed basis from which the other project contracts are subsequently developed.

The energy sales agreement -- at 11 o'clock -- is structured to provide an assurance of the purchase of power by the state utility on terms which will allow the project company to meet its obligations to its suppliers, lenders and shareholders, subject to the project company delivering power on budget and schedule and at a guaranteed level of availability. A wide range of issues must be addressed in the energy sales agreement, issues like currency of payment, the mix between fixed and cost-recovery pricing, and if the latter, the treatment of inflation and the structure of the equity servicing payments. It also addresses all the technical and management issues relating to the project's interface with the national grid.

The fuel supply agreement -- at 4 o'clock -- is geared to assuring the reliable supply of a sufficient quantity and quality of fuel on an agreed pricing basis. We will see later how the fuel price flows into the power tariff under a cost-of-service BOT pricing structure. Because of the weight of the fuel price in the power tariff -- typically averaging about 40% over the BOT term -- the pricing basis is typically negotiated directly between the Government as power purchaser and the fuel supplier.

The contractual structure I've just outlined for you is what financiers call a "limited recourse" financing structure. These buzz words -- limited recourse -- mean that there is no direct unconditional guarantor for servicing of the project loans -- the lenders' recourse in the event of non-payment by the Project Company by the various parties to the project in the contractual documents. While the limited recourse approach has been in use for a long time for projects in the industrial and mining sectors, its application to mega-scale infrastructure projects in the developing countries is rather recent. And, as I've indicated, there are a host of issues that have to be resolved on a project-by-project basis -- we'll preview some of those in a minute.

But I'm ahead of myself -- what about the T in BOT? The T stands for Transfer and refers to the handover of the privately-held shares of the Project Company to the host Government at the end of the agreed BOT operating term. Rather than sell the shares at the end of the term for a balloon payment, an installment purchase payment mechanism for the shares is typically built into the power pricing together with an agreed year-by-year return on investment. The equity investors take a gamble on the project's implementation and operational success -- for example, the unit power price will typically not include recovery of the capital servicing costs for overruns that are deemed under the arrangements to be the Project Company's responsibility, nor will sufficient revenues be generated during the operating term to earn the return and recover the capital if the plant operates

below the guaranteed availability and energy efficiency levels. Hence, the project shareholders put their investment fully at risk on the downside for the project's commercial success. This leads to another whole set of risk-reward issues relating to upside performance, such as how cost underruns are compensated, and the basis for payment for plant availability above the guaranteed level.

In summary, the BOT -- limited recourse -- commercial structure involves a process of allocating implementation responsibilities and divying up the project risks and rewards among the participants in such a way that all parties are happy with the prospective outcome, and are motivated throughout the BOT term by the contractual undertakings to achieve project commercial success.

Because we are inventing a wheel and the stakes are very large, putting a BOT project together is a long, expensive process. To have a chance of being successful, it requires the establishment and maintenance of mutual confidence among all the parties that the game is worth the price of admission, and that it will be played out to a commercially and economically profitable conclusion. While the journalism and speech-writing industries have thus far been BOT's main beneficiaries, all of us are here because we believe BOT may offer a partial solution for the provision of badly needed new power generating capacity in the developing countries. So our goal today is to understand the issues and the cost-benefit tradeoffs better, with the hope that the legal and regulatory framework structuring process currently underway in the Philippines will succeed in coaxing out this potential. To accomplish this, we have brought together a panel of knowledgeable speakers who will tell us about their experiences in other countries. Don Vial of the California Public Utility Commission, and Jim Harrall of Pacific Gas and Electric, will tell us about the California private power experience from the perspective of the public interest agency and the purchasing public utility, respectively. Next, Bill Stevenson of Bechtel Financing Services, Inc., followed by Jerry Vargo of Combustion Engineering, will share their perspectives as private U. S. developers and potential investors in overseas BOT power projects, drawing largely from their Turkish experience. And finally, Bill Dykes of Citibank-Hong Kong will bring to bear his perspective as an experienced BOT power project lender in the Asia region, with a special focus on the Hopewell Project in China.

As a group, our panelists will be addressing the full range of issues that come into play in conceiving, structuring, and implementing a BOT power project. As an appetizer, for example, consider the following questions:

- Why did California, with a large and successful investor-owned utility system in place, decide to launch into small privatized power projects?

- What have been the results to date?

- How has it been accomplished?

- Under what circumstances does it make sense for a developing country to encourage the development of BOT projects?

- Broadly speaking, how are the risks laid off among the project participants in such a way as to gain access to the benefits of private sector initiative and efficiency, but minimize the cost of power?

- What is a fair rate of return for the investors? How should it be structured?

- How is it possible to accommodate a Government takeover of the private ownership before the end of the BOT term within the BOT structure?

- What security is required to attract the lenders who are expected to provide most of the financing?

- And finally, given the cost and uncertainty of pursuing one of these projects, what must a Government do to attract prospective project sponsors to enter the process in the first place?

- And finally, given the cost and uncertainty of pursuing one of these projects, what must a Government do to attract prospective project sponsors to enter the process in the first place?

It is especially this last question that I expect we'll gain a better understanding of today. But all of these and many more issues have to be satisfactorily resolved for one of these projects to move beyond the talking stage.

As a final point of introduction, I think it may be useful for us to take a quick look at some relevant basic country data as a context for our panelists' case studies.

In Figure 2, we see comparative per capita income and electricity consumption data for 1986. China is at the far left, and moving across to the right, we see Indonesia, the Philippines in the middle, Turkey, and California on the right. The income bars are shaded and are scaled on the left vertical axis. The electricity consumption bars are in black and are measured on the right vertical axis. We can see that California's per capita power consumption is a multiple of about 18 times that of the Philippines, whereas Turkey's is about 75% larger, and China's is only about 15 per cent larger than the Philippines' consumption. So the first obvious implication is that the power situation and BOT experiences of the developing countries have a great deal more in common with each other than they do with those of California. And this being so, we will not be surprised to learn that the privatization objectives, benefits and problems in these energy short, capital-constrained countries are quite different from the California experience as well.

But along with this have/have-not contrast, this picture also shows quite clearly the close correlation between income level and power consumption. And in a dynamic dimension, power consumption tends to increase at a faster rate than income as countries develop from lower - to middle-income economies. For example, Turkey's per capita power consumption is 5 times that of Indonesia, whereas its per capita income is only 2-1/2 times larger. This is what economists call positive income elasticity. There is obviously a circular relationship here -- power availability allows industrial production, and industrialization is the driving force of export and income growth, which in turn pull up power demand.

Everyone here knows this intuitively. But it deserves to be pointed out at the outset of this roundtable that what we are talking about here today is one of the most basic issues for the future of the Philippine economy -- the absolute necessity of attracting capital for the creation of power generating capacity.

And since that is really our subject today, the comparative country financial data are more relevant than power sector data themselves. Let's have a look again at China, Turkey, Indonesia, and the Philippines from a lender's perspective.

While Figure 3 is more properly Bill Dykes' realm to address, it does give us some of the broad comparative indicators that lenders look at it in setting overall country exposure limits. The first two columns show sovereign credit ratings published by two different agencies.

The first is the July 1988 rating prepared by the Japan Center for International Finance, a semi-official agency affiliated with the top 50 Japanese banks. Their rating system is similar to a school report card, A being top and F being the lowest. The grades relate to debt repayment performance and prospects -- you can see JCIF's criteria for the grades under their rating column.

Basically, a C raises flags and a D signals trouble. The second column shows the country credit ratings published semi-annually by Institutional Investor, which is an international finance periodical. The scale is from 0 to 100, with zero for the least credit-worthy, and 100 given to those countries with the least chance of default on their debt obligations.

The survey covers 112 countries, and the scores reflect the combined ratings received from a survey of 75 to 100 international banks. This latest survey was released last month. The global average score for the 112 countries was 38.7; Japan was at the top with a score of 94.8, and North Korea was at the bottom with 4.5. Noteworthy for today's purposes is that China is considered an attractive credit to banks, ranked -- at number 23 -- just below New Zealand and South Korea, and just below the top 20 percent. Indonesia and Turkey are right together in the number 43 and 44 slots, which puts them just inside the top 40 percent. And the Philippines' score places it in the number 72 rank, in the bottom 40 percent.

The comparative country foreign debt data in the right two columns are the latest to be published, and relate to 1986.

Here we see Total Foreign Debt -- in the third column from the left -- expressed as a percentage of Gross Domestic Product. The column on the right shows 1986's long-term foreign debt service payments as a percentage of export revenues. What we have here are two measures of the relative burden of total foreign debt on a country and its ability to pay. Not surprisingly, we see that there is an inverse relationship between relative attractiveness to banks -- in the rating columns -- and the relative burden of existing foreign debt. From a banker's perspective, we can see that China is a case of relative under-borrowing, whereas the Philippines is very highly leveraged. On a debt service cash flow basis, Turkey and Indonesia appear even more leveraged than the Philippines.

The point of all this is that BOT project credit structure has to reflect a country's relative appeal to the international lenders. Simply put, the higher the sovereign credit rating, and the lower the existing debt burden, the more likely that A, the banks will be open for new lending business in the country, and B, lenders will be willing to take more project risk within a BOT structure.

So we've defined BOT, flagged some of the issues, and given you a quick overview of the relative country contexts you're going to hear about today.

*Figure 1*

## Typical BOT Power Project Contractual Structure

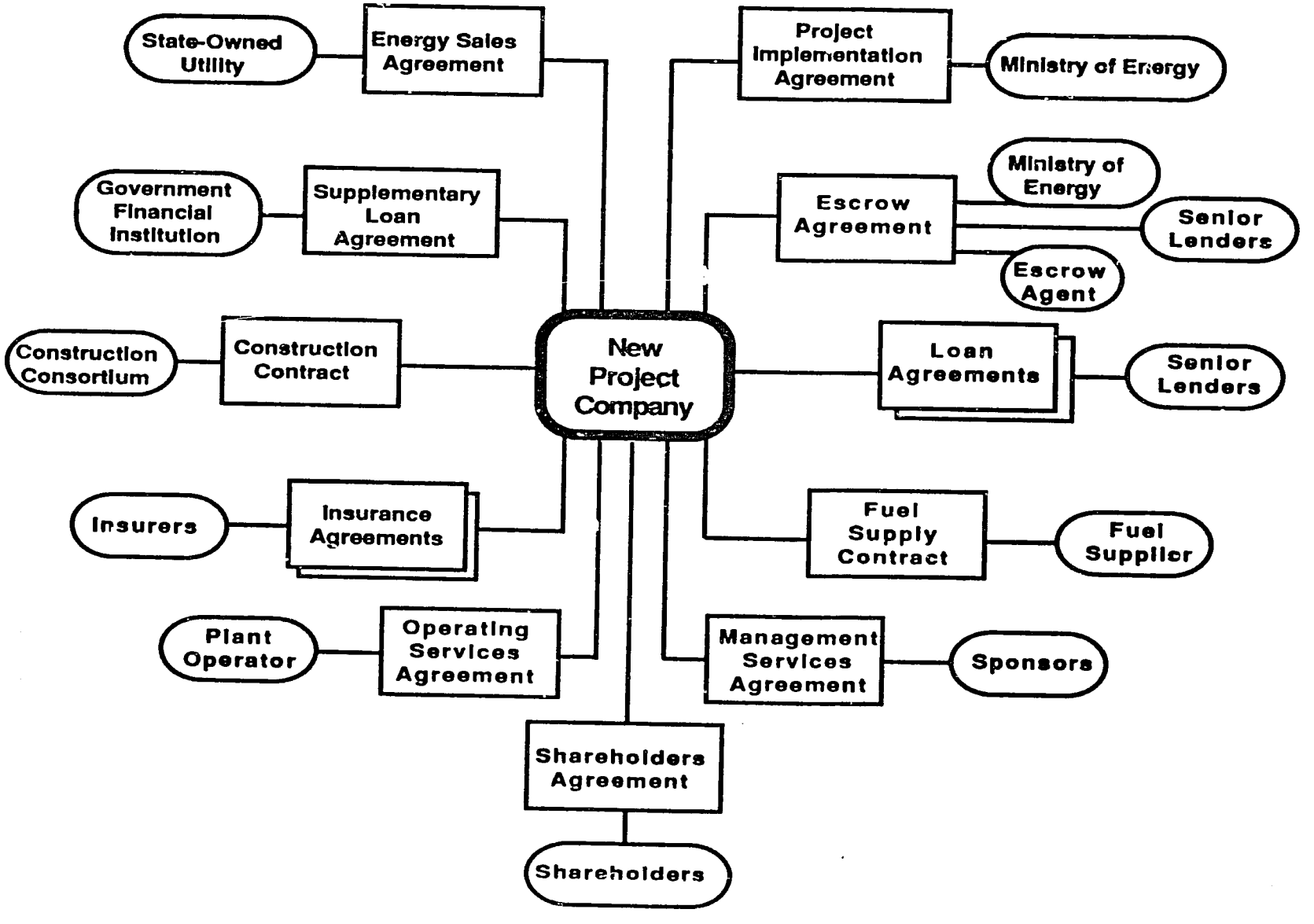

*Figure 2*

# 1986 Per Capita Income and Electricity Consumption

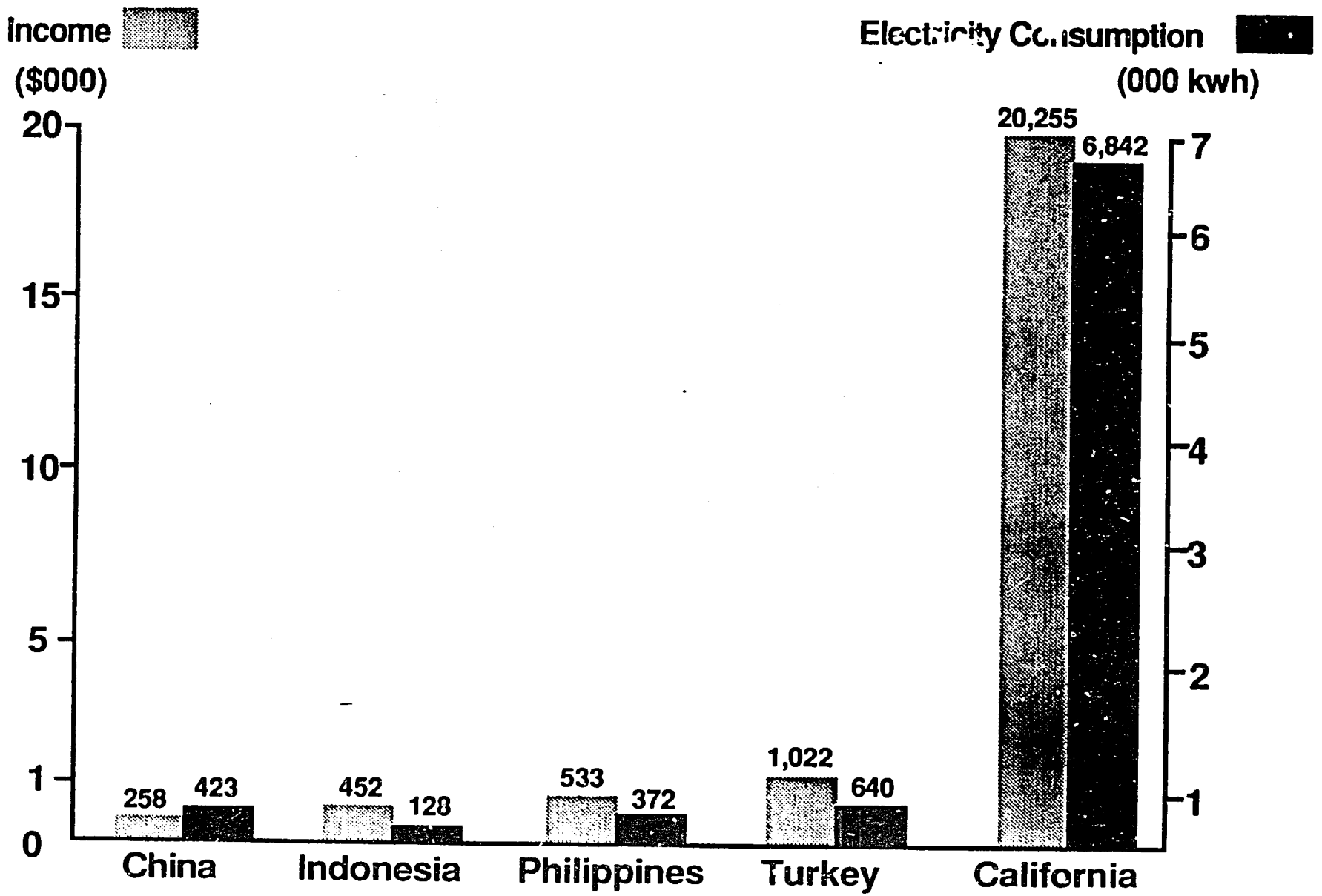

*Figure 3*

# Country Credit Ratings and Foreign Debt Data

| | 1988 Credit Rating | | 1986 Financial Data | |
|---|---|---|---|---|
| | JCIF | Institutional Investor | Total Foreign Debt As % of GDP | Total LT Foreign Debt Service As % of Exports |
| China | B | 63.3 | 8 | 8 |
| Turkey | B- | 41.1 | 60 | 32 |
| Indonesia | C | 42.9 | 56 | 33 |
| Philippines | D | 24.0 | 92 | 21 |

B = "...Capable of Meeting Present Debt Repayments...No Difficulties...Up Until 1990."

c = "...Capable of Meeting Debt Repayments at Present...(But) May...Encounter Difficulties...Up Until 1990."

D = "...On the Verge of...Debt Repayment Difficulties in the Near Future."

Sources: Ratings: - Japan Center for International Finance, July 1988
- Institutional Investor, September 1988

Data: - World Development Report 1988

# Independent Power Generation and Electricity Market Structure -- A California Regulator's Perspective

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Philippines Seminar: Private Power Generation Through Build, Own, and Transfer (BOT)

Manila, Philippines
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## I. Introduction

This paper describes the California experience in promoting the development of independent power generation, including cogeneration and alternative energy sources. Our program began as an effort to increase the diversity of electricity supply. It grew far faster than most of us expected, and may well become the centerpiece for electric utility planning in California. The program can be viewed as an enormous success. However, it may also have "opened the door" for a number of major changes in the structure of the electric industry, changes we did not fully appreciate at the time. This paper will indeed review some of the factors that made our program a success, as well as some of the hard lessons we have learned about implementing such a program. But I would feel remiss if I did not discuss as well the broader implications of this program for the structure and future of California's electricity industry. In planning an independent power program, it is important to think beyond the implementation details, and consider the shape of the industry overall.

## II. Background

### Beginnings

Oil and gas were cheap in California during the 1950s and 1960s, and by the time the first oil price shock hit in 1973, California was dependent on oil and gas for over 60 percent of its power supplies. California utilities had been actively developing conventional coal and nuclear power plants, but these plants were becoming more and more difficult to site, partly due to their environmental effects.

In the aftermath of the doubling of oil prices following the 1973 embargo, and facing electricity demand growth then

estimated at seven or eight percent annually, California began to explore the feasibility of developing alternative energy sources to gas and oil, including cogeneration, and wind, solar and biomass energy. The state legislature created the California Energy Commission in 1975 to develop an independent forecast of demand, promulgate energy standards for appliances and new buildings, foster alternative sources of energy, and to site any conventional power plants still needed on a statewide basis.

The California Public Utilities Commission, on which I serve, retained authority to set rates and review the activities and budgets of the state's investor-owned utilities. (From now on, I'll refer to the Public Utilities Commission simply as "the Commission.") The Commisson had begun to experiment with basing electricity rates on marginal costs to provide the right signals to consumers to economize on energy in a climate of escalating fuel costs. Complementing these actions, the Commission supported conservation programs to encourage energy-efficient investment in long-lived plant and equipment. The Commission also ordered one of California's utilities to buy power from independent power producers at the utility's marginal cost.

Implementing PURPA

These initiatives were given national impetus in the late 1970s when Congress acted to spur development of new energy sources by passing the Public Utility Regulatory Policy Act of 1978, or PURPA, as it became familiarly known. Section 210 of the Act authorized the Federal Energy Regulatory Commission (FERC) to develop regulations for fostering new energy supplies from cogenerators and renewable energy sources.

Essentially, PURPA required utilities to purchase power from any "Qualifying Facility," or QF, from certain desirable technologies. Because of the perceived need to reduce dependence on foreign oil and distrust of conventional technology such as

nuclear power, PURPA was aimed at diversifying the sources of power, emphasizing those sources thought to be environmentally compatible, especially those based on conservation and renewable resources, namely cogeneration, geothermal, biomass, solar, small hydroelectric, and wind. It was felt that monopoly utilities, despite their proven abilities to build and operate plants, were giving short-shrift to these technologies.

The critical issue was: on what terms would the utilities buy this power? To assure that consumers would be no worse off by using QF power, utilities were required to pay QFs no more than a utility's avoided cost, that is, the cost the utility avoided by not having to generate the power itself. State utility commissions were directed to design avoided cost methodologies and use them in their QF programs. Complementing this program was a set of fiscal incentives for the new industry in the form of special energy tax credits and accelerated cost recovery provisions provided by both Federal and State tax legislation.

Note that PURPA was set within the traditional US regulatory framework for electric utilities. Most believed that PURPA resources would provide only a marginal contribution to electricity supplies. Therefore, monopoly utilities were expected to identify resource needs, apply to state and federal regulators for permission to build them, and to construct these resources. Regulators would review the prudence of construction expenditures, and allow only reasonable costs to be passed along to consumers. The vertically-integrated utility was to remain the center of the utility infrastructure, with full responsibility for providing a reliable electric supply to any customer that demanded it. This has been called the utility's "obligation to serve."

## IV. The California Program

At first, QFs and utilities individually negotiated contracts, usually a time-consuming process. As well, utilities were observed to be hesitant to buy power from QFs, even from those in operation. It is not clear what the origins of that reluctance were. Some may have stemmed from doubt about the reliability of the new technologies, or from concern whether agreements with QFs would be deemed reasonable by the Commission. Part of the reluctance may have reflected traditional concerns about losing significant market share, or the fact that the costs of transacting on an case-by-case basis were too high to make it worthwhile.

There was an early policy debate about how much QFs should be paid for their power. PURPA specified only that QFs should be paid no more than avoided cost. Some utilities argued that they should use their market power to pay QFs only a fraction of avoided cost in order to save money for consumers. Federal regulators, with the support of the California Commission, decided that the goal of PURPA was to maximize independent power production, as long as consumers were not hurt economically, and therefore ordered payment of full avoided cost. Implicit in this policy was the view that QFs would not provide enough power to affect planning significantly, so that all that was supplied would be needed.

By this time, I should note, revised demand forecasts showed far lower demand growth for electricity than had been expected just a few years earlier. Within California, at least, we were generally confident that utilities could meet electricity needs if necessary. We felt that QFs, however, would be preferable if available at the same price.

The Commission did its best to monitor negotiations to assure that utilities were negotiating in good faith with QFs. At one point, the Commission fined one utility five million dollars

because of its apparent lack of cooperation. But this approach was not destined to be very successful, since independent producers were hesitant to criticize utilities publicly, for fear of harming future negotiations.

In California, the Commission finally resolved the impasse by developing a set of standardized contracts called standard offers, or SOs, that are described more fully in the next section. Utilities were required to provide these contracts to prospective QFs, setting out, among other things, the prices at which they would purchase power from a QF, with those prices based on the utilities' avoided costs and approved by the Commission.

Standard offers had further advantages. They assured the application of a consistent methodology across all of California's utilities. The existence of standard offer contracts also facilitated the negotiation of non-standard contracts by providing a reference benchmark.

## The Standard Offers

The Commission developed four standard offers in implementing its program. Each pays for both avoided energy and "capacity" costs; the latter is a shortage cost reflecting the effect of additional capacity on reserve margins. The contracts differ as to whether payments for energy and/or capacity are guaranteed, and the length of the contract for which they are guaranteed.

The first standard offer, referred to as SO #1, pays prices for capacity and energy based on utilities' actual short-run avoided cost. Energy payments are adjusted every quarter to reflect changing fuel prices and capacity payments are adjusted every year to reflect the utility's reserve margin. (Another Standard Offer, #3, was issued with similar terms but was simplified for producers of 100 kW or less.

However, independent producers argued that these two offers were not sufficient. They argued that, even with favorable tax policies, it was difficult to finance their projects because of the uncertainty in the utility's short-run cost. Therefore, the Commission began to issue offers which provided a greater degree of price security to independent producers. Of course, such contracts also offered price stability to consumers.

Standard Offer 2, for example, pays short-run energy cost, but fixes capacity payments on the forecasted value of capacity for horizons as long as thirty years. This offer is well-suited for technologies that use the same fuel as the utility's short-run avoided plant but at the same time require some payment certainty. Gas-fired cogeneration is a good example of such a technology in California.

But QFs argued that to maximize QF development, California would have to issue a standard offer that offered security for both energy and capacity payments. In theory, such an offer should reflect the cost of new resources on the utility's system. But there was considerable controversy about the assumptions behind such a calculation. For example, what power plant should be assumed to be the utility's next project? There were of course a range of potential plants, and a range of potential costs for each plant.

To expedite development of a long-term offer, the Commission asked the utilities and QF developers to negotiate with the Commission's staff, and to agree on a set of long-term prices for electricity. The parties in fact agreed on what was to be called our Interim Standard Offer #4. This offer has different payment options that provide for firm capacity payments fixed in advance (the same as for SO #2); but also up to ten years of fixed energy payments. Because cogenerators argued that they would be bankrupted by another oil price spike, we also

offered an option in which energy payments were tied to actual oil prices at the time of the payment.

As I think I've indicated before, the standard offers, particularly SO #4, received an enormous response. By 1982, California's utilities had signed contracts for 1,000 megawatts of independent power, the equivalent of a major conventional power plant. By the next year, that had risen to 4,000 megawatts, and then 10,000, and finally, by 1985, there were signed contracts for 15,000 megawatts of electric capacity. To provide some context, the state's overall installed capacity is roughly 40,000 megawatts.

Not all of these plants have actually come on line, but the results are still impressive. In 1980 independent power sources represented less than one percent of capacity in California. By 1988, they represented six percent of capacity, and it is estimated they will account for ten percent by 1990.[1] QF development is anticipated to meet the state's growth in load demand through the 1990s. This phenomenon is perhaps most vividly illustrated by the fact that the contribution from QF capacity has allowed deferral of two large utility coal-burning plants, even though siting approval for the two plants already has been obtained.

California's program was particularly successful when viewed nationwide. California is be among the leaders in size and diversity of cogeneration and renewable energy projects. Over two-thirds of total nation-wide QF capacity either operating or under development is situated in California, and in the cases

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1 Table 1 shows total capacity, on-line and contracted, for California's three large investor-owned utilities, which account for nearly all of the state's QF capacity. Tables 2 through 4 and Charts 1 through 3 show the breakdown of capacity by technology for each utility.

of wind and geothermal development, California accounts for 95 percent of the capacity coming from these sources.

## V. Lessons from California Experience

I want to review now the lessons of California's experience, at least as I see them in the context of the U.S. utility system. To what extent these lessons apply in other contexts, I will leave to the audience to decide. First, we can examine the factors that produced such a large response from independent energy producers. A second set of lessons concern the actual operations of QFs within a utility system. But I also will discuss a third set of lessons, namely, that encouraging independent power will not remove the need to plan the development of the electric system, and may in fact complicate that task, requiring a greater emphasis on planning processes, goals and objectives. Fourth and finally, the development of the independent power industry may, as it has in the US, prompt a reexamination of the US utility system, because the development of the industry raises critical public policy issues and creates new political actors.

### Why Was California's Program Successful?

Why was California's program so successful? Some factors were inherent in California's economy, including a strong industrial and commercial sector, and relatively high short-term avoided costs due to the state's dependence on oil. But a large part of the success was due to three provisions of the state' program.

First, the presence of standardized contracts reduced the uncertainty and negotiation barriers discussed in detail earlier. As well, having utilities publish a set of prices at which they were willing to purchase QF power proved a particularly efficient

way of "uncovering" the alternative resource opportunities available--especially where resources were small, dispersed geographically, or technologically novel. Finding out this information in any other way might have been prohibitively expensive, and indeed might have been impossible because of its private, proprietary nature.

The second factor helping to draw out a relatively large amount of QF development was the decision to pay for both energy and capacity, and to offer long-term, fixed-payment contracts. In retrospect this seems clearly the correct thing to have done, despite the mistakes we made in developing our initial long-term offers. But at the time, the decision was much more venturesome. In the early 1980s, when the SOs were being introduced, fuel prices were so high--and especially in California--that paying for energy costs alone was thought to be attractive enough to attract QF developers.

Many other states decided that paying for capacity was unnecessary. Because of the "lumpiness" of utility investment--the large, discrete nature of the typical utility-owned power plant--the traditional utility policy had been to build sufficiently far in advance of projected need always to have enough capacity. Thus by definition there was no need to pay QFs for capacity. The difficulty with this argument was that it was self-fulfilling: denied compensation for capacity, QFs would be unlikely to build any, leaving utilities to provide it all (and, by their argument, providing a justification for not paying QFs for it in the first place).

Third, California offered long-term contracts, allowing QFs to finance their projects. While the Commission also recognized that fixed price contracts shifted some of the risk of changing energy and capacity prices to the consumer, it believed that the long-term benefits to the consumer from a successful QF program outweighed these concerns.

## How QFs Fit Into a Utility System

California's program demonstrates that QFs can in fact provide reliable power to an integrated utility system. Because they can be successfully integrated, consumers can reap a number of benefits.

First, California's experience demonstrates that with a reasonable set of technical requirements for interconnection and contractual options for dispatch, QFs can be integrated in an existing utility system without major problems. In particular, there have been no serious technical problems in adding small, dispersed generation units to the system. Just as many small conventional plants (such as hydroelectric stations) can be integrated into a larger grid, so can a large number of independent generators.

QFs are required to meet the electricity system's technical standards. To that end, the Commission adopted a set of interconnection standards and directed the utilities to file interconnection guidelines for QFs based on these standards. With some exceptions, the QF has the option of owning, operating and maintaining the interconnection equipment itself, or paying the utility to do so. Costs of equipment in excess of the minimum standards are borne by the party requesting the upgrade.

Second, QF facilities can be relied upon to provide firm capacity. Standard offer contracts offering firm capacity payments require in turn certain performance standards from the QFs. One utility's Standard Offer 2 contract, for example, essentially requires that a QF's power be dispatchable by the utility, subject to an allowance for forced outages and scheduled maintenance. The contract specifies as well the penalties for the QF if it fails to meet the performance standard.

Third, QFs can provide significant electricity resources without adding to the financing burden of utilities. In effect, California's utilities were able to secure additional power

without their needing to go directly to capital markets to find the financing. Thus, for example, the nearly 6,000 megawatts of on-line QF capacity represent an investment of approximately 12 billion dollars--equal to what utilities would have had to spend over a 5 to 7 year period to meet current growth in demand.

Fourth, an independent power program can tap small, dispersed and diversified technologies for the advantages they offer. Many of these technologies provide power that does not depend on oil. About 40 percent of California's on-line QF capacity represents non-petroleum sources such as wind, solar, and biomass fuels. And in the case of oil-using cogeneration facilities, their superior efficiency and short lead times has still allowed reducing the system's dependence on oil.

Fifth, QFs can add flexibility to a system. In the U.S. regulatory environment, independent power projects can come on line much more quickly than large conventional power plants. All of the S04 contracts, for example, require that power be delivered within 5 years of the execution of the contract. Similarly, some QF responses to a recent SO2 released by San Diego Gas and Electric indicated deliveries could be made within 24 months-- shorter than the siting review process alone for conventional utility plants. Moreover, independent power is often available from modular, small-scale technologies. With proper contracting arrangements, such power can be exploited when needed, avoiding the surplus capacity problem inherent in having to build large utility plants well in advance of load growth.

## Some Problems and Complications

Along with the major success of California's program came a number of major problems. As I describe them to you, I think you'll realize that integrating QFs into a utility system requires as much planning as it does to build conventional utility plants. In fact, since attracting independent generation

requires sending correct price signals, the job of the regulator may actually be more complicated than before.

I've already described the enormous response to our Standard Offers: by June, 1988, 15,900 megawatts of power contracts in a system of about 40,000 megawatts. However, as the contracts came in, we became concerned over the very success of our program. As more power came in, of course, we were expecting to displace more and more efficient plants. As a result, our expected avoided costs were dropping. Moreover, the number of plants that signed up were, surprisingly, more than were needed to meet our reserve capacity target, so that it was hard to justify paying all these plants the full capacity value specified in SO #4 and #2. Therefore, we stopped issuing new contracts under the long-term standard offers, at least until new capacity needs arose. And since that time, of course, oil and gas prices have dropped markedly.

In short, the success of the program is tempered by the fact that we did not predict the future accurately, and therefore may be paying too much for at least some of the QF power. Some of the capacity that we receive under contract is worth far less than we are paying, because we already have all of the capacity we need. The energy picture is brighter. The contracts that are tied to oil prices are providing power at very attractive prices. And those with fixed energy prices, while relatively high, will remain fixed even if oil prices rise in the future.

In evaluating our Interim Standard Offer #4, I think it's important to examine the situation we faced at the time the offer was issued. Interim SO #4 was not based on any particular forecast of electricity costs or needs, although each participant in the negotiations had a forecast in mind. I think it is fair to say that most of us expected the offer to have a relatively minor impact on the state's electricity system. The California Energy Commission expected perhaps 3,000 megawatts on line by the year 2000, requiring substantial construction by the utility to

meet demand. Utilities criticized even this limited estimate as being unrealistically high. But the state decided that any contribution would be helpful, as long as it did not raise consumer costs. QFs were to be integrated into the existing utility infrastructure, and were regarded as helpful, but not crucial, in meeting electricity needs. Remember that PURPA required payment of avoided cost only to certain power technologies that utilities had neglected. Thus, our emphasis on avoided cost pricing, and its limitation to qualifying technologies, arose from our particular situation at the time.

So one lesson from our experience is the darker side of the success story I mentioned earlier: not only may Standard Offers "call out resources" one didn't know about, they may call out far more or less than one expected. One solution is to limit the total number of contracted megawatts to the estimated need for capacity.

But the enormous response to our initial offer suggests that the notion of "avoided cost" has clear limitations. If paying full avoided cost produces an oversupply of power, why not simply drop the price until the number of independent contracts just meets the need? In effect, in the future that is exactly what we will do. Our new Standard Offer #4 will be offered at full avoided costs, but only during a short "open bidding period.[2]" QFs will have the opportunity to submit individual

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2 The following procedure will be used to develop the new Standard Offer #4. Every two years, the state's utilities will submit resource plans detailing their proposals for meeting electricity needs, including conservation (demand-side) programs as well as new generation. The California Commission will determine how much capacity the utility needs to add during the next eight years, and use the cost and capacity of those potentially "avoidable plants" as the basis for the offer. Then, during a six-month "open period," QFs submit bids which specify both capacity to be supplied and the price of that capacity. Note the intensive involvement of both the utilities and the California Commission in this planning process.

price bids to meet the utility's need. If the response is less than the need, all bidding QFs will be accepted and paid full avoided cost. But if the response exceeds the need, only the lowest bidders will be accepted, and all will receive the lowest losing bid, which may be below avoided cost. This is called a second price auction; without going into the details, let me just say that it is designed to remove any incentive to bid strategically.

Avoided cost has been a powerful and important concept in the US utility industry, but there's no reason to etch that concept into stone. And in some circumstances, where paying avoided cost will result in fewer than the needed number of QFs, it may be appropriate to pay above avoided cost.

Finally, I want to mention a further complication with the use of independent power. As independent producers grow to be a major part of the utility system, we have to assure that they "fit" together to allow the utility to dispatch its system to meet load, to meet local needs for voltage support, and to assure that the system can recover from emergencies. In an integrated utility system, planners decide what plants are needed to make the system work and the utility builds them. But how can planners structure a bidding system to assure that the bidding QFs have the characteristics that the utility needs? One approach is to require that each independent producer "mimic" the needed utility plant exactly, but that would bar many QFs that might be economic from the competition. In theory, a better approach is to use a pricing strategy to compensate for differences in the characteristics of power supplied by a QF. Under our new long-term framework, the Commission currently is wrestling with the feasibilty of contract "adders" (and possibly "subtractors") that could be added to QF offers to compensate for special features, such as dispatchability, in the service provided by QFs. The hope is that by paying the "right amount" for certain characteristics, we can "buy" just enough.

I see some problems in this approach. First, just as we ended up with too much capacity, we could end up with too much or too little of a particular special feature. Furthermore, adders and subtractors are in effect a point system; QFs that earn the most points will win. But a utility system is an interdependent thing, with its parts fitting together a little like a jigsaw puzzle. I'm not sure that simply picking the QFs with the highest point scores will put that puzzle together; a combination of lower-scoring QFs might actually work together better.

I don't mean to make too much of these difficulties. The Commission is committed to integrating independent power into California's utility system, maintaining our franchised private utilities at the center of resource planning. Rather, my point is that managing independent power, whether through megawatt limits or "adders and subtractors" requires a high degree of accuracy and sophistication on the part of planners. If anything, planning becomes more complicated. So merely moving to independent power sources does not remove the planning and forecast risks, such as the risk of overcapacity and undercapacity, faced by a conventional utility system. Planners still have a major responsibility to identify how to meet expected load at the lowest possible cost.

Finally, I want to emphasize that our whole program is aimed at enhancing the viability of the utility transmission and distribution systems, maintaining the focus on the integrated utility to maintain the electrical infrastructure. We are using a marketplace approach only in a limited way, in order to maintain the reliability of the electrical system, which is crucial for economic and social development.

## Proposed Changes in the US Regulatory System

Implementation of PURPA has lead to partial deregulation of generation, in the sense that we no longer regulate QF prices

according to the traditional cost-of-service system. Even though this "free market" development has taken place in the context of traditional monopoly utilities, some have been encouraged to develop proposals, particularly at the federal level to move toward a "competitive market" in electricity. Such proposals suggest opening all electricity supply to competitive bidding and "marketplace" pricing of electricity. These proposals could open the door to eventual complete deregulation of the generation of electricity and separating generation from transmission and distribution, which would continue to be regulated. The proponents tend to favor more market-oriented mechanisms for moving electricity between utilities. Such proposals could have major effects on the future of the integrated US electricity network.

Further, PURPA encouraged the rapid spread of small-scale electrical technology. Because this technology is widely available, and because oil and gas prices are currently quite low, many electrical users can now produce electricity at less than the price charged by monopoly utilities, which made major investments in long-lived central generating plants in order to meet their obligation to serve those large customers. Utilities which have made sunk investments to serve those electrical users find it preferable to drop prices to keep these customers on line, as long as the prices remain above operating costs. Thus, the costs of the central plants are shifted onto those customers who have no alternatives. Therefore, customers who can generate their own power can receive power from the central utility if the utility plants turn out to be economic, but leave the system at their convenience, forcing the risks of plant construction onto smaller customers who have no alternatives. The development of independent power, therefore, may force us to reexamine the traditional "obligation to serve."

In general, this competition is forcing regulators to price at economic costs, and forego the traditional social goals

of regulation. These developments require new approaches to balancing public and private interests.

In addition, independent generators are increasing their pressure to be allowed to use utility transmission systems in order to underprice the utilities themselves. Such access would increase their ability to "cherry-pick" those customers that are cheapest to serve, again forcing additional costs on those who have no alternatives. And the implementation of wheeling will require vast changes in transmission and distribution networks currently geared to vertically integrated electric utilities operating as franchised monopolies.

Again, I don't wish to suggest that the one should not embark on a QF program. But I do suggest that planners must consider the effects of competitive generation in designing their program. Making provision for independent power requires a sharper focus on the compatibility of transmission and distribution systems with the public policy objectives behind the encouragement of such generation.

## Interpreting California's Lessons

In interpreting the lessons of California's experience with PURPA it is important to keep in mind that legislation's strategy. PURPA sought to encourage development of alternative energy sources by providing incentives to independent producers. Utilities themselves, although they had an important role to play as customers for this new power, were not themselves used by policy as the primary vehicle for developing alternative energy.

Several different reasons probably were responsible for this strategy, although it is not clear how important each one was. In the first place, there may have been a concern that the corporate outlook, or "mentality" of the typical utility would not make the latter responsive to exploring the potential of new, unfamiliar energy sources. This might especially be a problem

where small-scale resources were involved, given the utilities' traditional expertise and experience in developing large-scale projects.

The regulatory environment also may have contributed to the PURPA strategy. Traditional cost of service regulation gave little incentive for utilities to take on whatever risk would be involved tapping alternative energy supplies. As well, political resistance to rising energy rates as fuel prices escalated in the 1970s left some utilities in battered shape financially, making them poor instruments for raising the financing for new energy development.

These considerations are relevant in considering the applicability of a PURPA-type program to other countries. In many countries the public utilities are state-owned and operated, unlike in the U.S., where typically public policy objectives for utilities are carried out by government regulation of investor-owned enterprises. However, this distinction may not be as important as it first seems. Presumably it is not whether the utility is state or privately-owned per se that matters. The relevant issue, as the considerations discussed above suggest, is whether the enterprise's organizational structure, its internal "world view" or "culture," and the incentives it faces make it an effective mechanism for developing alternative energy sources. That is not the only consideration, of course. As was pointed out earlier, fostering independent power production may allow tapping new sources of financing, increasing the total amount of capital available for investment in power production.

I'll conclude by briefly mentioning a few questions about transferability of the US's experience with regard to the structure of the electric industry. Looking more broadly at the structure of the Philippines' electricity system, the US experience may have limited application. The objectives of introducing private power, for example, to achieve more rapid expansion of energy supply for accelerated economic growth may or

may not embrace the concept of allowing co-generators or other independent producers to sell directly to end users, in addition to cooperative and private utility distribution systems. Obviously, granting independent producers authority to sell directly to end-users is going to result in a different type of transmission and distribution system than policies that seek to advance the economies of scale inherent in a monopoly transmission and distribution system.

In the U.S., for reasons peculiar to our system of regulated utilities, we have carefully avoided compulsory "retail" wheeling that would allow QFs to sell their power to end-users. Such sales could result in uneconomic bypass of a fully integrated utility system, and interfere with the ability of that system to fully capture all the economies of scale and scope in a least-cost development and distribution system. In the US, QF development has spawned a whole new focus on wheeling issues, as the policy of deferring increasingly to market forces in the generation of electricity impacts the viability and reliability of the transmission and distribution networks.

Therefore, the Philippines may very well take a very different road from that taken in the U.S. What may work for the U.S. may not be compatible with Philippine goals and objectives of introducing private power in the future development of a largely government-owned system. In isolated areas targeted for economic growth where no viable utility system exists, for example, the development of private distribution systems may be the basis for an evolving electric utility. The problem is to guard against distribution arrangements that leave customers who are expensive to serve on the government's system, while private producers take care of larger customers who are cheaper to serve.

Finally, it should be recognized that much of the concern in the US about integrating QF energy has been about bypass of existing, developed utility systems. As indicated above, this concern may have no meaning where the primary policy objective

may be to bring electricity to an area which at present does not have an infrastructural system to promote growth and expansion.

In the end, the success of a set of rules to promote private power development will be determined by the clarity with which the goals and objective of such development are embraced and refined as the policy is implemented. Policy choices need to be confronted in the planning process as soon as they can be identified and analyzed. As in California's experience, mistakes inevitably will be made. What is important is to have the capacity to correct them before they get out of hand. I think we have demonstrated that capacity in California. We did not permit fear of the unknown to prevent us from developing a program that has become a critical part of our energy future.

TABLE 1

SUMMARY OF COGENERATION AND SMALL POWER PRODUCTION PROJECTS
IN SERVICE AREAS
OF PG&E, SCE AND SDG&E

(As of June 30, 1988)

| Utility Service Area | Projects With Signed Contracts: Number of Projects | Projects With Signed Contracts: Projects On Line MW | Projects With Signed Contracts: Project Commitments MW | Projects With Signed Letter of Agreements: Number of Projects | Projects With Signed Letter of Agreements: Project Commitments MW | Projects Under Active Discussion: Number of Projects | Projects Under Active Discussion: Estimated Project Size MW |
|---|---|---|---|---|---|---|---|
| | (A) | (B)1/ | (C) | (D) | (E) | (F) | (G) |
| PG&E | 766 | 2,592.00 | 8,947.00 | - | - | 111 | 589.00 |
| SCE | 472 | 3,140.00 | 6,552.00 | - | - | 50 | 262.00 |
| SDG&E | 190 | 122.00 | 382.00 | 42 | 24.00 | 4 | 4.00 |
| Totals | 1,428 | 5,854.00 | 15,881.00 | 42 | 24.00 | 165 | 855.00 |

1/ Figures in this column are included in Column C.

TABLE 2

PACIFIC GAS & ELECTRIC COMPANY
COGENERATION AND SMALL POWER PRODUCTION1/

(As of June 30, 1988)

| Line No. | Item | Signed Contracts: Projects On Line: No. of Projects | Signed Contracts: Projects On Line: MW | Signed Contracts: Projects Not Yet On Line: No. of Projects | Signed Contracts: Projects Not Yet On Line: MW | Projects With Signed Letter Of Agreement2/: No. of Projects | Projects With Signed Letter Of Agreement2/: MW | Total Committed Projects (A+B+C): No. of Projects | Total Committed Projects (A+B+C): MW | Projects Under Active Discussion: No. of Projects | Projects Under Active Discussion: MW | TOTAL (D+E): No. of Projects | TOTAL (D+E): MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (A) | | (B) | | (C) | | (D) | | (E) | | (F) | |
| 1 | Cogeneration | 170 | 1,462.33 | 100 | 3,195.58 | - | - | 270 | 4,657.91 | 54 | 299.89 | 324 | 4,957.80 |
| 2 | Biomass/Solid Waste | 46 | 225.52 | 40 | 771.61 | - | - | 86 | 997.13 | 10 | 169.37 | 96 | 1,166.50 |
| 3 | Solar | 11 | 6.96 | 1 | 14.10 | - | - | 12 | 21.07 | - | - | 12 | 21.07 |
| 4 | Small Hydro | 94 | 124.99 | 126 | 652.55 | - | - | 220 | 777.54 | 45 | 98.75 | 265 | 876.28 |
| 5 | Wind | 136 | 692.03 | 30 | 1,624.48 | - | - | 166 | 2,316.52 | 1 | 20.00 | 167 | 2,336.52 |
| 6 | Geothermal | 2 | 80.70 | 10 | 96.06 | - | - | 12 | 176.76 | 1 | 1.25 | 13 | 178.01 |
| 7 | Total | 459 | 2,592.54 | 307 | 6,354.38 | - | - | 766 | 8,946.92 | 111 | 589.26 | 877 | 9,536.18 |

1/ PG&E did not report their utility-owned projects. No utility-owned projects are included in this tabulation.

2/ Includes letter of agreement and "notice of intent" to subsequently sign a contract.

TABLE 3

SOUTHERN CALIFORNIA EDISON COMPANY
COGENERATION AND SMALL POWER PRODUCTION1/

(As of June 30, 1988)

| Line No. | Item | Signed Contracts: Projects On Line: No. of Projects | Signed Contracts: Projects On Line: MW | Signed Contracts: Projects Not Yet On Line: No. of Projects | Signed Contracts: Projects Not Yet On Line: MW | Projects With Signed Letter Of Agreement2/: No. of Projects | Projects With Signed Letter Of Agreement2/: MW | Total Committed Projects (A+B+C): No. of Projects | Total Committed Projects (A+B+C): MW | Projects Under Active Discussion: No. of Projects | Projects Under Active Discussion: MW | TOTAL (D+E): No. of Projects | TOTAL (D+E): MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (A) | | (B) | | (C) | | (D) | | (E) | | (F) | |
| 1 | Cogeneration | 163 | 1,845.01 | 38 | 874.37 | - | - | 201 | 2,719.38 | 38 | 134.98 | 239 | 2,854.36 |
| 2 | Biomass/Solid Waste | 28 | 172.63 | 19 | 461.40 | - | - | 47 | 634.03 | 5 | 22.65 | 52 | 656.67 |
| 3 | Solar | 21 | 134.91 | 7 | 440.00 | - | - | 28 | 574.91 | - | - | 28 | 574.91 |
| 4 | Small Hydro | 44 | 100.60 | 16 | 57.78 | - | - | 60 | 158.38 | 4 | 40.19 | 64 | 198.57 |
| 5 | Wind | 59 | 655.44 | 52 | 1,081.59 | - | - | 111 | 1,737.03 | 2 | 49.00 | 113 | 1,786.03 |
| 6 | Geothermal | 10 | 230.80 | 15 | 497.94 | - | - | 25 | 728.74 | 1 | 15.00 | 26 | 743.74 |
| 7 | Total | 325 | 3,139.38 | 147 | 3,413.08 | - | - | 472 | 6,552.46 | 50 | 261.82 | 522 | 6,814.28 |

1/ SCE reports 31 utility-owned projects totaling 102 MW. No utility-owned projects are included in this tabulation.

2/ Includes letter of agreement and "notice of intent" to subsequently sign a contract.

TABLE 4

SAN DIEGO GAS & ELECTRIC COMPANY
COGENERATION AND SMALL POWER PRODUCTION1/

(As of June 30, 1988)

| Line No. | Item | Signed Contract: Projects On Line: No. of Projects | Signed Contract: Projects On Line: MW | Signed Contract: Projects Not Yet On Line: No. of Projects | Signed Contract: Projects Not Yet On Line: MW | Projects With Signed Letter Of Agreement2/: No. of Projects | Projects With Signed Letter Of Agreement2/: MW | Total Committed Projects (A+B+C): No. of Projects | Total Committed Projects (A+B+C): MW | Projects Under Active Discussion: No. of Projects | Projects Under Active Discussion: MW | TOTAL (D+E): No. of Projects | TOTAL (D+E): MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (A) | | (B) | | (C) | | (D) | | (E) | | (F) | |
| 1 | Cogeneration | 111 | 102.38 | 11 | 172.00 | 33 | 22.28 | 155 | 296.66 | 3 | 0.85 | 158 | 297.51 |
| 2 | Biomass/Solid Waste | 3 | 6.45 | 2 | 87.90 | 1 | 0.14 | 6 | 94.49 | - | - | 6 | 94.49 |
| 3 | Solar | 38 | 5.00 | 8 | 0.02 | 6 | 0.10 | 52 | 5.12 | 1 | 3.00 | 53 | 8.12 |
| 4 | Small Hydro | 6 | 6.33 | 1 | 0.45 | 2 | 1.39 | 9 | 8.17 | - | - | 9 | 8.17 |
| 5 | Wind | 9 | 1.50 | 1 | 0.29 | - | - | 10 | 1.79 | - | - | 10 | 1.79 |
| 6 | Total | 167 | 121.66 | 23 | 260.66 | 42 | 23.91 | 232 | 406.23 | 4 | 3.85 | 236 | 410.08 |

1/ SDG&E reports 7 utility-owned projects totaling 60 MW. No utility-owned projects are included in this tabulation.

2/ Includes letter of agreement and "notice of intent" to subsequently sign a contract.

CHART 1

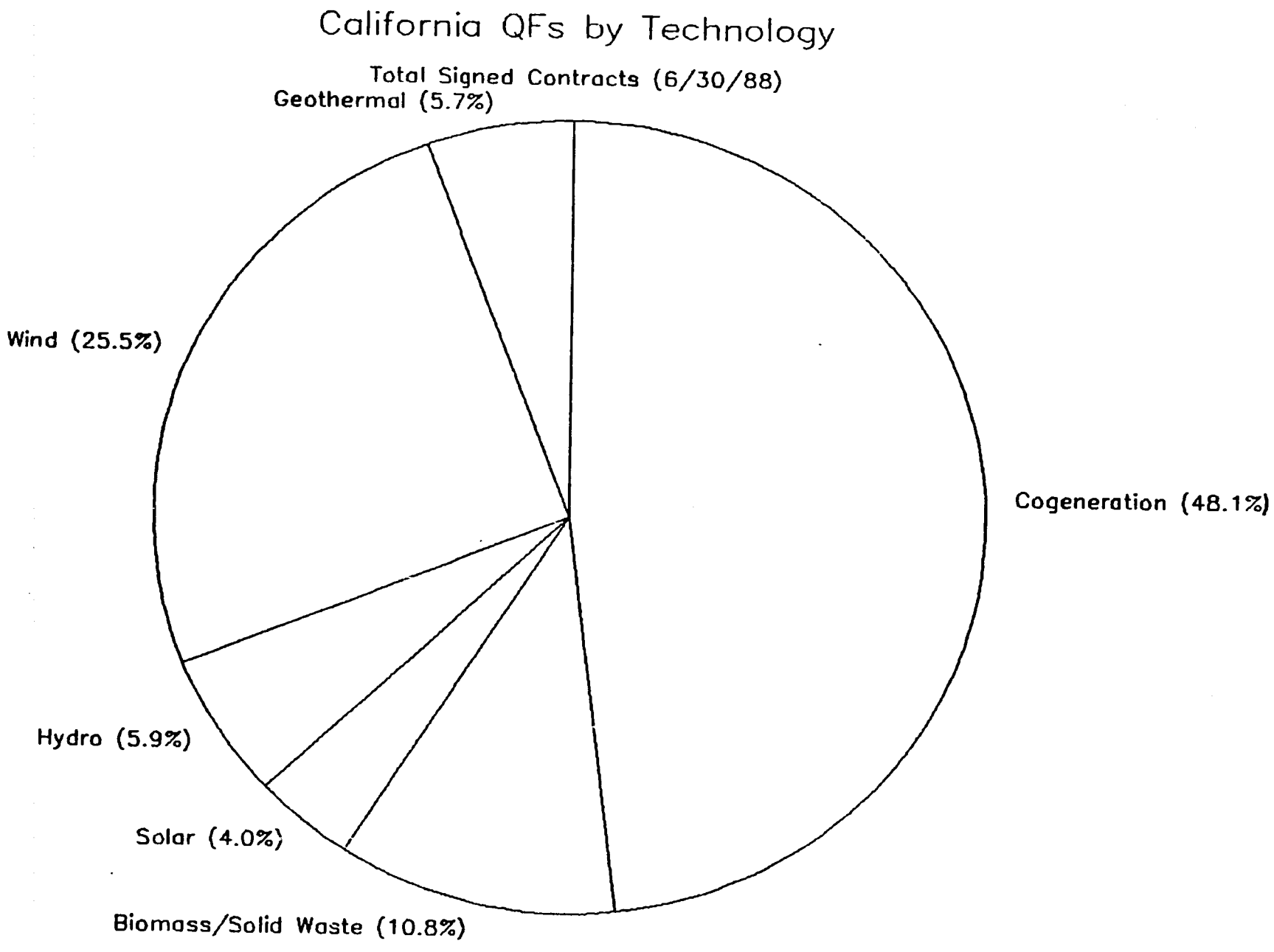

California QFs by Technology
Total Signed Contracts (6/30/88)
Geothermal (5.7%)
Wind (25.5%)
Cogeneration (48.1%)
Hydro (5.9%)
Solar (4.0%)
Biomass/Solid Waste (10.8%)

CHART 2

# California QFs by Technology

On line as of June 30, 1988

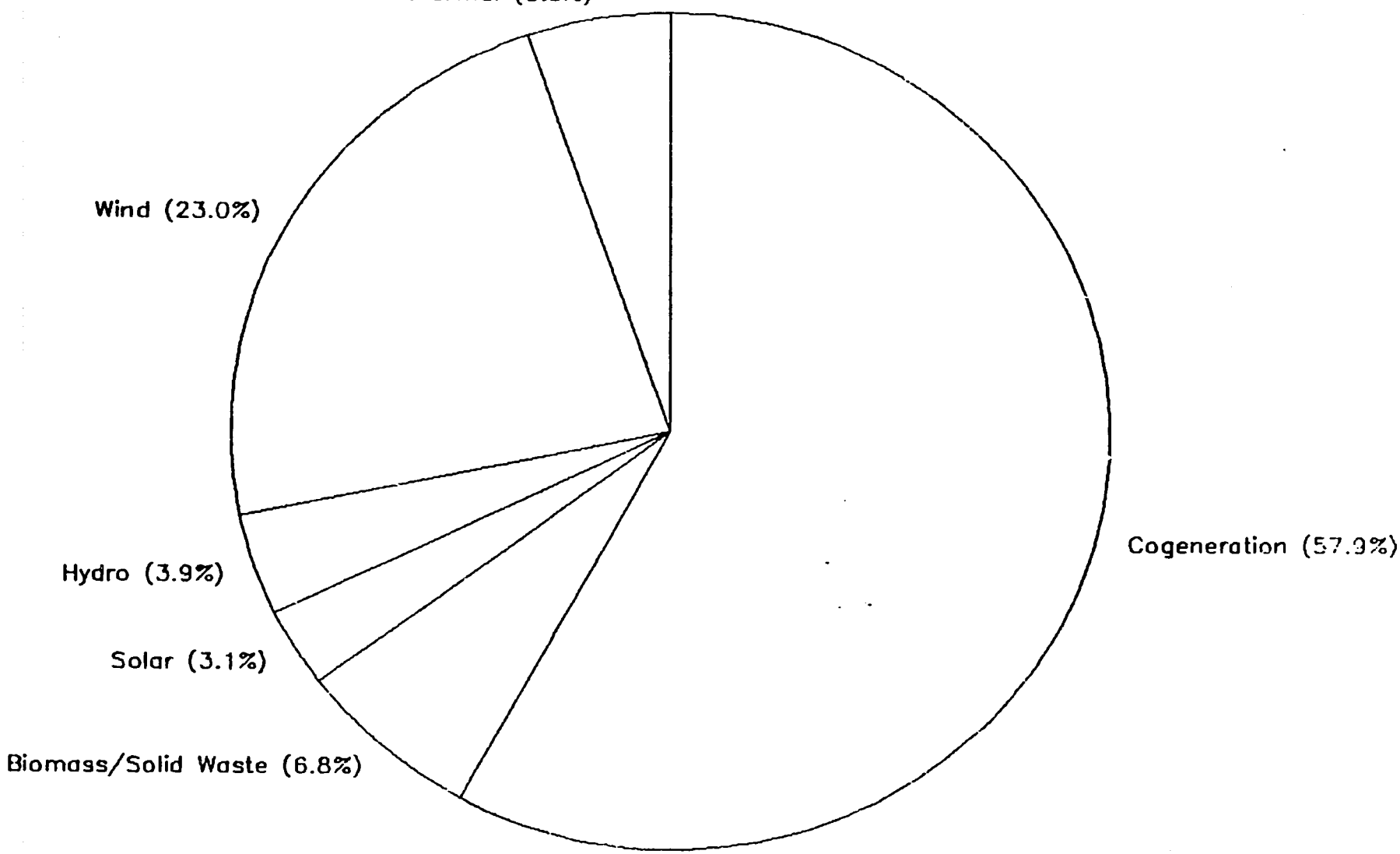
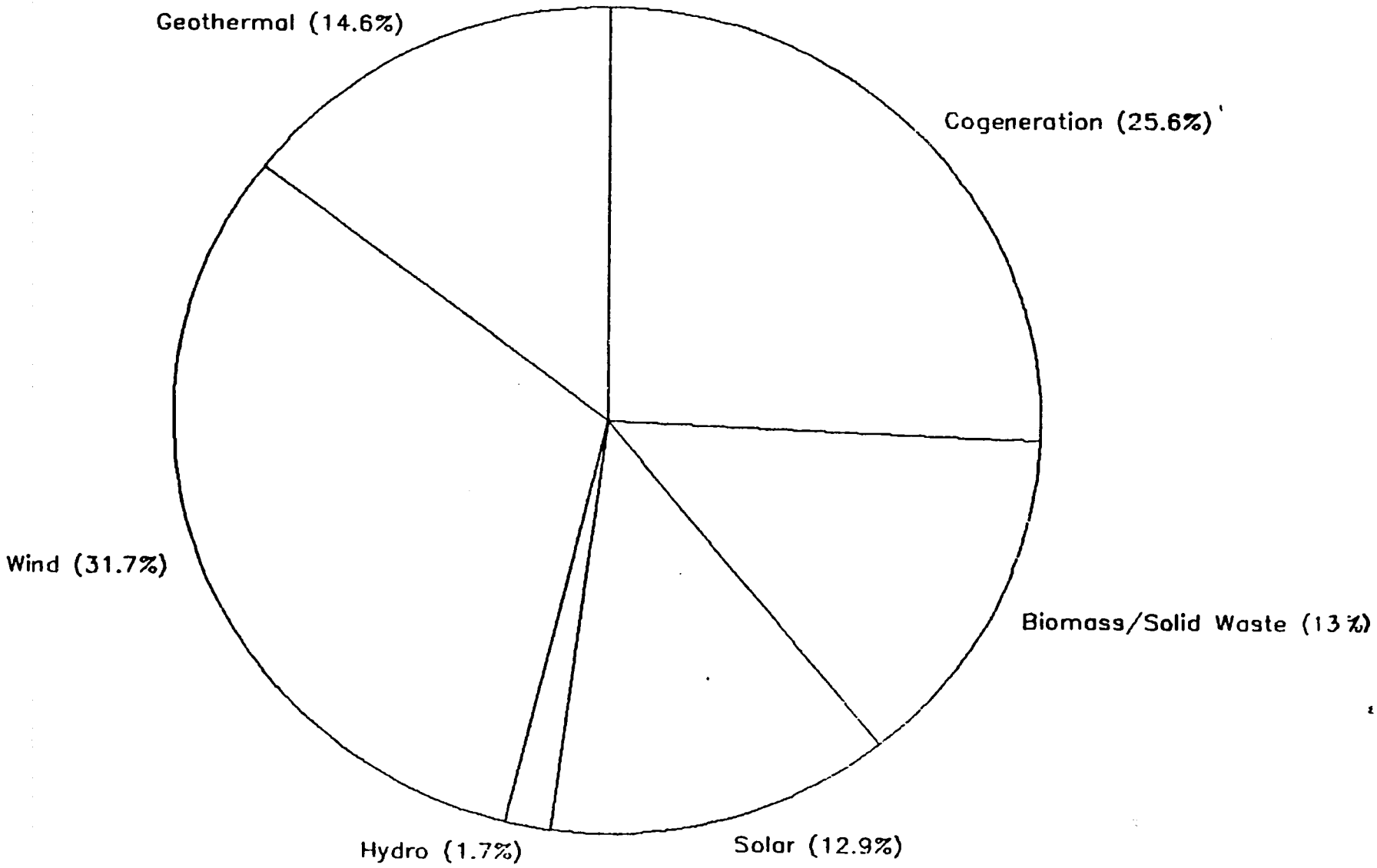


CHART 3

# California QFs by Technology

Contracted, but not on-line (6/30/88)



# A UTILITY PERSPECTIVE IN PURCHASING POWER FROM THIRD PARTY PROJECTS

James K. A. Harral
Pacific Gas and Electric Company

Philippine Private Power Seminar

October 5-6, 1988

# A UTILITY PERSPECTIVE IN PURCHASING POWER FROM THIRD PARTY POWER PROJECTS

## Introduction

Ladies and gentlemen, it is truly my pleasure to be here today with you.

Our countries have shared so many experiences that I find it impossible not to have a feeling of kinship towards the Philippines.

And now it appears that we are about to share another experience--the introduction of marketplace economics into the world of electric utility generation.

In the United States, the reality of competition to provide new sources of generation is clearly evident. Its impact upon traditional modes of utility operation is growing. The Public Utility Regulatory Policy Act (PURPA) and the Federal Energy Regulatory Commission (FERC) proposed rulemakings dealing with independent power producers, bidding to provide new generation, and the determination of avoided cost for qualifying generation facilities (QFs) under PURPA do and will aid this growth.

It is this experience and these trends that I would like to draw upon in offering you encouragement on the path you have chosen to develop sources of power supplementary to those traditionally provided by the National Power Corporation of the Philippines and in offering a few cautions that may be of some value to your future implementation of Executive Order No. 215.

PG&E's Experience

By most standards, PG&E is the largest combined electric and gas utility in the United States. With a service territory that encompasses northern and central California, an installed capacity of nearly 16,000 MW owned by PG&E and approximately 4 million electric customers, we have had a great deal of experience in constructing electric facilities; generating, buying, and selling electricity; and providing related transmission services.

In addition to our large generating capacity, however, power that we purchase from third parties plays a major role in PG&E's resource base. In 1987, for example, approximately 37% of the energy provided by PG&E to customers within PG&E's planning area came from sources other than PG&E owned generation. The other sources include 4,282 MW from other utilities, 2,330 MW through imports from the Pacific Northwest, 969 MW from Irrigation District Projects, and

3,013 MW from self generation and QFs (see Figure 1). Table 1 summarizes QF projects operational in 1987 by type of technology and shows the installed capacity and energy delivered in that year for each category. Resource additions to PG&E's system for the near future are expected to be made primarily by QFs.

This approach is not new to PG&E. As early as 1921 PG&E purchased a little over nine million kilowatthours of energy from two mining companies and a lumber company. In 1940 the Company started up the first of three cogeneration plants located near oil refiners in the Bay Area. In the northern part of PG&E's operating territory, at Fort Bragg, California, the Georgia Pacific Lumber Company began operation of a wood waste fired cogeneration plant in January, 1945.

With the advent of PURPA in 1978, the cogeneration business began to mushroom. Today in PG&E's service territory there are more QF projects with more generating capacity than in the service territory of nearly any other utility in the country. As of the end of 1987, PG&E had signed contracts for approximately 800 projects representing over 9,000 MW of QF capacity, including operational projects having a total installed capacity of 2,275 MW.

Cogenerators and small power producers have become a resource of major importance for PG&E. In 1987 approximately 10% of the energy provided by PG&E to its customers came from QF generation.

Purchasing power from other parties has clearly been a beneficial approach to developing an electric supply. It has helped us provide our customers with electrical service that is stable, diverse, and, with the exception of some QF purchases, competitively priced.

## The Benefits of Purchases from Third Parties

In the United States, the benefits of augmenting franchised utility company generation with power purchased from third parties have been increasingly recognized. Those benefits include:

- an expanded capital resource base to develop capital intensive projects;
- freeing utility company revenues to be used for the care and maintenance of the electric system;
- an impetus for the development of new technologies;

- increased diversity, and thus improved stability of supply;

- competition among third party suppliers that leads to economically efficient pricing for new supplies;

- a spur for utility companies to minimize their own construction and operation costs;

- a shifting of some cost and risk burdens from overextended utilities to new participants in the electric market.

These benefits do not come easily. They require full participation and oversight by the purchasing utilities and pertinent regulatory bodies and, most importantly, proper contractual incentive provisions and recourse for lack of performance to insure satisfactory performance by the third party suppliers.

## The Parallel Between Order No. 215 and PURPA and the FERC Rulemakings

The benefits of third party generation are obviously well recognized in the Philippines. As I read the "Rules and Regulations to Implement Executive Order No. 215 on Private Sector Participation in Power Generation" that was prepared

by the National Power Corporation of the Philippines, I was struck by the analogy it provides to our experience in the United States regarding the development of non-utility sources of power.

It presents, in many respects, a parallel between Order No. 215 and PURPA and FERC's proposed rulemakings in the United States.

Like Order No. 215, PURPA and the FERC proposed rulemakings are intended to stimulate the development of new power supplies using competition to provide such supplies at the lowest possible prices, thus fostering gains in economic efficiency.

PURPA's purpose was to boost the development of alternative sources of supply in the United States. This it succeeded well in doing, but inaccuracies in determining the price utilities such as PG&E had to pay for QF power under PURPA led, in many instances, to a cost for third party QF purchases higher than the cost of alternative supplies. The rulemakings now being proposed by FERC on bidding, IPPs, and avoided cost are generally intended to enlarge the group of prospective third party suppliers, increase competition to promote economic efficiency, and improve the manner in which avoided costs are determined in order to assure that the most cost competitive supplies are those developed.

Order No. 215, in large measure, seems to have much the same objective. What is called "private sector participation in power generation" by the National Power Corporation is the equivalent of what I have referred to here as third party suppliers of electricity to private utilities such as PG&E.

PG&E's experience indicates that the general direction pursued by Order No. 215, to broaden the spectrum of potential supply options by encouraging the participation of private developers in the generation of electricity, is exactly correct. The potential benefits of a broader base for development of electric generating resources that were recited earlier are real and can be realized. I would strongly encourage you to pursue the opportunity Order No. 215 offers to supplement National Power Corporation generation with generation resources provided by the private sector.

## Cautions Regarding the Implementation of Rule No. 215

This endorsement, however, is not without certain cautions that stem from PG&E's experiences with power purchases generally and PURPA and the newly proposed FERC rulemakings specifically.

The similarity between Order No. 215 and the regulatory directions being taken in the United States demonstrates that many of these concerns have been identified and are already addressed in Order No. 215, especially in those sections of the Order that deal with contract provisions.

Nonetheless, I feel that it is important to emphasize a few points, such as generation bypass, wheeling, interconnection, bidding, and future utility construction, that may deserve more attention as Order No. 215 is implemented.

- Generation Bypass and the Accurate Determination of Avoided Cost

  In the Philippines today, concern properly centers upon finding ways to develop needed power generation and the thrust of Order No. 215 focuses on satisfying that need. Localized circumstances can arise, however, where an area's power needs are met and lack of proximate transmission does not permit the transfer of excess electrical supplies to other areas where they may be needed. In these situations, the development of electrical capacity in excess of need provides no net societal benefit and runs counter to efforts to promote economic efficiency. It would simply add to society's costs by bringing on new capacity at the expense of idling existing, still useful capacity. PG&E's

experience with the implementation of PURPA in California demonstrates how this undesirable result can occur.

PURPA required that PG&E purchase capacity from new generation facilities if the facilities met PURPA's definition of a "Qualifying Facility" and would sell their power to PG&E at PG&E's avoided cost. Avoided cost rates were defined as rates not in excess of "the incremental cost to the electric utility of alternative electric energy". Incremental cost was further defined as the cost of the electric energy which, but for the purchase from the QF, such utility would generate or purchase from another source.

On the surface, this arrangement appears sound. Because of the way in which it was implemented, however, it caused PG&E and other utilities, at least two major problems:

1. The requirement that PG&E purchase without regard to need led to an excess of capacity, wasting capital resources and adding to consumers' costs.

2. The avoided cost price which PG&E was forced to pay was not reviewed or redetermined frequently enough to match the actual cost of other supplies

available to PG&E. This resulted in "overpayments" by PG&E for supplies it did not need (payments in excess of the price at which alternative supplies were available to PG&E).

It also led to the development of substantially more QF capacity than was actually needed. Figure 2 gives an indication of the situation.

Third party developers have signed contracts with PG&E to provide 9,019 MW of capacity. Of these, 2,275 MW are now operational and 2,513 more MW are expected to develop by the end of 1992. Payments for QF energy in 1987, at 53.5 mills/kWh, were higher than PG&E's average generation costs of 19.8 mills/kWh and higher than the price of energy available to PG&E from other sources, including our own generating units.

Although these problems have now been largely remedied, it is far better to carefully plan so they are avoided at the outset by proceeding with rules that allow utilities to match supplies with demand and only pay prices that realistically reflect the utility's avoided cost.

The accurate determination of avoided cost is essential. If it is not properly done, it can encourage uneconomic

generation bypass of available existing generation capacity with attendant adverse cost impacts for electric customers.

- Wheeling

We have just described one way in which a form of generation bypass can occur. Another occurs if a utility is required to wheel power from a private producer to a customer, such as industrial or large commercial user, that the utility would otherwise serve itself. Since the utility has undoubtedly planned to serve such customers, wheeling for the private producer will cause bypass of utility generation to the economic detriment of the utility's remaining customers.

In considering this problem, the issues of the utility's "obligation to serve" those customers who opt for private producer power, and the difficulties of operating a system where wheeling for third parties is mandatory, must be addressed.

- Interconnection

A utility's transmission system is designed and intended for the customers the utility serves. Mandatory wheeling could jeopardize such service. To the extent a

utility provides wheeling it must be voluntary and consistent with the capacity constraints of the utility's transmission system. Interconnection should not be required unless transmission capacity exists or is to be constructed to accommodate such interconnection at a fully compensatory price paid by the private party requesting the wheeling.

- Bidding

At PG&E we have come to the conclusion that a bidding system, whereby private parties compete through bidding to provide all or part of new capacity needs that a utility has put up for bid, is the most economically efficient and fair means to obtain such power. Factors that must be considered in selecting bids, should, in addition to price, include non-price factors such as dispatchability and load following ability. The utility must be free to consider all factors in evaluating and accepting or rejecting bids.

- Utility Construction

The utility must retain the right to determine what it believes is the most desirable mix of utility construction of generation and purchased power, and plan for and construct new facilities accordingly. Such

control is vital to the long term reliability and cost of the utility's service. It is the utility, not the private producers, that has the obligation to serve customers in its service territory.

## Integrating Private Suppliers into a Utility's System

Because of the significant impact QFs have had on PG&E's operations, some special commentary regarding third party generators that provides both words of caution and encouragement seem in order.

The customer demand in PG&E's system takes some healthy swings with a difference between the system peak and minimum load of about 10,000 MW not being uncommon. PG&E's operation of its power system centers around the task of following these load swings to meet customer load in a reliable manner and with the most economic mix of resources. Figure 3 shows how the various generating resources are used to meet load on a typical day.

Note that the proportion of thermal-electric generation under the load curve varies in direct relation to the total load. On the other hand, the load served by the QFs, which is included in the California Purchases band, is relatively constant throughout the 24 hours. PG&E has virtually no operational control over the magnitude or timing of the

output from a QF nor has the price paid for QF energy been an adequate mechanism to control QF output. This is because QF prices have not been determined to accurately reflect a utility's true avoided cost.

QF power is essentially base load generating capacity. Finding a place under the load curve for the 5,000 MW of such QF capacity expected to be operational by 1990 while holding to the objective of minimizing total cost is going to be an increasingly difficult task.

In conjunction with being concerned about minimizing the cost of electricity, PG&E is also responsible for the economic operation of its electric transmission system in Northern California. The parameters of concern in this regard include system voltage, system frequency, and the reactive power component.

QFs, as partners with PG&E in providing electric energy, are responsible for controlling the voltage and VAR (Volt-Amperes Reactive) output from their facility. This responsibility is specified in the Power Purchase Agreement and Interconnection Agreement that each QF signs. The Agreement specifically refers to the fact that the interconnected facility shall participate in voltage and reactive support as directed by the utility dispatchers.

The most economical point for reactive control is at the generator. We need the full support and cooperation of all the generators on the line--PG&E owned and third party (e.g., QFs)--to make this work. Here again the objective is to minimize the cost of generating and transmitting the energy. With few exceptions, QF operators cooperate with PG&E to adjust the amount of reactive power produced by their facilities.

System frequency control is another major concern of PG&E. Frequency control is one of the major parameters around which the system is managed. QFs over one MW capacity are required to have a free-operating governor on their operator. As the amount of QF generation increases and becomes a larger portion of total generation in the area, load frequency control of larger QF generators will become necessary.

PG&E has developed an elaborate system for gathering and reporting the results of operations for the power system. We are legally required by various regulatory agencies to report this data, but more importantly the data serve as the basis for the Company's long and short range electric system planning processes. This, along with energy consumption data from our Daily Service Report (DSR), are the foundations on which PG&E's electric resource plans are built. It is therefore important for PG&E to gather accurate and timely data on QF performance. Our contracts with the QFs require

reporting of operating results. Facilities over 10 MW are required to telemeter output to PG&E's Energy Control Center in San Francisco. Initially, participation by QFs in providing operating data was poor. However, PG&E is now working with QF developers to maintain effective and timely communications regarding plant operation.

The value of QF contributions to the stability of PG&E's system operation have been manifested during periods of system disturbances and during peak load conditions.

Initially QF projects tended to disconnect from PG&E's system during system disturbance conditions. During a storm in December 1982, all QF projects disconnected from PG&E's system when a drop in frequency occurred. However, as QF operators gain experience and confidence with their projects, a larger percentage of QF projects are staying through the storms, thereby helping to stabilize system voltage and frequency. In 1984, 40 MW of QF power stayed connected to the system during a system disturbance condition out of 105 MW on line before the disturbance. Very few QF projects have been disconnected manually from the system during system disturbance conditions which have been experienced in the last few years.

During our latest peak load conditions this past July, QFs provided over 1,000 MW of capacity to help meet the 18,490 MW

of demand experienced by PG&E's system. As Table 2 shows, geothermal QFs performed best, providing 100% of their expected output. Cogeneration QFs provided 72.5% of their expected output with hydro, solar and wind providing 60% or less.

PG&E's experience is that private or third party generators, as exemplified by the QFs on its system can provide a valuable contribution to the utility's system. We expect that operational problems created by the utility's current lack of control over the magnitude and timing of output from QF projects will soon be completely remedied by amendments to existing regulation.

Summary

The cautions I have just recited are not intended to discourage the National Power Corporation from relying upon the development of generation by the private sector. They simply argue for the careful implementation of Rule No. 215.

PG&E heartily recommends the development of private sector power generation, with the caveats that we have expressed.

For many years PG&E has successfully relied upon purchases of power from third parties, and we conclude the benefits of such purchases are too numerous to ignore.

In fact, our success in purchasing has been so good that we are now drawing upon our experience as a builder and buyer of electrical power to try our hand at building and operating electrical facilities to supply the needs of other utilities through a joint venture we have formed with Bechtel. We are now one of many potential providers of electric generation in the competitive environment that is developing in the United States and elsewhere.

## Conclusion

I am grateful for the opportunity that I have had to speak before you today, because in preparing my remarks, the occasion forced me to clearly focus on the situation that my own Company finds itself in in the United States.

This situation, that of competition in the marketplace as represented by private sector generators in the Philippines, is one that can benefit all parties. I believe you will find, as has PG&E, that if the issues it gives rise to are carefully identified and addressed, competition is the key to a successful electric future.

## TABLE 1

### Operating QF Projects By Technology

### As Of December 31, 1987

| Project Type | Nameplate Capacity MW | Energy Delivered GWh |
|---|---|---|
| Cogeneration | 1502 | 4980 |
| Geothermal | 80 | 701 |
| Hydro | 100 | 169 |
| Wind | 586 | 875 |
| Solar | 7 | 12 |
| Total QF | 2275 | 6736 |

## TABLE 2

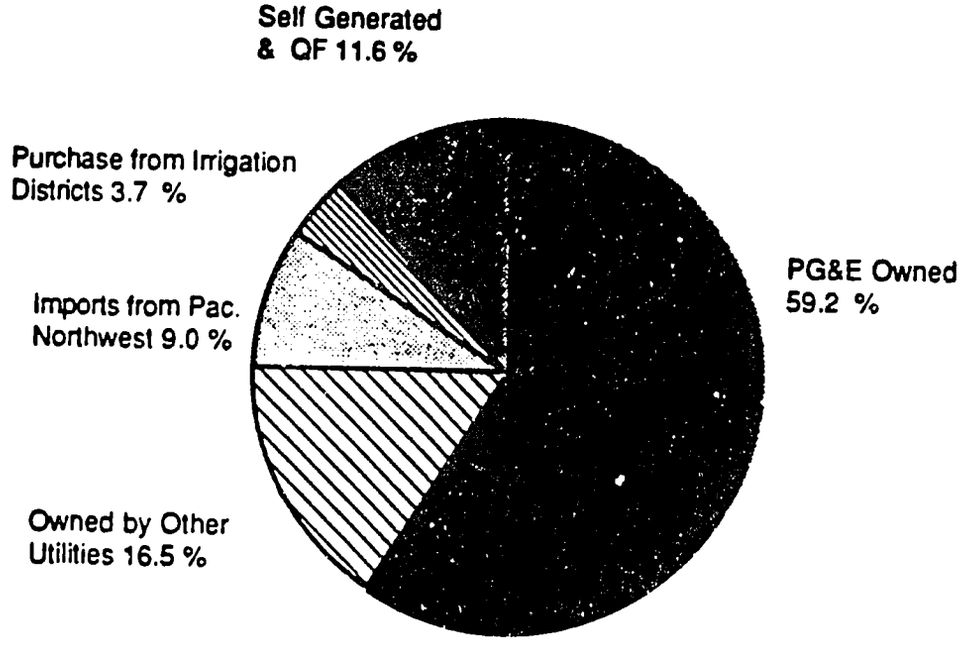
### QF Capacity During Peak Load Conditions

(18,490 MW in July, 1988)

| Project Type | Expected MW | Actual MW | Percent |
|---|---|---|---|
| Cogeneration | 1241 | 900 | 72.50 |
| Geothermal | 80 | 80 | 100.00 |
| Hydro | 80 | 39 | 48.90 |
| Wind | 513 | 76 | 14.70 |
| Solar | 5 | 3 | 57.00 |
| Total QF | 1919 | 1098 | 57.20 |

FIGURE 1

# 1987 ELECTRIC RESOURCES
# PG&E PLANNING AREA *
# (CAPACITY)




| | NAMEPLATE MW | PERCENT |
|---|---|---|
| Total Capacity | 26004.5 | 100.0 |
| PG&E Owned | 15404.6 | 59.2 |
| Owned By Other Utilities | 4282.1 | 16.5 |
| Imports From Pac. Northwest | 2330.0 | 9.0 |
| Purchase From Irrigation Districts | 969.2 | 3.7 |
| Self Generated & QF | 3013.4 | 11.6 |

FIGURE 2

# QF Development
## (out of 9019 MW signed contracts)

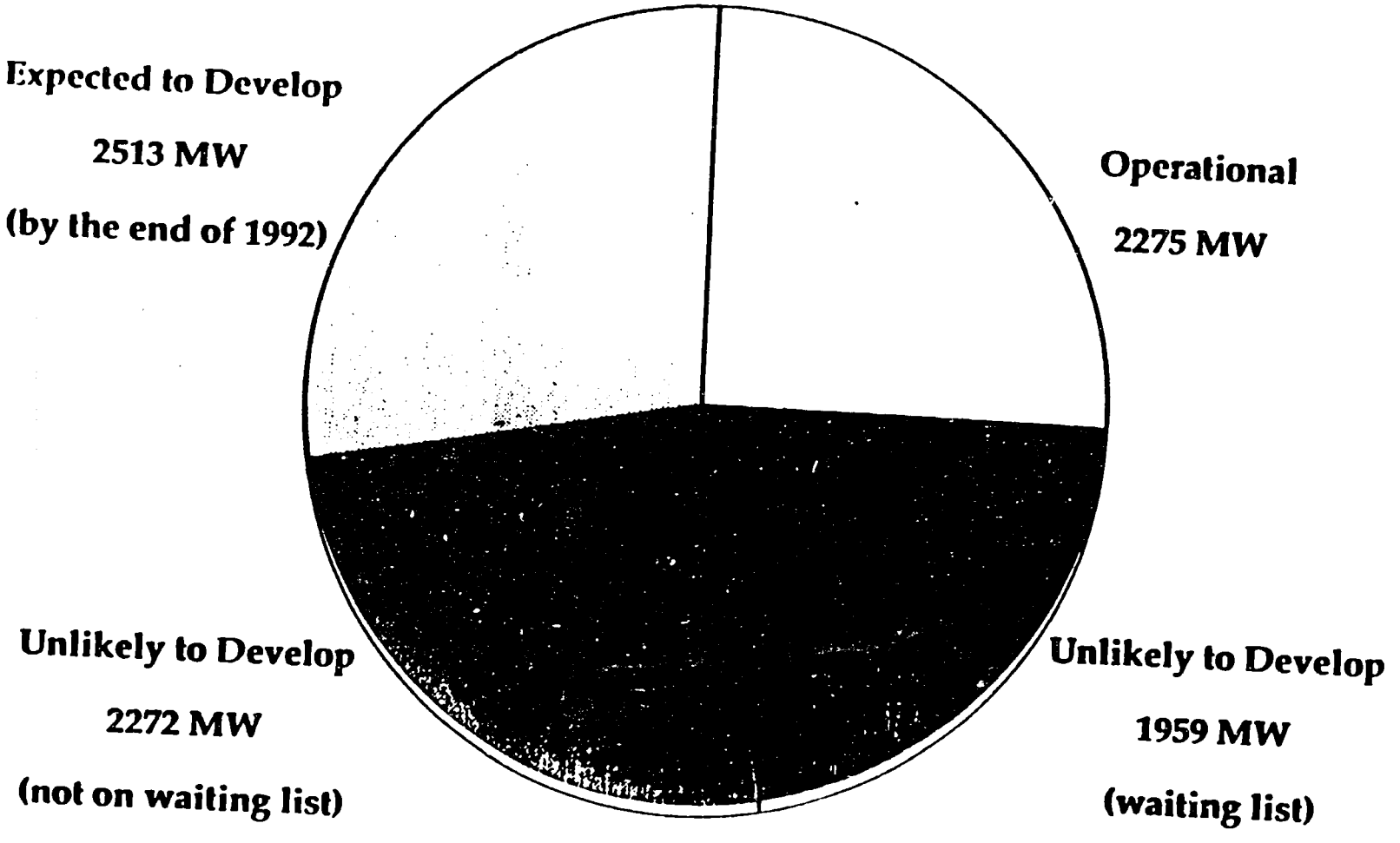
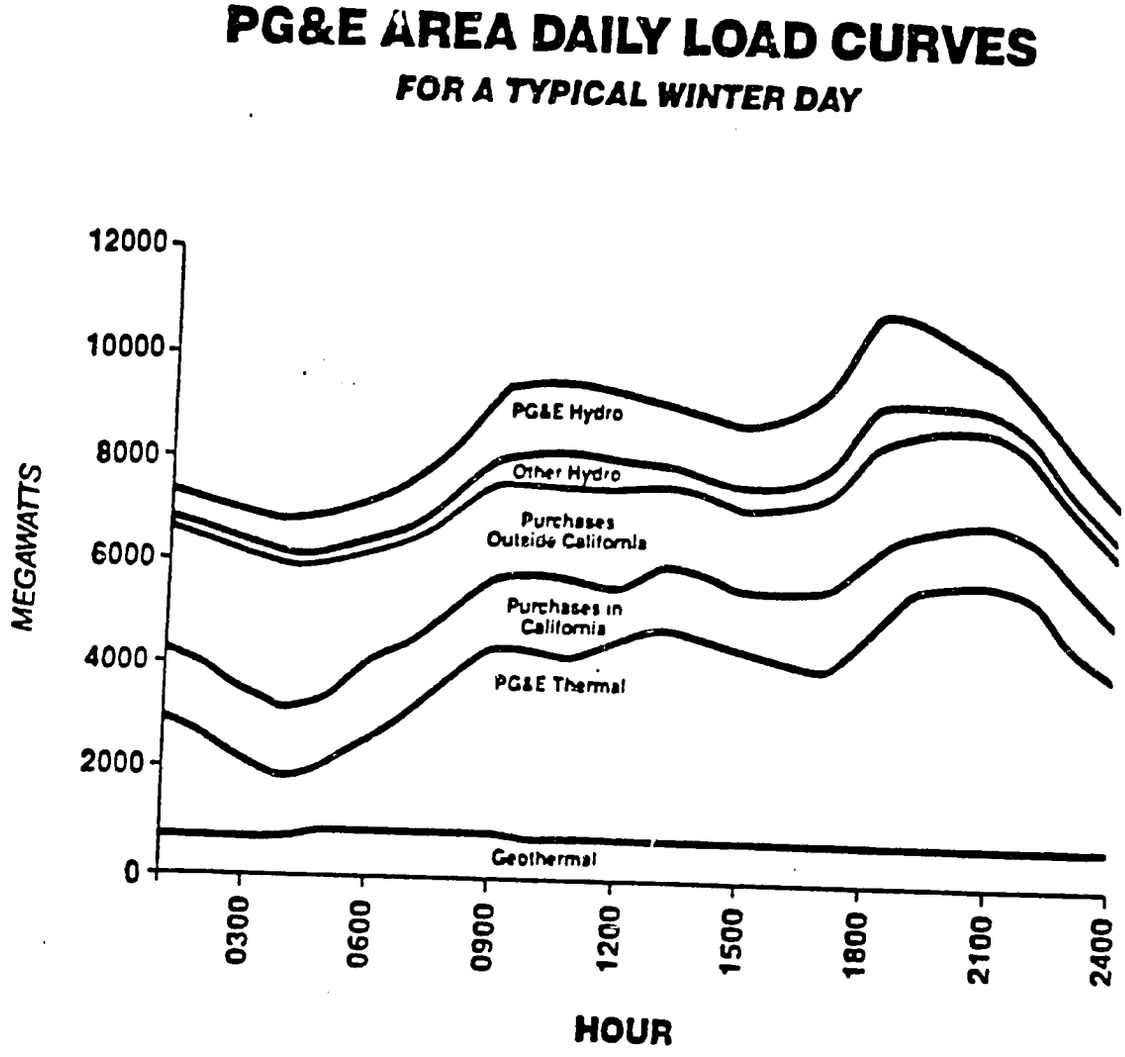


FIGURE 3


PG&E AREA DAILY LOAD CURVES
FOR A TYPICAL WINTER DAY
MEGAWATTS
12000
10000
8000
6000
4000
2000
0
PG&E Hydro
Other Hydro
Purchases Outside California
Purchases in California
PG&E Thermal
Geothermal
0300
0600
0900
1200
1500
1800
2100
2400
HOUR

# The Turkish BOT Power Project Experience

William E. Stevenson
Vice President and Manager
Bechtel Financing Services, Inc.

Speech Delivered to the PCCI-USAID Sponsored Seminar
"Private Power Generation Through Build Own and Transfer (BOT)"
Manila, Philippines
October 5-6, 1988

Good [afternoon]. As many of you know, Turkey has been at the forefront of the movement to capture the benefits of private sector initiative, capital and efficiency for the expansion of national power generating capacity. My company has been closely involved with that process over the past four years. During that time we have also actively pursued privatized power proposals in the U.S., the U.K., Pakistan, and Jamaica, based upon a variety of fuels, capacity and commercial configurations. I should say right at the outset that, with the exception of the U.S., none of these efforts has to date borne fruit for us as an engineering and construction company, despite the expenditure of many millions of dollars by our sponsor groups and the application of some of our best and brightest talent.

You'll understand why during the next couple of hours. But I believe that along the way, we have learned a great deal about what it takes for one of these projects to be realized. I'm here today to share my personal perspective as a veteran of perhaps the longest running BOT development process, the Turkish coal-fired BOT power projects.

Because I think it is highly relevant and instructive to the process you are encouraging here, I'm going to give you a summary of the Turkish development experience to date. Then I'll describe what I believe to be the most important of the major issues that have to be faced up to and resolved, drawing from that experience and our experience elsewhere as well.

My basic message today is that there is an enormous gap between the promise of privatization benefits, on the one hand, and the practice of pulling one together, on the other. Under the very best of circumstances, as you will see, BOT project development is a costly and risky enterprise to embark upon, both for host governments and for prospective private sponsors. So from our perspective as a potential project sponsor, the decision to engage in a BOT development exercise makes sense only if three conditions exist going in. First, the host government must be firmly committed -- as a matter of stated preference for the sector and overall strategic development policy -- to putting the responsibility for the creation and operation of new generating capacity into the hands of the private sector, with reliance upon the public sector only as a last resort fall back.

Second, the host government must understand private sector incentive mechanisms, be realistic in its risk-reward sharing expectations, and always keep in view the full opportunity cost of failing to conclude the process with success. And third, the government must be seen by the project sponsors and lenders to have a credible commitment to concluding a deal. This means setting out and adhering to a credible schedule, conducting a sound process for inviting proposals and awarding a sole-source development mandate, and delivering on its timing commitments for reaching project financial close. If any of these three ingredients are missing, the BOT exercise is almost certain to fail in its purpose and its promise, perhaps even at its outset.

So that's where we're going. Now let me tell you where we're coming from.

In September 1984 -- four years ago -- the head of Turkey's State Planning Organization requested Bechtel Power Corporation to carry out a techno-economic-commercial prefeasibility study for the development of a 600-to-1,000 MW electric power generating project, to be fueled by imported coal, located at a coastal site in western Turkey, and financed by a new, privately owned project company.

It was left to the study to recommend the exact plant size and configuration, and the choice of site. Other study objectives were

- to establish the need for the power output in relation to the recommended project capacity.

- to establish the project's economic competitiveness with both a domestic lignite-based project of similar scale financed and built by the Turkish State Utility, TEK, and with other BOT fuel options.

- to establish the project's ability to comply economically with widely accepted environmental standards.

- And last, to assess the feasibility of arranging the required amount of financing on the security of a power sales agreement with TEK, without loan repayment guarantees from the Turkish Republic.

In summary, the study addressed the four basic questions -- what, how, where and why.

The study's $500,000 cost was shared by Bechtel and the U.S. government through a reimbursable grant arranged by Bechtel from the Trade and Development Program.

[SLIDE - **Prefeasibility Study Conclusions**]

Completed in April 1985, the prefeasibility study concluded that:

- establishment of such a facility was a feasible and economically attractive alternative for Turkey to meet part of the projected growth in demand for power.

- looking at the future supply-demand balance, there was a pressing need to proceed as quickly as possible with development and implementation of the project in order to reduce reliance upon electricity imports and avoid load-shedding before 1990.

- high grade imported steam coal was widely available in a long-term buyer's market.

- the power price required to attract the capital would be very competitive with public sector generating alternatives.

- subject to the Government's being willing to accept certain specified risk-sharing undertakings, it appeared probable that the necessary funding could be attracted within the broad BOT framework.

[SLIDE off]

In May 1985, the SPO approved the study findings and requested that Bechtel proceed with a second phase study focussing on the development of a contractual structure and commercial and financial implementation plan. This quickly evolved into a request for a full commercial proposal.

We spent the summer of 1985 in an intensive effort aimed at refining the key contractual terms, selecting a financial adviser and equipment supplier/equity partners, and seeking other preliminary financing commitments on the basis of the proposed BOT contractual structure. This phase ended with our presentation to the Turkish Government in September 1985 of a full commercial proposal to proceed with negotiating contracts for a $1 billion, 960 MW coal-fired project under the BOT contractual structure.

The process then seemed to fall into a hole. The 18 months between June 1985 and January 1987 were spent in an epic tug-of-war between the Turkish Government, on one end of the rope, and the U.S. Eximbank -- on the other end -- over the issue of loan repayment guarantee. With Bechtel as the mediating party and interested deal maker, the Turkish team pulled the Eximbank team by inches in the direction of assuming project risk. I'll come back to that later. In the meantime, along the way, the Turkish Government was approached by other sponsor groups and encouraged them to develop additional imported-coal based project proposals, sited at different coastal locations, but all in the same general cost and scale range as ours. The Government hoped that the competing sponsor groups would pressure their export credit agencies to break ranks with U.S. Eximbank and agree to assume BOT project credit risk.

The Government was determined -- as a basic BOT principle -- that the project loans be without direct repayment recourse to the Government in the event the project company was unable -- for reasons of its own contractual default -- to earn sufficient revenues to service its loans.

And U.S. Eximbank was equally determined to have the repayment of its very large loan to the Project Company unconditionally guaranteed by the Turkish Republic.

In January 1987, a compromise was reached, the credit structure tug-of-war was declared a mutual victory, and the Government decided to proceed with a project selection process leading to the development -- in sequence -- of three BOT projects, all of which were needed in order to meet demand growth.

In March 1987, the Government issued a call for project proposals to six multinational contractor/supplier consortia. After several rounds of further clarifications, the Government announced its ranking decision in September 1987, thirteen months ago. Negotiations proceeded immediately with the first-ranked group, but were in effect suspended in December when one of its major equity participants withdrew. During the first half of 1988, the Government undertook a round-robin series of negotiations with the second, third and fourth-ranked groups, ratcheting the contractual risk-reward relationship in its favor by playing each group off against the others and holding out the prospect of being mandated as the first project to proceed.

Finally, in August -- two months ago -- the Government announced its decision to return once again to sole-source negotiations with the original first-ranked group. That consortium has been given until the end of January 1989 to finalize all contracts, arrange the required financing and sign all the financing agreements -- what we call reaching financial close -- to be able to start construction. Whether or not they will succeed in getting there is an open question at this point. But even assuming that they can, and assuming further that they achieve their committed construction schedule, it would mean that the last of their four turbine/generator units would come into commercial operation only in the last quarter of 1993.

[SLIDE - Turkish BOT Power Project Milestones]

Here you see a summary of the project development milestones I've just described to you. You can see that -- at the earliest -- it will have been 9 years from the time the Turkish Government initiated the BOT investigation process until the first BOT power project comes into full commercial operations. For context, this compares with the World Bank's finding in 1985 that at the then-current 10% annual growth in electricity demand -- compared with actual growth since then of 13% -- Turkey would have to increment its on-line generating capacity at the rate of one 1,000 MW plant per year for 10 years starting from 1990.

[SLIDE off]

So, what has frustrated the process? What has gone wrong? And what can the Philippines learn from it? Well, the reality is that it is one thing for governments, lenders and project sponsors to agree on joint objectives, and even to agree in the abstract on what should be a reasonable contractual structure.

But it's quite another for these three major groups of players to sit down and mutually agree on the hundreds of risk-reward, "what-if" mini-decisions that lead up to a deal, especially in a context of sometimes irresponsible competitive pressure, political accountability, intra-Government agency dynamics, personnel changes and rapidly evolving economic conditions. The fact is that this has been a wheel-invention exercise with very high stakes for all the parties involved.

So, all things considered, and with the benefit of hindsight, the time required to bring the process to this point -- four years -- is a measure of the distance between the rhetoric and the reality of putting together a billion-dollar-plus deal while making up the rules on a changing playing field at the same time.

But now that the Turkish process has come this far, let's be specific. I want to briefly describe the three issues which I believe are the most important for a Government to consider in deciding whether to embark upon the BOT journey.

[SLIDE - The Key Issues]

These issues are the project credit structure, the basic risk-reward principles, and the management of the BOT project development process.

I've picked these three because how a Government approaches them will determine to a large extent whether private companies such as my own decide to enter the process in the first place.

[SLIDE off]

The first and most basic of the issues that has to be resolved concerns the credit structure -- simply put, what are the lenders being offered as the security for the servicing of their loans? I mentioned earlier that the resolution of the credit issue occupied about 18 months of the four year development history to date in Turkey.

The first point is that the lenders are expected to provide 80-85 percent of the total financing, and these are very large projects, so their exposure individually is unusually large. For example, U.S. Eximbank's commitment to our project was a large as its entire existing Turkish loan portfolio. A lender simply cannot afford to take the same risks on a $350 million loan that he might consider taking on a $10 million loan. Also, for the most part the lenders have no particular project or country commercial interest pushing them to provide new loans for a BOT project. In the case of commercial banks, as a group they are trying to sell-off existing developing country sovereign loans, not add new ones dependent for repayment on the same borrowers but on a less secure basis. Yet, the lenders are expected to provide up to 85% of the project financing. All of this places them in a rather strong bargaining position as to what they will and will not do.

[SLIDE -- Credit Structure Determinants]

The credit structure for a project financing is determined largely by who the lenders are. To raise the financing for a typically large BOT power project -- say at a cost scale above $300 million or so -- in a B to D rated developing country, will absolutely require the participation of the official export credit agencies either as direct lenders or as guarantors of commercial bank loans. There is nowhere else to turn for the credit capacity.

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[SLIDE off]

In the Turkish saga, U.S. Eximbank -- by agreeing to be pulled part of the way towards a project financing credit -- turned out to be the most responsive of the export credit agencies to the Turkish Government's BOT risk-sharing proposal. What they agreed to -- after hundreds of hours of negotiation and 18 months of project development impasse -- is summarized on this slide.

[SLIDE -- Turkish BOT Lender Security Structure]

Let me take you through it, then we'll comment on how close it comes to the off-recited BOT principles and advantages.

- The project company is the borrower.

- The project company arranges all the financing needed to reach full commercial operations. This includes provision for funding an escrow account -- called the Installment Escrow Account -- from the date of first loan drawdown until the last repayment.

This first escrow account holds a balance of funds to be maintained in an amount equal as of any date to the debt service payments falling due during the subsequent six months -- in effect, a permanent earnest-money deposit for the next loan service installment, and early warning alarm for payment problems. The escrow balance must build up with the drawdown of the loans during construction and then gradually declines again as the loans are paid off.

- Once the plant starts operating, the Government utility is committed to pay the project company for all available power. The power is priced in the currencies of the company's costs for the period, assuming on-budget project completion, achievement of plant availability at a guaranteed percentage of capacity, and fuel consumption at the guaranteed heat rate.

[SLIDE -- Turkish BOT Power Tariff Structure]

Here you see this cost-recovery power tariff structure with the BOT term on the horizontal axis, and the tariff expressed in constant ¢/kwh on the vertical axis. Again this is the power price per kilowatt hour as it looks over the BOT operating term, normally 10-15 years.

The price for a given period is multiplied times the actual plant availability achieved during that period to give the power payments due from the utility to the Project Company. The capital servicing costs for paying off the project financing are shown at the top. The debt service component for a given year is equal to the Project Company's interest and principal payments falling during that year, calculated on the assumption that the project construction is completed on budget.

The up-slope in the first operating year reflects the delayed start of loan principal payments as the grace periods come to an end.

The steep decline after the first operating year followed by a more gradual decline reflects the fact that the commercial bank loans are paid off on a shorter schedule -- typically three or four years after the end of the grace period -- than the export credit and institutional loans. This alignment of the power tariff with the actual debt service structure provides the first source of security to the lenders -- if the Project Company and its contractors perform, and if the utility pays its bills on time, the power revenues will be adequate to meet the project debt service on schedule, without any recourse outside the Project Company.

The second layer of security for the lenders is also internal to the project cash flow, and derives from the equity servicing component of the power payments.

You can see the equity servicing strip in the tariff at the top. Like the debt service component, the equity service payments are calculated on the assumption that the project cost comes in on budget, so that the share capital actually required to be drawn down will earn a committed rate of return through the power payments if the plant operates at the guaranteed availability and heat efficiency levels, and the O&M costs are controlled within budget.

[SLIDE -- Turkish BOT Lender Security Structure]

- The equity servicing component of the payments for available power is captured by the escrow agent for the lenders as back-up loan security and placed in a second and third escrow account.

These accounts continue to capture all the equity cash generation as available until the combined balances in the three escrow accounts equal the remaining debt principal outstanding. At that point, the company may declare dividends for the first time from any additional cash generation. Before that point, the shareholders may borrow from the escrow accounts by providing acceptable bank guarantees to secure the borrowed funds. So you can see that the shareholders' cash generation from the project is entirely dedicated as security against the project's successful and timely repayment of its loans for the entire loan repayment term.

As a third layer of security, the Government commits to make available to the Project Company, in the form of subordinated loans, any additional funding required to maintain the Installment Escrow Account balance at the committed level.

For example, if there are unrecoverable construction cost overruns, or if plant availability is low because of operating problems, the power payments may not be sufficient for the Project Company to meet the debt service payments in a given period.

In such an event, any funds available in the second and third escrow accounts are used first to fund the Installment Escrow Account shortfall.

But if there are insufficient escrowed funds from past cash generation to meet the shortfall, a Government financial institution is committed to disburse the needed funds into the Installment Escrow Account.

The subordinated loans, in turn, are repayable at interest by the Project Company from its future cash generation, ahead of escrow account additions and dividends. So in effect, they are a form of last-resort bridge financing against the expectation of future improved operating performance.

- The Government's obligation to make subordinated loans available for timely senior debt service remains in place until the later of three operating years, or until the balance in the second escrow account builds up to one year's forward debt service.

Beyond that point in time -- called Project Creditworthiness -- the Government back-up guarantee to provide subordinated loans for senior debt service falls away, and the senior lenders are on a project-success basis for the remaining loan repayments. Of course, at that point the three escrow accounts hold almost 3 years of the remaining forward debt service, so the timely debt service is largely assured and is impervious to any month-to-month operating cash flow problems

- Importantly, the Government's back-up funding obligation remains in place through the final loan repayment for revenue shortfalls resulting from events of force majeure, Government default on its contractual obligations to the Project Company, and during any disputes.

- The Turkish Treasury puts the full faith and credit of the Republic behind the payment obligations of its utility and its subordinated lender institution.

- And finally, if the Government takes over the privately-owned shares before the end of the BOT term, the project loans become the direct repayment obligation of the Republic.

[SLIDE off]

Now let's look at this structure in relation to the BOT objectives and claimed advantages.

- Does it attract new capital to the country? Absolutely, both in the form of private equity and in the loan financing -- especially that from the commercial banks and institutions like IFC and OPIC who, without the private sponsors' involvement, would not participate in new loans to the country.

- Is the borrower a private company instead of the Government? Yes.

- Are the lenders at risk for project failure? Only after the project has matured, and more in form than substance.

  By the time the subordinated loan back-up obligation falls away, by definition the project has been successfully built and operated for some time, so it is unlikely to suddenly develop serious long-term problems. And the escrow account security requirement must be paid for through higher capital servicing costs in the power tariff.

- Is the Project Company motivated to earn sufficient revenues to meet its debt service obligations on schedule and avoid reliance upon the Government for loan servicing support?

Most definitely. We saw that the shareholders' cash generation is entirely captured in the escrow accounts for most of the BOT term, for use as the first line of recourse for Project Company performance default. And any subordinated loans must be fully repaid ahead of dividends. Remember also that recovery by the investors of their share capital principal itself is built into the power tariff at the guaranteed performance levels, and extends beyond the end of the scheduled loan terms.

So the shareholders will lose all their returns and their entire capital investment before the Project Company defaults on the subordinated loan servicing.

In summary, the credit structure developed for the Turkish BOT projects successfully marries the lenders' security requirement to the Government's interest in giving the project sponsors strong incentives to succeed, while still allowing the investors an opportunity to earn an acceptable return if the sponsors succeed in meeting the project's economic and contractual objectives.

[SLIDE -- The Key Issues]

So that's a BOT credit structure that was bankable for Turkey, a B-minus sovereign credit. Let's turn now to the second issue -- the basic risk-reward principles that were addressed in structuring the Turkish deal.

[SLIDE off]

In the broadest terms, we have the three parties -- the Government, the lenders, and the project sponsors representing the Project Company shareholders and its contractors. The lenders' terms -- as we've seen -- are a given. They don't need the project, and they don't need to book additional exposure in low credit countries.

They lend at stated interest rate spreads over their costs of funds, with no upside benefit if things go better than expected. The Government benefits from the fact that the required power tariff is lower to the extent that debt is cheaper to service than equity, reflecting debt's first claim on revenues, lower risk of capital loss, earlier recovery and relatively greater availability than equity funds.

The lenders' credit structure pushes the repayment risk onto the shareholders as first recourse for successful project execution and operation, and onto the Government as first recourse for Government default on its obligations, force majeure, and contractual disputes. With the lenders' requirements accommodated by the credit structure terms, the Government and the Project Sponsors are left to carve up the sharing of the residual risks and rewards as between themselves.

The broad principle that Bechtel agreed at the outset with the State Planning Organization and reflected in the original prefeasibility study, was simple.

To attract the substantial equity required for the project -- about $150 million dollars from mainly foreign corporate and institutional sources -- required that the Government agree to take responsibility for the risks deemed to not be under the Project Company's control. The Project Company and through it, its contractors, would in turn be financially responsible -- up to specified limits -- for the elements that were deemed to be under their control. For committing their capital and taking these controllable risks, the shareholders would have the opportunity to earn an agreed range of compensation on their investment depending upon how well the company performed its responsibilities.

On the downside, if the Project Company failed to meet its contractuals commitments, the shareholders would, in the first instance, have to participate up to an agreed limit in the required financing for project cost overruns -- increasing their financial exposure -- and would also have their entire share capital exposed to loss for operating performance under the terms of the energy sales agreement, as described earlier.

So let's look briefly at how the risks were allocated in the framework of the contractual structure diagram that Ernie Lam described in generic terms in his introduction.

In the development process, long before you have a new Project Company for implementation, you have a Project Sponsor Group that must wear several hats for development.

The Bechtel project sponsor group is comprised of Bechtel as development group leader and project engineer/construction manager, two equipment suppliers, a Turkish civil contractor, a trading company, a coal supplier and a utility operator. So the sponsor group is comprised of individual companies who would have various roles in the project's execution, and in most cases, multiple roles individually as well, but each with somewhat different commercial interests.

[SLIDE -- Turkish BOT Power Project Contractual Structure]

For example, some of the sponsor companies are in the construction consortium -- at 9 o'clock -- to supply the plant, some will also provide management personnel to the Project Company through the Management Services Agreement -- at 5 o'clock, and some will form a separate joint venture company to provide plant operating services to the Project Company. All of the sponsors would be shareholders -- down at 6 o'clock -- and as a group they would provide about 60% of the required share capital. Since the sponsors must arrange additional equity funding from passive investors, and since they must each justify their own equity investments to their respective boards of directors, the share capital must stand on its own feet as a competitive use of scarce investment funds being placed at cross-border risk for a long term.

In other words, the Sponsors would not consider investing overseas in the first place were it not for the prospect of supplying equipment or services to the project, but such a sole-source sales prospect does not mean that they are in a position to accept an unrealistic risk-reward structure as investors.

The point, more generally, is that the BOT structure, to be financeable, requires that each of the individual contractual arrangements making up the network, stand on its feet independently in linking the individual responsibility for performance to the reward and risk assumptions under that agreement.

As one example, the plant operations contract must be structured to provide the operations contractor with a financial incentive to achieve high plant availability, through a bonus arrangement for better-than-guaranteed availability performance. But it is not realistic to impose a financial penalty on the operator for lower than guaranteed performance beyond 100% of his profits at the expected availability performance level. To summarize, the next basic risk sharing principle is to carve the responsiblilities and risks up individually among the private participants in relation to their competence, the compensation you are willing to pay them, and the penalties you expect them to accept for their failures.

The last basic principle of risk-reward structuring is that the upside performance rewards have to bear some reasonable proportionality balance to the downside performance risk assumptions.

For example, if the shareholders will earn a 20% return if the company achieves the guaranteed plant availability of 75%, but will see their return drop to 10% return at 70% availability, they obviously will expect a return in the 20-30% range if the actual plant availability averages 80%. And the associated higher equity servicing payments at the higher-than-guaranteed availability levels is money well spent by the Government, because their resulting overall average power cost per kwh will still be lower than at the guaranteed availability level. And any incremental generated power has a high economic opportunity value.

Simply put, high plant efficiency yields a bigger pie, so it is economic common sense to encourage it. The same logic applies to construction cost underruns. The power tariff structure should give a positive inducement, for example, for earlier than guaranteed project completion, because the interest cost savings are dramatic -- in our porject's case, averaging about $115,000 per day saved in the completion schedule.

There is a compelling logic for the Government to share the avoided interest cost between itself and the Project Company -- through the power tariff -- so that the Project Company can in turn provide a bonus incentive to the contractor for early completion. This is what the BOT development process should be all about -- intelligently structured incentives for economic performance.

What it should <u>not</u> be about is trying to push off all the downside risks onto the private participants while giving them no upside incentives.

[SLIDE -- Basic BOT Risk-Reward Principles]

So there you see summarized the broad risk-reward principles we've just described.

I've spent the last 20-minutes or so talking about the elements of a viable BOT contractual structure. But getting the structure right is not enough.

My story of the Turkish BOT development process to date hinted at something that is equally critical -- the host Government must be credible in how it goes about the development process itself. Given the criticality of this aspect for attracting the kind of serious project sponsors you must attract to close a BOT project, that is a subject that deserves a lot of further discussion today, and my fellow Turkish veteran, Jerry Vargo, will go into it in more detail. But as I said at the outset, process credibility starts with the enlightened definition of a policy framework aimed at coaxing out serious responses to reasonable incentives, as opposed to one which features a reluctant state utility dictating terms to potential foreign sponsors and lenders to ensure that it will have no competition.

Next, credibility means setting a realistic development schedule, assigning clear responsibility to appropriate Government representatives who understand the art of the possible and are committed to the BOT objectives, and adhering to a timetable. From there, credibility moves on to setting out -- in the RFP's themselves -- as much specificity as possible concerning what the Government wants and the risks the Government is prepared to assume.

It also means engaging a competent, objective and respected financial adviser to provide sound advice to the Government for the difficult economic, technical, commercial and financial value-judgements that have to be made going-in and along the way.

Credibility means concluding the competitive selection part of the process on objective criteria within a few months of the RFP and assigning a sole-source negotiation mandate to a single project sponsor group for moving up to financial close.

And finally, credibility means a cooperative spirit of mutual enterprise between the Government and the selected sponsor group in overcoming the obstacles to reaching financial close.

Experience to date has shown that it's a lot harder than giving speeches about the abstract wonderfulness of BOT to an enthusiastic audience. Thank you for the opportunity of sharing our perspective with you.

# Pre-Feasibility Study Conclusions
(April 1985)

- Project feasible and economically attractive
- Pressing need for project capacity
- Fuel widely available, competitive
- Competitive power price
- Financing feasible within BOT structure

# Turkish BOT Power Project Milestones

| Project Month | Date | | Milestone |
|---|---|---|---|
| 0 | September | 1984 | GOT prefeasibility study request |
| 3 | December | " | USTDP commits study funding |
| 7 | April | 1985 | Prefeasibility study submitted |
| 12 | September | " | Bechtel commercial proposal |
| 27 | January | 1987 | GOT/USXM agree credit structure |
| 30 | March | " | GOT calls for BOT tenders |
| 35 | September | " | GOT announces negotiation award |
| 46 | August | 1988 | GOT announces financing mandate |
| *54(?)* | *April* | *1989(?)* | *Financial close* |
| *108(?)* *(9 years)* | *October* | *1993(?)* | *Full commercial operation* |

# The Key Issues

- Credit structure
- Basic risk-reward principles
- Development process management

# Credit Structure Determinants

Country
Creditworthiness
+
Project Cost Scale

→ Project Lenders

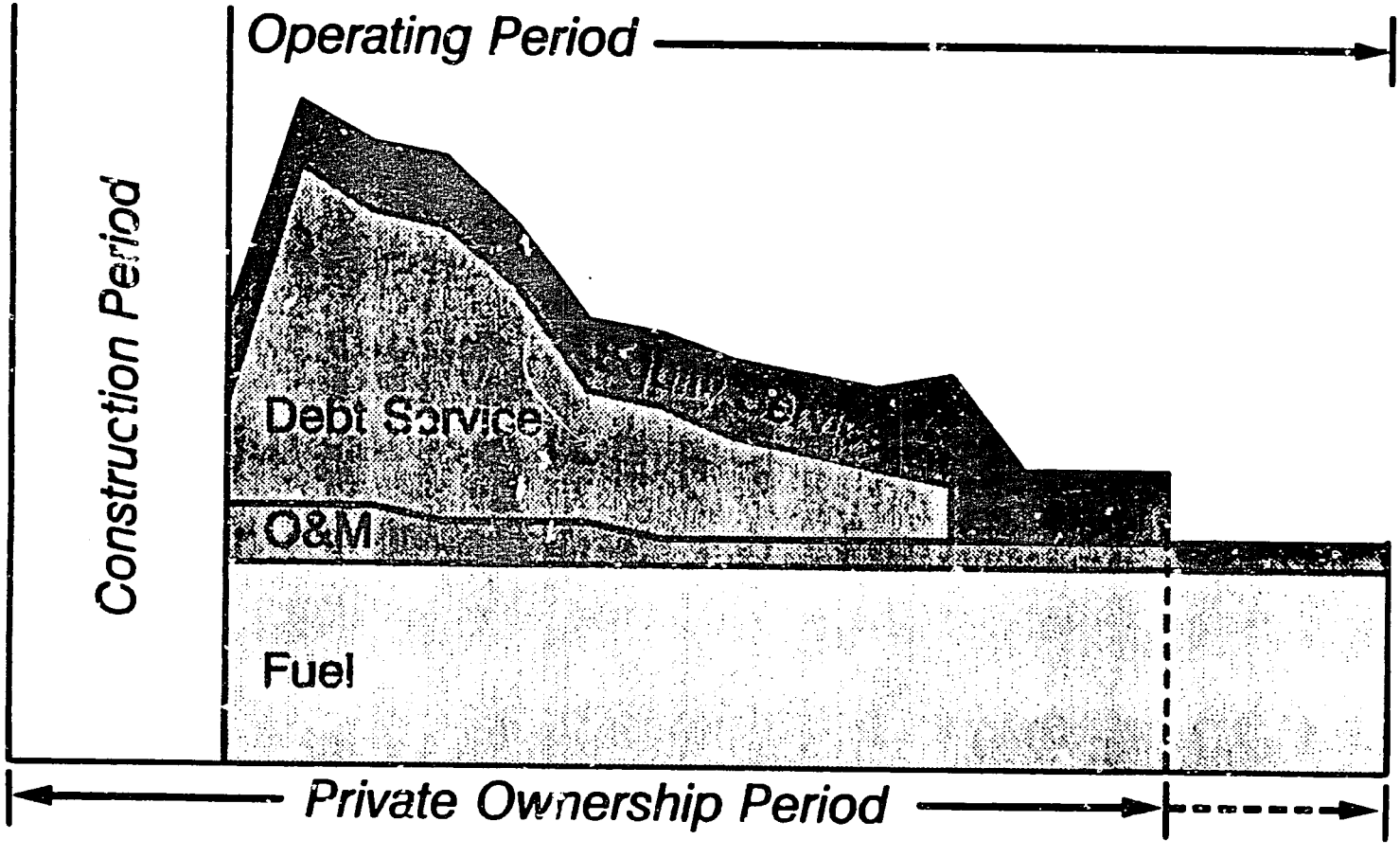
→ Project
Credit Structure

# Turkish BOT Lender Security Structure

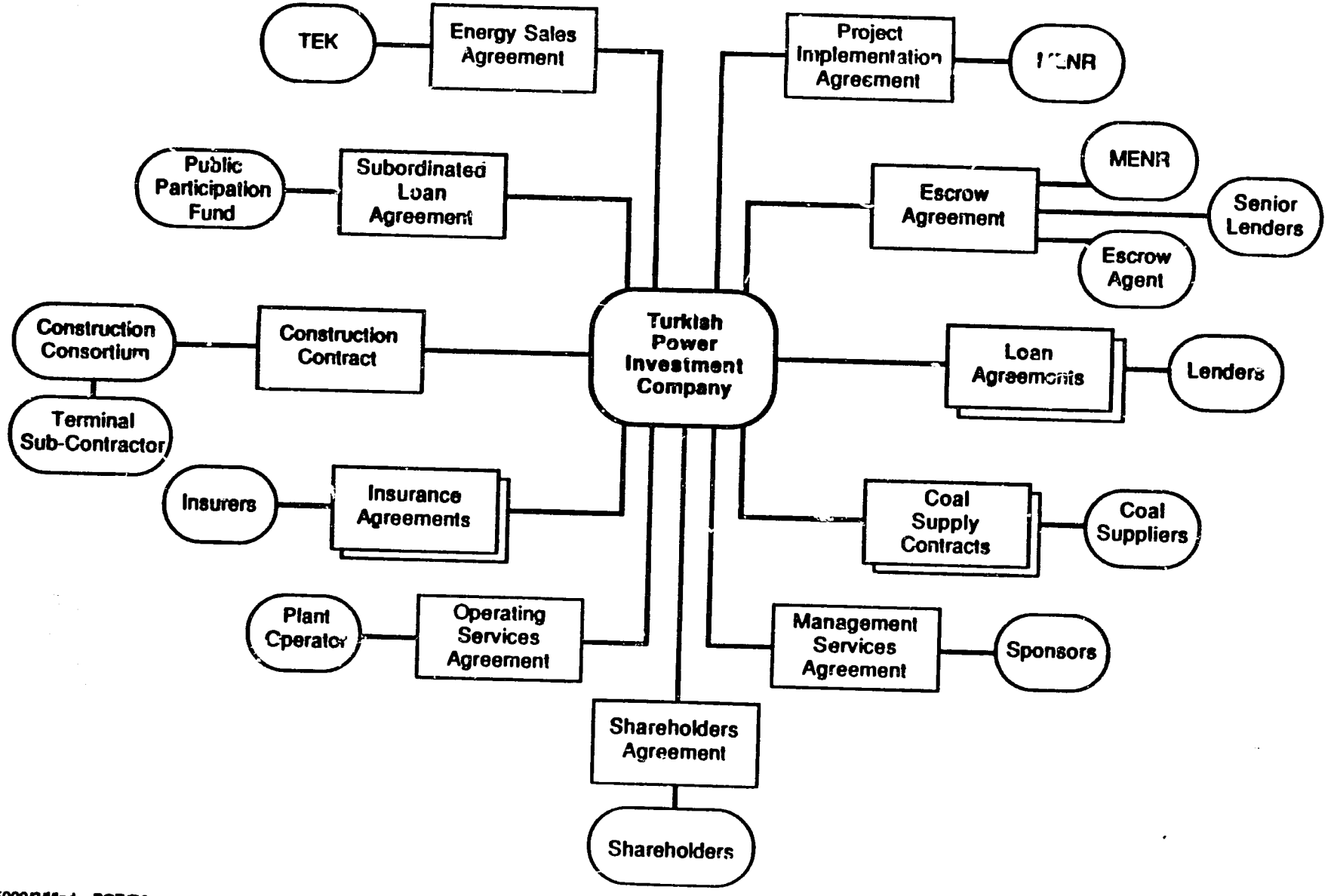
- Borrower is project company
- Installment escrow account
- Cost recovery power pricing
- Power payments in cost currencies
- Cash generation into escrow accounts
- Subordinated loan commitment
- Treasury guarantees payments to company
- Loans assumed in takeover

# Turkish BOT Power Tariff Structure

**In Constant ¢/kwh**



## Turkish BOT Power Project
## Contractual Structure

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# Basic BOT Risk-Reward Principles

- Accommodate lender security requirements
- Project company takes controllable risks
- Government covers remaining risks
- Each functional contract assigns responsibility/compensation/penalties
- Inducements for upside performance
- Upside compensation balances downside penalties

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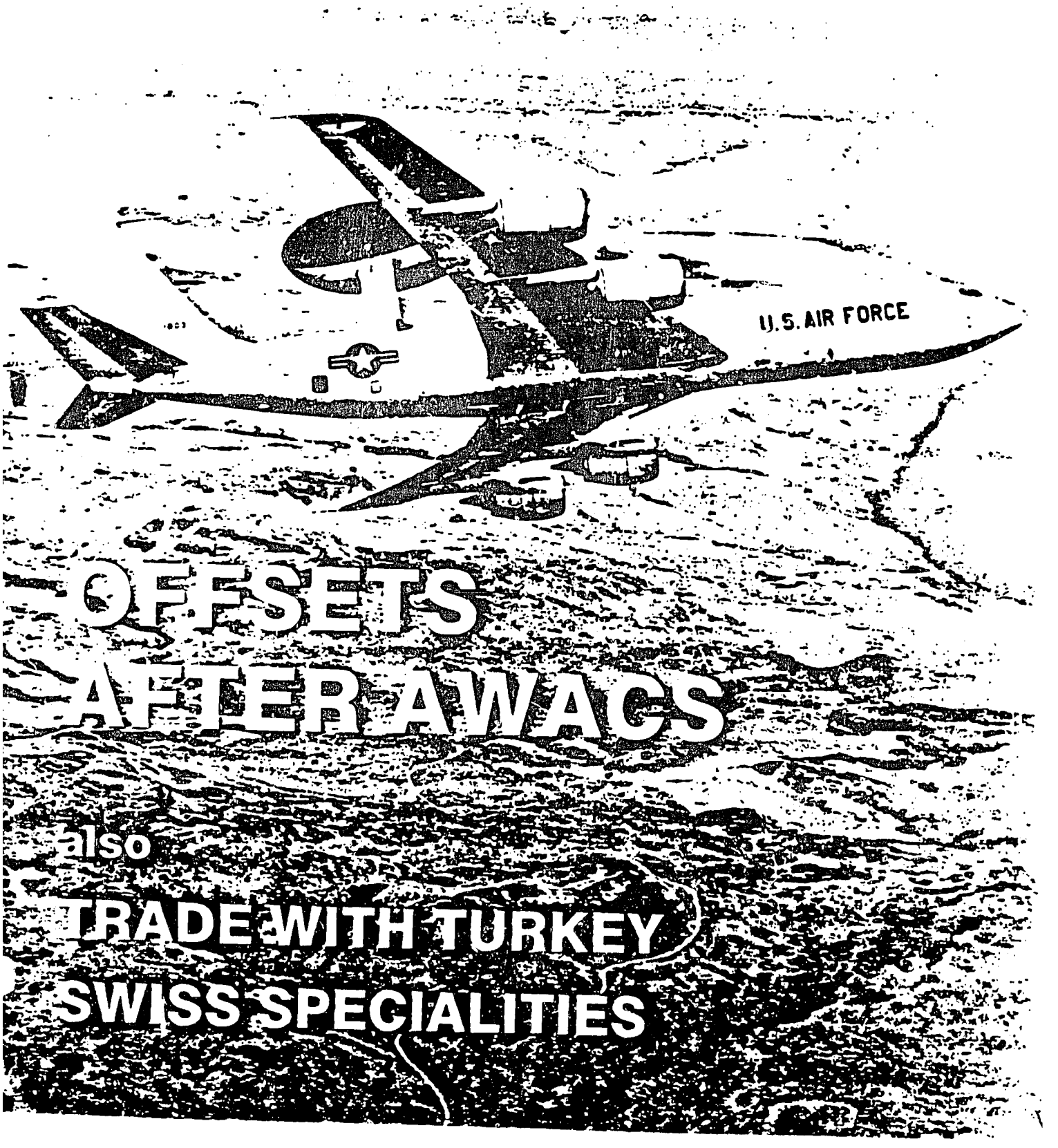


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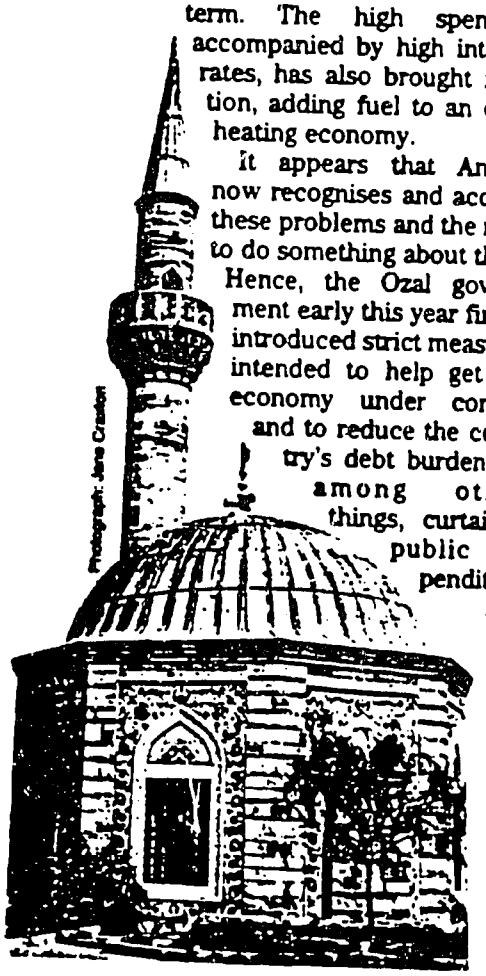
# BEYOND THE BOT

**Despite its recent economic difficulties, it may be short-sighted to believe that the only opportunities for trade and investment in Turkey lie in its booming tourism sector. Ankara is counting on investment incentives, import liberalisation and alternative trade and project financing to draw foreign funds into other areas of the economy as well.**

The government of Turgot Ozal has spent great sums in recent years on large municipal and infrastructure projects, but the result has been a rise in Turkey's foreign debt, about 20% of which is short-term. The high spending, accompanied by high interest rates, has also brought inflation, adding fuel to an overheating economy.



Photograph: Jane Craston

It appears that Ankara now recognises and accepts these problems and the need to do something about them. Hence, the Ozal government early this year finally introduced strict measures intended to help get the economy under control and to reduce the country's debt burden by, among other things, curtailing public expenditure and attracting foreign investment. Goals include bringing inflation down to 34% a year, from recent levels of 50% and more, and bringing Gross National Product growth to 5% a year.

"The policy in coming years will be aimed at stability in the Turkish economy," Yusuf Bozkurt Ozal, minister of state for economic affairs said at a seminar staged in London earlier this year by the Confederation of British Industries (CBI).

On the one hand, then, the immediate prospects for foreign heavy contractors have been reduced by less spending on infrastructure projects, and on the other hand the recent high inflation and interest rates are disincentives to foreign investors.

However, although it is unlikely that Ankara's goals to stabilise its economy this year or early next can be realised in that time frame, there is a degree of optimism even outside the country that Turkey will provide substantial trade and investment opportunities over the long term for companies that are willing to accept high inflation and interest rates in the short term. And whereas the main opportunities in the past may have been in contracting and heavy goods, future growth is expected to be seen in automobiles and other consumer products.

One UK industrialist returned from a Confederation of British Industries (CBI) mission early this year warning that companies in the USA, West Germany and other countries apparently have already begun to place themselves in the Turkish market in expectation of future improvements, and another executive on the same trip went so far as to give Turkey good odds for overtaking Greece and Portugal in industry and trade in the next decade or so.

A major attraction to one executive on the mission was that Turkey as a country effectively appeared to be a large free trade zone in which materials and goods used in products to be exported can be imported quite freely. This flexibility is the result of a move by Ankara to indirectly assist heightened export efforts through temporary liberalisation of imports. As one Turkish trade official noted, however, the move is not only intended to increase the availability of competitively priced raw materials needed by exporting manufacturers, but also to present a challenge that might move Turkish manufacturers to improve productivity and quality.

"The liberalisation of imports has also been to create a more competitive standing for our industries," explained Gülnur Üçok, Turkish economic and commercial counsellor in London. "Imports add motivation to make better products."

Üçok conceded that there was some opposition to import liberalisation from Turkish parties who feared it would result in a major surge of competitive goods coming into the country to the detriment of Turkish industry. However, she maintains that the rise in imports has not been that severe.

Figures from the State Institute of Statistics, meanwhile, indicate that liberalised imports through the first four months of 1988 were up more than 50% to $4.75bn or 84% of total imports, compared with $3.16bn, or 81% of all imports in the same period of 1987.

Üçok's comments echoed those made previously by economic affairs minister Ozal, who seemed to recognise Ankara's past misjudgement in attempting to address deficits by raising prices of imported goods like energy and steel. "We tried to reduce the demand for foreign exchange by limiting import demand."

He said that moves towards freeing up interest and foreign currency exchange rates should bring the Turkish economy and industry

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further in line with the rest of the world, eventually improving the country's ability to attract foreign investment and to export more competitively. "It requires perseverance," he added, however, likening some of Turkey's bullet-biting efforts to those being pressed on indebted Latin American countries by bodies like the World Bank and International Monetary Fund.

In an interview with C&B, Üçok repeatedly stressed that Ankara's new or revised economic and trade policies should not be dissected individually, but instead should be viewed in the broader context of a basic re-organisation of the Turkish economy, business and industry.

"Our government policies are not concentrated primarily on boosting exports," she says, for example. "Rather, they are aimed at a far-reaching restructuring programme."

Other policy changes have included liberalisation of foreign ventures, she says, explaining that pre-1985 policies requiring such ventures to have a Turkish partner and an export component no longer apply. In addition, she cites the establishment of free zones, a "major restructuring" of the merchant banking sector, and a variety of incentives for new investors in business and industry.

"The incentives are available for all investors, not just foreign investors," says Üçok, citing provisions that include exemption from corporation tax during the investment (set-up) period, freedom to import machinery for projects, and "no problem repatriating profits" when the venture in question is foreign. Some incentives, like more freedom to import, apply specifically to ventures that are export-oriented and/or add significantly to employment levels.

## Public projects

In addition to trying to attract foreign funds and technology into its private manufacturing and export base, Turkey is seeking ways to reduce the cost of government-owned operations. In some cases, state holdings in business and industrial sectors will be privatised, but this still leaves public services – an area in which the government of Turgot Ozal remains under some pressure to maintain the momentum of development built up in recent years. That move will help reduce government spending by eliminating some subsidies, but Turgot Ozal's administration needs to maintain some momentum in development of the country's infrastructure. As noted, however, Ankara has placed a moratorium on new spending on major public projects unless alternative financing – preferably foreign – can be arranged.

Of course this is where the build-operate-transfer (BOT) model comes in. Turkey has used this method of finance to plan a number of energy and transport projects, but until recently the projects have involved more rhetoric than reality.

"We used the BOT to save us from disaster in energy," said Yusuf Ozal at the CBI conference. "It was developed to get around shortages of foreign exchange, and in coal-powered plants we are very serious about it."

***Government policies are aimed at a far-reaching restructuring programme***

At the time, however, he conceded that none of several BOT power plant agreements existing at that time had actually been signed, and he attributed part of the delay to foreign companies waiting to see the outcome of last year's elections in Turkey. He said he expected a deal to be finalised shortly though, and a few months later, a final agreement of sorts was reached with a consortium led by the USA's Westinghouse Electric Corp and Chiyoda Corp of Japan. That BOT project covers a 1,200 megawatt coal-fired thermal station and related facilities to be built on Turkey's Mediterranean coast at a cost of $1bn-$1.3bn. The plant is to be operated for 15 years by a joint company that will sell the electricity, after which it presumably will be handed over to the Turks. Credits for the project are to be supplied by the US and Japanese Export-Import Banks with additional funds to be secured from commercial banks.

Although several details still need to be worked out before the project actually goes ahead, Ankara was quick to predict that agreement on this deal will pave the way for more BOT projects. Other BOT deals under discussion include more power plants, the Ankara Metro, and a third bridge crossing the Bosphorus.

Economic affairs minister Yusuf Ozal has also suggested that things could go one step further from the BOT with some projects being financed through build-lease-transfer deals, the acronym for which would no doubt be BLT. "I am a strong supporter of leasing as a way of doing off-balance-sheet financing," he said in London. "Leasing means it would be private money invested, maybe foreign, and it doesn't have to cost the government anything," he added, noting that this form of financing has already been used in Turkey's telecommunications sector.

However, foreign observers are not as optimistic that Ankara can convince contractors and bankers to commit themselves to too many high-cost projects of the BOT or BLT sort, particularly since Turkey refuses to provide guarantees for the projects. Turkish officials, on the other hand, don't see this position as being unreasonable.

"By definition, BOT means that the government will not guarantee the investment," notes commercial counsellor Üçok. "If the government guarantees BOTs, the banks might not care if the project is feasible or not."

Whatever the outcome of the BOT in Turkey, the current need to conserve funds while boosting domestic industry makes the country favourably disposed to a variety of alternative methods of trade and project finance. In private industry this is expected to mean continued growth of countertrade in general, and the government will continue to request offset agreements for major defence and high-technology acquisitions on the grounds that such deals help to create new products or markets for the domestic industries.

A case in point is the realisation, at last, of a three-year-old armoured vehicle manufacturing project, which is now due to get started in October under an offset deal with an ▶

American firm. The $1bn deal was signed recently by FMC Corp of the USA and Turkey's Defence Industry Development Administration (DIDA) after months of negotiations, and it calls for FMC to form a joint company with Nurol AS of Turkey for local production of some 1,700 vehicles.

Although at times the competition against FMC reportedly reached official levels, presumably from Germany, DIDA is believed to have been swayed by the American company's offer of 70% direct and indirect offset commitments, and willingness to license the new joint company to produce the vehicles for local and export sales. Financing will include credits and capital from FMC, as well as credits from the US Eximbank and American commercial banks led by Chase Manhatten.

## Beyond Turkey

In addition to any attractions of the Turkish market itself, particularly if efforts at stabilising the economy and improving GNP are successful, some exporters and investors may see the country as a convenient location from which to penetrate markets in the Middle East. It should be noted, however, that some of the impetus behind Turkey's export diversification efforts has been an expectation that its own sales to Mideast neighbours will continue to decline because lower oil prices have reduced those countries' ability to import. Earlier this year, Turkey's central bank decided to stop guaranteeing Turkish exports on credit to Iraq after that country failed to pay about $2bn owed for previous exports. This effectively put a hold on a market that at times has represented close to 10% of Turkey's total exports.

However, Turkish or foreign companies that are willing to consider countertrade or other alternatives to "straight" trade may find some interesting new opportunities in the region. In addition, if recent peace efforts in the Gulf are successful, war-torn Iran and Iraq would both be in the market for many more goods and services, although neither would have a lot of money to buy them with. ■

# A BOT BAKER'S DOZEN

**As outlined by Turkish trade officials, the Build-Operate-Transfer method for self-financing of infrastructure and other public projects should conform with a particular model that incorporates the following 13 principles:**

1 – A joint venture company will be formed to design, engineer, construct, finance, own, manage and maintain the project in question.

2 – The debt-to-equity ratio should be no less than 80/20.

3 – The Republic of Turkey is willing to invest up to 30% of the equity in the joint venture company.

4 – While all financing except for the equity portion will be arranged by the sponsors, the project finance will remain the responsibility of the joint venture company.

5 – The joint venture company is obliged to complete the project under a turnkey, fixed price contract, but the liability of the contractors for failure to complete the project will be joint.

6 – Construction cost overruns, other than force majeure and "Republic default events", shall be borne by the joint venture company.

7 – If the project is not completed on schedule, or operations are interrupted, the joint venture company will use various secondary sources of funds to meet its debt service obligations. These may include standby financing arranged by the company to cover at least 12 months of debt service, any damages available from contractors and/or suppliers, any available insurance proceeds, and/or a reserve fund built up during operation to cover at least 12 months of debt service.

8 – Using appropriate channels, the Republic of Turkey will buy the products and services from the joint venture company in amounts to be agreed annually, and payments will be guaranteed by the Treasury.

9 – The terms and conditions of the purchase of goods or services will be set out in a sales agreement.

10 – Tariffs will be calculated according to the agreed annual amounts of goods or services to be produced.

11 – Tariffs will be paid in the currency in which the project is financed, and will be made up of a "capital charge" component based on lenders' terms to cover debt, an "operating charge" component to cover the costs of operation, administration and a maintenance reserve, and a "dividend" component to provide the joint venture company with return on equity that is sufficient to attract investors.

12 – Equity will be repatriated after all "senior" debt has been repaid.

13 – Once debt has been repaid and equity capital has been repatriated, the plant or project will be transferred to the Republic of Turkey, unless the partners agree that the joint venture company should operate the project for another set period.



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CITICORP CITIBANK

# PHILIPPINE PRIVATE POWER SEMINAR

OCTOBER 5TH AND 6TH 1988

# THE BANKERS PERSPECTIVE

Presentation by

WILLIAM DYKES
MANAGING DIRECTOR
CITICORP INTERNATIONAL LIMITED
HONG KONG

# DEVELOPMENT OF POWER PLANTS IN THE PHILIPPINES WITH PRIVATE OWNERSHIP

During the past two years, I have seen a considerable amount of interest developing in shifting the ownership of power stations to the private sector. Privatisation of existing state-owned utilities is spreading worldwide, but the interesting change is the development of power stations by private sector companies adopting the "Build-Operate-Transfer" (BOT) approach. Todate, very few BOT projects have been concluded, but as a banker, I am frequently requested to provide financing indications to support bids prepared by equipment suppliers from many different countries around the world. During this year in the Asian region alone, I have been involved in supporting bidders for projects in China, Thailand, Malaysia, Indonesia, India, Pakistan as well as here in Philippines. Todate, however, the only power plant project that I am aware of that has been completed on a BOT basis is the 2 x 350 MW coal fired station located at Shajiao, Guangdong Province, PRC. This plant was developed by the Hopewell Group of Hong Kong together with other PRC interests. I will describe the structure of this project in more detail later in this presentation. The successful conclusion of that project certainly provides a structure worthy of consideration for other projects involving BOT investors.

In the limited time available, let me outline my thoughts of how a suitable credit/security structure could be arranged in a manner likely to be acceptable to commercial banks as well, outlining some advantages of the BOT/private sector approach. In addition, I will discuss possible financing sources with particular regard to potential Philippines projects.

## Advantages of Private Sector Development & Ownership - Build-Operate-Transfer (BOT)

- Attracts private entrepreneurial energy and capital.
- Shifts debt from government sector to private sector.
- Non-Philippines equity ownership brings outside capital investment.
- BOT parties assume all responsibilty for equity and debt, i.e. all are carried on balance sheet of private sector party rather than government or government owned power company.
- BOT owner/operator would handle all supplier contracts and arrange financing.
- BOT party responsible for on-going operation and maintenance of plant.

## Projects Developed & Owned by Private Sector - Security Structure Likely to be Required by Commercial Bank Lenders

- Parties to BOT structure or other form of ownership must be acceptable.
- Consider joint venture ownership between non-Philippines party and Philippines private sector party.

- Privately owned power plant should have firm contract to supply minimum quantity of electricity to national utility on a "take-or-pay" basis.
- Agreed purchase by national utility should be on a pre-determined price basis.
- Fuel supply contract should be entered into probably with national utility. Imported fuel could be considered from reputable and reliable sources if this results in cheaper power.
- Fuel supply should be assured and on an agreed price basis - ideally fixed.
- Fuel supply should be on "supply-or-pay" basis.
- "Supply-or-pay" contracts in respect of fuel and "take-or-pay" contracts in respect of power delivered can be based on an availability basis, i.e. contracts are only effective if plant is capable of delivery.
- "Take-or-pay" in respect of electricity purchase and "supply-or-pay" in respect of fuel supply should be backed by a strong guarantee or type of performance bond throughout life of loans.
- Ideal guarantor for performance of offtake and fuel supply is Republic of Philippines and this guarantee should be unconditional.
- Contract between BOT/private sector parties should clearly indicate date on which ownership of plant will switch to national utility, i.e. is transfer conditional or any financial consideration involved?
- There must be clear linkage with power transmission/distribution system with continous operation assured.
- All governmental consents must be in place prior to commencement of construction ownership - BOI, Dept of Finance, Central Bank, Monetary Board etc.
- Governmental consents should be complete in terms of private sector involvement and be particularly precise in terms of currencies of denomination of the power payment and/or convertibility terms if appropriate. This will be a critical factor in any financing requirement for a project in Philippines given the existing debt rescheduling situation.

Sources of Financing Available for
<u>Private Sector Developed/Owned Projects</u>

Given the existing situation in the Philippines regarding re-scheduling of debt, sources of "new money" are severely limited. Sources could be:-

- External equity
- Supplier credit - it is necessary to secure maximum volume of supplier credit by way of export credit facilities. Generally export credit agencies are unwilling to finance BOT directly, but given the refusal of commercial banks to put up new money or

give guarantees, it will be essential to push the export credit agencies hard to accept project risk to an extent accepted in other similar BOT projects elsewhere.

- IFC, Washington and ADB, Manila - both IFC and ADB appear to be willing providers of new funds and equity. Co-financing with IFC/ADB is possible on a case by case basis. It is still possible to find commercial banks willing to co-finance although this is a very limited source. Benefit of co-financing is agreement with Philippines Government that IFC/ADB debt will not be re-scheduled.
- Philippines's debt/equity swaps (subject to government approval and availability).
- Relending of existing Philippines external debt (conversion of Central Bank paper).

SHAJIAO "B" STATION 2 X 350 MW COAL FIRED POWER PLANT
- A BOT PROJECT NOW FULLY OPERATIONAL

To alleviate the severe shortage of electrical power in Guangdong Province, the Provincial Government and the Central Government authorised the development of new power plants in 1984. The severe power shortage had been aggravated by the very rapid industrial development taking place in Guangdong Province and in particular the Shenzhen Special Economic Zone immediately adjacent to Hong Kong. In 1984, Guangdong General Power Company started construction of Shajiao "A" station, a plant comprising 3 x 200 MW coal fired units. Shortly afterwards, the Shenzhen Municipal People's Government established a power development company to form a joint venture with Hopewell (the Hong Kong Group) and other PRC interests to develop the Shajiao "B" station. The joint venture comprised "Party A" - Shenzhen Special Economic Power Development Company (a vehicle solely created for the purpose of this joint venture) and "Party B" - a limited liability company called Hopewell Power (China) Limited. Shared ownership in Party B is as follows:-

| Shareholders | Equity (%) |
|---|---|
| Hopewell China Development Ltd | 50.0 |
| China Development Investment (HK) Ltd | 40.0 |
| Kanematsu-Gosho Ltd | 5.0 |
| Yue Xiu Enterprises Ltd | 2.5 |
| Shum Yip Development Co Ltd | 2.5 |
| | --- |
| | 100.0 |

Party B was to be responsible for arranging all foreign currency financing for the project and together with Hopewell Construction Company for its construction. Party B untertook to manage, operate and maintain the project for a period of ten years from 1 April 1988.

This period is commonly known as the "concession period" or "cooperation period". The PRC party, Party A, provided the land and arranged special tax treatment for the project. Party A executed coal supply and offtake agreements with Party B. These supply and offtake agreements were the most critical elements in the project financing structure. Party A committed to supply coal to Party B at a fixed price throughout the concession period. In addition, Party A agreed to purchase a minimum quantity of electricity at a fixed price throughout the concession period. These contractual obligations by Party A were supported by a performance guarantee provided by a financial institution in Guangdong Province. It is emphasised, however, that this was not an overall financial guarantee. In essence, Party A had provided "supply-or-pay" and "take-or-pay" contracts. The "take-or-pay" obligation is only effective if the plant is capable of delivery. The lenders took completion risk and operating risk.

Party B retains 100% of project revenue throughout the concession period after payment of all project expenses including cost of coal. At the end of the concession period (10 years), the operation of the joint venture will cease and full ownership and control will transfer to Party A without compensation.

Project revenue consists of proceeds resulting from the sale of electricity in accordance with the offtake agreement. Party A pays for electricity monthly, half in RMB and half in foreign currency. Payment of foreign currency project expenses include all debt service. The PRC party took all foreign exchange risks, however, the FX risk was shared by both Party A and Party B in respect of profit remittances.

Construction Consortium

The consortium was arranged by Hopewell with Mitsui & Company arranging equipment supplies from Toshiba and IHI (Ishikawajima Harima Heavy Industries). Slipform Engineering Limited (a Hopewell subsidiary) performed all of the civil engineering tasks. The consortium was responsible for the design, construction and commissioning of the plant on a joint and several turnkey basis. The consortium committed supervisory operating staff during the period of commissioning including reliability trials. Operation of the power station was to be undertaken by "an experienced and reliable operator" appointed for an initial four-year period following completion. This role is being performed by a company called Electrical Power Services, a joint venture between Central Electricity Generating Power (UK) and Fluor Daniel (USA).

Project Costs/Project Financing Requirements

The total financing requirements were approximately HK$4 billion (US$512 million). This sum included fixed construction price in respect of civil engineering and electrical and mechanical equipment. In addition, this cost included start-up expenses as well as various financing costs including capitalised interest during construction and insurance costs.

The project costs were funded by a combination of shareholder equity, subordinated loans, deferred payments in RMB and debt financing. The debt portion included a fixed rate supplier credit in domestic Yen of approximately 50 billion which was supported by EXIM Bank of Japan. EXIM Bank of Japan, however, would not accept the credit risks involved and Citicorp arranged a syndicate of commercial banks to take the project risk and provide a guarantee to Japan EXIM. The balance of the project cost were funded from commercial bank sources with Euroyen 434 million and Hong Kong Dollar 586 million loans together with a RMB loan of 720 million. All of the financing facilities were executed in April 1986 when plant construction commenced. Site preparation had commenced earlier. The first electricity was generated 22 months following commencement of construction with plant completion being achieved 28 months following completion - an impressive record.

Refinancing

The 50 billion yen supplier credit (EXIM JAPAN) originally carried a fixed rate of 7.3% per annum. By May 1987, Yen interest rates had fallen substantially and Citicorp recommended that a refinancing exercise be undertaken. We subsequently arranged a new syndicated loan from commercial banks in the amount of Yen 49 billion on a floating rate basis. The proceeds of the new loan were used to pre-pay the Japanese supplier credit and we subsequently arranged to swap the floating rate yen into fixed rate which led to approximately US$40 million saving in interest costs. This refinancing was completed by Citicorp in August 1987.

The original supplier credit carried a 10-year maturity from April 1986, but in anticipation of very early project completion, we were able to shorten the final maturity in the refinancing package to approximately 7 years which produced a further reduction in the fixed interest rate resulting from the swap.

I have visited the power plant several times and it works very smoothly indeed. The average availability since commissioning is 98% with the average offtake since handover exceeding 70%. I think you will agree that the Shajiao "B" case is an excellent example of BOT in operation and proves the point that with the entrepreneurial Hong

Kong skills, dedication to hard work and dynamic approach that a project of this scale could be completed successfully and quickly even in PRC. Quite frankly, we are already in discussion regarding the next project at Shajiao which will be called Shajiao "C" station and is likely to comprise 2 x 660 mw units. An agreement has been reached with Hopewell and discussions with potential suppliers are already underway.

I should also mention that Citicorp arranged the export credit and commercial financing for the power transmission lines linking Shajiao A and B stations to the Guangdong Province grid. Bechtel was the main contractor of this project together with SAE Italy and Brown Boveri, Switzerland.

Thank you for your attention and I will be glad to answer any questions.

# PRIVATIZATION WITHIN THE POWER SECTOR

# A CONTRACTOR'S VIEW ON

# DEVELOPMENT AND RISK ISSUES

J. W. VARGO

COMBUSTION ENGINEERING, INC.

PRIVATE POWER GENERATION THROUGH BUILD-OPERATE-TRANSFER

MANILA, PHILIPPINES

OCTOBER 5, 1988

Good morning ladies and gentlemen. up to this point today you have heard about the U.S. experience in power sector privatization from perspectives addressing; the intentions and results of U.S. Legislation designed to induce private participation, also a U.S. utility's experience and observations regarding negotiation and integration of private facilities into an existing infrastructure, and, just now, actual experience gained internationally in structuring and negotiating approaches to realize a privatized power plant project in Turkey. It is my intention to attempt to provide a view of some of the considerations important to the developer, investor and contractor involved in this process.

Although different models for privatization have evolved, from Build, Own, Operate, transfer--otherwise referred to as B.O.T., to Leaseback arrangements, for the purpose of my speech I will reference the B.O.T. approach in order to be consistent with the Turkish experience.

As you have heard and by now fully realize, pursuing project opportunities on a B.O.T. basis is very complex. In order to put my comments in context with this type of arrangement, I think it's important that we once again highlight some of the major differences between a project that develops on a traditional basis with one involving B.O.T.

On a traditional international project the borrower is normally a public company (with 100% government ownership guaranteed by the sovereign state) or the sovereign state directly. Loan guarantees are provided by the government through the Ministry of Finance, the Central Bank, or some other designated sovereign entity. No project assets are required to be secured. Rather, the credit is the full faith and credit of the sovereign state. Importantly, the government takes most of the project implementation risk and all of the operating risk. On a B.O.T. basis, however, the borrower is a private, newly established joint venture. The venture must obtain financing on the merits of the project itself and its participants, with no unconditional direct guarantee of fund availability. Additionally as you've just heard, typically the venture must assign the assets of the project in order to secure the funding

with the risks shared among the government, the private shareholders and the lenders.

Due to the nature of participants involved in the B.O.T. joint venture company, the structure of the financial arrangement is much more complicated than on a traditional basis. Since the risks to the lenders are higher than a project with direct sovereign guarantees, so too are the financing costs, and the overall time period to put the entire package together is much longer than it would be if the project were structured on a more traditional basis.

With this basic understanding of the major front end differences between private and conventional approaches, for the remainder of my presentation I would like to concentrate on two central issues confronting the developer/investor involved in B.O.T. projects. These are; the development process, and, assumption of risk by the private joint venture company.

I would first like to discuss the development process and the actions required to structure and execute a B.O.T. project.

The development process for B.O.T.'s has in itself evolved to be a complex, time consuming and expensive affair for the developer. Extensive input is required on all technical, commercial, legal and financial aspects of the project if it is to be tailored to meet the objectives and needs of the host country while satisfying the needs of the investors and the lenders. Typical activities that are integral to this process include performance of:

- Project feasibility studies which define the general blueprint for the plant to be constructed.

- Plant design and scope analyses which establish fuel to be utilized, environmental impact, availability and reliability factors and other detailed technical aspects related to the physical plant.

- Project economic analyses which look at plant construction, operation and maintenance costs.

- Financial analyses which set the debt structure for the project and provide commercial input on cost of money.

- Financial plans which incorporate the technical, economic, and financial analyses into a master project schedule resulting in a total investment cost and a projected cost of power.

  and . . .

- Development of legal documents which establish overall agreements to be reached relative to project implementation including; the turnkey construction contract, fuel supply contracts, operation and maintenance contracts, the power sales agreement and tariff structure as well as the articles of association and shareholders agreement of the joint venture company to name a few.

Once these activities have been accomplished, the overall project framework then exists which next must be negotiated to the satisfaction of all parties involved. That is to say; the equipment vendors, the fuel suppliers, the prospective shareholders, the lenders, the utility client and the host government. Our experience indicates that these steps of the development process can take two to four years to complete for an international project. However, much of the work accomplished to date in developing current models is applicable to other B.O.T. projects and therefore can short circuit the time and expense required for new project development. This of course assumes an unequivocal commitment of all project proponents to achieving financial close.

To date, two basic avenues of approach have been utilized to develop a B.O.T. project. The first approach involves a group of power plant designers, manufacturers and contractors who associate themselves to

undertake the tasks required leading up to a sound financial plan. Typically the services of a financial advisor is also retained who provides valuable input data on the requirements of the financial community as the project is being structured. The power plant sponsors then negotiate all contractual agreements directly with the utility, host government and financial institutions becoming equity investors and shareholders in the joint venture project company at financial close. In this approach the project developers are typically involved in the complete plant life cycle, from development to plant turnover after some agreed upon operating period with ultimate return on investment tied to their overall performance--from design to long term operation and maintenance.

The second approach involves entrepreneurs who perform or contract out the various project feasibility studies and negotiate principle project agreements directly with the host utility. The project developers then proceed to raise the project debt and equity requirements in line with budgets established by the feasibility studies and negotiate the turnkey construction contract and operation and maintenance contracts. This approach differs from the first in that the contractor is held at arms length and he may or may not have an equity stake in the project after completion of commissioning. The ultimate success of the project then relies solely on the project company's ability to manage. This approach does however solve the potential conflict of interest existing in the first approach with developer, contractor, project company and operator basically being the same entity during the structuring process. Many of the cogeneration projects in the United States are currently following the latter mode of development.

Regardless of the approach taken recent efforts in this field indicate that there are a few considerations of critical significance to the developer which must be established early in the process if a project is to ultimately proceed within a reasonable time frame. First, the host utility or government has to provide a clear signal as to its objectives for entering into privatization. Several factors could be involved including; alternative financing (sometimes referred to as off balance

sheet finance), interest in attracting foreign investment, introduction of foreign management practices into plant operations to increase availability and reliability, introduction of new technology which otherwise could not compete on its own against conventional approaches; or, as you have heard in the case of California, stimulating utilization of alternative energy sources within a grid.

Whatever the case, the utility and/or government must clearly define its intentions in order to attract serious participants and also to ensure that the end product meets the initial objectives. It should be noted however, and here is as good a place as any to introduce it, low cost is not the normal reason for pursuing privatization. Because of the relatively higher cost of equity and debt servicing for a privately held company versus sovereign borrowing, by its very nature privatized power tends to be more expensive than conventional power prior to adjustment for; faster and on budget project execution, higher plant capacity factors, and allowance for the passing of risks on to the lenders and private shareholders.

Secondly, there must be a reasonable incentive established for the developer to invest the considerable resources required to conceive the project. Using California once again as an example, legislation was passed which provided avoided cost price structuring and investment tax credits to attract participants. Obviously it is important that the incentives offered must be consistent with the central privatization objectives.

Finally, it is necessary for the client to issue a set of conditions with an attendant milestone schedule forming the basis for proposals which must be met by prospective developers. In essence these conditions would serve as a general specification outlining; plant size and scope of supply, number of units, fuel source, plant availability target, term of operation and basis of turnover, components to be included in the total invested cost, basis for the power pricing and requirement for a comprehensive financial plan.
The importance of this step is that it sets a consistent criteria for objective evaluation and selection of a single developer party at a

relatively early stage in the project development schedule. As a result it would limit the amount of upfront sunk development costs of the various contenders, which to date has been a serious impediment to attracting widespread active interest in B.O.T. projects. It also allows for an early teaming between client and developer to work out the complex detail project arrangements optimizing the ability to achieve project objectives and come to a timely financial close.

To date I believe that very few international privatized power projects have succeeded in reaching financial close due to a lack of appreciation of the considerations involved. In fact we have all been going through an on the job learning process developing rules to accommodate issues as the projects evolve. Hopefully we are now at a point where sufficient commercial R&D has taken place and we can take advantage of the lessons learned from our past experience.

Now, having covered the development experience and hopefully providing some advice for future undertakings, I would like to shift discussion to the second basic issue of my presentation and that is the risk sharing formula to be applied for B.O.T. projects.

First of all, we should examine the different perspective which typically develops between the host utility and the private joint venture company as to how the private facility is to be treated as an operating plant within the system. It is a natural tendency for the host utility to view the private facility on an equal basis to all other plants within the grid. This would appear to be fair along with the expectation that the private facility be operated and managed consistent with existing policy with payment for power made available at rates competitive to similar plants within the system.

However, the practical reality that the private joint venture company is confronted with is not compatible with the fair and equal treatment concept. Let's take a look at the situation. In order to raise the private investment equity and the debt required to finance the project,

certain prerequisites must be met. First the joint venture company must be viewed by the investors and lenders as technically, commercially and economically viable. This means that the financiers have to have the confidence in the overall commercial structure and the ability of the joint venture company to generate revenues sufficient to provide a competitive return on investment and to satisfy the loan obligations and related security arrangements. Secondly the amount of risk assumed by the joint venture company has to be limited to areas within its own control so that risk versus reward potential is reasonable and the probability of project company bankruptcy is viewed as negligible provided the joint venture company performs.

Given these crucial constraints, it is not hard to see why privatized power projects are financially driven and the ability of the joint venture company to operate on an equal basis to other plants in the system is severely limited.

As an outgrowth of this situation there are several areas which have to be analyzed relative to the joint venture company's viability in order to ensure compatibility between structural arrangement and financial requirements. I would like to address a few of the important considerations in this regard.

From a technical view point in order to maximize generation of revenue, the plant must be designed with reliability and availability as a central focus point. This would in itself tend to exclude introduction of new technologies where experience is a factor unless the technology issue was one of the original privatization objectives. In this case, special dispensation would be required to allow sufficient cash flow given anticipated lower and less predictable availabilities.

A second area falling into the same category is the fuel source. In order to assure maximum plant availability high quality fuels are required with reliable delivery in both terms of quality and quantity. For this reason, most privatized coal based schemes that I am aware of involve imported fuel unless high grade indigenous fuels are readily accessible.

Other technical issues of importance when viewing availability include the number of generating units within a facility to produce a given plant output and the environmental restrictions under which the plant is to operate.

Commercially several areas of concern related to revenue generation must be accommodated. A few of the major items in this category would include:

- The presumption of a base loaded facility with energy paid for on a take if available basis.

- Fuel costs handled on a pass through basis assuming operation and maintenance in accordance with good utility practice.

- Provision in the energy tariff to handle pass through of uncontrollable, unforeseen or unbudgeted costs including impact of physical and economic force majeure events.

  and . . .

- Ability to pass through on a shared basis unabsorbable impacts resulting from construction performance such as delays in commercial operation which are not totally covered by liquidated damage provisions or insurance.

Of course as previously mentioned the joint venture company must be held accountable for events or actions within its own control and penalized in turn on the extent of its ability to earn a return on investment.

Over the last 15 minutes or so I have attempted to provide you with a feel for the experience gained from working in the trenches on B.O.T. projects in the power sector from the supplier viewpoint. I have passed over several areas and mentioned others briefly in the interest of time and sanity.

My intention has been to offer as pragmatic an account as possible. It is clear that privatized power projects can be realized internationally, but before the process is entered into, all parties should have a realistic understanding of the principles and commitment to the objectives involved. I hope my presentation has helped serve this purpose.

Thank you.

## COMPARISON OF TRADITIONAL VS. PRIVATIZED APPROACHES

| | TRADITIONAL | PRIVATIZED |
|---|---|---|
| BORROWER: | SOVEREIGN STATE DIRECT OR INDIRECT | PRIVATE JOINT VENTURE COMPANY |
| GUARANTOR: | M.O.F. OR CENTRAL BANK | NONE |
| ASSET SECURITIES: | NONE | PROJECT ASSETS, INSURANCE PROCEEDS, OFFSHORE ESCROW |
| SOURCE OF REPAYMENT: | NOT PROJECT RELATED | PROJECT CASH FLOW |
| STRUCTURE: | SIMPLE | COMPLEX |
| COST: | LOWER | HIGHER |
| TIME TO IMPLEMENT: | SHORTER | LONGER |
| OWNERSHIP/MANAGEMENT: | GOVERNMENT | PRIVATE COMPANY |

THE

## B.O.T. DEVELOPMENT PROCESS

- PERFORM PROJECT DEFINITION STUDIES
  - PREFEASIBILITY STUDY
  - FEASIBILITY STUDY
  - PLANT DESIGN AND SCOPE ANALYSES
  - PROJECT ECONOMIC ANALYSIS
  - FINANCIAL ANALYSIS
  - FINANCIAL PLAN
- DEVELOP PROJECT IMPLEMENTATION AGREEMENTS
  - TURNKEY CONSTRUCTION CONTRACT
  - FUEL SUPPLY CONTRACT
  - OPERATION AND MAINTENANCE CONTRACTS
  - POWER PURCHASE AGREEMENT
  - JOINT VENTURE ARTICLES OF ASSOCIATION AND SHAREHOLDER AGREEMENT
  - ESCROW AGREEMENT
  - BUY OUT AGREEMENT
- NEGOTIATE ALL AGREEMENTS
  - SUPPLIERS
  - SHAREHOLDERS
  - LENDERS
  - HOST UTILITY/GOVERNMENT
- FINANCIAL CLOSE

## RECOMMENDATIONS TO OPTIMIZE THE DEVELOPMENT PROCESS

- GOVERNMENT MUST DEFINE PRIVATIZATION OBJECTIVES.
- INCENTIVES MUST BE ESTABLISHED TO ATTRACT SERIOUS PARTICIPANTS.
- ISSUE PROJECT SPECIFICATION.
- SELECT PARTNER EARLY.
- JOINTLY DEVELOP PROJECT ARRANGEMENTS.

## DEVELOPMENT APPROACHES

- CONTRACTOR DIRECT APPROACH
  - FORM TURNKEY CONSORTIUM
  - RETAIN FINANCIAL ADVISOR
  - PERFORM ALL PROJECT ANALYSES
  - DEVELOP FIXED PRICE CONSTRUCTION CONTRACT
  - DIRECTLY NEGOTIATE ALL PROJECT AGREEMENTS
  - SYNDICATE PROJECT FINANCING
  - FORM AND PARTICIPATE IN JOINT VENTURE COMPANY
  - CONSTRUCT PLANT
  - OPERATE AND MAINTAIN FACILITY
  - TURNOVER PLANT IN ACCORDANCE WITH BUYOUT AGREEMENT
- VENTURE CAPITAL APPROACH
  - COMPLETE FEASIBILITY STUDIES
  - NEGOTIATE PROJECT AGREEMENTS WITH CLIENT UTILITY
  - SYNDICATE FINANCING
  - NEGOTIATE AND HAVE TURNKEY CONSTRUCTION CONTRACT EXECUTED
  - NEGOTIATE O&M CONTRACTS
  - TURNOVER PLANT IN ACCORDANCE WITH BUYOUT AGREEMENT

## JOINT VENTURE COMPANY INTERNAL CONSTRAINTS

- MUST SATISFY INVESTOR AND LENDER REQUIREMENTS
  - ADEQUATE RETURN ON EQUITY
  - ABILITY TO SERVICE DEBT
  - SECURITY OF INVESTMENT

## JOINT VENTURE COMPANY
## VIABILITY ISSUES

- DESIGN PLANT FOR MAXIMUM RELIABILITY/AVAILABILITY
  - PROVEN EXPERIENCE
  - HIGH QUALITY FUEL AND RELIABILITY OF SUPPLY
  - OPTIMIZE NUMBER OF GENERATING UNITS
  - ENVIRONMENTAL CONSIDERATIONS
- BASE LOADED FACILITY
- TAKE IF AVAILABLE ENERGY
- PASS THROUGH OF FUEL COSTS
- PASS THROUGH OF UNCONTROLLABLE OR UNFORESEEN RISK

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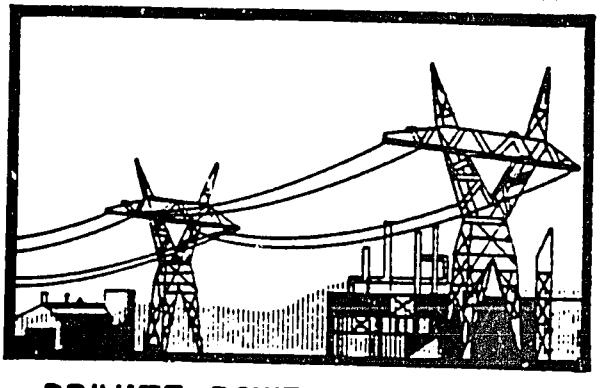

# PRIVATE POWER GENERATION THROUGH BUILD-OPERATE-TRANSFER

Manila Hilton Ballroom A

October 5, 1988

# PROGRAMME

| | | |
|---|---|---|
| 7:45 - 8:30 | Registration | |
| 8:30 - 8:35 | Welcome Remarks | Mr. Tristan Calasanz<br>Chairman, Energy Committee<br>Philippine Chamber of Commerce and Industry |
| 8:35 - 8:50 | Keynote Address | Hon. Catalino Macaraig Jr.<br>Executive Secretary |
| 8:50 - 9:05 | Keynote Address | Mr. Malcolm Butler<br>Mission Director<br>US Agency for International Development |
| 9:05 - 9:20 | Keynote Address | Mr. Victor Lim<br>President<br>Philippine Chamber of Commerce and Industry |
| 9:20 - 9:50 | Coffee Break | |
| 9:50 - 10:00 | "The Power Crisis: A Role for BOT?" | Dr. Alberto J. Sabadell<br>Deputy Director<br>Office of Energy, USAID |
| 10:00 - 10:30 | "The BOT Concept" and Introduction of Resource Persons | Dr. Ernest Y. Lan<br>Technical Director<br>AID Conventional Energy Technical Assistance Project |
| 10:30 - 11:00 | "Independent Power Generation and Electricity Market Structure- A California Regulator's Perspective" | Mr. Donald Vial<br>Commissioner<br>Public Utility Commission<br>California |
| 11:00 - 11:15 | Open Forum | |
| 11:15 - 11:45 | "A Utility Perspective In Purchasing Power From Third Party Projects" | Mr. James K. A. Harral<br>Assistant Vice President<br>Power Planning and Contracts<br>Pacific Gas and Electric Company |
| 11:45 - 12:00 | Open Forum | |
| 12:00 - 1:00 | Lunch | |
| 1:00 - 1:30 | "The Turkish BOT Power Project Experience" | Mr. William K. Stevenson<br>Vice President<br>Bechtel Financing Services, Inc. |
| 1:30 - 1:45 | Open Forum | |
| 1:45 - 2:15 | "Privatization Within the Power Sector - A Contractor's View on the Development and Risk Issues" | Mr. Jerry W. Vargo<br>Vice President and Director<br>International Business Development and Sales<br>Combustion Engineering, Inc. |
| 2:15 - 2:30 | Open Forum | |
| 2:30 - 3:00 | Coffee Break | |
| 3:00 - 3:30 | "The Bankers Perspective" | Mr. William Dykes<br>Vice President and Managing Director<br>Citicorp International, Ltd. |
| 3:30 - 4:15 | Open Forum | |
| 4:15 - 4:30 | Closing Remarks | Atty. Wenceslao R. dela Paz<br>Executive Director<br>Office of Energy Affairs |