Strategies for Electricity Supply in the Province of Mendoza: A Multi-Attribute Trade-Off Analysis Application

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Abstract

The aim of the thesis is to provide valuable information to private and government agents about the most efficient and robust way to meet Mendoza's growing electricity demand. The region faces two problems. In the short run, the already existing transmission constraints can have substantial economic costs. Over the medium term, the Province faces brownouts and blackouts if no new supply sources are built.

An Energy Balance Model for the Province of Mendoza was developed to simulate the electric power sector in the region. Emphasis was given on transmission restrictions and pollutant emissions. Various supply alternatives were evaluated using Multi-Attribute Trade-Off curves generated by the Energy Balance Model. In the short run, the obvious solution is to strengthen the transmission link with the rest of the country. Over the medium term, the solution is to build local generation capacity. However, it is not clear what type of generation is the most efficient. The analysis shows a clear trade-off between thermal plants associated with high emissions and low regional energy dependency on the rest of the country, and hydroelectric plants associated with low emissions and high dependency. The policy implications of this trade-off are very important. The most efficient source of energy supply will be determined by the region's valuation of emissions and dependency. Given this valuation, the government can introduce different economic incentives to guide private investors decision to the most efficient alternatives.

The analysis presented here gives clear evidence that independent comprehensive studies can still prove very valuable in the context of deregulated markets. In this deregulated environment, market signals are supposed to provide all the relevant information for the attainment of efficient solutions. However, as markets are incomplete and imperfect, multi-attribute trade-off analysis remains a powerful tool for planning exercises.

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que he recibido de Uds.

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Introduction

The 1980s has been dubbed "the lost decade" for Latin America. The region was plagued by severe economic crisis characterized by high inflation levels and sharp declines in industrial output. Many countries are still below their 1980 level in GDP per capita terms. As a result, the decade marked the end of the statist model of development in which the government played a crucial and dominant role in economic activity and gave rise to a liberal reform wave. This reform was characterized by fiscal balance, free trade and sweeping deregulation of the various sectors of the economy. As part of the deregulation process, liberal reform introduced competition converting the private sector as the main engine for investment and growth. Deregulation also reduced the government to a regulatory role only. Under the new model and under the efficient market banner, the regulatory framework was set up so that the market provides the right signals and incentives for the efficient allocation of resources. In such structure, there is no room for a centrally planned investment strategy coordinated by some government agency.

It would seem, then, that in deregulated markets independent comprehensive studies to identify the best solutions to a particular problem are somewhat redundant as efficient markets already give clear signals as to what these solutions are. This is particularly so if the study is to be used by the government to implement these solutions. Under the efficient market banner, if private initiative has not already moved in the direction of these solutions, it is because they are not the best solutions and there is no point for the government to implement them. On a theoretical basis, efficient markets signals do indeed give valuable information about the most efficient solutions. However, markets are not always efficient, and worse, they are not always complete. That is, even if markets are efficient in the establishment of price signals based on the available information, these signals might not be complete as they might not incorporate some valuable information.

The reason for this incompleteness might be the lack of markets to channel the relevant missing information. A clear example are emission permit markets. Without these markets, information about the value of emissions would not be available and thus could not be incorporated in price signals, resulting in suboptimal levels of emissions. It is in this context that comprehensive studies can prove valuable in deregulated markets environment. On the one hand, these studies can incorporate valuable information neglected by market mechanisms, and thus can give a better understanding of the most efficient solutions to a particular problem. On the other hand, these studies can provide a better understanding of the ways to incorporate the relevant information into market mechanisms, via taxes for instance. Moreover, these studies can also prove valuable for private investors, as they can use this information to update and reevaluate their investment strategies. In sum, independent comprehensive studies about the best solutions to a particular problem can definitely prove very valuable even in deregulated markets.

The aim of the MIT-Universidad de Cuyo (UNC) collaboration agreement is in line with this line of reasoning. In particular, the aim is to transfer analysis methodology that will eventually help the Province of Mendoza perform better studies and, as a result, implement better policies in a deregulated market environment. This thesis is relevant to the water and energy project of the MIT-UNC collaboration, which is concerned with identifying the most efficient and robust alternatives to meet future water and energy demand. The thesis deals with the energy part of the project. Multi-attribute trade-off analysis has proved to be a powerful methodology for planning exercises. It provides a robust tool not only to understand the different trade-offs associated with the alternatives selected, but also to rank these alternatives in order to identify the best solution to the problem at hand. It is for this reason that this methodology was chosen as the most efficient and powerful for this project. It is important to note, however, that multi-attribute trade-off analysis is a recursive process. The results in this thesis represent only the first stages in the analysis. In order to reach a complete and comprehensive analysis, the models used in this thesis will need to be enhanced. It is expected that UNC professionals and students will engage in this exercise, once they understand the methodology. Furthermore, multi-attribute trade-off analysis should not be viewed as a final solution. Rather, its aim is to identify the most attractive alternatives and point at the trade-offs associated with them. Once these alternatives have been identified, more in-depth studies will need to be performed so as the determine the right size and specifications of the project for final implementation. It is in this sense that multi-attribute trade-off analysis should be viewed as an early stage in the planning exercise.

With all this in mind, the thesis performs a multi-attribute trade-off analysis assuming a deregulated environment. Argentina arguably has been the most aggressive country in the region pushing deregulation through during the 1990s. The electric power sector was no exception. The new power sector structure is perhaps the most sophisticated pool-based model in the world. There is even some talk of imitating certain aspects of it in the deregulation of the U.S. industry. The impact of the deregulation process has been very strong. As a result of the competitive nature of the new structure, electricity prices have consistently decreased in the last four years. Average price at the end of 1995 was 25% lower than that of 1992. Also, deregulation improved considerably the availability of thermal plants, making allocation of resources more efficient. The new structure seems to run very smoothly, except for some bottlenecks in the transmission system. Some regions in the country are currently experiencing transmission constraints with the rest of the country. Because of lack of investments in new transmission capacity, these restrictions are likely to remain present over the near future.

The Mendoza Province is one of the regions experiencing these transmission constraints. The province is a net energy importer and is linked to the rest of the country via a single high-voltage line with a relatively small transmission capacity. The economic consequences of these constraints can be very high. Furthermore, demand in the province is expected to grow at a solid rate of 4% to 5% a year, aggravating the problem. Indeed, if no new generation capacity or new transmission capacity is built, the Mendoza region might experience some blackouts and brownouts over the medium term. In sum, any energy policy for the Mendoza region should aim at reducing or eliminating transmission restrictions over the short run, and meet the growing demand in the most efficient way over the medium to long term. In the context of the Argentine power structure, new capacity (either generation or transmission) must come from private initiative. But, as explained before, the province can provide for the necessary private incentives so that the most efficient solutions are implemented. Multi-attribute trade-off analysis can contribute to these aims, and this thesis presents some preliminary results.

Two models were developed to aid in the analysis: (i) the Energy Balance Model, and (ii) the Multi-Attribute Trade-Off Model. The first model simulates the Mendoza system on a yearly basis. The second model uses the information provided by the first model to generate trade-off curves and rank the different alternatives based on the different attributes identified. The second model considers new thermal plants, new transmission lines and the different hydroelectric projects under study as alternatives. The hydroelectric projects include Potrerillos, Los Blancos, El Baqueano and Portezuelo del Viento, with perhaps the first project being the closest to the implementation stage.

The analysis seeks to answer three questions: (i) is not doing anything an attractive solution, (ii) is the Potrerillos project worth implementing, and (iii) what is the most efficient and robust alternative to meet the short run and medium run problems described above. The analysis yield the following conclusions. First, not doing anything is definitely not an attractive solutions. Second, based on the assumptions of the models, the Potrerillos project is not worth implementing. Among the different hydroelectric projects Los Blancos and Portezuelo del Viento rank better than Potrerillos on every attribute. Third, there seems to be a trade-off between thermal plants and hydroelectric plants. On the one hand, thermal plants can generate more electricity and thus represent less supply dependency on the rest of the country. This benefit comes at the expense of higher emissions. Hydroelectric plants, on the other hand, generate no emissions at all but at the expense of higher dependency on supply from the rest of the country. Fourth, it seems that the best short term solution is to strengthen the only transmission link the province has with the rest of the country. Finally, over the medium term as energy import capacity reaches its limit, the province should build more generation capacity so as to catch up with the growing demand. Because of the trade-off described above, it is not clear what type of generation is the most efficient for Mendoza. A decision will have to depend on the region's valuation of emissions and dependency. Of course, all these conclusions are sensitive to the assumptions of the models. This sensitivity is discussed in the thesis as well.

The thesis is separated into three chapters. The first chapter provides detailed background information about the Argentine and Mendoza power sector. The chapter starts with a description of the operation and rules of the national wholesale electricity market. It also provides numbers on prices, supply and demand at the national level and provincial level for Mendoza. Chapter II gives a description of the aims and assumptions of the models. The chapter also discusses the limitations of the models in terms of their omissions and assumptions. Finally, the third and last chapter describes the results of the models and makes a series of recommendations based on the analysis of the results. The results of the Base Case Future are described in detail. Finally, the thesis ends with some concluding remarks, and directions for the enhancement of the models and analysis.

Chapter I: Background Information on Argentina and the Mendoza Province

A. Argentina

During the early 1990s, Argentina has gone under profound structural reforms in most sectors of the economy. The electricity sector was no exception. In 1991, the Argentine government started an aggressive privatization program of the generation, transmission and distribution companies. It also introduced a set of new operating rules for the electricity sector designed to foster competition and efficiency. The exposition of the Argentine situation is going to be divided into two parts: (i) the new operating rules of the sector, in which the Wholesale Electricity Market plays a crucial role, and (ii) the electricity sector in terms of demand, supply and prices.

A.1 The Wholesale Electricity Market

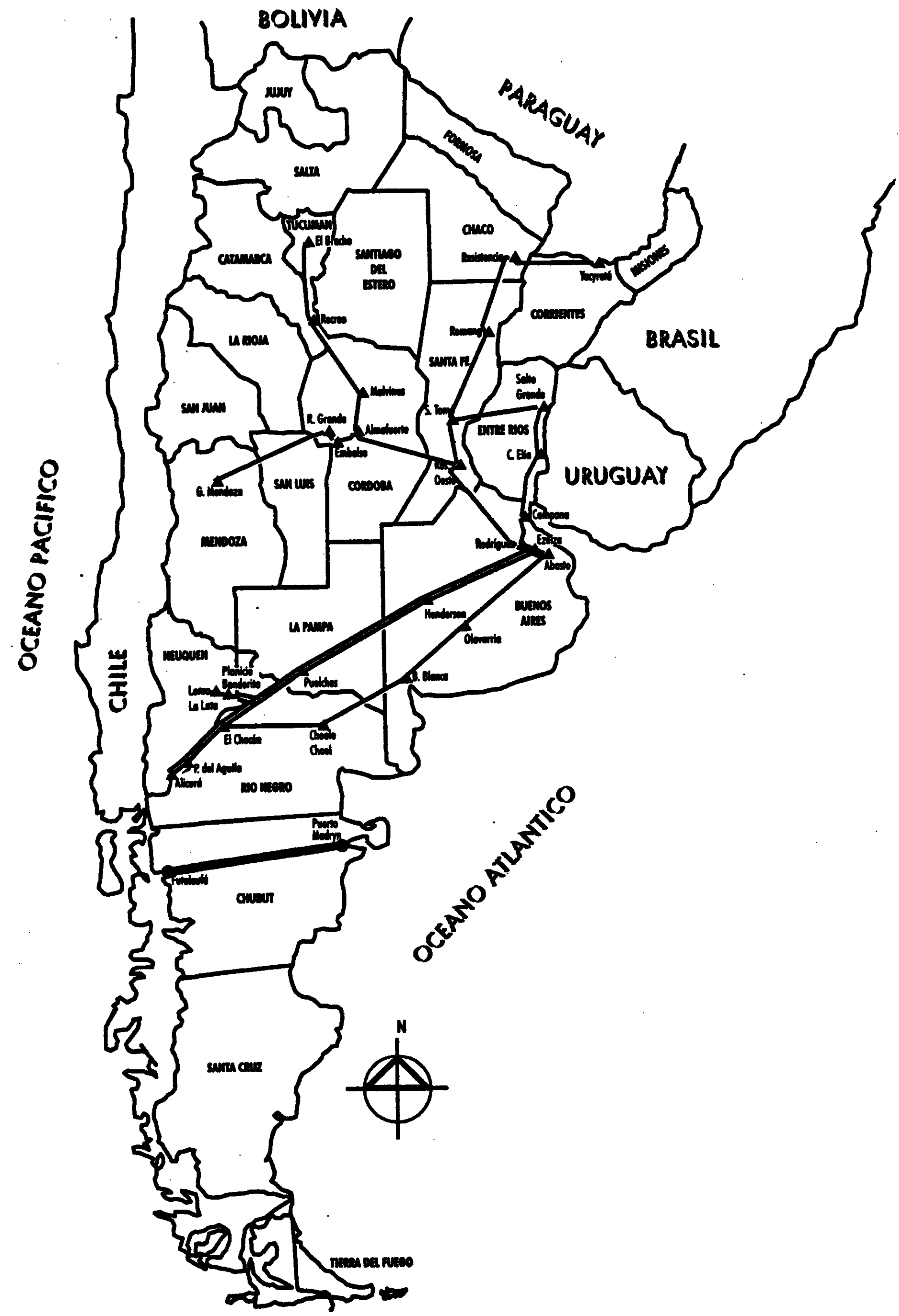
A.1.1 Overview and History

A.1.1.1 Introduction

The purchase and sale of wholesale electricity in Argentina has been coordinated, brought together and regulated by the Argentine government in the form of the Wholesale Electricity Market ("WEM"). The WEM, whose agents are generators, transmitters, distributors and large users connected to the National Grid System (depicted in Graphic 1), is designed to maintain competitive pricing, while increasing efficiency and reducing overall costs. The WEM's design shares similarities with the electricity markets of the UK and Chile as both were restructured in the last ten years to increase efficiency and reduce costs.

Under the WEM, a Spot Market is established in which generators, distributors and large users can buy and sell electricity at prices determined by supply and demand forces. Complementing the Spot Market are long term electricity supply contracts into which

Graphic 1: The Argentine National Transmission System



Source: CAMMESA

agents of the WEM may enter.

A.1.1.2 History

Prior to 1991, the Argentine Electricity sector was dominated by state-run companies, of which Agua y Energía ("AyE") was the largest. AyE was established with the objective of developing hydroelectric generation, transmission and distribution in various regions of the country. Another important state-owned company was SEGBA, in charge of the generation and distribution of electricity in the metropolitan area of Buenos Aires. The third largest state-owned company was HIDRONOR, in charge of generation and transmission. The role of the state in the electricity sector was so important that state-owned companies represented 98% of total generation in 1991. The few private generators were built only by large industrial users to satisfy their own demand.

Under this scheme of heavy government intervention, the state proved to be a bad administrator, planner and operator of the Argentine electricity system. On the one hand, state-owned companies experienced big economic losses. During 1990, the central government pumped up to US$290MM to SEGBA, AyE and HIDRONOR to cover their losses. This represented a drain of money for the central government at moments of economic crisis in the country. On the other hand, the state did not have a coherent investment plan to meet the growing energy demand, often undertaking huge, very costly and unnecessary hydroelectric and nuclear projects. Finally, the state did not keep the existing infrastructure well maintained, resulting in a high unavailability of the generating plants and transmission lines.

By 1991, the Argentine system was virtually in shambles. Peak demand reached 8,851MW and installed capacity was 15,800MW. However, despite the excess capacity and because of the high unavailability rate of more than 45%, there was a high risk of another energy crisis like the one in 1988-1989, if there was not sufficient snow fall for the hydroelectric plants to generate the necessary electricity to meet demand.

In sum, the situation of the electric system under state intervention was not sustainable. Drastic measures were needed. These changes came in 1991 with Law 24,065 that reincorporated private investments as the main driver for efficiency in the system.

A.1.1.3 Administration

The most important element of the Law 24,065 was the introduction of the WEM and of CAMMESA, which was created with the sole responsibility to administer the WEM.[1] The board of directors of CAMMESA is comprised by the Secretary of Energy and representatives of the four types of WEM agents: generators, transmitters, distributors and large users. CAMMESA's administrative costs are funded by a levy which currently may not exceed 0.85% of the gross transactions in the WEM (including long term contracts) and which must be paid proportionally by each agent of the WEM. Graphic 2 summarizes the different financial transactions in the WEM. The operation and settlements in this market are explained below.

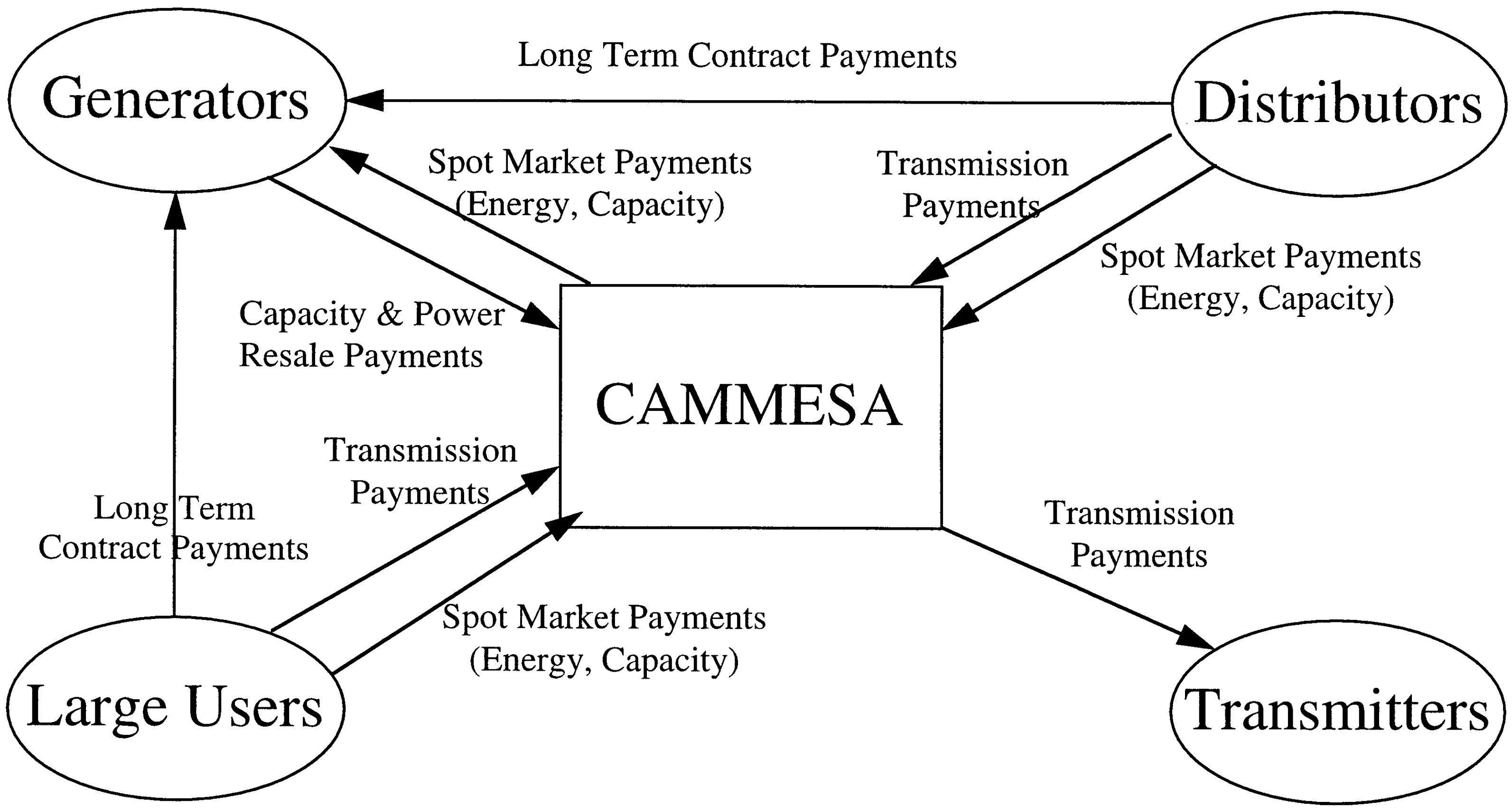
A.1.1.4 The Electricity Market

The Spot Market provides for a marginal pricing system for electricity. Generating units are dispatched according to their hourly bids for marginal costs and generators are remunerated for energy according to the bid of the last unit dispatched. Generators can also collect revenue for capacity charges when dispatched or scheduled for dispatch and capacity charges for making units available as reserve.

Distributors are able to pass through to their customers the stabilized seasonal price set for a period of six months. At the end of the period, distributor companies settle their purchases valued at spot market prices against the seasonal price with the difference going

[1]CAMMESA stands for "Compañia Administradora del Mercado Mayorista Electrico S.A.", which translates into Wholesale Electricity Market Administrator Company.

Graphic 2:Financial Transactions in the WEM



or coming from the Price Stabilization Fund established for this purpose. It is important to note that the seasonal price can be adjusted after three months to reflect significant differences between actual and projected operating conditions. Transmitters are paid for transmitting electricity from generators to distributors and to large users.

CAMMESA is the organization responsible for the operation and administration of the market, including scheduling, dispatch and payments. It is the sole organization in the WEM in charge of the physical transfer of energy among the different agents of the market.

A.1.2 Operation of The Spot Market

A.1.2.1 Location , Node and Adjustment Factors

The spot market is physically located at the Ezeiza Airport node outside of Buenos Aires. This represents the reference node for the market.

Nodes have been identified at key points on the transmission system. Each WEM agent is connected to the transmission network at a node. Each node has a node factor and an adjustment factor associated with it. The node factor reflects the increase in expected losses in the transmission system per unit increase in demand at a particular node. In other words, it represents the marginal losses per unit of demand at a particular node. The node factor is used for energy pricing at different nodes in the system. The adjustment factor, on the other hand, represents the quality and reliability of the connection between each node and the load center at Ezeiza Airport as well as the economic cost associated with transmission lines failures. That is, the adjustment factor represents an economic signal for the need of new links out of a particular node and new local generation capacity at that node.

A.1.2.2 Scheduling

In order to take into account both the long term and short term restrictions on resources and to provide future price references, CAMMESA establishes both a seasonal and short term (weekly and daily) dispatch schedules for each generator based on information provided by generators. Seasonal schedules are for November 1 to April 30 and for May 1 to October 31 periods which have different hydrological and demand characteristics. The seasonal schedule is performed using information provided by generators for the period in question. This information includes programmed maintenance and forecast of water levels and any details of downstream restrictions which influence hydroelectric dispatch. This information, together with forecasts of fuel prices, is fed into CAMMESA's MARGO model to determine seasonal prices that distributors are allowed to pass through to their customers.

Daily and weekly scheduling, on the hand, are carried out with a system-wide hydrothermal dispatch model. In order to achieve the lowest possible cost and highest reliability of service, the model takes into account the following: (i) forecast demand provided by large users and distributors, (ii) transmission considerations, (iii) generation availability, (iv) fuel availability, (v) speed and cost of start-up, (vi) water reserve availability, (vii) interaction of hydroelectric stations, and (viii) downstream restrictions.

A.1.2.3 Thermal Dispatch

Thermal units are dispatched in inverse order of marginal cost bids by generators until system demand is fulfilled. The effective bid is calculated by CAMMESA based on transmission losses and risks in delivering the energy to the system's central node.

Because of pipeline capacity limitations, many thermal plants are unable to run on natural gas during winter months. Consequently, some plants are forced to run at higher oil-fired marginal cost during the winter. Until May 1994, some thermal plants that were assumed to have access to natural gas during times of limited availability and were unable to secure gas supply, were dispatched as natural gas fired plants but were remunerated at its higher oil-fired costs. This measure created some distortions in both the natural gas and electricity markets. However, this measure was eliminated in May 1994 and now low cost plants unable to secure gas will be paid the Spot Market marginal cost even though dispatched at a higher oil-fired cost.

A.1.2.4 Hydroelectric Dispatch

Dispatching of hydroelectric plants is based on marginal costs calculated by CAMMESA using a computer model called OSCAR. Hydroelectric marginal costs are then compared to the thermal units bids to determine the optimal dispatch. The marginal cost calculation takes into account the most efficient use of hydrological resources given energy replacement costs as determined by thermal fuel costs, as well as water level and downstream restrictions. Thus, hydroelectric generators are typically not dispatched as base load, but rather at off-valley hours[2] when thermal fuel is most expensive.

Based on water restrictions, hydroelectric plants were divided into four categories:

<u>Seasonal Plants</u>

Based on current and historical hydrological information, CAMMESA formulates a seasonal dispatch schedule for these plants which achieves the lowest overall cost for the system. Generally, Seasonal Plants will be dispatched during times of highest demand to reduce spikes in spot market levels.

<u>Monthly Plants</u>

Concessionaires operating Monthly Plants have the option of setting their own monthly marginal prices according to reservoir levels or by blocks of energy production. During the month, the plant will be available for dispatch when the spot market levels reach or exceed the selected price. If an operator chooses not to set its monthly marginal price, CAMMESA will formulate a

[2] CAMMESA separates the day into three time categories: "peak", "valley" and "rest". Valley hours are defined to be from 12 midnight to 6 in the morning.

dispatch schedule for every unit of that generator with the objective of minimizing the overall cost of the system.

Weekly and Run of River Plants

Concessionaires operating Weekly Plants have the same flexibility as those operating Monthly Plants except that they set their marginal prices only for the coming week. The marginal cost of Run of River Plants is permanently set at zero, ensuring base load production.

A.1.2.5 Market Price of Electricity

The market price of electricity is determined by the marginal cost bid of the last unit dispatched adjusted by the node factor of the location of that unit.

A.1.2.6 Remuneration to Generators

Generators can receive the following payments as participants in the spot market:

Energy Payments

The price that generators are paid for electricity sold in the spot market is calculated by adjusting the market price of electricity according to the location of the generator in the system using the node factor.

Capacity Payments for Dispatch

Generators scheduled to dispatch one day in advance or actually dispatched during weekday-off-valley hours receive a predetermined capacity payment. The Secretariat of Energy is responsible for setting the dispatched capacity price. Generators receive this price modified by the adjustment factor of the node at which they are connected.

The price of dispatched capacity has been originally set at US$5 per MW per hour dispatched during weekday-off-valley hours. Starting in April 1994, this price was increased to US$10 per MW per hour. It is expected that this price will remain at this level over the medium term.

Other Capacity Terms

In addition to dispatched capacity, generators may receive cold reserve capacity payments. A cold reserve contract is an option agreement under which a generator receives an option payment for making available a specified amount of capacity at a future date. Cold reserve bidding is limited to gas turbine generators with the maximum bid currently limited to US$5 per MW per hour before applying the adjustment factor. All gas turbines generators submitting a cold reserve bid are paid the cold reserve capacity payment whether they are eventually dispatched (in which case they do not receive the dispatched capacity payment) or held in cold reserve.

Steam turbine generators, generally base load producers, receive an additional seasonal capacity payment for off-valley hours when dispatched.

Availability Incentive Payments

If a shortfall between supply and demand of more than 0.7% of demand is forecast for a particular week, CAMMESA will declare that week to have a Failure Risk and will pay an additional capacity charge for electricity produced during weekday-off-valley hours. This additional charge is calculated by estimating the magnitude of the deficit and the cost of energy non-supplied if the shortfall were to occur.

Ancillary Service Payments

Each generator must contribute a proportion of its output to frequency regulation. Hydroelectric generators will be able to sell spinning reserve, over and above the minimum requirements, to thermal generators in the WEM. Generators will pay, as appropriate, for the system services from which they benefit such as frequency regulation (when they are not providing it themselves), voltage control and reactive power.

A.1.2.7 Payments by Distributors and Large Users

Distributors and large users pay the "monomic" price for their purchases of energy on the spot market. The monomic price is comprised by: (i) the marginal cost bid of the last unit dispatched, (ii) an additional charge for risk of failure, and (iii) an additional charge for capacity dispatched. As mentioned above, distributors are only allowed to pass through the seasonal price to their customers .

A.1.2.8 Settlement

Billing for all spot market transactions is done on a monthly basis, with CAMMESA acting as the agent for all participants in the market. CAMMESA is responsible for the preparation of all the necessary information, for dispatch of the invoices and for administering collection.

A.1.3 The Term Contract Market

A.1.3.1 Overview

Generators can enter into term contracts to supply electricity with distributors, large users and other generators and are free to agree on the conditions, time frames, volumes and prices. Thermal generators fix an hourly loading curve and hydroelectric generators a monthly energy supply agreement. Contracts must be at least one year long in duration. Details of each contract are required to be made public.

A.1.3.2 Generators

Generators may only contract the energy which they are able to produce. For hydroelectric generators, the maximum quantity allowed to be contracted is determined based on availability (accepted by CAMMESA and processed into the seasonal programming) or on the concept of "firm energy". This concept corresponds to the quantity of energy that the hydroelectric generator can be 70% certain of exceeding.

A.1.3.3 Large Users and Distributors

There are two types of large users in the WEM: major large users (in Spanish "GUMA") with a demand exceeding 1 MW, and minor large users ("GUME") with a demand between 100 kW to 1 MW. There is already some talk that the threshold for GUME will be reduced probably to 50 kW.

GUMA who want to participate in the term contract market must contract at least 50% of their estimated energy demand. Otherwise they must purchase directly from their local distributor. GUME, on the other hand, must contract 100% of their energy and capacity demand, and their contracts are administered by their local distributor for a fee.

Distributors are able to contract all or part of their estimated demand, with the non-contracted portion of their demand being met with spot market transactions.

A.1.3.4 Transmission

Generators are responsible for transmission from their connection node to the load center node in Ezeiza, whereas distributors and large users are responsible from the load center to the receiving node. Transmission costs are independent of any contracts between generators and distributors or large users. The guarantee of supply given by a generator in a contract does not cover the risks of failure in the transmission system so the two parties must take into account the quality of the physical interconnection between them when entering into the contract.

A.1.3.5 Dispatch and Delivery

Mismatches between the actual output of a generator and its contractual commitments are covered by spot market trading. If the generator is dispatched below the contracted power, it must buy the difference at the market price. If a generator is dispatched above the contracted power, it must sell the excess in the spot market and receive the relevant market price. It is assumed that electricity contracted is bought and sold at the load center of the system at the Ezeiza Airport. If a generator is unable to satisfy its contracts due to lack of availability, it must either purchase in the spot market or enter into a contract with another generator.

If there is a shortfall in the spot market and as a result a generator is unable to fulfill his contractual commitments, the distributors and large users holding the contracts with the generator are subject to restrictions in the supply of electricity. Distributors who are unable to supply their customers are subject to penalties in accordance with the terms of their concessions.

A.1.3.6 Settlements

Term contracts are directly settled by the parties involved. CAMMESA, however, remains responsible for the settlement of all transactions carried out in the spot market.

A.1.4 Transmission Charges

A.1.4.1 Connection Charge

A connection charge is levied by CAMMESA on all WEM members for their connection to the transmission network. The charge can be seen as a contribution to the continuing maintenance costs for connection equipment serving a particular user.

A.1.4.2 Capacity of Transmission Charge

A fixed charge is made to all users of the system. The idea is that the total amount of revenue raised through this charge reflects the operation and maintenance costs of the transmission equipment. The charge is allocated to users in proportion to their usage of the capacity system. This is measured as the relative demand of each user on the transmission system at the time of maximum system demand.

A.1.4.3 Energy Charge

Transmitters receive an energy charge based on the difference between the value of the energy received at a receiving node and the value of energy at a sending node. The difference is a function of the node factors of both nodes.

A.1.5 Transmission Constraints and Local Pricing

When a restriction preventing optimum dispatch occurs within the transmission system, the group of nodes affected and isolated by the restriction are considered as an independent area and form an independent market with their own local price. The local price is determined by the marginal cost bid of the last unit dispatched within the independent region. Local prices may differ widely from spot market prices. Net importer areas have higher local prices than spot market prices, whereas net exporter areas have lower local prices.

A.2. The Argentine Electricity Sector

A.2.1 Demand Side

A.2.1.1 Electricity Consumption in Argentina

Over the period 1970 to 1990, electricity consumption in Argentina increased by an average of 4.0% per annum, reaching 41,036 GWh in 1990. In 1994, consumption rose 6.4% reaching 51,900 GWh and in 1995 it rose 3.6% to 53,800 GWh despite the 4.4% drop in GDP. The following table shows the trend in consumption of electricity between 1990 and 1995, compared with population and GDP.

Table 1: Electricity Consumption, Population and GDP Statistics

Year	Total Consumption (GWh)	% Change	Population (*) (Thousands)	% Change	GDP (US$ MM)	% Change
1990	41,036		32,143		208,507	
1993	48,800	19%	33,810	5%	260,878	25%
1994	51,900	6%	34,385	2%	279,400	7%
1995	53,800	4%	35,564	2%	267,106	-4%

(*) Last population census was in 1991. Table assumes a 1.7% per annum growth rate after 1991.
Source: CAMMESA, The Economist Intelligence Unit

The table above shows that, over the period 1990 to 1995, the compound annual growth rate of electricity is approximately 5.5% compared with population growth of 2.0% and GDP growth of 5.1% per annum. The Secretariat of Energy believes that electricity consumption will be strong during the remainder of the 1990s mainly driven by two factors: (i) strong economic performance, and (ii) falling electricity prices.

A.2.1.2 Consumption by Sector

There are three important categories of electricity consumption in Argentina: industrial, commercial and residential. Historically, industrial consumption has grown the fastest, closely followed by residential consumption. Table 2 summaries the evolution of energy consumption by sector.

Table 2: Energy Consumption by Sector (GWh)

Year	Industrial	Commercial	Residential	Other	Total
1990	21,863	3,142	11,265	4,766	41,036
1993	26,516	4,502	12,328	5,454	48,800
1994	27,046	5,447	13,191	6,215	51,900
1995	27,587	5,556	13,851	6,806	53,800

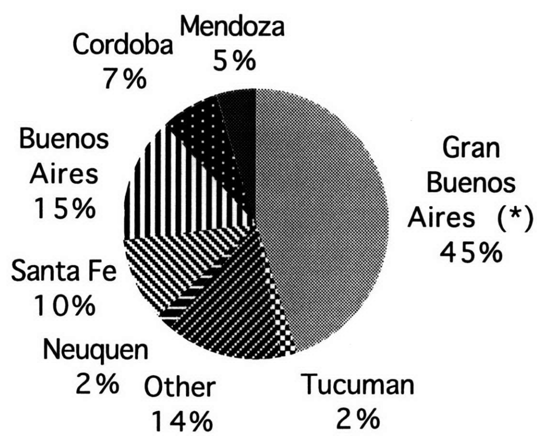
Source: CAMMESA, The Economist Intelligence Unit, CS First Boston

As noted in the table above, the industrial sector is the largest source of demand, accounting for approximately 52.8% of total demand in 1995. Residential and commercial users accounted for approximately 25.2% and 10.3%, respectively. It is interesting to note, however, that the growth rates in the last couple of years has changed from the historical trend with commercial growing the fastest at an average rate of 12% per annum between 1990 and 1995, compared to 4.7% and 4.2% for industrial and residential, respectively.

A.2.1.3 Consumption by Region

The Buenos Aires Province is by far the most important region in terms of energy consumption, representing 60% in 1995. This does not come as a surprise since about one third of the country's population lives in the metropolitan area of Buenos Aires, and industry is concentrated in this area. The breakdown of regional electricity consumption is given in Graphic 3 below.

Graphic 3: Regional Electricity Consumption (1995)

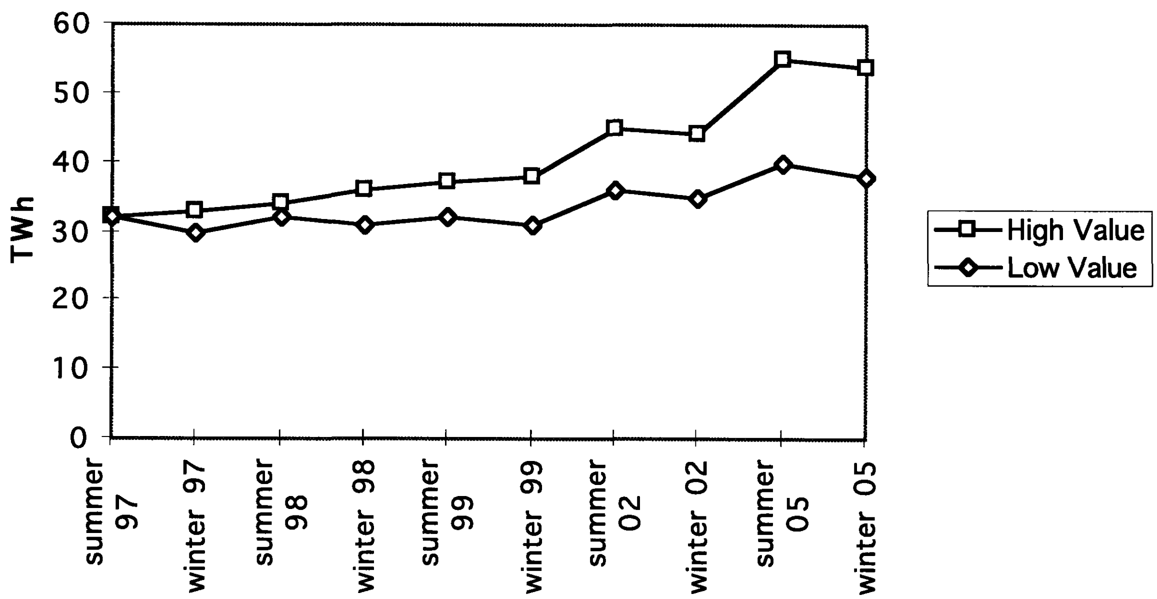


(*) Represents the metropolitan area of Buenos Aires
Source: CAMMESA

A.2.1.4 Demand Forecast

The graphic below shows demand forecast range prepared by CAMMESA. We see that an increase in demand is expected.

Graphic 4: Demand Forecast



Source: CAMMESA

A.2.2 Supply Side

A.2.2.1 Installed Capacity

Table 3 summarizes the evolution of installed capacity in Argentina between 1990 and 1995.

As can be seen in the table, Argentina is predominantly hydroelectric which accounts for 48% of total capacity in 1995. We also see that natural gas plants are becoming more important within the thermal type. Comahue (south west region of the country) is the most important region for installed capacity, accounting for 31% of total capacity and 56% of total hydroelectric capacity. The Buenos Aires Province, on the other hand, accounts for 63% of total thermal capacity and 28% of total system capacity, representing another major region for capacity.

Table 3: Installed Capacity by Type (MW)

Type	1990	1995
Hydroelectric	6,586	8,123
Steam	5,174	4,867
Natural Gas	2,208	2,972
Diesel	683	4
Nuclear	1,108	1,005
Total	15,669	16,971

Source: CAMMESA, CS First Boston

A.2.2.2 Energy Generated

Table 4 shows the participation of the different sources of energy in total gross energy available in the Argentine system.

Table 4: Gross Energy Generation by Type (GWh)

Year	Hydroelectric	Thermal	Nuclear	Imports & Self Generation	Total
1990	15,730	19,983	7,280	122	43,115
1993	20,320	24,689	7,750	1,638	54,397
1994	24,660	24,129	8,290	1,125	58,204
1995	24,852	27,220	7,117	1,089	60,278

Source: CAMMESA

Thermal participation in gross generation has jumped from 41% in 1994 to 45% in 1995. This increase is partially due to the increase in installed capacity, but more importantly, it is the result of improved availability of thermal units. In 1994, thermal availability averaged 61%, and in 1995 it increased to 72%. This represents one of the major accomplishments of privatization and restructuring of the electric power sector processes in Argentina.

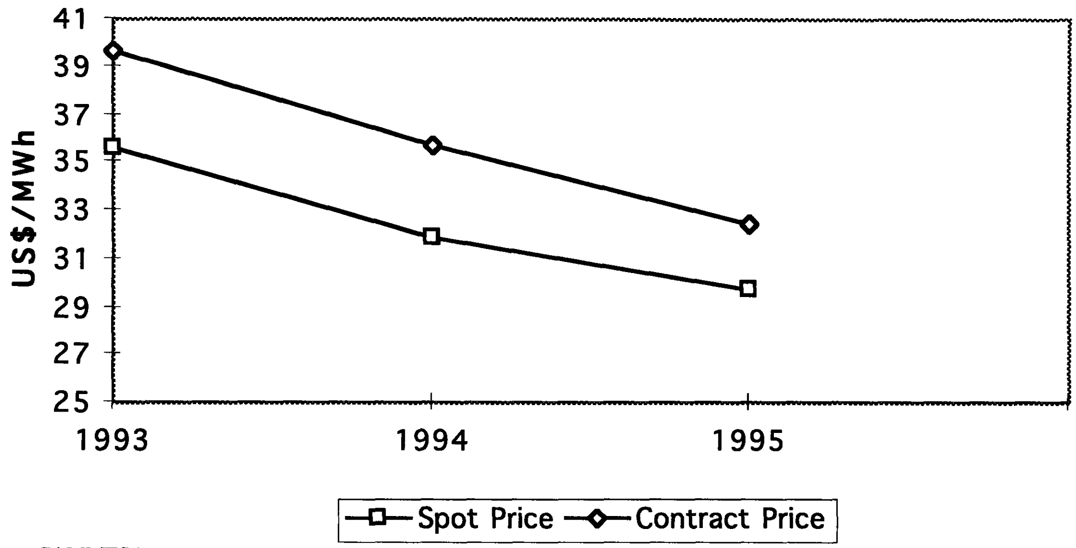
A.2.2.3 New Projects

Currently, there are many major plant projects in Argentina. Among the thermal projects, there are two 1000MW projects in the Buenos Aires area, and one 600MW in the Comahue region. These are efficient combined cycle projects. Among the hydroelectric projects, the most important one is Yacyreta. This plant located on the northeastern part of the country on the border with Brazil, has twenty 195MW turbines, totaling 4,000MW. It is expected that all turbines will be fully operational by 1998. This project is bound to have a big impact on the Argentine market. It is expected to generate up to 25,000MW, representing close to half of 1995 energy demand. In 1995, Yacyreta already generated close to 6% of gross generation. As a run of river plant, Yacyreta's marginal cost of electricity is close to zero. The impact on price, however, will be determined by the structure of the privatization of the plant, and by the amount of energy dispatched to Brazil. Yacyreta definitely represents the biggest concern for potential investors in the generation side of the market.

A.2.3 Prices in the WEM

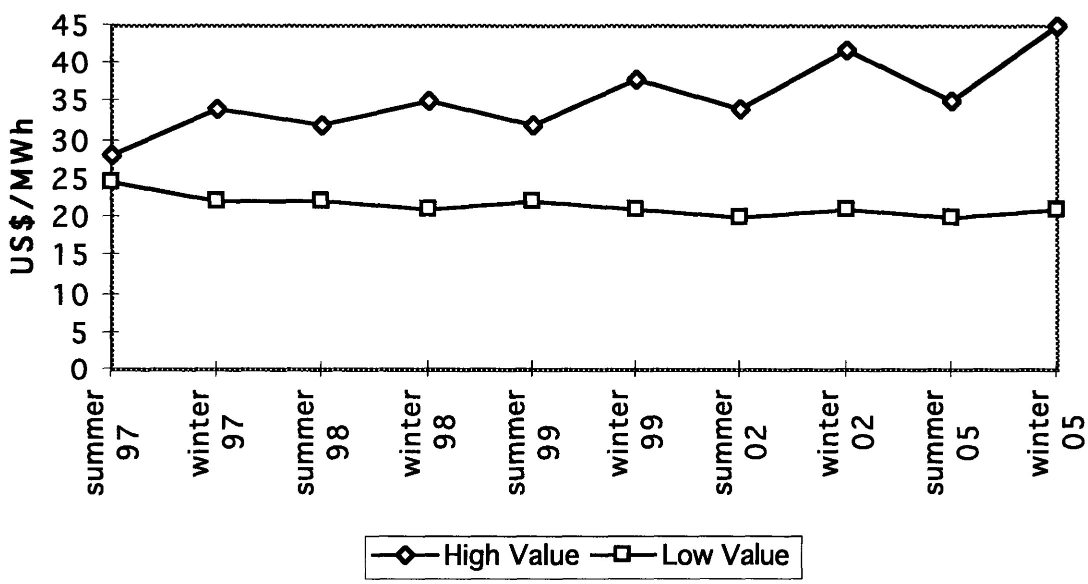
One of the main results of the privatization and restructuring processes has been the steep decline in wholesale prices because of the increased competition at the generation level. At the end of 1995, there were 46 generators participating in the WEM, indicating the high level of competition in the generation side. It is expected that, on average, prices in the near future will decline as Yacyreta and other projects become operational. Over the long run, prices are expected to increase as demand increases. The two graphics below show the evolution of prices between 1993 to 1995, and the price forecast range prepared by CAMMESA.

Graphic 5: Evolution of Energy and Capacity Prices



Source: CAMMESA

Graphic 6: Energy and Capacity Price Forecast



Source: CAMMESA

B. Mendoza

The province of Mendoza is located in the foothills of the Andes mountains in the western part of Argentina bordering Chile. Most of the economic activity in the province is in the city of Mendoza, the fifth largest in Argentina. Among the most important economic activities in the province, there is agriculture (in particular vineyards), industry, and some oil and natural gas fields.

The electric power sector in Mendoza abides by the WEM regulations explained above. However, the province is in the midst of passing provincial regulation to meet local objectives. It is not expected that the provincial law will interfere with the operation of the WEM in Mendoza. The Mendoza province is connected to the WEM via a single link at Cruz de Piedra. This link supplies the whole Cuyo region, which includes the Mendoza and the San Juan provinces, with Mendoza representing close to 83% of the regional demand. Until 1988, the Cuyo region was a net energy exporter. This situation reverted itself, and today it is a net energy importer and sometimes transmission restrictions result in the Cuyo system being isolated from the rest of the country.

B.1 Demand

Together the San Juan and Mendoza provinces represented a mere 6.5% of total demand in Argentina during 1995. The bulk of demand comes from the industrial sector, followed by residential demand. Table 5 below, shows demand for the San Juan and Mendoza provinces for 1992 and 1993.[3]

[3]Data for later years was not readily available.

Table 5: Electricity Demand in the Cuyo Region by Sector (GWh)

	Mendoza Province		San Juan Province	
Demand	**1992**	**1993**	**1992**	**1993**
Industrial	1,465.49	1,599.25	200.45	270.37
Commercial	99.55	116.17	63.26	47.41
Residential	521.34	561.17	152.74	173.91
Agricultural	281.09	288.07	18.00	15.15
Other	163.12	162.59	44.41	44.15
Total	2,530.59	2,727.25	478.86	550.99

Source: Secretariat of Energy

Most of the energy demanded is met by EMSE (the local distribution company in Mendoza), EDESSE (the local distribution company in San Juan) and some cooperatives. The Cuyo region has very few large users. During 1995, only 11% of total demand came from large users.

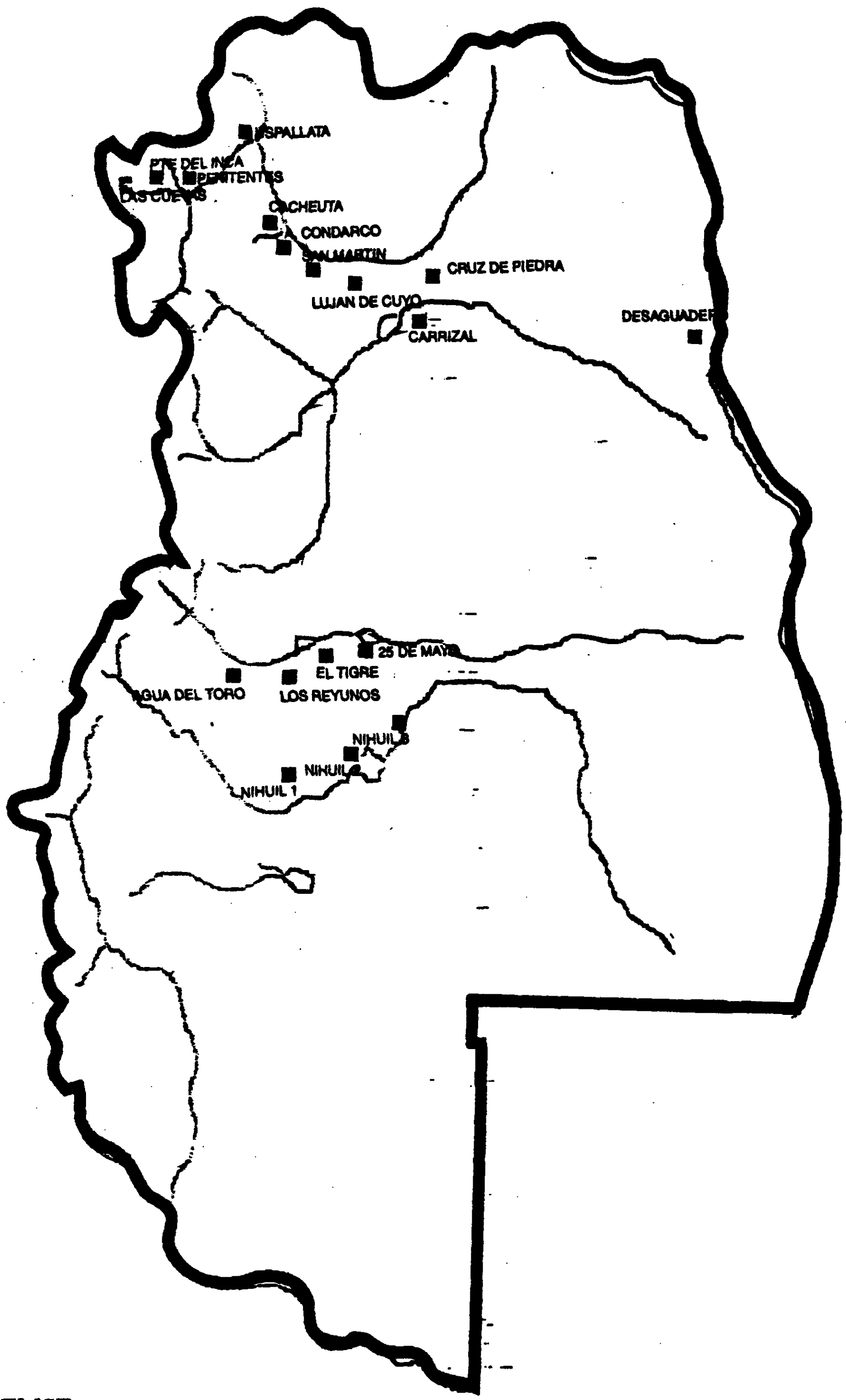
Demand in the Cuyo region is expected to grow at an average of 4% in the next five years, and 3% after that until 2008.

B.2 Supply

The Cuyo region represents 6.6% of total installed capacity in the country, with the Mendoza province representing 96% of this capacity. Hydroelectric capacity represents close to 65% of installed capacity in the Mendoza province. Graphic 7 shows a schematic of the location of generators in the Mendoza province.[4] The bulk of hydroelectric capacity is located in the south of the province. Thermal capacity, on the other, hand is located around the city Mendoza close to industrial demand. There are five generation companies

[4] In this Thesis I shall concentrate on the Mendoza province and neglect the San Juan province for two reasons: (i) This project is part of an agreement between MIT and the Province of Mendoza, and (ii) San Juan represents a small part of the installed capacity in the Cuyo region. However, the San Juan demand is taken into account in the modelling exercise.

Graphic 7: Location of Generators in the Mendoza Province



Source: EMSE

in the province: HIDISA, HINISA, CTMSA, Nihuil IV and Hidroelectrica Mendoza. HINISA and Nihuil IV generate electricity on the Atuel River, HIDISA does it on the Diamante River, and Hidroelectrica Mendoza on the Mendoza and Tunuyan rivers. Only three companies operate in the WEM: HINISA, HIDISA and CTMSA. The first two are partially owned and operated by Electricité de France (EDF) and the last one is owned by CMS of the U.S. Nihuil IV is owned by a cooperative and sells energy to EMSE on a 16 year contract. Hidroelectrica Mendoza used to be the generation arm of EMSE, and was spinned off to prepare EMSE for its privatization. It also sells all its energy to EMSE. Table 6 below summarizes the capacity of each company as well as their average energy generated per year.

Table 6: Installed Capacity and Annual Generation per Company

Company	Type	Installed Capacity (MW)	Average Generation per Year (GWh)(*)
HINISA	Hydroelectric	263	900
HIDISA	Hydroelectric	385	520
CTMSA(**)	Thermal	408	592
Nihuil IV	Hydroelectric	25	150
Hidroelectrica Mendoza	Hydroelectric	67	350
Total		1,148	2,512

Source: CAMMESA and AyE
Notes: (*) Average Generation for CTMSA represents actual generation for 1995
(**) CTMSA capacity does not include new projects such as the LDC 11 unit conversion .

From the above table thermal capacity represents close to 24% of the energy generated while representing 35% of the installed capacity. It is worth noting as well that the hydroelectric plants in the province are not run of river plants and thus do not produce base load electricity. Indeed, there are many downstream restrictions in the operation of these plants, making them mainly monthly plants. The operation of monthly plants has been described before.

B.3 The Link with the WEM

As mentioned before, the Cuyo region is linked to the WEM by a single 500kV line at the Cruz de Piedra node to the east of Mendoza city. The capacity of this line is 540MW. Because of physical constraints on the line, the Cuyo region is isolated from the WEM many times during the year, with no more capacity to import or export. In such cases, if the region is a net importer demand must be met with local high cost supplies resulting in higher prices in the Cuyo region relative to the WEM. On the other hand, if the region is a net exporter demand is met with low cost sources relative to the WEM resulting is lower prices in the region. Table 7 below summarizes the transmission constraint in and out of the region for 1995.

Table 7: Transmission Restrictions

	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
% of time	0%	5%	41%	46%	77%	82%	70%	31%	27%	17%	0%	0%
Local Price	0	25.2	23.7	22.0	25.2	26.6	22.3	18.8	21.7	25.5	0	0
WEM Price	22.2	27.4	23.0	21.3	21.0	23.8	22.0	22.4	21.1	24.3	18.8	23.5

Source: CAMMESA
Prices are in US$/MWh

On average, there were transmission restrictions during 33% of the time in nine months of 1995. The restrictions occurred on both flow directions. During February and August, the Cuyo region was net exporter as evidenced by a lower local price. During the other restriction months, the region was a net importer. The highest resulting local price occurred during the month of May, with a local price 20% higher relative to the WEM price.

B.4 Capacity Projects

There are a number of projects that are either under way or still under study that could increase the capacity of the province if implemented. The most important projects are the hydroelectric plants. Because of the capital costs involved, the government has a major role in the development of these. Most of these projects were first studied under the old structure of the sector, with Agua y Energía as the responsible agency. With the new structure of the sector, these projects are not to be developed by the federal government but rather by the provincial government. One of the aims of this thesis is to determine whether these projects are worth developing or not. The most important hydroelectric projects are Potrerillos on the Mendoza River, Los Blancos on the Tunuyan River, El Baqueano on the Diamante River and Portezuelo del Viento on the Grande River. The Potrerillos project is perhaps the closest to the implementation phase. It involves the refurbishing of two already existing plants, Alvarez Condarco and Cacheuta, of Hidroelectrica Mendoza. Size, cost and generation capabilities of these projects are described in Chapter II.

Among private projects, there are two new units being built by CTMSA. The first project involves the conversion of the 60MW LDC 11 unit from fuel oil to natural gas. The project should be fully operational by September 1996. The second project is a 290MW combined cycle unit, using parts of the LDC 25 and LDC 13 units, no longer on service. The project should be completed by April 1998. With these two projects operational, CTMSA will have an installed capacity of 510MW and an average generation of 3,085GWh per year[5].

B.5 Natural Gas Availability

Natural gas production in the Cuyo region is very limited. The region relies on supply from the northern part of the country transported through the Transportadora de Gas del Norte (TGN) pipeline system. Currently, there are capacity constraints in the gas transportation system to Mendoza. In order to secure its natural gas supply, CTMSA had

[5]This is based on operational hours per unit of 6,000 to 6,500 hrs per year. See Model for more details about the units.

to buy an equity stake in TGN, and still does not have a secure supply during the heavy demand winter months. However, this constrained supply situation can change over the medium term with the new Gas Andes pipeline that is currently being constructed. This new pipeline will run from the Neuquen region to the south of the province and will enter Chile through San Rafael in the Mendoza province, to the south west of the city of Mendoza. It is expected that this new line will be fully operational by 1998. The capacity of this line is 8MM m3/day, once all compression units are installed. The natural gas transported on this line will primarily go to thermal plants in Chile. There is still capacity left that can be used by generators in the Cuyo region. As of June 30, 1996, there are no restrictions as to the availability of this gas for use in the Mendoza region.

Chapter II: Aims and Description of the Model

A. The Aims

As was explained in Chapter I of the thesis, the Cuyo region is currently experiencing drastic transmission constraints with the WEM. The economic consequences of such constraints can be substantial as the Cuyo region becomes increasingly a larger net energy importer region . These consequences are in terms of local prices, unmet demand and reliability of the system. These are explained below:

Local Prices

As a net importer region, local prices will be higher than the WEM price every time there are transmission restrictions. As the region becomes increasingly more of an importer, the cases of lower-than-WEM local prices, as experienced during the months of February and August 1995, will occur less and less frequently. Moreover, because of the bid based dispatching system, local prices can potentially be much higher than WEM prices. For instance, if CTMSA anticipates transmission restrictions, that local generation is not sufficient to meet local demand and as a result will have all its units dispatched, then it can bid more than the marginal cost of the unit since it knows it will be dispatched no matter what. Furthermore, the lack of retail customer incentives to shift demand from peak to valley hours, when transmission constraints are less likely, does not alleviate this problem. Indeed, customers do not see hourly local prices but only seasonal prices, and as such are unaffected by local prices. Hence, the Cuyo region can see its energy expenditure rise substantially as local prices become increasingly higher and more frequent.

Unmet Demand

Local generation capacity may not be sufficient to supply local demand in periods of transmission constraints. Furthermore, as noted above, customers have no incentive to change consumption patterns shifting demand from peak to valley hours. Consequently, the Cuyo region can have substantial shortages of energy in periods of transmission constraints.

Reliability of the System

Even if transmission restrictions do not occur very often, heavy reliance on the WEM can prove disastrous. Should the link fail most of the region will find itself without its main supply of energy. Furthermore, as the link reaches its transmission capacity, the probabilities of failure increase, putting the whole Cuyo region at greater risk. This increased probability of failure can have some consequences on contract prices of local generators with parties outside the Cuyo region. As mentioned in Chapter I, the guarantee of supply given by a generator in a contract does not cover the risks of failure in the transmission system. Hence, large users and distributors will have to pay higher premiums in order to guarantee supply from Cuyo generators if transmission fails. This results in Cuyo generators being less competitive on the WEM and/or absorbing the extra cost.

The above discussion suggests that the province of Mendoza will most certainly have severe problems in the future if it does not reduce transmission restrictions. These problems will become more acute as energy demand in Mendoza grows at the solid rate of 4% per year, as expected. As such, the aim of this thesis, and of the MIT-UNC project altogether, is to identify the most robust and efficient way to satisfy future energy needs of the province of Mendoza, while at the same time *reducing* the transmission constraints. The word "reducing" should be stressed because eliminating these transmission constraints altogether might not prove to be efficient at all. Multi-attribute trade-off analysis can prove a valuable methodology to address this aim. In particular, it can be very helpful in ranking existing hydroelectric projects (Potrerillos, Portezuelo del Viento, El Baqueano, Los Blancos) with other power generation projects (most notably thermal) so as to identified the most efficient and robust projects.

Such an aim seems to be at odds with a deregulated electricity market dominated by private initiative and investment. It would only make sense for a centralized planning institution such as the provincial government, and not in the context of self-regulating efficient markets. Indeed, one would argue that there are enough economic signals in the WEM to incentivise private investors to build capacity in the Cuyo region and thus to reduce the transmission constraints problems. One such signal is the adjustment factor, explained in the first chapter of the thesis. As of April 30, 1996, the Cuyo region adjustment factor is the largest in the WEM at 1.167, which could lead to substantial investments in the region. However, although the WEM signals seem to be working, most of them leave externalities out. One such externality is emissions. There is not even a permits market or emission taxes that could take into account these variables. By internalizing these effects, multi-attribute trade-off analysis can prove a valuable methodology for a coherent analysis of the different alternatives. Based on the results of the analysis, Mendoza province government officials could introduce legislation so as to internalize these effects. Moreover, the methodology can help the province in evaluating their energy policy. For instance, there is a strong support in the provincial government to subsidize hydroelectric projects. The analysis in this thesis can shed light as to whether such subsidies is the most efficient use of their resources.

In sum, the analysis performed in this thesis is consistent with a deregulated market. It can prove very helpful for private investors by providing information not available through market mechanisms, allowing them to evaluate their investment strategies. Furthermore, it can save private investors some costs by already performing analysis that they would have to do anyhow, and making the results available to them. It will also definitely prove very valuable for the provincial government as it can use the results to introduce legislation to internalize environmental emissions, as well as to evaluate their subsidy policy to hydroelectric projects.

B. The Model

Two models were developed to perform the desired analysis. The first is the Energy Balance Model, and the second is the Multi-Attribute Analysis Model. The data of the first model is used by the second model to generate the trade-off curves which form the core of the analysis. Both these models are described in detail in the following paragraphs.

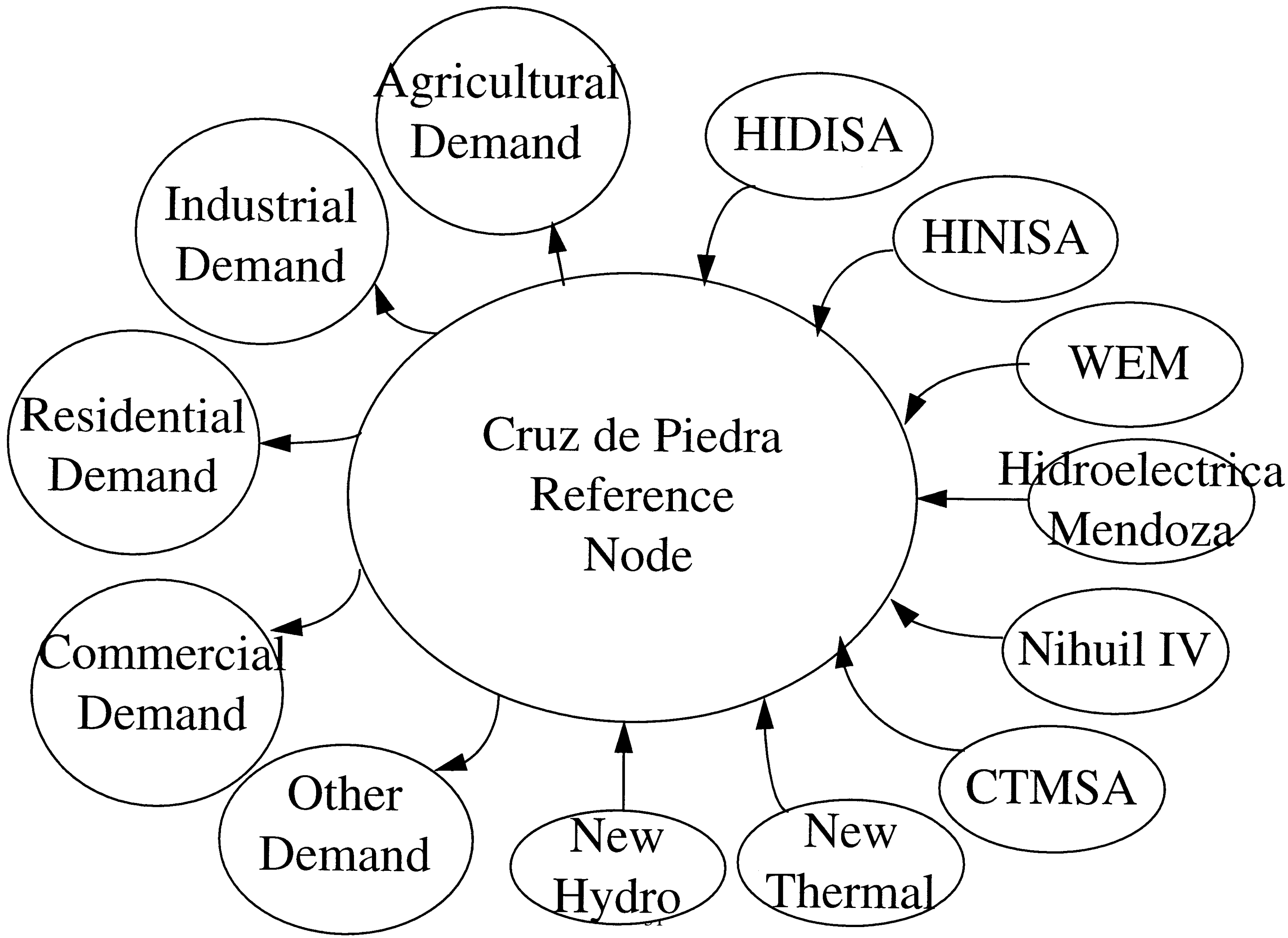
B.1 The Energy Balance Model

B.1.1 Model Set Up

As its name indicates, the model used performs an accounting function of the electricity system in the Cuyo region. The Cruz de Piedra node is taken as the reference point for this exercise. As noted before, Cruz de Piedra is where the Cuyo region is connected to the WEM via a 500 kV transmission line. The model treats the Cruz de Piedra point as a sink for all the energy generated locally and imported from the WEM, and as a source for all the energy demanded in the region. That is, the model treats all the energy generated and imported as flowing first to Cruz de Piedra, and then as being redistributed to the demand areas. The model also incorporates the losses involved in the energy flow between the generation centers and Cruz de Piedra and between Cruz de Piedra and the demand centers. Graph 8 depicts this set up of the model.

Although this is somewhat of an unrealistic simulation of energy flows within the system, one could argue that given the objectives of the MIT-UNC project, the model

Graphic8: Set up of the Energy Balance Model



represents a very good first approximation. Indeed, in reality energy does not flow as assumed by the model but rather follows the least resistance path. As such, the losses associated with the real system are smaller than those modeled. That is, the energy required to meet local demand is in reality less than that stipulated by the model and as such the model presents a more drastic case of over demand. It is in this sense that the model is a more conservative approximation of the real system.

Another feature of the model is the assumption that all transactions are spot market based. That is, all the energy generated locally is sold to the WEM and all the energy purchased comes from the same market. The model does not treat long term contracts at all. This assumption can be defended on the following grounds: (i) it is very difficult to simulate the evolution of long term contracts over long periods of time, (ii) in efficient markets the spread between long term prices and spot prices is very thin and thus, from a planning perspective, energy revenues and costs can be best approximated using spot market prices. At the same time, the model assumes that the Cuyo region is a price taker in the WEM. This is a natural assumption as the Cuyo region represents 6.5% of Argentina's demand and 6.6% of its installed capacity.

The Energy Balance Model is run on a yearly basis, and thus represents a yearly average. Obviously, many things go on in real time that are not captured by the model. However, for the planning purposes of the MIT-UNC project, these real time changes are irrelevant.

Please refer to Appendix A for a copy of the Energy Balance Model.

B.1.2 Assumptions about Energy Demand

The model desegregates demand into Agricultural, Industrial, Commercial, Residential and Other, as shown in Graphic 8. The model incorporates demand for the entire Cuyo region; that is, it takes into account demand from both San Juan and Mendoza provinces. Assumptions about the future evolution of energy demand change with each Future within the Multi-Attribute Model. These are explained later.

B.1.3 Assumptions about the Dispatch of Local Generators

The model incorporates both existing capacity and new capacity projects. The level of new capacity is varied within the Multi-Attribute Model and is explained later. The dispatching of the different generation units depends on whether they are hydroelectric or thermal plants, as explained below.

B.1.3.1 Hydroelectric Plants

All hydroelectric plants are assumed to operate at a marginal cost below spot price. Thus, they always get dispatched to and sell their energy on the WEM However, as was mentioned earlier, none of the Mendoza plants (including projects) are run of river plants and as such they are not base load plants. That is, none of the hydroelectric plants are assumed to dispatch 100% of the time. The amount of energy generated depends on the different capacity factors assumed for each plant[6]. These assumptions are described later.

Hydroelectric plants are assumed to operate primarily during weekday-off-valley hours, and thus receive the corresponding remuneration for dispatched capacity for the first 4,604 hours (i.e. the number of weekday-off-valley hours in a year). That is, if a plant generates the equivalent of 5,000 hours a year, it is assumed that it generates during all 4,604 weekday-off-valley hours, and during 396 of non weekday-off-valley hours. This assumption tends to give a bias in favor of hydroelectric projects as it increases their revenues.

[6]Capacity Factor represents the effective percentage of time that a unit operates at full capacity. It is a measure of the operational availability of a plant.

B.1.3.2 Thermal Plants

Depending on the fuel type and price, thermal plants can operate at marginal costs either above or below spot price. Those with a marginal cost above spot price are dubbed "high cost plants" and those with a marginal cost below spot price are dubbed "low cost plants". Just like hydroelectric plants, low cost plants always get dispatched to and sell their energy in the WEM. Again, they are not assumed to generate 100% of the time. The amount they generate depends on the number of hours they are assumed to be available for operation.

High cost plants, on the other hand, generate only if (i) there are restrictions in the importation of electricity from the WEM, and (ii) there is not enough low cost and hydroelectric capacity to meet local demand. In such cases, high cost plants get dispatched in order of increasing marginal cost adjusted by the loss coefficient on transmission from the generation plant to Cruz de Piedra.

Both high cost and low cost plants are assumed to operate primarily during weekday-off-valley hours and, as with hydroelectric plants, get remunerated for dispatched capacity for the first 4,604 hours. This assumption also gives a bias in favor of thermal plants, but less so compared to the hydroelectric case. Indeed, it is natural to assume that high cost thermal plants will get to be dispatched on weekday-off-valley hours; otherwise they would not be high cost plants. Low cost plants, on the other hand, because of higher marginal costs tend, on average, to get dispatched during weekday-off-valley hours more often than hydroelectric plants. In sum, the bias of primary weekday-off-valley hour operation works more to the advantage of hydroelectric plants than thermal plants.

B.1.4 Energy Prices

The model determines an energy price for the Cuyo region for generators, distributors and large users. When there are no transmission restrictions, the price is the

WEM price given the price taker nature of the Cuyo region. It is important to note that the WEM price in the model already takes into account the Cuyo node factor. That is, it represents WEM price at the Cruz de Piedra node. This assumption simplifies somewhat the analysis, as the node factor is directly incorporated and need not be taken into account anymore.

When there are transmission constraints, the model calculates the resulting local price. The local price is determined by the marginal cost of the last unit dispatched adjusted by the transmission losses from the node of that last unit to the reference Cruz de Piedra node. In this sense, the Cruz de Piedra node is equivalent to the Ezeiza node in the determination of the WEM price. It is worth noting that the determination of local prices in the model is based on actual marginal costs rather than marginal cost bids as it is in reality. The model, thus, does not allow for the possibility of high marginal cost overbids, as discussed earlier. The reason for this assumption is that modeling auctions using game theoretical mechanisms can prove a substantial task for an operational decision rather than a planning decision. Furthermore, marginal cost based prices are a good conservative approximation of bid based prices. In normal situations, because of the level of competition in the wholesale market, marginal cost bids are very close to the actual marginal cost. Bids would differ from the actual marginal cost only in the case where there is an anticipation of transmission constraints and of insufficient local generation capabilities to meet local demand. As mentioned before, in such cases bids can be very high relative to actual marginal costs, but never below as generators would not make a profit. That is, the marginal cost of the last unit dispatched represents a floor for local prices, and it is in that sense that marginal cost based pricing is a conservative approximation to bid based local prices.

B.1.5 Capacity and Transmission Charges

The model takes into account prices for capacity dispatched. This price is determined by the Secretariat of Energy, as explained in Chapter I. The model assumes that generators receive this charge for every weekday-off-valley hour that they generate. On the demand side, the model approximates total capacity dispatched payments using the following formula:

$$TCDP = APD \times \Pr ice \times NWOVH$$

where $TCDP$ = Total Capacity Dispatched Payments

APD = Average Power Demand in a year

$\Pr ice$ = Capacity Dispatched Price

$NWOVH$ = Number of Weekday-Off-Valley Hours in a year

Average Power Demand is calculated by dividing Total Energy Demand by 8,760 hours (the number of hours in a year).

As described in Chapter I, generators, distributors and large users see a capacity dispatched price modified by the adjustment factor. The model assumes the adjustment factor to be equal to 1. The main reason for this assumption is that it was very difficult to estimate a relationship between the adjustment factor and increasing local generation capacity. As described in Chapter I, the adjustment factor varies as a function of the reliability of the link and is determined once a year based on the economic cost of unmet energy. On the one hand, an estimate for this economic cost was not readily available. On the other hand, with only three different data points, it was impossible to obtain a meaningful econometric relationship between adjustment factor, local generation, link capacity and power demand. This assumption, by lowering the actual adjustment factor, will tend to decrease both the revenues of generators and the expenditures of distributors and large users.

The model does not treat at all the other kinds of capacity charges (e.g. cold reserve capacity, seasonal capacity), Availability Incentive Payments and Ancillary

Service Payments discussed in Chapter I. On the one hand, decisions about cold reserve and seasonal capacities, as well as ancillary services can be seen more as operational rather than planning. They have been excluded from the model for this reason. On the other hand, for the model to include availability incentive payments it would need to include a model of the whole WEM. Obviously, this alternative is beyond the scope of this thesis. Nevertheless, the model does not loose much by ignoring these other charges and payments as the bulk of non-energy remuneration for generators comes from dispatched capacity charges.

The model also ignores all the transmission charges described in Chapter I (e.g. energy transmission, transmission capacity and connection charges). Transmission capacity and connection charges are distributed among the WEM players following a formula that needs specific information about the WEM system during peak hours. The model, being on a regional and yearly basis, had no way of providing that information. Energy charges, on the other hand, were ignored for two reasons. First, the formula for distributing energy charges among different lines out of a single node was not readily available. This would create a problem in those scenarios that involve the construction of new transmission lines. Second, even if such a distribution formula was available, incorporating energy charges would not prove valuable once the model ignores the other transmission charges. Typically, energy charges alone barely cover operational and investment costs of transmission lines, thus including them and excluding the other charges would result in low profitability for transmission lines which is clearly not the case. This could lead to a bias against transmission projects in our trade-off analysis. As will be discussed later, ignoring these transmission charges did not alter the findings of the analysis at all.

B.1.6 Assumptions about Existing and New Electricity Supply Sources

The following summarizes the assumptions of the model about existing and new electricity supply sources in terms of capacity, availability, generation capacity, efficiency and capital costs.

B.1.6.1 Existing Supply Sources

The model takes into account the current five generation companies in the Mendoza province: HINISA, HIDISA, Hidroelectrica Mendoza, Nihuil IV and CTMSA. As mentioned before, the model does not take into account generation capabilities in the San Juan province, as these are relatively small. The assumptions per generation unit for each of these companies are summarized in the tables below. It is important to note that these assumptions are based on the information provided by these companies.

Table 8: Assumptions about Generation Units of HINISA

Generation Unit	Installed Capacity (MW)	Capacity Factor	Average Generation Capacity (GWh/yr) (*)	Equivalent Number of Generation Hours per Year (*)
Nihuil I	75	0.61	400.8	5,343.6
Nihuil II	136	0.33	393.2	2,890.8
Nihuil III	52	0.35	159.4	3,066.0
Total	263		953.4	3,624.9(**)

Notes: (*) Average Generation Capacity and Equivalent Number of Generation Hours were derived form the Capacity Factor and Installed Capacity Assumptions.
(**) Represents a weighted average.

Table 9: Assumptions about Generation Units of HIDISA

Generation Unit	Installed Capacity (MW)	Capacity Factor	Average Generation Capacity (GWh/yr) (*)	Equivalent Number of Generation Hours per Year (*)
Agua del Toro	150	0.28	367.9	2,452.8
Los Reyunos	224	0.13	255.1	1,138.8
El Tigre	11	0.52	50.1	4,555.2
Total	263		673.1	1,748.4(**)

Table 10: Assumptions about Generation Units of Hidroelectrica Mendoza

Generation Unit	Installed Capacity (MW)	Capacity Factor	Average Generation Capacity (GWh/yr) (*)	Equivalent Number of Generation Hours per Year (*)
Cacheuta	9.3	0.86	70.1	7,533.6
Alvarez Condarco	27.4	0.67	160.6	5,869.2
San Martin	6.0	0.36	18.9	3,153.6
El Carrizal	18.0	0.49	77.3	4,292.4
Los Coroneles	6.6	0.6	34.9	5,256.0
Total	67.3		361.8	5,374.9(**)

Table 11: Assumptions about Nihuil IV

Generation Unit	Installed Capacity (MW)	Capacity Factor	Average Generation Capacity (GWh/yr) (*)	Equivalent Number of Generation Hours per Year (*)
Nihuil IV	25	0.65	142.4	5,694.0

With regard to the CTMSA units, the model incorporates the two projects that are currently undergoing construction. These include the conversion of the LDC 11 unit from fuel oil to natural gas, and the combined cycle plant using parts of the LDC 13 and LDC 25 units. The table below summarizes the assumptions about CTMSA.

Table 12: Assumptions about Generation Units of CTMSA

Generation Unit	Fuel Type	Installed Capacity (MW)	Availability (Hrs/yr)	Average Generation Capacity (GWh/yr) (*)	Fuel Efficiency
LDC 12	Fuel Oil	60	6,000	360.0	30.4%
LDC 21	Natural Gas	25	6,000	150.0	38.7%
LDC 22	Natural Gas	25	6,000	150.0	38.7%
LDC 23	Natural Gas	25	6,500	162.5	26.1%
LDC 24	Natural Gas	25	6,500	162.5	26.1%
LDC 11 Converted	Natural Gas	60	6,000	360.0	38.7%(***)
Combined Cycle	Natural Gas	290	6,000	1,740.0	53.0%(***)
Total		510	6,049.0(**)	3,085.0	

Notes: (*) Average Generation Capacity is derived form the Availability and Installed Capacity assumptions.
(**) Represents a weighted average.
(***) Assumptions are based on industry averages.

Obviously, another important source of electricity for the Cuyo region is the WEM. Table 13 summarizes the assumptions about the only WEM link to the Cuyo region.

Table 13: Assumptions about the WEM Link

Link	Installed Capacity (MW)	Availability (Hrs/yr)	Average Transmission Capacity (GWh/yr) (*)
Cruz de Piedra	540	8,760.0	4,730.4

Note: (*) Average Transmission Capacity is derived form the Availability and Installed Capacity assumptions.

The model assumes that the link is available 100% of the time. This is somewhat of an unrealistic assumption. As energy transmission gets closer to its physical limit, the probability of failure increases, and thus the expected availability is less than 100%. This assumption introduces, then, a bias by underestimating the need for local generation capabilities. However, this relationship between risk of failure and actual energy transmission was ignored because it is very difficult to estimate it as it would take a model of the entire WEM transmission system to do it.

B.1.6.2 New Supply Sources

The analysis performed takes into account a set of different new generation alternatives. These include new hydroelectric plants, new thermal plants and new transmission capabilities. The new hydroelectric plants considered are those projects under study by the Mendoza province mentioned in Chapter I. Table 14 summarizes the information about these projects

Table 14: Assumptions about Hydroelectric Projects

Project	Capacity (MW)	Average Energy Generated per year (GWh)	Capacity Factor (*)	Capital Costs (US$ MM)	Capital Costs (US$/KW)
Los Blancos	324	900	0.32	200	617
Cacheuta - Potrerillos	131	490	0.43		
A. Condarco - Potrerillos	54	270	0.57	300(**)	1,622(**)
El Baqueano	180	460	0.29	120	667
Portezuelo del Viento	223	978	0.50	250	1,121

Notes: (*) Capacity Factor is derived from Average Energy Generated per Year and Capacity.
(**) Represents total for Potrerillos as a whole.

With regard to new thermal projects, the model assumes that they will all involve combined cycle units using natural gas as fuel. Indeed this is an industry trend. The capacity of the new projects is varied within the Multi-Attribute Trade-Off Model. The assumptions related to thermal plants are listed in the table below.

Table 15: Assumptions about New Thermal Plants

Thermal Plant Type	Fuel Type	Availability (Hrs/yr)	Fuel Efficiency	Capital Costs (US$/KW)
Combined Cycle	Natural Gas	6,000	53.0%	800

Finally, the model considers three different new transmission alternatives: (i) a stronger Cruz de Piedra-WEM link, (ii) a new transmission line to Chile, and (iii) a new transmission line to the Comahue region to the south of the Mendoza province. The assumptions about these projects are listed below.

Table 16: Assumptions about New Transmission Projects

Link	Installed Capacity (MW)	Availability (Hrs/yr)	Average Transmission Capacity (GWh/yr) (*)	Capital Costs (US$/KW)
Stronger Cruz de Piedra Link	400(**)	8,760	3,504.0(**)	10
New Chile Line	161	8,760	1,410.4	559
New Comahue Line	500	8,760	4,380.0	230

Notes: (*) Average Transmission Capacity is derived from Availability and Installed Capacity.

Strengthening the current link is relatively inexpensive because it involves the addition of new capacitors to the line and not much construction. These numbers have been provided by the UNC personnel in Mendoza. According to them, the Chile link is small because of some protocol constraints between the two countries. It is worth noting that, as in the case of current transmission capacity, the model assumes that new transmission projects are available 100% of the time.

B.1.7 Assumptions about Pollutant Emissions and Coefficient of Losses

The model calculates the amount of pollutants emitted by existing and new thermal plants. The amount emitted per type and amount of fuel is listed below.

Table 17: Assumptions about Emissions (lb/10E9 of Natural Gas and lb/Tonne of Fuel Oil)

Type of Fuel	Hydrocarbons	NOx	SOx(*)	CO	Particulate
Natural Gas	42	413	940	115	14
Fuel Oil	1.50	18.26	3,771.04	4.15	1.35

Source: The U.S. Environmental Protection Agency (EPA), Report AP-42: Compilation of Air Pollutant Emission Factors
Notes: (*) Sulfur emissions are calculated in the following manner: If the factor is 940 (natural gas case) and the sulfur content is 0.001%, sulfur emissions equal 940*0.001, or 9.4lb/10E9 Btu of natural gas.

The model needs assumptions to determine the transmission losses from the generation units to the Cruz de Piedra node, and from the Cruz de Piedra node to the demand nodes. Transmission lines within the Cuyo region have been divided into three types: (i) high voltage lines, (ii) medium voltage lines, and (iii) low voltage lines. Roughly these types correspond to the following voltage ranges:

High voltage:	132kV-550kV
Medium voltage:	13kV-132kV
Low voltage:	0.22kV-13kV

Each line from Cruz de Piedra to either a generation plant or a demand node is assumed to be one of these types, and thus has the associated transmission loss coefficient. The coefficients were estimated using EMSE's loss data by type of line. These assumptions are summarized below.

Table 18: Assumptions about Transmission Line Losses

Line from Cruz de Piedra to ...	Type of Line	Coefficient of Losses
HINISA	High Voltage	2.4%
HIDISA	High Voltage	2.4%
Nihuil IV	High Voltage	2.4%
Hidroelectrica Mendoza	Medium Voltage	6.2%
CTMSA	Medium Voltage	6.2%
New Thermal Plants	Medium Voltage	6.2%
Los Blancos	Medium Voltage	6.2%
Potrerillos	Medium Voltage	6.2%
El Baqueano	High Voltage	2.4%
Portezuelo del Viento	High Voltage	2.4%
Agricultural Demand Node	Medium Voltage	6.2%
Industrial Demand Node	Medium Voltage	6.2%
Commercial Demand Node	Low Voltage	16.3%
Residential Demand Node	Low Voltage	16.3%
Other Demand Node	Low Voltage	16.3%

The model does not take into account the transmission losses from the WEM, as the WEM price incorporates already the node factor and as Cruz de Piedra (the connection with the WEM) acts as the reference node.

B.2 The Multi-Attribute Trade-Off Model

The smaller and simpler Multi-Attribute Trade-Off Model is divided in two: (i) Futures, and (ii) Scenarios. Futures embody the uncertainties related to the planning exercise, and thus represents those variables that are beyond the control of the policy maker. Scenarios, on the other hand, embody the variables that are controlled by the policy maker. In the present context, the uncertainties were identified to be: (i) evolution of demand, (ii) evolution of WEM prices (energy and capacity), (iii) evolution of fuel prices, (iv) the discount rate and (v) the impact of a Chile line on WEM prices. This last uncertainty is measured as the ratio of the WEM price with a Chile line and the WEM price without the Chile line. It is expected that, because of the heavy Chilean reliance on cheap hydroelectric energy and the one hour lag between the two countries peak times, the WEM price would be lower with a Chile line than without. Also, it is important to note that the model assumes that part of the natural gas transmitted in the Gas Andes pipeline is available for consumption in the Cuyo region. Relative prices of natural gas are used to indicate whether the transportation capacity of the line is becoming small relative to demand in the region.

In contrast, the variables controlled by the policy maker are the different new energy source alternatives described above. In particular these variables are: (i) the capacity of new thermal plants and the time they enter into service, (ii) the time new hydroelectric plants enter into service, and (iii) the time new transmission capabilities enter into service.

Each Future assumes a pattern or a value for each of the uncertainties. Within each Future, the same fifteen Scenarios are run using the Energy Balance Model incorporating the assumptions of both the Future and Scenario in question. Each Scenario is run for the 1997-2027 period. The fifteen Scenarios run within each Future are summarized below.

Table 19: Summary of the Fifteen Scenarios Considered

	Year that Project enters into Service							
Scenario	Los Blancos	Potrerillos	El Baqueano	Portezuelo del Viento	Stronger Link	Chile Link	Comahu e Link	New Thermal
1	--	--	--	--	--	--	--	--
2	--	1997	--	--	--	--	--	--
3	--	--	--	--	--	--	--	375MW in 1997
4	1997	--	--	--	--	--	--	--
5	--	--	1997	--	--	--	--	--
6	--	--	--	1997	--	--	--	--
7	--	--	--	--	1997	--	--	--
8	--	--	--	--	--	1997	--	--
9	--	--	--	--	--	--	1997	--
10	--	--	--	--	1997	--	--	375MW in 2000
11	--	2000	--	--	1997	--	--	--
12	2000	--	--	--	1997	--	--	--
13	--	--	--	--	1997	2010	--	400MW in 1997
14	--	--	--	--	1997	2010		400MW in 1997 and 200MW every year beginning 2013
15	--	--	--	--	1997	--		400MW in 1997 and 200MW every year beginning 2010

The first 9 scenarios represent each new electricity source on its own. It is worth mentioning that Scenario 3 has a capital cost equal to that of the Potrerillos project. The next seven Scenarios represent a combination of those alternatives that have consistently dominated the others. Please refer to the discussion of the Base Case Future results for an explanation of the selected combinations.

Within each Future, the fifteen different Scenarios are compared on their performance according to different attributes. There are 11 attributes identified to be relevant for this analysis. These are:

- Percentage of Energy Demand not Met over the 30 year analysis period. A positive value would mean during a year, the region would on average experience some brownouts and blackouts.
- Percentage of Energy Demand Met with High Cost Plants (i.e. Thermal Plants with a marginal cost higher than the WEM price). Again, high cost plants will get dispatched only if there are transmission constraints in the importation of energy.
- Percentage of Energy Demand Met with Importations from WEM.
- Particulate Emissions
- NOx Emissions
- SOx Emissions
- Hydrocarbons Emissions
- CO Emissions
- Net Present Value of Net Energy Revenues (Sales - Purchases of Energy). A positive value would represent an energy trade surplus (in dollar terms) with the WEM and thus an influx of money to the region.[7]
- Net Present Value of Net Capacity Revenues (Capacity Remunerations - Capacity Payments). By the same token, a positive value represents a trade surplus in capacity dispatched.
- Scenario NPV. Scenario revenues include energy and capacity dispatched remuneration. Scenario costs include capital and fuel costs.
- Scenario IRR

[7] This is based on electricity trade with the WEM only. Other sources of energy (e.g. fuel oil and natural gas) are excluded from this figure as it was difficult to determine the quantities of fuel produced in the Mendoza region, and those imported.

It is important to note that because the Energy Balance Model does not take into account any of the transmission charges, NPV and IRR for those Scenarios involving only new transmission projects are not available.

How each Scenario ranks on these different attributes is determined by the Energy Balance Model. This data is used to generate the Multi-Attribute Trade-Off Curves that form the core of the analysis. Chapter III presents the results of the multi-attribute trade-off analysis.

Chapter III: Results and Recommendations

This chapter first presents the results of the Base Case Future and explains them in detail. Later, it evaluates whether the conclusions drawn from the Base Case Future still hold in the other Futures studied. Finally, the chapter draws some final conclusions about the analysis and makes final recommendations about the most efficient and robust strategy to meet future energy needs in the Cuyo region. The analysis seeks to answer three main questions: (i) is not doing anything an attractive alternative, (ii) is any of the hydroelectric projects, in particular Potrerillos, worth implementing, and of course (iii) what is the most efficient and robust alternative.

A. Base Case Future Results

A.1 Future Assumptions

The assumptions of the Base Case Future with regard to the variables that are beyond the control of policy makers are described below.

A.1.1 Demand

Demand is separated into 5 different groups. Each group is assumed to start the analysis period with a demand equal to that of 1993 for both the Mendoza and San Juan provinces.

Agricultural Demand

It is assumed to remain constant over the 30 year period.

Industrial Demand

It is assumed to remain constant until 2001, and to start growing at a 5% annual rate beginning in the year 2002 until the end of the analysis period.

Residential, Commercial and Other Demand

These three types of demand are assumed to grow at a 5% annual rate over the entire analysis period.

These assumptions are optimistic in the sense that demand is expected to grow between 3% to 4% a year. Nevertheless, it is not inconceivable that demand will not grow at an average of 5% considering the high Argentine and regional demand growth during the 1990s. Also, this Base Case Future assumes that Agricultural demand has reached a plateau and it is not going to vary at all. Indeed, agricultural energy demand is expected to grow very little or nothing in the future.

A.1.2 Prices

Prices are assumed to have a long term upward trend as described below.

WEM Prices

These are assumed to start at US$ 30/MWh in 1997, decrease at a rate of 6% per year until year 2000, and increase at a rate of 1% per year beginning in 2001 until the end of the analysis period. This assumption is consistent with CAMMESA's forecasts. Over the short run, prices are expected to decrease as new cheap capacity (in particular Yacyreta) becomes operational. Over the medium and long term, prices are expected to grow as demand increases. The increase over the long run should not be very steep as Yacyreta will still be an important source of energy.

Fuel Prices

The price of natural gas is assumed to start at US$ 1.9/MMBtu, and increase at a rate of 1.5% per year for the entire analysis period. The price of fuel oil, on the other hand, is assumed to start at US$ 152/tonne, and increase at a rate of 1.0% per year. That is, the relative price of natural gas is assumed to go up over the 30 year period. This is indeed consistent with a worldwide trend. First, natural gas is increasingly becoming more valuable as it is more environmental friendly and the technology for natural gas fired plants has improved substantially. Second, the increasing relative price of natural gas may also be a signal of the availability of both fuels in the Cuyo region. The Gas Andes pipeline capacity may prove to be insufficient to supply both the Chilean market and the Cuyo region market. This would result in a higher price for natural gas. This effect, however, is smoothed out over the 30 year period and does not correspond to spikes over short periods of time.

Capacity Prices

As mentioned before, the price for dispatched capacity is fixed by the Secretariat of Energy. It has been set at US$ 10/MW per weekday-off-valley hours in 1994. The Basic Future Case assumes that this price will be kept until 1999, and will decrease to US$ 8/MW per weekday-off-valley hours beginning in the year 2000 until the end of the analysis period. This assumption is consistent with industry expectations.

A.1.3 Impact of Chile Line on WEM Prices

It is assumed that WEM will be 10% lower as a result of a Chile link. This assumption might be high, considering the size of the Chilean market relative to the Argentine market.

A.1.4 Discount Rate

It is assumed that the prevailing discount rate is 12% per year. This rate is assumed to remain constant over the entire analysis period. This rate might be in the lower range of discount rates used in the Cuyo region.

A.2 Analysis of Results

Base Case Future results are summarized in Table 20. The resulting Trade-Off Curves are shown in Appendix B, together with a more complete table of results.

Table 20: Summary of Base Case Future Results

Scenario	% of Demand... ... not Met	... Met with High Cost Plants	... Met with WEM	NOx Emissions (MM lb)	Net Present Value (US$ MM) Net Energy Revenues	Net Capacity Revenues	Scenario	First Year with Unmet Demand
1	5.52	2.21	32.87	249.62	(223.0)	111.9	--	2021
2	4.08	1.90	29.41	245.64	(86.4)	156.9	(59.1)	2022
3	0.98	0.97	19.78	419.25	349.0	243.8	82.1	2025
4	3.22	1.66	27.15	242.67	10.4	182.7	86.8	2023
5	4.21	1.92	29.73	245.92	(98.0)	148.5	32.1	2022
6	2.97	1.61	26.45	242.02	38.9	189.1	71.1	2023
7	0.00	0.26	40.34	224.65	(161.3)	110.6	--	--
8	0.00	0.00	40.59	221.36	(152.8)	110.4	--	--
9	2.05	1.34	37.20	236.80	(193.2)	109.2	--	2024
10	0.00	0.00	21.73	388.85	207.2	198.0	29.5	--
11	0.00	0.03	35.36	221.76	(70.4)	140.1	(53.4)	--
12	0.00	0.00	32.04	221.36	(8.8)	157.5	48.8	--
13	0.00	0.00	20.75	419.16	411.1	252.1	66.8	--
14	0.00	0.00	0.00	802.00	642.1	305.2	(3.9)	--
15	0.00	0.00	0.00	964.71	822.7	340.3	36.5	--

The first observation that can be drawn from the above table is that the Cuyo region will not face a drastic problem of unmet demand over the medium term. Indeed, according to the results, if no new sources of energy supply are put in service, there will be unmet demand starting on the year 2021, more than twenty years hence. However, it is very important to point out that the model is on a yearly basis and not on an hourly basis. Thus, it is likely that there will be unmet demand during peak hours prior to the year 2021. Furthermore, the model does not take into account the increased probabilities of transmission failure as the WEM link reaches its capacity. Therefore, the expected first year of unmet demand is earlier than the year 2021. Nevertheless, in this Base Case Future, the Cuyo region is not likely to suffer unmet demand at least for the medium term. This should give policy makers sufficient time to study and implement a coherent plan to face this problem.

The second observation that can be drawn is that not doing anything right now is not the best solution. As noted above, new sources of energy must be put in service at some point in the future to face the unmet demand problem. However, the sooner a plan is implemented, the better. The above table shows that not doing anything immediately (i.e. Scenario 1) is clearly dominated by more than one scenario in every attribute. For instance, the Cuyo region is clearly better off by building Los Blancos immediately than by not doing anything. That is, the fact that there is no unmet energy yet should *not* serve as an excuse for policy makers for not doing anything right away[8].

Also, the Potrerillos hydroelectric project (Scenario 2) is the least attractive among the hydroelectric projects. (Scenarios 2,4,5 and 6) in terms of financial returns. Potrerillos is the only hydroelectric project with a negative Net Present Value. Also, among hydroelectric projects, Potrerillos ranks second to last on every attribute. Clearly, at least from an energy perspective, the Potrerillos project is not worth implementing only on the basis of the alternative hydroelectric projects. Moreover, as a comparison, Scenario 3 represents a 375MW thermal plant with a capital cost equal to that of Potrerillos. This thermal plant ranks higher than Potrerillos in every attribute except, of course, total emissions. Obviously, there might be some other non-energy related benefits not incorporated in the model that make Potrerillos worth implementing. The other part of the MIT-UNC project precisely deals with this issue.

Among the hydroelectric projects, Los Blancos and Portezuelo del Viento are clearly the most attractive. Both projects rank very close to each other on most of the attributes, with Los Blancos having a higher NPV and IRR. In the analysis that follows, both projects will be assumed to be equivalent and will be run using Los Blancos numbers.

[8]Of course, a decision to implement one of the Scenarios right now should be weighted against alternative uses of that money in other sectors (e.g. transportation, etc.) However, it is clear that implementing one of the scenarios right now should be given considerable attention, and not be delayed on the basis of the non-urgency of the problem.

New transmission capabilities also seem to be very attractive alternatives. The three transmission scenarios (Scenarios 7,8 and 9) and in particular a stronger WEM link and a new Comahue line (7 and 8, respectively) clearly offer some advantages, relative to hydroelectric projects, with regard to emissions, unmet energy and energy met with high cost thermal plants. This, however, comes at the expense of higher dependency on the WEM and higher energy trade deficits. Among the transmission scenarios, a stronger WEM link and the Comahue line clearly dominate the Chile link. Furthermore, the first two are very close to each other in every attribute. But, because strengthening the current link involves much lower capital costs than building a new Comahue line, the stronger link Scenario is assumed to dominate the Comahue line Scenario.

The above analysis leaves three undominated scenarios among the first nine: a 375MW thermal plant (Scenario 3), Los Blancos (Scenario 4) and a stronger WEM link (Scenario 7). The next 6 scenarios combine the alternatives in the first nine scenarios. The aim of Scenarios 10 to 15 is to determine whether a combination of alternatives dominates any of the pure alternatives. It is important to note that combination of only the three scenarios identified above are considered without risk of ignoring more attractive combinations because the Utility Independence Axiom is assumed to be true. This axiom states that the ranking of alternatives is a concave set. That is, if each of two alternatives are mixed with a third one, then the preference ordering of the two resulting mixtures does not depend on (i.e. is *independent* of) the particular third alternative used. This axiom is illustrated by Scenario 11 (a stronger link and Potrerillos) and Scenario 12 (a stronger link and Los Blancos). As mentioned before, Scenario 4 (Los Blancos) completely dominates Scenario 2 (Potrerillos). Thus, consistent with the Utility Independence Axiom, Scenario 11 is dominated by Scenario 12. Using this axiom, then, allows the safe disregard of combinations involving dominated alternatives.

Also, some of the combination scenarios include a Chile link, although this alternative is dominated by others. The reason a Chile link is included is because its construction most likely depends on federal Argentine policy, and as such the Mendoza control over this project is most likely to be limited. The scenarios assume that a Chile link is not likely to be built in the very near future. Rather, if it is to be built, it is assumed it will enter into service in the year 2010.

From the above table, there is an advantage to combining the different alternatives. For instance, if scenarios 3 and 10 are compared, the latter is less prone to have unmet demand problems as well as less emissions.[9] This, however, comes at a cost of higher dependency on the WEM as there is more importation capabilities. The same conclusion is reached if scenarios 4 and 12 are compared. There is less emissions with a stronger link as it would eliminate transmission restrictions, and thus high cost thermal plants (in particular the heavy pollutant CTMSA fuel oil unit) would not be dispatched. Again, this comes at the expense of higher dependency on the WEM.

Adding a Chile link does not add much. It would definitely help in the stability of the system (not incorporated in the model), but it does not help much with regard to emissions and the energy trade surplus for the region.

In sum, it seems that the best alternative is to strengthen the link in the short run, so as to add more stability to the system and avoid transmission constraints. Over the medium term, some new plants will have to be incorporated. From the above analysis it seems that the choice should be between thermal plants and either Los Blancos or Portezuelo del Viento. Both thermal plants and either of the hydroelectric projects have their benefits and drawbacks. A thermal plant would mean higher energy trade surpluses as the energy capabilities are higher than with hydroelectric projects. This of course, comes at the expense of higher emissions. In any case, however, it is clear that Potrerillos

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[9]It is very important to note that the two scenarios are not quite comparable. Scenario 3 has the thermal plant in operation beginning in 1997, whereas Scenario 10 has it operational beginning in 2000. However, Scenario 10 is expected to have less emissions if the thermal plant is operational in year 1997 because it would still not have any of the high cost plants being dispatched, as Scenario 3 does.

should not be built from an energy point of view. Both the Los Blancos and Portezuelo del Viento scenarios involve higher financial returns, less emissions, higher energy trade surpluses and less problems with unmet demand. If Potrerillos is to be built, there has to be other benefits not incorporated in this model that would compensate for its shortcomings.

B. Other Futures

Seven other futures were run in addition to the Base Case Future. Please refer to Appendix C for the results of each future, and the Trade-Off curves of each future.

B.1 Assumptions

Each future represents different assumptions about the uncertainties described above. In the seven other futures run, emphasis was given on varying demand and prices growth, and not much on the Chile line effect or the discount rate. However, the Chile effect took three different values, measured as the ratio between the resulting WEM price with a Chile link over the WEM price without the link, (0.95, 0.99 and 1.0). The discount rate also took three different values (12%, 10% and 14%). It is important to note that, as in the Base Case Future, demand in 1997 is equal to that of the entire Cuyo region for 1993, in every sector of demand. Please refer to Table 21 for a summary of the different assumptions taken in each future.

B.2 Results

The conclusions drawn for the Base Future Case effectively hold for all the other seven futures considered. These are described in the following paragraphs.

Table 21: Other Futures Assumptions

Future	Demand Growth Rates: Agricultural	Industrial	Residential	Commercial	Other	Chile Line Effect on WEM Prices	Discount Rate
2	4% until 2027	0% until 2001 4% from 2002 on	4% until 2027	4% until 2027	4% until 2027	0.95	12%
3	1% until 2027	0% until 2001 6% from 2002 on	6% until 2027	6% until 2027	6% until 2027	1	12%
4	0% until 2027	0% until 2001 5% from 2002 on	5% until 2027	5% until 2027	5% until 2027	0.95	14%
5	1% until 2001 0% from 2002 on	0% until 2001 5% from 2002 to 2010 3% from 2010 on	5% until 2005 3% from 2006 on	5% until 2005 3% from 2006 on	5% until 2005 3% from 2006 on	0.95	10%
6	0% until 2027	0% until 2001 1% from 2002 on	1% until 2027	1% until 2027	1% until 2027	0.95	12%
7	2% until 2027	0% until 2001 8% from 2002 on	8% until 2027	8% until 2027	4% until 2027	0.95	12%
8	0% until 2027	0% until 2001 10% from 2002 on	10% until 2027	10% until 2027	4% until 2027	0.99	12%

Future	Prices in 1997: WEM	Natural Gas	Fuel Oil	Capacity Prices (*)	Prices Growth Rates: WEM	Natural Gas	Fuel Oil
2	US$ 28/MWh	US$1.72/MMBtu	US$152/tonne	US$10 until 2000 US$8 from 2001 on	-2% until 2000 1% from 2001 on	1.5% until 2027	1% until 2027
3	US$ 28/MWh	US$1.72/MMBtu	US$152/tonne	US$10 until 2000 US$8 from 2001 on	2% until 2027	0% until 2027	0% until 2027
4	US$ 28/MWh	US$1.72/MMBtu	US$152/tonne	US$ 10 until 2027	1% intil 2005 2% from 2006 on	0% until 2005 1.5% from 2006 on	0% until 2005 1% from 2006 on
5	US$ 28/MWh	US$1.72/MMBtu	US$152/tonne	US$ 10 until 2027	2% until 2005 1% from 2006 on	0% until 2002 1% from 2003 on	0% until 2027
6	US$ 28/MWh	US$1.72/MMBtu	US$152/tonne	US$10 until 2002 US$8 from 2003 on	1% intil 2027	0% until 2002 1% from 2003 on	0% until 2027
7	US$ 30/MWh	US$1.72/MMBtu	US$152/tonne	US$10 until 2000 US$8 from 2001 on	3% intil 2000 2% from 2001 on	2% until 2027	1.5% until 2027
8	US$ 28/MWh	US$1.72/MMBtu	US$152/tonne	US$10 until 2002 US$8 from 2003 on	3% until 2027	2% until 2027	1% until 2027

(*) Price in US$ per MW per Weekday-Non-Valley Hours

All futures indicate that the unmet demand problem is not one that needs immediate and urgent solutions. Indeed, the earliest appearance of unmet demand is the year 2016, corresponding to Future 8, with the highest demand growth. Again, it is important to note that brownouts and blackouts might occur during peak hour times prior to 2016, not captured by the model as it is run on a yearly basis. Nevertheless, even with such an unrealistic high demand growth assumption, it is not expected that the Cuyo region will experience unmet demand problems over the medium term.

All futures show that Potrerillos is completely dominated by both Los Blancos and Portezuelo del Viento in every attribute. However, as demand growth increases, these three scenarios tend to be equivalent with respect to emissions. This is indeed what is expected. As demand growth increases, transmission constraints occur more frequently and local generation might not be sufficient to meet demand. Thus, all thermal units end up being dispatched in the three scenarios, emitting the same amount of pollutants. However, it is the case that both Los Blancos and Portezuelo del Viento are ranked higher in dependency on WEM electricity, unmet demand, demand met with high cost, and trade surplus with WEM simply because Potrerillos generates less electricity than any of the other two. Furthermore, Potrerillos in all futures except for Future 5, shows a negative NPV while the other two always show positive NPVs. The low discount rate (10%) is the reason why Potrerillos shows in Future 5 a positive return, although it is still lower than that of the other two projects. Among the hydroelectric projects, Los Blancos and Portezuelo del Viento are again the most attractive and rank pretty much the same on every attribute.

The trade-off between lower emissions with hydroelectric projects on the one hand, and lower dependability on the WEM, lower levels of unmet demand and higher energy trade surpluses with thermal projects, on the other hand, is again present in these futures. One difference with the Base Case Future, however, is the higher NPV of thermal plants relative to either Los Blancos or Portezuelo del Viento in every future. The reason for this difference is the higher prices seen on average throughout the analysis period on these futures relative to the Base Case Scenario. The thermal plant considered (i.e. a 375MW plant) has more opportunity to capitalize on higher prices as its generation capabilities are much bigger than those of either hydroelectric project. This opportunity definitely compensates the advantage of Los Blancos and Portezuelo del Viento over thermal projects with regard to capital costs per MW installed.

A stronger link also seems to dominate the other two transmission alternatives. The lower capital cost involved is definitely one of the main reason for its dominance. Moreover, all futures show the Utility Independence Axiom to be true, and thus, without risking to loose attractive combinations, the interesting combinations involve Los Blancos, a stronger link and a thermal plant. Again, in futures when demand does not grow very rapidly, the choice seems to be between a stronger link and a thermal plant, on the one hand, and a stronger link and Los Blancos on the other hand. However, when demand does grow substantially, the most attractive case is a stronger link with many new thermal plants. Building a Chile line does not seem to alter the choices.

In sum, all these futures show a clear trade-off between high dependency on WEM and bigger trade surplus, on the one hand, and lower emissions on the other. Because of bigger generation capacities, thermal plants seem to answer best concerns about dependency on WEM, unmet demand and demand met with high cost thermal plants. Hydroelectric plants, in contrast, seem to answer best concerns about pollutant emissions as the electricity generation does not involve any fossil fuel at all. However, there might be some other environmental impacts associated with hydroelectric plants, ignored by this model that would tip the balance in favor of thermal plants.

It seems from the analysis that the discount rate does not affect neither the trade-off present nor the ranking of the alternatives considered, as it applies in the same manner to each scenario. In contrast, although prices and the Chile line impact on WEM prices do not seem to affect the trade-off, they do seem to affect the ranking of the scenarios depending on the relative utility of the region with regard to the attributes. As WEM prices go up relative to fuel prices, more thermal plants are dispatched (in particular the more pollutant one such as the fuel oil units), and thus the amount of emissions increases. This makes hydroelectric projects more valuable relative to thermal plants with the same capital cost. However, at the same time, as WEM prices go up there is more opportunity for thermal plants to capitalize on the higher prices as they can generate more electricity and thus obtain higher returns than hydroelectric projects. If returns are valued more than emissions, then clearly the choice should be for thermal plants. The converse holds if emissions are more valuable. The same is true if we consider the Chile line effect on the relative ranking of these scenarios. As the Chile line effect increases, WEM prices decrease. This impact, then, would work in the opposite direction of a direct increase in prices. Changes in demand also seems to affect the ranking of the scenarios. As demand increases, new thermal plants become more valuable as they are able to generate more electricity than hydroelectric plants and thus result in less dependency on the WEM. Again, this benefit comes at the expense of higher emission levels. The ranking of these alternatives would depend on the relative valuation of emissions vis-à-vis dependency on the WEM. Relative valuation of the attributes is crucial for final decision about which alternative to implement.

C. Recommendations

In the short run, the aim of any regional energy policy should be to eliminate the transmission constraints currently being experienced. Because of its yearly nature, the model does not capture these constraints on a real time basis. Over the long run, the aim of any energy policy should be to meet the growing energy demands with the most efficient and robust alternatives. The above analysis definitely provides some answers to these aims. In the short run, the most attractive alternative to answer the transmission constraint problem is definitely strengthening the current WEM link. This solution will definitely provide the region with a quick, economical and environmentally clean answer. However, it might also worsen the region dependency on the WEM, and worse, on its dependency on one single line. Should the line fail, the energy consequences for the region could be dire as described earlier. The risk of failure will increase with the growing demand, as the enhanced lines will reach its transmission capacities, and the transmission constraints problem will arise once again.

In order to reduce this drawback, new generation capabilities or new transmission lines should be built over the medium term. It seems that on the transmission side, the most attractive project is a Comahue line, as it involves lower capital costs than a Chile line as well as larger transmission capacity. On the new generation side, the choice is between new combined cycle thermal capacity and new hydroelectric capacity, in particular Los Blancos and/or Portezuelo del Viento. The model presented here has the limitation of not fully evaluating the Comahue line as its revenues were not taken into account. Thus, a full comparison between new generation capacity and the Comahue line was not performed. However, should building new generation capabilities be the solution, the model clearly shows a trade-off between new thermal and the hydroelectric project mentioned. A decision between the two should depend on the relative valuation of emissions and dependency on the WEM, as explained earlier.

In any case, under the assumptions of the model, Potrerillos should not be built based on energy considerations alone. The Los Blancos and Portezuelo del Viento clearly represent better alternatives, partly because of their lower capital costs. But even if capital costs were equal, Potrerillos would still rank lower because of smaller generation capabilities. Potrerillos can prove to be an attractive alternative only be if other benefits (or costs in the other alternatives) not incorporated in the model compensate for the shortcomings. These could include irrigation benefits, tourism, etc.

It is important to note that it is best if there is a time delay between strengthening the link and building new generation capacity. The size of new generation plants should depend on how demand grows. A stronger link should eliminate transmission constraints for some time. New generation capacities should be built only as transmission restrictions on the stronger link resurface.

In sum, the above analysis yield the following recommended steps to be taken by the Cuyo region as part of a comprehensive energy planning policy:

- Strengthen the link over the short run.
- Over the medium term to long term, build new thermal plants and/or the hydroelectric projects Los Blancos and Portezuelo del Viento, as a function of how demand in the region is evolving and how it affects the risk of transmission failure. Which of the two types of plants is more efficient for the region depends on the relative valuation of emissions and dependency on the WEM
- Potrerillos should not be built under the assumptions of the model.

Finally, these recommendations do, of course, depend on the assumptions and limitations of the model. In particular, they depend on the following: (i) thermal and hydroelectric plants are assumed to operate primarily during weekday-off-valley hours, (ii) transmission charges have been ignored all together, (iii) transmission lines are assumed to operate 100% of the time and probabilities of transmission failure has been ignored, and (iv) hydroelectric plants do not have any environmental impacts. The following paragraphs described how these assumptions and limitations have influenced the recommendations drawn from the multi-attribute trade-off analysis.

First, as mentioned in Chapter II, the assumption of operation primarily during weekday-off-valley hours introduces a bias in favor of hydroelectric plants. Indeed, hydroelectric plants are more likely to be dispatched during non weekday-off-valley hours than thermal plants. This assumption, then, tends to increase the return of hydroelectric projects relative to thermal plants because of capacity dispatched remuneration. This assumption does not alter the above recommendations much. It lessens, however, the financial return advantage of thermal plants relative to hydroelectric projects, and thus could have somewhat of an impact in weighting the trade-offs associated with these two types of plants.

Second, the exclusion from the model of transmission charges did not allow for a full comparison between a Comahue line and other alternatives. Comahue could very well be as attractive as a thermal plant or Los Blancos. It is important to note, however, the exclusion of transmission charges did not affect our recommendation of strengthening the current WEM. Given the low capital costs and the low environmental impact involved, this alternative is definitely the most attractive in the short run. As explained above, other steps must be taken over the medium term in order to compensate for its drawbacks.

Third, by ignoring probabilities of transmission failures, the model effectively introduced a bias in favor of transmission lines. Incorporating these probabilities would mean lower expected transmission capacity thereby reducing the relative ranking of transmission projects. Again, because strengthening the current link is such an obvious choice over the short run, the incorporation of probabilities of transmission failures would be relevant only for the comparison between Comahue and the other alternatives. The same arguments hold for the incorporation of maintenance hours and the operation of the transmission lines for less than 100% of the time.

Fourth, the above recommendations are definitely sensitive to environmental impacts assumptions of the different scenarios. Incorporating environmental impacts for hydroelectric projects could really tip the balance off in favor of thermal plants. Indeed, the only benefit of Los Blancos and Portezuelo del Viento relative to thermal plants is the low level of emission associated with them. By the same token, by including other benefits, alternatives discarded on the basis of this analysis can prove to be very attractive. One such alternative is, of course, the Potrerillos hydroelectric project, which might be very attractive on the basis of irrigation benefits. In such a case, of course, the implementation of the Potrerillos project would depend on the relative valuation of energy (considered in this analysis) and irrigation criteria.

Lastly, all the results presented here depend on the numerical assumptions as well. The numbers used here were provided by the Province of Mendoza. In order to simplify the analysis, sensitivity analysis was performed only on demand and prices. Capital costs and generation capacity of new projects were assumed to be correct. Varying these might, of course, alter the recommendations. One example is the low capital cost of Los Blancos; on a per MW installed basis, Los Blancos costs less than thermal plants. Increasing Los Blancos capital costs might yield negative present values, and thus tip the trade-off balance in favor of thermal plants.

Conclusions

The recommendations presented here are based on energy considerations only. They do not incorporate any benefits and costs associated with other economic activities, such as irrigation and tourism. It is in this context that the analysis of this thesis should not be taken as final. The water part of this MIT-UNC collaboration project deals with the irrigation component of hydroelectric generation projects, in particular the Potrerillos project.. Taking this study into consideration might lead to the conclusion that Potrerillos is indeed the best alternative available to meet future energy and water demands in the region. This is not to say that this analysis is not valuable. On the contrary, the results of this multi-attribute trade-off analysis can prove very valuable both for private investors and for regional policy makers alike.

On the one hand, private investors can use the information provided by this analysis to reevaluate their models and investment strategies. For instance, this analysis reveals that thermal plants in the Cuyo region are associated with reasonable investment returns. Private investors could have overseen this in their investment strategies, and thus the results would push to reevaluate their assumptions and consider investing in the Cuyo region. This example illustrates that making new information available is never harmful.

On the other hand, this analysis will probably be more valuable for regional policy makers. First, the analysis clearly ranks the different projects that the government of the Province of Mendoza plans to implement. The analysis identifies those alternatives with the highest "bang for the buck", that is, those with the highest benefits and the least costs. Second, the analysis clearly points out a trade-off between emissions and dependency on the rest of country. Depending on the region's valuation of these attributes, the policy maker can design incentives to guide private investors decisions to the those alternatives that the analysis has identified as the most efficient and robust. For example, if emissions are to be avoided at all costs, the region would be better off if hydroelectric plants are built rather than thermal plants, even though the latter might rank better on the less valuable attribute of dependency on the rest of the country. However, private investors might guide their decisions based on investment returns only in which case they would prefer investing in thermal plants than in environmentally friendlier hydroelectric plants. This would mean that the market, left on its own, would dictate suboptimal solutions for the region despite the fact that thermal plants might considerably reduce the region's dependency on the WEM. This not only illustrates the concept of incomplete markets but also the value of multi-attribute analysis. Private investors do not have an incentive to select hydroelectric plants because emissions is not part of the investment return equation. The analysis in this thesis can provide some ideas as to how to include the emissions externality. For example, taxes on emissions can be included in the model so as to evaluate their effect on the relative investment returns of thermal plants. With the right tax and other incentives, private investors might find worthwhile to build hydroelectric rather than thermal plants. In sum, the above discussion illustrates the value of the multi-attribute trade-off analysis in the context of deregulated markets.

It is important to note that the results in this thesis should not be taken as final. Despite the limitations of the models, the results presented here give a good understanding of the different issues at stake. The models developed for this thesis are a solid start, but enhancement work has to be done before the results of the multi-attribute trade-off analysis can be incorporated into policies. As was stated in the introduction, it is expected that UNC professionals engage in this exercise, once they understand the methodology. The models in this thesis need enhancements primarily in three different areas: (i) transmission system assumptions, (ii) environmental impact assumptions, and (iii) non-energy issues. First, in order to fully compare the transmission alternatives with thermal and hydroelectric alternatives, the model needs to incorporate the different transmission remunerations. This includes not only energy charges, but capacity and connection charges as well. The model would also benefit from the incorporation of transmission failure probabilities. A simple WEM model will have to be developed in order to incorporate these items into the model. Second, the models as they are presented in this thesis, have an important bias in favor of hydroelectric plants with regard to environmental impact. Clearly these plants have environmental impacts that have been omitted in this study. Incorporating them might drastically alter the results of this analysis. Third, there might be some benefits in merging the models presented here with other multi-attribute models. Such mergers might fully incorporate all the non-energy related benefits and costs of the different alternatives. This would give a better understanding of the different alternatives considered. Finally, it would be convenient if the Energy Balance Model is modified to distinguish between peak and valley hours. This would prove valuable because the model as it stands now, takes yearly average and does not capture what goes on real time. Unfortunately, the computation cost for this enhancement is substantial.

It would be convenient to end this thesis by reminding that multi-attribute trade-off analysis is an recursive process. The results presented here are only the first stage in a comprehensive study. Once the models are enhanced, other futures and alternatives need to be considered. Furthermore, other attributes ignored here might be deemed important and thus included in later stages. Once again, it is expected that UNC professionals will undertake this process.

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Appendix A: Energy Balance Model

INPUT SHEET

NUMBER OF YEARS TO RUN ANALYSIS		31

ENERGY DEMAND, NEW CAPACITY AND PRICES

Year	Energy Demand (GWh) at demand nodes					
	Agricultural	Industrial	Commercial	Residential	Other	Total
1997	303.223	1869.616	163.575	735.083	206.75	3278.247
1998	303.223	1869.616	165.21075	742.43383	215.02	3295.504
1999	303.223	1869.616	166.8628575	749.8581683	223.6208	3313.181
2000	303.223	1869.616	168.5314861	757.35675	232.565632	3331.293
2001	303.223	1869.616	170.2168009	764.9303175	241.8682573	3349.851
2002	303.223	2056.5776	171.9189689	772.5796207	251.5429876	3555.842
2003	303.223	2262.23536	173.6381586	780.3054169	261.6047071	3781.007
2004	303.223	2488.458896	175.3745402	788.108471	272.0688954	4027.234
2005	303.223	2737.304786	177.1282856	795.9895557	282.9516512	4296.597
2006	303.223	3011.035264	178.8995685	803.9494513	294.2697172	4591.377
2007	303.223	3312.138791	180.6885642	811.9889458	306.0405059	4914.08
2008	303.223	3643.35267	182.4954498	820.1088353	318.2821261	5267.462
2009	303.223	4007.687937	184.3204043	828.3099236	331.0134112	5654.555
2010	303.223	4408.45673	186.1636083	836.5930229	344.2539476	6078.69
2011	303.223	4849.302403	188.0252444	844.9589531	358.0241055	6543.534
2012	303.223	5334.232644	189.9054969	853.4085426	372.3450698	7053.115
2013	303.223	5867.655908	191.8045518	861.942628	387.2388726	7611.865
2014	303.223	6454.421499	193.7225974	870.5620543	402.7284275	8224.658
2015	303.223	7099.863649	195.6598233	879.2676749	418.8375646	8896.852
2016	303.223	7809.850014	197.6164216	888.0603516	435.5910671	9634.341
2017	303.223	8590.835015	199.5925858	896.9409551	453.0147098	10443.61
2018	303.223	9449.918516	201.5885116	905.9103647	471.1352982	11331.78
2019	303.223	10394.91037	203.6043968	914.9694683	489.9807101	12306.69
2020	303.223	11434.4014	205.6404407	924.119163	509.5799385	13376.96
2021	303.223	12577.84155	207.6968451	933.3603546	529.9631361	14552.08
2022	303.223	13835.6257	209.7738136	942.6939582	551.1616615	15842.48
2023	303.223	15219.18827	211.8715517	952.1208978	573.208128	17259.61
2024	303.223	16741.1071	213.9902672	961.6421068	596.1364531	18816.1
2025	303.223	18415.21781	216.1301699	971.2585278	619.9819112	20525.81
2026	303.223	20256.73959	218.2914716	980.9711131	644.7811877	22404.01
2027	303.223	22282.41355	240.1206188	1079.068224	670.5724352	24575.4

INPUT SH

NUMBER OF

ENERGY DEM

Year	New Capacity						
	New Thermal Generation Capacity		New Hydro Plants (1 = in service, 0 = not constructed)				
	New Capacity (MW)	Total MW of new installed	Los Blancos	Potrerillos	El Baqueano	Portezuelo del Viento	
1997	400	400	0	0	0	0	
1998	0	100	0	0	0	0	
1999	0	100	0	0	0	0	
2000	0	100	0	0	0	0	
2001	0	100	0	0	0	0	
2002	0	100	0	0	0	0	
2003	0	400	0	0	0	0	
2004	0	100	0	0	0	0	
2005	0	400	0	0	0	0	
2006	0	100	0	0	0	0	
2007	0	400	0	0	0	0	
2008	0	100	0	0	0	0	
2009	0	400	0	0	0	0	
2010	200	600	0	0	0	0	
2011	200	800	0	0	0	0	
2012	200	1000	0	0	0	0	
2013	200	1200	0	0	0	0	
2014	200	1400	0	0	0	0	
2015	200	1600	0	0	0	0	
2016	200	1800	0	0	0	0	
2017	200	2000	0	0	0	0	
2018	200	2200	0	0	0	0	
2019	200	2400	0	0	0	0	
2020	200	2600	0	0	0	0	
2021	200	2800	0	0	0	0	
2022	200	3000	0	0	0	0	
2023	200	3200	0	0	0	0	
2024	200	3400	0	0	0	0	
2025	200	3600	0	0	0	0	
2026	200	3800	0	0	0	0	
2027	200	4000	0	0	0	0	

INPUT SH

NUMBER OF

ENERGY DEM

Year	Transmission Lines Added (1 = in service, 0 = not constructed) Added Capacity to Link	Comahue Link	Chile Link	Prices in (US$/Unit) Natural Gas (MMBtu)	Fuel Oil (tonne)	MEM Spot Mkt (MWh)	MEM Capacity (MW-HOVW)
1997	1	0	0	1.72	152	28	8
1998	1	0	0	1.7544	153.52	28.84	8
1999	1	0	0	1.789488	155.0552	29.7052	8
2000	1	0	0	1.8252778	156.605752	30.596356	8
2001	1	0	0	1.8617833	158.17181	31.51424668	8
2002	1	0	0	1.899019	159.753528	32.45967408	8
2003	1	0	0	1.9369994	161.351063	33.4334643	10
2004	1	0	0	1.9757393	162.964574	34.43646823	10
2005	1	0	0	2.0152541	164.594219	35.46956228	10
2006	1	0	0	2.0555592	166.240161	36.53364915	10
2007	1	0	0	2.0966704	167.902563	37.62965862	10
2008	1	0	0	2.1386038	169.581589	38.75854838	10
2009	1	0	0	2.1813759	171.277405	39.92130483	10
2010	1	0	0	2.2250034	172.990179	41.11894398	10
2011	1	0	0	2.2695035	174.72008	42.3525123	10
2012	1	0	0	2.3148935	176.467281	43.62308766	10
2013	1	0	0	2.3611914	178.231954	44.93178029	10
2014	1	0	0	2.4084152	180.014274	46.2797337	10
2015	1	0	0	2.4565835	181.814416	47.66812571	10
2016	1	0	0	2.5057152	183.63256	49.09816949	10
2017	1	0	0	2.5558295	185.468886	50.57111457	10
2018	1	0	0	2.6069461	187.323575	52.08824801	10
2019	1	0	0	2.659085	189.196811	53.65089545	10
2020	1	0	0	2.7122667	191.088779	55.26042231	10
2021	1	0	0	2.7665121	192.999667	56.91823498	10
2022	1	0	0	2.8218423	194.929663	58.62578203	10
2023	1	0	0	2.8782792	196.87896	60.38455549	10
2024	1	0	0	2.9358447	198.847749	62.19609216	10
2025	1	0	0	2.9945616	200.836227	64.06197492	10
2026	1	0	0	3.0544529	202.844589	65.98383417	10
2027	1	0	0	3.1155419	204.873035	67.96334919	10

Note: MEM Spot Market includes Node Factor. HOVW=hrs off-valley weekday

GLOBAL INPUTS

CAPACITY INPUTS
(Please Refer to the Generation Sheet for Description of the Generation Plants)

Capacity Factor - Existing Plants

HINISA	Nihuil I	(0.6088)	0.61
	Nihuil II	(0.3358)	0.33
	Nihuil III	(0.3512)	0.35
HIDISA	Agua del Toro	(0.2740)	0.28
	Los Reyunos	(0.1325)	0.13
	El Tigre	(0.5189)	0.52
CTMSA	LDC 12	(NA)	6.000
(Available hrs)	LDC 21	(6.000)	6.000
	LDC 22	(6.000)	6.000
	LDC 23	(6.500)	6.500
	LDC 24	(6.500)	6.500
	LDC 11	(NA)	6.000
	LDC 25 + 13	(NA)	6.000
NIHUIL IV	Nihuil IV	(0.6849)	0.65
HIDRO ELEC	Cacheuta	(0.8592)	0.86
MENDOZA	Alvarez Condarco	(0.668)	0.67
	San Martin	(0.3615)	0.36
	El Carrizal	(0.4883)	0.49
	Los Coroneles	(0.6017)	0.6

Note: Capacity Factors for Hydro are in fraction; for Thermal in hours available. Numbers in parenthesis represent avearge historic capacity factors.

New Capacity (MW)

HYDRO	Los Blancos	324
	Cacheuta - Potrerillos	131
	A. Condarco - Potrerillos	54
	El Baqueano	180
	Portezuelo del Viento	223
TRANSMISS	Stronger MEM Link	400
	Comahue Link	500
	Chile Link	161

Note: The Potrerillos project comprises the upgrading of the Cacheuta and Alvarez Condarco plants and the building of a dan

Energy Generation Capacity - New Plants

THERMAL	Gas Fired Comb Cycle (Hrs)	6.000
HYDRO	Los Blancos	900
(GWh/yr)	Cacheuta - Potrerillos	490
to produce	A. Condarco - Potrerillos	270
	El Baqueano	460
	Portezuelo del Viento	978

EMISSIONS
(lb/10E9Btu for Gas, lb/Tonne for Fuel Oil)

Type of Fuel	Hydrocarbons	NOx	SOx(*)	CO	Particulate
Natural Gas	42	413	940	115	14
Fuel Oil	1.50	18.26	3,771.04	4.15	1.35

Note (*):For Sulfur, emissions are calculated in the following manner. If the factor is 940 and the sulfur content is 0.01 percent, the sulfur oxides would be 940 times 0.01, or 9.4lb/10E9 Btu, for the natural gas case

DESCRIPTION OF NATURAL GAS AND FUEL OIL USED IN MENDOZA

Sulfur Content of Natural Gas (%)	0.1%

Sulfur Content of Fuel Oil (%)	0.4%
Heating Value of Fuel Oil (Kcal/kg)	9,420

OTHER INPUTS

Spot Market w/ Chile Link (As % of MEM Spot Price)	99%

Discount Rate (% p.a.)	12%

Adjustment factor	1

Efficiency of Gas Fired Combined Cycles (%)

THERMAL	Gas Fired Comb Cycle	53%

Capital Costs - New Capacity

THERMAL (US$/kW)	Gas Fired Comb Cycle	800
HYDRO (US$ MM)	Los Blancos	200
Total Project Costs	Potrerillos	300
	El Baqueano	120
	Portezuelo del Viento	250
TRANSMIS (US$/kW)	Stronger MEM Link	10
	Comahue Link	230
	Chile Link	559

COEFFICIENT OF LOSSES (Existing and New Capacity)

PLANT			High/Medium/Low Voltage
	HINISA	0.024	High
	HIDISA	0.024	High
	CTMSA	0.062	medium
	NIHUIL IV	0.024	high
HIDRO ELEC MENDOZA	Cacheuta	0.062	medium
	Alvarez Condarco	0.062	medium
	San Martin	0.062	medium
	El Carrizal	0.062	medium
	Los Coroneles	0.062	medium
THERMAL	NEW THERMAL	0.062	medium
NEW HYDRO	Los Blancos	0.062	medium
	Cacheuta - Potrerillos	0.062	medium
	A. Condarco - Potrerillos	0.062	medium
	El Baqueano	0.024	high
	Portezuelo del Viento	0.024	high
TRANSMISS	MEM Link	0	NA
	Comahue Link	0	NA
	Chile Link	0	NA
DEMAND	Agricultural	0.062	medium
	Industrial	0.062	medium
	Commercial	0.163	low
	Residential	0.163	low
	Other	0.163	low

Note: These coefficients are based on the energy flow from the above nodes to the Cruz de Piedra Point.

High Voltage Lines Losses	2.4%
Medium Voltage Lines Losses	6.2%
Low Voltage Lines Losses	16.3%

HINISA

Generation Plants - Atuel River	MW	Average. Energy Generated (GWh/yr)	Historic Capacity Factor
Generation Nihuil I	75	400	0.608828006
Generation Nihuil II	136	400	0.335750739
Generation Nihuil III	52	160	0.351246927
Total	263	960	0.416688369

HIDISA

Generation Plants - Diamante River	MW	Average. Energy Generated (GWh/yr)	Historic Capacity Factor
Agua del Toro	150	360	0.273972603
Los Reyunos	224	260	0.132501631
El Tigre	11	50	0.518887505
Total	385	670	0.198659788

CTMSA

Generation Plants	MW	Average. Energy Generated (GWh/yr)	Historic Capacity Factor
LDC 12 - Franco Tosi (Fuel: Fuel-Oil)	60	0	NA
LDC 21 - Brown Boveri Comb. Cycle (Fuel: Natural Gas)	25	150	0.684931507
LDC 22 - Brown Boveri Comb. Cycle (Fuel: Natural Gas)	25	150	0.684931507
LDC 23 - Alsthom (Fuel: Natural Gas)	25	162.5	0.742009132
LDC 24 - Alsthom (Fuel: Natural Gas)	25	162.5	0.742009132
LDC 11 - Converted as of 9/1/96 (Fuel: Natural Gas)	60	0	NA
LDC 25 + 13 - Combined Cycle as of 4/98 (Fuel: Natural Gas)	290	0	NA
Total	510	625	0.139896141

NIHUIL IV

Generation Plants	MW	Average. Energy Generated (GWh/yr)	Historic Capacity Factor
Nihuil IV - Atuel River	25	150	0.684931507

HIDREOELECTRICA MENDOZA S.A.

Generation Plants	MW	Average. Energy Generated (GWh/yr)	Historic Capacity Factor
Cacheuta - Mendoza River	9.3	70	0.859233073
Alvarez Condarco - Mendoza River	27.36	160	0.667574568
San Martin - Mendoza River	6	19	0.361491629
El Carrizal - Tunuyan River	18	77	0.488330797
Los Coroneles - Tunuyan River	6.64	35	0.601721956
Total	67.3	361	0.612333517

HINISA

Generation Plants - Atuel River	Capacity Factor Used in Model	Energy Generation Capacity (GWh/yr)
Generation Nihuil I	0.61	400.77
Generation Nihuil II	0.33	393.1488
Generation Nihuil III	0.35	159.432
Total	0.413802281	953.3508

HIDISA

Generation Plants - Diamante River	Capacity Factor Used in Model	Energy Generation Capacity (GWh/yr)
Agua del Toro	0.28	367.92
Los Reyunos	0.13	255.0912
El Tigre	0.52	50.1072
Total	0.199584416	673.1184

CTMSA

Generation Plants	Capacity Factor Used in Model	Energy Generation Capacity (GWh/yr)
LDC 12 - Franco Tosi (Fuel: Fuel-Oil)	0.684931507	360
LDC 21 - Brown Boveri Comb. Cycle (Fuel: Natural Gas)	0.684931507	150
LDC 22 - Brown Boveri Comb. Cycle (Fuel: Natural Gas)	0.684931507	150
LDC 23 - Alsthom (Fuel: Natural Gas)	0.742009132	162.5
LDC 24 - Alsthom (Fuel: Natural Gas)	0.742009132	162.5
LDC 11 - Converted as of 9/1/96 (Fuel: Natural Gas)	0.684931507	360
LDC 25 + 13 - Combined Cycle as of 4/98 (Fuel: Natural Gas)	0.684931507	1740
Total	0.690527352	3085

NIHUIL IV

Generation Plants	Capacity Factor Used in Model	Energy Generation Capacity (GWh/yr)
Nihuil IV - Atuel River	0.65	142.35

HIDREOELECTRICA MENDOZA S.A.

Generation Plants	Capacity Factor Used in Model	Energy Generation Capacity (GWh/yr)
Cacheuta - Mendoza River	0.86	70.06248
Alvarez Condarco - Mendoza River	0.67	160.581312
San Martin - Mendoza River	0.36	18.9216
El Carrizal - Tunuyan River	0.49	77.2632
Los Coroneles - Tunuyan River	0.6	34.89984
Total	0.613569094	361.728432

HINISA

Generation Plants - Atuel River	Equivalent hrs of operation per yr
Generation Nihuil I	5343.60
Generation Nihuil II	2890.80
Generation Nihuil III	3066.00
Total	3624.91

HIDISA

Generation Plants - Diamante River	Equivalent hrs of operation per yr
Agua del Toro	2452.80
Los Reyunos	1138.80
El Tigre	4555.20
Total	1748.36

CTMSA

Generation Plants	Equivalent hrs of operation per yr	Efficiency (%)	Efficiency (Kcal/KWh)
LDC 12 - Franco Tosi (Fuel: Fuel-Oil)	6000.00	0.303832236	2830
LDC 21 - Brown Boveri Comb. Cycle (Fuel: Natural Gas)	6000.00	0.38731767	2220
LDC 22 - Brown Boveri Comb. Cycle (Fuel: Natural Gas)	6000.00	0.38731767	2220
LDC 23 - Alsthom (Fuel: Natural Gas)	6500.00	0.26055916	3300
LDC 24 - Alsthom (Fuel: Natural Gas)	6500.00	0.26055916	3300
LDC 11 - Converted as of 9/1/96 (Fuel: Natural Gas)	6000.00	0.38731767	2220
LDC 25 + 13 - Combined Cycle as of 4/98 (Fuel: Natural Gas)	6000.00	0.53	NA
Total	6049.02		

NIHUIL IV

Generation Plants	Equivalent hrs of operation per yr
Nihuil IV - Atuel River	5694.00

HIDREOELECTRICA MENDOZA S.A.

Generation Plants	Equivalent hrs of operation per yr
Cacheuta - Mendoza River	7533.60
Alvarez Condarco - Mendoza River	5869.20
San Martin - Mendoza River	3153.60
El Carrizal - Tunuyan River	4292.40
Los Coroneles - Tunuyan River	5256.00
Total	5374.87

Argentine Wholesale Market (MEM)

Link	MW installed	Energy Transmission Capacity (GWh/yr)
E.T. Cruz de Piedra Link - 500kV line to the east	540	4730.4

NEW GENERATION ALTERNATIVES

THERMAL PLANTS

	MW	Capacity Factor Used in Model	Energy Generation Capacity (GWh/yr)
Combined Cycle (Fuel: Natural Gas)	4000	0.684931507	24000

HYDROELECTRIC PLANTS

Generation Plants	MW	Capacity Factor Used in Model	Energy Generation Capacity (GWh/yr)
Los Blancos - Tunuyan River	324	0.31709792	900
Cacheuta - Proterillos Project - Mendoza River	131	0.426992924	490
Alvarez Condarco - Potrerillos Project - Mendoza River	54	0.570776256	270
El Baqueano - Diamante River	180	0.291730086	460
Portezuelo del Viento - Grande River	223	0.500645003	978

Note: The Potrerillos Project involves the upgrading of the Cacheuta and Alvaro Condarco Plants. As such the already existing capacity (e.g. 9MW and 27.36MW) will be replaced by the new capacity (131MW and 47 MW) if the Project is constructed.

TRANSMISSION LINES

New High Voltage Links	MW	Energy Transmission Capacity (GWh/yr)
Strengthening the link with MEM	400	3504
Link with Comahue	500	4380
Link with Chile	161	1410.36

NEW GENERATION ALTERNATIVES

THERMAL PLANTS

	Equivalent hrs of operation per yr	Efficiency (%)
Combined Cycle (Fuel: Natural Gas)	6000.00	53%

HYDROELECTRIC PLANTS

Generation Plants	Equivalent hrs of operation per yr
Los Blancos - Tunuyan River	2777.78
Cacheuta - Proterillos Project - Mendoza River	3740.46
Alvarez Condarco - Potrerillos Project - Mendoza River	5000.00
El Baqueano - Diamante River	2555.56
Portezuelo del Viento - Grande River	4385.65

Note: The Potrerillos Project involves the upgrading of the Cacheuta an existing capacity (e.g. 9MW and 27.36MW) will be replaced by the new

TRANSMISSION LINES

New High Voltage Links
Strengthening the link with MEM
Link with Comahue
Link with Chile

CALCULATION SHEET

MAX. GENERATION CAPACITY MEASURED AT SOURCE (GWh)

Existing Capacity

HINISA	Nihuil I	400.8
	Nihuil II	393.1
	Nihuil III	159.4
	TOTAL	953.4
HIDISA	Agua del Toro	367.9
	Los Reyunos	255.1
	El Tigre	50.1
	TOTAL	673.1
CTMSA	LDC 12	360.0
	LDC 21	150.0
	LDC 22	150.0
	LDC 23	162.5
	LDC 24	162.5
	LDC 11	360.0
	LDC 25 + 13	1,740.0
	TOTAL	3,085.0
NIHUIL IV	Nihuil IV	142.4
HIDRO ELEC MENDOZA	Cacheuta	70.1
	Alvarez Condarco	160.6
	San Martin	18.9
	El Carrizal	77.3
	Los Coroneles	34.9
	TOTAL	361.7
TRANSMISSION	MEM Link	4,730.4

New Capacity

THERMAL	Gas Fired Comb Cycle	24,000.0
HYDRO	Los Blancos	-
	Cacheuta - Potrerillos	
	A. Condarco - Potrerillos	-
	El Baqueano	-
	Portezuelo del Viento	
	TOTAL	
TRANSMISSION	Stronger MEM Link	3,504.0
	Comahue Link	
	Chile Link	
	TOTAL	3,504.0

New Power Capacity

THERMAL (MW)	Gas Fired Comb Cycle	[illegible]
HYDRO	Los Blancos	
(1 = in service,	Potrerillos	
0 = not constructed)	El Baqueano	
	Portezuelo del Viento	
TRANSMISSION	Stronger MEM Link	1.0
(1 = in service,	Comahue Link	
0 = not constructed)	Chile Link	

MAX. GENERATION CAPACITY MEASURED AT CRUZ DE PIEDRA (GWh)

Existing Capacity

HINISA	Total	930.5
HIDISA	Total	657.0
CTMSA	LDC 12	337.7
	LDC 21	140.7
	LDC 22	140.7
	LDC 23	152.4
	LDC 24	152.4
	LDC 11	337.7
	LDC 25 + 13	1,632.1
	TOTAL	2,893.7
NIHUIL IV	Nihuil IV	138.9
HIDRO ELEC MENDOZA	Cacheuta	65.7
	Alvarez Condarco	150.6
	San Martin	17.7
	El Carrizal	72.5
	Los Coroneles	32.7
	TOTAL	339.3
TRANSMISSION	MEM Link	4,730.4

New Capacity

THERMAL	Gas Fired Comb Cycle	22,512.0
HYDRO	Los Blancos	-
	Cacheuta - Potrerillos	-
	A. Condarco - Potrerillos	-
	El Baqueano	-
	Portezuelo del Viento	-
	TOTAL	-
TRANSMISSION	Stronger MEM Link	3,504.0
	Comahue Link	-
	Chile Link	-
	TOTAL	3,504.0

TOTAL GENERATION CAPACITY (GWh)	35,705.8

DEMAND MEASURED AT NODE (GWh)

Agricultural	303.2
Industrial	22,282.1
Commercial	240.1
Residential	1,079.1
Other	670.6
TOTAL	24,575.4

PRICES

Natural Gas (US$/MMBtu)	3.115541925
Fuel Oil (US$/tonne)	201.8730351
MEM Spot Price (US$/MWh)	67.96334919
Capacity Price (US$/MW-hr off-alley weekday)	10.00

Spot Market includ Chile Link	67.96334919

DEM MEASURED AT CRUZ DE PIEDRA (GWI

Agricultural	323.3
Industrial	23,755.2
Commercial	286.9
Residential	1,289.2
Other	801.2
TOTAL	26,455.8

DIFFERENCE
MAX. AVAIL. CAPACITY - DEMAND (GWh)
Measured at Cruz de Piedra

9,250.0

AVERAGE POWER DEMAND (MW)

3,020.06

NUMBER OF OFF-VALLEY HRS IN WEEKDAYS PER YEAR

4464.00

ACCOUNTING OF ENERGY GENERATION TO SATISFY MENDOZA DEMAND

Marginal Cost of Non-Hydro Sources and Delivery to Wholesale Mkt Given Spot Price (Measured at Cruz de Piedra)

GENERATION PLANT		Marginal Cost (US$/MWh)	Delivery (1=yes, 0=no)	Energy Delivered (GWh)
CTMSA	LDC 12	65.62	1	337.7
	LDC 21	29.26	1	140.7
	LDC 22	29.26	1	140.7
	LDC 23	43.49	1	152.4
	LDC 24	43.49	1	152.4
	LDC 11	29.26	1	337.7
	LDC 25 + 13	21.38	1	1,632.1
NEW THERMAL CAPACITY		21.39	1	22,512.0
			TOTAL	25,405.7

Total Energy Delivered by Hydro Sources to Wholesale Mkt

Energy Measured @ Cruz de Piedra - GWh	2,065.7

Resulting Energy to be Imported from Wholesale Market

Energy Measured @ Cruz de Piedra - GWh	(1,015.6)

Energy that can be Supplied by Wholesale Market

Energy Measured @ Cruz de Piedra - GWh	8,234.4

Resulting Energy to be Supplied by High Cost Sources

Energy Measured @ Cruz de Piedra - GWh	(9,250.0)

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MINIMIZATION OF GENERATION COSTS USING HIGH COST (NON HYDRO) PLANTS
(Minimization performed by hidden part of spreadsheet)

Effective Marginal Cost and Quantity of Energy Generated (Measured at Cruz de Piedra)

GENERATION PLANT		Effective MC (US$/MWh)	Energy Delivered (GWh)	Total Cost of Delivery (US$ MM)
CTMSA	LDC 12	20,000.00	-	-
	LDC 21	20,000.00	-	-
	LDC 22	20,000.00	-	-
	LDC 23	20,000.00	-	-
	LDC 24	20,000.00	-	-
	LDC 11	20,000.00	-	-
	LDC 25 + 13	20,000.00	-	-
NEW THERMAL CAPACITY		20,000.00	-	-
INFINITE SOURCE		1,000.00	-	-
		TOTAL	-	-

Note 1: If Plant is already delivering to Wholesale Mkt. then Eff MC=20,000 so as to make sure minimization algorithm does not choose that plant
Note 2: Eff MC for Infinite Source = 1,000 It represents amount of demand that is left unsatisfied

Determination of the MC (Measured at Cruz de Piedra) of the Last High Cost Plant Used
(This represents the amount per MWh paid to high cost plants)

GENERATION PLANT		High Cost (1=yes, 0=no)	Used Up to Cap? (0=yes, 1=no)	Effec Marginal Co (US$/MWh)	Answer (US$/MWh)
CTMSA	LDC 12	0	1	0	-
	LDC 21	0	1	0	
	LDC 22	0	1	0	
	LDC 23	0	1	0	
	LDC 24	0	1	0	(
	LDC 11	0	1	0	(
	LDC 25 + 13	0	1	0	(
NEW THERMAL CAPACITY		0	1	0	(
			Marginal Cost of Last High Cost Plant Used:		65.62

Note: An Effective Marginal Cost equal to 0 means either that the plant in question is a low cost plant or that it is not the last one dispatched among the high cost plants

Determination of Equivalent Hours of Generation for High Cost Plants

GENERATION PLANT		Energy Delivered (GWh)	Equivalent Hours of Generation
CTMSA	LDC 12	-	-
	LDC 21	-	-
	LDC 22	-	-
	LDC 23	-	-
	LDC 24	-	-
	LDC 11	-	-
	LDC 25 + 13	-	-
NEW THERMAL CAPACITY		-	-

TOTAL PRODUCTION OF ENERGY PER PLANT
(Measured at Source - GWh)

Existing Capacity

HINISA	Nihuil I	400.8
	Nihuil II	393.1
HIDISA	Agua del Toro	367.9
	Los Reyunos	255.1
	El Tigre	50.1
	TOTAL	673.1
CTMSA	LDC 12	360.0
	LDC 21	150.0
	LDC 22	150.0
	LDC 23	162.5
	LDC 24	162.5
	LDC 11	360.0
	LDC 25 + 13	1,740.0
	TOTAL	3,085.0
NIHUIL IV	Nihuil IV	142.4
HIDRO ELEC MENDOZA	Cacheuta	70.1
	Alvarez Condarco	160.6
	San Martin	18.9
	El Carrizal	77.3
	Los Coroneles	34.9
	TOTAL	361.7

New Capacity

THERMAL	New Thermal	24,000.0
HYDRO	Los Blancos	
	El Baqueano	-
	Portezuelo del Viento	-
	TOTAL	-

AMOUNT OF FUEL USED BY NON-HYDRO SOURCES AND COSTS OF FUEL
(10E9Btu for Natural Gas Plants, and 10E3Tonnes for Fuel Oil Plants, Cost in US$MM)

Plant		Amount of Fuel	Fuel Costs
CTMSA	LDC 12 (Fuel Oil)	108.2	22.16
	LDC 21 (Natural Gas)	1,321.3	4.12
	LDC 22 (Natural Gas)	1,321.3	4.12
	LDC 23 (Natural Gas)	2,127.8	6.63
	LDC 24 (Natural Gas)	2,127.8	6.63
	LDC 11 (Natural Gas)	3,171.2	9.88
	LDC 25 + 13 (Nat. Gas)	11,201.0	34.90
NEW THERMAL	Gas Fired Comb Cycle	154,496.8	481.34

EMISSIONS GENERATED BY NON-HYDRO PLANTS
(Measured in 10E3 lb)

GENERATION PLANT		Particulates	NOx	SOx	Hydrocarbons	CO
CTMSA	LDC 12	145.6	1,975.1	1,631.4	162.3	448.6
	LDC 21	18.50	545.71	0.62	55.50	151.95
	LDC 22	18.50	545.71	0.62	55.50	151.95
	LDC 23	29.79	878.78	1.00	89.37	244.70
	LDC 24	29.79	878.78	1.00	89.37	244.70
	LDC 11	44.40	1,309.69	1.49	133.19	364.68
	LDC 25 + 13	156.81	4,626.02	5.26	470.44	1,288.12
	TOTAL	443.36	10,759.78	1,641.39	1,055.63	2,894.72
THERMAL	Gas Fired Comb Cycle	2,162.96	63,807.19	72.61	6,488.87	17,767.13
	TOTAL	2,606.32	74,566.96	1,714.01	7,544.49	20,661.85

% OF ENERGY DEMAND NOT MET **(Measured @ Cruz de Piedra)**	0.00%
% OF ENERGY DEMAND MET BY HIGH COST **(Measured @ Cruz de Piedra)**	0.00%
% OF ENERGY DEMAND MET BY MEM **(Measured @ Cruz de Piedra)**	0.00%
IS FUEL OIL PLANT USED? **(1 = YES, 0 = NO)**	1
Marginal Cost of Last High Cost Plant Used **(US$/MWh - Measured @ CdP)**	-
NET ENERGY REVENUES (Excl. Fuel Costs) **(US$ MM)**	69.03
NET CAPACITY REVENUES (Cap. Dispatched) **(US$ MM)**	86.79

EXPENDITURES AND REVENUES OF ENERGY AND CAPACITY (US$MM)
(Measured at Cruz de Piedra)

Total Expenditures of Energy by Entire Province	1,798.02
Total Expenditure of Capacity by Entire Province	134.82

Total Energy and Capacity Revenues by Local Generators (US$ MM)
Existing Capacity

PLANT		ENERGY			CAPACITY	TOTAL
		Reven $/MWh	Total Revs	Total Net Revenues	Total Revenues	NET REVS
HINISA	Total	67.96334919	63.24	63.24	9.53	72.77
HIDISA	Total	67.96334919	44.65	44.65	6.73	51.38
CTMSA	LDC 12	67.96334919	22.95	0.79	2.68	3.47
	LDC 21	67.96334919	9.56	5.45	1.12	6.56
	LDC 22	67.96334919	9.56	5.45	1.12	6.56
	LDC 23	67.96334919	10.36	3.73	1.12	4.85
	LDC 24	67.96334919	10.36	3.73	1.12	4.85
	LDC 11	67.96334919	22.95	13.07	2.68	15.75
	LDC 25 + 13	67.96334919	110.92	76.03	12.95	88.97
	TOTAL		196.67	108.24	22.77	131.01
NIHUIL IV	Total	67.96334919	9.44	9.44	1.12	10.56
HIDRO ELEC	Cacheuta	67.96334919	4.47	4.47	0.42	4.88
MENDOZA	Alvarez Condarco	67.96334919	10.24	10.24	1.22	11.46
	San Martin	67.96334919	1.21	1.21	0.19	1.40
	El Carrizal	67.96334919	4.93	4.93	0.77	5.70
	Los Coroneles	67.96334919	2.22	2.22	0.30	2.52
	TOTAL		23.06	23.06	2.89	25.95

New Capacity

PLANT		ENERGY			CAPACITY	TOTAL
		Reven/MWh	Total Revs	Total Net Revenues	Total Revenues	NET REVS
THERMAL	Gas Fired Comb Cycle	67.96334919	1,529.99	1,048.65	178.56	1,227.21
HYDRO	Los Blancos	67.96334919	-	-	-	-
	Cacheuta - Potrerillos	67.96334919	-	-	-	-
	A. Condarco - Potrerillos	67.96334919	-	-	-	-
	El Baqueano	67.96334919	-	-	-	-
	Portezuelo del Viento	67.96334919	-	-	-	-
	TOTAL		-	-	-	-

Total Energy Revenues by Generators in the Province (excl. fuel costs)	1,867.05
Total Capacity Revenues by Generators in the Province	221.60

MINIMIZATION ALGORITHM
(Effective MC in (US$/MWh) and Energy Deli

GENERATION PLANT	Effective MC (US$/MWh)	First Run Energy delivered	Effec MC	sec run	Effec MC	Third run	Effec MC
CTMSA	20.000.00	-	20.000.00	-	20,000.00	-	20,000.00
	20.000.00	-	20.000.00	-	20,000.00	-	20,000.00
	20.000.00	-	20.000.00	-	20,000.00	-	20,000.00
	20.000.00	-	20.000.00	-	20,000.00	-	20,000.00
	20.000.00	-	20.000.00	-	20,000.00	-	20,000.00
	20.000.00	-	20.000.00	-	20,000.00	-	20,000.00
	20.000.00	-	20.000.00	-	20,000.00	-	20,000.00
NEW THERMAL CAPACITY	20.000.00	-	20.000.00	-	20,000.00	-	20,000.00
INFINITE SOURCE	1.000.00	-	1.000.00	-	1,000.00	-	1,000.00
	TOTAL	-		-		-	
	LEFT TO SUPPLY	(9.250.04)		(9.250.04)		(9.250.04)	

Note: In each run. the algorithm chooses the least expensive plant based on the Effective MC, and decides how much of that plant to

MINIMIZATION ALGORITHM
(Effective MC in (US$/MWh) and Energy Deli

GENERATION PLANT	Fourth Run	Effec MC	Fifth Run	Effec MC	Sixth Run
CTMSA	-	20,000.00	-	20,000.00	-
	-	20,000.00	-	20,000.00	-
	-	20,000.00	-	20,000.00	-
	-	20,000.00	-	20,000.00	-
	-	20,000.00	-	20,000.00	-
	-	20,000.00	-	20,000.00	-
	-	20,000.00	-	20,000.00	-
NEW THERMAL CAPACITY	-	20,000.00	-	20,000.00	-
INFINITE SOURCE	-	1,000.00	-	1,000.00	-
	-		-		-
	(9,250.04)		(9,250.04)		(9,250.04)

use to meet demand

MINIMIZATION ALGORITHM
(Effective MC in (US$/MWh) and Energy Deli

GENERATION PLANT	Effec MC	Seventh Run	Effec MC	Eight run	Total Energy
CTMSA	20,000.00	-	20,000.00	-	-
	20,000.00	-	20,000.00	-	-
	20,000.00	-	20,000.00	-	-
	20,000.00	-	20,000.00	-	-
	20,000.00	-	20,000.00	-	-
	20,000.00	-	20,000.00		-
	20,000.00	-	20,000.00	-	-
NEW THERMAL CAPACITY	20,000.00	-	20,000.00	-	-
INFINITE SOURCE	1,000.00	-	1,000.00	-	-
		-		-	-
		(9,250.04)		(9,250.04)	

Outp

Year	Percentage of Energy Demand Not Met	Percentage of Energy Demand Met w/ High Cost	Percentage of Energy Demand Met by MEM	Is Fuel Oil Used? (1=yes, 0=no)	MC Last High Cost (US$/MWh @ CdP)
1997		-		-	0
1998				-	0
1999				-	0
2000			-	-	0
2001		-	-	-	0
2002	-	-	-	-	0
2003	-	-	-	-	0
2004	-	-	-	-	0
2005	-	-	-	-	0
2006		-	-	-	0
2007		-	-	-	0
2008	-	-	-	-	0
2009	-	-	-	-	0
2010	-	-	-	-	0
2011	-	-	-	-	0
2012		-	-	-	0
2013	-	-	-	-	0
2014	-	-	-	-	0
2015	-	-	-	-	0
2016	-	-	-	-	0
2017	-	-	-	-	0
2018	-	-	-	-	0
2019	-	-	-	-	0
2020	-	-	-	-	0
2021	-	-	-	-	0
2022	-	-	-	-	0
2023	-	-	-	-	0
2024	-	-	-	-	0
2025	-	-	-	-	0
2026	-	-	-	1.00	0
2027	-	-	-	1.00	0
TOTAL	0.00%	0.0%	0.00%		0

Year	Emissions (10E3 lb), Total in (10E6 lb)					Net Energy Revs (excl. fuel Cost) (US$ MM)	Net Capacity Revs (US$ MM)
	Particulates	NOx	SOx	Hydrocarbons	CO		
1997	514.1	15,165.4	172.6	1,542.2	4,222.8	90.6	31.7
1998	514.1	15,165.4	172.6	1,542.2	4,222.8	92.7	31.7
1999	514.1	15,165.4	172.6	1,542.2	4,222.8	94.9	31.6
2000	514.1	15,165.4	172.6	1,542.2	4,222.8	97.1	31.5
2001	514.1	15,165.4	172.6	1,542.2	4,222.8	99.3	31.4
2002	514.1	15,165.4	172.6	1,542.2	4,222.8	95.0	30.5
2003	514.1	15,165.4	172.6	1,542.2	4,222.8	89.8	36.9
2004	514.1	15,165.4	172.6	1,542.2	4,222.8	83.4	35.5
2005	514.1	15,165.4	172.6	1,542.2	4,222.8	75.6	34.1
2006	514.1	15,165.4	172.6	1,542.2	4,222.8	66.3	32.4
2007	514.1	15,165.4	172.6	1,542.2	4,222.8	55.2	30.7
2008	514.1	15,165.4	172.6	1,542.2	4,222.8	42.1	28.7
2009	514.1	15,165.4	172.6	1,542.2	4,222.8	26.8	26.6
2010	622.2	18,355.8	208.9	1,866.7	5,111.2	55.2	33.2
2011	730.4	21,546.1	245.2	2,191.1	5,999.5	83.4	39.6
2012	838.5	24,736.5	281.5	2,515.6	6,887.9	111.2	45.8
2013	946.7	27,926.8	317.8	2,840.0	7,776.2	138.2	51.6
2014	1,054.8	31,117.2	354.1	3,164.5	8,664.6	164.0	57.2
2015	1,163.0	34,307.6	390.4	3,488.9	9,553.0	188.3	62.5
2016	1,271.1	37,497.9	426.7	3,813.3	10,441.3	210.4	67.4
2017	1,379.3	40,688.3	463.0	4,137.8	11,329.7	229.8	71.9
2018	1,487.4	43,878.6	499.3	4,462.2	12,218.0	245.8	76.0
2019	1,595.6	47,069.0	535.7	4,786.7	13,106.4	257.6	79.6
2020	1,703.7	50,259.4	572.0	5,111.1	13,994.7	264.3	82.7
2021	1,811.9	53,449.7	608.3	5,435.6	14,883.1	264.7	85.2
2022	1,920.0	56,640.1	644.6	5,760.0	15,771.5	257.8	87.1
2023	2,028.2	59,830.4	680.9	6,084.5	16,659.8	242.0	88.3
2024	2,136.3	63,020.8	717.2	6,408.9	17,548.2	215.8	88.8
2025	2,244.4	66,211.2	753.5	6,733.3	18,436.5	177.3	88.4
2026	2,498.2	71,376.6	2,421.2	7,220.0	19,773.5	146.7	89.8
2027	2,606.3	74,567.0	2,457.5	7,544.5	20,661.9	69.0	86.8
TOTAL	34.7	1,019.6	14.8	103.6	283.7	4,330.2	1,695.0

Year	Revenues to New Generation Capacity (US$ MM)					
	New Thermal	Los Blancos	Cacheuta	A. Condarco	El Baqueano	P. del Viento
1997	50.7	-	-	-	-	-
1998	52.1	-	-	-	-	-
1999	53.5	-	-	-	-	-
2000	55.0	-	-	-	-	-
2001	56.5	-	-	-	-	-
2002	58.0	-	-	-	-	-
2003	63.2	-	-	-	-	-
2004	64.9	-	-	-	-	-
2005	66.6	-	-	-	-	-
2006	68.3	-	-	-	-	-
2007	70.2	-	-	-	-	-
2008	72.1	-	-	-	-	-
2009	74.0	-	-	-	-	-
2010	114.1	-	-	-	-	-
2011	156.3	-	-	-	-	-
2012	200.7	-	-	-	-	-
2013	247.6	-	-	-	-	-
2014	296.9	-	-	-	-	-
2015	348.9	-	-	-	-	-
2016	403.5	-	-	-	-	-
2017	461.1	-	-	-	-	-
2018	521.6	-	-	-	-	-
2019	585.3	-	-	-	-	-
2020	652.3	-	-	-	-	-
2021	722.7	-	-	-	-	-
2022	796.8	-	-	-	-	-
2023	874.6	-	-	-	-	-
2024	956.4	-	-	-	-	-
2025	1.042.3	-	-	-	-	-
2026	1.132.5	-	-	-	-	-
2027	1.227.2	-	-	-	-	-
TOTAL	11.545.8	-	-	-	-	-

NET REVENUES OF ENERGY AND CAPACITY		First Year When....				
NPV (US$MM)		When Demand Not Met	...When High Cost Used	...When Fuel Oil Used		
Energy (excl. fuel cost)	Capacity				New Thermal	Los Blancos
912.2991599	342.729283	NA	NA	2026	580.00	-

Ou

FINANCIAL RESULTS OF NEW CAPACITY INVESTMENTS									
NPV (US$MM)				IRR (%)					
Potrerillos	El Baqueano	P. del Viento	Scenario	New Thermal	Los Blancos	Potrerillos	El Baqueano	P. del Viento	Scenario
-	-	-	580.00	23.959%	NA	NA	NA	NA	23.96%

Appendix B: Base Case Future Results and Trade-Off Curves

BASE CASE FUTURE

Description:

Demand: 1997 equals to 1993 demand. Each sector grows at 5%/yr, except for Industrial which remains constant until 2001, and starts growing at 5%/yr, beginning in 2002.

Agricultural Sector does not grow at all

Prices

Natural Gas (US$/MMBtu) prices start at 1.9 and increase by 1.5%/yr

Fuel Oil (US$/tonne) start at 152 and increases at 1%

Spot Price ($/MWh) start at 30, decrease by 6% until 2000, and start increasing at 1% after that

Capacity Price ($/MW-hr off-valley weeday) starts at 10 until 2000, and goes down to 8 after that.

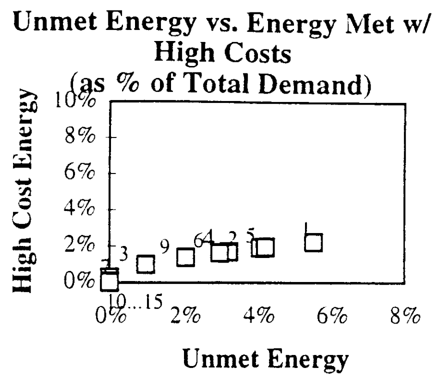
Spot Market w/ Chile Link (As % of MEM Spot Price)	0.9

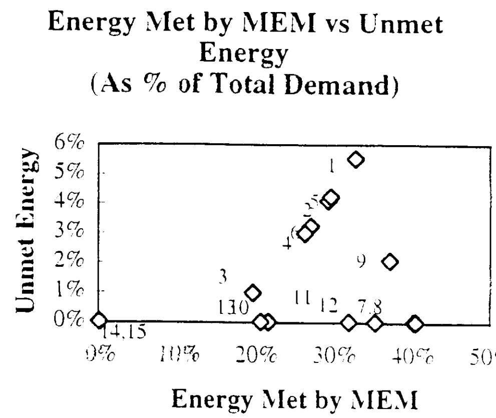
Discount Rate (% p.a.)	12%

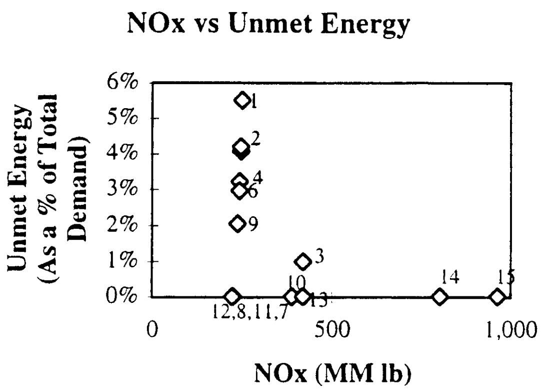
Scenario #	Percentage of Energy Demand Not Met	Percentage of Energy Demand Met w/ High Cost	Percentage of Energy Demand Met by MEM	MC Last High Cost (US$/MWh @ CdP)	Emissions (MM lb)				
					Particulates	NOx	SOx	Hydrocarbons	CO
1	5.52%	2.21%	32.87%	65.62	9.03	249.62	14.41	25.11	68.78
2	4.08%	1.90%	29.41%	65.62	8.80	245.64	12.56	24.75	67.78
3	0.98%	0.97%	19.78%	65.62	14.45	419.25	9.60	42.52	116.44
4	3.22%	1.66%	27.15%	65.62	8.65	242.67	11.53	24.47	67.02
5	4.21%	1.92%	29.73%	65.62	8.82	245.92	12.79	24.77	67.85
6	2.97%	1.61%	26.45%	65.62	8.61	242.02	11.00	24.41	66.87
7	0.00%	0.26%	40.34%	65.62	7.68	224.65	3.81	22.82	62.47
8	0.00%	0.00%	40.59%	-	7.50	221.36	2.52	22.51	61.64
9	2.05%	1.34%	37.20%	65.62	8.36	236.80	9.55	23.92	65.50
10	0.00%	0.00%	21.73%	-	13.18	388.85	4.43	39.54	108.28
11	0.00%	0.03%	35.36%	41.46	7.52	221.76	2.52	22.55	61.75
12	0.00%	0.00%	32.04%	-	7.50	221.36	2.52	22.51	61.64
13	0.00%	0.00%	20.75%	-	14.21	419.16	4.77	42.63	116.71
14	0.00%	0.00%	0.00%	-	27.19	802.00	9.13	81.56	223.32
15	0.00%	0.00%	0.00%	-	32.70	964.71	10.98	98.11	268.62

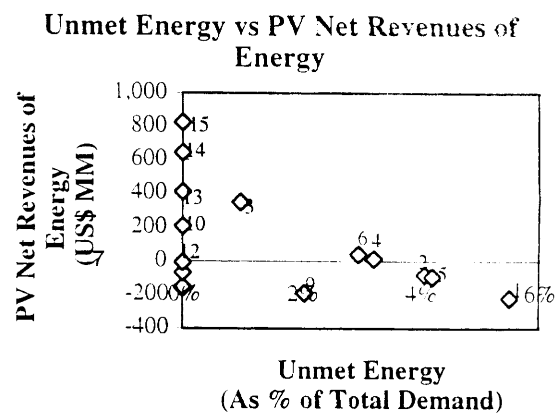
Scenario	NET REVS OF ENERGY AND CAPACITY		First Year When....								
	NPV (US$MM)		...When Demand	...When High	...When Fuel	NPV of New Capacity Investment (US$MM)					
#	Energy (excl. fuel cost)	Capacity	Not Met	Cost Used	Oil Used	New Thermal	Los Blancos	Potrerillos	El Baqueano	P. del Viento	Scenario
1	(223.048)	111.902	2021	2020	2020	-	-	-	-	-	-
2	(86.374)	156.893	2022	2021	2021	-	-	(59.091)	-	-	(59.091)
3	348.963	243.835	2025	2024	2025	82.104	-	-	-	-	82.104
4	10.410	182.739	2023	2022	2022	-	86.772	-	-	-	86.772
5	(98.011)	148.481	2022	2021	2021	-	-	-	32.058	-	32.058
6	38.895	189.089	2023	2022	2022	-	-	-	-	71.063	71.063
7	(161.252)	110.539	NA	2027	2027	-	-	-	-	-	-
8	(152.793)	110.409	NA	NA	NA	-	-	-	-	-	-
9	(193.218)	109.173	2024	2023	2023	-	-	-	-	-	-
10	207.242	198.034	NA	NA	NA	29.523	-	-	-	-	29.523
11	(70.447)	140.129	NA	2027	NA	-	-	(53.444)	-	-	(53.444)
12	(8.779)	157.519	NA	NA	NA	-	48.768	-	-	-	48.768
13	411.101	252.053	NA	NA	NA	66.772	-	-	-	-	66.772
14	642.067	305.203	NA	NA	NA	(3.889)	-	-	-	-	(3.889)
15	822.668	340.340	NA	NA	NA	36.469	-	-	-	-	36.469

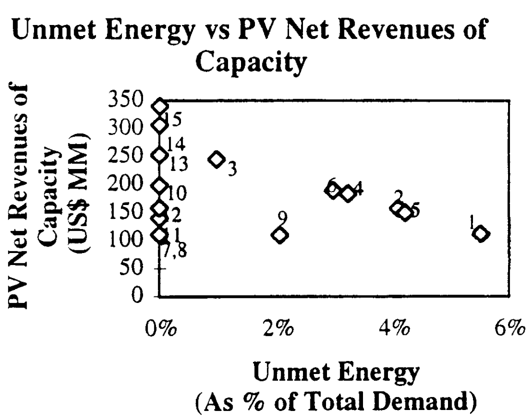
Scenario	IRR of New Capacity Investment (%)						
#	New Thermal	Los Blancos	Potrerillos	El Baqueano	P. del Viento	Scenario	NOTES
1	NA	NA	NA	NA	NA	NA	
2	NA	NA	9.27%	NA	NA	9.27%	
3	16.33%	NA	NA	NA	NA	16.33%	
4	NA	18.40%	NA	NA	NA	18.40%	
5	NA	NA	NA	15.81%	NA	15.81%	
6	NA	NA	NA	NA	16.13%	16.13%	
7	NA	NA	NA	NA	NA	NA	
8	NA	NA	NA	NA	NA	NA	
9	NA	NA	NA	NA	NA	NA	
10	14.17%	NA	NA	NA	NA	14.17%	14.17% represents IRR on investment from 2000-2027
11	NA	NA	8.16%	NA	NA	8.16%	8.16% represents IRR on investment from 2000-2027
12	NA	17.21%	NA	NA	NA	17.21%	17.21% represents IRR on investment from 2000-2027
13	15.68%	NA	NA	NA	NA	15.68%	
14	11.69%	NA	NA	NA	NA	11.69%	11.69% can be misleading because of negative CF due to late invest.
15	13.69%	NA	NA	NA	NA	13.69%	13.69% can be misleading because of negative CF due to late invest

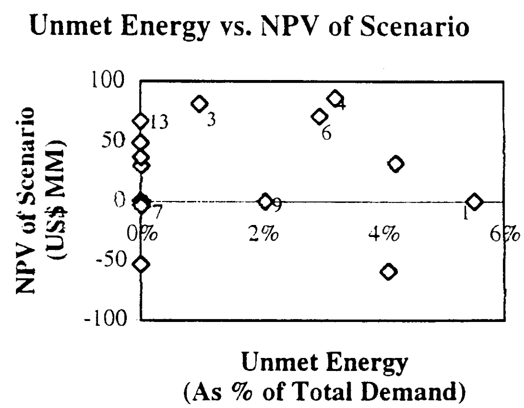

Unmet Energy vs. Energy Met w/ High Costs (as % of Total Demand)
High Cost Energy
10%
8%
6%
4%
2%
0%
0%
2%
4%
6%
8%
Unmet Energy

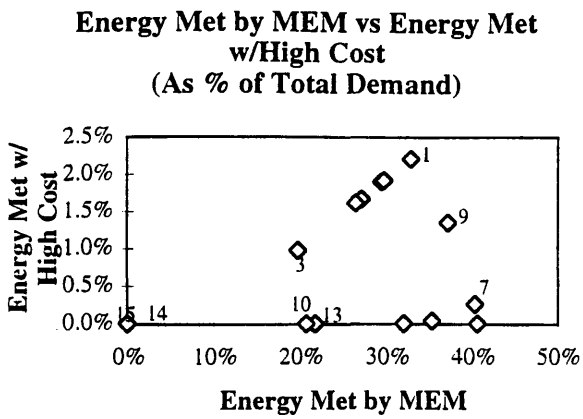

Energy Met by MEM vs Unmet Energy (As % of Total Demand)
Unmet Energy
6%
5%
4%
3%
2%
1%
0%
10%
20%
30%
40%
50%
Energy Met by MEM

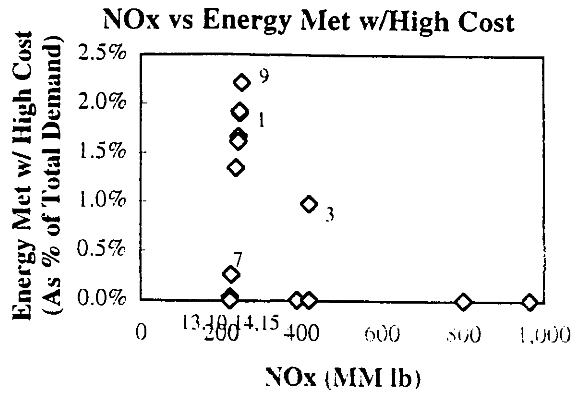

NOx vs Unmet Energy
Unmet Energy (As a % of Total Demand)
6%
5%
4%
3%
2%
1%
0%
0
500
1,000
NOx (MM lb)

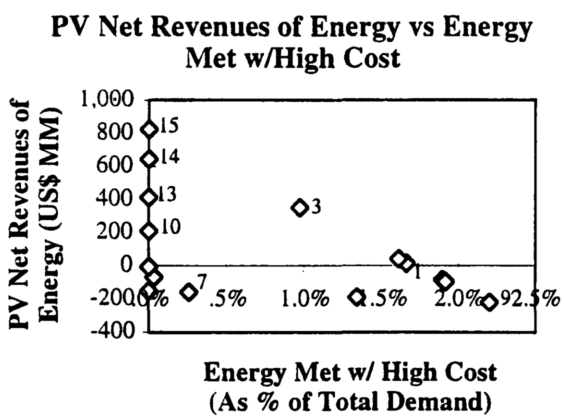

Unmet Energy vs PV Net Revenues of Energy
PV Net Revenues of Energy (US$ MM)
1,000
800
600
400
200
0
-200
-400
Unmet Energy (As % of Total Demand)

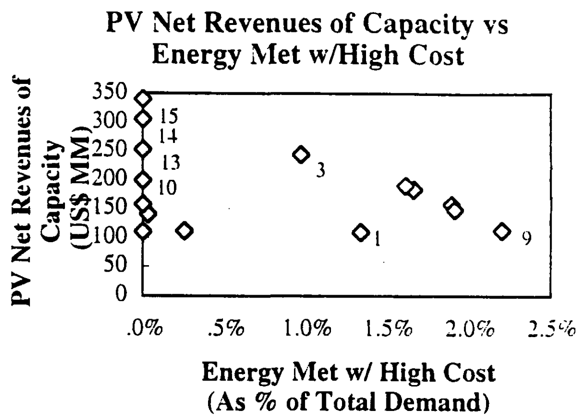

Unmet Energy vs PV Net Revenues of Capacity
PV Net Revenues of Capacity (US$ MM)
350
300
250
200
150
100
50
0
0%
2%
4%
6%
Unmet Energy (As % of Total Demand)

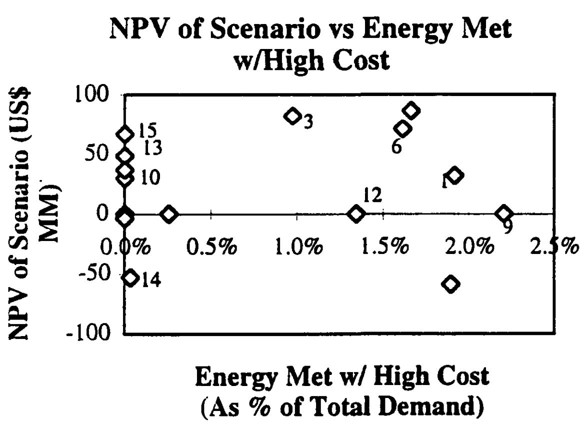

Unmet Energy vs. NPV of Scenario
NPV of Scenario (US$ MM)
100
50
0
-50
-100
0%
2%
4%
6%
Unmet Energy (As % of Total Demand)

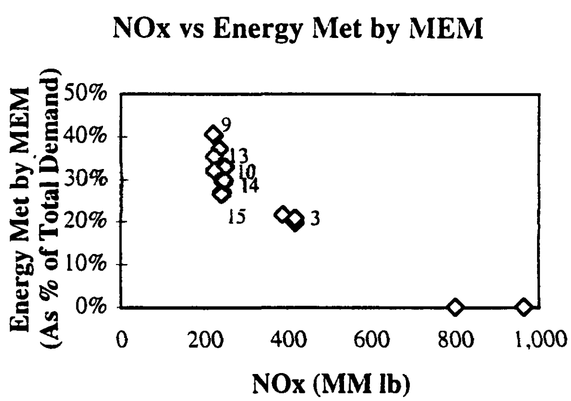

Energy Met by MEM vs Energy Met w/High Cost (As % of Total Demand)
Energy Met w/ High Cost
2.5%
2.0%
1.5%
1.0%
0.5%
0.0%
0%
10%
20%
30%
40%
50%
Energy Met by MEM

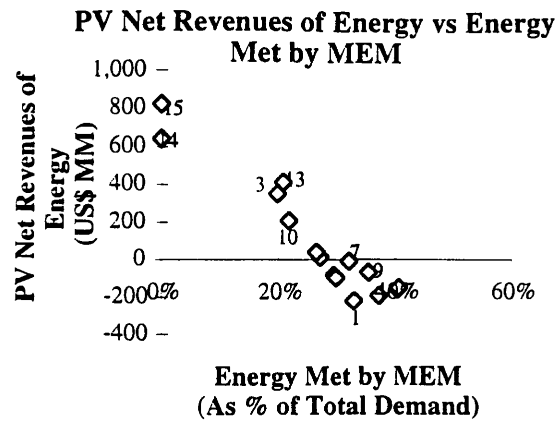

NOx vs Energy Met w/High Cost
Energy Met w/ High Cost (As % of Total Demand)
2.5%
2.0%
1.5%
1.0%
0.5%
0.0%
0
200
400
600
800
1,000
NOx (MM lb)

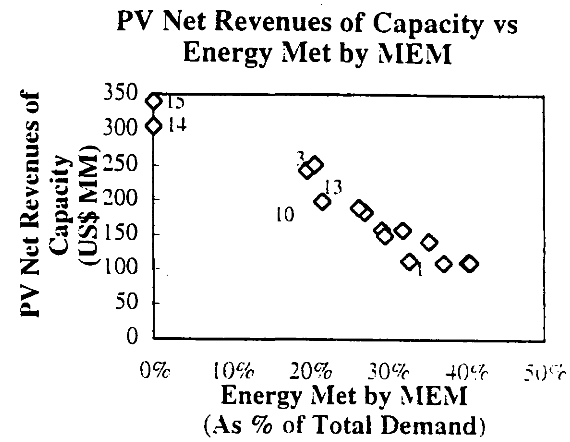

PV Net Revenues of Energy vs Energy Met w/High Cost
PV Net Revenues of Energy (US$ MM)
1,000
800
600
400
200
0
-200
-400
Energy Met w/ High Cost (As % of Total Demand)

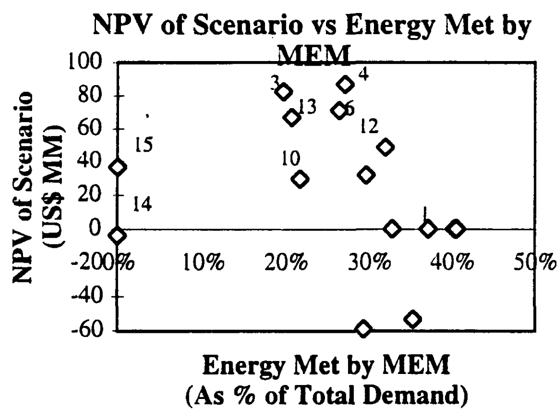

PV Net Revenues of Capacity vs Energy Met w/High Cost
PV Net Revenues of Capacity (US$ MM)
350
300
250
200
150
100
50
0
.0%
.5%
1.0%
1.5%
2.0%
2.5%
Energy Met w/ High Cost (As % of Total Demand)

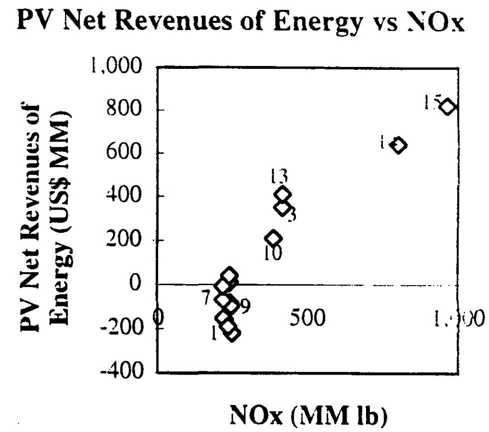

NPV of Scenario vs Energy Met w/High Cost
NPV of Scenario (US$ MM)
100
50
0
-50
-100
0.0%
0.5%
1.0%
1.5%
2.0%
2.5%
Energy Met w/ High Cost (As % of Total Demand)

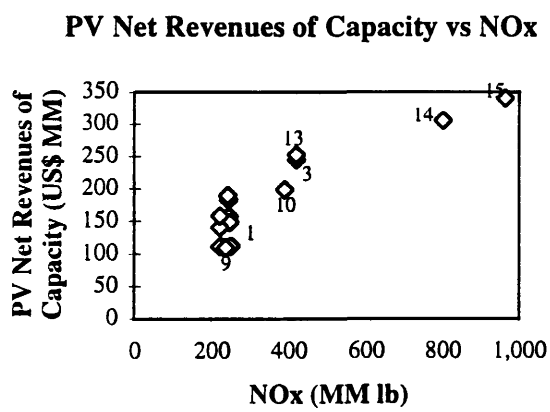

NOx vs Energy Met by MEM
Energy Met by MEM (As % of Total Demand)
50%
40%
30%
20%
10%
0%
0
200
400
600
800
1,000
NOx (MM lb)

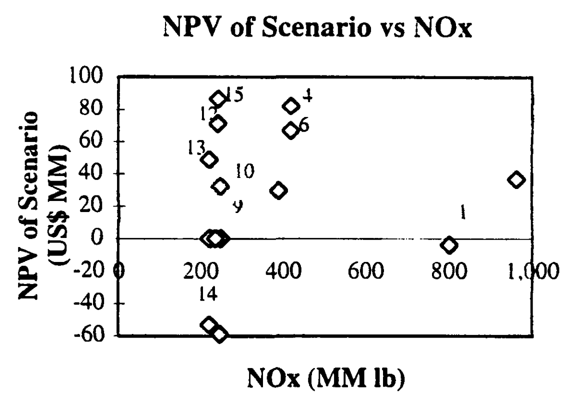

PV Net Revenues of Energy vs Energy Met by MEM
PV Net Revenues of Energy (US$ MM)
1,000
800
600
400
200
0
-200
-400
0%
20%
40%
60%
Energy Met by MEM
(As % of Total Demand)


PV Net Revenues of Capacity vs Energy Met by MEM
PV Net Revenues of Capacity (US$ MM)
350
300
250
200
150
100
50
0
0%
10%
20%
30%
40%
50%
Energy Met by MEM
(As % of Total Demand)

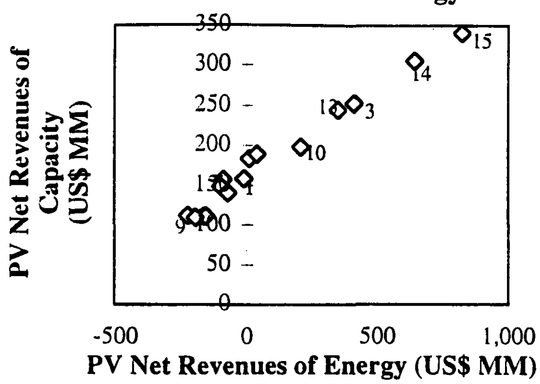

NPV of Scenario vs Energy Met by MEM
NPV of Scenario (US$ MM)
100
80
60
40
20
0
-20
-40
-60
0%
10%
20%
30%
40%
50%
Energy Met by MEM
(As % of Total Demand)


PV Net Revenues of Energy vs NOx
PV Net Revenues of Energy (US$ MM)
1,000
800
600
400
200
0
-200
-400
0
500
1,000
NOx (MM lb)

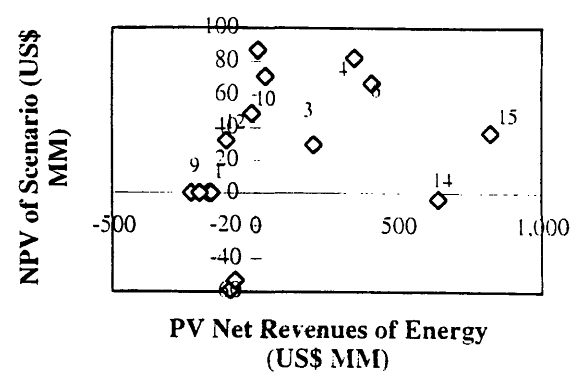

PV Net Revenues of Capacity vs NOx
PV Net Revenues of Capacity (US$ MM)
350
300
250
200
150
100
50
0
0
200
400
600
800
1,000
NOx (MM lb)


NPV of Scenario vs NOx
NPV of Scenario (US$ MM)
100
80
60
40
20
0
-20
-40
-60
0
200
400
600
800
1,000
NOx (MM lb)

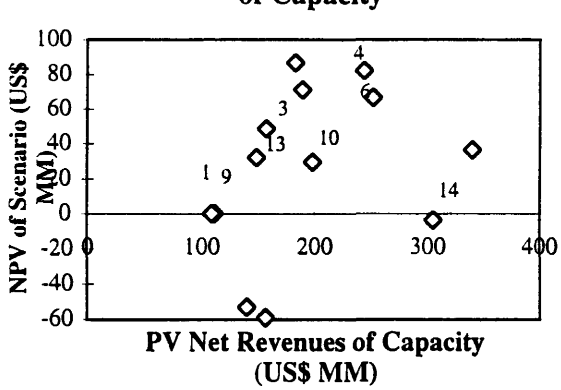
PV Net Revenues of Capacity vs PV Net Revenues of Energy



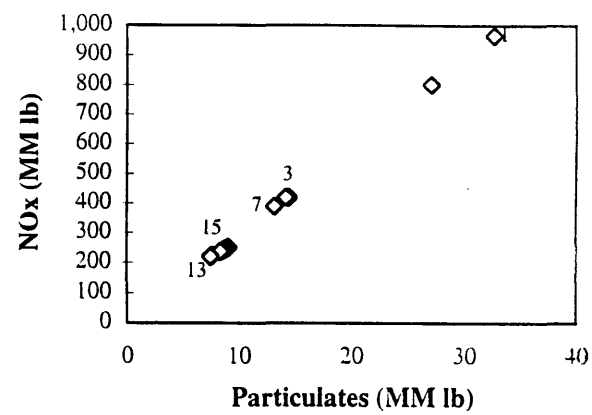
NPV of Scenario vs PV Net Revenues of Energy



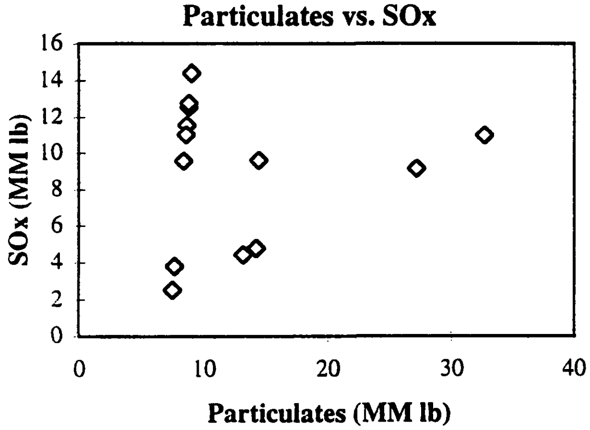
NPV of Scenario vs PV Net Revenues of Capacity



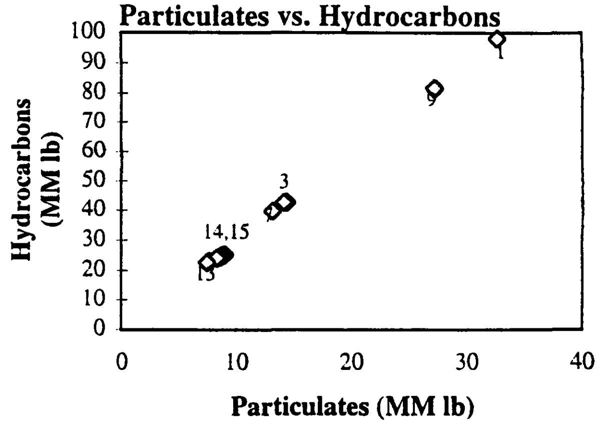
Particulates vs. NOx

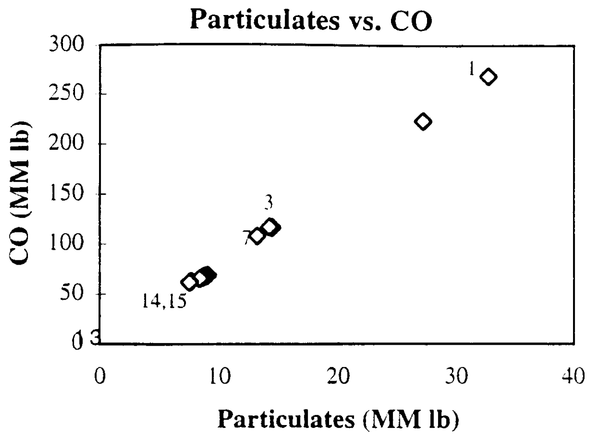


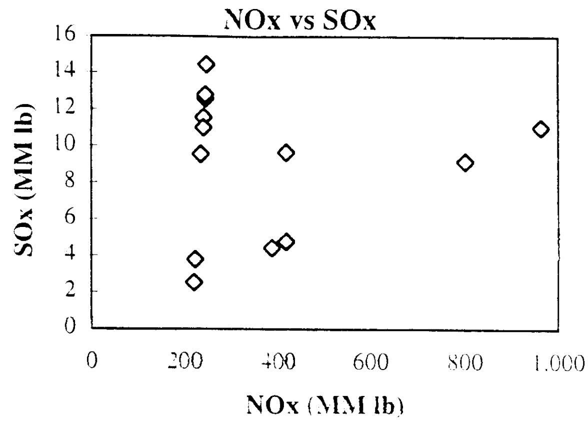
Particulates vs. SOx

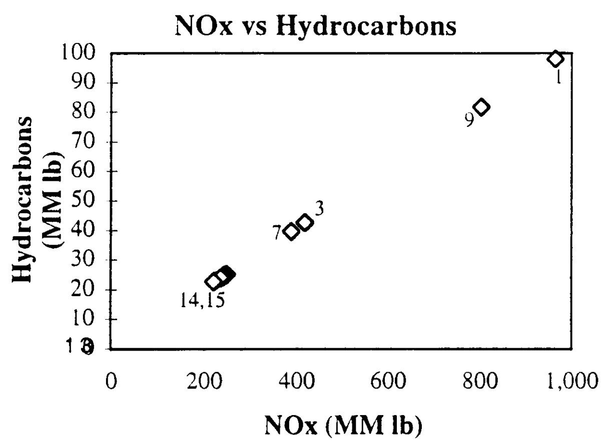


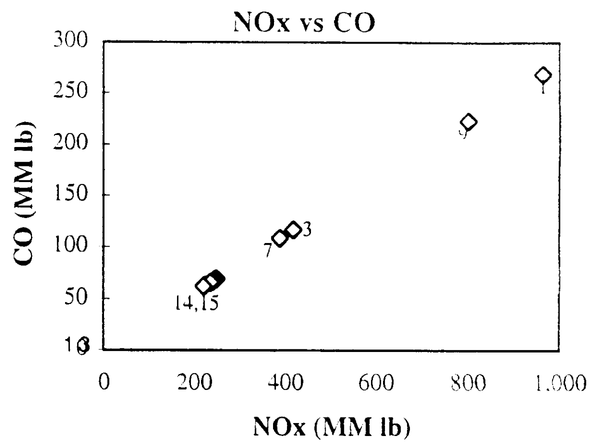
Particulates vs. Hydrocarbons

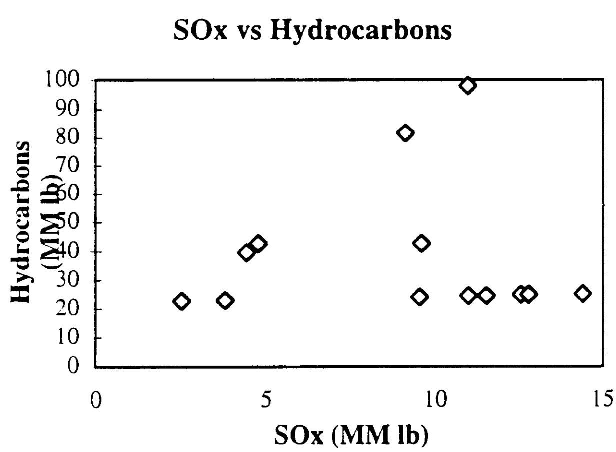


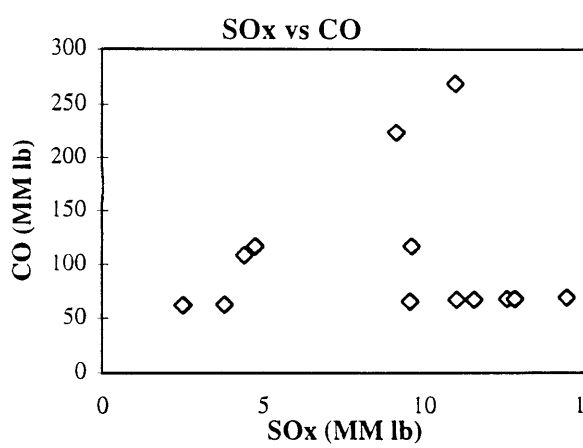

Particulates vs. CO
CO (MM lb)
Particulates (MM lb)
300
250
200
150
100
50
0
0
10
20
30
40
1
3
7
14,15


NOx vs SOx
SOx (MM lb)
NOx (MM lb)
16
14
12
10
8
6
4
2
0
0
200
400
600
800
1,000


NOx vs Hydrocarbons
Hydrocarbons (MM lb)
NOx (MM lb)
100
90
80
70
60
50
40
30
20
10
0
200
400
600
800
1,000
1
9
3
7
14,15


NOx vs CO
CO (MM lb)
NOx (MM lb)
300
250
200
150
100
50
0
200
400
600
800
1,000
1
9
3
7
14,15


SOx vs Hydrocarbons
Hydrocarbons (MM lb)
SOx (MM lb)
100
90
80
70
60
50
40
30
20
10
0
0
5
10
15


SOx vs CO
CO (MM lb)
SOx (MM lb)
300
250
200
150
100
50
0
0
5
10
15

Appendix C: Other Futures Results and Trade-Off Curves

FUTURE 2
Description:

Demand: 1997 equals to 1993 demand. Each sector grows at 4%/yr, except for Industrial which remains constant until 2001, and starts growing at 4%/yr beginning in 2002

Prices
Natural Gas (US$/MMBtu) prices start at 1.72 and increase by 1.5%/yr
Fuel Oil (US$/tonne) start at 152 and increases at 1%
MEM Spot Price (US$/MWh) start at 28, decrease by 2% until 2000, and start increasing at 1% after that
MEM Capacity Price (US$/MW-hr off-valley weeday) starts at 10 until 2000, and goes down to 8 after that.

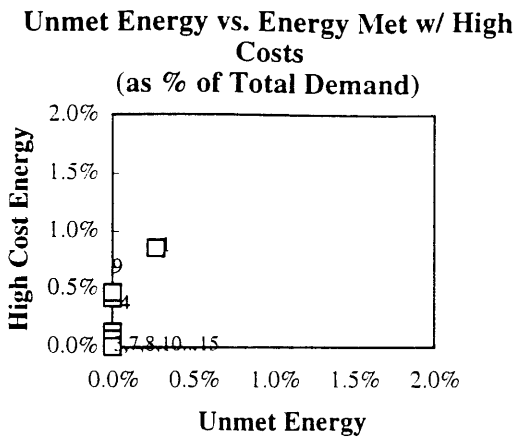
Spot Market w/ Chile Link (As % of Spot Price)	0.95

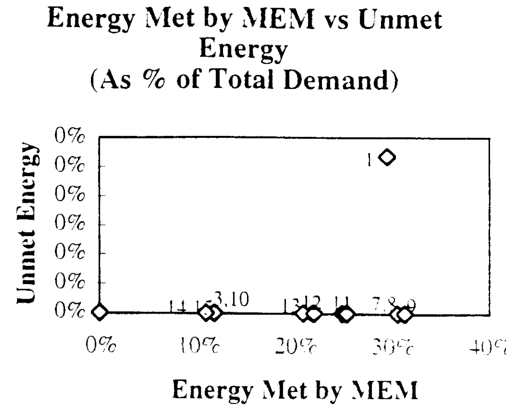
Discount Rate (% p.a.)	12%

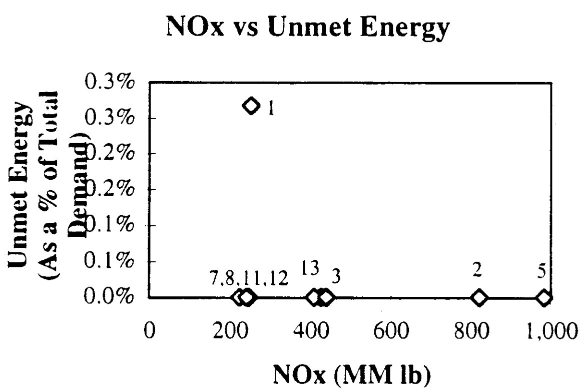
Scenario #	Percentage of Energy Demand Not Met	Percentage of Energy Demand Met w/ High Cost	Percentage of Energy Demand Met by MEM	MC Last High Cost (US$/MWh @ CdP)	Emissions (MM lb)				
					Particulates	NOx	SOx	Hydrocarbons	CO
1	0.27%	0.86%	29.53%	65.62	8.65	250.15	6.26	25.36	69.44
2	0.00%	0.42%	24.99%	65.62	8.38	245.33	4.15	24.92	68.23
3	0.00%	0.00%	11.83%	-	14.45	426.13	4.85	43.34	118.66
4	0.00%	0.13%	21.97%	37.53	8.21	242.08	2.75	24.62	67.41
5	0.00%	0.47%	25.42%	65.62	8.41	245.88	4.38	24.97	68.37
6	0.00%	0.07%	20.99%	37.53	8.18	241.44	2.75	24.55	67.23
7	0.00%	0.00%	30.66%	-	8.16	240.69	2.74	24.48	67.02
8	0.00%	0.00%	30.66%	-	8.16	240.69	2.74	24.48	67.02
9	0.00%	0.00%	31.37%	-	7.56	223.11	2.54	22.69	62.13
10	0.00%	0.00%	11.83%	-	13.84	408.18	4.65	41.51	113.66
11	0.00%	0.00%	25.41%	-	8.16	240.69	2.74	24.48	67.02
12	0.00%	0.00%	22.10%	-	8.16	240.69	2.74	24.48	67.02
13	0.00%	0.00%	10.93%	-	14.86	438.49	4.99	44.59	122.10
14	0.00%	0.00%	0.00%	-	27.84	821.33	9.35	83.53	228.70
15	0.00%	0.00%	0.00%	-	33.36	984.04	11.20	100.07	274.01

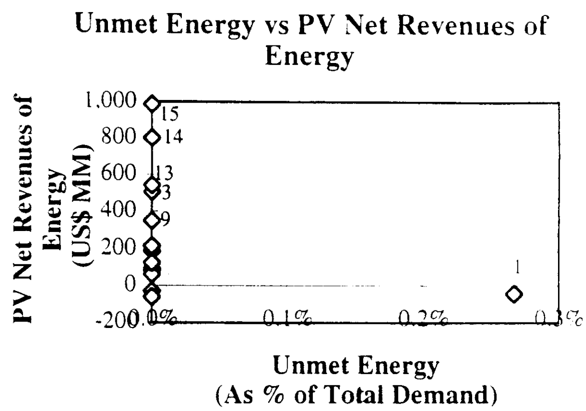
Scenario	NET REVS OF ENERGY AND CAPACITY		First Year When....			NPV of New Capacity Investments (US$MM)					
	NPV (US$MM)		...When Demand	...When High	...When Fuel						
#	Energy (excl. fuel cost)	Capacity	Not Met	Cost Used	Oil Used	New Thermal	Los Blancos	Potrerillos	El Baqueano	P. del Viento	Scenario
1	(46.233)	133.314	2026	2025	2025	-	-	-	-	-	-
2	90.596	178.420	NA	2026	2027	-	-	(60.193)	-	-	(60.193)
3	505.404	265.864	NA	NA	NA	115.392	-	-	-	-	115.392
4	183.560	204.322	NA	2027	NA	-	85.500	-	-	-	85.500
5	78.942	169.997	NA	2026	2027	-	-	-	30.994	-	30.994
6	211.407	210.699	NA	2027	NA	-	-	-	-	69.886	69.886
7	(31.329)	132.948	NA	NA	NA	-	-	-	-	-	-
8	(31.329)	132.948	NA	NA	NA	-	-	-	-	-	-
9	(65.052)	124.587	NA	NA	NA	-	-	-	-	-	-
10	349.453	220.573	NA	NA	NA	69.653	-	-	-	-	69.653
11	58.257	162.648	NA	NA	NA	-	-	(46.647)	-	-	(46.647)
12	120.984	180.058	NA	NA	NA	-	57.067	-	-	-	57.067
13	541.857	274.592	NA	NA	NA	117.295	-	-	-	-	117.295
14	799.703	327.741	NA	NA	NA	88.263	-	-	-	-	88.263
15	984.577	362.878	NA	NA	NA	129.290	-	-	-	-	129.290

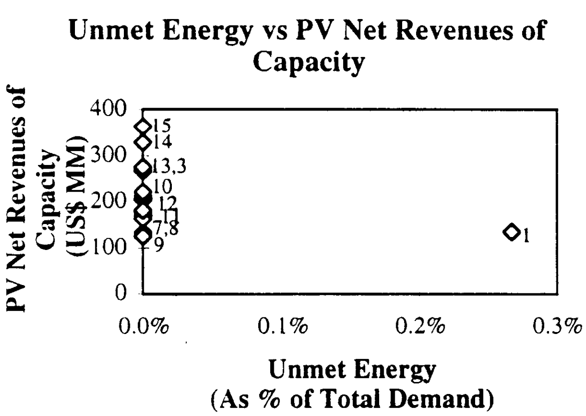
Scenario #	IRR of New Capacity Investments (%)						NOTES
	New Thermal	Los Blancos	Potrerillos	El Baqueano	P. del Viento	Scenario	
1	NA	NA	NA	NA	NA	NA	
2	NA	NA	9.05%	NA	NA	9.05%	
3	18.17%	NA	NA	NA	NA	18.17%	
4	NA	18.55%	NA	NA	NA	18.55%	
5	NA	NA	NA	15.86%	NA	15.86%	
6	NA	NA	NA	NA	16.23%	16.23%	
7	NA	NA	NA	NA	NA	NA	
8	NA	NA	NA	NA	NA	NA	
9	NA	NA	NA	NA	NA	NA	
10	17.11%	NA	NA	NA	NA	17.11%	17.11% represents IRR on investment from 2000-2027
11	NA	NA	8.65%	NA	NA	8.65%	8.65% represents IRR on investment from 2000-2027
12	NA	18.11%	NA	NA	NA	18.11%	18.11% represents IRR on investment from 2000-2027
13	18.00%	NA	NA	NA	NA	18.00%	
14	16.62%	NA	NA	NA	NA	16.62%	16.62% can be misleading because of negative CF due to late invest.
15	17.06%	NA	NA	NA	NA	17.06%	17.06% can be misleading because of negative CF due to late invest

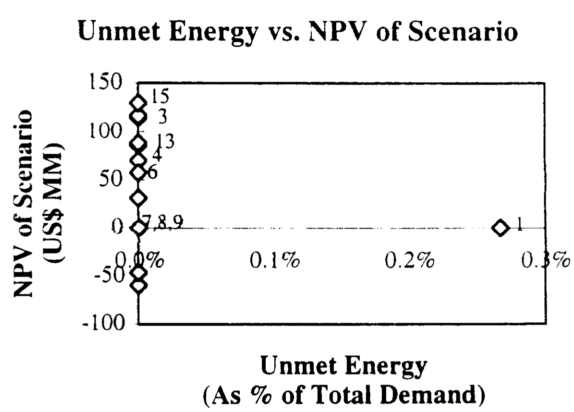

Unmet Energy vs. Energy Met w/ High Costs
(as % of Total Demand)
High Cost Energy
Unmet Energy
2.0%
1.5%
1.0%
0.5%
0.0%
0.0%
0.5%
1.0%
1.5%
2.0%

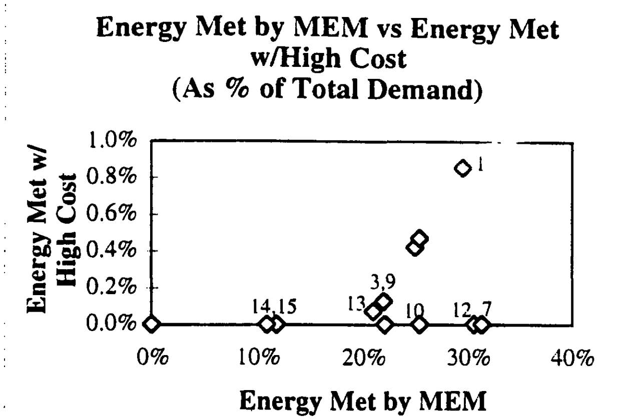

Energy Met by MEM vs Unmet Energy
(As % of Total Demand)
Unmet Energy
Energy Met by MEM
0%
10%
20%
30%
40%

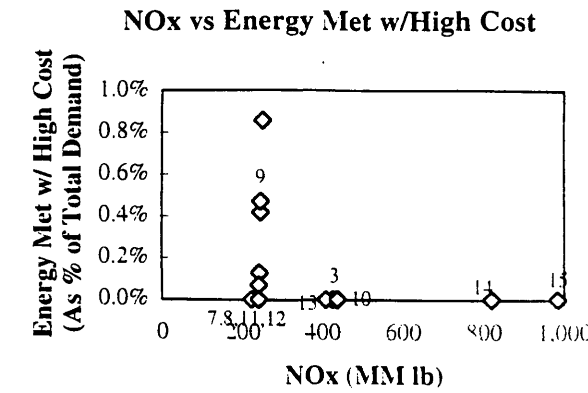

NOx vs Unmet Energy
Unmet Energy
(As a % of Total Demand)
NOx (MM lb)
0.3%
0.2%
0.1%
0.0%
0
200
400
600
800
1,000

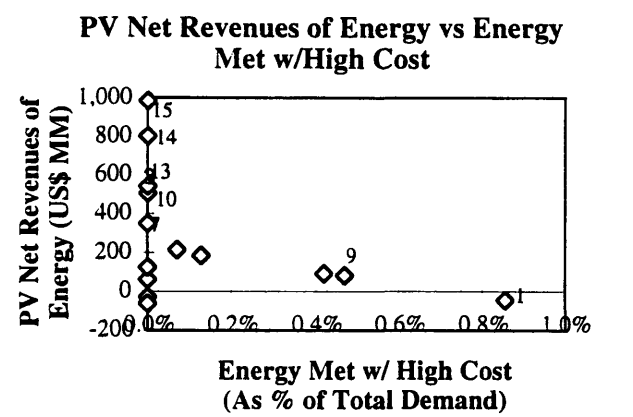

Unmet Energy vs PV Net Revenues of Energy
PV Net Revenues of Energy
(US$ MM)
Unmet Energy
(As % of Total Demand)
1,000
800
600
400
200
0
-200

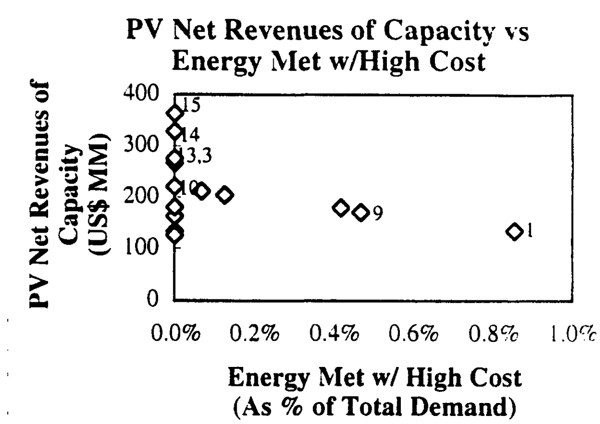

Unmet Energy vs PV Net Revenues of Capacity
PV Net Revenues of Capacity
(US$ MM)
Unmet Energy
(As % of Total Demand)
400
300
200
100
0
0.0%
0.1%
0.2%
0.3%

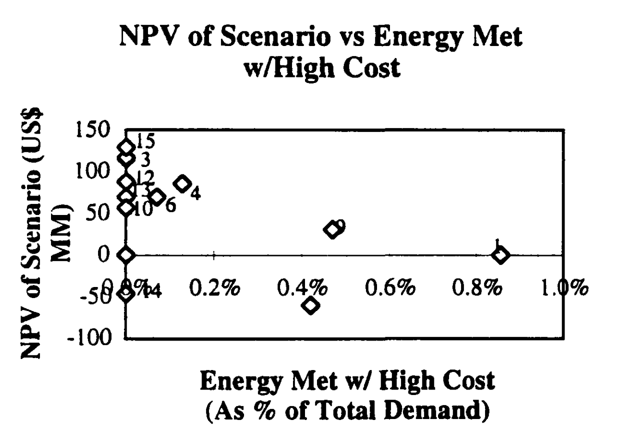

Unmet Energy vs. NPV of Scenario
NPV of Scenario
(US$ MM)
Unmet Energy
(As % of Total Demand)
150
100
50
0
-50
-100
0.1%
0.2%

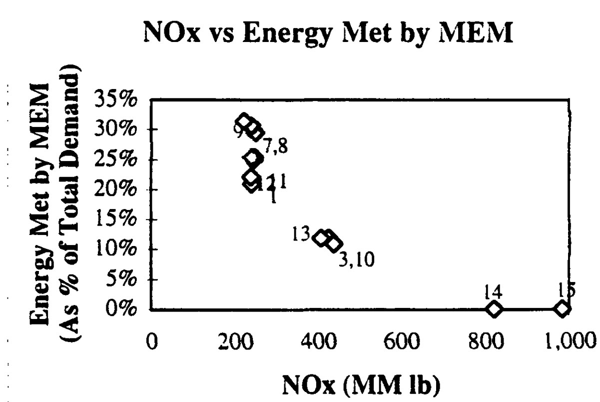

Energy Met by MEM vs Energy Met w/High Cost (As % of Total Demand)
Energy Met w/ High Cost
1.0%
0.8%
0.6%
0.4%
0.2%
0.0%
0%
10%
20%
30%
40%
Energy Met by MEM
1
3,9
13
14,15
10
12,7

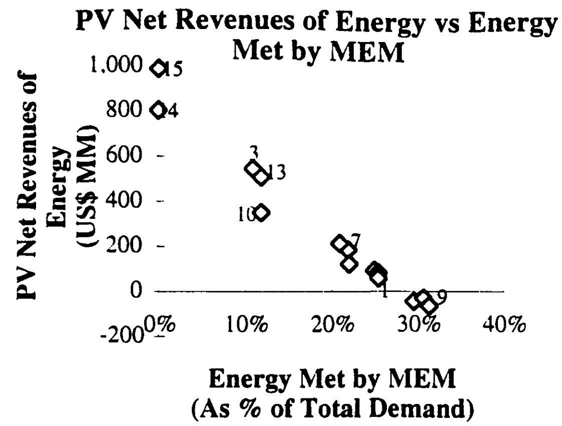

NOx vs Energy Met w/High Cost
Energy Met w/ High Cost (As % of Total Demand)
1.0%
0.8%
0.6%
0.4%
0.2%
0.0%
0
200
400
600
800
1,000
NOx (MM lb)
9
3
13
10
7,8,11,12
14
15

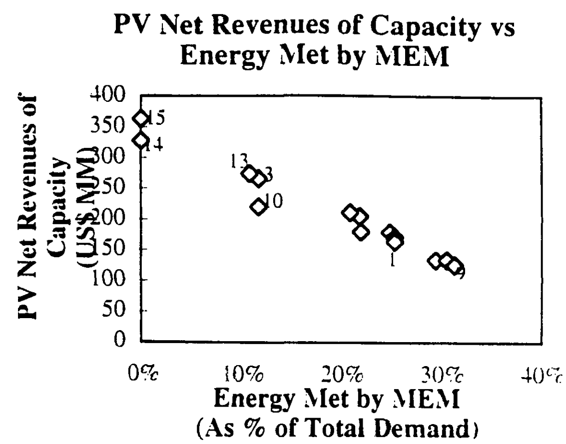

PV Net Revenues of Energy vs Energy Met w/High Cost
PV Net Revenues of Energy (US$ MM)
1,000
800
600
400
200
0
-200
0.0%
0.2%
0.4%
0.6%
0.8%
1.0%
Energy Met w/ High Cost (As % of Total Demand)
15
14
13
10
9
1

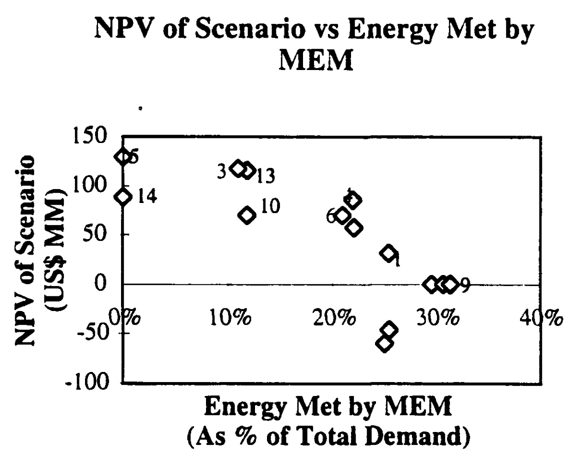

PV Net Revenues of Capacity vs Energy Met w/High Cost
PV Net Revenues of Capacity (US$ MM)
400
300
200
100
0
0.0%
0.2%
0.4%
0.6%
0.8%
1.0%
Energy Met w/ High Cost (As % of Total Demand)
15
14
3,3
10
9
1

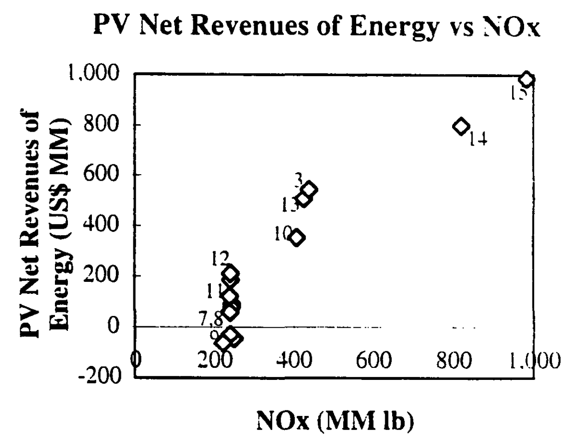

NPV of Scenario vs Energy Met w/High Cost
NPV of Scenario (US$ MM)
150
100
50
0
-50
-100
0.0%
0.2%
0.4%
0.6%
0.8%
1.0%
Energy Met w/ High Cost (As % of Total Demand)
15
3
12
10
4
6
14
1

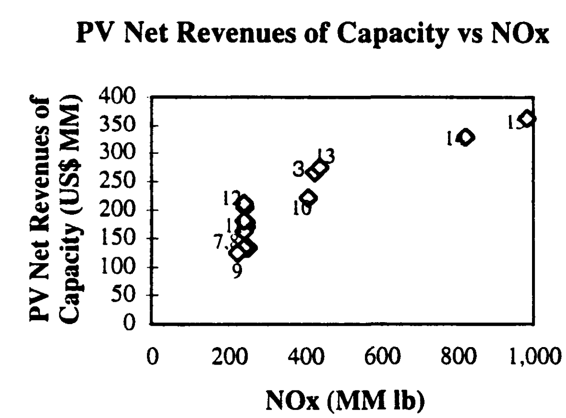

NOx vs Energy Met by MEM
Energy Met by MEM (As % of Total Demand)
35%
30%
25%
20%
15%
10%
5%
0%
0
200
400
600
800
1,000
NOx (MM lb)
7,8
13
3,10
14
15

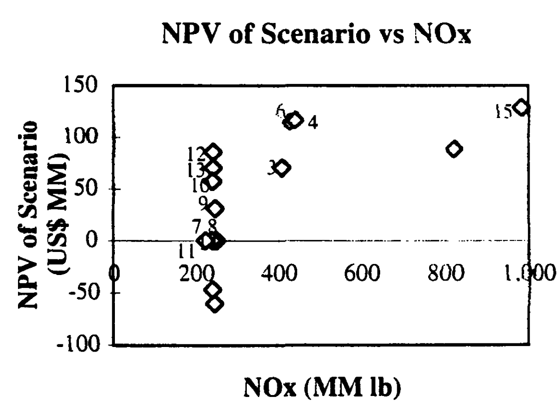

PV Net Revenues of Energy vs Energy Met by MEM
PV Net Revenues of Energy (US$ MM)
Energy Met by MEM (As % of Total Demand)

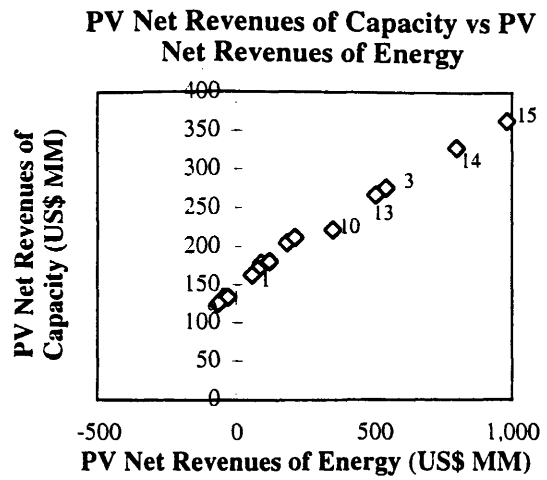

PV Net Revenues of Capacity vs Energy Met by MEM
PV Net Revenues of Capacity (US$ MM)
Energy Met by MEM (As % of Total Demand)

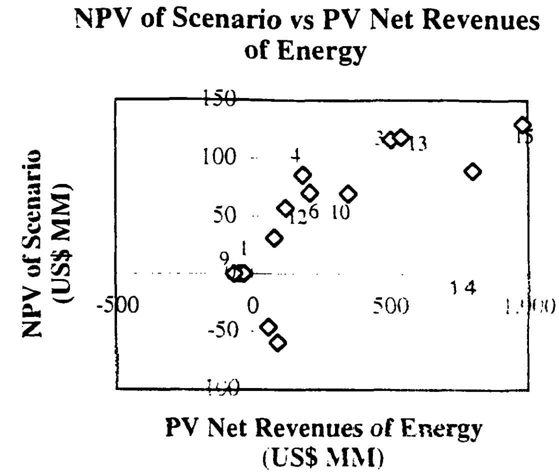

NPV of Scenario vs Energy Met by MEM
NPV of Scenario (US$ MM)
Energy Met by MEM (As % of Total Demand)

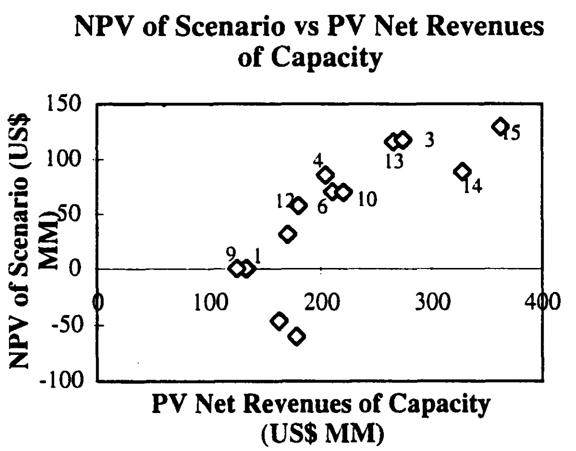

PV Net Revenues of Energy vs NOx
PV Net Revenues of Energy (US$ MM)
NOx (MM lb)

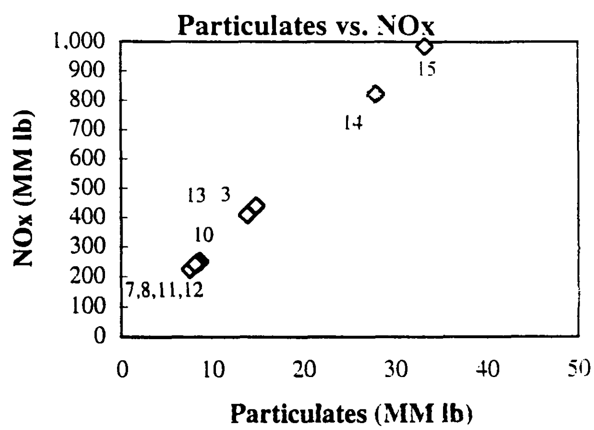

PV Net Revenues of Capacity vs NOx
PV Net Revenues of Capacity (US$ MM)
NOx (MM lb)

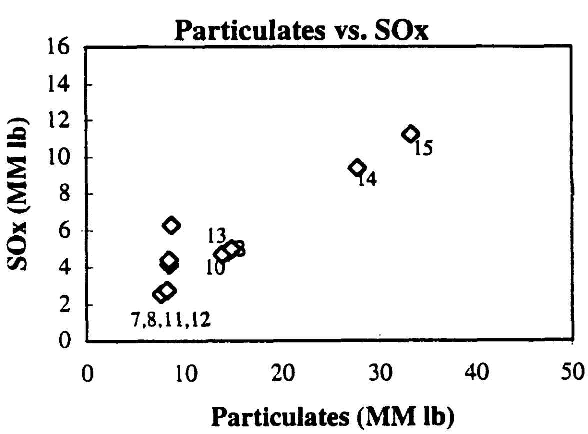

NPV of Scenario vs NOx
NPV of Scenario (US$ MM)
NOx (MM lb)

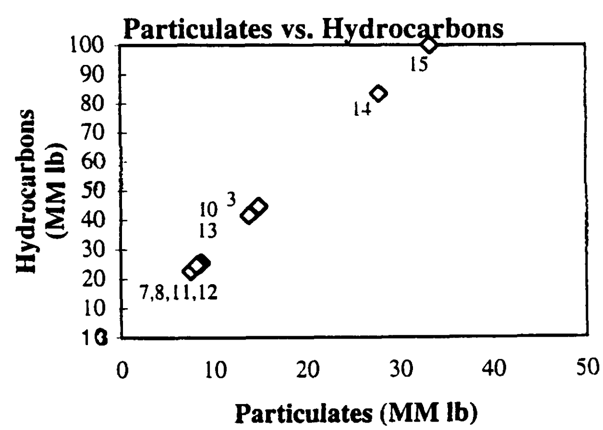

PV Net Revenues of Capacity vs PV Net Revenues of Energy
PV Net Revenues of Capacity (US$ MM)
PV Net Revenues of Energy (US$ MM)

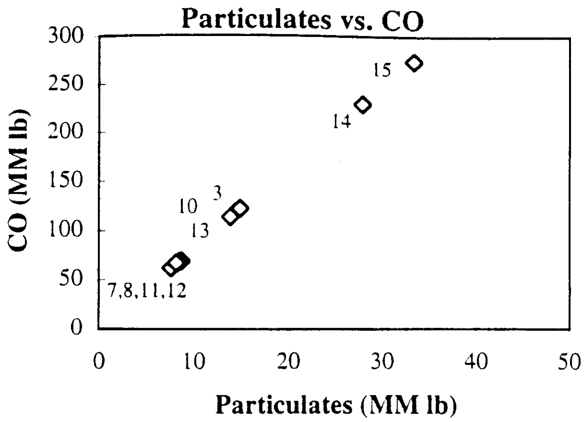

NPV of Scenario vs PV Net Revenues of Energy
NPV of Scenario (US$ MM)
PV Net Revenues of Energy (US$ MM)

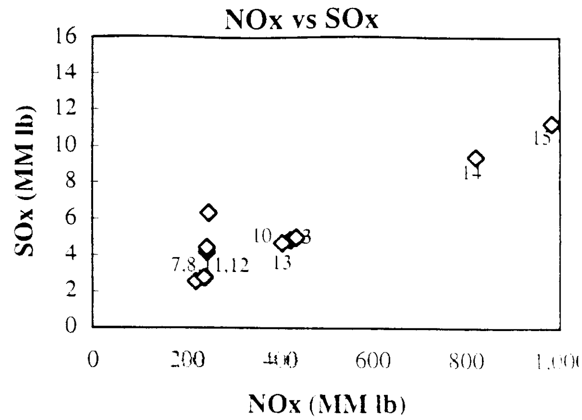

NPV of Scenario vs PV Net Revenues of Capacity
NPV of Scenario (US$ MM)
PV Net Revenues of Capacity (US$ MM)

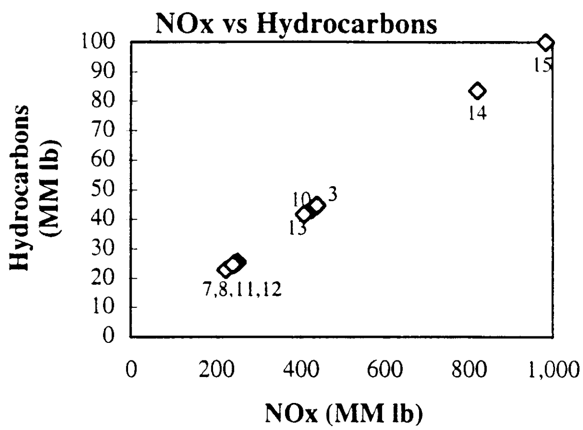

Particulates vs. NOx
NOx (MM lb)
Particulates (MM lb)

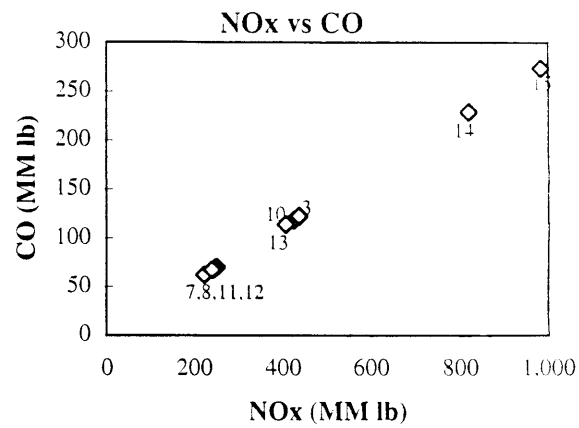

Particulates vs. SOx
SOx (MM lb)
Particulates (MM lb)

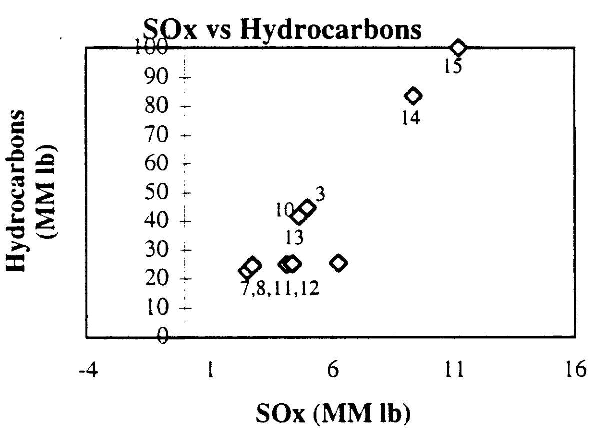

Particulates vs. Hydrocarbons
Hydrocarbons (MM lb)
Particulates (MM lb)

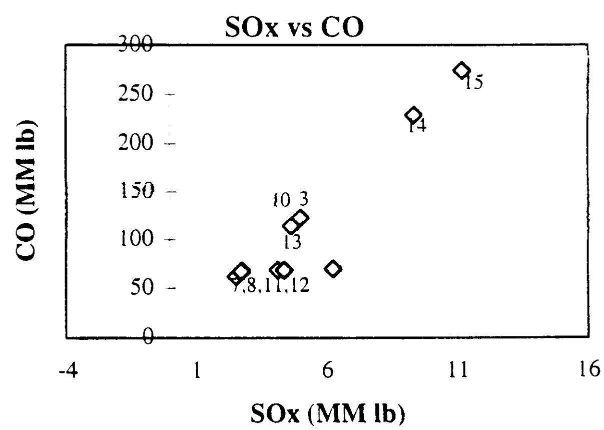

Particulates vs. CO
CO (MM lb)
Particulates (MM lb)
0
50
100
150
200
250
300
0
10
20
30
40
50
15
14
10
3
13
7,8,11,12


NOx vs SOx
SOx (MM lb)
NOx (MM lb)
0
2
4
6
8
10
12
14
16
0
200
400
600
800
1,000
15
14
10
3
13
7,8,11,12


NOx vs Hydrocarbons
Hydrocarbons (MM lb)
NOx (MM lb)
0
10
20
30
40
50
60
70
80
90
100
0
200
400
600
800
1,000
15
14
10
3
13
7,8,11,12


NOx vs CO
CO (MM lb)
NOx (MM lb)
0
50
100
150
200
250
300
0
200
400
600
800
1,000
14
10
3
13
7,8,11,12


SOx vs Hydrocarbons
Hydrocarbons (MM lb)
SOx (MM lb)
0
10
20
30
40
50
60
70
80
90
100
-4
1
6
11
16
15
14
10
3
13
7,8,11,12


SOx vs CO
CO (MM lb)
SOx (MM lb)
0
50
100
150
200
250
300
-4
1
6
11
16
15
14
10
3
13
7,8,11,12

FUTURE 3

Description:

Demand: 1997 equals to 1993 demand. Each sector grows at 6%/yr, except for Industrial which remains constant until 2001, and starts growing at 6%/yr, beginning in 2002. Agriculatural demand grows at 1%

Prices (constant through the 30 yr period)

Natural Gas (US$/MM	1.72
Fuel Oil (US$/tonne)	152

Spot prices starts at US$28/MWh and increases by 2% yearly

MEM Capacity Price (US$/MW-hr off-valley weeday) starts at 10 until 2000, and goes down to 8 after that.

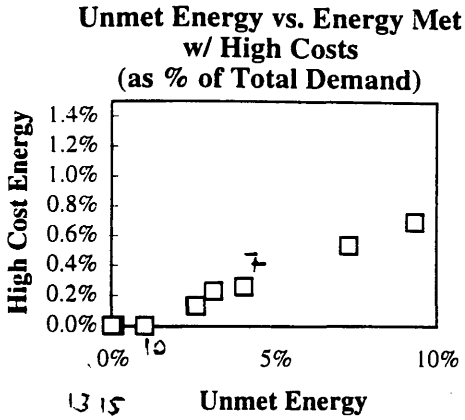
Spot Market w/ Chile Link (As % of Spot Price)	1

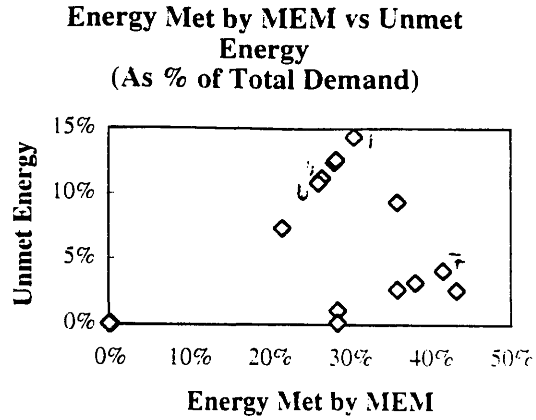
Discount Rate (% p.a.	12%

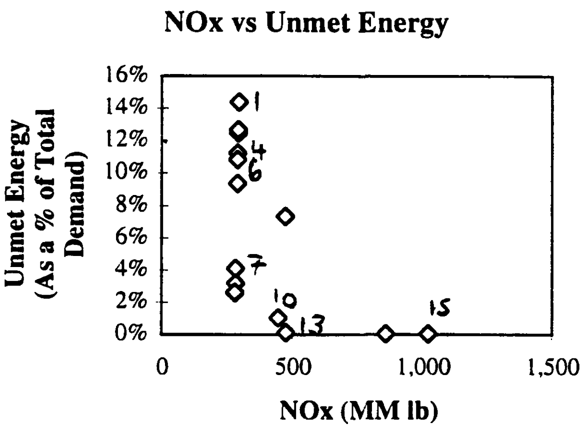
Percentage of Energy Demand Not Met	Percentage of Energy Demand Met w/ High Cost	Percentage of Energy Demand Met by MEM	MC Last High Cost (US$/MWh @ CdP)	Emissions (MM lb)				
				Particulates	NOx	SOx	Hydrocarbons	CO
14.37%	1.04%	30.55%	48.68	10.83	294.05	21.04	29.48	80.76
12.45%	0.91%	28.21%	48.68	10.69	292.08	19.41	29.32	80.32
7.30%	0.53%	21.66%	48.68	16.54	471.70	16.72	47.70	130.63
11.21%	0.81%	26.68%	48.68	10.57	290.45	18.07	29.18	79.95
12.63%	0.91%	28.43%	48.68	10.69	292.08	19.41	29.32	80.32
10.83%	0.78%	26.20%	48.68	10.54	290.10	17.78	29.15	79.87
4.06%	0.26%	41.64%	48.68	9.96	282.22	11.27	28.51	78.08
2.55%	0.13%	43.28%	48.68	9.81	280.23	9.62	28.34	77.62
9.34%	0.69%	35.94%	48.68	10.43	288.64	16.58	29.03	79.54
1.01%	0.00%	28.48%	48.68	15.35	445.74	9.90	45.21	123.81
3.14%	0.23%	38.21%	48.68	9.92	281.73	10.87	28.47	77.96
2.60%	0.13%	35.97%	48.68	9.81	280.23	9.62	28.34	77.62
0.09%	0.00%	28.48%	48.68	16.37	476.05	10.24	48.30	132.25
0.00%	0.00%	0.20%	-	29.35	858.90	14.60	87.23	238.86
0.00%	0.00%	0.00%	-	34.87	1,021.60	16.45	103.78	284.16

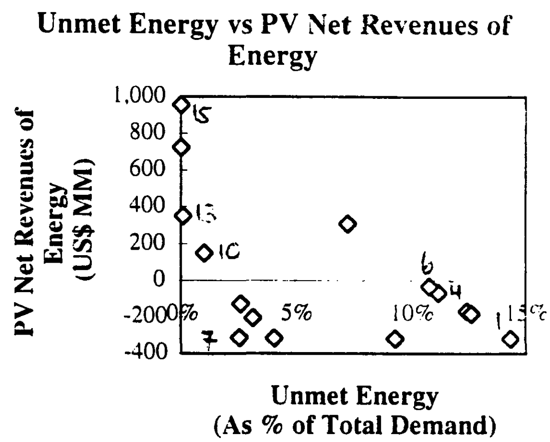
NET REVS OF ENERGY AND CAPACITY		First Year When....			NPV of New Capacity Investments (US$MM)					
NPV (US$MM)		...When Demand	...When High	...When Fuel						
Energy (excl. fuel cost)	Capacity	Not Met	Cost Used	Oil Used	New Thermal	Los Blancos	Potrerillos	El Baqueano	P. del Viento	Scenario
(324.373)	110.116	2017	2017	2017	-	-	-	-	-	-
(174.232)	155.184	2018	2018	2018	-	-	(29.814)	-	-	(29.814)
306.581	242.288	2021	2020	2020	233.170	-	-	-	-	233.170
(71.576)	181.060	2019	2018	2018	-	122.357	-	-	-	122.357
(188.083)	146.747	2018	2018	2018	-	-	-	50.126	-	50.126
(36.336)	187.417	2019	2019	2019	-	-	-	-	111.008	111.008
(318.357)	109.094	2023	2022	2022	-	-	-	-	-	-
(317.035)	108.981	2024	2024	2024	-	-	-	-	-	-
(321.625)	109.577	2020	2019	2019	-	-	-	-	-	-
145.835	196.505	2026	NA	2025	178.779	-	-	-	-	178.779
(208.183)	138.789	2024	2023	2023	-	-	(18.692)	-	-	(18.692)
(131.698)	156.091	2024	2024	2024	-	90.091	-	-	-	90.091
349.057	250.524	2027	NA	2025	247.508	-	-	-	-	247.508
724.467	303.674	NA	NA	2025	378.928	-	-	-	-	378.928
952.905	338.810	NA	NA	2025	478.501	-	-	-	-	478.501

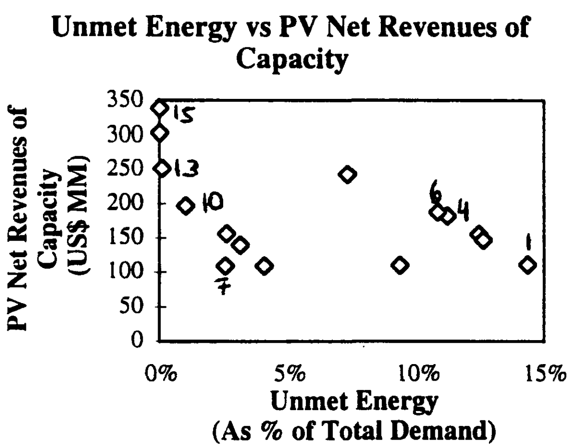
IRR of New Capacity Investments (%)						
New Thermal	Los Blancos	Potrerillos	El Baqueano	P. del Viento	Scenario	NOTES
NA	NA	NA	NA	NA	NA	
NA	NA	10.64%	NA	NA	10.64%	
22.47%	NA	NA	NA	NA	22.47%	
NA	20.63%	NA	NA	NA	20.63%	
NA	NA	NA	17.81%	NA	17.81%	
NA	NA	NA	NA	18.20%	18.20%	
NA	NA	NA	NA	NA	NA	
NA	NA	NA	NA	NA	NA	
NA	NA	NA	NA	NA	NA	
23.63%	NA	NA	NA	NA	23.63%	23.63% represents IRR on investment from 2000-2027
NA	NA	10.73%	NA	NA	10.73%	10.73 represents IRR on investment from 2000-2027
NA	21.18%	NA	NA	NA	21.18%	21.18% represents IRR on investment from 2000-2027
22.45%	NA	NA	NA	NA	22.45%	
23.04%	NA	NA	NA	NA	23.04%	23.04% can be misleading because of negative CF due to late invest.
23.48%	NA	NA	NA	NA	23.48%	23.48% can be misleading because of negative CF due to late invest

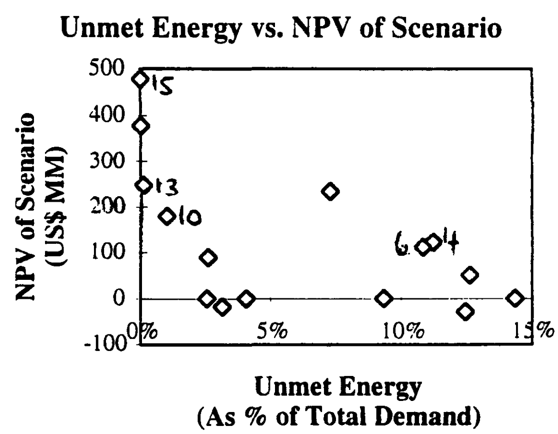

Unmet Energy vs. Energy Met w/ High Costs (as % of Total Demand)
High Cost Energy
1.4%
1.2%
1.0%
0.8%
0.6%
0.4%
0.2%
0.0%
0%
5%
10%
Unmet Energy


Energy Met by MEM vs Unmet Energy (As % of Total Demand)
Unmet Energy
15%
10%
5%
0%
0%
10%
20%
30%
40%
50%
Energy Met by MEM

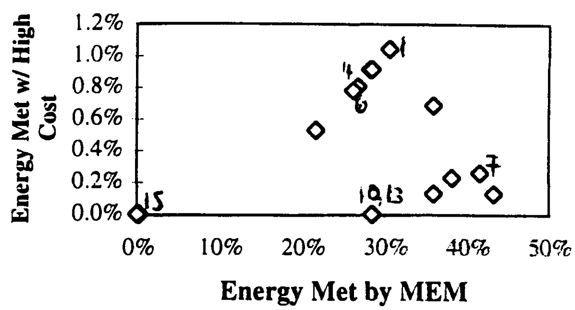

NOx vs Unmet Energy
Unmet Energy (As a % of Total Demand)
16%
14%
12%
10%
8%
6%
4%
2%
0%
0
500
1,000
1,500
NOx (MM lb)


Unmet Energy vs PV Net Revenues of Energy
PV Net Revenues of Energy (US$ MM)
1,000
800
600
400
200
0
-200
-400
0%
5%
10%
15%
Unmet Energy (As % of Total Demand)

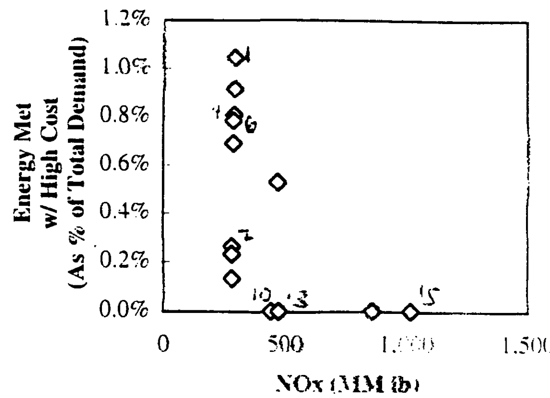

Unmet Energy vs PV Net Revenues of Capacity
PV Net Revenues of Capacity (US$ MM)
350
300
250
200
150
100
50
0
0%
5%
10%
15%
Unmet Energy (As % of Total Demand)


Unmet Energy vs. NPV of Scenario
NPV of Scenario (US$ MM)
500
400
300
200
100
0
-100
0%
5%
10%
15%
Unmet Energy (As % of Total Demand)

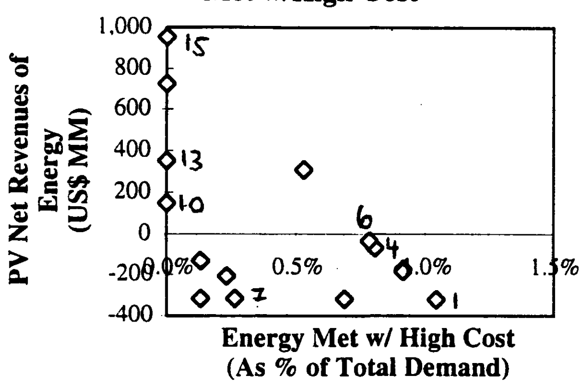
Energy Met by MEM vs Energy Met w/High Cost (As % of Total Demand)



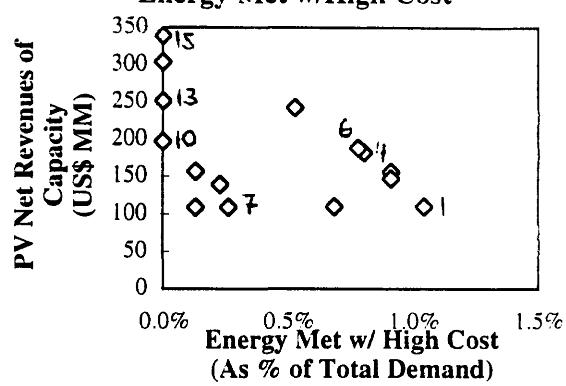
NOx vs Energy Met w/High Cost



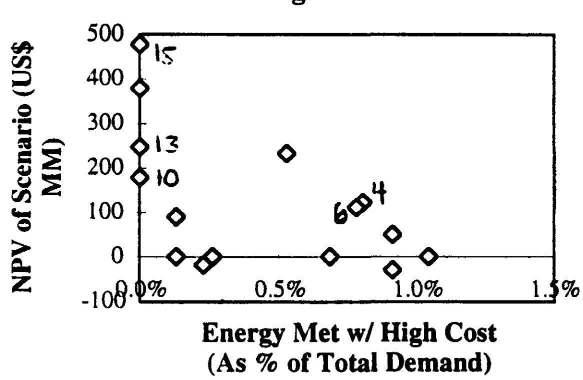
PV Net Revenues of Energy vs Energy Met w/High Cost



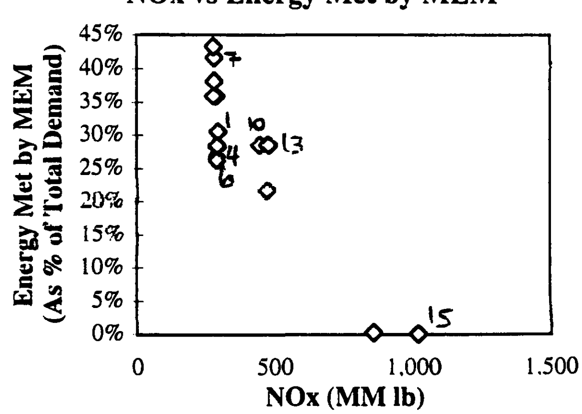
PV Net Revenues of Capacity vs Energy Met w/High Cost

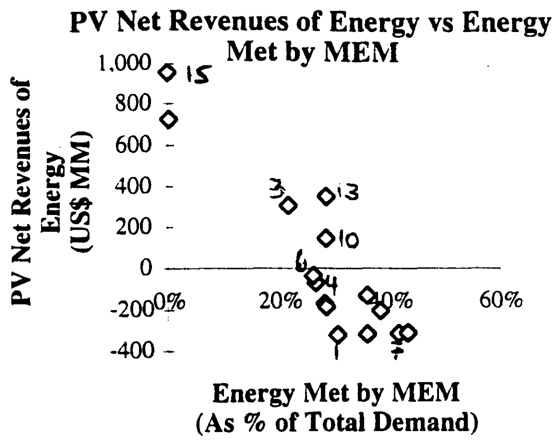


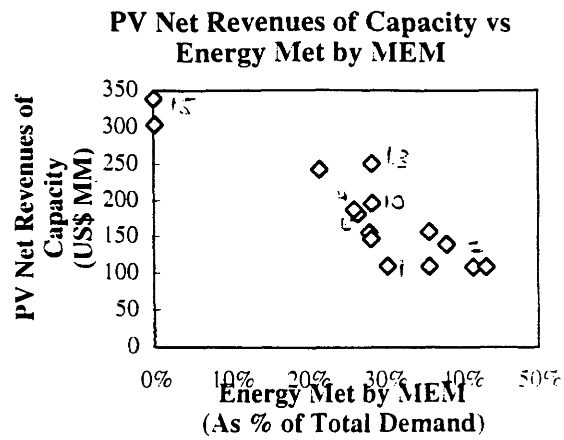
NPV of Scenario vs Energy Met w/High Cost

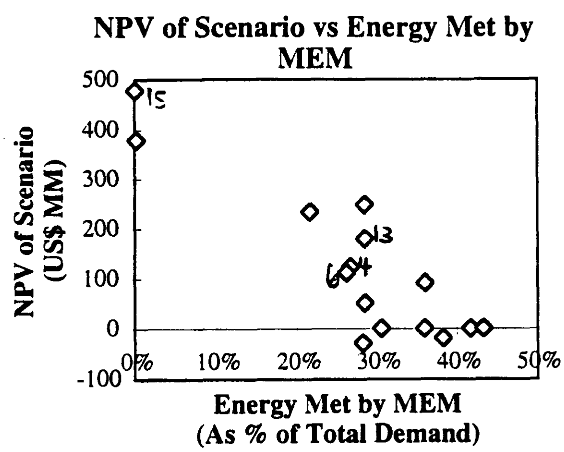


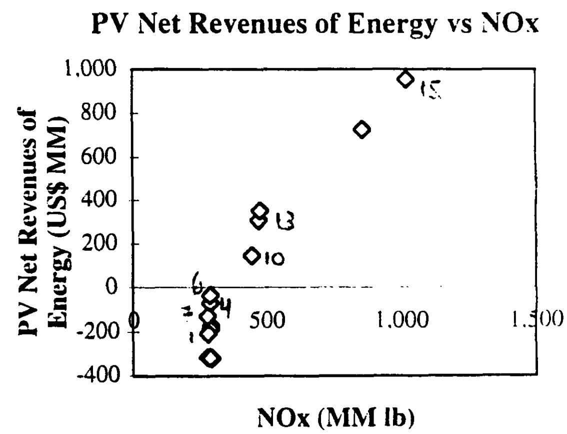
NOx vs Energy Met by MEM

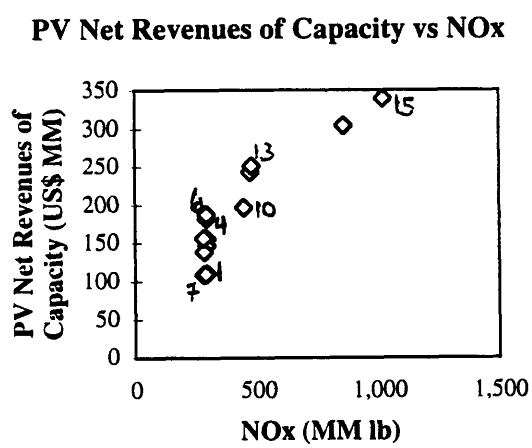


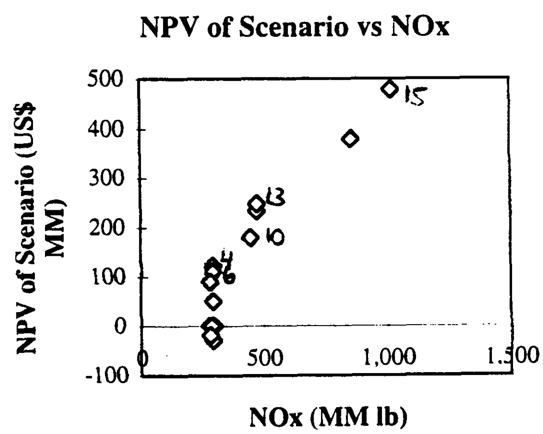

PV Net Revenues of Energy vs Energy Met by MEM
PV Net Revenues of Energy (US$ MM)
1,000
800
600
400
200
0
-200
-400
0%
20%
40%
60%
Energy Met by MEM (As % of Total Demand)
15
3
13
10
6
4

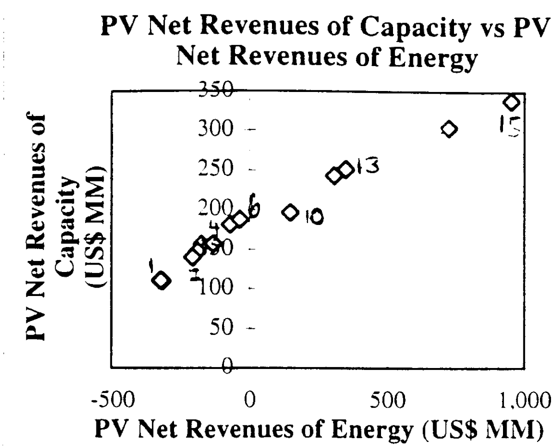

PV Net Revenues of Capacity vs Energy Met by MEM
PV Net Revenues of Capacity (US$ MM)
350
300
250
200
150
100
50
0
0%
10%
20%
30%
40%
50%
Energy Met by MEM (As % of Total Demand)
13
10

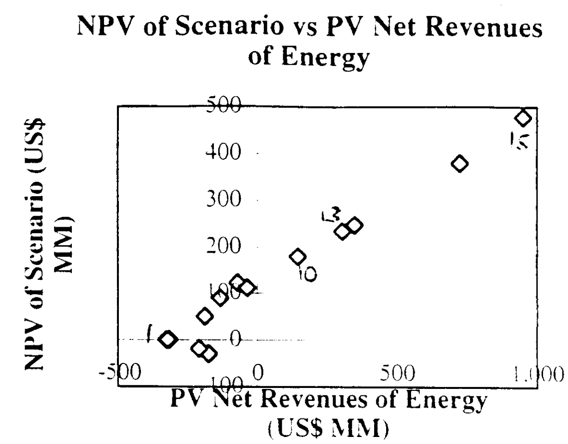

NPV of Scenario vs Energy Met by MEM
NPV of Scenario (US$ MM)
500
400
300
200
100
0
-100
0%
10%
20%
30%
40%
50%
Energy Met by MEM (As % of Total Demand)
15
13
6
4

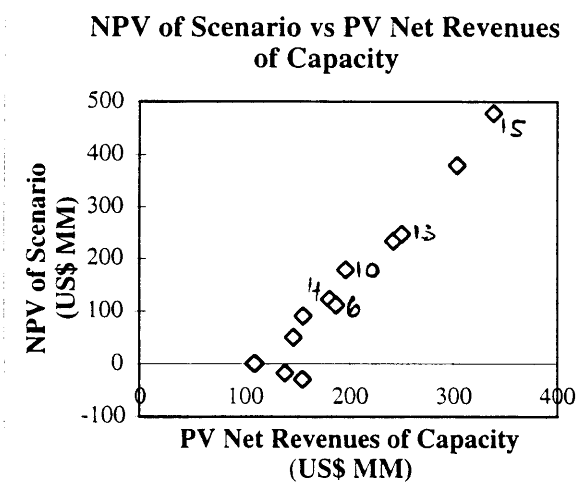

PV Net Revenues of Energy vs NOx
PV Net Revenues of Energy (US$ MM)
1,000
800
600
400
200
0
-200
-400
0
500
1,000
1,500
NOx (MM lb)
15
13
10
6
4

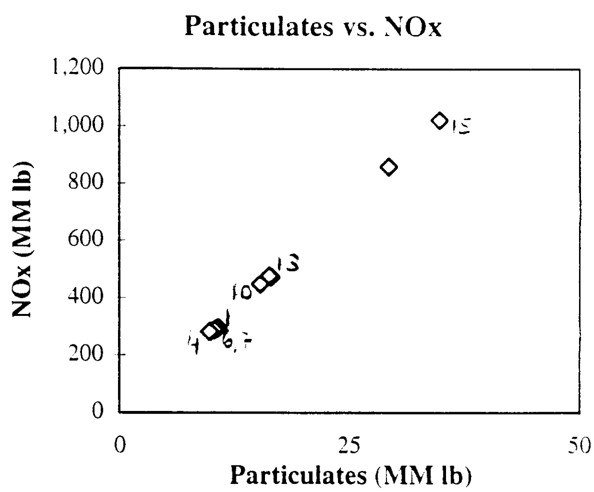

PV Net Revenues of Capacity vs NOx
PV Net Revenues of Capacity (US$ MM)
350
300
250
200
150
100
50
0
0
500
1,000
1,500
NOx (MM lb)
15
13
10
6
4
7

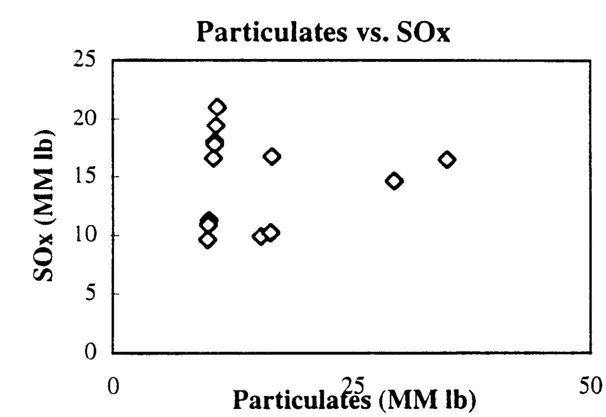

NPV of Scenario vs NOx
NPV of Scenario (US$ MM)
500
400
300
200
100
0
-100
0
500
1,000
1,500
NOx (MM lb)
15
13
10
4
6

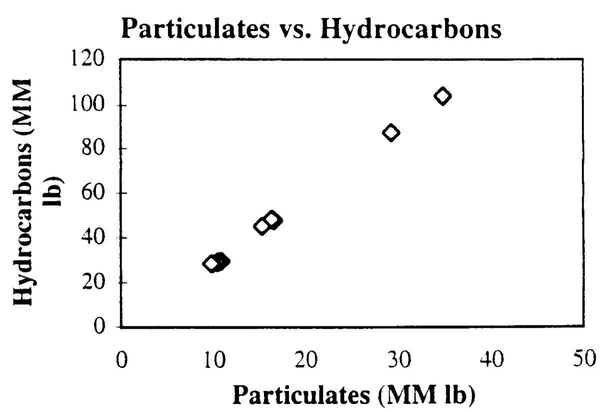

PV Net Revenues of Capacity vs PV Net Revenues of Energy
PV Net Revenues of Capacity (US$ MM)
350
300
250
200
150
100
50
0
-500
0
500
1,000
PV Net Revenues of Energy (US$ MM)
1
4
6
10
13
15

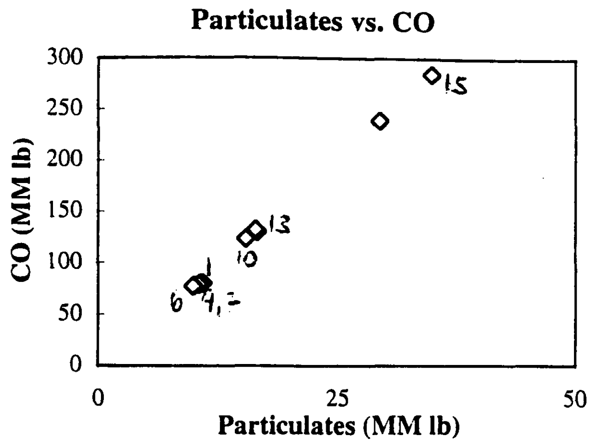

NPV of Scenario vs PV Net Revenues of Energy
NPV of Scenario (US$ MM)
500
400
300
200
100
0
-100
-500
0
500
1,000
PV Net Revenues of Energy (US$ MM)
1
10
13
15

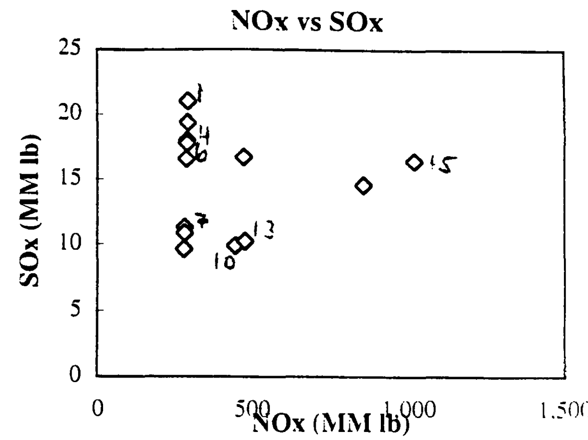

NPV of Scenario vs PV Net Revenues of Capacity
NPV of Scenario (US$ MM)
500
400
300
200
100
0
-100
0
100
200
300
400
PV Net Revenues of Capacity (US$ MM)
4
6
10
13
15

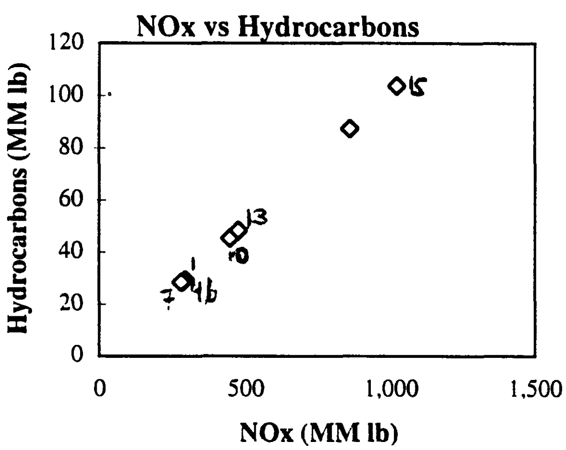

Particulates vs. NOx
NOx (MM lb)
1,200
1,000
800
600
400
200
0
0
25
50
Particulates (MM lb)
4
6, 7
10
13
15

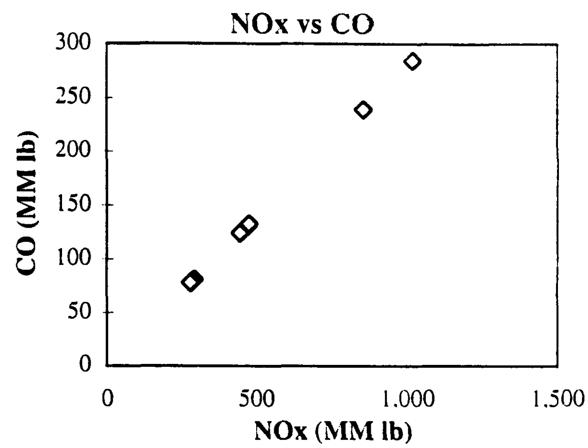

Particulates vs. SOx
SOx (MM lb)
25
20
15
10
5
0
0
25
50
Particulates (MM lb)

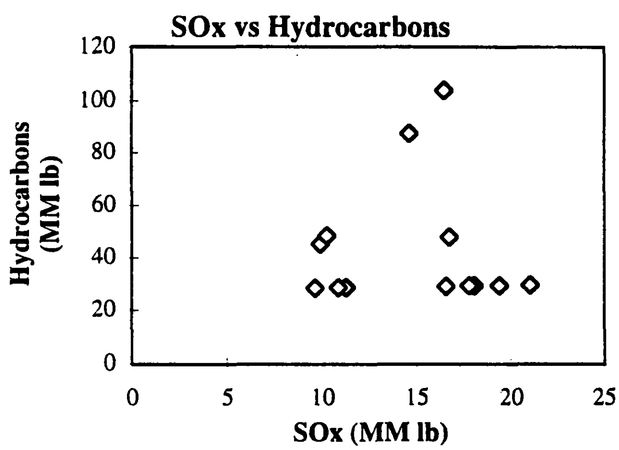

Particulates vs. Hydrocarbons
Hydrocarbons (MM lb)
120
100
80
60
40
20
0
0
10
20
30
40
50
Particulates (MM lb)

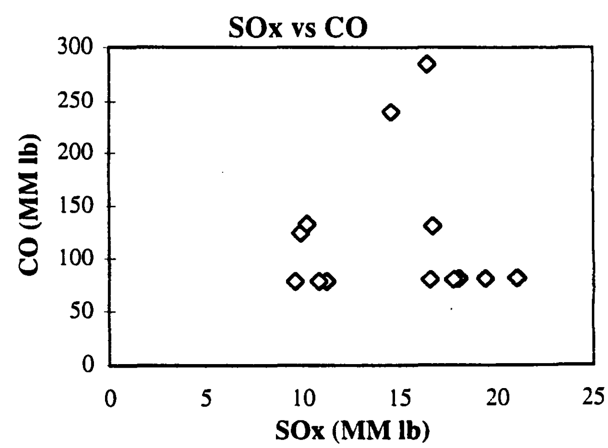

Particulates vs. CO
CO (MM lb)
300
250
200
150
100
50
0
0
25
50
Particulates (MM lb)
15
13
10


NOx vs SOx
SOx (MM lb)
25
20
15
10
5
0
0
500
1,000
1,500
NOx (MM lb)
15
13
10


NOx vs Hydrocarbons
Hydrocarbons (MM lb)
120
100
80
60
40
20
0
0
500
1,000
1,500
NOx (MM lb)
15
13


NOx vs CO
CO (MM lb)
300
250
200
150
100
50
0
0
500
1,000
1,500
NOx (MM lb)


SOx vs Hydrocarbons
Hydrocarbons (MM lb)
120
100
80
60
40
20
0
0
5
10
15
20
25
SOx (MM lb)


SOx vs CO
CO (MM lb)
300
250
200
150
100
50
0
0
5
10
15
20
25
SOx (MM lb)

FUTURE 4

Description

Demand: 1997 equals to 1993 demand. Each sector grows at 5%/yr except for Industrial which remains constant until 2001 and starts growing at 5%/yr. beginning in 2002. Agricultural demand remains constant.

Prices

Natural Gas (US$/MMBtu) prices starts and remains at 1.72 until 2005 and increase by 1.5%/yr after that

Fuel Oil (US$/tonne) start and remains at 152 until 2005 and increases at 1% after that

MEM Spot Price (US$/MWh) start at 28, increases by 1% until 2005 and by at 2% after that

MEM Capacity Price (US$/MW-hr off-valley weekday) remains contat at 10

Spot Market w/ Chile Link (As % of Spot Price)	0.95

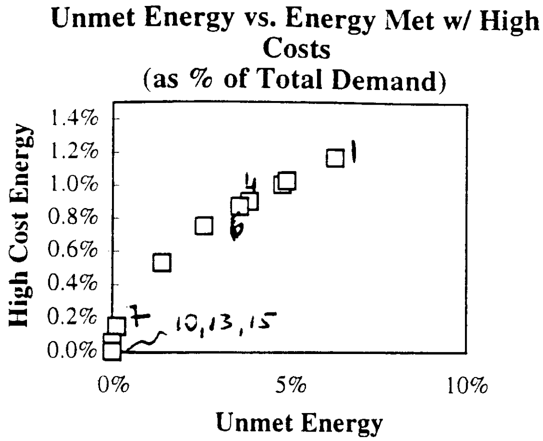
Discount Rate (% p.a.	14%

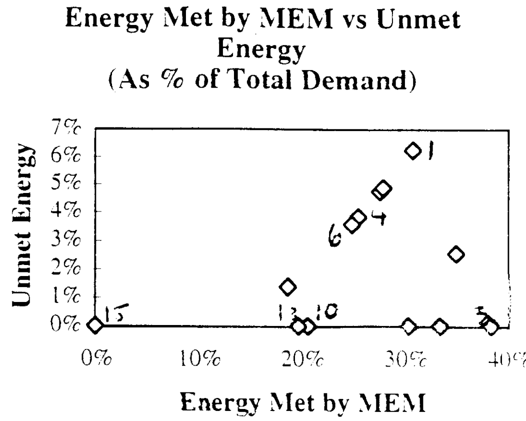
Scenario #	Percentage of Energy Demand Not Met	Percentage of Energy Demand Met w/ High Cost	Percentage of Energy Demand Met by MEM	MC Last High Cost (US$/MWh @ CdP)	Emissions (MM lb) Particulates	NOx	SOx	Hydrocarbons	CO
1	6.28%	1.17%	30.81%	61.20	10.36	287.61	15.72	28.95	79.30
2	4.78%	1.00%	27.62%	61.20	10.20	285.50	13.98	28.78	78.82
3	1.39%	0.53%	18.72%	61.20	16.03	464.76	10.99	47.13	129.05
4	3.85%	0.90%	25.53%	61.20	10.10	284.18	12.89	28.67	78.52
5	4.91%	1.03%	27.92%	61.20	10.22	285.78	14.21	28.80	78.88
6	3.59%	0.87%	24.89%	61.20	10.07	283.75	12.54	28.63	78.42
7	0.12%	0.15%	37.98%	61.20	9.38	274.30	4.73	27.86	76.28
8	0.00%	0.00%	38.25%	-	9.23	272.33	3.10	27.69	75.83
9	2.57%	0.75%	34.93%	61.20	9.96	282.17	11.23	28.50	78.07
10	0.00%	0.00%	20.65%	-	14.91	439.82	5.01	44.73	122.47
11	0.00%	0.05%	33.35%	61.20	9.28	273.01	3.66	27.75	75.98
12	0.00%	0.00%	30.29%	-	9.23	272.33	3.10	27.69	75.83
13	0.00%	0.00%	19.70%	-	15.94	470.13	5.35	47.81	130.91
14	0.00%	0.00%	0.00%	-	28.91	852.97	9.71	86.74	237.51
15	0.00%	0.00%	0.00%	-	34.43	1,015.68	11.56	103.29	282.82

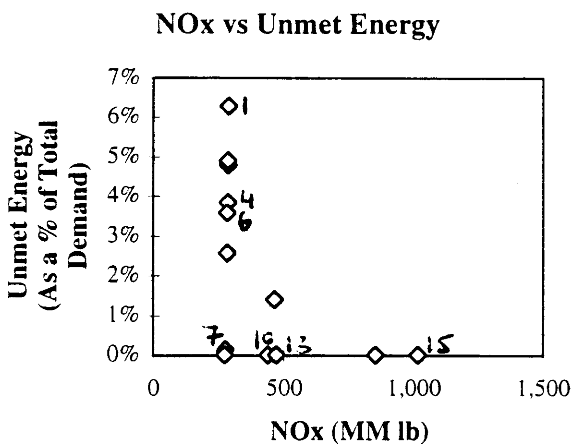
Futu

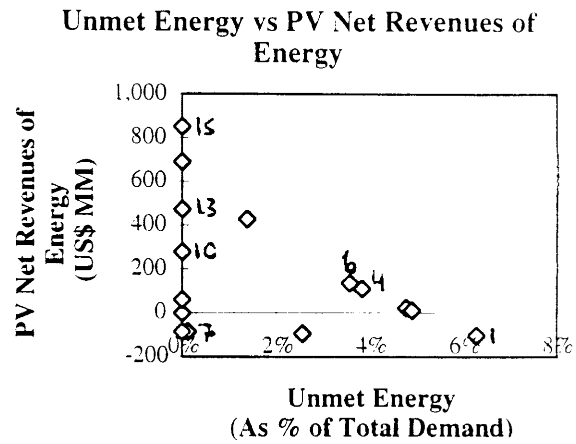
Scenario	NET REVS OF ENERGY AND CAPACITY NPV (US$MM)		First Year When...			NPV of New Capacity Investments (US$MM)					
#	Energy (excl. fuel cost)	Capacity	When Demand Not Met	When High Cost Used	When Fuel Oil Used	New Thermal	Los Blancos	Potrerillos	El Baqueano	P. del Viento	Scenario
1	(107 009)	128 101	2021	2020	2020	-	-	-	-	-	-
2	19 905	173 694	2022	2021	2021	-		(63 867)	-		(63 867)
3	426 908	261 873	2025	2024	2024	149 024		-	-	-	149 024
4	109 471	199 887	2022	2022	2022	-	81 489		-		81 489
5	8 483	165 191	2022	2021	2021	-	-	-	28 680	-	28 680
6	136 681	206 348	2023	2022	2022			-	-	65 320	65 320
7	(88 826)	127 467	2027	2027	2027		-	-	-	-	-
8	(86 825)	127 414	NA	NA	NA		-	-	-	-	-
9	(95 806)	127 762	2024	2023	2023	-	-	-	-	-	-
10	275 386	217 074	NA	NA	NA	108 317	-	-	-	-	108 317
11	(3 740)	157 828	NA	2027	2027	-	-	(40 796)	-	-	(40 796)
12	58 060	175 618	NA	NA	NA	-	58 094	-	-	-	58 094
13	470 785	270 454	NA	NA	NA	150 804	-		-	-	150 804
14	689 373	314 237	NA	NA	NA	192 145	-	-	-	-	192 145
15	848 683	345 514	NA	NA	NA	258 474	-	-	-	-	258 474

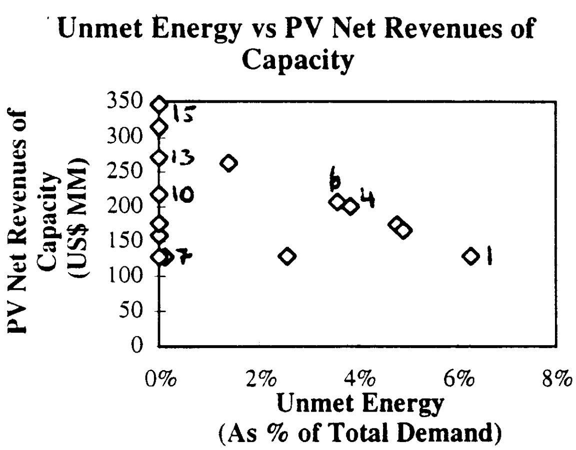
Scenario #	IRR of New Capacity Investments (%)						NOTES
	New Thermal	Los Blancos	Potrerillos	El Baqueano	P. del Viento	Scenario	
1	NA	NA	NA	NA	NA	NA	
2	NA	NA	10.70%	NA	NA	10.70%	
3	21.95%	NA	NA	NA	NA	21.95%	
4	NA	20.59%	NA	NA	NA	20.59%	
5	NA	NA	NA	17.78%	NA	17.78%	
6	NA	NA	NA	NA	18.17%	18.17%	
7	NA	NA	NA	NA	NA	NA	
8	NA	NA	NA	NA	NA	NA	
9	NA	NA	NA	NA	NA	NA	
10	22.87%	NA	NA	NA	NA	22.87%	22.87% represents IRR on investment from 2000-2027
11	NA	NA	10.69%	NA	NA	10.69%	10.69% represents IRR on investment from 2000-2027
12	NA	21.18%	NA	NA	NA	21.18%	21.18% represents IRR on investment from 2000-2027
13	21.78%	NA	NA	NA	NA	21.78%	
14	21.96%	NA	NA	NA	NA	21.96%	21.96% can be misleading because of negative CF due to late invest
15	22.58%	NA	NA	NA	NA	22.58%	22.58% can be misleading because of negative CF due to late invest

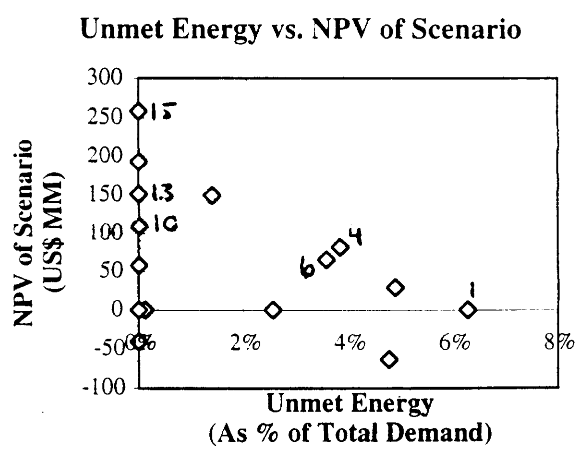

Unmet Energy vs. Energy Met w/ High Costs
(as % of Total Demand)
High Cost Energy
1.4%
1.2%
1.0%
0.8%
0.6%
0.4%
0.2%
0.0%
0%
5%
10%
Unmet Energy
1
4
6
7
10, 13, 15


Energy Met by MEM vs Unmet Energy
(As % of Total Demand)
Unmet Energy
7%
6%
5%
4%
3%
2%
1%
0%
0%
10%
20%
30%
40%
Energy Met by MEM
1
4
6
15
13
10

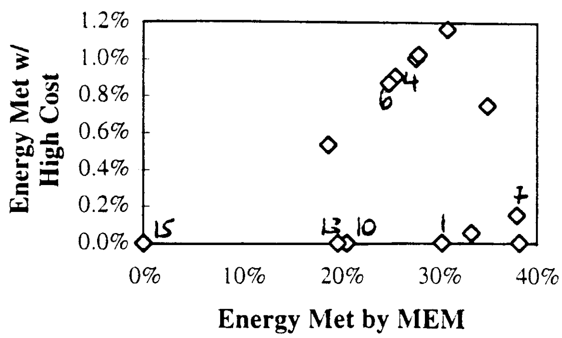

NOx vs Unmet Energy
Unmet Energy (As a % of Total Demand)
7%
6%
5%
4%
3%
2%
1%
0%
0
500
1,000
1,500
NOx (MM lb)
1
4
6
7
10
13
15


Unmet Energy vs PV Net Revenues of Energy
PV Net Revenues of Energy (US$ MM)
1,000
800
600
400
200
0
-200
0%
2%
4%
6%
8%
Unmet Energy
(As % of Total Demand)
15
13
10
7
6
4
1

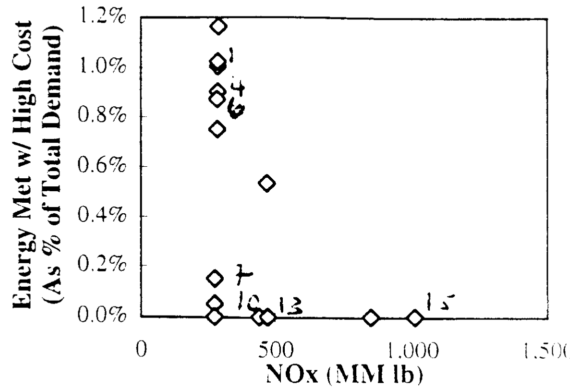

Unmet Energy vs PV Net Revenues of Capacity
PV Net Revenues of Capacity (US$ MM)
350
300
250
200
150
100
50
0
0%
2%
4%
6%
8%
Unmet Energy
(As % of Total Demand)
15
13
10
7
6
4
1


Unmet Energy vs. NPV of Scenario
NPV of Scenario (US$ MM)
300
250
200
150
100
50
0
-50
-100
0%
2%
4%
6%
8%
Unmet Energy
(As % of Total Demand)
15
13
10
6
4
1

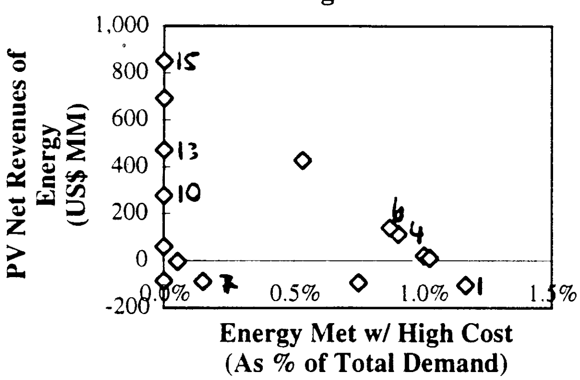
Energy Met by MEM vs Energy Met w/High Cost (As % of Total Demand)



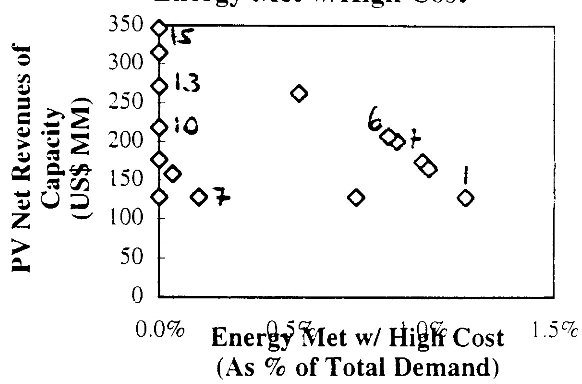
NOx vs Energy Met w/High Cost



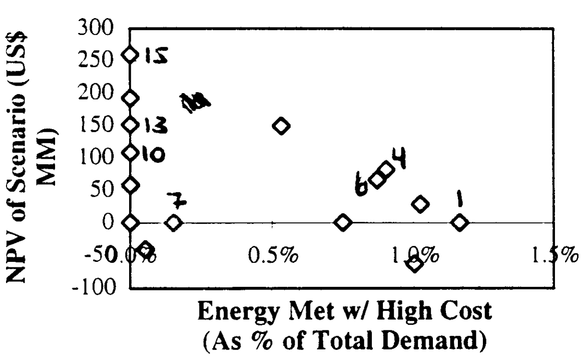
PV Net Revenues of Energy vs Energy Met w/High Cost



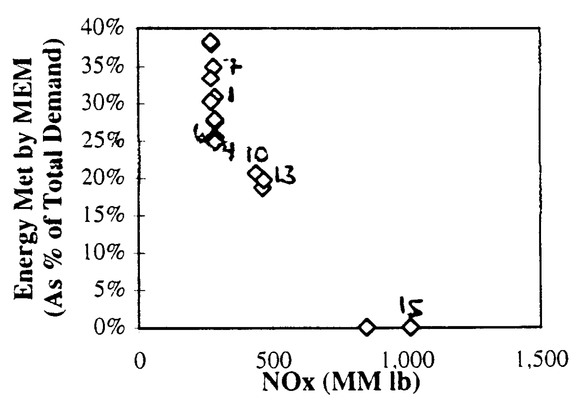
PV Net Revenues of Capacity vs Energy Met w/High Cost

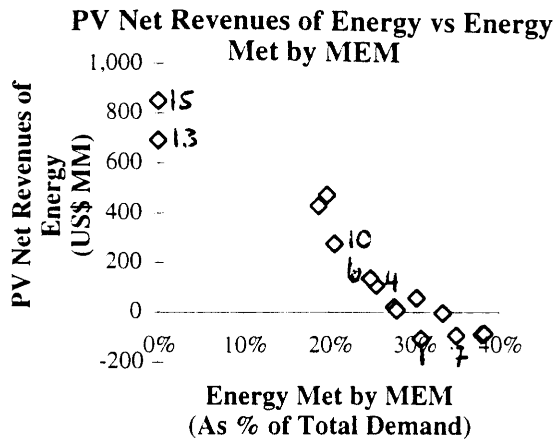


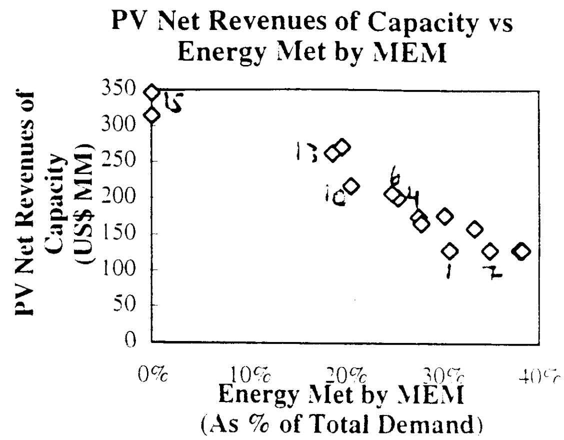
NPV of Scenario vs Energy Met w/High Cost

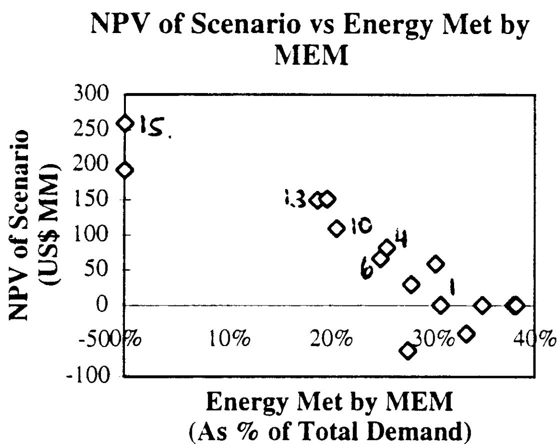


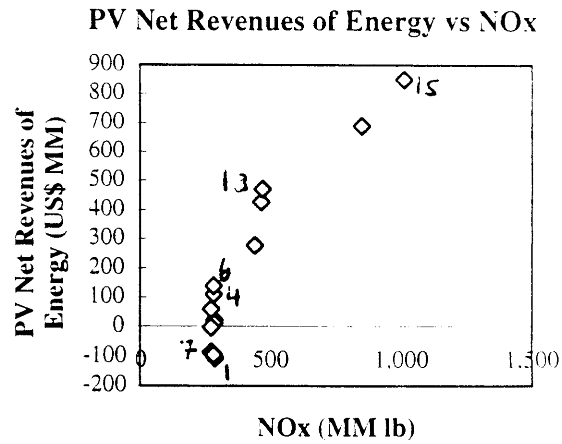
NOx vs Energy Met by MEM

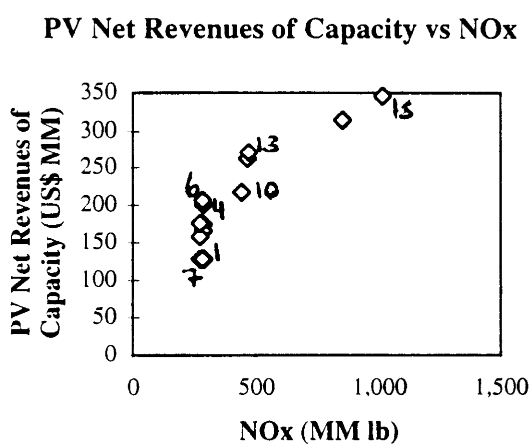


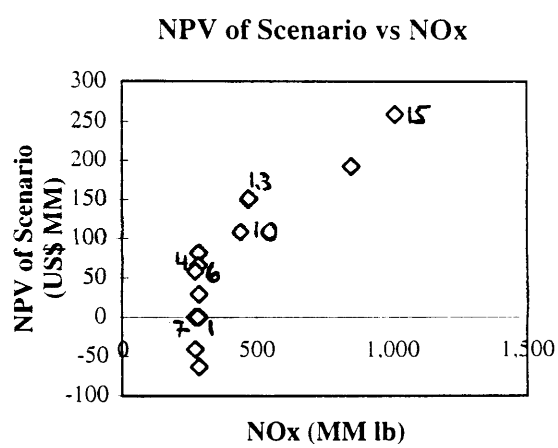

PV Net Revenues of Energy vs Energy Met by MEM
PV Net Revenues of Energy (US$ MM)
1,000
800
600
400
200
0
-200
0%
10%
20%
30%
40%
Energy Met by MEM (As % of Total Demand)
15
13
10
6
4
1
7

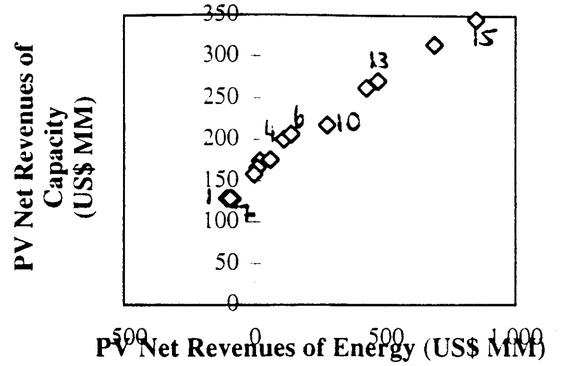

PV Net Revenues of Capacity vs Energy Met by MEM
PV Net Revenues of Capacity (US$ MM)
350
300
250
200
150
100
50
0
0%
10%
20%
30%
40%
Energy Met by MEM (As % of Total Demand)
15
13
10
6
4
1
7


NPV of Scenario vs Energy Met by MEM
NPV of Scenario (US$ MM)
300
250
200
150
100
50
0
-50
-100
0%
10%
20%
30%
40%
Energy Met by MEM (As % of Total Demand)
15.
13
10
6
4
1

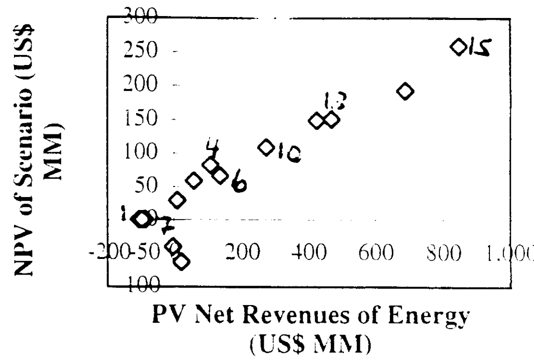

PV Net Revenues of Energy vs NOx
PV Net Revenues of Energy (US$ MM)
900
800
700
600
500
400
300
200
100
0
-100
-200
0
500
1,000
1,500
NOx (MM lb)
15
13
6
4
7
1


PV Net Revenues of Capacity vs NOx
PV Net Revenues of Capacity (US$ MM)
350
300
250
200
150
100
50
0
0
500
1,000
1,500
NOx (MM lb)
15
13
10
6
4
1
7

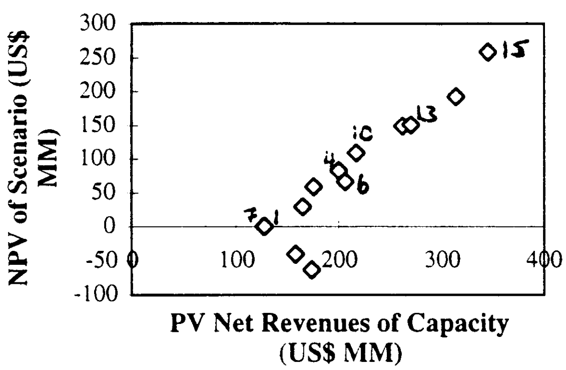

NPV of Scenario vs NOx
NPV of Scenario (US$ MM)
300
250
200
150
100
50
0
-50
-100
0
500
1,000
1,500
NOx (MM lb)
15
13
10
4
6
7
1



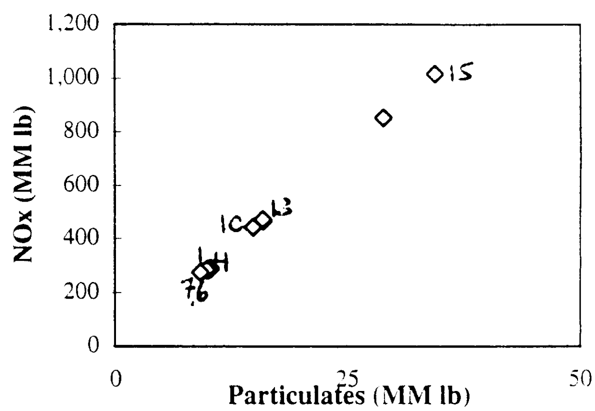
PV Net Revenues of Capacity vs PV Net Revenues of Energy



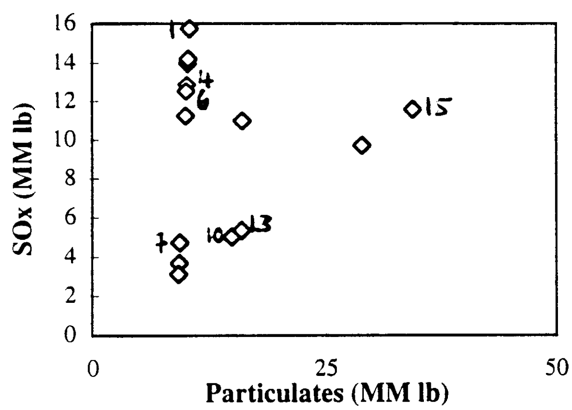
NPV of Scenario vs PV Net Revenues of Energy



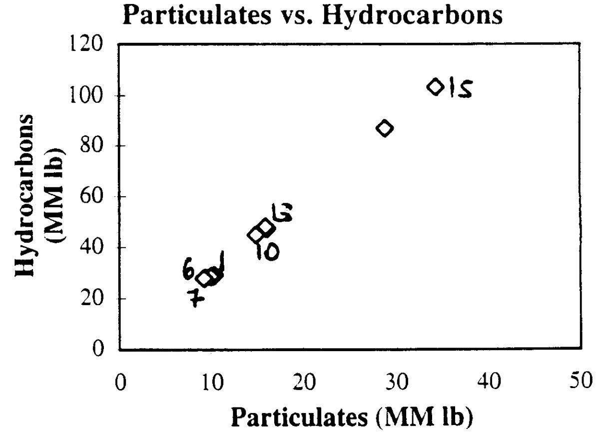
NPV of Scenario vs PV Net Revenues of Capacity



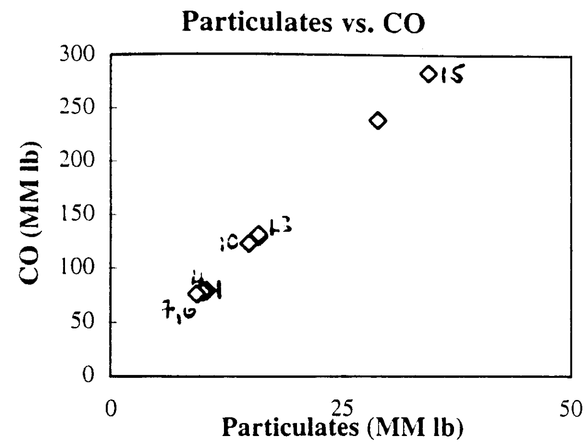
Particulates vs. NOx

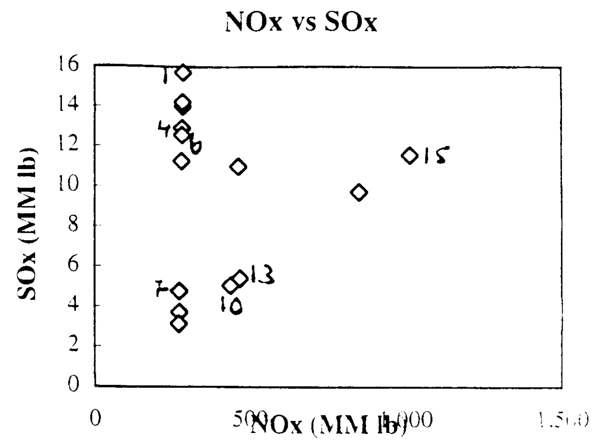


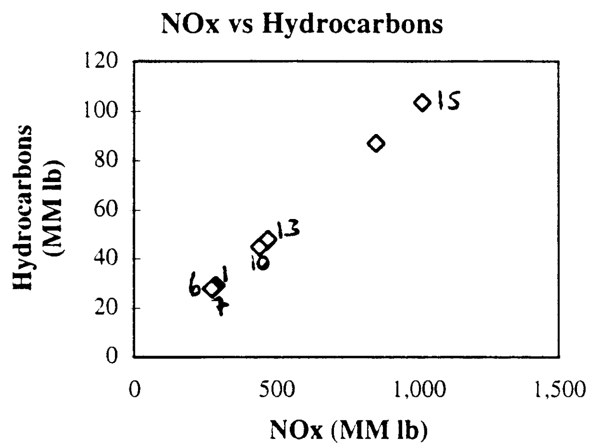
Particulates vs. SOx

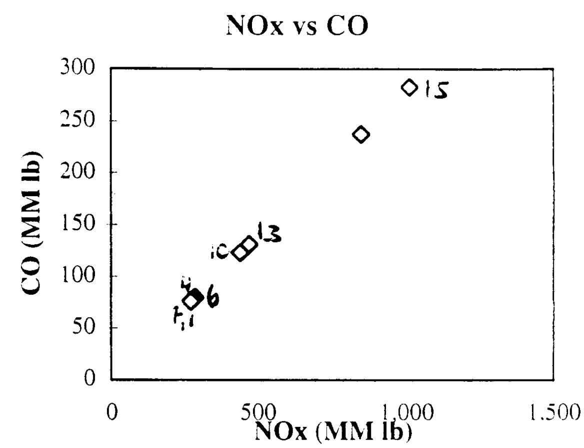


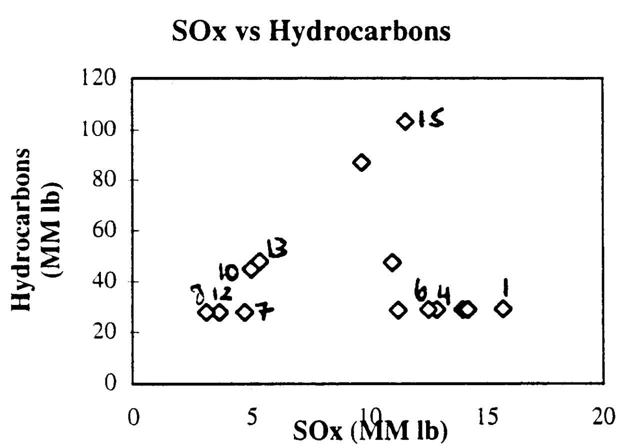
Particulates vs. Hydrocarbons

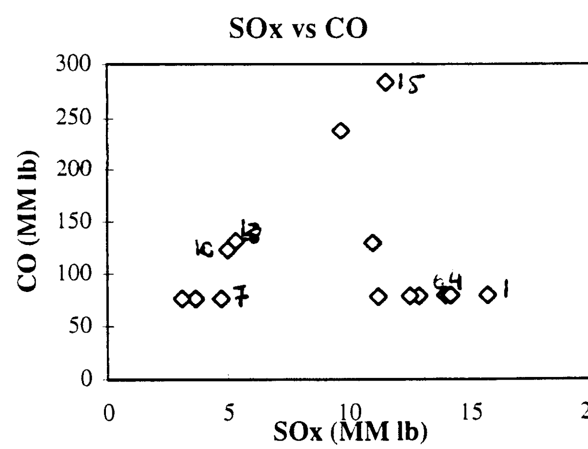

Particulates vs. CO
CO (MM lb)
300
250
200
150
100
50
0
0
25
50
Particulates (MM lb)
15
10
13
4
7,10
1


NOx vs SOx
SOx (MM lb)
16
14
12
10
8
6
4
2
0
0
500
1,000
NOx (MM lb)
1
4
6
15
13
7
10


NOx vs Hydrocarbons
Hydrocarbons (MM lb)
120
100
80
60
40
20
0
0
500
1,000
1,500
NOx (MM lb)
15
13
10
6
1
7


NOx vs CO
CO (MM lb)
300
250
200
150
100
50
0
0
500
1,000
1,500
NOx (MM lb)
15
10
13
4
6
7,1


SOx vs Hydrocarbons
Hydrocarbons (MM lb)
120
100
80
60
40
20
0
0
5
10
15
20
SOx (MM lb)
15
10
13
3
12
7
6
4
1


SOx vs CO
CO (MM lb)
300
250
200
150
100
50
0
0
5
10
15
20
SOx (MM lb)
15
10
13
7
6
4
1

FUTURE 5

Description:

Demand: 1997 equals to 1993 demand. Each sector, except for Industrial, grows at 5%/yr until 2005 and 3% after that. Industrial remains constant until 2001, and starts growing at 5%/yr, beginning in 2002 until 2010, and 3% after that. Agricultural demand grows at 1% until 2001, and remains constant after that

Prices

Natural Gas (US$/MMBtu) prices starts and remains at 1.72 until 2002 and increase by 1%/yr after that

Fuel Oil (US$/tonne) start and remains at 152 until 2027

MEM Spot Price (US$/MWh) start at 28, increases by 2% until 2005 and by 1% after that

MEM Capacity Price (US$/MW-hr off-valley weeday) remains constat at 10

Spot Market w/ Chile Link (As % of Spot Price)	0.95

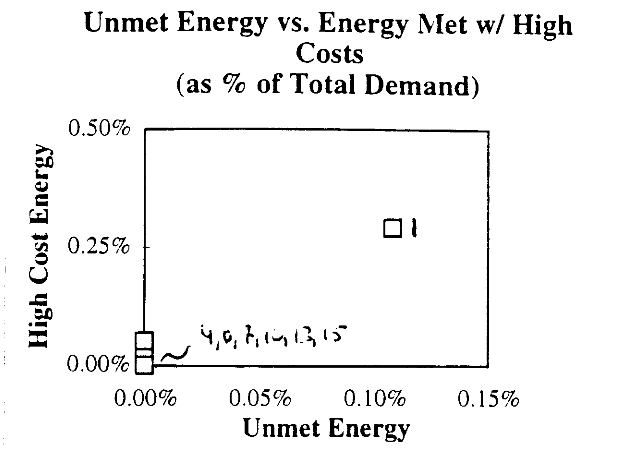
Discount Rate (% p.a.)	10%

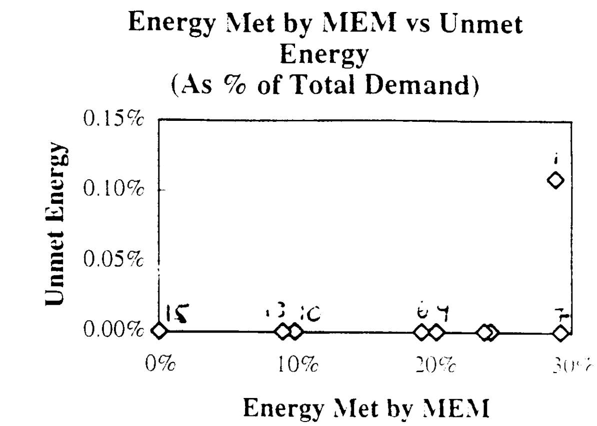
Scenario	Percentage of Energy	Percentage of Energy	Percentage of Energy	MC Last High Cost	Emissions (MM lb)				
#	Demand Not Met	Demand Met w/ High Cost	Demand Met by MEM	(US$/MWh @ CdP)	Particulates	NOx	SOx	Hydrocarbons	CO
1	0.11%	0.29%	28.82%	48.68	9.48	275.66	5.85	27.97	76.59
2	0.00%	0.03%	23.64%	48.68	9.25	272.64	3.36	27.72	75.90
3	0.00%	0.00%	9.91%	-	15.52	457.76	5.21	46.55	127.46
4	0.00%	0.00%	20.16%	-	9.23	272.33	3.10	27.69	75.83
5	0.00%	0.05%	24.12%	48.68	9.27	272.92	3.59	27.74	75.96
6	0.00%	0.00%	19.10%	-	9.23	272.33	3.10	27.69	75.83
7	0.00%	0.00%	29.21%	-	9.23	272.33	3.10	27.69	75.83
8	0.00%	0.00%	29.21%	-	9.23	272.33	3.10	27.69	75.83
9	0.00%	0.00%	29.21%	-	9.23	272.33	3.10	27.69	75.83
10	0.00%	0.00%	9.91%	-	14.91	439.82	5.01	44.73	122.47
11	0.00%	0.00%	23.66%	-	9.23	272.33	3.10	27.69	75.83
12	0.00%	0.00%	20.16%	-	9.23	272.33	3.10	27.69	75.83
13	0.00%	0.00%	9.04%	-	15.94	470.13	5.35	47.81	130.91
14	0.00%	0.00%	0.00%	-	28.91	852.97	9.71	86.74	237.51
15	0.00%	0.00%	0.00%	-	34.43	1,015.68	11.56	103.29	282.82

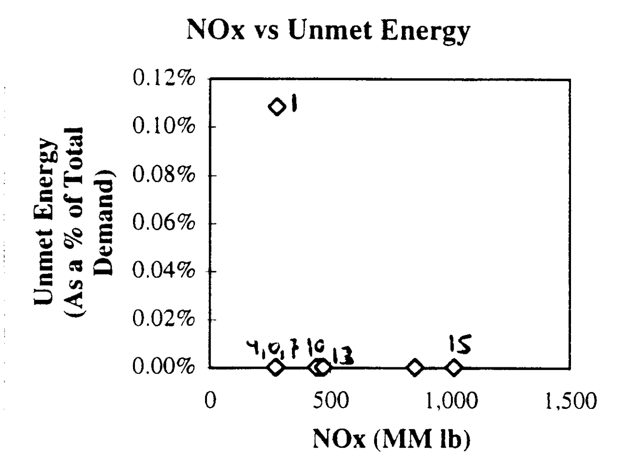
Scenario	NET REVS OF ENERGY AND CAPACITY		First Year When....			NPV of New Capacity Investment (US$MM)						
	NPV (US$MM)		...When Demand	...When High	...When Fuel							
#	Energy (excl. fuel cost)	Capacity	Not Met	Cost Used	OIl Used	New Thermal	Los Blancos	Potrerillos	El Baqueano	P. del Viento	Scenario	New Thermal
1	(149.351)	158.106	2027	2026	2026	-	-	-	-	-	-	NA
2	16.392	217.326	NA	2027	2027	-	-	11.701	-	-	11.701	NA
3	551.423	332.613	NA	NA	NA	298.065	-	-	-	-	298.065	22.42%
4	133.776	251.648	NA	NA	NA	-	171.940	-	-	-	171.940	NA
5	1.123	206.228	NA	2027	2027	-	-	-	76.262	-	76.262	NA
6	170.115	260.001	NA	NA	NA	-	-	-	-	166.631	166.631	NA
7	(145.321)	157.806	NA	NA	NA	-	-	-	-	-	-	NA
8	(145.321)	157.806	NA	NA	NA	-	-	-	-	-	-	NA
9	(137.705)	157.806	NA	NA	NA	-	-	-	-	-	-	NA
10	386.815	286.560	NA	NA	NA	231.247	-	-	-	-	231.247	23.64%
11	(20.126)	201.448	NA	NA	NA	-	-	10.578	-	-	10.578	NA
12	67.533	227.029	NA	NA	NA	-	131.814	-	-	-	131.814	NA
13	599.128	344.133	NA	NA	NA	308.133	-	-	-	-	308.133	22.29%
14	1,055.924	446.206	NA	NA	NA	392.068	-	-	-	-	392.068	22.18%
15	1,361.031	508.675	NA	NA	NA	536.747	-	-	-	-	536.747	22.66%

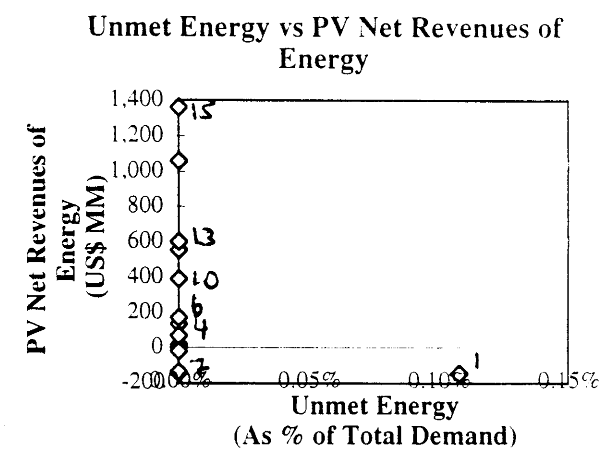
Fi:

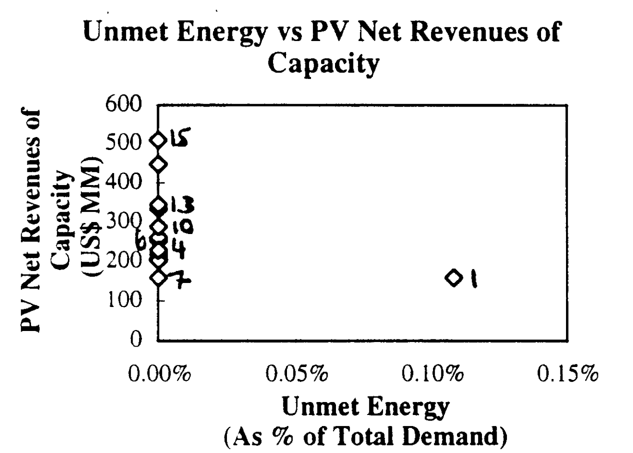
Scenario	IRR of New Capacity Investment (%)					
#	Los Blancos	Potrerillos	El Baqueano	P. del Viento	Scenario	Notes
1	NA	NA	NA	NA	NA	
2	NA	10.50%	NA	NA	10.50%	
3	NA	NA	NA	NA	22.42%	
4	20.81%	NA	NA	NA	20.81%	
5	NA	NA	17.89%	NA	17.89%	
6	NA	NA	NA	18.31%	18.31%	
7	NA	NA	NA	NA	NA	
8	NA	NA	NA	NA	NA	
9	NA	NA	NA	NA	NA	
10	NA	NA	NA	NA	23.64%	23.64% represents IRR on investment from 2000-2027
11	NA	10.62%	NA	NA	10.62%	10.62% represents IRR on investment from 2000-2027
12	21.59%	NA	NA	NA	21.59%	21.59% represents IRR on investment from 2000-2027
13	NA	NA	NA	NA	22.29%	
14	NA	NA	NA	NA	22.18%	22.18% can be misleading because of negative CF due to late invest.
15	NA	NA	NA	NA	22.66%	22.66% can be misleading because of negative CF due to late invest

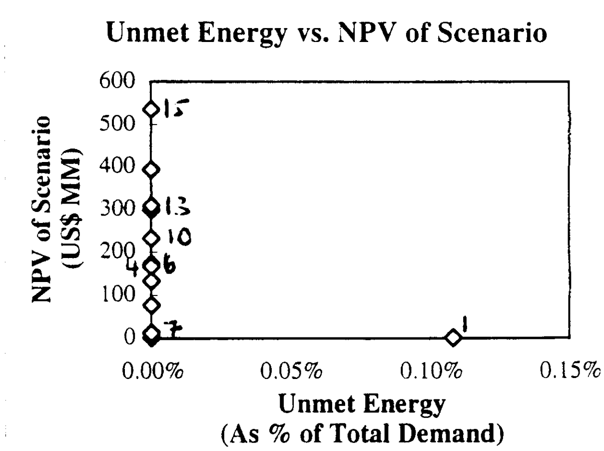

Unmet Energy vs. Energy Met w/ High Costs
(as % of Total Demand)
High Cost Energy
0.50%
0.25%
0.00%
0.00%
0.05%
0.10%
0.15%
Unmet Energy


Energy Met by MEM vs Unmet Energy
(As % of Total Demand)
Unmet Energy
0.15%
0.10%
0.05%
0.00%
0%
10%
20%
Energy Met by MEM

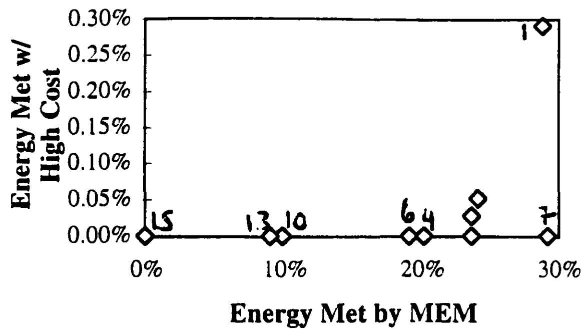

NOx vs Unmet Energy
Unmet Energy
(As a % of Total Demand)
0.12%
0.10%
0.08%
0.06%
0.04%
0.02%
0.00%
0
500
1,000
1,500
NOx (MM lb)


Unmet Energy vs PV Net Revenues of Energy
PV Net Revenues of Energy
(US$ MM)
1,400
1,200
1,000
800
600
400
200
0
-200
0.05%
0.10%
0.15%
Unmet Energy
(As % of Total Demand)

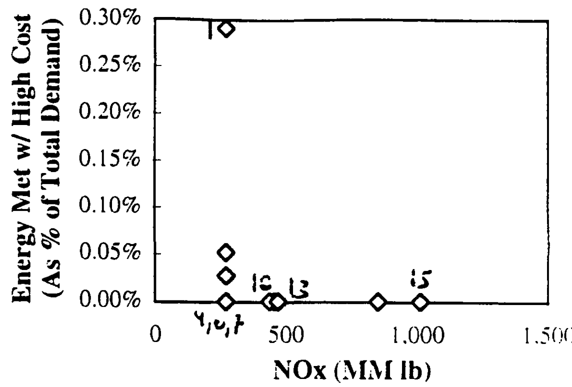

Unmet Energy vs PV Net Revenues of Capacity
PV Net Revenues of Capacity
(US$ MM)
600
500
400
300
200
100
0
0.00%
0.05%
0.10%
0.15%
Unmet Energy
(As % of Total Demand)


Unmet Energy vs. NPV of Scenario
NPV of Scenario
(US$ MM)
600
500
400
300
200
100
0
0.00%
0.05%
0.10%
0.15%
Unmet Energy
(As % of Total Demand)

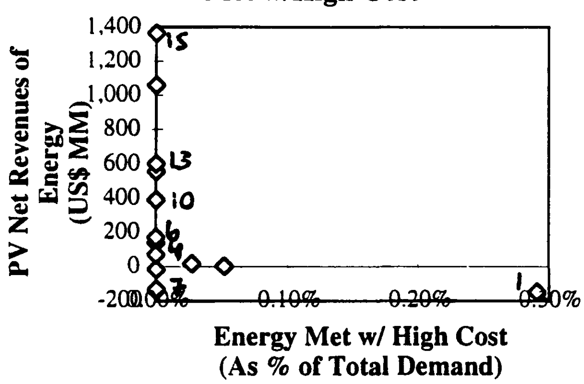
Energy Met by MEM vs Energy Met w/High Cost (As % of Total Demand)



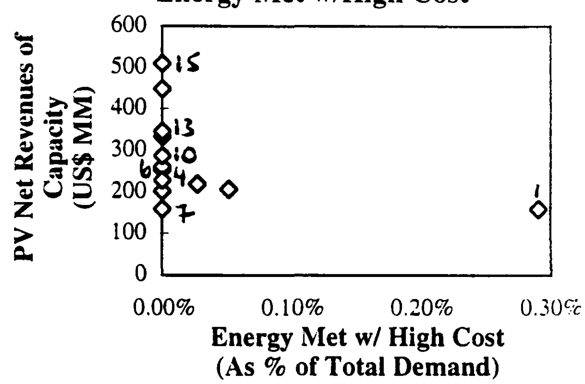
NOx vs Energy Met w/High Cost



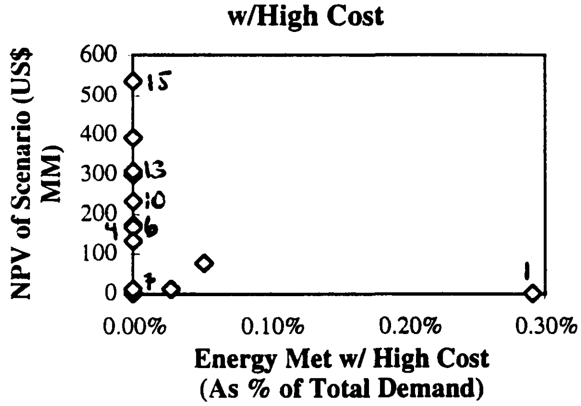
PV Net Revenues of Energy vs Energy Met w/High Cost



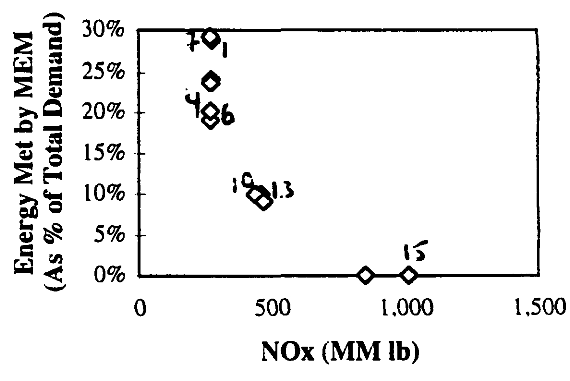
PV Net Revenues of Capacity vs Energy Met w/High Cost

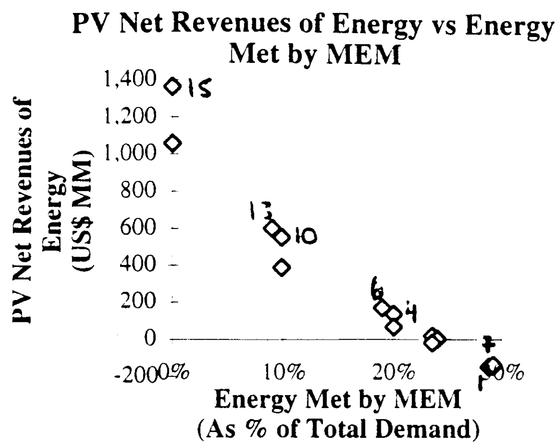


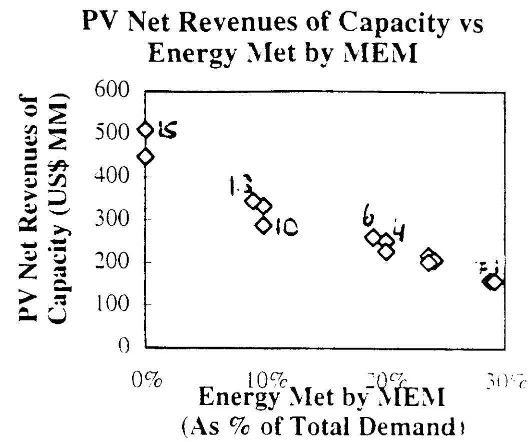
NPV of Scenario vs Energy Met w/High Cost

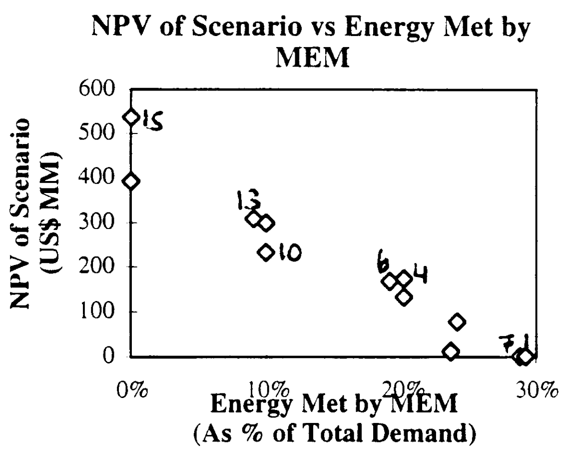


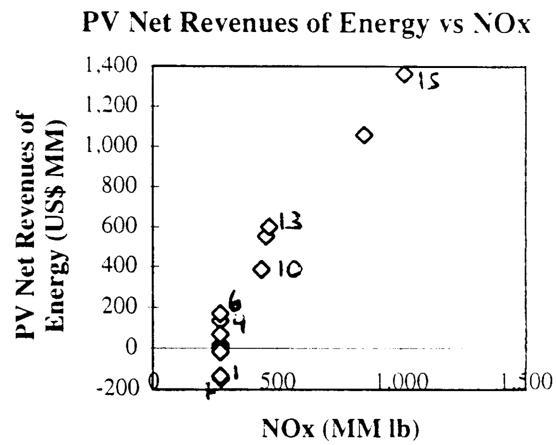
NOx vs Energy Met by MEM

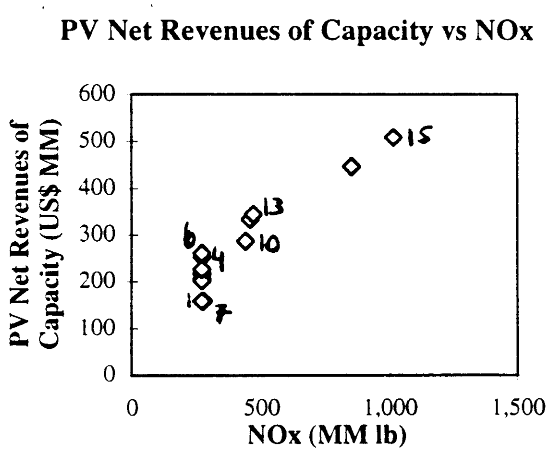


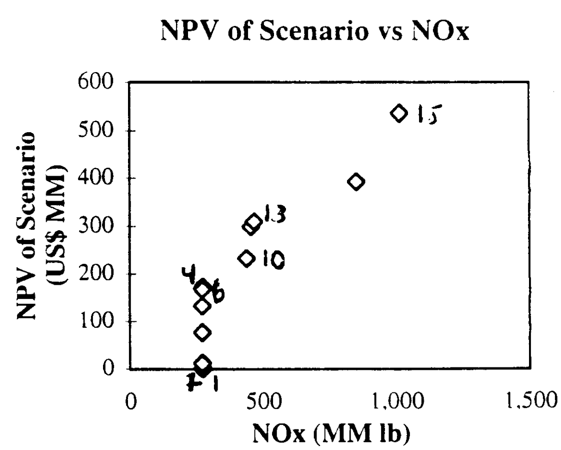

PV Net Revenues of Energy vs Energy Met by MEM
PV Net Revenues of Energy (US$ MM)
Energy Met by MEM (As % of Total Demand)

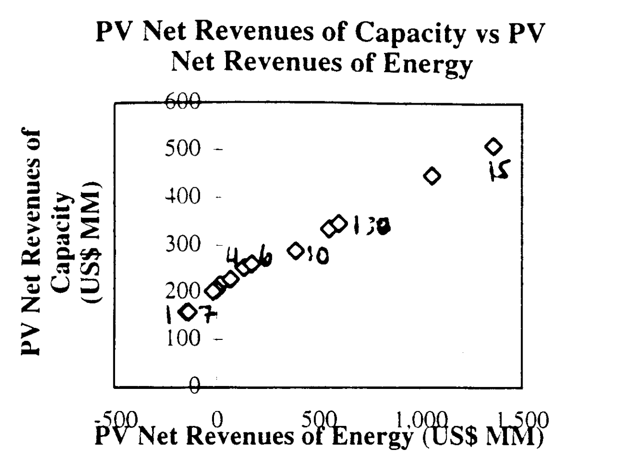

PV Net Revenues of Capacity vs Energy Met by MEM
PV Net Revenues of Capacity (US$ MM)
Energy Met by MEM (As % of Total Demand)

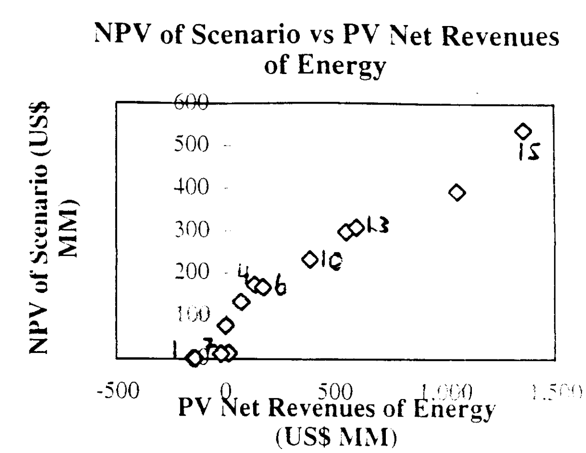

NPV of Scenario vs Energy Met by MEM
NPV of Scenario (US$ MM)
Energy Met by MEM (As % of Total Demand)

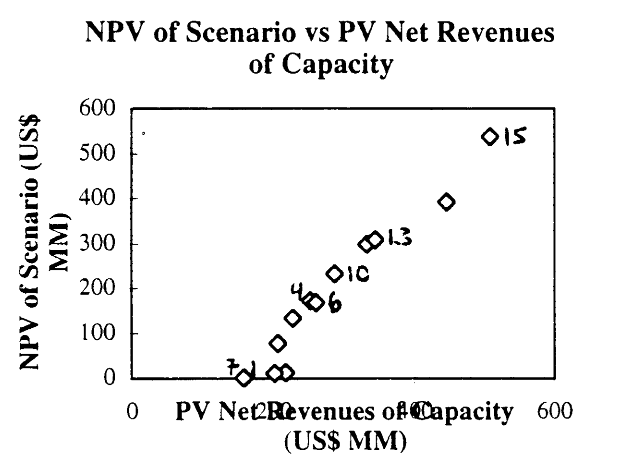

PV Net Revenues of Energy vs NOx
PV Net Revenues of Energy (US$ MM)
NOx (MM lb)

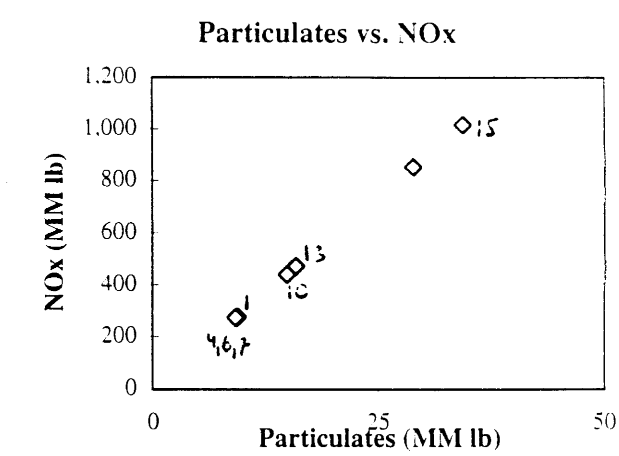

PV Net Revenues of Capacity vs NOx
PV Net Revenues of Capacity (US$ MM)
NOx (MM lb)

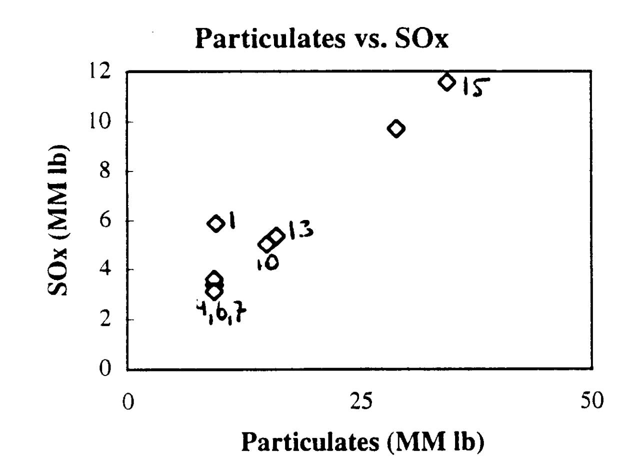

NPV of Scenario vs NOx
NPV of Scenario (US$ MM)
NOx (MM lb)

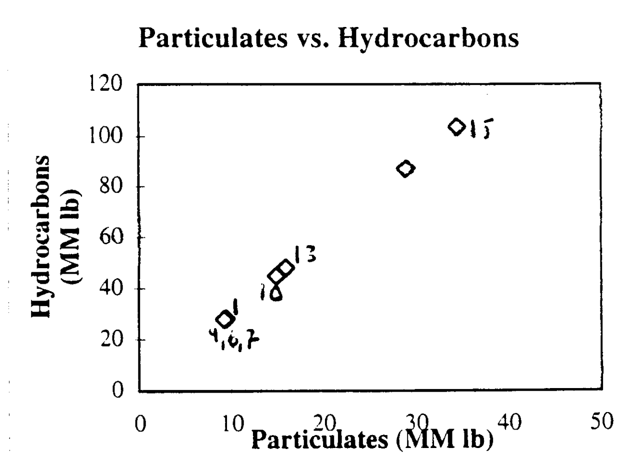

PV Net Revenues of Capacity vs PV Net Revenues of Energy
PV Net Revenues of Capacity (US$ MM)
600
500
400
300
200
100
0
-500
0
500
1,000
1,500
PV Net Revenues of Energy (US$ MM)
15
13
10
4
6
1
7

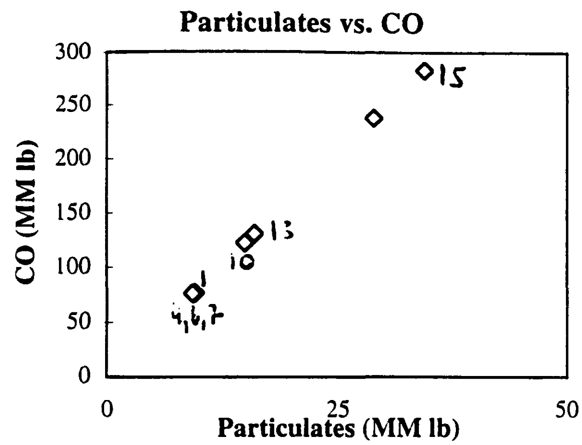

NPV of Scenario vs PV Net Revenues of Energy
NPV of Scenario (US$ MM)
600
500
400
300
200
100
-500
0
500
1,000
1,500
PV Net Revenues of Energy (US$ MM)
15
13
10
4
6
1

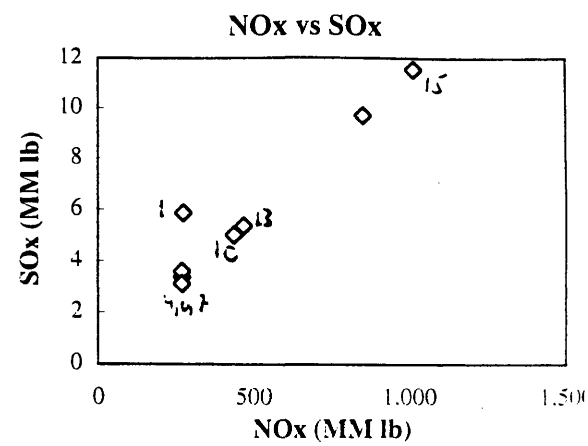

NPV of Scenario vs PV Net Revenues of Capacity
NPV of Scenario (US$ MM)
600
500
400
300
200
100
0
0
600
PV Net Revenues of Capacity (US$ MM)
15
13
10
4
6
7
1

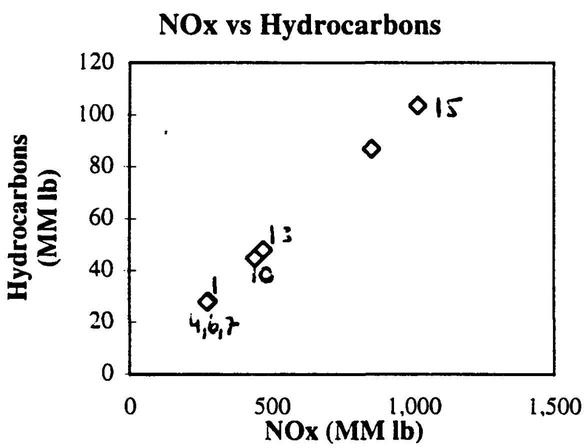

Particulates vs. NOx
NOx (MM lb)
1,200
1,000
800
600
400
200
0
0
25
50
Particulates (MM lb)
15
13
10
1
4,6,7

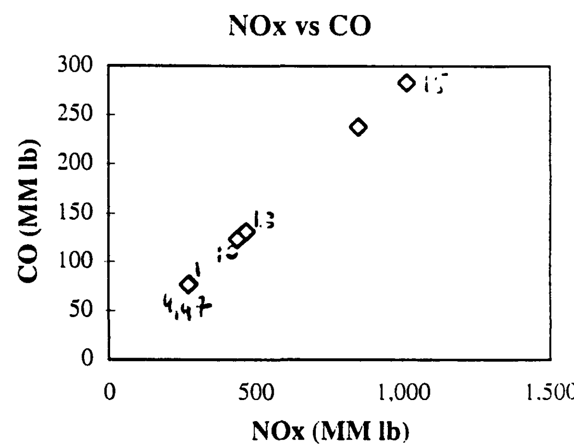

Particulates vs. SOx
SOx (MM lb)
12
10
8
6
4
2
0
0
25
50
Particulates (MM lb)
15
1
13
10
4,6,7

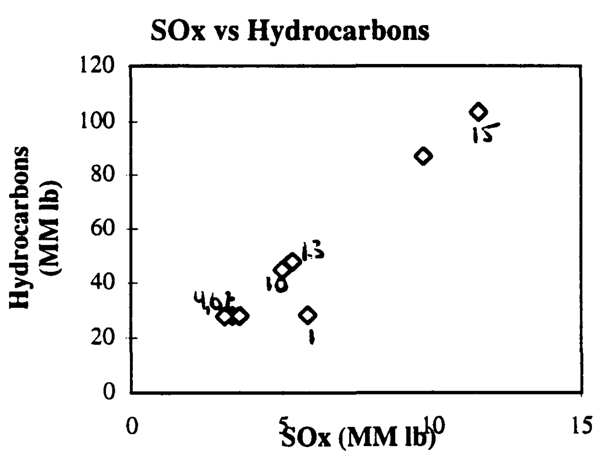

Particulates vs. Hydrocarbons
Hydrocarbons (MM lb)
120
100
80
60
40
20
0
0
10
20
30
40
50
Particulates (MM lb)
15
13
10
1
4,6,7

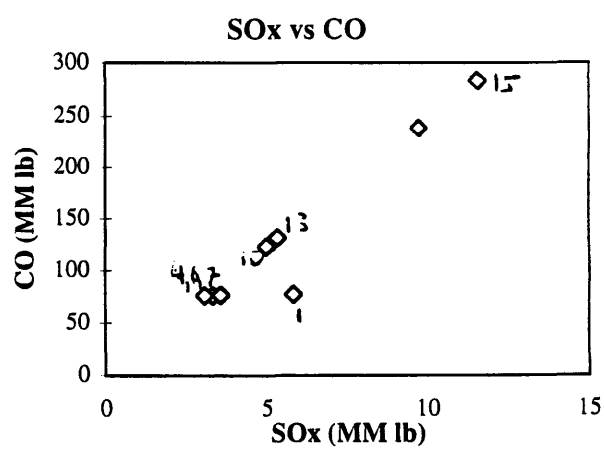

Particulates vs. CO
CO (MM lb)
300
250
200
150
100
50
0
0
25
50
Particulates (MM lb)
15
13
10
1
4,6,7


NOx vs SOx
SOx (MM lb)
12
10
8
6
4
2
0
0
500
1,000
1,500
NOx (MM lb)
15
13
10
1
4,6,7


NOx vs Hydrocarbons
Hydrocarbons (MM lb)
120
100
80
60
40
20
0
0
500
1,000
1,500
NOx (MM lb)
15
13
10
1
4,6,7


NOx vs CO
CO (MM lb)
300
250
200
150
100
50
0
0
500
1,000
1,500
NOx (MM lb)
15
13
10
1
4,6,7


SOx vs Hydrocarbons
Hydrocarbons (MM lb)
120
100
80
60
40
20
0
0
5
10
15
SOx (MM lb)
15
13
10
1
4,6,7


SOx vs CO
CO (MM lb)
300
250
200
150
100
50
0
0
5
10
15
SOx (MM lb)
15
13
10
1
4,6,7

FUTURE 6

Description:

Demand: 1997 equals to 1993 demand. Each sector grows at 1%/yr, except for Industrial which remains constant until 2001, and starts growing at 1%/yr, beginning in 2002. Agricultural Sector does not grow at all

Prices

Natural Gas (US$/MMBtu) prices starts and remains at 1.72 until 2002 and increase by 1%/yr after that

Fuel Oil (US$/tonne) start and remains at152 until 2027

MEM Spot Price (US$/MWh) start at 28, increases by 1% per yr

MEM Capacity Price (US$/MW-hr off-valley weeday) starts and remains at 8 until 2002, and then remains constant at 10 until 2027

Spot Market w/ Chile Link (As % of Spot Price)	0.95

Discount Rate (% p.a.	12%

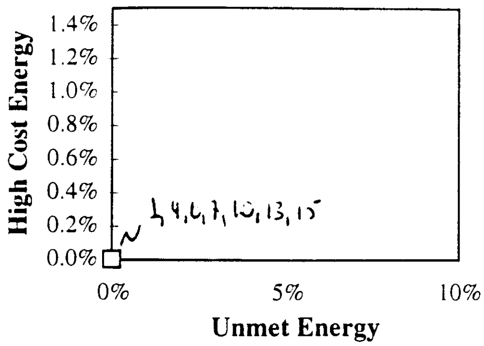
Scenario #	Percentage of Energy Demand Not Met	Percentage of Energy Demand Met w/ High Cost	Percentage of Energy Demand Met by MEM	MC Last High Cost (US$/MWh @ CdP)	Emissions (MM lb)				
					Particulates	NOx	SOx	Hydrocarbons	CO
1	0.00%	0.00%	0.07%	-	9.23	272.33	3.10	27.69	75.83
2	0.00%	0.00%	0.00%	-	9.23	272.33	3.10	27.69	75.83
3	0.00%	0.00%	0.00%	-	15.52	457.76	5.21	46.55	127.46
4	0.00%	0.00%	0.00%	-	9.23	272.33	3.10	27.69	75.83
5	0.00%	0.00%	0.00%	-	9.23	272.33	3.10	27.69	75.83
6	0.00%	0.00%	0.00%	-	9.23	272.33	3.10	27.69	75.83
7	0.00%	0.00%	0.07%	-	9.23	272.33	3.10	27.69	75.83
8	0.00%	0.00%	0.07%	-	9.23	272.33	3.10	27.69	75.83
9	0.00%	0.00%	0.07%	-	9.23	272.33	3.10	27.69	75.83
10	0.00%	0.00%	0.00%	-	14.91	439.82	5.01	44.73	122.47
11	0.00%	0.00%	0.00%	-	9.23	272.33	3.10	27.69	75.83
12	0.00%	0.00%	0.00%	-	9.23	272.33	3.10	27.69	75.83
13	0.00%	0.00%	0.00%	-	15.94	470.13	5.35	47.81	130.91
14	0.00%	0.00%	0.00%	-	28.91	852.97	9.71	86.74	237.51
15	0.00%	0.00%	0.00%	-	34.43	1,015.68	11.56	103.29	282.82

	NET REVS OF ENERGY AND CAPACITY		First Year When....								
Scenario	NPV (US$MM)		...When Demand	...When High	...When Fuel	NPV of New Capacity Investments (US$ MM)					
#	Energy (excl. fuel cost)	Capacity	Not Met	Cost Used	Oil Used	New Thermal	Los Blancos	Potrerillos	El Baqueano	P. del Viento	Scenario
1	210.456	168.174	NA	NA	NA	-	-	-	-	-	-
2	346.368	214.789	NA	NA	NA	-	-	(46.353)	-	-	(46.353)
3	787.636	303.949	NA	NA	NA	178.147	-	-	-	-	178.147
4	441.728	241.182	NA	NA	NA	-	103.280	-	-	-	103.280
5	333.687	205.912	NA	NA	NA	-	-	-	39.968	-	39.968
6	471.817	247.903	NA	NA	NA	-	-	-	-	90.089	90.089
7	210.456	168.174	NA	NA	NA	-	-	-	-	-	-
8	210.456	168.174	NA	NA	NA	-	-	-	-	-	-
9	200.283	168.174	NA	NA	NA	-	-	-	-	-	-
10	627.290	268.316	NA	NA	NA	135.737	-	-	-	-	135.737
11	308.524	202.117	NA	NA	NA	-	-	(29.004)	-	-	(29.004)
12	377.190	222.014	NA	NA	NA	-	78.217	-	-	-	78.217
13	817.891	313.134	NA	NA	NA	182.822	-	-	-	-	182.822
14	1,100.149	379.571	NA	NA	NA	213.250	-	-	-	-	213.250
15	1,311.478	423.492	NA	NA	NA	293.155	-	-	-	-	293.155

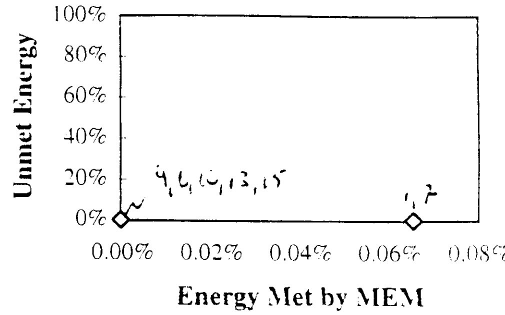
Fu

Scenario	IRR of New Capacity Investments (%)						
#	New Thermal	Los Blancos	Potrerillos	El Baqueano	P. del Viento	Scenario	NOTES
1	NA	NA	NA	NA	NA	NA	
2	NA	NA	9.83%	NA	NA	9.83%	
3	20.48%	NA	NA	NA	NA	20.48%	
4	NA	19.45%	NA	NA	NA	19.45%	
5	NA	NA	NA	16.76%	NA	16.76%	
6	NA	NA	NA	NA	17.15%	17.15%	
7	NA	NA	NA	NA	NA	NA	
8	NA	NA	NA	NA	NA	NA	
9	NA	NA	NA	NA	NA	NA	
10	21.50%	NA	NA	NA	NA	21.50%	21.50% represents IRR on investment from 2000-2027
11	NA	NA	9.96%	NA	NA	9.96%	9.96% represents IRR on investment from 2000-2027
12	NA	20.20%	NA	NA	NA	20.20%	20.20% represents IRR on investment from 2000-2027
13	20.34%	NA	NA	NA	NA	20.34%	
14	20.15%	NA	NA	NA	NA	20.15%	20.15% can be misleading because of negative CF due to late invest.
15	20.72%	NA	NA	NA	NA	20.72%	20.72% can be misleading because of negative CF due to late invest

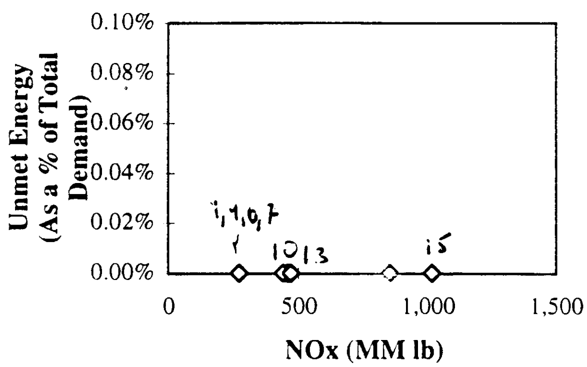
Unmet Energy vs. Energy Met w/ High Costs (as % of Total Demand)



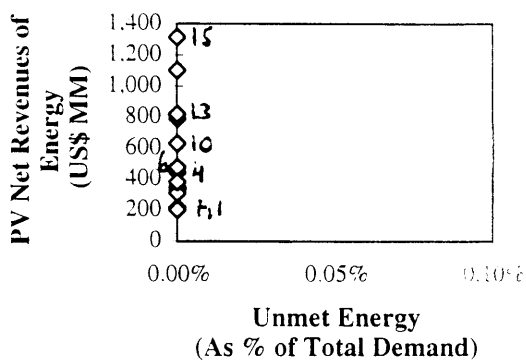
Energy Met by MEM vs Unmet Energy (As % of Total Demand)



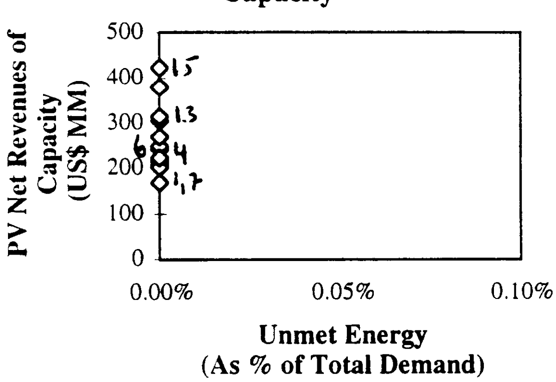
NOx vs Unmet Energy



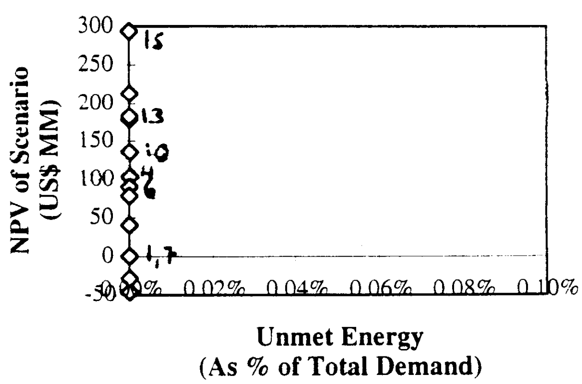
Unmet Energy vs PV Net Revenues of Energy

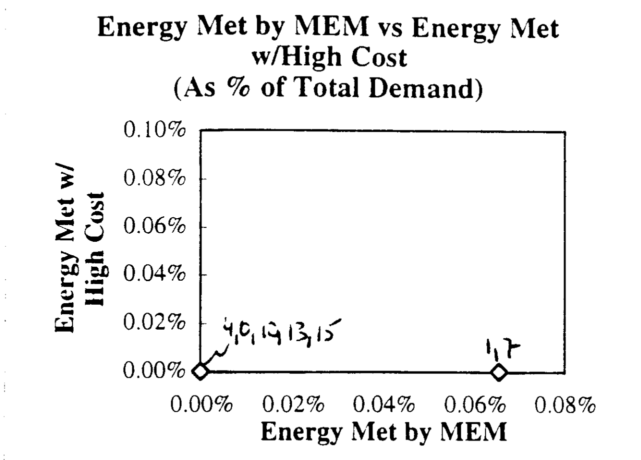


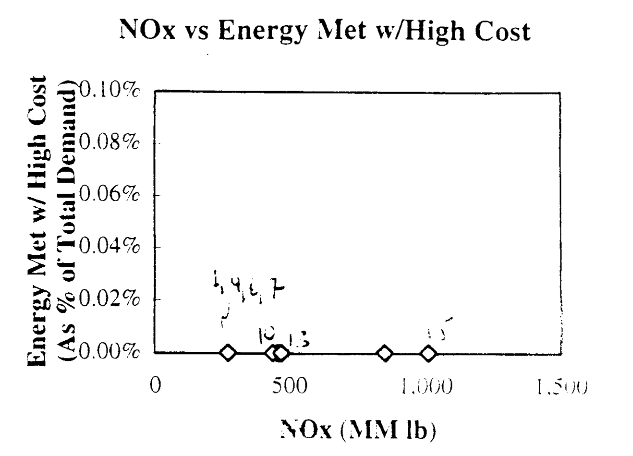
Unmet Energy vs PV Net Revenues of Capacity

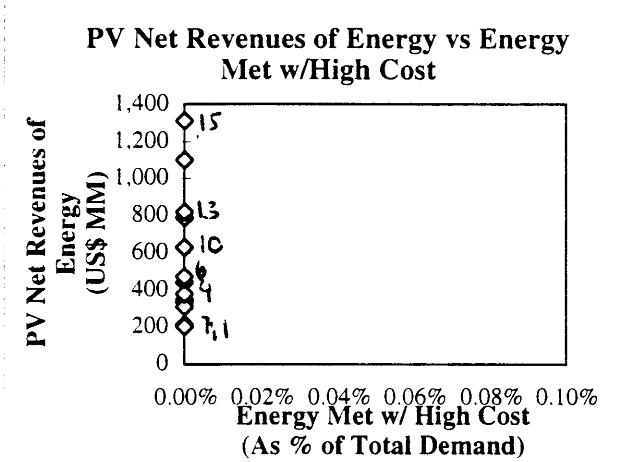


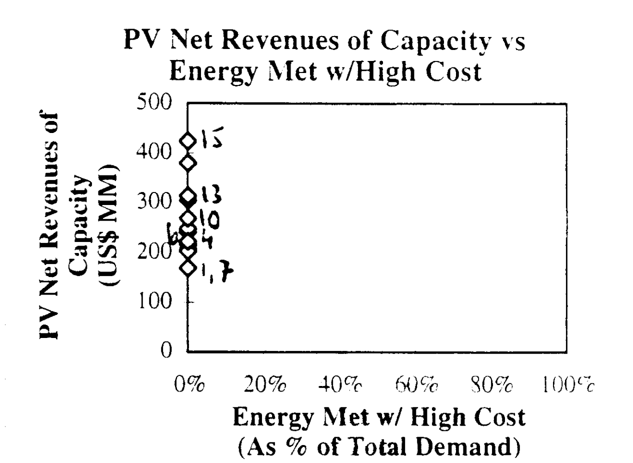
Unmet Energy vs. NPV of Scenario

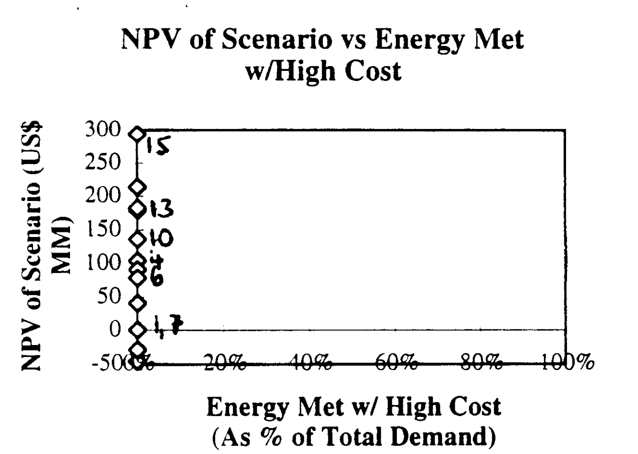


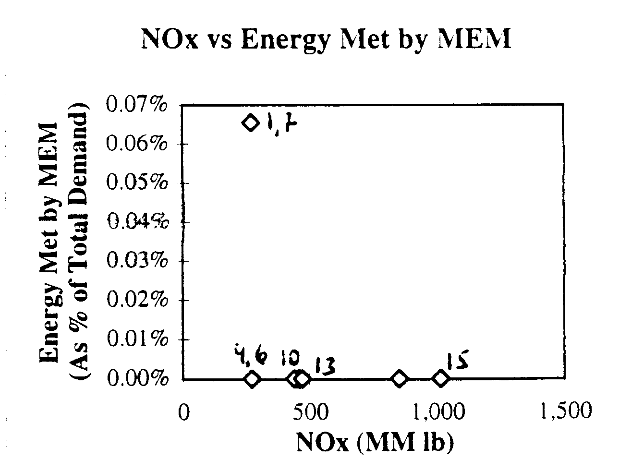

Energy Met by MEM vs Energy Met w/High Cost (As % of Total Demand)
Energy Met w/ High Cost
Energy Met by MEM
0.10%
0.08%
0.06%
0.04%
0.02%
0.00%
4,6,10,13,15
1,7

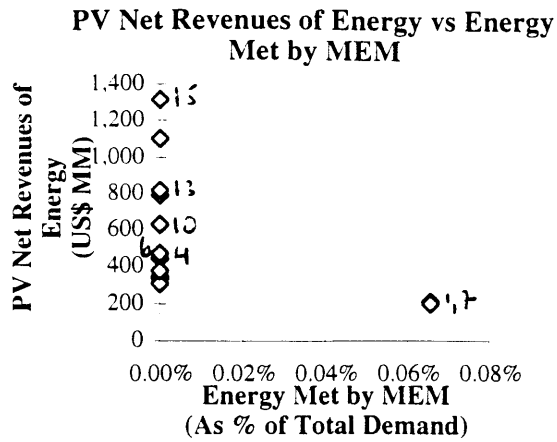

NOx vs Energy Met w/High Cost
Energy Met w/ High Cost (As % of Total Demand)
NOx (MM lb)
0
500
1,000
1,500

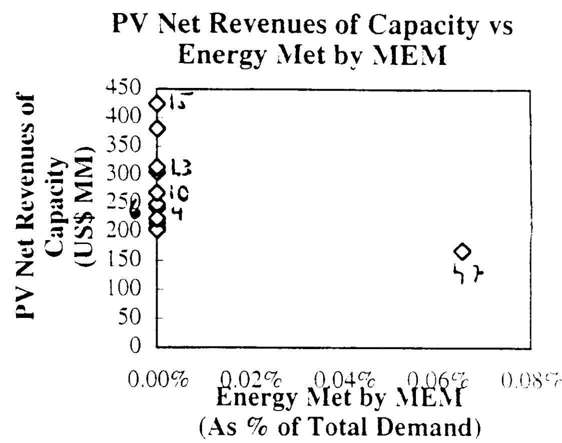

PV Net Revenues of Energy vs Energy Met w/High Cost
PV Net Revenues of Energy (US$ MM)
Energy Met w/ High Cost (As % of Total Demand)
1,400
1,200
1,000
800
600
400
200
0
15
13
10

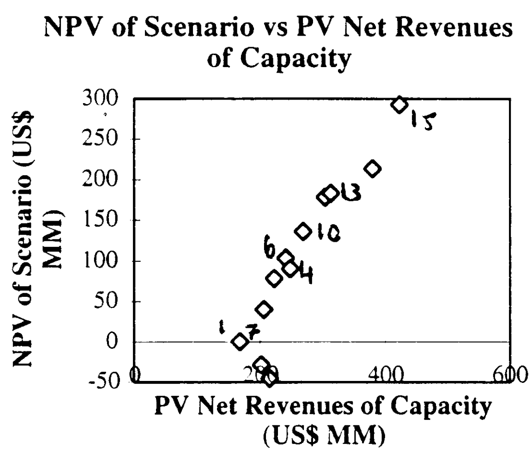

PV Net Revenues of Capacity vs Energy Met w/High Cost
PV Net Revenues of Capacity (US$ MM)
Energy Met w/ High Cost (As % of Total Demand)
500
400
300
200
100
0
15
13
10

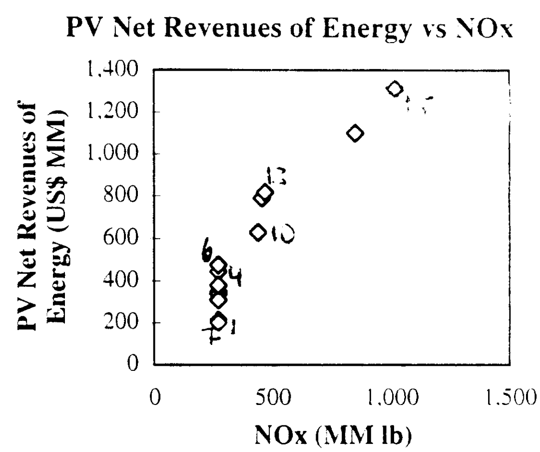

NPV of Scenario vs Energy Met w/High Cost
NPV of Scenario (US$ MM)
Energy Met w/ High Cost (As % of Total Demand)
300
250
200
150
100
50
0
15
13
10
6

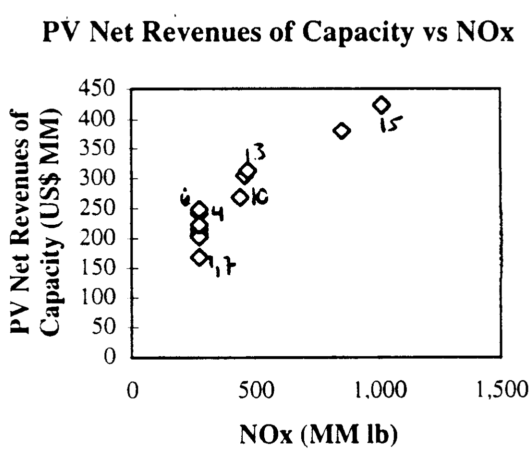

NOx vs Energy Met by MEM
Energy Met by MEM (As % of Total Demand)
NOx (MM lb)
0.07%
0.06%
0.05%
0.04%
0.03%
0.02%
0.01%
0.00%
0
500
1,000
1,500
13
15

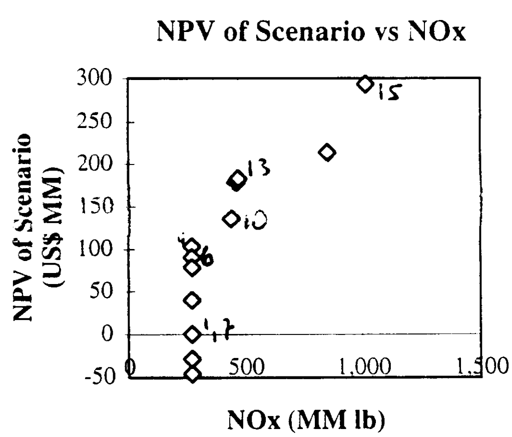

PV Net Revenues of Energy vs Energy Met by MEM
PV Net Revenues of Energy (US$ MM)
Energy Met by MEM (As % of Total Demand)
15
13
10
6
4
1,7


PV Net Revenues of Capacity vs Energy Met by MEM
PV Net Revenues of Capacity (US$ MM)
Energy Met by MEM (As % of Total Demand)
15
13
10
4
1,7

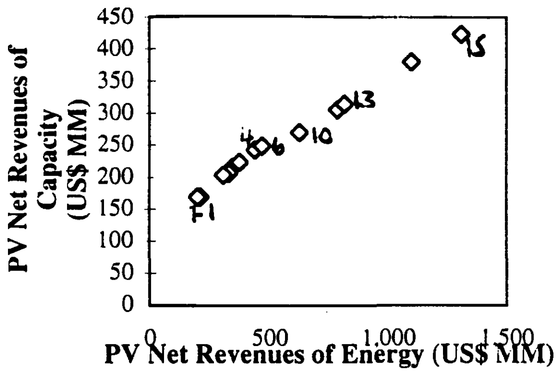

NPV of Scenario vs PV Net Revenues of Capacity
NPV of Scenario (US$ MM)
PV Net Revenues of Capacity (US$ MM)
15
13
10
6
4
1
7


PV Net Revenues of Energy vs NOx
PV Net Revenues of Energy (US$ MM)
NOx (MM lb)
13
10
6
4
1

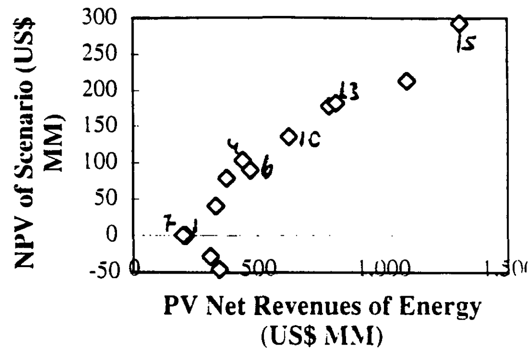

PV Net Revenues of Capacity vs NOx
PV Net Revenues of Capacity (US$ MM)
NOx (MM lb)
15
13
10
6
4
1,7


NPV of Scenario vs NOx
NPV of Scenario (US$ MM)
NOx (MM lb)
15
13
10
6
1,7

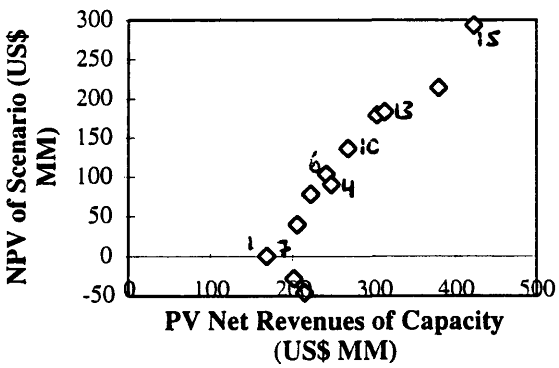
PV Net Revenues of Capacity vs PV Net Revenues of Energy



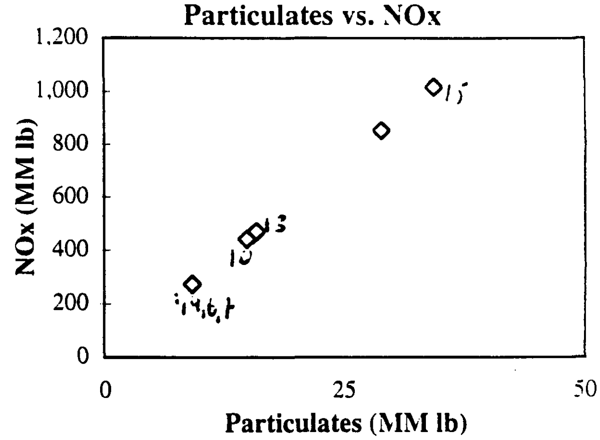
NPV of Scenario vs PV Net Revenues of Energy



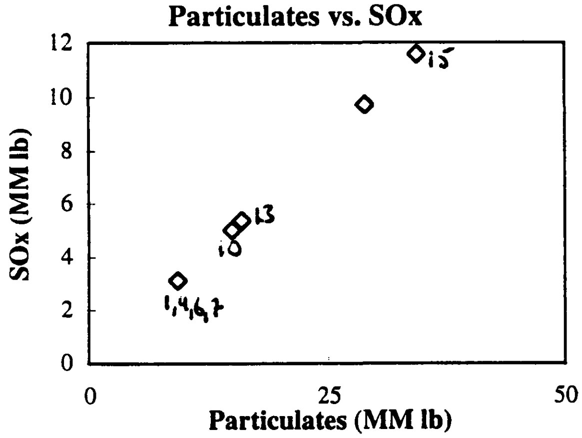
NPV of Scenario vs PV Net Revenues of Capacity



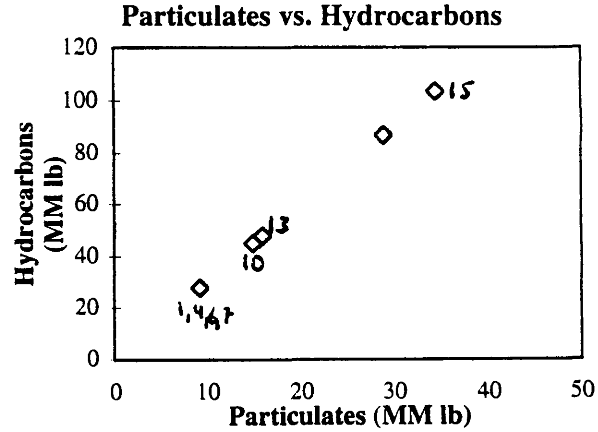
Particulates vs. NOx

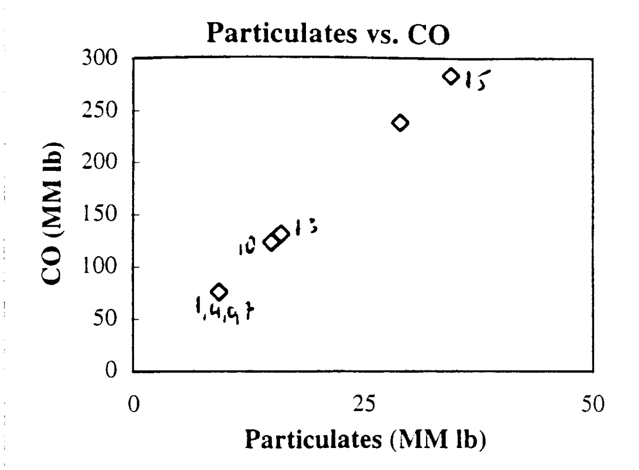


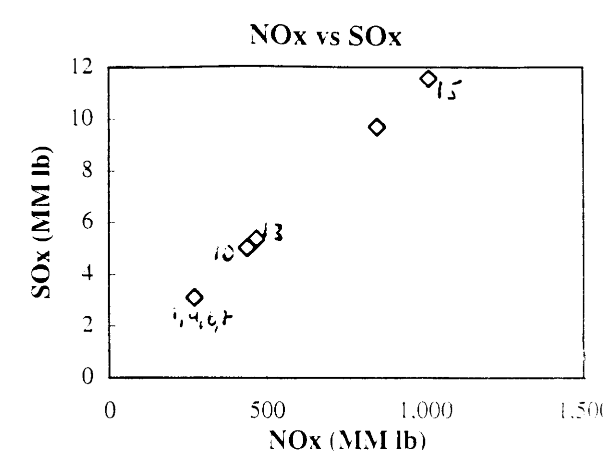
Particulates vs. SOx

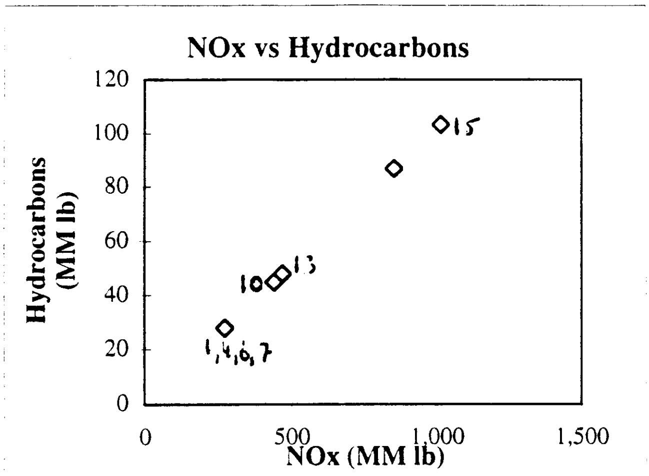


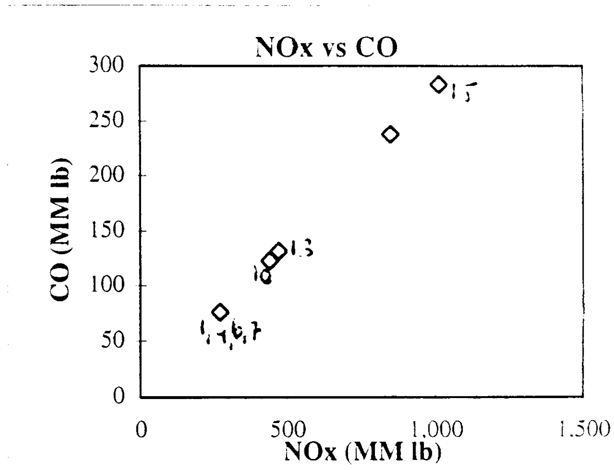
Particulates vs. Hydrocarbons

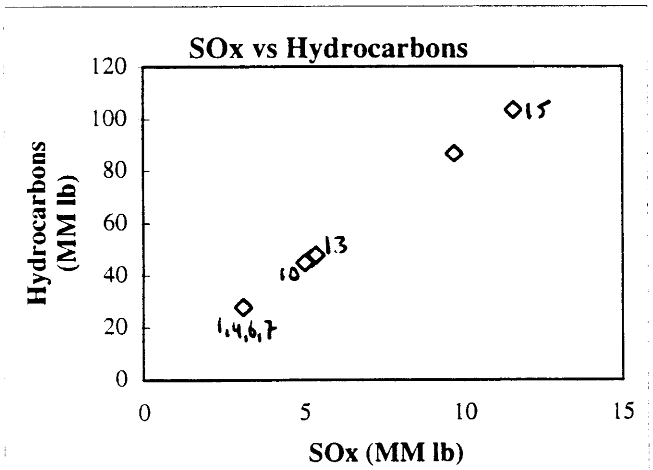


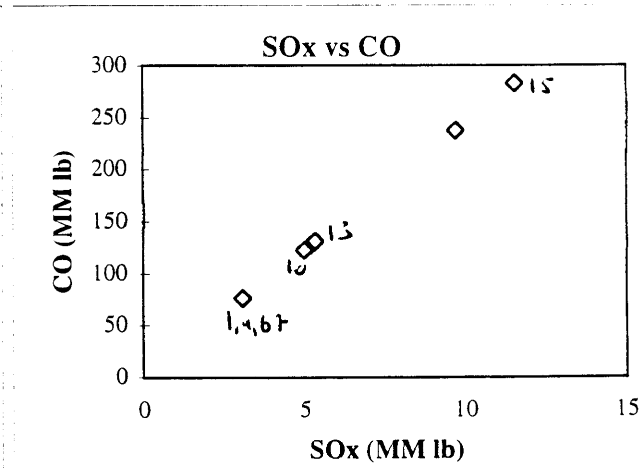

Particulates vs. CO
CO (MM lb)
300
250
200
150
100
50
0
0
25
50
Particulates (MM lb)
15
10
13
1,4,6,7


NOx vs SOx
SOx (MM lb)
12
10
8
6
4
2
0
0
500
1,000
1,500
NOx (MM lb)
15
10
13
1,4,6,7


NOx vs Hydrocarbons
Hydrocarbons (MM lb)
120
100
80
60
40
20
0
0
500
1,000
1,500
NOx (MM lb)
15
10
13
1,4,6,7


NOx vs CO
CO (MM lb)
300
250
200
150
100
50
0
0
500
1,000
1,500
NOx (MM lb)
15
10
13
1,4,6,7


SOx vs Hydrocarbons
Hydrocarbons (MM lb)
120
100
80
60
40
20
0
0
5
10
15
SOx (MM lb)
15
10
13
1,4,6,7


SOx vs CO
CO (MM lb)
300
250
200
150
100
50
0
0
5
10
15
SOx (MM lb)
15
10
13
1,4,6,7

FUTURE 7
Description:

Demand: 1997 equals to 1993 demand. Each sector grows at 8%/yr, except for Industrial which remains constant until 2001, and starts growing at 8%/yr, beginning in 2002. Agricultural Sector grows at 2%. Other demand increases by 4%/yr

Prices
Natural Gas (US$/MMBtu) prices start at 1.72 and increase by 2%/yr
Fuel Oil (US$/tonne) start at 152 and increases at 1.5%
MEM Spot Price (US$/MWh) start at 30, increase by 3% until 2000, and by 2% after that
MEM Capacity Price (US$/MW-hr off-valley weeday) starts at 10 until 2000, and goes down to 8 after that.

Spot Market w/ Chile Link (As % of Spot Price)	0.95

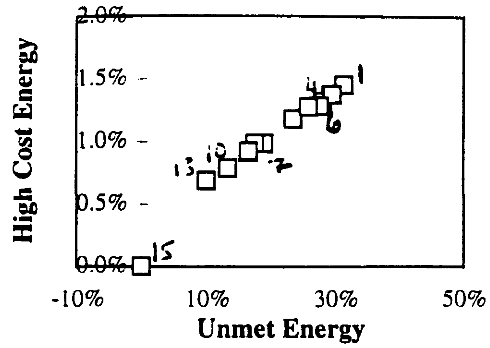
Discount Rate (% p.a.)	12%

Scenario #	Percentage of Energy Demand Not Met	Percentage of Energy Demand Met w/ High Cost	Percentage of Energy Demand Met by MEM	MC Last High Cost (US$/MWh @ CdP)	Emissions (MM lb)				
					Particulates	NOx	SOx	Hydrocarbons	CO
1	31.44%	1.45%	26.49%	76.10	11.38	301.45	27.16	30.09	82.44
2	29.42%	1.38%	25.11%	76.10	11.27	299.98	25.94	29.97	82.11
3	23.46%	1.18%	21.24%	76.10	17.26	481.47	24.79	48.50	132.85
4	28.06%	1.32%	24.21%	76.10	11.18	298.77	24.94	29.87	81.83
5	29.61%	1.38%	25.23%	76.10	11.27	299.98	25.94	29.97	82.11
6	27.64%	1.29%	23.95%	76.10	11.13	298.12	24.41	29.81	81.69
7	19.05%	0.98%	39.35%	76.10	10.69	292.08	19.41	29.32	80.32
8	16.56%	0.92%	41.91%	76.10	10.58	290.69	18.27	29.20	80.00
9	25.91%	1.28%	32.19%	76.10	11.12	298.00	24.31	29.80	81.66
10	13.44%	0.79%	31.65%	76.10	16.07	455.62	18.06	46.03	126.06
11	17.60%	0.98%	37.32%	76.10	10.69	292.08	19.41	29.32	80.32
12	16.64%	0.92%	36.02%	76.10	10.60	290.87	18.42	29.22	80.04
13	10.07%	0.69%	34.35%	76.10	16.96	483.95	16.77	48.95	134.05
14	0.00%	0.00%	5.72%	-	28.91	852.97	9.71	86.74	237.51
15	0.00%	0.00%	0.09%	-	34.43	1,015.68	11.56	103.29	282.82

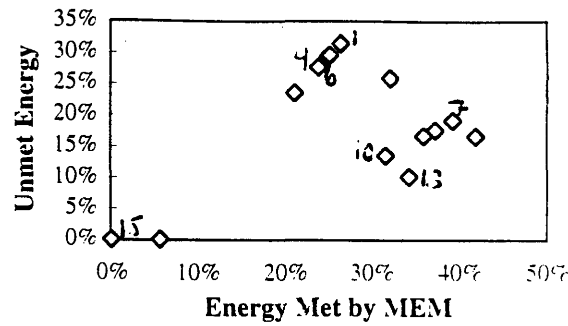
Scenario #	NET REVS OF ENERGY AND CAPACITY NPV (US$MM) Energy (excl. fuel cost)	Capacity	First Year When.... ...When Demand Not Met	...When High Cost Used	...When Fuel Oil Used	NPV of New Capacity Investments (US$MM) New Thermal	Los Blancos	Potrerillos	El Baqueano	P. del Viento	Scenario
1	(908.341)	65.017	2014	2013	2013	-	-	-	-	-	-
2	(722.456)	111.221	2014	2014	2014	-	-	7.485	-	-	7.485
3	(145.882)	199.643	2016	2016	2016	295.590	-	-	-	-	295.590
4	(603.704)	137.415	2015	2014	2014	-	166.667	-	-	-	166.667
5	(738.596)	102.344	2014	2014	2014	-	-	-	73.615	-	73.615
6	(565.601)	143.975	2015	2014	2014	-	-	-	-	161.499	161.499
7	(841.575)	63.27[illegible]	2018	2018	2018	-	-	-	-	-	-
8	(843.038)	63.124	2019	2018	2018	-	-	-	-	-	-
9	(874.041)	64.216	2015	2015	2015	-	-	-	-	-	-
10	(279.964)	162.952	2020	2020	2020	223.964	-	-	-	-	223.964
11	(714.557)	97.223	2018	2018	2018	-	-	12.561	-	-	12.561
12	(626.888)	116.993	2019	2018	2018	-	127.438	-	-	-	127.438
13	(33.216)	207.572	2021	2021	2021	288.083	-	-	-	-	288.083
14	462.628	273.107	NA	NA	NA	378.125	-	-	-	-	378.125
15	712.709	317.028	NA	NA	NA	512.041	-	-	-	-	512.041

Scenario #	IRR of New Capacity Investments (%)						NOTES
	New Thermal	Los Blancos	Potrerillos	El Baqueano	P. del Viento	Scenario	
1	NA	NA	NA	NA	NA	NA	
2	NA	NA	12.32%	NA	NA	12.32%	
3	24.17%	NA	NA	NA	NA	24.17%	
4	NA	22.42%	NA	NA	NA	22.42%	
5	NA	NA	NA	19.58%	NA	19.58%	
6	NA	NA	NA	NA	20.00%	20.00%	
7	NA	NA	NA	NA	NA	NA	
8	NA	NA	NA	NA	NA	NA	
9	NA	NA	NA	NA	NA	NA	
10	26.12%	NA	NA	NA	NA	26.12%	26.18% represents IRR on investment from 2000-2027
11	NA	NA	12.78%	NA	NA	12.78%	12.78% represents IRR on investment from 2000-2027
12	NA	24.01%	NA	NA	NA	24.01%	24.01% represents IRR on investment from 2000-2027
13	23.85%	NA	NA	NA	NA	23.85%	
14	24.05%	NA	NA	NA	NA	24.05%	24.05% can be misleading because of negative CF due to late invest.
15	24.71%	NA	NA	NA	NA	24.71%	24.71% can be misleading because of negative CF due to late invest

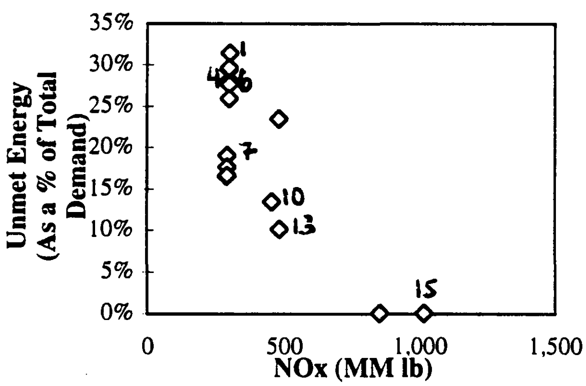
Unmet Energy vs. Energy Met w/ High Costs (as % of Total Demand)



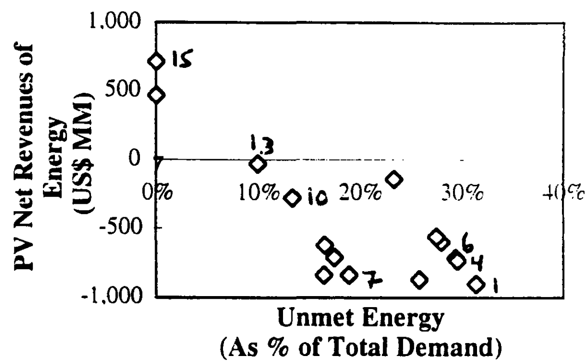
Energy Met by MEM vs Unmet Energy (As % of Total Demand)



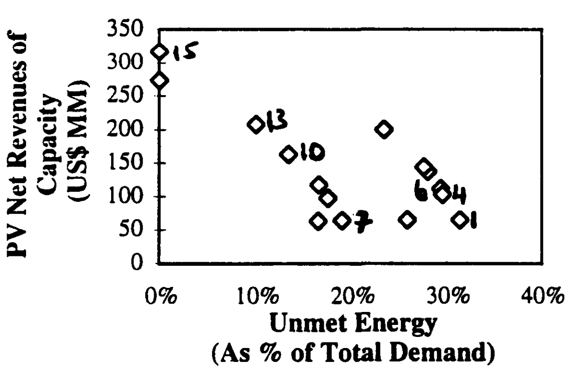
NOx vs Unmet Energy



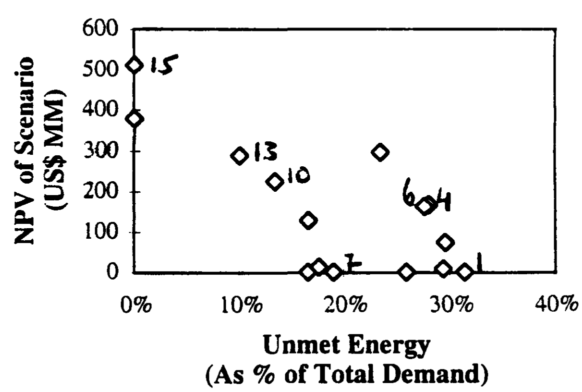
Unmet Energy vs PV Net Revenues of Energy

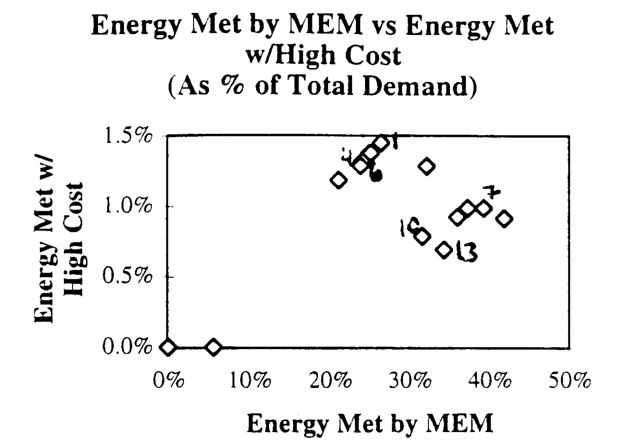


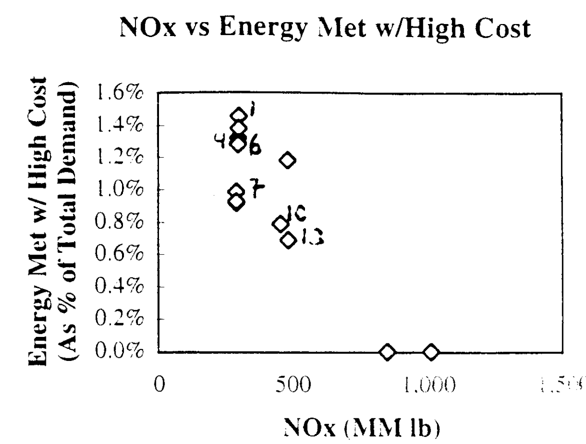
Unmet Energy vs PV Net Revenues of Capacity

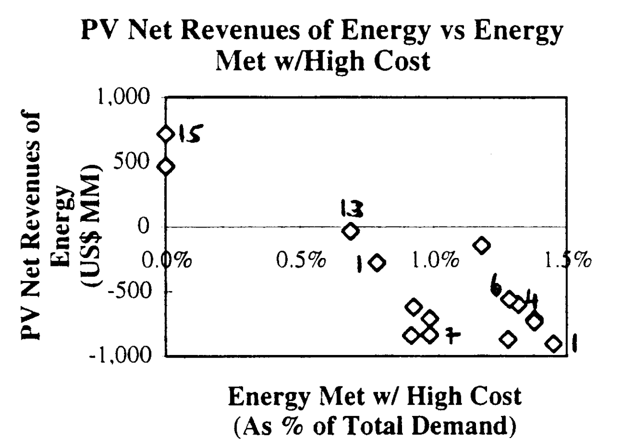


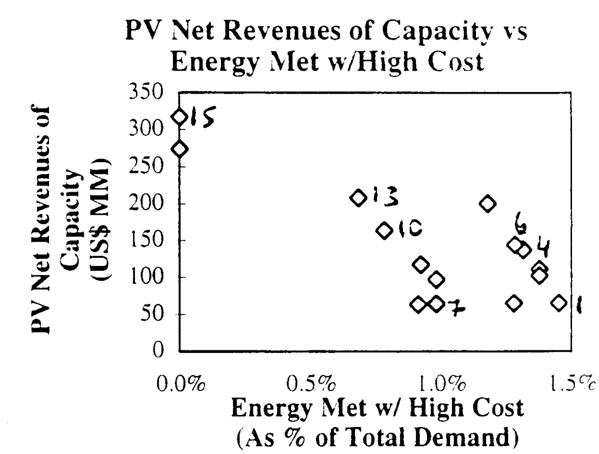
Unmet Energy vs. NPV of Scenario

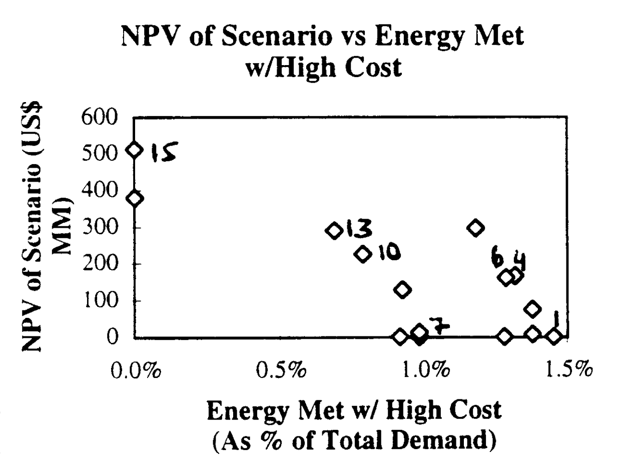


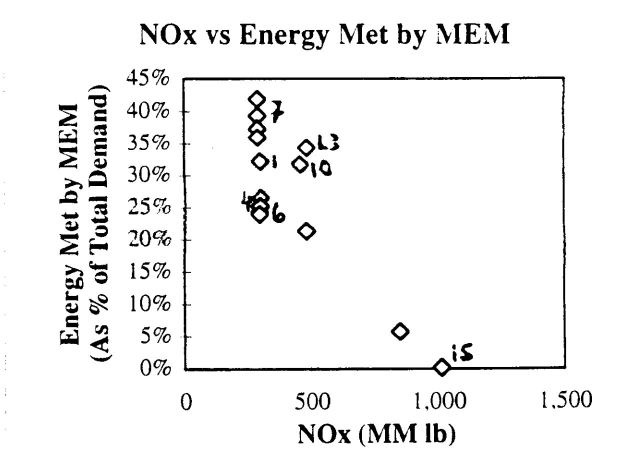

Energy Met by MEM vs Energy Met w/High Cost (As % of Total Demand)
Energy Met w/ High Cost
1.5%
1.0%
0.5%
0.0%
0%
10%
20%
30%
40%
50%
Energy Met by MEM

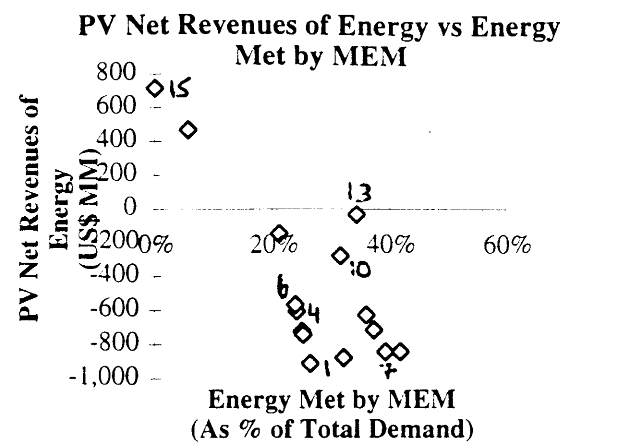

NOx vs Energy Met w/High Cost
Energy Met w/ High Cost (As % of Total Demand)
1.6%
1.4%
1.2%
1.0%
0.8%
0.6%
0.4%
0.2%
0.0%
0
500
1,000
NOx (MM lb)

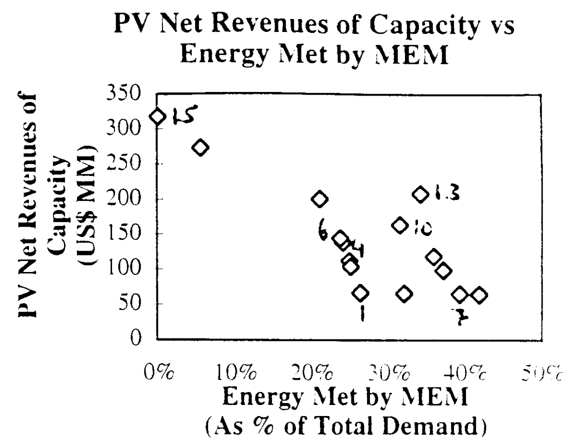

PV Net Revenues of Energy vs Energy Met w/High Cost
PV Net Revenues of Energy (US$ MM)
1,000
500
0
-500
-1,000
0.0%
0.5%
1.0%
1.5%
Energy Met w/ High Cost (As % of Total Demand)

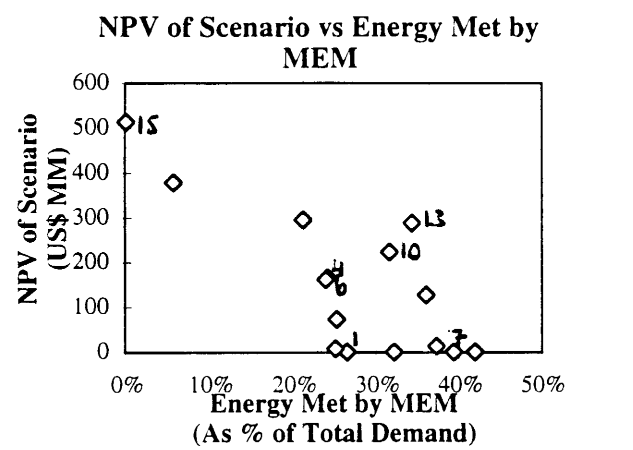

PV Net Revenues of Capacity vs Energy Met w/High Cost
PV Net Revenues of Capacity (US$ MM)
350
300
250
200
150
100
50
0
0.0%
0.5%
1.0%
1.5%
Energy Met w/ High Cost (As % of Total Demand)

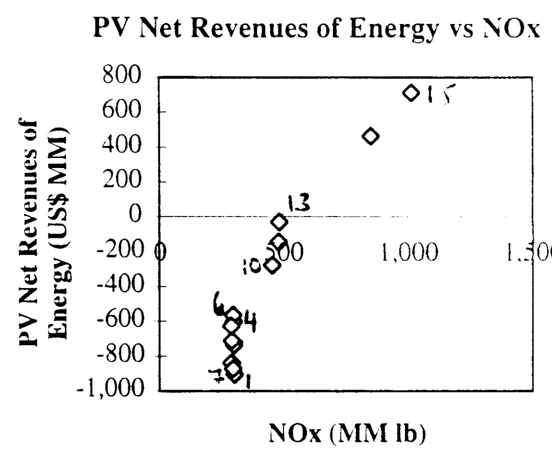

NPV of Scenario vs Energy Met w/High Cost
NPV of Scenario (US$ MM)
600
500
400
300
200
100
0
0.0%
0.5%
1.0%
1.5%
Energy Met w/ High Cost (As % of Total Demand)

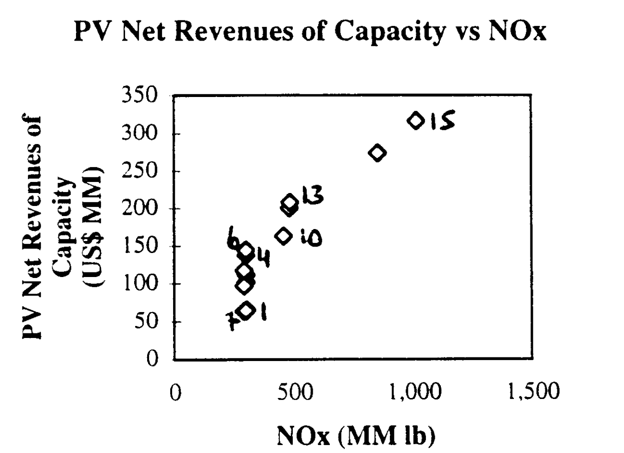

NOx vs Energy Met by MEM
Energy Met by MEM (As % of Total Demand)
45%
40%
35%
30%
25%
20%
15%
10%
5%
0%
0
500
1,000
1,500
NOx (MM lb)

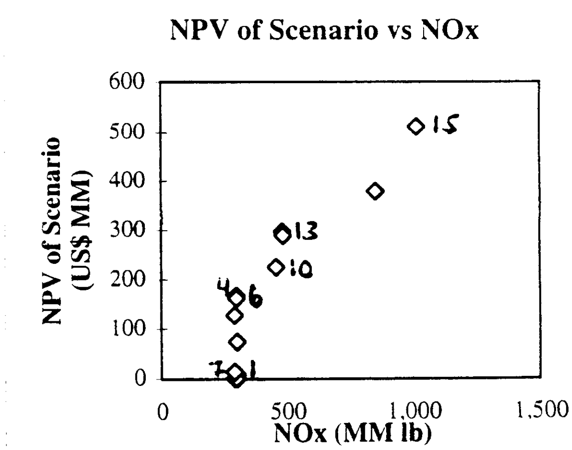

PV Net Revenues of Energy vs Energy Met by MEM
PV Net Revenues of Energy (US$ MM)
800
600
400
200
0
-200
-400
-600
-800
-1,000
0%
20%
40%
60%
Energy Met by MEM (As % of Total Demand)

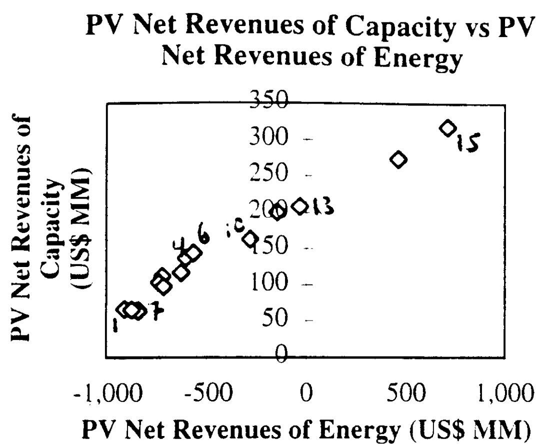

PV Net Revenues of Capacity vs Energy Met by MEM
PV Net Revenues of Capacity (US$ MM)
350
300
250
200
150
100
50
0
0%
10%
20%
30%
40%
50%
Energy Met by MEM (As % of Total Demand)

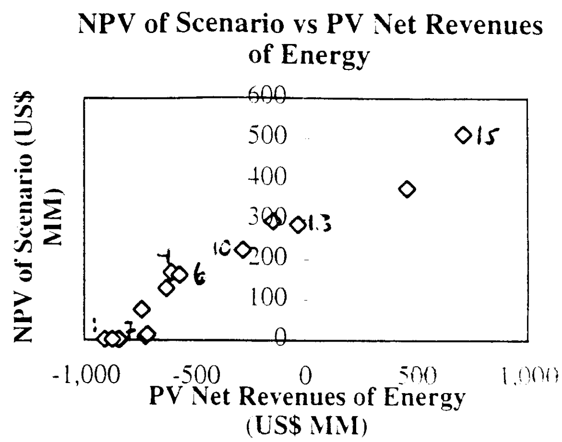

NPV of Scenario vs Energy Met by MEM
NPV of Scenario (US$ MM)
600
500
400
300
200
100
0
0%
10%
20%
30%
40%
50%
Energy Met by MEM (As % of Total Demand)

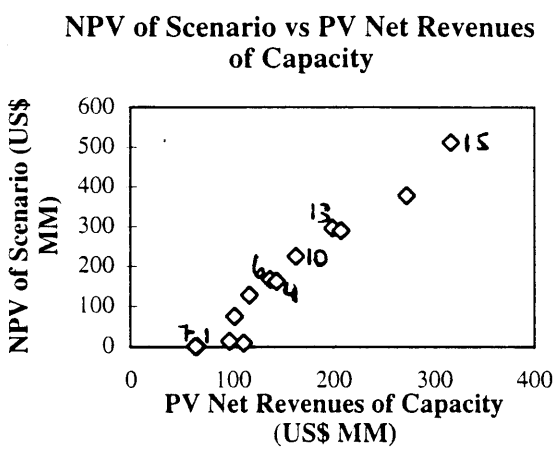

PV Net Revenues of Energy vs NOx
PV Net Revenues of Energy (US$ MM)
800
600
400
200
0
-200
-400
-600
-800
-1,000
0
500
1,000
1,500
NOx (MM lb)

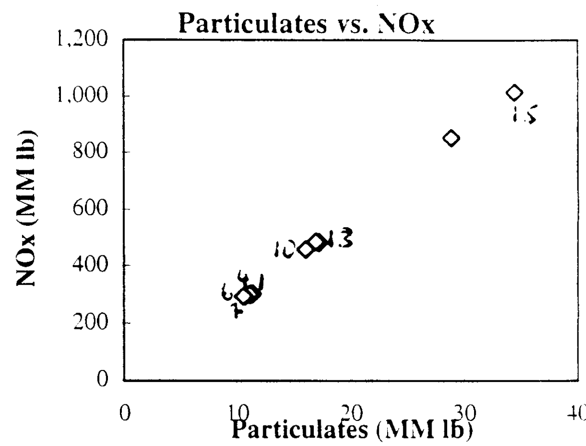

PV Net Revenues of Capacity vs NOx
PV Net Revenues of Capacity (US$ MM)
350
300
250
200
150
100
50
0
0
500
1,000
1,500
NOx (MM lb)

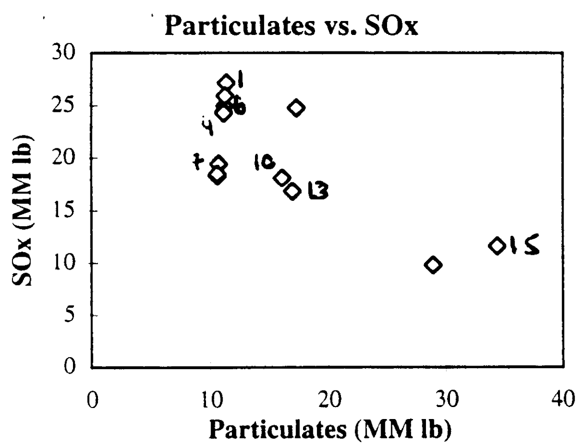

NPV of Scenario vs NOx
NPV of Scenario (US$ MM)
600
500
400
300
200
100
0
0
500
1,000
1,500
NOx (MM lb)

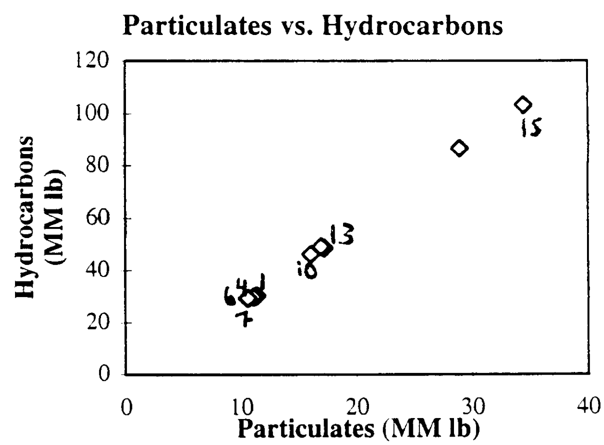

PV Net Revenues of Capacity vs PV Net Revenues of Energy
PV Net Revenues of Capacity (US$ MM)
350
300
250
200
150
100
50
0
-1,000
-500
0
500
1,000
PV Net Revenues of Energy (US$ MM)

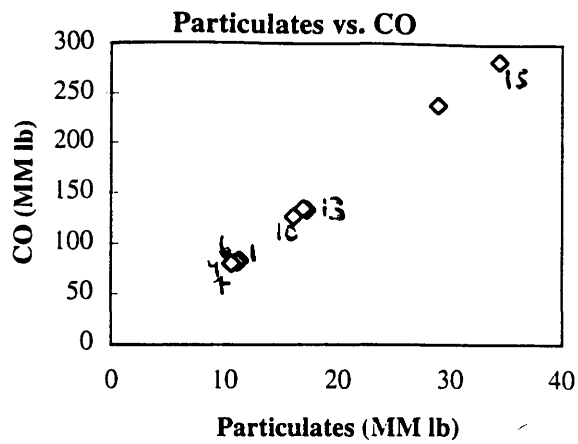

NPV of Scenario vs PV Net Revenues of Energy
NPV of Scenario (US$ MM)
600
500
400
300
200
100
0
-1,000
-500
0
500
1,000
PV Net Revenues of Energy (US$ MM)

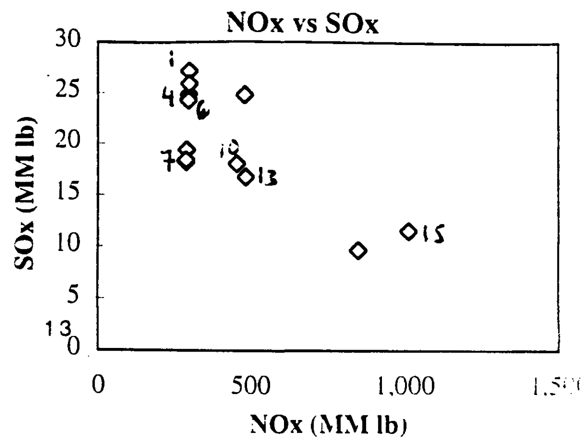

NPV of Scenario vs PV Net Revenues of Capacity
NPV of Scenario (US$ MM)
600
500
400
300
200
100
0
0
100
200
300
400
PV Net Revenues of Capacity (US$ MM)

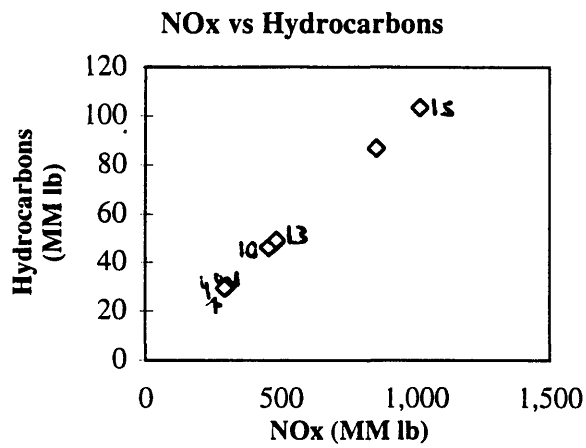

Particulates vs. NOx
NOx (MM lb)
1,200
1,000
800
600
400
200
0
0
10
20
30
40
Particulates (MM lb)

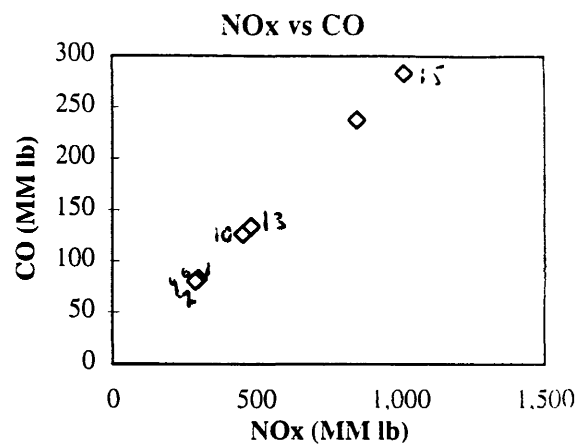

Particulates vs. SOx
SOx (MM lb)
30
25
20
15
10
5
0
0
10
20
30
40
Particulates (MM lb)

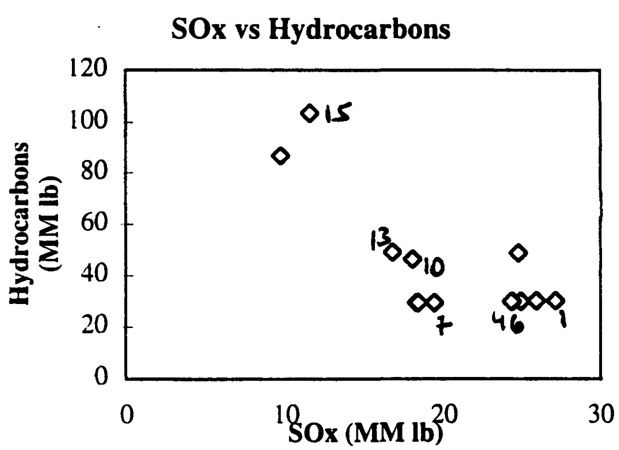

Particulates vs. Hydrocarbons
Hydrocarbons (MM lb)
120
100
80
60
40
20
0
0
10
20
30
40
Particulates (MM lb)

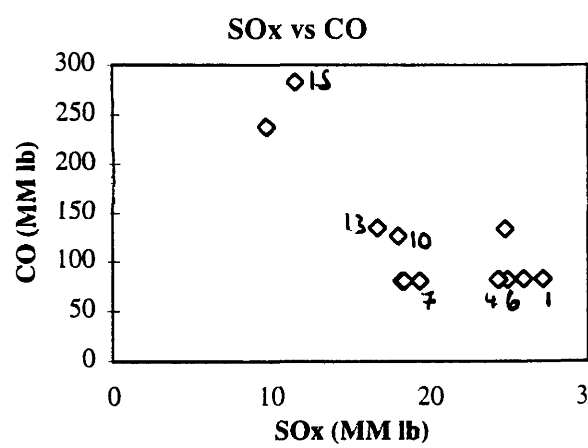

Particulates vs. CO
CO (MM lb)
Particulates (MM lb)


NOx vs SOx
SOx (MM lb)
NOx (MM lb)


NOx vs Hydrocarbons
Hydrocarbons (MM lb)
NOx (MM lb)


NOx vs CO
CO (MM lb)
NOx (MM lb)


SOx vs Hydrocarbons
Hydrocarbons (MM lb)
SOx (MM lb)


SOx vs CO
CO (MM lb)
SOx (MM lb)

FUTURE 8

Description:

Demand: 1997 equals to 1993 demand. Each sector grows at 10%/yr, except for Industrial which remains constant until 2001, and starts growing at 10%/yr, beginning in 2002. Agricultural Sector does not grow at all. Other Demand grows at 4%

Prices

Natural Gas (US$/MMBtu) prices starts at 1.72 and grows at 2%/yr

Fuel Oil (US$/tonne) starts at152and grows at 1%/yr

MEM Spot Price (US$/MWh) start at 28, increases by 3% per yr

MEM Capacity Price (US$/MW-hr off-valley weeday) starts and remains at 8 until 2002, and then remains constant at 10 until 2027

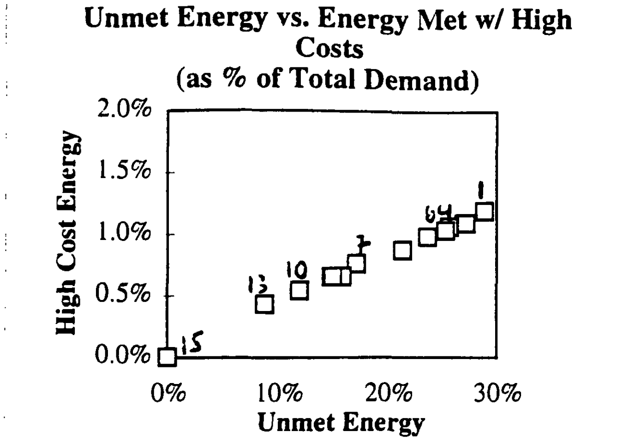
Spot Market w/ Chile Link (As % of Spot Price)	0.99

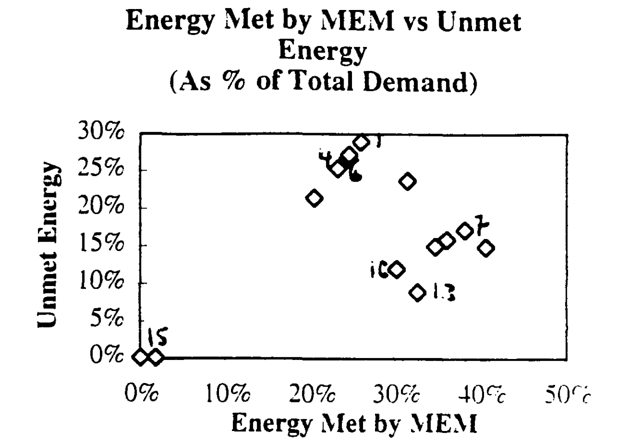
Discount Rate (% p.a.	12%

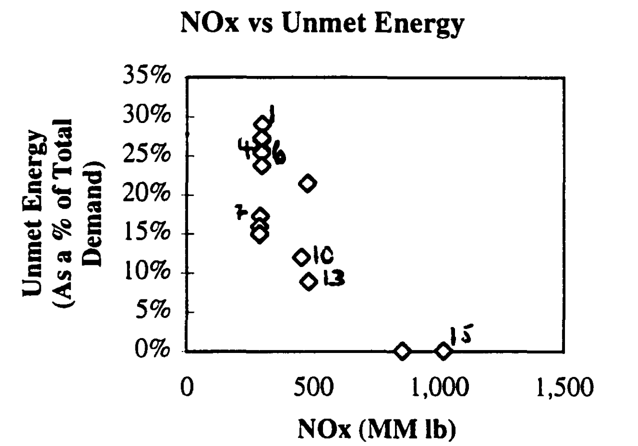
Scenario #	Percentage of Energy Demand Not Met	Percentage of Energy Demand Met w/ High Cost	Percentage of Energy Demand Met by MEM	MC Last High Cost (US$/MWh @ CdP)	Emissions (MM lb)				
					Particulates	NOx	SOx	Hydrocarbons	CO
1	28.97%	1.19%	26.01%	65.62	11.12	297.93	24.25	29.80	81.64
2	27.06%	1.08%	24.52%	65.62	10.98	296.03	22.68	29.64	81.21
3	21.41%	0.87%	20.46%	65.62	16.97	477.52	21.52	48.18	131.95
4	25.74%	1.06%	23.54%	65.62	10.95	295.63	22.35	29.61	81.12
5	27.24%	1.08%	24.65%	65.62	10.98	296.03	22.68	29.64	81.21
6	25.35%	1.03%	23.26%	65.62	10.90	294.99	21.82	29.56	80.98
7	17.23%	0.76%	38.18%	65.62	10.54	290.10	17.78	29.15	79.87
8	14.93%	0.65%	40.59%	65.62	10.40	288.13	16.15	28.99	79.42
9	23.74%	0.98%	31.45%	65.62	10.83	294.05	21.04	29.48	80.76
10	12.02%	0.54%	30.18%	65.62	15.93	453.64	16.42	45.86	125.61
11	15.91%	0.65%	36.10%	65.62	10.40	288.13	16.15	28.99	79.42
12	15.01%	0.65%	34.68%	65.62	10.40	288.13	16.15	28.99	79.42
13	8.89%	0.43%	32.65%	65.62	16.81	481.98	15.14	48.78	133.60
14	0.00%	0.00%	1.78%	-	29.21	856.92	12.97	87.07	238.41
15	0.00%	0.00%	0.00%	-	34.72	1,019.63	14.82	103.61	283.71

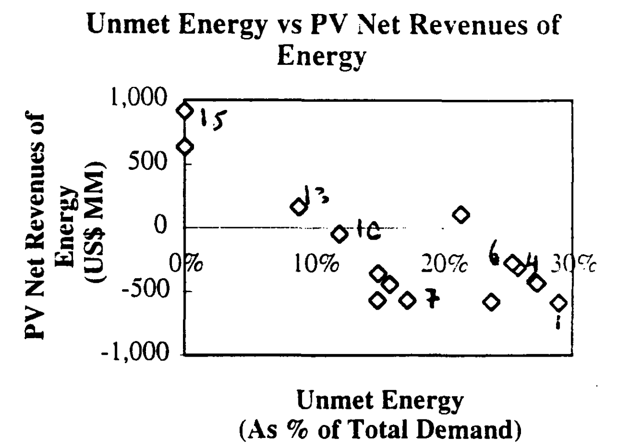
Scenario	NET REVS OF ENERGY AND CAPACITY		First Year When....			NPV of New Capacity Investments (US$MM)					
	NPV (US$MM)		...When Demand	...When High	...When Fuel						
#	Energy (excl. fuel cost)	Capacity	Not Met	Cost Used	Oil Used	New Thermal	Los Blancos	Potrerillos	El Baqueano	P. del Viento	Scenario
1	(590.867)	89.728	2016	2015	2015	-	-	-	-	-	-
2	(423.958)	135.994	2016	2016	2016	-	-	(8.287)	-	-	(8.287)
3	107.532	224.566	2018	2018	2018	257.592	-	-	-	-	257.592
4	(310.492)	162.387	2017	2016	2016	-	148.358	-	-	-	148.358
5	(439.179)	127.117	2016	2016	2016	-	-	-	63.942	-	63.942
6	(275.265)	168.983	2017	2016	2016	-	-	-	-	141.059	141.059
7	(574.297)	88.543	2019	2019	2019	-	-	-	-	-	-
8	(570.991)	88.322	2020	2020	2020	-	-	-	-	-	-
9	(580.846)	89.068	2017	2017	2017	-	-	-	-	-	-
10	(49.640)	188.266	2021	2021	2021	209.771	-	-	-	-	209.771
11	(448.773)	122.265	2020	2020	2020	-	-	5.669	-	-	5.669
12	(363.198)	142.161	2020	2020	2020	-	119.277	-	-	-	119.277
13	162.807	232.907	2022	2022	2022	268.305	-	-	-	-	268.305
14	634.680	298.808	NA	NA	2026	446.855	-	-	-	-	446.855
15	912.299	342.729	NA	NA	2026	580.004	-	-	-	-	580.004

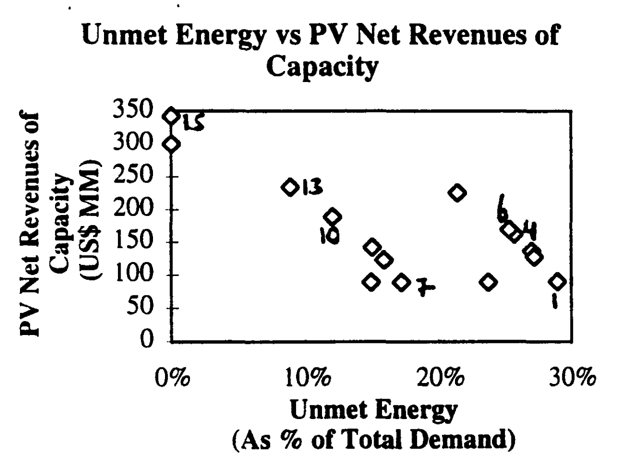
Scenario #	IRR of New Capacity Investments (%)						NOTES
	New Thermal	Los Blancos	Potrerillos	El Baqueano	P. del Viento	Scenario	
1	NA	NA	NA	NA	NA	NA	
2	NA	NA	11.69%	NA	NA	11.69%	
3	22.50%	NA	NA	NA	NA	22.50%	
4	NA	21.36%	NA	NA	NA	21.36%	
5	NA	NA	NA	18.66%	NA	18.66%	
6	NA	NA	NA	NA	19.06%	19.06%	
7	NA	NA	NA	NA	NA	NA	
8	NA	NA	NA	NA	NA	NA	
9	NA	NA	NA	NA	NA	NA	
10	24.79%	NA	NA	NA	NA	24.79%	21.50% represents IRR on investment from 2000-2027
11	NA	NA	12.36%	NA	NA	12.36%	9.96% represents IRR on investment from 2000-2027
12	NA	23.18%	NA	NA	NA	23.18%	20.20% represents IRR on investment from 2000-2027
13	22.42%	NA	NA	NA	NA	22.42%	
14	23.30%	NA	NA	NA	NA	23.30%	20.15% can be misleading because of negative CF due to late invest.
15	23.96%	NA	NA	NA	NA	23.96%	20.72% can be misleading because of negative CF due to late invest

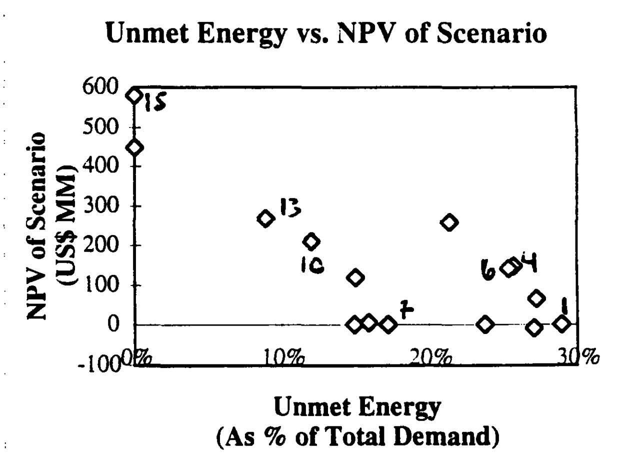

Unmet Energy vs. Energy Met w/ High Costs
(as % of Total Demand)
High Cost Energy
2.0%
1.5%
1.0%
0.5%
0.0%
0%
10%
20%
30%
Unmet Energy

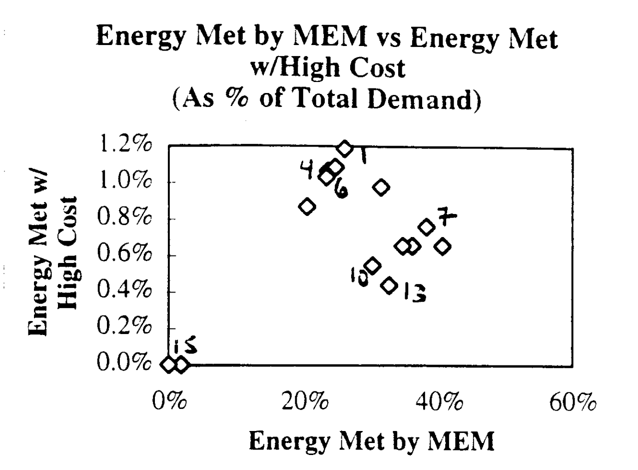

Energy Met by MEM vs Unmet Energy
(As % of Total Demand)
Unmet Energy
30%
25%
20%
15%
10%
5%
0%
0%
10%
20%
30%
40%
50%
Energy Met by MEM

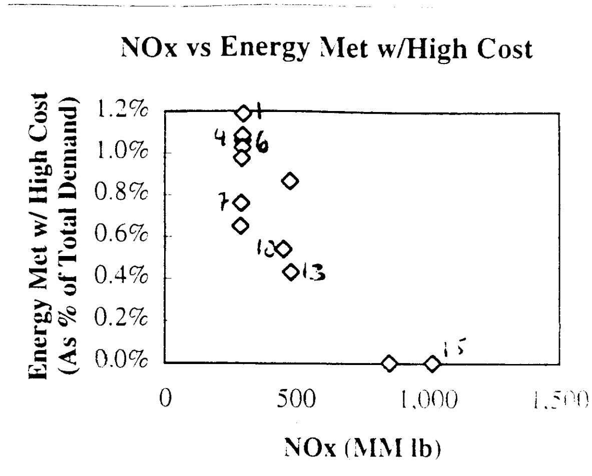

NOx vs Unmet Energy
Unmet Energy
(As a % of Total Demand)
35%
30%
25%
20%
15%
10%
5%
0%
0
500
1,000
1,500
NOx (MM lb)

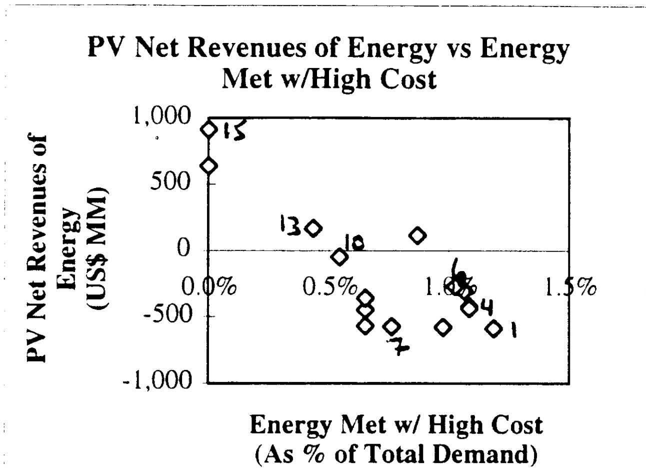

Unmet Energy vs PV Net Revenues of Energy
PV Net Revenues of Energy
(US$ MM)
1,000
500
0
-500
-1,000
0%
10%
20%
30%
Unmet Energy
(As % of Total Demand)

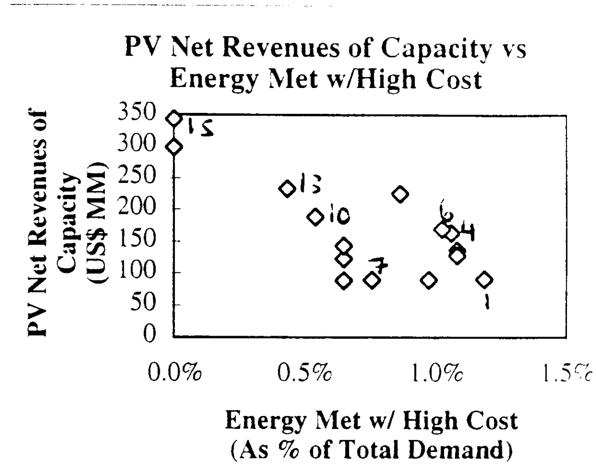

Unmet Energy vs PV Net Revenues of Capacity
PV Net Revenues of Capacity
(US$ MM)
350
300
250
200
150
100
50
0
0%
10%
20%
30%
Unmet Energy
(As % of Total Demand)

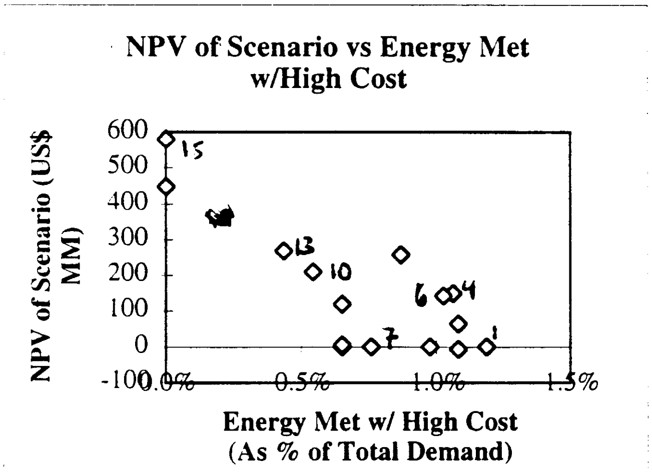

Unmet Energy vs. NPV of Scenario
NPV of Scenario
(US$ MM)
600
500
400
300
200
100
0
-100
0%
10%
20%
30%
Unmet Energy
(As % of Total Demand)

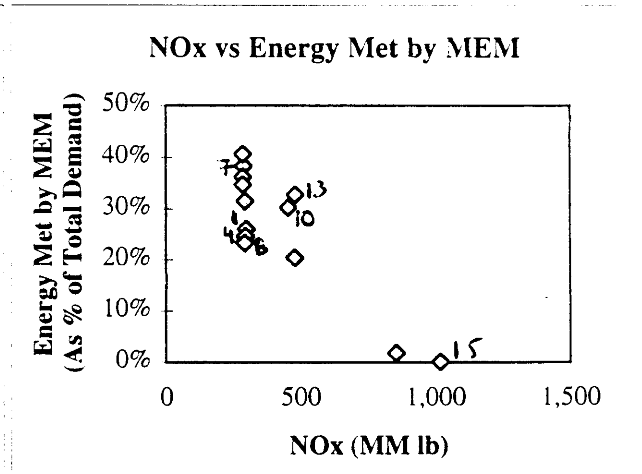

Energy Met by MEM vs Energy Met w/High Cost (As % of Total Demand)
Energy Met w/ High Cost
1.2%
1.0%
0.8%
0.6%
0.4%
0.2%
0.0%
0%
20%
40%
60%
Energy Met by MEM


NOx vs Energy Met w/High Cost
Energy Met w/ High Cost (As % of Total Demand)
1.2%
1.0%
0.8%
0.6%
0.4%
0.2%
0.0%
0
500
1,000
1,500
NOx (MM lb)

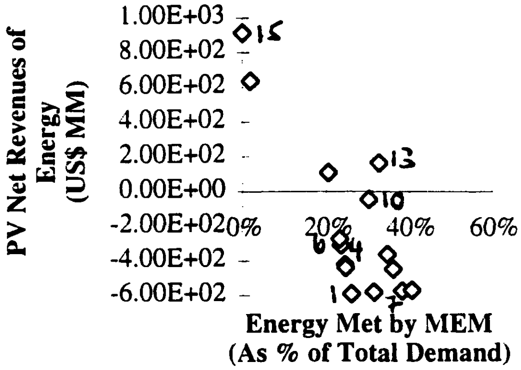

PV Net Revenues of Energy vs Energy Met w/High Cost
PV Net Revenues of Energy (US$ MM)
1,000
500
0
-500
-1,000
0.0%
0.5%
1.0%
1.5%
Energy Met w/ High Cost (As % of Total Demand)


PV Net Revenues of Capacity vs Energy Met w/High Cost
PV Net Revenues of Capacity (US$ MM)
350
300
250
200
150
100
50
0
0.0%
0.5%
1.0%
1.5%
Energy Met w/ High Cost (As % of Total Demand)

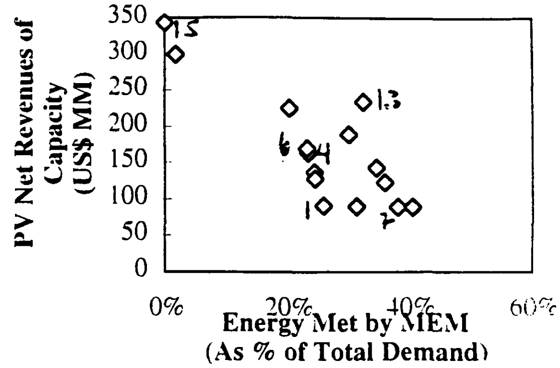

NPV of Scenario vs Energy Met w/High Cost
NPV of Scenario (US$ MM)
600
500
400
300
200
100
0
-100
0.0%
0.5%
1.0%
1.5%
Energy Met w/ High Cost (As % of Total Demand)


NOx vs Energy Met by MEM
Energy Met by MEM (As % of Total Demand)
50%
40%
30%
20%
10%
0%
0
500
1,000
1,500
NOx (MM lb)

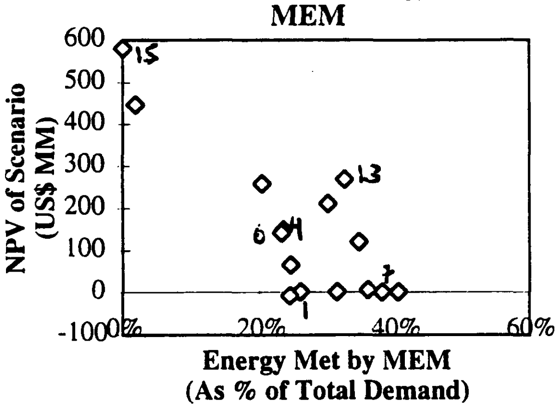
PV Net Revenues of Energy vs Energy Met by MEM



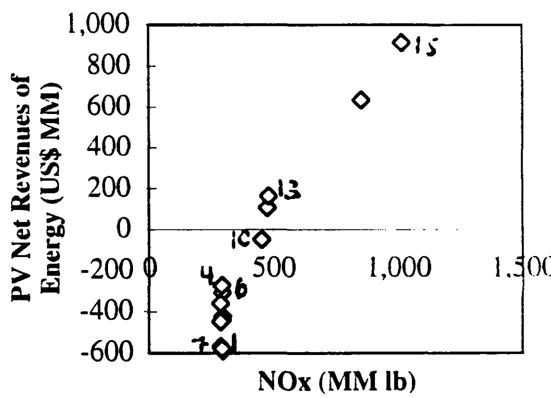
PV Net Revenues of Capacity vs Energy Met by MEM



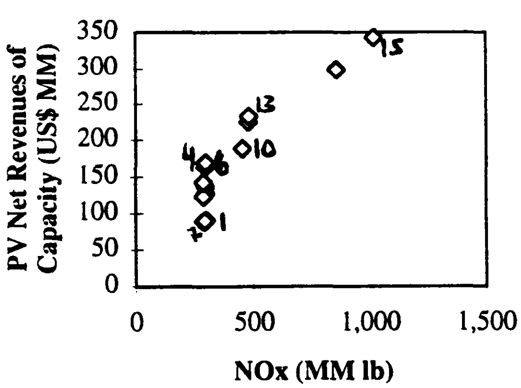
NPV of Scenario vs Energy Met by MEM



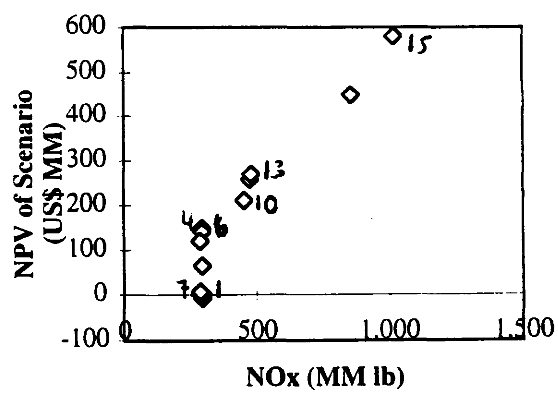
PV Net Revenues of Energy vs NOx

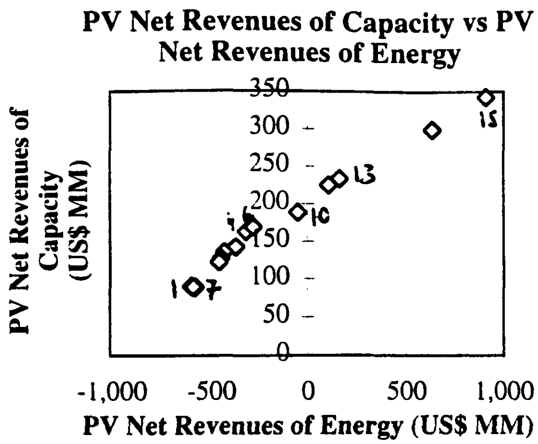


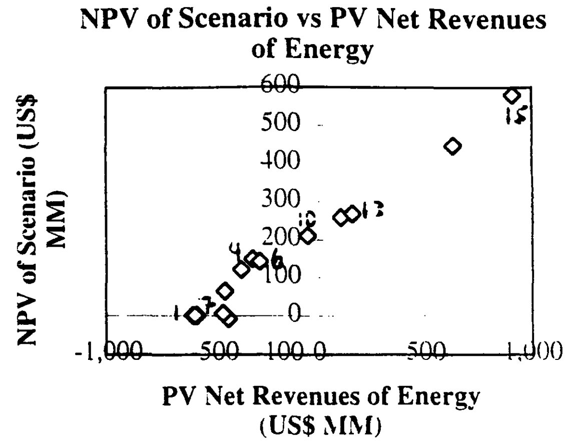
PV Net Revenues of Capacity vs NOx

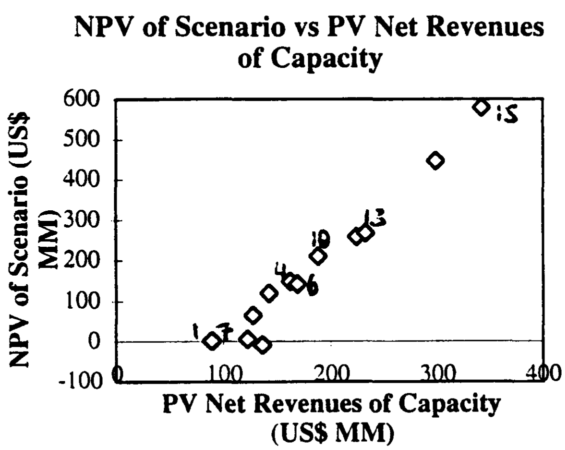


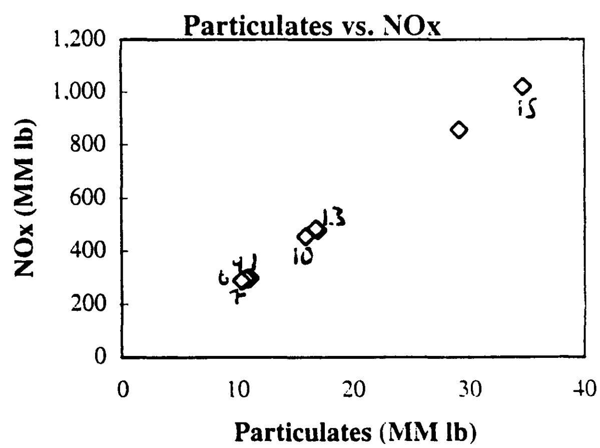
NPV of Scenario vs NOx

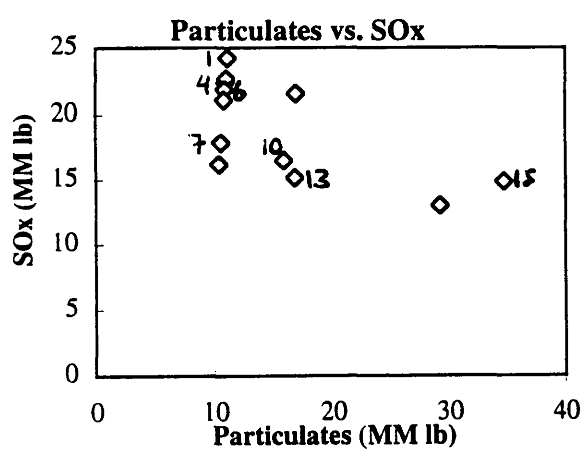


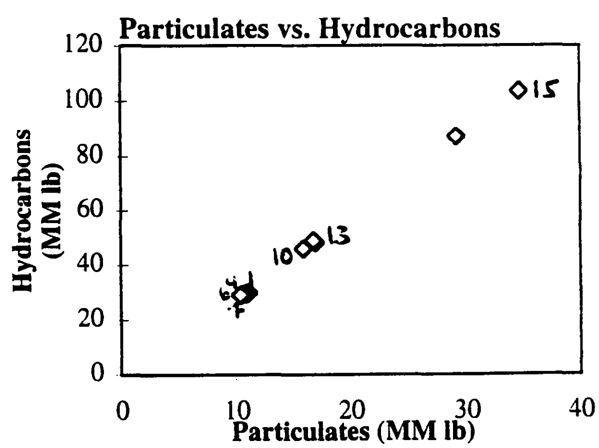

PV Net Revenues of Capacity vs PV Net Revenues of Energy
PV Net Revenues of Capacity (US$ MM)
350
300
250
200
150
100
50
0
-1,000 -500 0 500 1,000
PV Net Revenues of Energy (US$ MM)

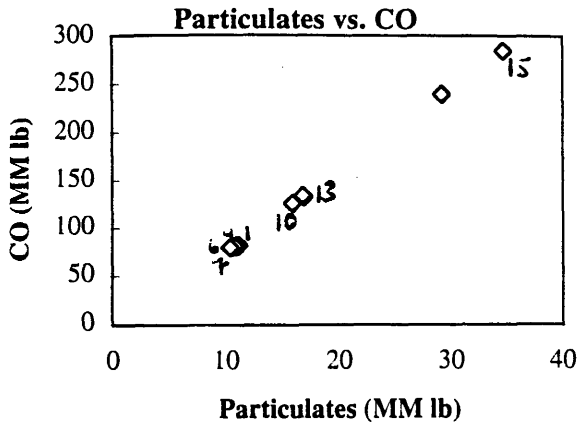

NPV of Scenario vs PV Net Revenues of Energy
NPV of Scenario (US$ MM)
600
500
400
300
200
100
0
-1,000 -500 -100 0 500 1,000
PV Net Revenues of Energy (US$ MM)

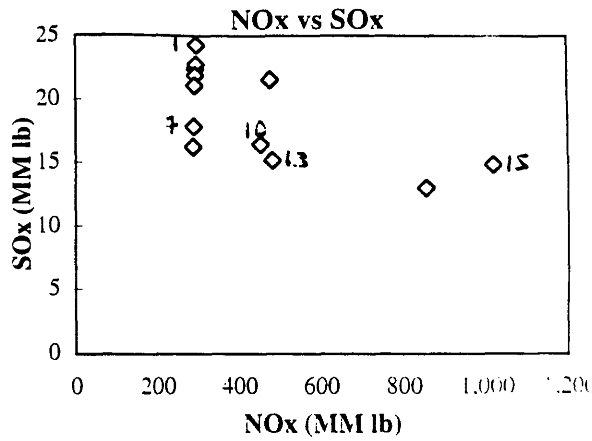

NPV of Scenario vs PV Net Revenues of Capacity
NPV of Scenario (US$ MM)
600
500
400
300
200
100
0
-100
0 100 200 300 400
PV Net Revenues of Capacity (US$ MM)

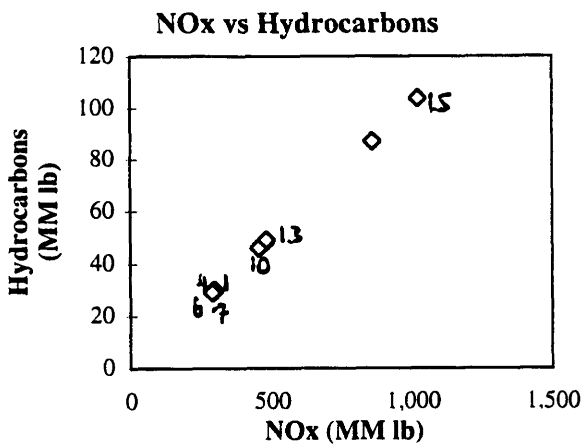

Particulates vs. NOx
NOx (MM lb)
1,200
1,000
800
600
400
200
0
0 10 20 30 40
Particulates (MM lb)

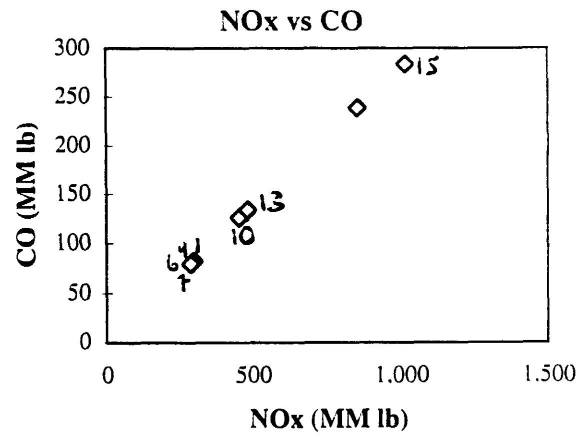

Particulates vs. SOx
SOx (MM lb)
25
20
15
10
5
0
0 10 20 30 40
Particulates (MM lb)

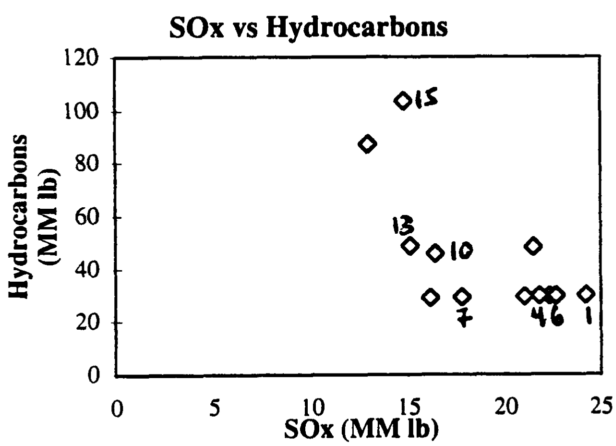

Particulates vs. Hydrocarbons
Hydrocarbons (MM lb)
120
100
80
60
40
20
0
0 10 20 30 40
Particulates (MM lb)

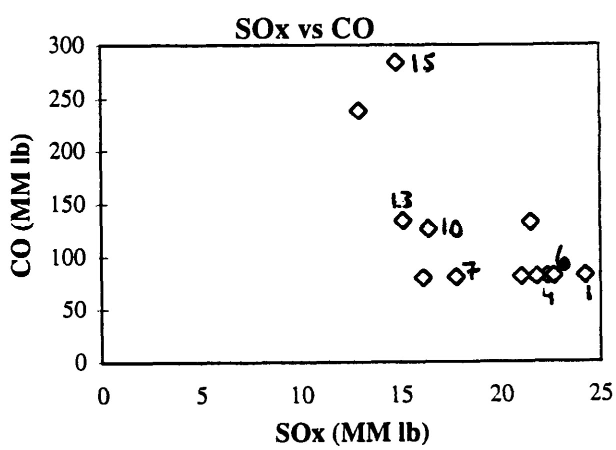

Particulates vs. CO
CO (MM lb)
Particulates (MM lb)
0
50
100
150
200
250
300
10
20
30
40
15
13
10


NOx vs SOx
SOx (MM lb)
NOx (MM lb)
0
5
10
15
20
25
200
400
600
800
13
15


NOx vs Hydrocarbons
Hydrocarbons (MM lb)
NOx (MM lb)
0
20
40
60
80
100
120
500
1,000
1,500
15
13
10


NOx vs CO
CO (MM lb)
NOx (MM lb)
0
50
100
150
200
250
300
500
1,000
1,500
15
13
10


SOx vs Hydrocarbons
Hydrocarbons (MM lb)
SOx (MM lb)
0
20
40
60
80
100
120
5
10
15
20
25
15
13
10


SOx vs CO
CO (MM lb)
SOx (MM lb)
0
50
100
150
200
250
300
5
10
15
20
25
15
13
10