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The China Energy Technology Program (CETP):
A Framework for Decision Support in the Electric Sector of Shandong Province

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# ELECTRIC SECTOR SIMULATION: A TRADEOFF ANALYSIS OF SHANDONG PROVINCE'S ELECTRIC SERVICE OPTIONS

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# Integrated Assessment of Sustainable Energy Systems in China:

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## Electric Sector Simulation: A Tradeoff Analysis of Shandong Province's Electric Service Options

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## Introduction

Three key aspects in transitioning to a sustainable energy future are technology development, deployment and use. This part of the China Energy Technology Program uses electric industry simulation models to explore the deployment and use of numerous electricity supply and end-use options which could provide Shandong Province with cheaper and cleaner electric service. To do this the Electric Sector Simulation (ESS) team uses the Scenario-Based Multi-Attribute Tradeoff Analysis approach developed at MIT's Laboratory for Energy and the Environment, and employed in previous Alliance for Global Sustainability projects. With the assistance of the analysis team, the tradeoff analysis approach allows stakeholders to look at a broad range of options and uncertainties and compare the performance of the resulting strategies. This "inclusive"–and therefore extensive–analytic approach was developed to help multi-stakeholder groups jointly evaluate combinations of options that meet their collective interests.

As well as being complex, future energy infrastructures must be designed for a highly uncertain future. Good short-term forecasts, especially for an export oriented province like Shandong, are extremely difficult to make; long-term ones are impossible. They are also dangerous to bet one's long term infrastructure decisions on. By looking at the performance of multiple-options across multiple uncertainties, tradeoff analysis helps identify robust long-term strategies which perform well across a range of futures. By looking at common aspects of the better performing strategies, Chinese decisionmakers can determine which actions to take.

Based upon the input and interests of the CETP's Stakeholder Advisory Group, the ESS team constructed a set of over a thousand strategies and looked at their costs, investment requirements, fuel consumption and power plant emissions for eighteen combinations of electricity demand growth and possible future fuel costs. The results are dramatic. Shandong Province has numerous opportunities to reduce its pollutant emissions at little or no impact on cost – relative to its historical course of action. These "cheap and clean" strategies require a rethinking of the problem, where old and new generation, and the growth in the province's need for electric service are managed in a coordinated fashion. Several of these options are currently being pursued by the Chinese government, however national initiatives to reform the power sector may weaken the government's ability to direct technology choice. Whether centrally planned or coordinated via market forces, to manage China's demand for electricity in an environmentally responsible manner Chinese decisionmakers will need to "manage" their infrastructure. The results presented in this chapter hopefully offer some useful insights on what course to follow.

The first part of this chapter describes the tradeoff analysis approach and construction of the electric sector scenarios for Shandong Province. It then looks at which types of options were most successful at reducing pollutant emissions and costs, and why. After looking at how these options perform as part of an integrated strategy, twelve of them are then selected for more detailed analysis of their life cycle and environmental impacts. and acceptability to Chinese decisionmakers.

## Scenario-Based Multi-Attribute Tradeoff Analysis

The Electric Sector Simulation task employs the Scenario-Based Multi-Attribute Tradeoff Analysis approach developed at MIT. In the early 1980s, researchers at the then Energy Laboratory at MIT employed a multi-scenario approach to evaluate alternative sites for a capacity constrained New York City. Faced with a capacity shortage and regulatory stalemate in New England in the late 1980's, the MIT team extended and refined the multi-scenario approach, using it to facilitate a discussion among stakeholders in the New England electric policy debate. In addition to helping electric utilities, economic and environmental regulators, large customers, and consumer and environmental advocates discuss issues outside of regulatory proceedings, the research team was able to identify new opportunities for dealing with the region's long-term challenges under shifting utility and environmental policies. Since then it has been used in various locales, and extended further in Alliance for Global Sustainability projects looking at China's, Mexico's and Europe's energy alternatives.

### Policy Relevant Research – Stakeholders and Scenarios

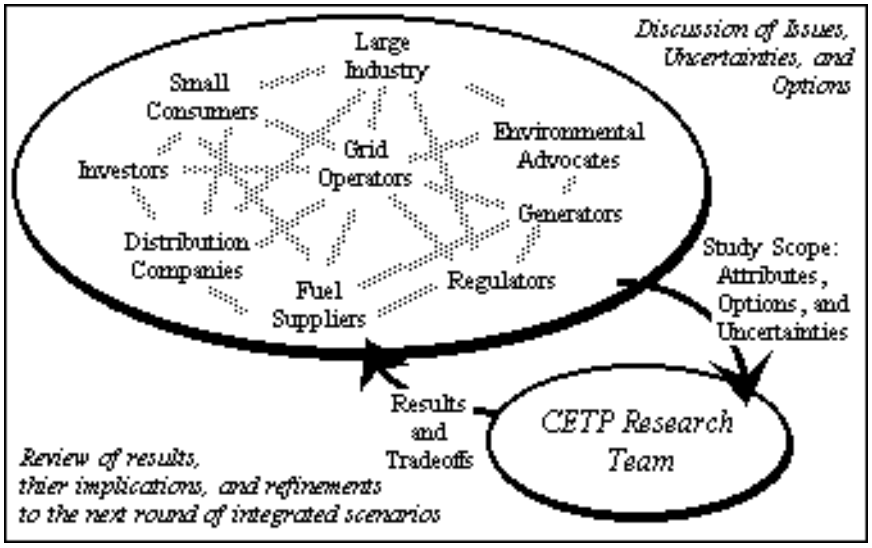
The tradeoff analysis approach was designed to conduct "policy relevant" research. The tradeoff analysis framework has been designed around a stakeholder dialogue, whereby the analysis team constructs a set of scenarios, and the attributes which measure a scenario's performance, based upon its discussions with regional stakeholders. The analysis team discusses with the stakeholder advisory group how it has "packaged" the group's collective interests and concerns into a scenario set, how it will be analyzing the scenarios, and the key assumptions they are making regarding the cost and performance of technologies, changes in electricity demand, fuel costs, regulations, etc., over time. The analysis team then analyzes the performance of the scenarios. The scenario team then presents the outcomes to the advisory group, and based upon a discussion of the results, a new revised and refined scenario set is developed which builds upon the knowledge generated in the previous set, and includes new topics, options, and uncertainties that may have arisen in discussion with the stakeholders.

During the course of its eight year run, the New England Project explored a wide, evolving range of issues and options, such as increasing demand for natural gas as a power plant fuel, the comparative performance of conservation, peak load management, wind and solar options, the costs and emissions implications of repowering old power plant sites, the emissions impacts of electric vehicle fleets, and sub-regional impacts of a cap and trade system for summertime nitrogen oxides (NOx) reductions.

Figure 6.1 shows the general structure of the tradeoff approach with its iterative design and evaluation of scenarios in support of a discussion among diverse stakeholders. With competition in the electric industry, the number and types of stakeholders has expanded.

In general, a simulation model is used, in this case an industry standard production costing model developed under sponsorship of EPRI in the United States.

Figure 6.1: Stakeholder – Analysis Team Interactions




In order to maintain the integrity of the stakeholder dialogue, each stakeholders' concerns and interests, as well as favorite options–good or bad–need to be included in the scenario set. As will be shown later in this chapter, this leads to rather large scenario sets. For this a simulation model, usually a bottom-up engineering model, is used. Simulation models generally run faster than optimization models, since they perform fewer iterations before coming up with a result, allowing for a greater number of scenarios to be analyzed. In the electric power industry, many optimization models also choose which future technologies to build, and may be less credible with some stakeholders if they fail to select their "favorite" technologies. This can be compensated for in the simulation approach by adding more scenarios. Finally, if the optimization model uses a "utility maximization" approach, derived from the utility functions, or preferences of a user, the dialogue process can get bogged down. The "utility functions" of differing stakeholders cannot reasonably be combined into a single utility function for society, and even if they could the results from those simulations may not be credible to some stakeholders as the integrated utility function does not sufficiently reflect their interests. Furthermore, the intent of the tradeoff analysis approach is to help stakeholders identify novel strategies. Thus, their perspectives, and therefore preferences regarding certain technologies and policies will change over time making the original utility functions obsolete.

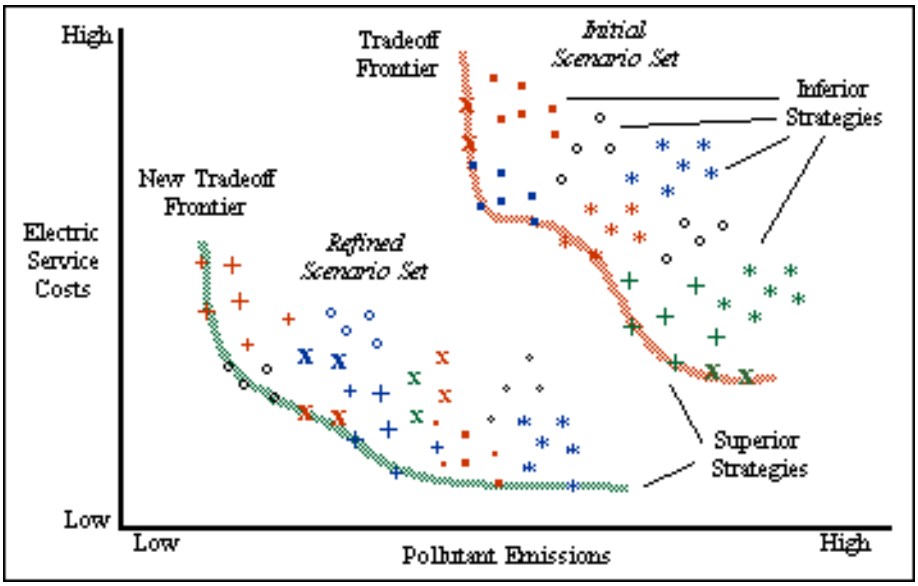
Tradeoff Analysis

As mentioned previously, one of the key uses of the tradeoff analysis approach is to identify robust strategies under uncertainty. Most optimization models implicitly "believe" the forecast they are optimizing the power system to. Such models are best used for near-term, tactical assessments where deviations from the forecast will not be

large. While more sophisticated optimization models may perform perturbations around a forecast, they have difficulty with "surprise," or "noisy" uncertainties, such as the Asian economic crisis, global conflict-oil price interactions, or a "step change" in regulations.

Figure 6.2 shows how the tradeoff analysis approach helps identify superior and inferior strategies. Here strategies are being evaluated for cost and emissions, usually one pollutant at a time. The group to the right reflects the initial set of scenarios performed for the stakeholder advisory group. By looking at the position of the scenarios, it is easy to identify strategies along the tradeoff frontier for which there are no strategies that are lower in *both* cost and emissions. Those on or near the tradeoff frontier are referred to as superior strategies, and those well back of the frontier are inferior or dominated strategies. Strategies not on the frontier for one pair of axis attributes may appear on the frontier for another pairing, or under another set of uncertainties, so care should used when identifying "reasonably good" strategies. Furthermore, strategies that may look just okay from a techno-economic viewpoint, through discussion with the stakeholders, may turn out to be better once political and implementation related factors are considered.

Figure 6.2: Identifying Superior Strategies




From this initial scenario set a second set of refined strategies is then developed and analyzed. Dropping the poor performing options or combinations of options from the scenario set, and introducing (hopefully) new and more refined options which moves the scenario set in the cheap-clean direction. Successive scenario sets can be analyzed until the group believes that all of the major opportunities for refinement, or additional issue exploration, have been evaluated.

Another important aspect of the tradeoff frontier is its shape. For the initial scenario set there are only a few strategies on the low-cost, higher emissions end of the tradeoff frontier. However for the refined scenario set, there are substantial slightly higher cost,

substantially lower emissions strategies populating the frontier before it "turns up." Such transition points are important stakeholders to know about, as decisions pushing emissions reductions beyond that point do so at considerable cost.

Two additional features of the tradeoff analysis approach should be noted. First, it is generally very difficult to give technologically prescriptive recommendations when looking at how to evolve an infrastructure out several decades. However, by looking at which strategies are consistently far from the tradeoff frontiers, researchers can inform stakeholders on what *not* to do. Second, in addition to identifying consistently bad combinations of options, the tradeoff plots show the overall range within which costs, emissions, reliability and other attributes can change.

Although stakeholders often have differing preferences, say for reducing costs before emissions, or visa versa, they generally agree that both should be reduced if possible. The tradeoff analysis approach allows them to see which combinations of options perform best. Stakeholders can then discuss which strategies on the tradeoff frontier might be the better long-term solution, rather than argue over favorite but inferior strategies. In contrast, optimization approaches by definition are intended to show the best one or two strategies, within the confines of the model's structure, leaving little bargaining room among stakeholders. The tradeoff analysis approach however informs stakeholders about the entire "option space," not just the portion of the tradeoff frontier intersecting a stakeholder's principal interests (utility function), or best guess circumstances (forecast).

Figure 6.3 shows the other dimension of the tradeoff analysis approach, identifying robust strategies. Here we see the performance of a group of superior strategies for three futures. Careful examination of the Figure shows that some strategies are on the frontier for one or two of three futures, but for the futures where they are not on the frontier, they are well back. Similarly, there are several strategies which not on the tradeoff frontier in each case, but are nevertheless close to it in all instances.

So far we have been discussing the tradeoff analysis approach without really defining its components. Figure 6.4 illustrates the components, or "building blocks" of a scenario. In our nomenclature a <u>strategy</u> is comprised of multiple <u>options</u>, often grouped into option-sets targeting some aspect of the system, old power plants for instance. Likewise individual <u>uncertainties</u> are combined into <u>futures</u>. A <u>scenario</u> is then the combination of one specific strategy with one unique future.

Figure 6.4 illustrates a scenario set comprised of three option-sets, with a total of nine individual options that must be selected. If there is a one alternative plus a reference option for each of these nine, then this set of strategies would be a combination of $2^9$ options, or 512 unique strategies. Often however the number is smaller since options are linked, with one only being possible if another is selected, such as subsidizing natural gas costs only when natural gas power plants are built. A similar calculation for the uncertainties yields $2^5$ or 32 futures. Combined there would be a little over sixteen thousand unique scenarios. Here the iterative nature of the tradeoff analysis approach helps deal with the combinatorial aspects of scenario formation. Certain options can be "held back," with stakeholder permission, to the next iteration, thereby making the process more manageable.

Figure 6.3: Identifying Robust Strategies

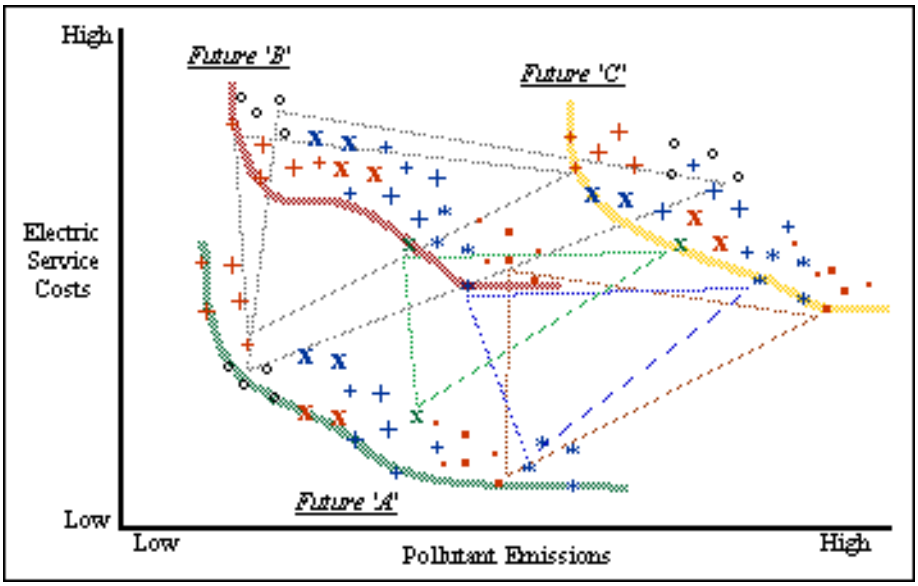
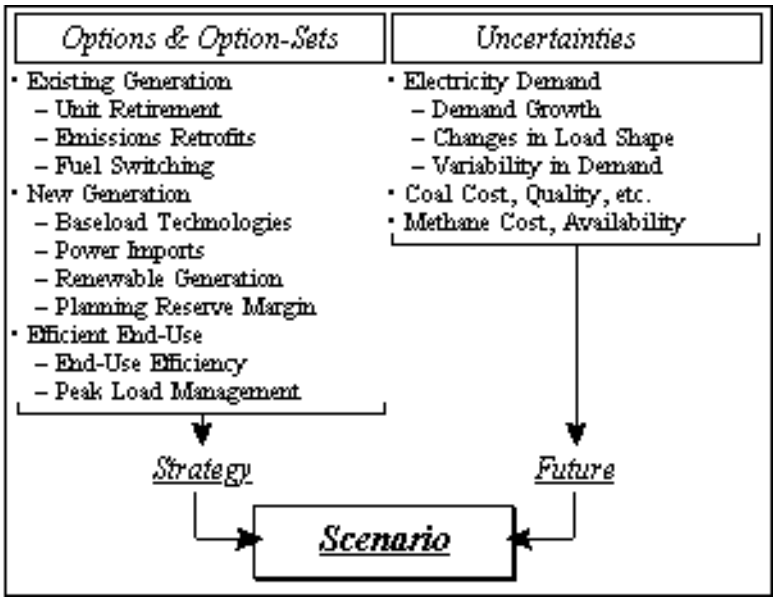



Figure 6.4: Scenario Components




Attributes are the metrics by which strategies are evaluated, becoming the axis of the tradeoff plots. Computer software allows analysts to perform real-time evaluation of tradeoff results with stakeholders, changing the attributes of the tradeoff plots, focusing in on specific groups of strategies, and then looking at specific scenarios in greater detail. For the Shandong scenario sets, the ESS analysis team set up the modeling to automatically calculate over two hundred attributes. While only a dozen or so of these were used in the tradeoff analysis, the remainder serve to help understand why the

scenarios performed the way they did in terms of capacity utilization, fuel consumption, or peak load growth, for example.

As will be shown below, from a computational viewpoint the scenario is the unit of analysis. However, from a conceptual viewpoint, the strategy is the unit of observation. Through the iterative analysis of scenarios, stakeholders, with–the analysis team's assistance–can design multi-option strategies which perform well across multiple futures.

One final aspect of the scenario-based multi-attribute tradeoff analysis approach addresses the issue of near-term actions in long-term infrastructure management. Strategies commonly look at which options a region should use to evolve its infrastructure out over several decades. Understanding the long-term path, and the actions needed to realize it over those intervening years is a highly valuable piece of knowledge. However, decisionmakers rarely lock-in such future decisions. They do not need to, and different decisions may need to be made as the future unfolds different from what was anticipated or hoped for.

One possible solution is to have stakeholders look at what common features, or sets of options the best strategies have. If there are similarities, then these can be considered robust options, and stakeholders, even if they cannot agree on an entire strategy, can at least agree that these options should be pursued. The differences among superior strategies reflect options that decisionmakers should take steps to develop, but withhold implementation of until the right circumstances occur. In this light, a robust strategy is comprised of *both* robust and flexible options, and by recognizing what they are, a near-term tactical plan can be devised from several long-term strategies.

Shandong Building Blocks

Previous tradeoff analysis on electric systems in other regions have shown that there are many factors that must be considered in the construction of useful, informative scenarios. It is important to include options which impact nearly every aspect of the infrastructure. Figure 6.5 illustrates the diversity components for which options should at least be considered. Here we see infrastructure components for both the supply (generation) and use of electricity, including the existing infrastructure. Not pictured, but also potentially important are fuel and cooling water supplies, and regulatory and fiscal policies related to the investment in and use of various elements of the infrastructure.

The arrows between components indicate that a decision targeting one component often influences the behavior of other components. One example that will reappear below is energy conservation. By promoting new "clean" demand, fewer new "clean" generators are required. However, new "clean" generators displace the operation of old "dirty" generators. Strategies should not only be constructed to uncover these interactions, but address them. In this example, an option turning an old "dirty" generator into an old "clean" generator by installing a scrubber could be considered, in addition to other options targeting the deployment and use of new electricity supplies and end-uses.

Figure 6.5: Electric Sector Resource Components

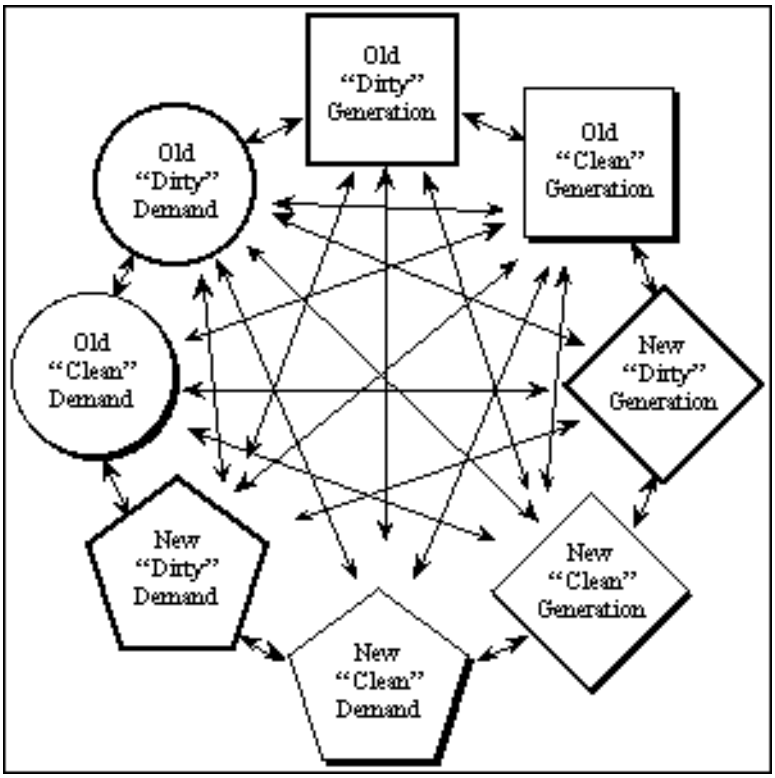



Table 6.1 shows the options sets and uncertainties incorporated into the Electric Sector Simulation group's Shandong scenario sets. Results reported on here represent the third scenario set analyzed in the project as various option were dropped, refined and reintroduced into the set. Beside each category of option or uncertainty is the number of alternatives evaluated.

As the table illustrates, it is very easy to get a great many scenarios. Good organizational skills, reasonable simulation times, and computer graphics has made scenario-based tradeoff analysis a useful planning and educational tool. The following sections show how individual scenarios were analyzed, and the key assumptions used in putting together the scenarios for Shandong Province.

Table 6.1: Option-Sets and Uncertainties

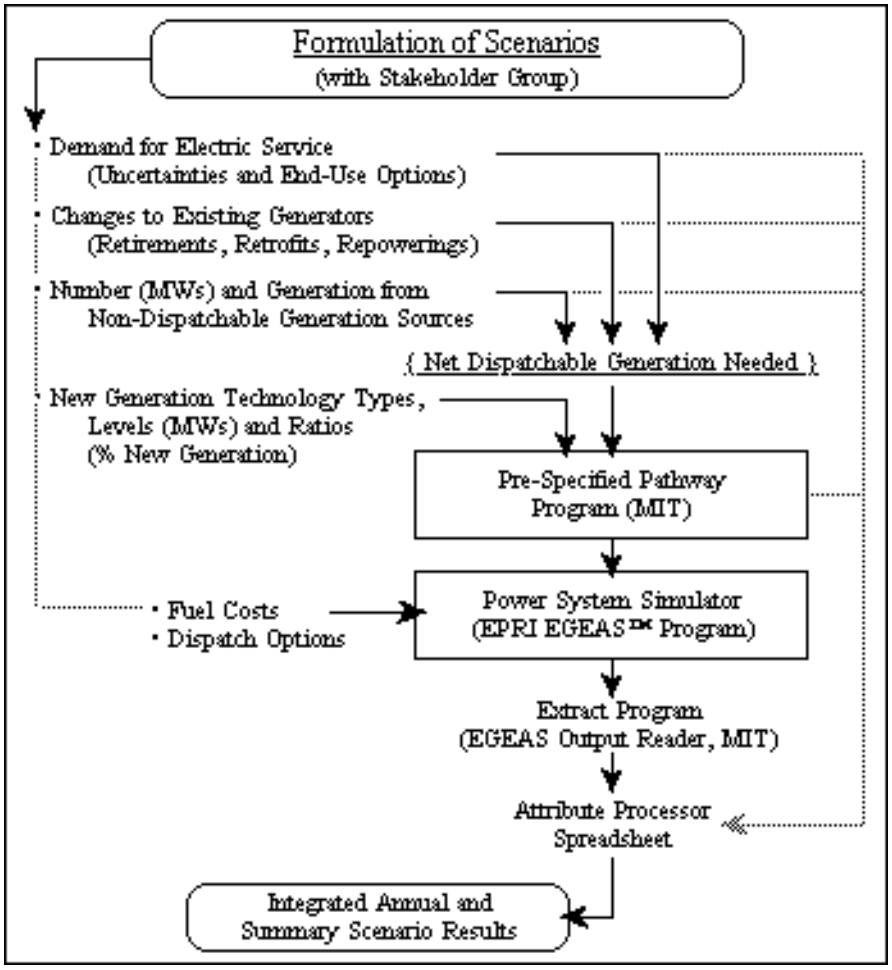
| | |
|---|---|
| ***Strategy Components*** | |
| *Option Sets* | *No. of Options* |
| *Existing Generation Options* | |
| Retire Additional Existing Units | 2 |
| Emissions Retrofit Existing Units with Sulfur FGD | 2 |
| Switch to Prepared Coal | 3 |
| *New Generation Options* | |
| Mix of Future Generation Technologies in Shandong | 7 |
| Extra-Provincial "By-Wire" Generation | 2 |
| *Demand-Side Options* | |
| Peak Load Management | 2 |
| End-Use Efficiency/Conservation | 3 |
| No. of Strategies | 1,008 |
| ***Future Components*** | |
| *Uncertainty Sets* | *No. of Uncertainties* |
| *Economy/Demand Growth* | |
| Demand for Electrical Energy | 3 |
| *Fuel Cost and Availability* | |
| Delivered Cost of Steam Coal | 3 |
| Delivered Cost of Pipeline Natural Gas | 2 |
| No. of Futures | 18 |
| Total No. Scenarios | 18,144 |

## Electric Sector Simulation

At the core of the tradeoff analysis approach is the analysis of individual scenarios. The above discussion focused on the "framework" for analysis, built around the dialogue with stakeholders. Figure 6.6 shows the overall process for how scenarios were analyzed on behalf of the CETP's Stakeholder Advisory Group. The scenarios outlined in Table 6.1 require changes to the model inputs, lower electricity demand resulting from end-use efficiency programs for example. In addition, various options may alter the parameters by which the model runs, a cap on emissions for example that will shift the utilization of system resources. After this "data management" and option construction phase is completed, the scenarios are ready to run. Two core models comprise the ESS's analytic implementation of the tradeoff analysis approach. The Pre-Specified Pathway program takes load growth uncertainties, power plant retirements and preferences for new generation and chooses how many of each technology get built and when. This and other parameters are then passed to the power system simulator. In this project we used the EPRI EGEAS™ program, which given a set of loads, generators, and various costs and operational constraints determines the relative "dispatch" of the generators. These two models are explained in greater detail below. Another program reads the output from the EGEAS simulation, making a condensed table of the simulator's results. These results are then dropped into the "Attribute Processor" spreadsheet which recombines the simulator's output with other information such as the savings and costs of implementing end-use efficiency programs. The attribute processor also performs some additional calculations, such as the calculation of transmission and distribution costs as a function of

electricity throughput, and finally calculates the scenario specific stream of attributes which are then appended to the results from other scenarios and used to perform tradeoff analysis. The attribute processor also holds the year by year results whereby analysts and decisionmakers can review in detail "what happened" in a specific scenario that makes its costs and emissions change.

Figure 6.6: Analyzing a Single Scenario




Simulating Growth in the Electric Sector

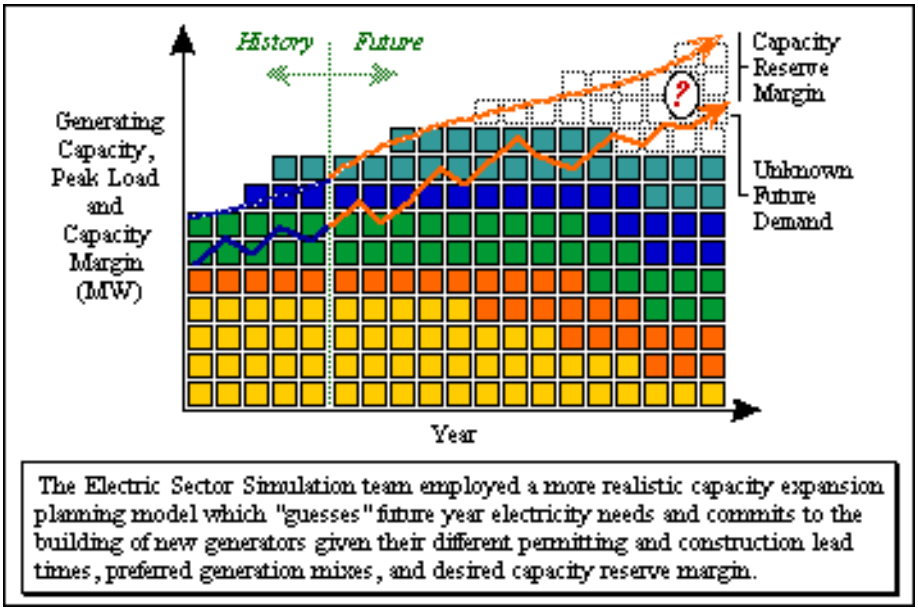
Growth in the demand for electric service, and the construction of generators to meet that demand is inherently lumpy. These year-to-year variations in load and capacity growth can be attributed to changes in the economy and the weather, and due to the time it takes to permit and build new power plants. If short of capacity, smaller, shorter lead-time generators may be built. Similarly, if there is excess capacity, power plants under consideration may be canceled or postponed.

Early in the development of the tradeoff analysis approach it became apparent that a more "human" capacity expansion model was needed to produce more "realistic"

trajectories showing the addition of new generators. While simulation programs like EGEAS had capacity expansion modules, it was found that they were "too good," and allowed the addition of new generators to meet demand, irrespective of their construction lead times. Such "optimal capacity expansion" modules also tend to build power plants to the exact forecast of load growth, when in fact power system planners must "guess" future capacity needs based upon past experience and current system conditions. To address these realities MIT researchers developed an "imperfect planning" program called the Pre-Specified Pathway (PSP) program.

Figure 6.7 shows the PSP's overall logic. Starting with known changes to the systems fleet of generators, including pre-determined unit retirements and power plants permitted and under construction, the program guesses the future need for capacity based upon past trends in load growth and the desired capacity reserve margin – the amount of extra installed capacity over anticipated peak load to account for unit outages and uncertainty in forecasting. The model then steps through the study period, in this case 2000 through 2024, and commits future units based upon the strategy's preferred mix of new technologies, the near term capacity situation, and the different lead times of those technologies.

Figure 6.7: Sub-Optimum Capacity Expansion




Deviations from the preferred mix of technologies are allowed in order to meet anticipated near term capacity shortages. Technologies are given both a permitting and construction lead time, so that if excess generation has been ordered but has not "broken ground" it can be cancelled or deferred. The PSP model's output is the schedule of new technologies that are built over the scenario's time horizon and fed to the EGEAS simulator. When compared to historical demand growth and capacity expansion, the PSP provides a realistic trajectory of capacity additions, given the different lead times of technologies and the "noisiness" of electricity demand growth.

Simulating Power System Operation

The simulation model used was the commercial program EGEAS (Electric Generation Expansion Analysis System). EGEAS was developed in the early 1980s by MIT and Stone & Webster (now a division of the Shaw Group) under contract with EPRI. The model offers numerous features including subperiod modeling, energy constrained unit dispatch, statistical modeling of non-dispatchable technologies, emissions constraints and shadow pricing, reliability analysis, sensitivity analysis and optimized expansion.

EGEAS is fed the output from the PSP program, as well as fuel costs and electricity demand uncertainties. It then decides which units run, and for how many hours, based upon system conditions, operational constraints and the units' relative operating costs. It also calculates the capital costs associated with the addition of new generators. This is critically important for estimating the costs and emissions impacts of changes to electricity demand and the mix of generation units. As will be shown below, if a new, cleaner power plant is added to the system it can displace more generation than an existing unit of similar size, by running at a higher capacity factor. Likewise, if for a given year the unit's operational cost are slightly higher, a clean unit may be used for fewer hours resulting in a smaller, or negative, impact on system emissions. The primary outputs of the model are generation utilization, fuel, operation and maintenance (O&M) and investment costs, fuel consumption and pollutant emissions. Other factors such as system reliability, aggregate generation efficiencies and other numerical results are also available.

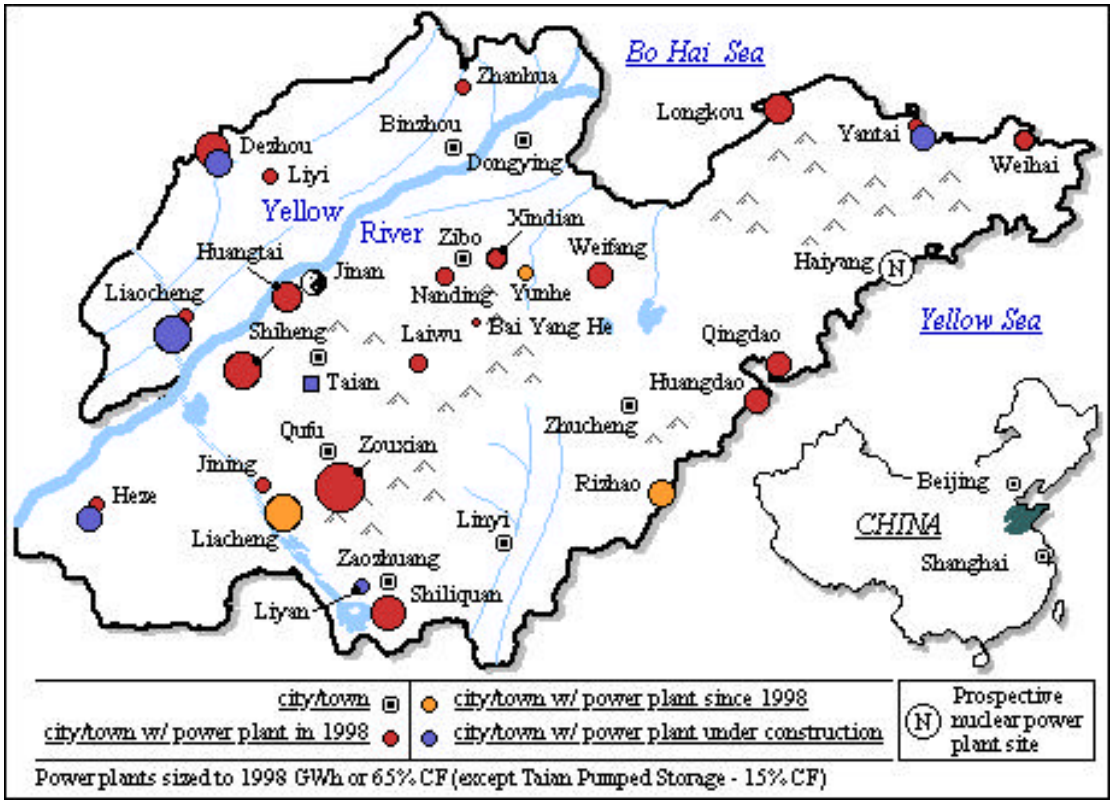
## Overview of the ESS Scenarios

Until now we have discussed the methodological approach and principal analytic components of the Electric Sector Simulation research, with only minor comments on how it was applied to Shandong Province. This section presents the scenarios and their key assumptions in detail before exploring their combined impacts on Shandong's electric sector.

Figure 6.8 shows a map of Shandong Province and the location of its larger, grid connected power plants. The circles indicating the location of generators are sized to their 1998 annual output if they are older (red) units. Recently completed generation plants (orange) and those under construction (blue) are shown with their circles sized to a 65% annual capacity factor, except for the Taian pumped storage power plant (15%).

Shandong is one of China's most highly populated and economically productive provinces, with a large export trade to Japan, Korea and elsewhere. It sits on China's northeastern seacoast, southeast of Beijing, between Tianjin and Shanghai. Shandong's population has increased to over 93 million people (2002), 10 million more than in 1990. (World Gazetteer, 2002). Shandong covers roughly 155 thousand square kilometers with the Yellow River (Huang He) river valley and delta being the principal geographic features in the West, with a mountain range extending from the South Central portion of the province to the Shandong Peninsula in the Northeast. Despite this mountainous area, Shandong's hydropower potential is considered very low. (Xue and Eliasson, 2000) The province is roughly 600 km from East to West, and 400 km from North to South.

Figure 6.8: Shandong Province's Principal Power Plants




Generation in Shandong is produced almost exclusively with coal mined within the province, but also shipped by rail, and rail and ship from Shanxi and other provinces to the Northeast. Only an exceeding small portion of the province's generation comes from oil-fired generation or hydropower. The Shandong Electric Power Group Corporation (SEPCO) manages generator dispatch and transmission system operations. Shandong is China's largest stand-alone provincial network, although current plans for power sector reform in China will integrate it into the North China Grid Company over time. (Connors et. al., 2002)

Attributes

The Electric Sector Simulation research team set up the Attribute Processor to automatically calculate over 240 attributes. A detailed list of them can be found in the report Shandong, China Electric Sector Simulation Assumption Book (Connors et. al., 2002). Table 6.2 shows the various classes of attributes that the team calculated.

Table 6.2: Classes of Attributes

*Cost Attributes*

Regional Costs: Present value cost of supplying electric service to Shandong Province.

Unit Costs: Average cost on a per kWh basis of supplying electricity and electric service to Shandong Province.

Component Costs: Present value cost of capital expenditures, fuel and operation and maintenance costs, demand-side expenditures, etc.

*Emissions and Effluent Attributes*

Power Plant Stack Emissions: Sulfur Dioxide (SO2), Particulate Emissions (PM10), Nitrogen Oxides (NOx) and Carbon Dioxide (CO2).

Solid Wastes and Consumables: Flyash and scrubber sorbent use.

Water Consumption: Cooling water not returned/evaporated, and boiler make-up water.

*Electricity Demand and Generation Attributes*

Electricity Demand and Growth: Cumulative and end-year (2024) electricity demand (generation and sales–GWh, and peak loads–MW), including growth rates and end-use impacts.

Generation by Type and Location: Annual and cumulative generation broken down by old versus new source, technology and fuel type, both installed MWs and GWh utilization.

Fuel Transport and Consumption by Fuel Type and Source: Breakdowns on the level and growth in fuel consumption by type, source and mode of transport.

Not included in the above list, but available for calculation were system efficiency (heat rate) and reliability attributes. Attributes generally fall into two categories, decision and descriptive attributes. Decision attributes are analogous to criteria, and measure performance relative to the stakeholders' interests. Table 6.3 shows the key decision attributes that will be used in presenting electric sector results in this chapter. (A different set of criteria were developed for the MCDA analysis, incorporating results from the life cycle, environmental impact, and risk and safety assessment tasks.) When performing tradeoff analysis it is handy to have attributes available that describe how many of which technologies were present, and the degree to which they were used. During the presentation of results to stakeholders, this helps explain why costs or emissions are higher for some strategies than others.

Within the electric sector simulation's scenario tradeoff analysis only direct costs and emissions from the sector were calculated. The life cycle and environmental impact assessment teams build upon these results adding emission from the entire fuel chain and external costs.

As shown in Table 6.1, the final large scenario set presented here was the third iteration of scenarios. The differences between the initial and final scenario sets focused mainly on the number and timing of additional unit retirements, several alternative mixes of new generation technologies involving the choice of clean coal technologies and the operational modes and location of natural gas-fired combined cycle generation, as well as several alternative coal and natural-gas fuel cost uncertainties. These are also presented in Connors et. al. (2002).

Table 6.3: Key Decision Attributes for Tradeoff Analysis

## *Cost Attributes*

Regional Cost of Electric Service :

(Net Present Value – Billion of 1999 Yuan (¥))

The direct cost of providing electric service to Shandong Province for the entire study period (2000-2024 inclusive), including non-utility costs such as those for end-use programs. Expressed as the present value of the twenty-five year cost stream using a discount rate of 10% (including an average inflation of ≈ 4%). It includes cost recovery for existing as well as new generation, as well as costs for transmission and distribution and other electric company operations costs.

Average Unit Cost of Electricity:

(Yuan/kWh– electricity sales)

Average of each year's cost of providing electric service (inflation adjusted), divided by electricity sales in that year. It represent the normalized *rate* for electric service in Shandong.

Average Unit Cost of Electric Service:

(Yuan/kWh – electric service)

Average of each year's cost of providing electric service (inflation adjusted), divided by the amount of electricity *service* provided in that year. The amount of electric service is in any given year is equal to the electricity sales plus the electricity consumption avoided by end-use efficiency programs. A measure of the average electricity *bill* for electric service in Shandong. As such, the Unit Cost of Electric Service is the more appropriate normalized metric for electric service costs, and is the one that appears in most tables and figures.

*(A uniform long-term exchange rate of 10¥ per U.S. Dollar was used in these analysis.)*

## *Emissions Attributes:*

Cumulative Power Plant Sulfur Dioxide Emissions:

(Millions of Tonnes of SO2, (Mt))

The sum of all power plant SO2 emissions from 2000-2024. Sulfur Dioxide contributes to acid deposition, and is a precursor of fine particulates (PM2.5).

Cumulative Power Plant Particulate Emissions:

(Millions of Tonnes of PM10, (Mt))

The sum of all power plant PM10 emissions from 2000-2024. Particulate emissions contribute to diminished visibility and respiratory and other health effects.

Cumulative Power Plant Nitrogen Oxides:

(Millions of Tonnes of NOx, (Mt))

The sum of all power plant NOx emissions from 2000-2024. Nitrogen Oxides contribute to acid deposition, and are a precursor of photochemical smog (ozone) and fine particulates (PM2.5).

Cumulative Power Plant Carbon Dioxide:

(Billions of Tonnes of CO2, (Gt))

The sum of all power plant CO2 emissions from 2000-2024. Carbon Dioxide is the principal greenhouse gas resulting from fossil fuel combustion.

*(Costs and emissions will be shown as annual numbers when performance trajectories are present in addition to tradeoff results.)*

## Shandong Uncertainties and Futures

For this analysis the ESS research team looked at how changes in electricity demand growth and coal and natural gas prices affect the performance of strategies. Table 6.4 lists the individual uncertainties incorporated into the analysis, including their letter codes by which the combined futures are identified, and employed in the analysis. The individual uncertainties are presented below.

Table 6.4: Shandong Electric Sector Uncertainties and Futures

| *Future Components* | | | |
|---|---|---|---|
| Uncertainty Set | Uncertainty | Code | No. |
| *Economy/Demand Growth* | | | |
| Demand for Electrical Energy (Shandong Grid) | | | |
| | Slow Demand Growth (<4%/yr) | T | 3 |
| | Moderate Demand Growth (>5%/yr) | **F** | |
| | Stong Demand Economy (>7%/yr) | S | |
| *Fuel Cost and Availability* | | | |
| Delivered Cost of Steam Coal | | | |
| | Business as Usual Coal | **I** | 3 |
| | Mechanized Mining Lowers Coal Costs | U | |
| | Transportation Investment Raises Costs | A | |
| Delivered Cost of Pipeline Natural Gas | | | |
| | Base Natural Gas Costs (¥26/GJ - 1999) | **B** | 2 |
| | Lower Natural Gas Costs (¥15/GJ - 1999) | F | |
| *(Ref. Future: FIB)* | No. of Futures | | 18 |

Combined, the three electricity demand uncertainties, three coal cost uncertainties and the two natural gas cost uncertainties yield eighteen unique futures. For this analysis we have selected the future 'FIB' as the "reference future," and most results present here will refer to this combination of load growth and fuel costs. Other combinations will cut across one or more uncertainties, with the series TAF, FIB, and SUB reflecting the "best" and "worst" futures from an emissions standpoint. TAF where electricity demand growth is low, coal costs high and natural gas costs low. SUB in contrast has electricity demand continuing to grow rapidly, with coal costs declining in constant terms.

### Demand for Electrical Energy

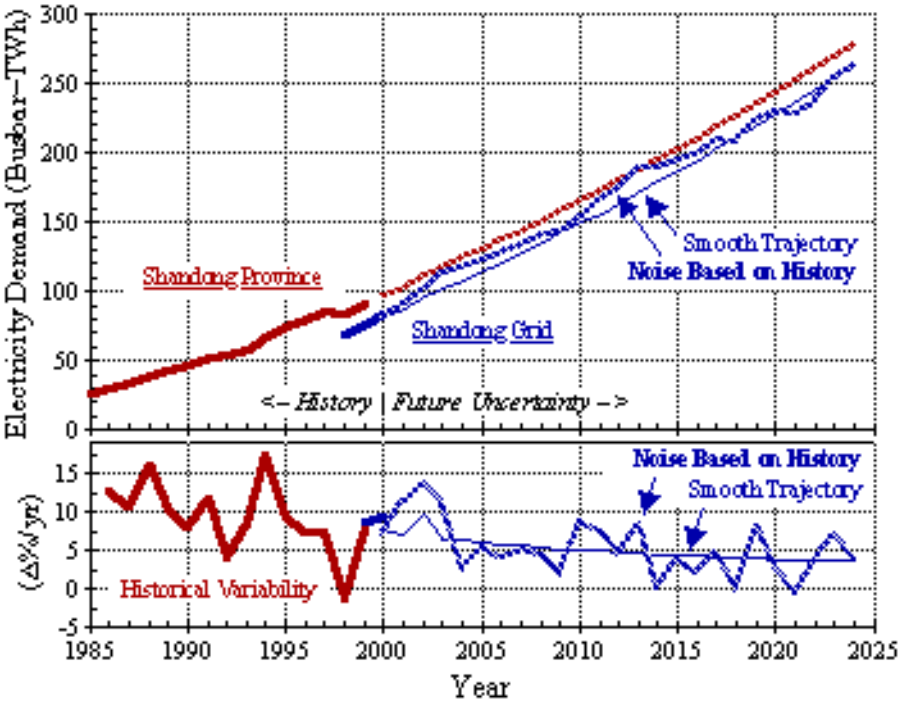
One of the largest uncertainties facing Shandong's electric sector is the rate at which the demand for electrical energy, or electric service, grows. Growth in the demand for electrical energy (TWh per year) influences the number and hours of operation of generators which impacts costs and emissions, and the need for new power plants. Growth in annual peak load (maximum MW of demand for the year) impacts the number and size of power plants needed to meet demand, and influences costs and emissions through investment requirements and its impacts on the generation mix and its use.

Figure 6.9 shows how the demand for electrical energy has grown in the recent past, with a projection based upon a curve fit of the past. Presented is "busbar demand" in terawatt-hours (TWh). This reflects generator output to the grid, prior to transmission and distribution (T&D) losses. In our analysis we assumed T&D losses of 6.2%, based

upon 1999 electricity generation and sales as reported by SEPCO. This is considerably lower than those of say the United States (≈ 10%), but considering the high level of industrial electricity demand it was considered reasonable. Electricity sales ("meter load") reflect the amount of electricity delivered to customers *after* T&D losses, and is used for unit cost (per kWh) calculations.

Statistics for Shandong electricity demand can reflect the entire province's electricity demand, or just the load served by the provincial grid. The difference (≈ 15 TWh) reflects self generation by some industrials and municipal electric companies. The ESS scenarios analyze the Shandong Grid, primarily because information on non-grid controlled generators and loads was unavailable. As most new generators and loads are connected to the provincial grid, the 15 TWh difference between the provincial and grid demand was held constant throughout the study period. Table 6.5 shows the historical growth rates for the available information on both provincial and grid level. Note the high rates of growth, and large swings in year to year growth rates.

Figure 6.9: Historical and Future Electricity Demand, Shandong




The other thing illustrated in Figure 6.9 is the variability in year to year growth. Note the drop in electricity demand from 1997 to 1998 due to the Asian Economic Crisis. ESS electricity demand uncertainties (which are not forecasts) also reflect this year-to-year variability or "noise," based upon the past variability. Figure 6.9 shows the "noise" superimposed on the long-term trend. This influences both the capacity planning in the PSP program, and the capacity margin in any given year and how that impacts power plant use.

Table 6.5: Historical Demand Growth, Shandong

| | Electricity Demand | | Peak Load |
|---|---|---|---|
| Annual Statistics | Province | Grid | Grid |
| 1998 | 84.33 | 69.61 | 11.27 |
| 1999 | 90.90 | 75.68 | 12.55 |
| 2000 | – | 82.72 | 13.00 |
| | (Busbar–TWh) | | (Busbar–GW) |

| Rates of Growth | Province (1985-99) | Grid (1998-00) | Grid (1996-00) |
|---|---|---|---|
| "Long-Term" Growth Rate | 9.16 | 9.01 | 7.23 |
| Minimum Annual Change | -1.43 | 8.72 | -4.44 |
| Maximum Annual Change | 17.53 | 9.30 | 19.90 |
| | (Δ%/yr) | | (Δ%/yr) |

Not only is Shandong electricity growing fast, but its peak demand is growing even faster. This can be seen in Figure 6.10, which shows hourly electricity demand for three years. It can be seen that peak loads occur in the evening and during summer heat waves, driven by residential and commercial demand for electricity. As Shandong's population becomes more affluent, this trend is likely to accelerate, putting greater pressure on the entire system, and especially the need for new power plants. Note the low load periods in February associated with the Chinese Lunar New Year.

These observations provide the source information for the Electric Sector Simulation's electricity demand uncertainties. The long-term growth trends are shown in Table 6.6, and are derived from different curve fitting approaches to the province's historical demand, except for the Strong/High demand uncertainty that was capped at 7%/yr. When the non-grid demand for electricity is subtracted out, Shandong Grid growth rates become higher.

Table 6.6: Electricity Demand Uncertainties Growth Rates

| | Electricity Demand Uncertainty | | |
|---|---|---|---|
| | Slow (T) | Moderate (F) | Strong (S) |
| | Electricity Demand (Busbar–GWh) | | |
| Shandong Province | 3.43 | 4.58 | 7.00 |
| Shandong Grid | | | |
| Historical Noise | 3.89 | 5.11 | 7.66 |
| Smooth | 3.89 | 5.12 | 7.65 |
| | Peak Load (Busbar–MW) | | |
| Shandong Grid | | | |
| Historical Noise | 4.19 | 5.58 | 8.36 |
| Smooth | 4.20 | 5.59 | 8.36 |
| | (Δ%/yr) | | |

Figure 6.10: Hourly Busbar Electricity Demand – Shandong Grid

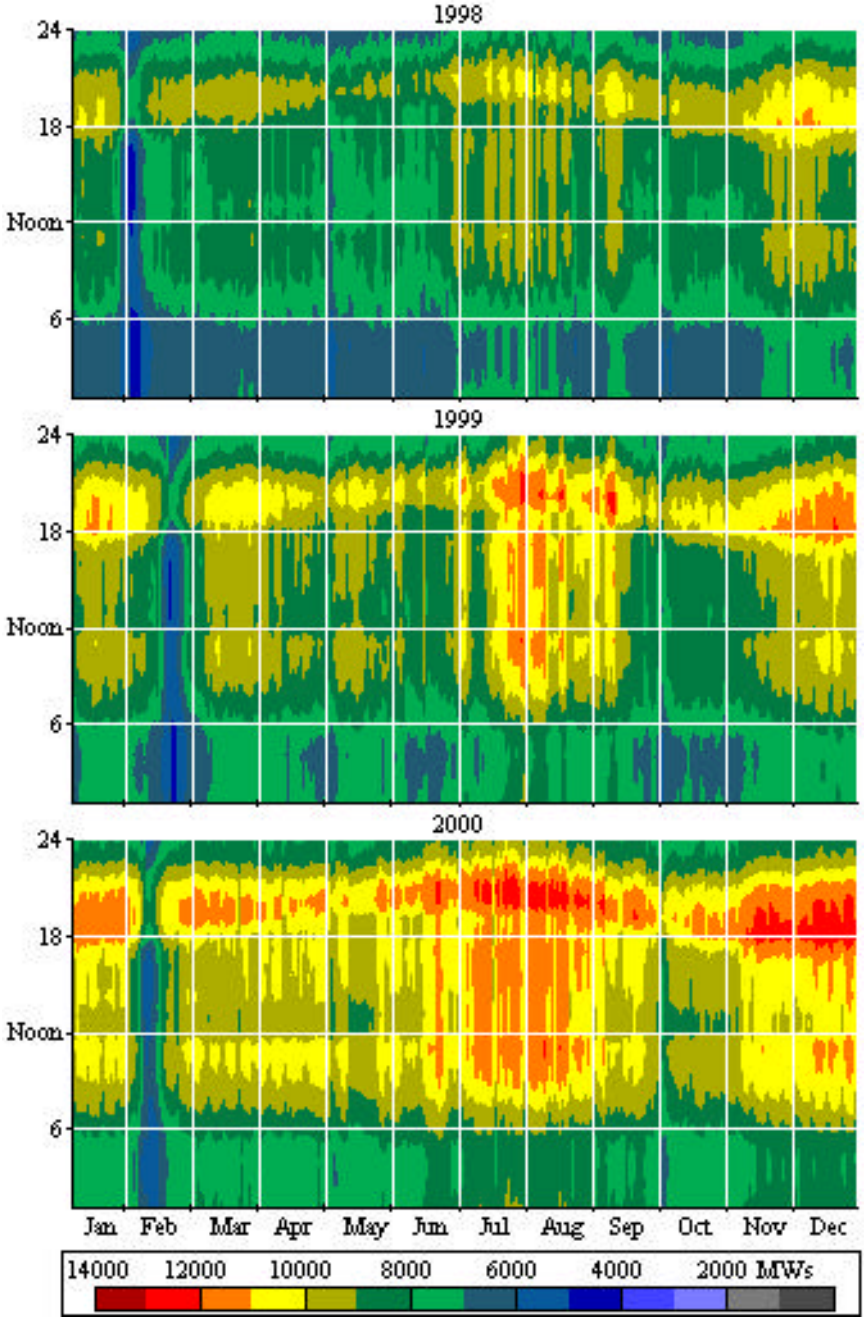


Figure 6.11: Electricity Demand Uncertainties

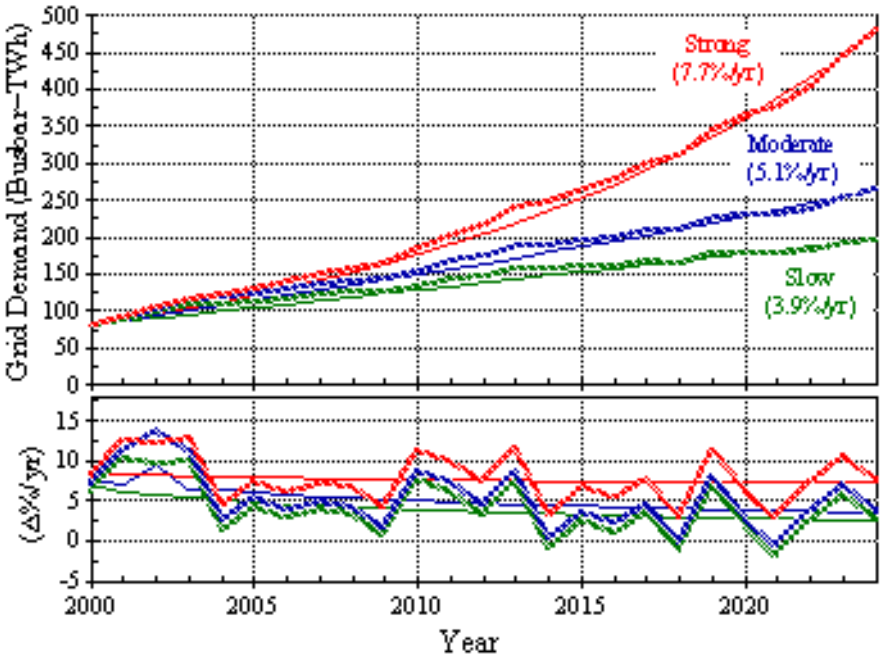
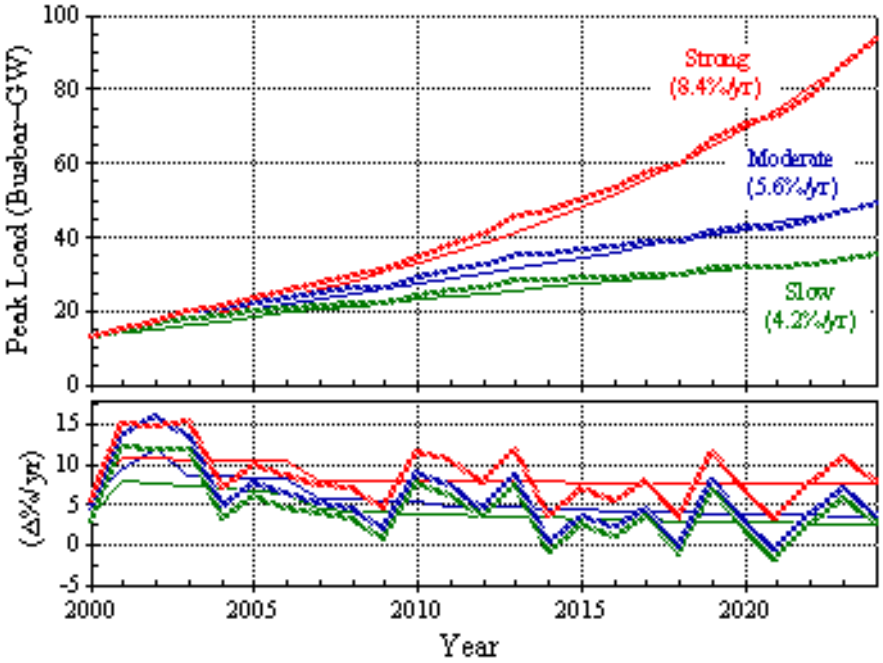



Figure 6.12: Peak Load Growth Uncertainties



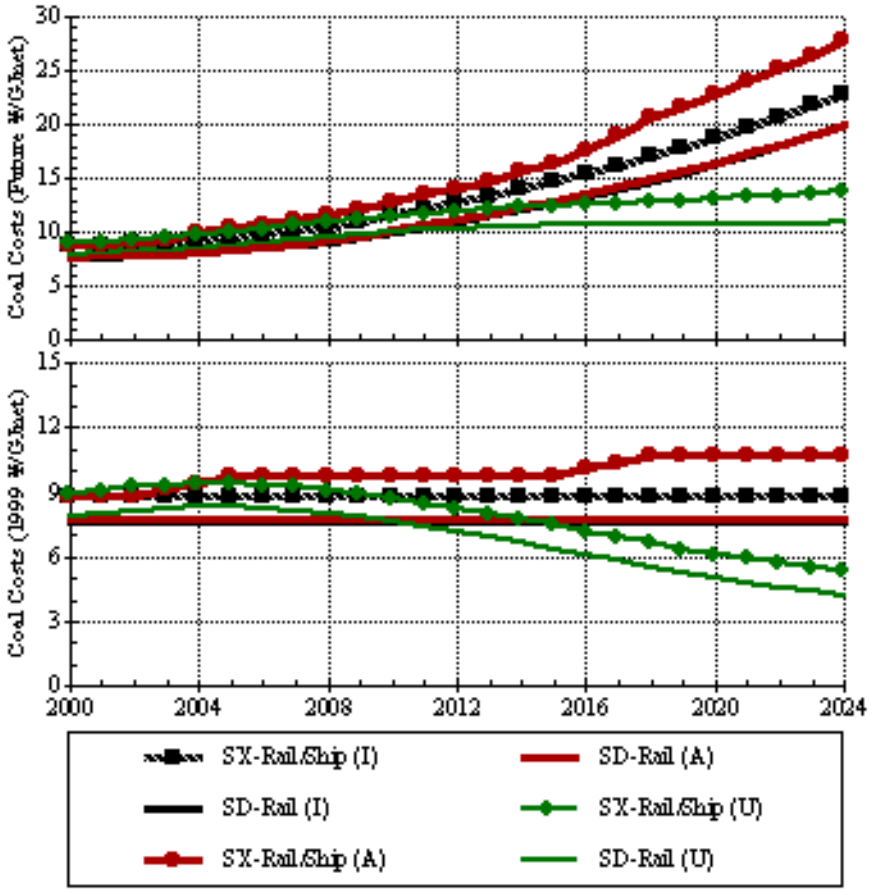
These ranges of electricity demand growth are analogous to those in the Energy Demand Forecasting chapter. The principal difference is that the ESS uncertainties have separate electricity demand and peak load growth trajectories, with peak load growing faster than annual electricity demand, indexed to the growth of residential and commercial electricity demand which contributes more to peak load than industrial end-uses. Figures 6.11 and 6.12 show the trajectories for electricity demand and peak load growth for the Slow, Moderate and Strong electricity demand uncertainties. Both the base smooth, and noisy trajectories for each TWh and GW trajectory are shown.

Steam Coal Cost Uncertainties.

As coal is the principal fuel for generating electricity in Shandong, and most of China, its delivered price to generators within the province is a major concern, and therefore uncertainty. Forecasts for the cost of delivered steam coal were unavailable, so these uncertainties are based upon some broader assumptions regarding the evolution of the Chinese coal industry. Figure 6.13 shows the cost trajectories for two types of coal, one from Shandong (SD) transported by rail, and another from Shanxi (SX) transported by rail and ship. We assumed all coal mined in Shandong is distributed within the province by rail. Coal brought into the province from Shanxi and other provinces to the Northwest is transported two ways. Inland power plants in the Western parts of the province receive their coal directly by rail, however those power plants using non-Shandong coal on the coast receive their fuel by ship. This coal is transported by rail to ports such as Qinhuangdao, where is loaded on ships for final delivery. As is shown in the figures, these increased transportation costs are reflected in the delivered cost of the coal. In our analysis, based upon the advice of Chinese research colleagues, *all* new coal-fired generation gets its coal from outside of Shandong Province.

The top portion of the graph shows coal costs in Future (current) Yuan, while the bottom shows coal costs in Base Year 1999 (constant) Yuan. The “Business as Usual” (I) coal cost uncertainty simply escalates coal costs with inflation. However, international coal statistics show that coal costs have declined dramatically over the past several decades, primarily due to increased mechanization of coal mining. The Mechanized Mining – Productive (U) coal cost uncertainty reflects this trend. A large portion of rail transport capacity in China is used for transporting coal, so the third coal cost uncertainty reflects a stressed or aggravated coal transport situation (A), where the need to invest in more rail transportation capacity is reflected in the delivered price of coal shipped from outside the province increases, first in 2005 and then again in 2016.

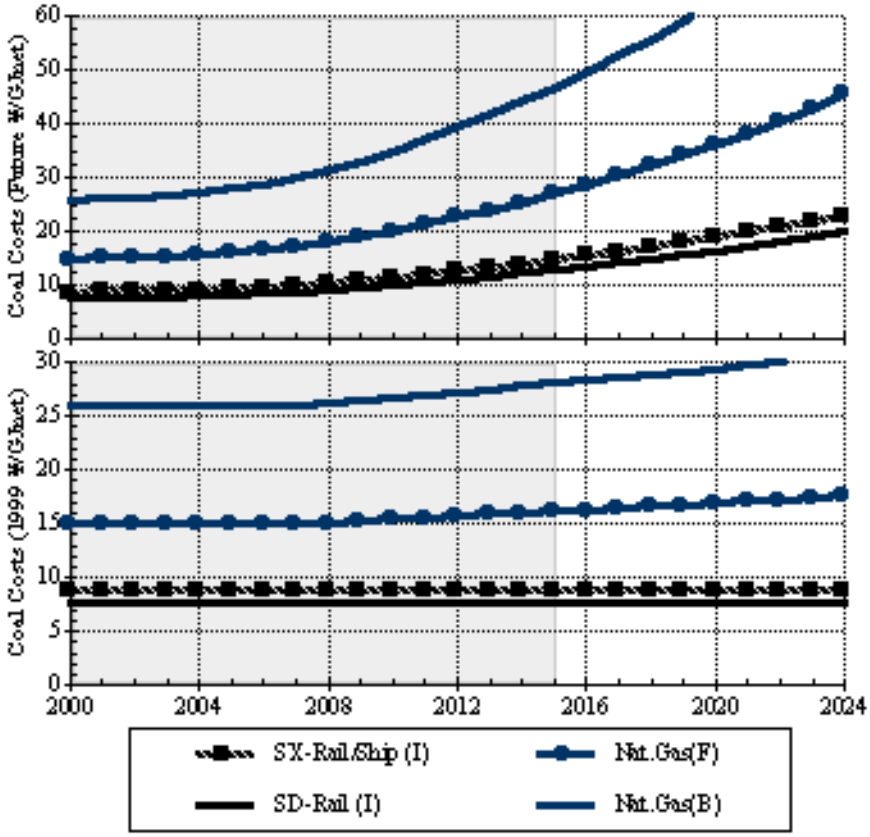
Figure 6.13: Coal Cost Uncertainties




Natural Gas Cost Uncertainty

Although there are no significant natural gas supplies to Shandong at present, that does not mean it may not be an important fuel for power generation in the future. As several of our strategies call for natural gas-fired generation, we included a natural gas cost uncertainty. The base cost for natural gas was assumed to be 26¥ per Gjnet (Gigajoule – Lower Heating Value or "net") and escalated through time as shown in Figure 6.14. A lower natural gas cost beginning at 15¥/Gjnet is the second uncertainty, and reflects either a drop in cost due to country-wide investment in gas transportation infrastructure, subsidization, or a combination of both. For comparison purposes, Figure 6.14 also shows Business as Usual uncertainty coal costs. Like the coal uncertainty graph future/current fuel costs are shown on top and base year-1999/constant costs are shown on the bottom. For both natural gas cost uncertainties, costs growth with inflation until 2008 and then are slightly higher than inflation. As the gray areas in the figure indicate, we assumed that power production from baseload natural-gas fired generation did could not occur until 2015, due to the time it takes to extend the pipeline infrastructure into the province in sufficient quantities to supply such generation.

Figure 6.14: Natural Gas Cost Uncertainties




## Shandong Options and Strategies

Strategies for Shandong's electric power sector were grouped into three categories, Existing Generation, New Generation and End-Use. Table 6.7 shows these categories, the options-sets within each of them, and the options and their letter codes that were combined to form 1008 strategies. Highlighted in each option-set is each group's reference option. Strung together they form the strategy "BOC-CONPAS." This "reference strategy" will be used as the basis for comparisons, and represents a "static technology" combination of options, not a "Business as Usual" forecast. With China's ongoing reform of the power sector, and its ascension to the World Trade Organization which will affect both the economy and access to technology, a "Business as Usual" strategy would be meaningless. After discussing some of the cross-cutting assumptions in the analysis of the ESS strategies, each set of options is presented.

Table 6.7: Shandong Electric Sector Options and Strategies

| *Strategy Components* | | | |
|---|---|---|---|
| Option Set | Option | Code | No. |
| *Existing Generation Options* | | | |
| Retire Additional Existing Units | | | |
| | Baseline Retirements 50 MW and Under by 2003 | **B** | 2 |
| | Retire Select Units by 2008 and at 35 Years | D | |
| Retrofit Existing Units with Sulfur FGD | | | |
| | None beyond Planned | **O** | 2 |
| | Retrofit Select Units | U | |
| Switch to Prepared Coal (Dry Processing) | | | |
| | No Switch to Prepared Coal | **C** | 3 |
| | Switch only Existing Coal Units | X | |
| | Switch All Conventional Coal Units | P | |
| *New Generation Options* | | | |
| Mix of Future Generation Technologies in Shandong | | | |
| | Conventional Coal with FGD & ESP | **C** | 7 |
| *Conv. Coal plus...* | AFBC Beginning 2010 | F | |
| | IGCC Beginning 2012 | L | |
| | Nat. Gas Combined Cycle Beginning 2015 | M | |
| | Nuclear Beginning 2010 | N | |
| | Nuclear and Natural Gas | D | |
| | Nuclear, Nat. Gas and IGCC | T | |
| Extra-Provincial Generation | | | |
| | No "Generation by Wire" | **O** | 2 |
| | Natural Gas from the West Beginning 2010 | A | |
| *End-Use Options* | | | |
| Peak Load Management/Peaking Generation | | | |
| | Nat. Gas Peaking Turbines Beginning 2008 | **P** | 2 |
| | Reduce Need for Peakers via Peak Load Mgt. | L | |
| End-Use Efficiency/Conservation | | | |
| | Current Efficiency Standards | **S** | 3 |
| | Moderate Efforts – 10% Cumulative Reduction | M | |
| | Aggressive Efforts – 20% Cumulative Reduction | G | |
| *(Ref. Strategy: BOC-CONPAS)* | No. of Strategies | | 1,008 |

## Baseline Assumptions

Although over a thousand multi-option strategies were analyzed for Shandong Province, there are still many common assumptions that cross all strategies. One that has been discussed already is transmission and distribution losses. Another was that all new coal-fired generation is supplied by coal mined outside Shandong Province, even if retirements of existing generators theoretically free up local mining capacity. Table 6.8 presents these key crosscutting assumptions and their derivation.

Table 6.8: Key Modeling Assumptions

*Power System Modeling Assumptions:*

Study Period: 2000 to 2024, inclusive.

Transmission and Distribution Losses:

Annual average of 6.2% between power plant output to grid (busbar generation) and end-use consumption (meter load) based on 1999 busbar generation of 75.73 TWh and electricity sales of 71.04 TWh. (SEPCO, 2000)

Planning Reserve Margin

A planning reserve margin of 20% was assumed for all scenarios. This represents the amount of extra generating capacity the power system would like to have in place, relative to annual peak load, to account for scheduled and unscheduled generator outages, and changes in the actual demand for electricity due to extreme weather and short-term changes in the economy.

Coal Supplies

For existing power plants, no changes from the current sources of coal were assumed. New generation was assumed to get their coal from Shanxi province, with inland units receiving it by rail, and coastal units receiving it by rail then ship.

Natural Gas Supplies

It was assumed that gas-fired peaking units could be supplied by associated natural gas from the Bo Hai oil fields beginning in 2008, however baseload natural gas combined-cycle units would have to wait for sufficient pipeline capacity bringing methane from the west or north to reach Shandong Province. Commissioning of gas combined-cycle generation was therefore prohibited before 2015 to reflect this availability constraint.

*Cost Modeling Assumptions*

Base Year for Costs: 1999

Discount Rate: 10%

A discount rate of 10%, including inflation was used to calculate the net present value of all cost streams in the results presented here

Borrowing Rate / Weighted Average Cost of Capital: 7%/year

By looking at the financial statements of Chinese independent power producers, a Weighted Average Cost of Capital (WACC) of 7% was assumed for future power plant capital expenditures, including inflation. This reflects roughly 75% of the financing coming from loans (debt) at 5%/yr., and 25% coming from the issuance of stock at 13%/yr. (Connors et. al., 2002)

Average Rate for Delivered Electric Power, 1999: 0.45 Yuan/kWh

In 1999, SEPCO's revenue from electricity sales totaled 32.07 billion Yuan, on sales of 71.04 TWh. This yields an average rate of 0.45 ¥/kWh. This number is used as to determine the balance of costs required beyond generation expenditures to provide power to Shandong grid customers. (SEPCO, 2000)

One of the principal challenges of the Electric Sector Simulation team was the estimation of transmission, distribution and other costs to add to the costs of generation which together represent the cost consumers pay for electric service. This was achieved by taking the electricity sales in the first year of the study period (2000) and multiplying it by 0.45 ¥/kWh to get the total revenue, and therefore revenue requirements, to provide the province with electric service. Power plant fuel and operating costs, plus new generation capital costs for 2000 obtained from the simulation model were then subtracted from 2000 revenue requirements. This difference represents the annual expenditure for the debt service on existing generators; maintenance and expansion of the

transmission and distribution system; and corporate general and administrative (G&A) costs. 50% of this difference was allocated to debt service of existing generators, which declined to zero over the course of the twenty-five year study period. Another 35% of the difference was allocated to transmission and distribution. This number was divided by 2000 sales to get a base Yuan/kWh T&D expenditure, which was then used to calculate future year annual T&D expenditures. The remaining 15% was handled in a similar fashion to calculate future G&A costs.

As the choice of new generating technologies is normally a high profile electric sector decision these options are covered next, followed by options targeting existing generators and fuel quality, and the consumption of electricity.

New Generation Options

The modeling of new generation options is a two step process. First, what technologies should be included, and when might they first come on line in Shandong Province? Second, what combinations of generation technologies should be examined? Tables 6.9 and 6.10 show the key performance and cost assumptions for the new generation technologies analyzed in the ESS's large scenario sets. These include new subcritical pulverized coal power plants, with and without flue gas desulfurization, two clean coal technologies, natural gas combined-cycle power plants and nuclear power. The two clean coal technologies were atmospheric fluidized bed combustion (AFBC) and integrated gasification combined-cycle (IGCC). Additional technologies such as windpower, advanced modular high temperature nuclear generation and waste-to-energy were examined as sensitivity analyses and are reported on later, and in Hansen. (2002) Details on all these technologies can be found in Connors et. al. (2002)

Table 6.9 shows the general performance characteristics of the technologies including size, thermal efficiency and percent reduction from uncontrolled emissions rates resulting from the installation of pollution control equipment. Two basic assumptions are made regarding the cost and performance of new generators, depending on whether they are located on the coast or inland. Coastal units are assumed to have Once Through Cooling where cooling water is returned to the sea, while inland power plants are modeled with evaporative or wet cooling systems. The cost of the cooling water return loop makes the coastal units slightly more expensive than the inland units with cooling towers. However, coastal units are slightly more efficient due to the smaller energy requirements of Once Through Cooling. All nuclear units were modeled as coastal units, while all natural gas combined-cycle units were modeled as inland units, proximate to pipeline natural gas supplies.

All conventional coal and fluidized bed units are assumed to have electrostatic precipitators (ESP) to control particulate emissions. Most large existing power plants in Shandong currently have ESPs or some other form of particulate control. We assumed the efficiency of ESPs to be 95%, due to the high ash content of Chinese coals. All new fossil-fueled generators are also assumed to have combustion modifications to reduce nitrogen oxide emissions, but no flue gas treatment for NOx.

While only a few Shandong coal units currently have flue gas treatment to capture sulfur dioxide, conventional coal units were all modeled with one type or another of flue gas desulfurization technology (FGD). Inland units employed the more common wet flue

gas desulfurization which uses lime or limestone as a sorbent. Coastal units however were assumed employ a sea water scrubber. Both are explained further in Connors et.al. (2002), with the principal differences being the increased capital cost and auxiliary power consumption of wet scubbers. Sulfur removal efficiencies were assumed to be 90%, again due to the high ash content of Chinese coals. Emissions requirements for new power plants in China call for flue gas sulfur controls on new units unless less than 1% sulfur coals are used. Based upon conversations with Chinese colleagues, the ESS team chose to model FGD on all new conventional coal fired power plants, since this provides plant operators greater flexibility with extra-provincial fuel suppliers. The impact this has on baseline sulfur emissions is shown later.

Table 6.9: New Generation Technology Characteristics

| Generation Technology | *Unit Size* | *Thermal Efficiency* | *Emissions Removal Efficiency* SO2 | PM10 | NOx |
|---|---|---|---|---|---|
| *Conventional Coal – Pulverized Coal, Subcritical Boilers (Conv.Coal)* | | | | | |
| *Coastal Locations – Once Through Cooling* | | | | | |
| No Desulfurization | 300 | 36.0 | | 95.0 | 50.0 |
| | 600 | 37.0 | | 95.0 | 50.0 |
| Sea Water Scrubbers | 300 | 35.0 | 90.0 | 95.0 | 50.0 |
| (OS) | 600 | 36.0 | 90.0 | 95.0 | 50.0 |
| *Inland Locations – Wet/Evaporative Cooling* | | | | | |
| No Desulfurization | 300 | 35.5 | | 95.0 | 50.0 |
| | 600 | 36.5 | | 95.0 | 50.0 |
| Wet Scrubbers | 300 | 34.5 | 90.0 | 95.0 | 50.0 |
| (WW) | 600 | 35.5 | 90.0 | 95.0 | 50.0 |
| *Atmospheric Fluidized Bed Combustion (AFBC)* | | | | | |
| Coastal-Once Through | 300 | 38.0 | 95.0 | 99.0 | 73.8 |
| Inland - Wet Cooling | 300 | 37.5 | 95.0 | 99.0 | 73.8 |
| *Integrated Gasification Combined-Cycle (IGCC)* | | | | | |
| Coastal-Once Through | 500 | 45.0 | 99.0 | *n/a* | 69.8 |
| Inland - Wet Cooling | 500 | 44.5 | 99.0 | *n/a* | 69.8 |
| *Natural Gas Fired Combustion Turbines (CT, Peaking)* | | | | | |
| Closed Loop Cooling | 155 | 38.0 | *n/a* | *n/a* | 70.0 |
| *Natural Gas Fired Combined-Cycle (NGCC)* | | | | | |
| Wet/Evaporative | 250 | 57.5 | *n/a* | *n/a* | 70.0 |
| Cooling | 500 | 57.5 | *n/a* | *n/a* | 70.0 |
| | 750 | 57.5 | *n/a* | *n/a* | 70.0 |
| *Nuclear – Advanced Light Water Reactors (ALWR)* | | | | | |
| Coastal-Once Through | 1000 | 33.0 | *n/a* | *n/a* | *n/a* |
| | (MW, Busbar) | (%, LHV) | (% reduced from uncontrolled) | | |

Cost assumptions were taken from the literature, and reflect adjustments for domestic production of components and Chinese labor rates. The OS and WW associated with the conventional coal units in the Tables 6.9 and 6.10 refer to Once Through Cooling and Sea Water Scrubbers (OS) for coastal units, and Wet Cooling and Wet Scrubbers (WW) for inland units. Differential impacts on these units' operation and maintenance costs were also assumed. Table 6.10 also presents the key availability metrics of annual scheduled maintenance in weeks per year, and the equivalent forced outage rate in percent of annual operation. The permitting and construction lead time associated with each technology is also provided.

Table 6.10: New Generation Technology Costs and Availability

| Generation Technology | *Capital Cost* | *Fixed O&M* | *Var. O&M* | *Main-tenance* | *Outage Rate* | *Lead Time* |
|---|---|---|---|---|---|---|
| *Conventional Coal – Pulverized Coal, Subcritical Boilers (Conv.Coal)* | | | | | | |
| *Coastal Locations – Once Through Cooling* | | | | | | |
| No Desulfurization | 600 | 20 | 1.0 | 7 | 5 | 5 |
| | 550 | 18 | 1.0 | 8 | 5 | 6 |
| Sea Water Scrubbers | 624 | 22 | 2.0 | 7 | 5 | 5 |
| (OS) | 574 | 20 | 2.0 | 8 | 5 | 6 |
| *Inland Locations – Wet/Evaporative Cooling* | | | | | | |
| No Desulfurization | 588 | 21 | 1.0 | 7 | 5 | 5 |
| | 540 | 19 | 1.0 | 8 | 5 | 6 |
| Wet Scrubbers | 660 | 23 | 4.0 | 7 | 5 | 5 |
| (WW) | 610 | 20 | 4.0 | 8 | 5 | 6 |
| *Atmospheric Fluidized Bed Combustion (AFBC)* | | | | | | |
| Coastal-Once Through | 900 | 30 | 4.0 | 5 | 5 | 5 |
| Inland - Wet Cooling | 880 | 31 | 4.0 | 5 | 5 | 5 |
| *Integrated Gasification Combined-Cycle (IGCC)* | | | | | | |
| Coastal-Once Through | 1200 | 30 | 1.0 | 5 | 8 | 6 |
| Inland - Wet Cooling | 1200 | 31 | 1.0 | 5 | 8 | 6 |
| *Natural Gas Fired Combustion Turbines (CT, Peaking)* | | | | | | |
| Closed Loop Cooling | 400 | 1 | 3.0 | 1 | 8 | 3 |
| *Natural Gas Fired Combined-Cycle (NGCC)* | | | | | | |
| Wet/Evaporative | 600 | 14 | 0.5 | 3 | 5 | 4 |
| Cooling | 600 | 13 | 0.5 | 3 | 5 | 5 |
| | 600 | 12 | 0.5 | 3 | 5 | 6 |
| *Nuclear – Advanced Light Water Reactors (ALWR)* | | | | | | |
| Coastal-Once Through | 1400 | 42 | 0.5 | 4 | 5 | 8 |
| | (Overnight, $99/kW) | ($/kW-yr) | ($/MWh) | (Wks) | (%) | (Yrs) |

Table 6.11 shows how these individual generation technologies were combined into portfolios, or generation mixes. In all cases conventional coal units are built in the early years of the study period, with the other technologies coming on line as they become available. The conventional coal mix ('C') continues to build pulverized coal throughout the twenty-five years, and for comparison purposes is considered the "reference" generation mix option. The following four (F–ABFC, L-IGCC, M-Methane and N-Nuclear) add one new generation technology in addition to pulverized coal. The final two mixes, 'D' and 'T' combine conventional coal with natural gas and nuclear, and those three plus IGCC.

Except for nuclear, each technologies' contribution to the mix is expressed as the percent of "new" megawatts built. For nuclear we assumed one new nuclear unit was added every other year beginning in 2010, resulting in a total of eight nuclear power units. This was independent of the load growth uncertainty. For the two clean coal mixes (F and L), no conventional coal generation was built after 2017. It should be noted that "new" power plants can be either "replacement" or "additional" capacity, replacing the megawatts from retired power plants or meeting the growth in demand. This allows for modernization of power generation beyond the need to meet just load growth. When peak load management programs are part of a strategy's broader mix of options, a slightly lower ratio of peaking combustion turbines was used.

Table 6.11: New Generation Technology Mixes

| | | *Peaking* | | *Baseload Generation* | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| *New Generation* | | No | Load | Conv. Coal | | Clean Coal | | Nat. Gas | Nuclear |
| *Technology Mixes* | | LM | Mgt. | Coastal | Inland | AFBC | IGCC | NGCC | ALWR |
| *First Year Avail.:* | | *2008* | | *2000* | | *2010* | *2012* | *2015* | *2010* |
| C | Conventional | 5 | | 50 | 45 | | | | |
| | Coal | | 3 | 50 | 47 | | | | |
| F | Clean Coal - | 5 | | 35 | 30 | 30 | | | |
| | AFBC | | 3 | 35 | 32 | 30 | | | |
| L | Clean Coal - | 5 | | 35 | 30 | | 30 | | |
| | IGCC | | 3 | 35 | 32 | | 30 | | |
| M | Natural Gas - | 5 | | 25 | 20 | | | 50 | |
| | NGCC | | 3 | 25 | 22 | | | 50 | |
| N | Nuclear - | 5 | | 50 | 45 | | | | *8 GW* |
| | ALWR | | 3 | 50 | 47 | | | | *8 GW* |
| D | Nat. Gas & | 5 | | 25 | 20 | | | 50 | *8 GW* |
| | Nuclear | | 3 | 25 | 22 | | | 50 | *8 GW* |
| T | Nat.Gas, IGCC | 5 | | 25 | 20 | | 25 | 25 | *8 GW* |
| | & Nuclear | | 3 | 25 | 22 | | 25 | 25 | *8 GW* |
| | | *(Percent of New MWs)* | | | | | | | (GW) |

Superimposed on the generation mixes was a "generation by wire" option. This assumed a firm purchase of natural-gas fired generation from a province or provinces to the west. Starting with 500 MWs of must run generation in 2010 this option added an additional 500 MW for each of the following nine years. An additional T&D loss of 5% was added to account for long distance transmission. Coal-by-wire and hydro-by-wire were also considered. While the "gas-by-wire" option substantially reduced SO2, NOx and CO2 emissions, due to its expensive fuel and must-run formulation it cost substantially more, therefore we will not be discussed in detail in the results section of this chapter.

Existing Generation Options

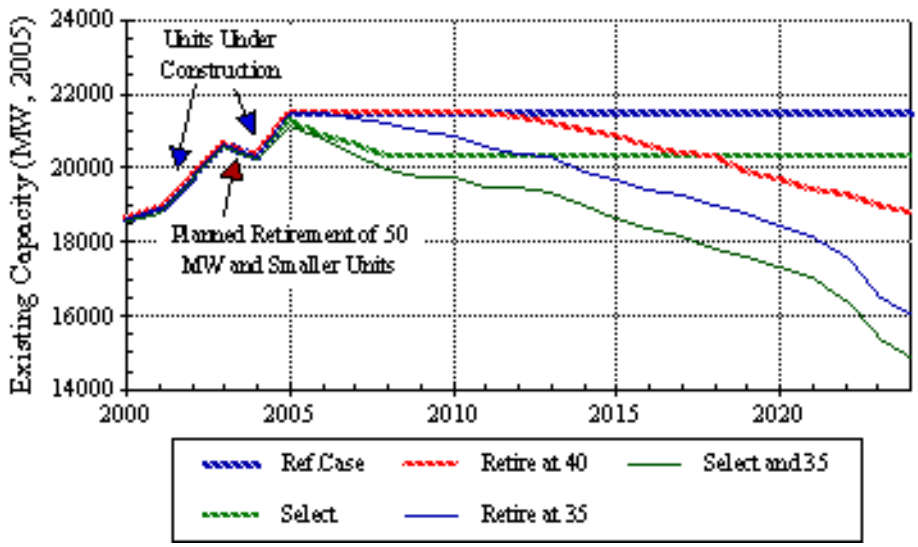
There were three option-sets targeting existing generation. First was the additional retirement of old power plants. Second was retrofitting select existing units with FGD. Third was assuming the processing of coal at or near mines to reduce ash content, and that coal's use in either existing or all coal-fired generation.

*Retire Additional Existing Units*

Current Chinese policy requires old power plants 50 MW or smaller in size to be turned off after 2003, and this is reflected in the ESS's reference strategy – BOC-CONPAS. The other assumption in the reference strategy was that units are not otherwise retired unless there was a firm retirement year specified. Before this final scenario set, several approaches to additional retirements were tested. The first was "select" retirements, where based upon annual output, numerous units were considered for retirement if they operated few hours but had large emissions. Here nine units, totaling 1175 MW were retired over the years 2006 to 2008. Another 600 MW of municipal generating units were retired between 2006 and 2016 in this option a well. Finally, firm retirement dates were considered at 35 and 40 years from unit start date. Figure 6.15 show the impact this

has on the longevity of existing and units already under construction. The Select plus Retire at 35 year option (D) results in 30% reduction from the Reference retirements option (B). No extra decommissioning costs were assumed for these options, nor was any site value ascribed if the location became the site for a new generation unit.

Figure 6.15: Changes to Existing Capacity




*Retrofit Existing Units with Sulfur FGD*

The second existing unit set of options was to install flue gas desulfurization units on existing power plants. Some FGD retrofits have already been planned or completed and are incorporated into the Reference Case. Additional candidates for FGD retrofit were units that had relatively high capacity factors but high emissions rates. These totaled 14 units with a total of 3670 MWs, with the retrofits phased in between 2004 and 2007.

*Switch to Prepared Coal*

During the course of formulating the initial scenario set it became apparent that the high ash content of Chinese coals has a substantial impact on the operational and emissions performance of Chinese power plants. Therefore a set of options looking at mine-based treatment of coals to reduce their ash content were developed. As some sulfur is bound up in the ash, sulfur reductions also occur. Due to water availability issues in coal mining regions, only dry preparation techniques, consisting primarily of sorting and screening raw coal, were considered. The assumptions regarding coal preparation are presented in Connors et. al. (2002) Table 6.12 shows examples of how dry preparation of coal impacted it chemical composition, energy content and cost assuming a preparation cost of five Yuan per tonne.

Table 6.12: Composition and Cost Impacts of Coal Preparation

| Select Bituminous Coals *by Source, Transport and Preparation* | | Ash Content | Total Sulfur | Total Carbon | Energy Content | 1999 Coal Cost Energy | Mass |
|---|---|---|---|---|---|---|---|
| | | (weight %) | | | (GJn/t) | (¥/GJnet) | (¥/t) |
| Shandong by Rail | *Raw* | 22.39 | 0.75 | 43.22 | 22.50 | 7.74 | 174.2 |
| *Low Sulfur – Prepared* | | 10.47 | 0.65 | 50.61 | 24.66 | 7.83 | 193.2 |
| | (Δ%) | (53.2) | (14.0) | 17.1 | 9.6 | 1.2 | 10.9 |
| Shandong by Rail | *Raw* | 29.09 | 1.25 | 39.81 | 21.50 | 7.76 | 166.8 |
| *Medium Sulfur – Prepared* | | 16.00 | 1.08 | 48.07 | 23.92 | 8.07 | 193.1 |
| | (Δ%) | (45.0) | (14.0) | 20.8 | 11.3 | 4.1 | 15.8 |
| Shanxi by Rail | *Raw* | 15.70 | 0.75 | 46.64 | 23.50 | 8.37 | 196.7 |
| *Low Sulfur – Prepared* | | 10.47 | 0.65 | 50.61 | 24.66 | 8.44 | 208.2 |
| | (Δ%) | (33.3) | (14.0) | 8.5 | 5.0 | 0.8 | 5.8 |
| Shanxi by Rail/Ship | *Raw* | 15.70 | 1.25 | 46.64 | 23.50 | 8.80 | 206.7 |
| *Medium Sulfur – Prepared* | | 10.47 | 1.08 | 50.61 | 24.66 | 8.85 | 218.2 |
| | (Δ%) | (33.3) | (14.0) | 8.5 | 5.0 | 0.6 | 5.6 |

Operational impacts of "switching" to prepared coals in pulverized coal units included an increase in ESP removal efficiency from 95% to 97%. The availability of old generators was also assumed to improve with scheduled maintenance dropping from 10 weeks per year down to 8, as well as a reduction in the unit's equivalent forced outage rate from 8% to 5%, essentially the same as for new conventional coal units.

This option assumed that prepared coal was used instead of raw coal for the entire study period, an overestimation of the degree of actual coal switching that could actually occur. Two levels of switching to prepared coals were assumed. First, in all existing conventional coal units (X), and second, in both existing and all new coal-fired power plants (P), including clean coal technologies.

Demand-Side Management Options

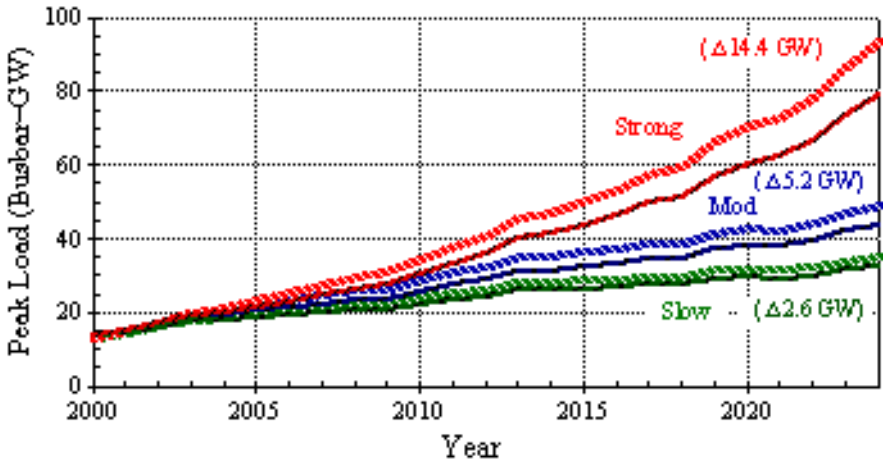
The third category of options were those aimed at the demand for electricity, commonly referred to as demand-side management (DSM). It is also the category for which there was the least amount of information upon which to base assumptions. The peak load management (PLM) and end-use efficiency (EUE) options shown here should therefore be considered theoretical. Even so, they do allow the determination of the benefits of achieving the assumed levels of conservation and peak load reduction, identifying the avoided operating and investment costs in delivering power, and its associated stack emissions, and therefore what the province should be "willing-to-pay" for DSM.

*Peak Load Management*

As shown above in the demand uncertainty section, annual peak load is assumed to grow faster than annual electrical energy. In the peak load management option peak load is assumed to grow at the *same rate* as annual electrical energy. Peak load management is modeled as a pure load shift with no impact on the annual demand for electrical energy (TWh per year). The cost of peak load management was assumed to be 120 Yuan per kW-yr ($15/kW-yr) from the no Peak Load Management level of demand, and increased with inflation. Figure 6.16 shows the peak load impacts of this option across the three

load growth uncertainties. As you can see, peak load growth is substantially different across the three load growth uncertainties. The 2.6, 5.2 and 14.4 GW peak load reductions associated with the Slow, Moderate and Strong electricity demand uncertainties must by increased by 20% to get the GWs of avoided generation investment.

Figure 6.16: Peak Load Management Impact on Annual Peak Load




*End-Use Efficiency*

The second DSM option was end-use efficiency. Here we assume that the deployment of efficiency end-use technologies achieve Moderate 10% (M) and Aggressive 20% (G) reductions in cumulative electricity sales over the twenty-five year period, relative to the no-DSM option "current standards" (S). These saving are phased in over time by end use sector. Figure 6.17 shows these reductions. Most reductions are attained in the industrial sector. In the Moderate case, efficiency savings start in the first year and achieve a level of 15% by 2015. Percent reductions in the services and residential sectors are identical and begin in 2005, leveling out at 10% in 2014. Industry sector efficiency gains in the Aggressive option are double those of the Moderate Option. For the services and residential sectors, the doubling to 20% is phased in over a longer time period, from 2000 to 2019.

The impact these two levels of end-use efficiency have on total demand for electricity is show in Figure 6.18, for each of the three load growth uncertainties. Moderate load growth with aggressive efficiency programs, has about the same electricity demand as Slow load growth with no end-use efficiency. Figure 6.10 showed that peak electricity demand in Shandong is strongly influenced by residential demand for electricity. We modeled growth in residential demand as a having greater impact on peak load growth. Therefore, reductions in electricity demand from that and other sectors also reduces peak load growth. These impacts are shown in Figure 6.19.

Figure 6.17: Electricity Demand Reductions by Sector
(Reduction from Current Standards option)

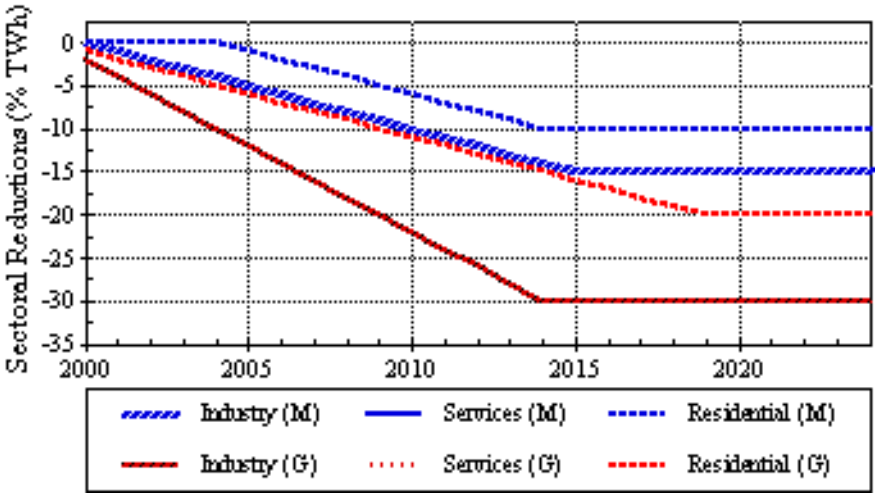



Table 6.13: Combined DSM MW Impacts

| | Demand-Side Option Impacts | | |
|---|---|---|---|
| | Slow (T) | Moderate (F) | Strong (S) |
| | Growth in Electricity Demand (Busbar–GWh) | | |
| No DSM | 3.89 | 5.11 | 7.66 |
| 20% End-Use Efficiency | 3.31 | 4.55 | 7.08 |
| 10% End-Use Efficiency | 2.62 | 3.87 | 6.40 |
| | Growth in Peak Load (Busbar–MW) | | |
| No DSM | 4.19 | 5.58 | 8.36 |
| Peak Load Mgt. | 3.89 | 5.12 | 7.66 |
| 20% End-Use Efficiency | 3.65 | 5.05 | 7.82 |
| 10% End-Use Efficiency | 3.01 | 4.41 | 7.19 |
| 20% EUE & PLM | 3.30 | 4.54 | 7.07 |
| 10% EUE & PLM | 2.62 | 3.87 | 6.40 |
| | (Long-Term Growth Rate – Δ%/yr) | | |

| | | | |
|---|---|---|---|
| | Electricity Demand Reductions (Busbar–GWh) | | |
| 20% End-Use Efficiency | -13.25 | -13.00 | -12.76 |
| 10% End-Use Efficiency | -26.51 | -26.01 | -25.52 |
| | (Δ% GWh in 2024 from No-DSM) | | |
| | Peak Load Reductions (Busbar–MW) | | |
| Peak Load Mgt. | -2635 | -5248 | -14377 |
| 20% End-Use Efficiency | -4447 | -6047 | -11277 |
| 10% End-Use Efficiency | -8894 | -12094 | -22554 |
| 20% EUE & PLM | -6951 | -10940 | -24502 |
| 10% EUE & PLM | -11268 | -16631 | -34628 |
| | (ΔMW in 2024 from No DSM) | | |

Figure 6.18: End-Use Efficiency Impacts on Electricity Demand

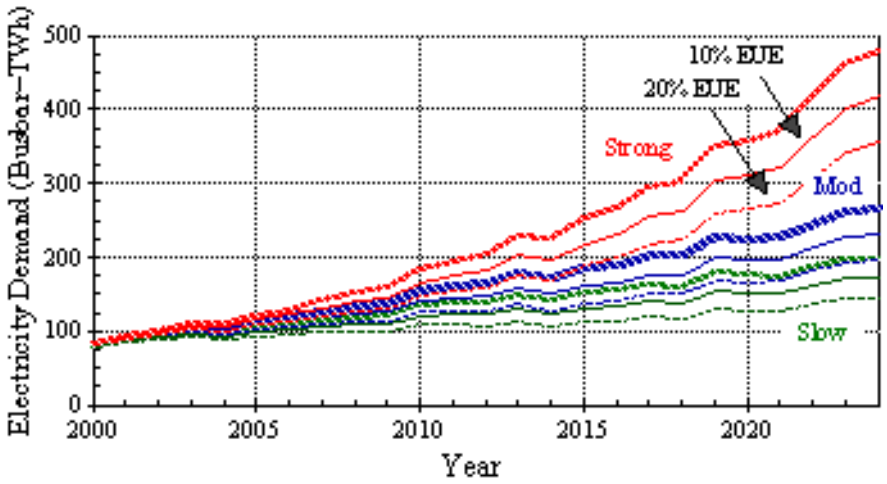
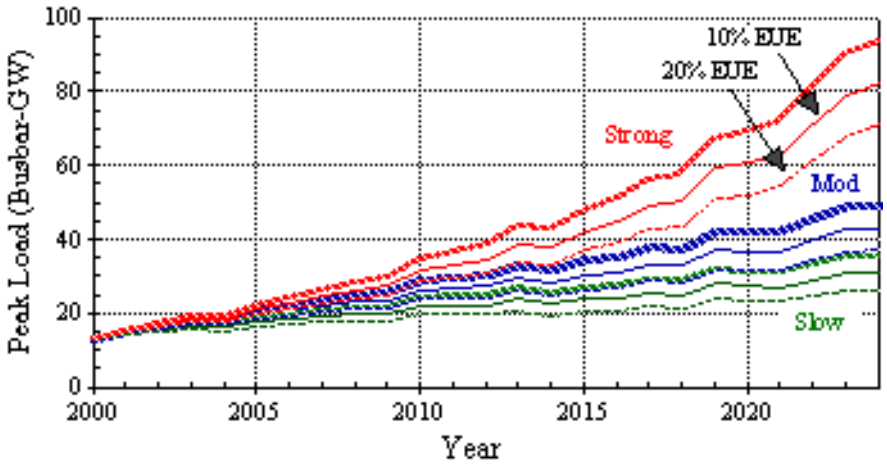



Figure 6.19: End-Use Efficiency Impacts on Peak Load Growth




Both DSM options, peak load management and end-use efficiency can work together. Table 6.13 shows the separate and combined impacts of the DSM options across all three load growth uncertainties as changes to long-term growth rates in electrical energy and peak load growth, as well as the percent reduction in electricity demand and peak load in 2024.

Like peak load management, we assumed a cost for implementing end-use efficiency programs. DSM cost assumptions were derived from Yang and Lau. (1999) For the Moderate EUE option the cost of end-use efficiency was assumed to be 0.10 ¥/kWh for industry, 0.15 for services and 0.20 for residential applications. For the Aggressive option, 0.15, 0.20 and 0.25 ¥/kWh costs were used to reflect that lower cost applications had been used up. These DSM implementation costs escalated with inflation. Much greater detail on these and all the other options can be found in Connors et. al. (2002)

## The Reference Strategy and the Impact of Growth and Fuel Cost Uncertainties

The above sections gave a quick overview of the various options used to construct the strategies for Shandong Province's electric sector. Each of the two new generation options is coupled to each of the three existing generation and then the two demand side options, for a total of 1008 unique strategies. Additional sensitivity analyses were done in addition to these, such as the reference strategy without FGD. Each strategy is in turn coupled with a future comprised of an electricity demand, and a coal and a natural gas cost uncertainty. In this chapter many results will be shown in comparison to the reference strategy (BOC-CONPAS), and future (FIB). So, before jumping into the broad set of results, we will review the performance of this scenario.

Figure 6.20 shows the capacity expansion, capacity utilization and costs of supplying Shandong grid customers electric service for the entire twenty-five year study period, for the FIB future. The top graph also shows the growth in peak load and the capacity target which is the peak load plus the planning reserve margin of 20%. Except for some combustion turbines built for peak generation beginning 2008, all new generation is subcritical pulverized coal with flue gas desulfurization. Due to long lead times of five and six years for the coal units, some years are over and under the capacity target. The middle graph shows how the simulation model dispatches the available generation. Old generation is grouped by location within the province, and new generation by is grouped by technology type. These designations were used to help calculate population exposures for the environmental impact assessment. The third plot shows the costs of operating the system, beginning with generation and T&D capital costs on the bottom, general and administrative costs, and then operation and maintenance and fuel costs for generation. Costs are shown in base year Yuan (1999), and grow with the level electricity demand. Unit costs will be shown later.

These plots show the true value of a simulation approach. As new coal generation enters the system it displaces most of the generation by older power plants, since the new units are more efficient and cheaper to operate. The impact this has on emissions are shown in Figure 6.21. Here SO2, PM10, NOx and CO2 emissions are plotted. Old generation has been aggregated into emissions from old-small, old-large and new generation.

The emissions results show several things. First is that the current policy of retiring old units 50 megawatts or smaller is very sound from an emissions viewpoint. However, emissions from small units continue to contribute substantially to particulate emissions. Both SO2 and particulate emissions drop in the first third of the study period and then increase gradually, even though annual electricity demand more than triples. NOx and CO2 emissions however continue to grow.

Figure 6.20: Reference Scenario Technical and Cost Performance
(BOC-CONPAS-FIB)

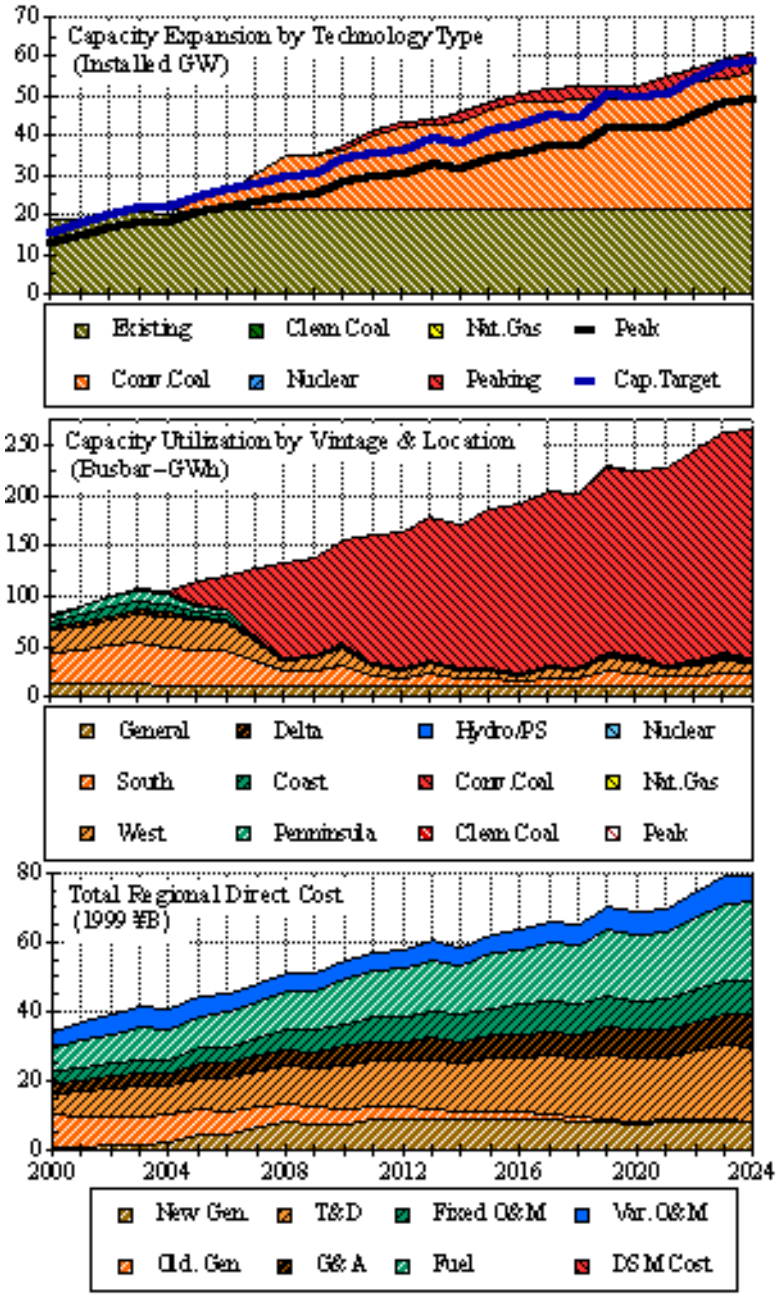


Figure 6.21: Reference Scenario Emissions Performance
(BOC-CONPAS-FIB)

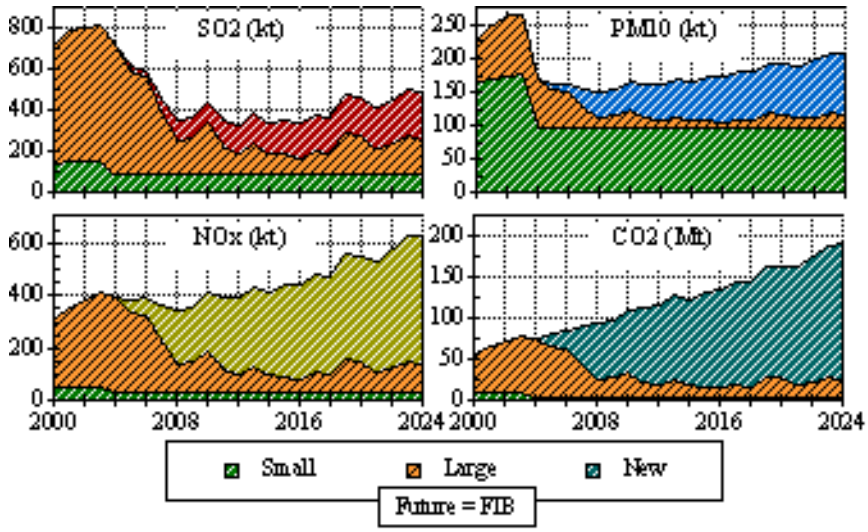
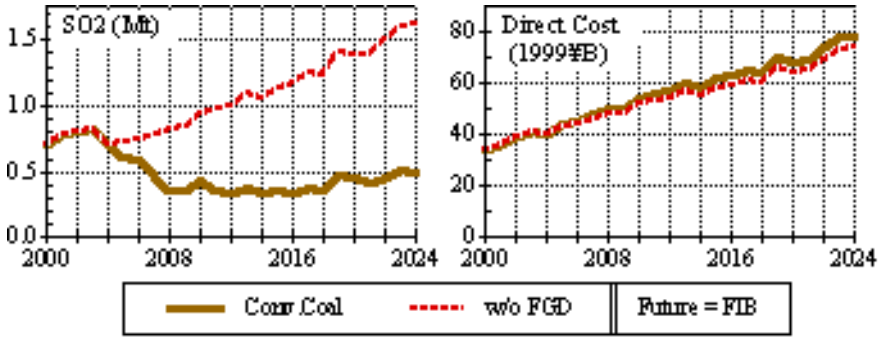



Figure 6.22 shows how the assumption that new conventional coal units use FGD instead of low sulfur coal impacts SO2 emissions and costs. While the cost of the reference case without FGD is slightly lower, due to the reduced cost of non-FGD generators, and their slightly better efficiency, sulfur emissions grow substantially. Particulate, NOx and CO2 emissions were effectively the same with and without FGD. Therefore, assuming FGD on new conventional coal units is the better option of the two allowed in by China's current sulfur reduction policy.

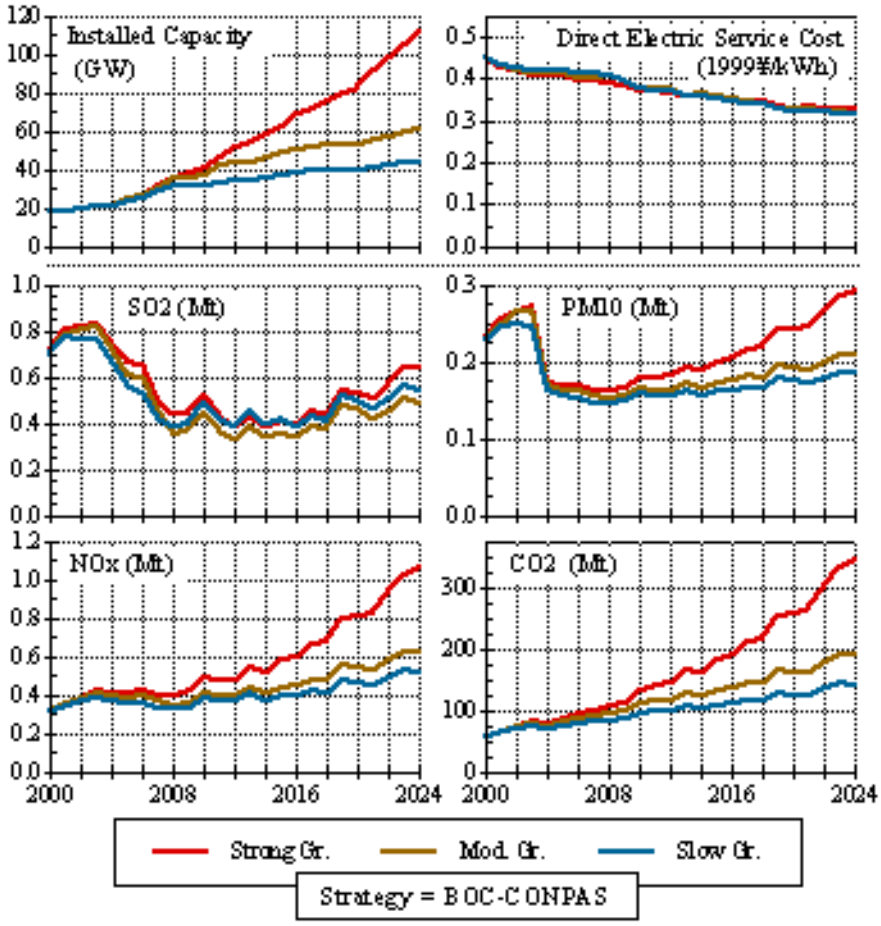
Figure 6.22: Impact of the FGD Assumption




How does the reference case perform across uncertainties? Figure 6.23 shows how the reference strategy performs for the slow, moderate and strong load growth uncertainties, retaining the reference uncertainties for coal and natural gas costs (_IB). Displayed are installed capacity, the *unit* cost of electric service, and the four principal air emissions. While capacity grows, cost to the consumer remains about the same, as the increased costs are spread over a greater number of kilowatt-hours. Total direct costs continue to grow as in the previous graph. Sulfur emissions stay about the same as well, as the operation of high SO2 emitting older units cannot increase by too much. Close

examination of Figure 6.23 shows that SO2 emissions are higher in the slow growth case compared to moderate growth, highlighting the dynamics between old and new generation. There is greater emissions growth in the other three pollutants, especially CO2 and NOx, whose emissions do not benefit from the retirement of older smaller units at the end of 2003.

Figure 6.23: Impact of Load Growth on Capacity, Costs and Emissions



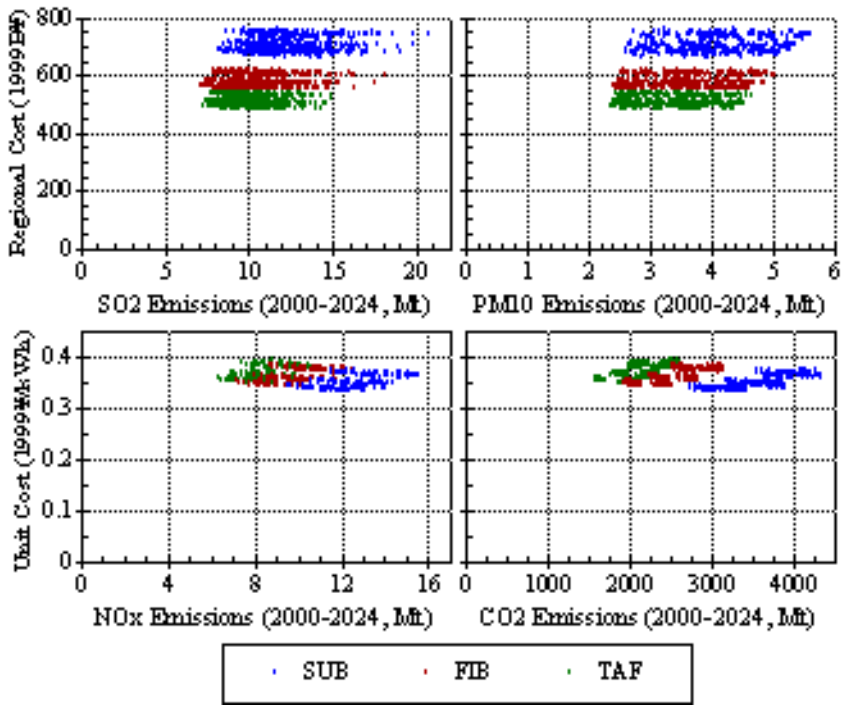

In the following sections we examine how the choice of options around the reference case impact emissions and costs, then we look at those options in combination.

## Performance of ESS Scenarios

Before delving into the performance of individual options and strategies it is important to understand the range over which costs and emissions change due to both options and uncertainties. Figure 6.24 shows costs versus emissions for three of the eighteen futures analyzed. Depicted are all the strategies without gas-by-wire for the reference future FIB, and two other future selected so that emissions would be either high or low. The low emissions future is where electricity demand is slow, coal prices high and natural gas prices low so that generation shifts to units with higher efficiency or other fuels (TAF). In contrast, the high emissions future is where growth in electricity demand is high, coal

costs low, and natural gas costs high (SUB). The top two plots show cumulative SO2 and PM10 emissions versus the present value of total direct regional costs, while the bottom two show NOx and CO2 against the average unit cost of electric service. Each plot has a zero-zero origin so that the true relative movement in costs and emissions can be evaluated.

Figure 6.24: Range of Variation in Costs and Emissions Across Futures




Significant in Figure 6.24 is the overlap in the emissions and unit costs across the futures. For regional costs there is almost no overlap on costs, due to the scale effects of the different load growth rates and the amount of electricity being produced. Normalizing this in the lower two graphs eliminates the overlap, and actually makes the unit cost for strong demand slightly lower since growth in demand is slightly faster than growth in expenditures. This trend should be treated with caution however, as the costing, especially of non-generation activities, was calculated using a benchmarking technique rather than with confidential utility cost information. Ranges from highest to lowest unit costs within these three futures 11%, and 16% maximum to minimum cost across the three futures.

More significant perhaps is the lack of overlap along the emissions axes. The overlap among SO2, PM10 and NOx emissions is substantial. CO2 emissions overlap to a lesser degree. The ranges are considerably higher than those for cost. Roughly 52-61% reductions for SO2, 49-54% for PM10, 39-43% for NOx and 37-41% for CO2. This implies two important lessons. First, there is more opportunity to reduce emissions than there are costs. Second, that while ranges in costs are less important in a design-oriented tradeoff analysis, the design element in crafting scenarios will have a very large impact on the emissions performance of the strategies. With these thoughts in mind, we next

look at the performance of the individual classes of options and their cumulative and annual impacts on costs and emissions.

New Generation Options

How did the seven combinations of conventional coal, clean coal, natural gas and nuclear generation technologies plus the gas-by-wire option perform? Table 6.14 shows how these options performed relative to the reference strategy for the moderate growth FIB future, without any other option choices. The reference case was the cheapest of the eight strategies shown, with the AFBC and gas-by-wire strategies being the most expensive. In the AFBC case, these clean coal units had roughly the same efficiency as the pulverized coal units, and so did not provide any operational cost savings to offset their higher capital cost. In the gas-by-wire case, must-run dispatch with a high fuel cost and additional transmission losses, makes it the most expensive new supply alternative.

Focusing on emissions performance, the combinations with IGCC and nuclear performed best, with the nuclear combinations providing substantial reductions in CO2 as well. The NGCC and Nuclear and NGCC options had relatively poor environmental performance in the FIB future, with substantial increases in SO2 emissions. Although natural gas units were built, they operated very few hours due to the high cost of natural gas relative to coal. The emissions increases occur because older, higher emissions power plants are not displaced as they are with the other options. In the lower natural gas cost futures, this does not occur as much.

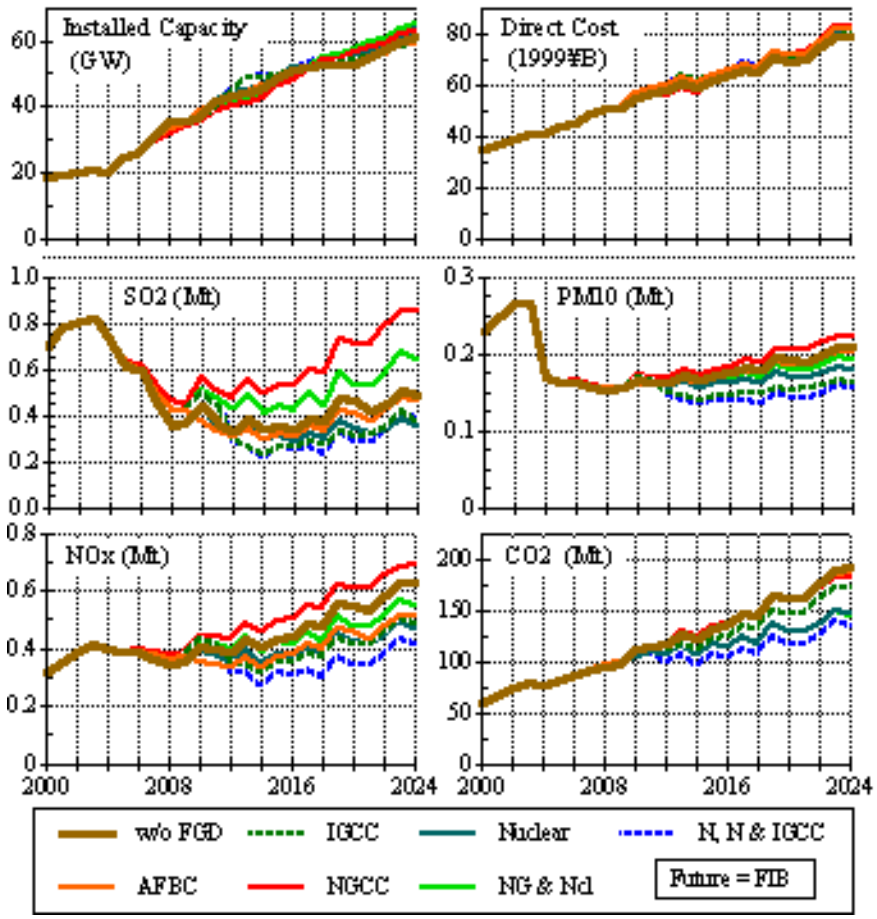
Table 6.14: Cost and Emissions Performance of
New Generation Technology Options

| New Generation Options | *Electric Service Direct Costs* | | *Power Plant Stack Emissions* | | | |
|---|---|---|---|---|---|---|
| | Regional | Unit | SO2 | PM10 | NOx | CO2 |
| Reference | 601.0 | 0.373 | 12.34 | 4.69 | 11.05 | 3.01 |
| AFBC-2010 | 610.8 | 0.379 | 11.91 | 4.64 | 9.91 | 2.96 |
| IGCC-2012 | 606.5 | 0.377 | 11.31 | 4.28 | 9.79 | 2.84 |
| NGCC-2015 | 602.5 | 0.374 | 15.98 | 4.87 | 12.00 | 2.99 |
| Nuclear-2010 | 604.5 | 0.375 | 11.26 | 4.47 | 9.81 | 2.64 |
| Nuclear & NGCC | 603.9 | 0.375 | 14.15 | 4.60 | 10.66 | 2.65 |
| Nuc., NGCC & IGCC | 608.4 | 0.378 | 11.30 | 4.18 | 9.06 | 2.52 |
| NGCC by Wire | 612.6 | 0.381 | 11.38 | 4.50 | 10.00 | 2.85 |
| | (NPV¥B) | (¥/kWh) | (Mt) | (Mt) | (Mt) | (Gt) |
| *Percent Change from Reference - Conventional Coal with FGD* | | | | | | |
| AFBC-2010 | 1.6 | 1.7 | (3.5) | (1.0) | (10.3) | (1.4) |
| IGCC-2012 | 0.9 | 0.9 | (8.4) | (8.7) | (11.4) | (5.5) |
| NGCC-2015 | 0.2 | 0.3 | 29.6 | 3.9 | 8.6 | (0.5) |
| Nuclear-2010 | 0.6 | 0.6 | (8.7) | (4.7) | (11.2) | (12.0) |
| Nuclear & NGCC | 0.5 | 0.5 | 14.7 | (1.9) | (3.5) | (11.8) |
| Nuc., NGCC & IGCC | 1.2 | 1.3 | (8.4) | (10.9) | (18.0) | (16.3) |
| NGCC by Wire | 1.9 | 2.0 | (7.7) | (4.0) | (9.5) | (5.1) |
| *(Future = FIB)* | (Δ%) | (Δ%) | (Δ%) | (Δ%) | (Δ%) | (Δ%) |

Figure 6.25 shows how all but the gas-by-wire options perform on an annual basis. Apparent are the similarities in performance for the amount of installed capacity and

regional direct costs. Another important observation is that substantial costs and emissions impacts only occur as the new technologies come on-line in sufficient numbers. As seen before, SO2 and PM10 emissions drop as planned retirements of old, smaller generators occur. Differences in CO2 emissions are directly linked to those options including combinations of nuclear and IGCC. Here the failure of natural gas options to displace older generation and reduce SO2, PM10 and NOx emissions is apparent. Furthermore, the strategies with nuclear and/or IGCC are able to sustain, to some degree, SO2 and PM10 reductions over time.

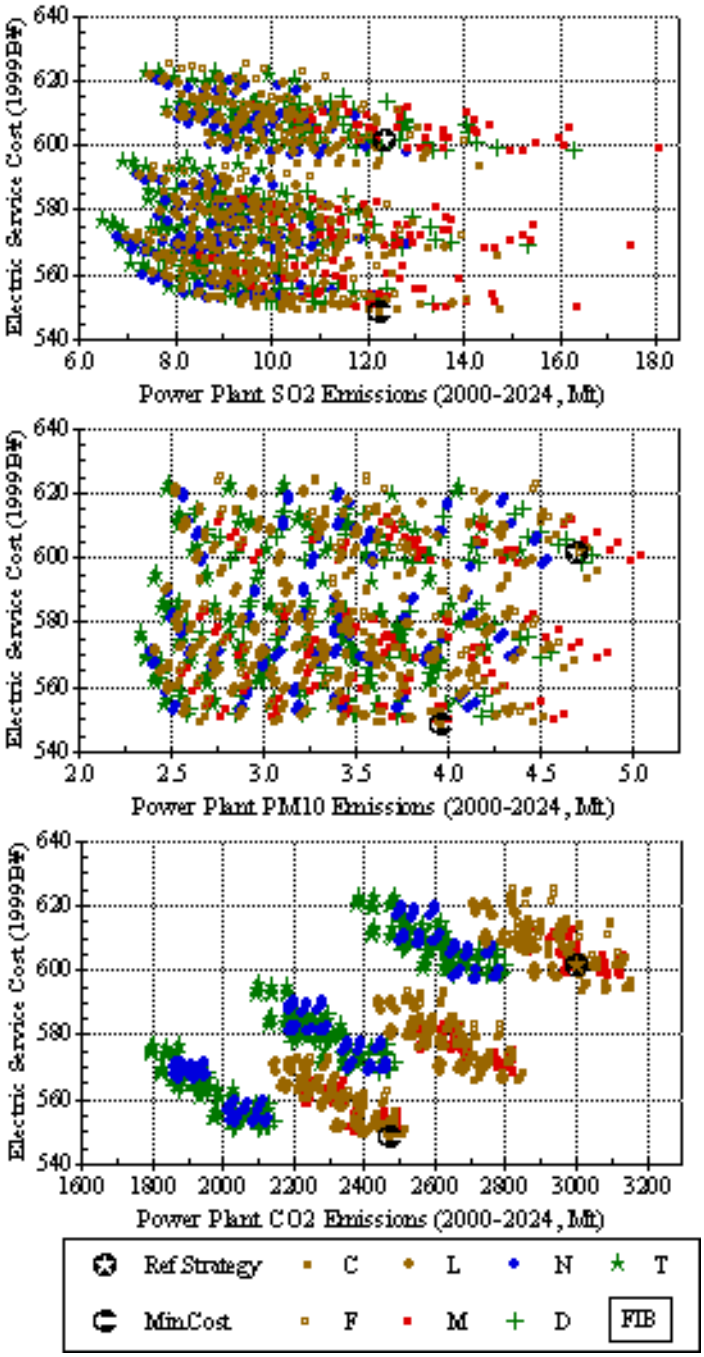
Figure 6.25: Annual Performance of Generation Mix Options




How well does the selection of generation technology perform as we add back in the other options? The 5 to 20% reductions in emission is only part of the overall 40-55% range shown in Figure 6.24. Figure 6.26 shows all of the 1008 strategies for the FIB future, keyed by choice of new generation technology mix. Highlighted are the positions of the reference strategy (BOC-CONPAS), and the least-cost (BOX-CONLAG) strategy which defines the low-cost, high emissions end of the tradeoff frontier for the FIB future. As can be seen, the choice of new generating technologies is not the principal driver for reducing SO2 and PM10 emissions, as there is substantial overlap in the generation technology clusters. Some differentiation does occur in the cost versus CO2 plot with the

options including nuclear clustered to the left, although other options are exerting significant influence here as well. We explore what these are in the next sections.

Figure 6.26: Comparative Performance of FIB Strategies
Keyed by Future Generation Mix



Existing Generation Options

Existing generation options include the select retirement of old power plants, as well as the "forced" retirement of units after 35 years of operation, plus select scrubber retrofits, and the use of lower-ash, lower-sulfur prepared coals. The switch to prepared coal option is a hybrid option as it was also applied to new coal-fired generation in the "switch all" formulation. When these options were combined, units scheduled for early retirement were not given scrubbers. Similar to the presentation of new generation technology option results, Table 6.15 and Figures 6.27 and 6.28 show the performance of these options relative to the reference case, and across all options.

Compared to the reference strategy, all cost slightly more, except for the "switch existing" option. In this case, making the older units slightly more expensive shifted even more generation to the newer, more efficient generators. Reasons for the cost increases are the additional cost of the prepared coal, and replacement capacity (retire) and FGD systems (retrofit) investment costs. Given the uncertainties in the cost assumptions and how they propagate through time, these options are effectively the same cost.

Overall the emissions reductions from these options are more than double those from the choice of new generation technology, except for CO2, for little or no cost impact. When the options are combined, emissions reductions are greater still. The increase in CO2 is attributed to the retirement of cogenerators which were not only efficient from an electricity generation viewpoint, but assumed to be industrial thermal-following units, and therefore modeled on a "must-run" basis.

Table 6.15: Cost and Emissions Performance of Existing Generation Options

| Existing Generation Options | *Electric Service Direct Costs* | | *Power Plant Stack Emissions* | | | |
|---|---|---|---|---|---|---|
| | Regional | Unit | SO2 | PM10 | NOx | CO2 |
| Reference | 601.0 | 0.373 | 12.34 | 4.69 | 11.05 | 3.01 |
| Retire Select | 601.9 | 0.374 | 10.87 | 3.78 | 10.73 | 3.01 |
| FGD Retrofit Some | 602.6 | 0.374 | 11.73 | 4.71 | 11.03 | 3.01 |
| Switch Existing | 600.5 | 0.373 | 10.80 | 4.35 | 11.05 | 3.05 |
| Switch All Conv. Coal | 601.1 | 0.373 | 10.27 | 3.65 | 11.05 | 3.12 |
| Retire & Sw. Exist | 601.4 | 0.373 | 9.54 | 3.49 | 10.73 | 3.06 |
| Retire, FGD & Sw. All | 603.9 | 0.375 | 8.68 | 2.74 | 10.72 | 3.14 |
| | (NPV¥B) | (¥/kWh) | (Mt) | (Mt) | (Mt) | (Gt) |
| *Percent Change from Ref. - No Retirements, Retrofits or Cleaner Coals* | | | | | | |
| Retire Select | 0.1 | 0.2 | (11.9) | (19.5) | (2.9) | 0.3 |
| FGD Retrofit Some | 0.3 | 0.3 | (4.9) | 0.4 | (0.1) | 0.2 |
| Switch Existing | (0.1) | (0.1) | (12.5) | (7.2) | 0.0 | 1.6 |
| Switch All Conv. Coal | 0.0 | 0.0 | (16.8) | (22.2) | 0.0 | 3.9 |
| Retire & Sw. Exist | 0.1 | 0.1 | (22.7) | (25.6) | (2.9) | 1.7 |
| Retire, FGD & Sw. All | 0.5 | 0.5 | (29.7) | (41.7) | (3.0) | 4.4 |
| *(Future = FIB)* | (Δ%) | (Δ%) | (Δ%) | (Δ%) | (Δ%) | (Δ%) |

Figure 6.27 shows the year to year performance of the existing generation options. As can be seen overall installed capacity and direct costs are essentially the same, as are

NOx and CO2 emissions. Early reduction in SO2 and PM10 come from switching to prepared coal. Whether such a degree of fuel switching could actually occur needs to be explored. The switch and retire combinations achieve the largest reductions, and are roughly half the year 2000's SO2 and PM10 emissions.

Figure 6.27: Annual Performance of Existing Generation Options

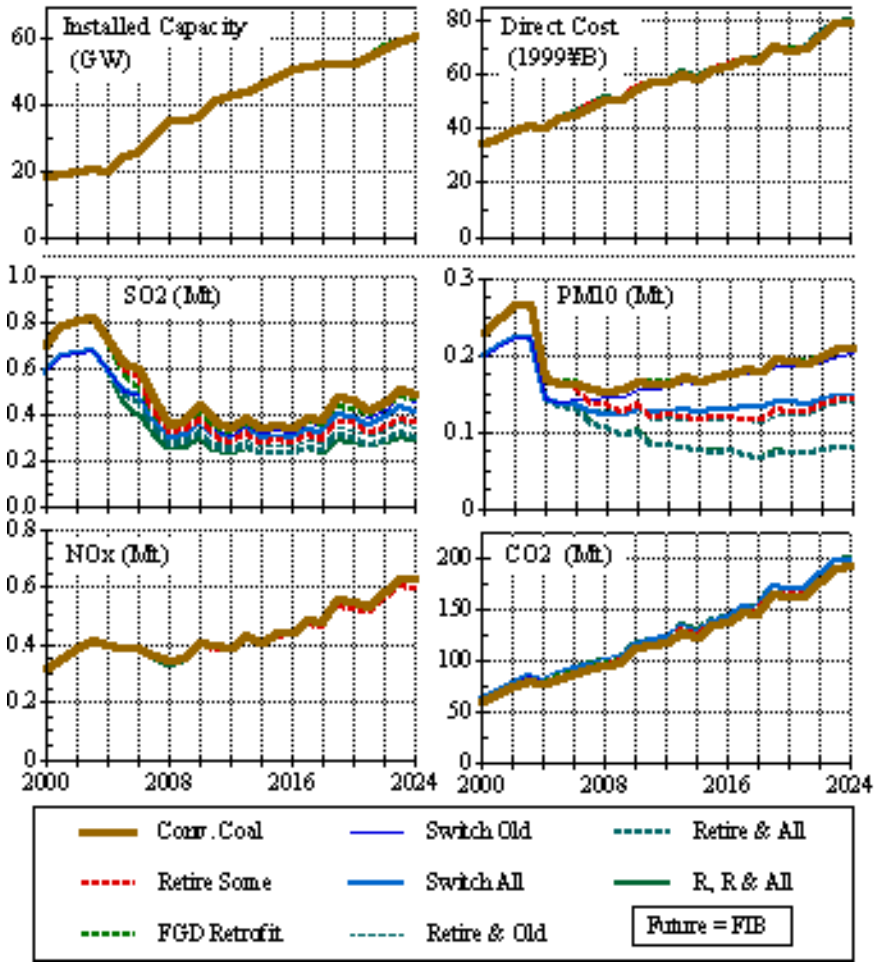
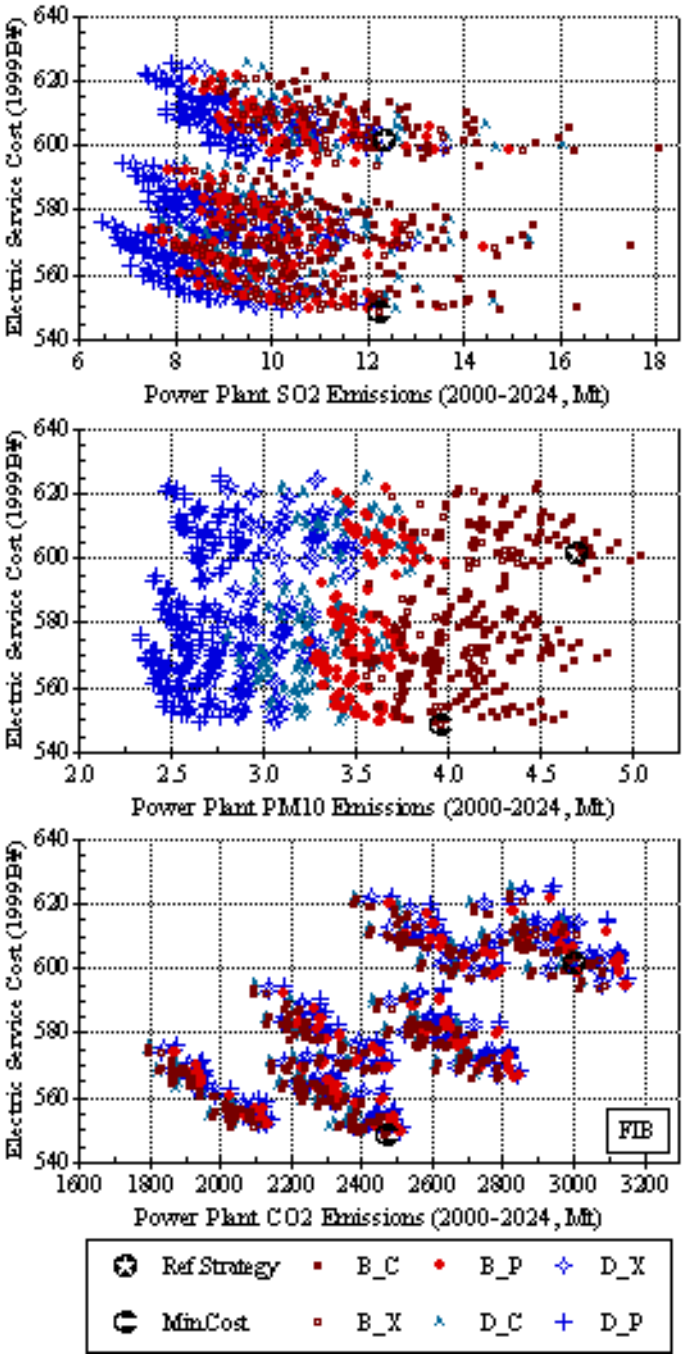



Figure 6.28 shows the performance of these options along with all the other choices. Strategies are grouped by their combination of retirement (B, D) and switching (C, X, P) options. The impact this has on SO2, and especially PM10 emissions is readily apparent.

Figure 6.28: Comparative Performance of FIB Strategies
Keyed by Existing Generation Options



Demand-Side Options

To look at the avoided costs and emissions of alternate types and levels of demand-side management, the electric sector strategies included 10% (M, Moderate) and 20% (G, Aggressive) reductions in total electricity demand, compared with current efficiency standards (S) option. These reductions were phased in over time, and contributed to reductions in peak load as well. In addition to end-use efficiency programs, the impact of peak load reductions were also analyzed (P–No Peak Management, L-Load Management). Table 6.16 shows the impacts of these end-use efficiency options working alone and together with peak load management.

Again the dynamic among electricity demand, and old and new generation is apparent. The peak load management option, where peak load grows at the same rate as annual electricity demand, avoids the need for new power plants, but not the need for additional generation. While this saves considerable cost, it means that there are fewer new generators to displace the hours of operation of the older dirtier units. Costs go down, but emissions go up. End-use efficiency in contrast achieves both reductions in costs and emissions. Enough generation is avoided such that the increased use of older generators still results in a net reduction in emissions.

Table 6.16: Cost and Emissions Performance of Demand-Side Options

| Demand-Side Options | *Electric Service Direct Costs* | | *Power Plant Stack Emissions* | | | |
|---|---|---|---|---|---|---|
| | Regional | Unit | SO2 | PM10 | NOx | CO2 |
| Reference | 601.0 | 0.373 | 12.34 | 4.69 | 11.05 | 3.01 |
| Peak Load Mgt. | 593.8 | 0.369 | 14.32 | 4.76 | 11.69 | 3.01 |
| Moderate Efficiency | 571.1 | 0.354 | 12.16 | 4.51 | 10.22 | 2.70 |
| Moderate & Load Mgt. | 565.9 | 0.351 | 14.71 | 4.62 | 11.04 | 2.71 |
| Aggressive Efficiency | 552.7 | 0.342 | 12.08 | 4.31 | 9.39 | 2.37 |
| Aggressive & Load Mgt. | 548.7 | 0.340 | 14.74 | 4.45 | 10.22 | 2.39 |
| | (NPV¥B) | (¥/kWh) | (Mt) | (Mt) | (Mt) | (Gt) |
| *Percent Change from Ref.- Current Eff. Standards and No Peak Load Mgt.* | | | | | | |
| Peak Load Mgt. | (1.2) | (1.2) | 16.1 | 1.4 | 5.8 | 0.3 |
| Moderate Efficiency | (5.0) | (5.1) | (1.4) | (3.8) | (7.5) | (10.2) |
| Moderate & Load Mgt. | (5.8) | (6.0) | 19.2 | (1.4) | (0.1) | (9.7) |
| Aggressive Efficiency | (8.0) | (8.2) | (2.1) | (8.0) | (15.0) | (21.0) |
| Aggressive & Load Mgt. | (8.7) | (8.9) | 19.5 | (5.0) | (7.5) | (20.5) |
| *(Future = FIB)* | (Δ%) | (Δ%) | (Δ%) | (Δ%) | (Δ%) | (Δ%) |

When both end-use efficiency and peak load management are pursued together, emissions still go down for all pollutants except sulfur dioxide. This is apparent when the annual changes in installed generation, costs and emissions are examined in Figure 6.29. Since both old and new conventional coal-fired generation have roughly equivalent conversion efficiencies and particulate controls, there is little divergence between end-use efficiency and peak load management programs' emissions. The difference between new and old generation–without flue gas desulfurization–however makes a large difference in annual SO2 emissions.

Figure 6.29: Annual Performance of Demand-Side Options

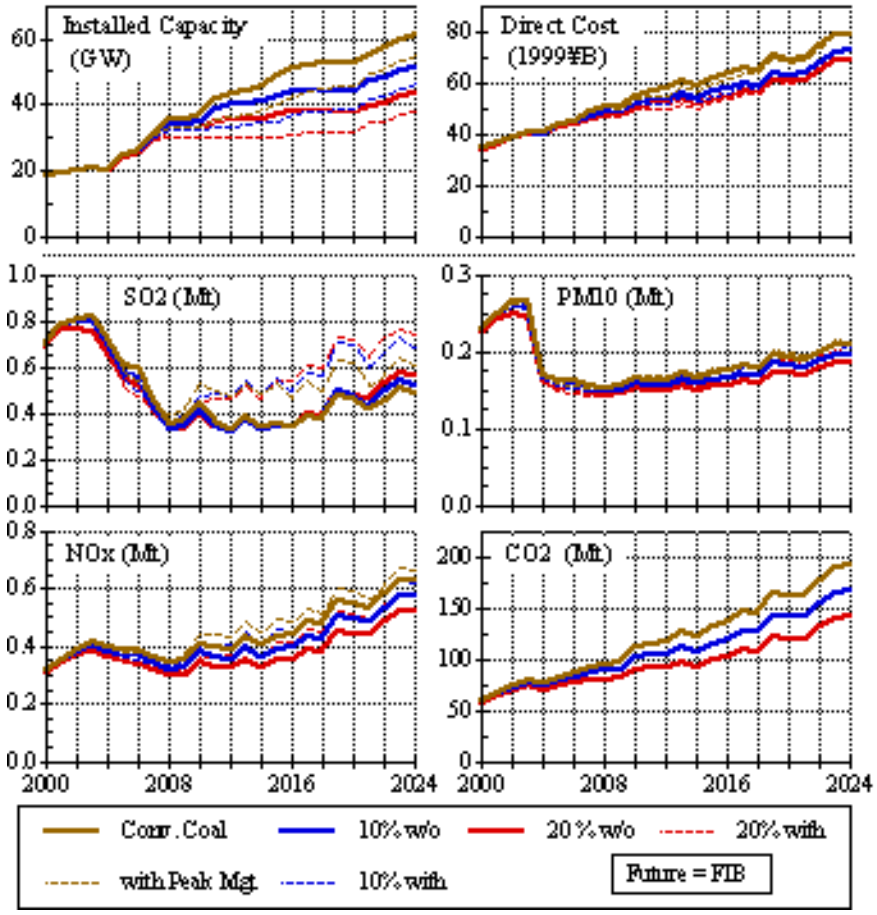
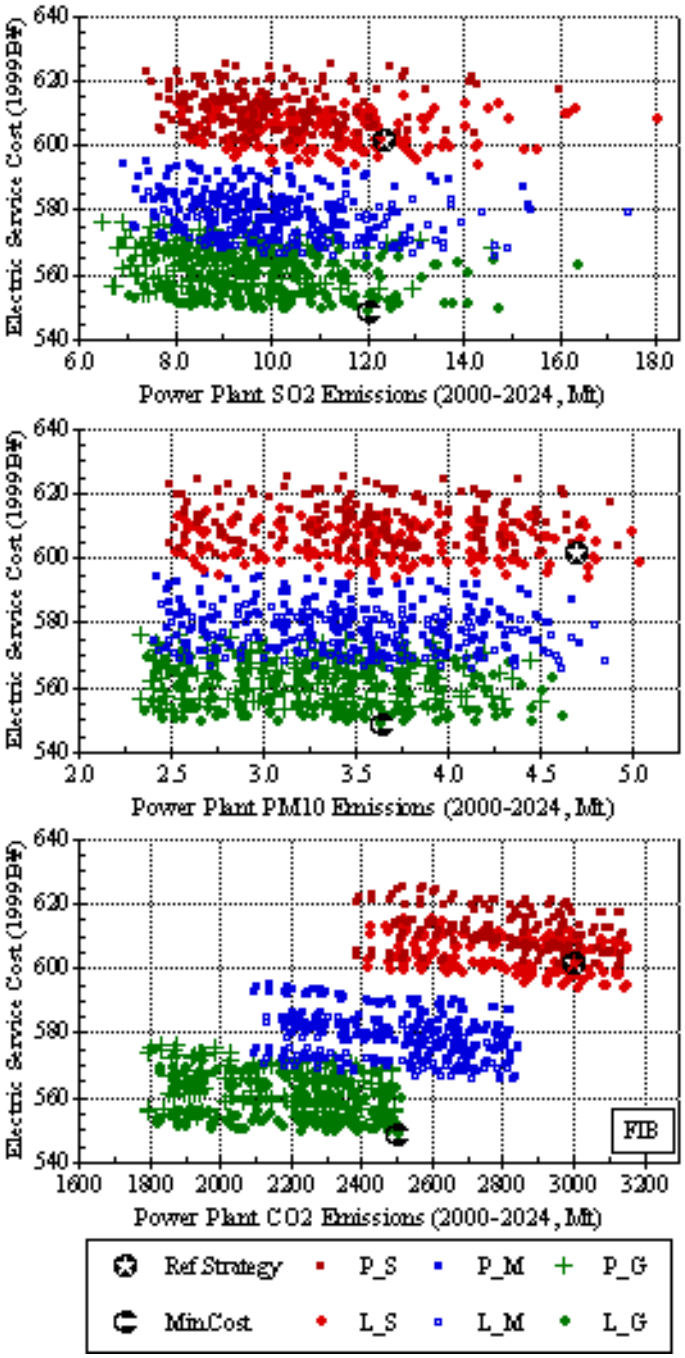



Figure 6.30 shows how the DSM options perform when all the other options are in force. Here we see dramatic reductions in costs and CO2 emissions, but like the choice of new generation technologies, only minor reductions in SO2 and particulate emissions. Like the 10% and 20% reductions in electricity demand, the costs of implementing DSM are to a large degree hypothetical, and need to be refined. However, a quick sensitivity analysis, where the cost of implementing end-use efficiency was doubled, made these strategies roughly the same cost as the no EUE strategies, but still with substantially lower PM10, NOx and CO2 emissions.

Figure 6.30: Comparative Performance of FIB Strategies
Keyed by Demand-Side Options



Integrated Supply and Demand-Side Strategies

As the above sections showed, phasing out or cleaning up older generation and the fuels it uses leads to large reductions in particulate and sulfur dioxide emissions. End-use efficiency and investment in higher efficiency and lower carbon generation technologies reduced carbon dioxide. End-use efficiency and peak load management were the lower cost strategies. How do these options perform in combination? Table 6.17 shows the performance of strategies that retire select units and units as they reach thirty-five years of operation (D), use of prepared coal in all coal fired generation (P), plus peak load management (L) and aggressive (20%) end-use efficiency programs (G). These "DPLG" strategies are shown for conventional coal, IGCC, nuclear, nuclear and natural gas, and nuclear, natural gas and IGCC new generation mixes. As can be seen, all offer substantial cost and emissions reductions, compared to the reference case.

Table 6.17: Cost and Emissions Performance of Integrated Strategies

| Integrated Demand-Side & Existing Unit Strategies | *Electric Service Direct Costs* | | *Power Plant Stack Emissions* | | | |
|---|---|---|---|---|---|---|
| | Regional | Unit | SO2 | PM10 | NOx | CO2 |
| Reference | 601.0 | 0.373 | 12.34 | 4.69 | 11.05 | 3.01 |
| with "DPLG" | 549.0 | 0.340 | 10.23 | 2.66 | 9.73 | 2.51 |
| plus IGCC-2012 | 551.0 | 0.341 | 9.41 | 2.56 | 8.96 | 2.42 |
| plus Nuclear-2010 | 552.5 | 0.342 | 8.66 | 2.51 | 8.19 | 2.12 |
| plus Nuclear & NGCC | 551.4 | 0.342 | 9.93 | 2.58 | 8.70 | 2.13 |
| plus Nuc., NGCC & IGCC | 554.0 | 0.343 | 8.32 | 2.46 | 7.74 | 2.06 |
| | (NPV¥B) | (¥/kWh) | (Mt) | (Mt) | (Mt) | (Gt) |
| *Percent Change from Reference - BOC-CONPAS* | | | | | | |
| with "DPLG" | (8.7) | (8.8) | (17.1) | (43.4) | (11.9) | (16.6) |
| plus IGCC-2012 | (8.3) | (8.5) | (23.8) | (45.4) | (18.9) | (19.3) |
| plus Nuclear-2010 | (8.1) | (8.2) | (29.8) | (46.6) | (25.8) | (29.4) |
| plus Nuclear & NGCC | (8.2) | (8.4) | (19.5) | (45.0) | (21.3) | (29.0) |
| plus Nuc., NGCC & IGCC | (7.8) | (8.0) | (32.6) | (47.6) | (29.9) | (31.3) |
| *(Future = FIB)* | (Δ%) | (Δ%) | (Δ%) | (Δ%) | (Δ%) | (Δ%) |

Figure 6.31 shows the annual performance of these six strategies. By bundling the best performing individual options from each of the new generation, old generation, and end-use classes of options, substantial and sustained reductions in all emissions are achieved. By concurrently promoting DSM and the renewal of the province's fleet of generators, the problem of aggressive DSM contributing to the increased use of old, dirty generators is avoided. If newer, cleaner generation technologies are selected in addition to this, then emissions are lower still.

Figure 6.31: Annual Performance of Integrated Strategies

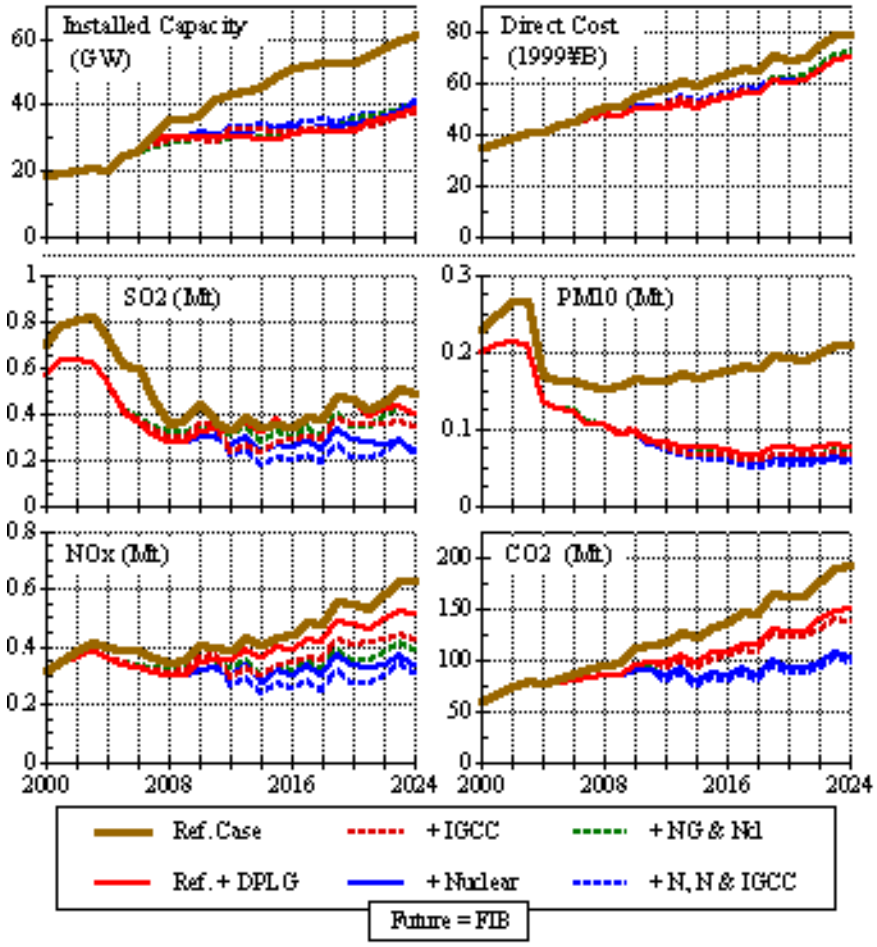
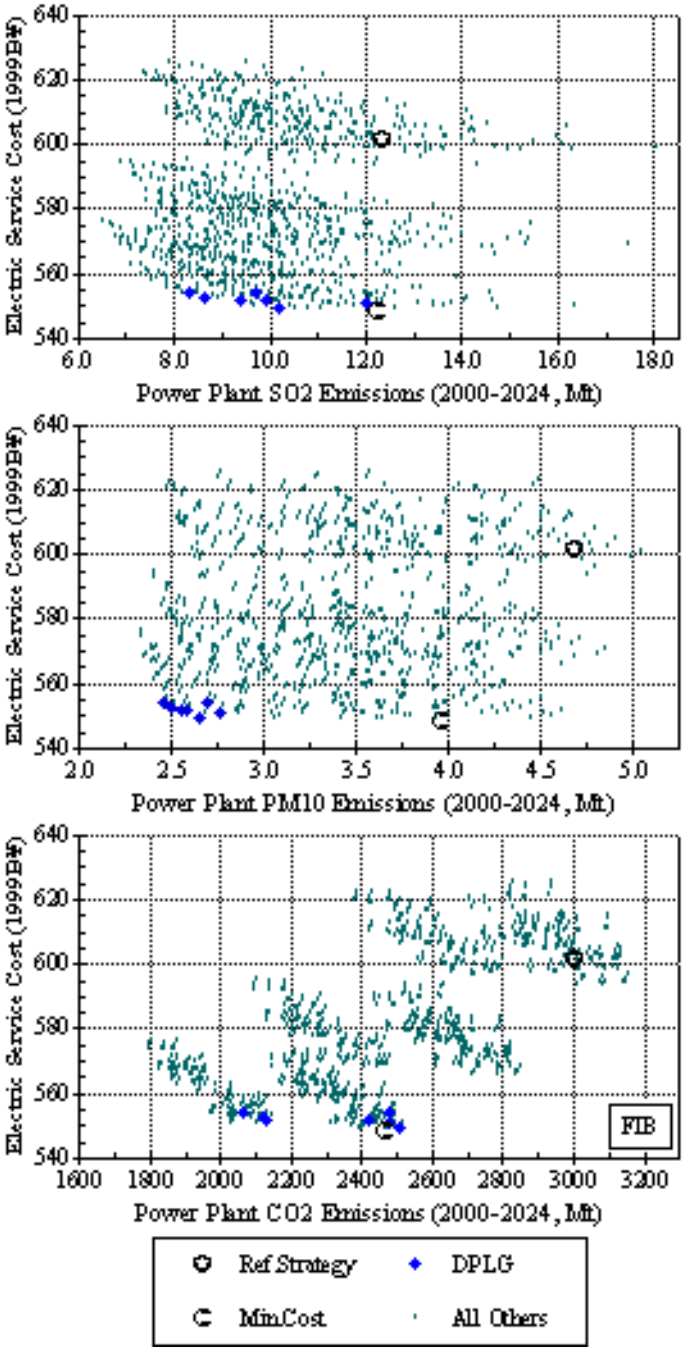



Figure 6.32 shows how seven of the twenty-eight "DPLG" strategies perform in comparison to the others. These seven include all of the new generation mixes, but not the gas-by-wire and FGD retrofit options. These are at or near the bend in the frontiers for all three cost-emissions tradeoff plots. Strategies with even lower sulfur emissions include a the FGD retrofit and No Peak Load management options. Lower CO2 strategies either do not use as much prepared coal, or retire as many old units.

Figure 6.32: Comparative Performance of Select FIB Strategies
Keyed by Strategies with Retirements, Prepared Coal,
Peak Load Management and Aggressive End-Use Efficiency



Selection of Strategies for Further Analysis

The current scope of the electric sector simulation task was to identify the direct cost and power plant emissions characteristics of a broad mix of options, combined into multi-option strategies. A subset of twelve of these strategies were then selected for further analysis in the life-cycle analysis (LCA), environmental impact assessment (EIA), and multi-criteria decision-aiding (MCDA) tasks. These "MCDA Strategies" are shown in Table 6.18. Rather than just selecting the reference case and the tradeoff frontier strategies, such as those just presented, a cross section of the scenario set was chosen. This was done to respect the uncertain feasibility and implementability of certain options, which includes not only their technology performance and cost, but timing. A cross section also helps decisionmakers determine the consequences of "half measure" strategies, where some but not all of the better options are implemented.

Table 6.18: The MCDA Strategies

| | MCDA Strategies | Retire More | Retrofit FGD | Prep. Coal | New Gen. | FGD on New | Peak Mgt | End-Use Eff. |
|---|---|---|---|---|---|---|---|---|
| (1) | BOC-CENPAS | – | - | - | C | **No** | *No* | – |
| (2) | BOC-CONPAS | - | - | - | C | Yes | *No* | – |
| (3) | BOX-CONPAM | - | - | Exist. | C | Yes | *No* | 10% |
| (4) | DOX-CONLAG | Yes | - | Exist. | C | Yes | Yes | 20% |
| (5) | BOX-LONLAM | - | - | Exist. | L | Yes | Yes | 10% |
| (6) | DOX-MONLAM | Yes | - | Exist. | M | Yes | Yes | 10% |
| (7) | BOC-NONLAS | - | - | - | N | Yes | Yes | 20% |
| (8) | BOX-NONLAM | - | - | Exist. | N | Yes | Yes | 10% |
| (9) | BOX-NONLAG | - | - | Exist. | N | Yes | Yes | 20% |
| (10) | DOX-TONLAG | Yes | - | Exist. | T | Yes | Yes | 20% |
| (11) | DUX-DONLAG | Yes | Yes | Exist. | D | Yes | Yes | 20% |
| (12) | DUX-TONPAS | Yes | Yes | Exist. | T | Yes | No | – |

The MCDA scenarios include the reference case (2) and also the same strategy without flue gas desulfurization (1) on new conventional coal-fired units. The remaining ten strategies reflect alternate combinations of options which clean up electricity supplies, reduce the demand for electricity, or both. The next strategy (3) builds upon the reference case, BOC-CONPAS, by using prepared coal in existing units only, and achieving a 10% reduction in electricity demand without a separate peak load management program. For the MCDA strategies, use of prepared coal was restricted to existing generators due to uncertainties regarding how large and fast coal preparation technologies could be deployed in the coal mining sector. Also, using prepared coal in existing units only makes these generators slightly more expensive to operate relative to new coal units, thereby achieving an additional shift in dispatch to newer, cleaner generators. The next strategy (4) adds retirement of old units, 20% end-use efficiency and peak load management. This strategy will be shown in detail below, and has been named "*Conventional Coal Plus*," for descriptive purposes, as it aggressively pursues cleaning up older generation and implementing DSM, but continues to rely upon conventional coal-fired technologies for the production of electric power. Then next two strategies (5, 6) pursue moderate EUE and PLM, but choose coal-gasification or natural

gas combined-cycle generation in addition to conventional coal. The strategy with natural gas combined cycle also retires old units to address the fact that natural gas units may be "underutilized" if natural gas costs remain high relative to coal costs. The next three strategies (7, 8, 9) look at coal plus nuclear with peak load management, and different combinations of fuel switching and end-use efficiency. Strategies 10 and 11 reflect full spectrum strategies, with retirements, fuel switching, 20% EUE and peak load management. Strategy 10 has nuclear, IGCC and natural gas generation. Below we refer to this strategy as the "*Modernization*" strategy. Strategy 11 has only nuclear and natural gas, but retrofits select existing generation with desulfurization equipment. The final MCDA strategy (12) focuses only on the supply side, with retirements, FGD retrofits, fuel switching as well as nuclear, IGCC and natural gas generation, but no end-use efficiency or peak load management. Below this is referred to as the *"Clean Supply"* strategy.

Table 6.19: Cost and Emissions Performance of the MCDA Strategies

| MCDA Strategy | *Electric Service Direct Costs* | | *Power Plant Stack Emissions* | | | |
|---|---|---|---|---|---|---|
| | Regional | Unit | SO2 | PM10 | NOx | CO2 |
| BOC-CENPAS | 578.5 | 0.359 | 26.59 | 4.66 | 10.89 | 2.95 |
| BOC-CONPAS | 601.0 | 0.373 | 12.34 | 4.69 | 11.05 | 3.01 |
| BOX-CONPAM | 570.7 | 0.354 | 10.54 | 4.16 | 10.22 | 2.75 |
| DOX-CONLAG | 548.6 | 0.340 | 10.54 | 3.06 | 9.73 | 2.47 |
| BOX-LONLAM | 568.1 | 0.352 | 11.40 | 3.90 | 10.14 | 2.68 |
| DOX-MONLAM | 569.6 | 0.353 | 12.93 | 3.23 | 11.18 | 2.77 |
| BOC-NONLAS | 597.0 | 0.371 | 12.83 | 4.50 | 10.32 | 2.65 |
| BOX-NONLAM | 568.4 | 0.352 | 10.85 | 3.93 | 9.55 | 2.41 |
| BOX-NONLAG | 552.6 | 0.342 | 10.22 | 3.72 | 8.52 | 2.08 |
| DOX-TONLAG | 553.7 | 0.343 | 8.53 | 2.73 | 7.74 | 2.03 |
| DUX-DONLAG | 552.7 | 0.343 | 9.25 | 2.88 | 8.70 | 2.12 |
| DUX-TONPAS | 610.7 | 0.379 | 8.16 | 2.94 | 8.75 | 2.57 |
| | (NPV¥B) | (¥/kWh) | (Mt) | (Mt) | (Mt) | (Gt) |
| *Percent Change from BOC-CONPAS* | | | | | | |
| BOC-CENPAS | (3.7) | (3.8) | 115.6 | (0.6) | (1.5) | (1.8) |
| BOX-CONPAM | (5.0) | (5.2) | (14.5) | (11.3) | (7.5) | (8.5) |
| DOX-CONLAG | (8.7) | (8.9) | (14.6) | (34.7) | (11.9) | (17.9) |
| BOX-LONLAM | (5.5) | (5.6) | (7.6) | (16.8) | (8.3) | (10.7) |
| DOX-MONLAM | (5.2) | (5.3) | 4.8 | (31.1) | 1.2 | (7.7) |
| BOC-NONLAS | (0.7) | (0.7) | 4.0 | (4.0) | (6.5) | (11.7) |
| BOX-NONLAM | (5.4) | (5.6) | (12.0) | (16.3) | (13.6) | (19.8) |
| BOX-NONLAG | (8.1) | (8.2) | (17.2) | (20.7) | (22.9) | (30.8) |
| DOX-TONLAG | (7.9) | (8.0) | (30.9) | (41.9) | (29.9) | (32.5) |
| DUX-DONLAG | (8.0) | (8.2) | (25.0) | (38.6) | (21.3) | (29.6) |
| DUX-TONPAS | 1.6 | 1.7 | (33.9) | (37.4) | (20.8) | (14.5) |
| *(Future = FIB)* | (Δ%) | (Δ%) | (Δ%) | (Δ%) | (Δ%) | (Δ%) |

Table 6.19 and Figure 6.33 show the costs and emissions for the twelve MCDA strategies for the FIB future. Highlighted are the reference strategy and the three "named" strategies mentioned above. Note that sulfur emissions of the no FGD version of reference case are well outside the plot area in Figure 6.33. While cumulative SO2 emissions of this strategy are more than double those of the reference case with FGD, the other emissions of the no FGD strategy are slightly lower. This is due to the dispatch effect, where new conventional coal units without FGD displace more older generation, since they are even less expensive to operate, as well as more efficient than new units with FGD.

Figure 6.34 shows the installed capacity, annual cost, SO2, PM10, NOx and CO2 emissions for the reference case (1, BOC-CONPAS), Clean Supply (12, DUX-TONPAS), Conventional Coal Plus (4, DOX-CONLAG), and Modernization (10, DOX-TONLAG) strategies. There are several fundamental dynamics illustrated by this figure. First is that growth in electricity production, here indicated by the installed capacity, is *not* a proxy for changes in pollutant emissions. While the two high DSM strategies (Conventional Coal Plus and Modernization) avoid significant investment in new generation, the Conventional Coal Plus strategy has SO2 and NOx emissions roughly equivalent with those of the reference case in later years. In contrast, the Clean Supply and Modernization strategies, by pursuing a future mix of generating technologies including nuclear, IGCC and NGCC, have the lowest SO2, PM10 and NOx emissions, even though the Clean Supply strategy has no DSM. It is only the Modernization strategy, by including options for old dirty generation, new cleaner generation technologies, *and* the growth in electricity demand, that achieves superior performance for costs and *all* emissions.

Figure 6.33: Comparative Performance of the MCDA Strategies for the FIB Future

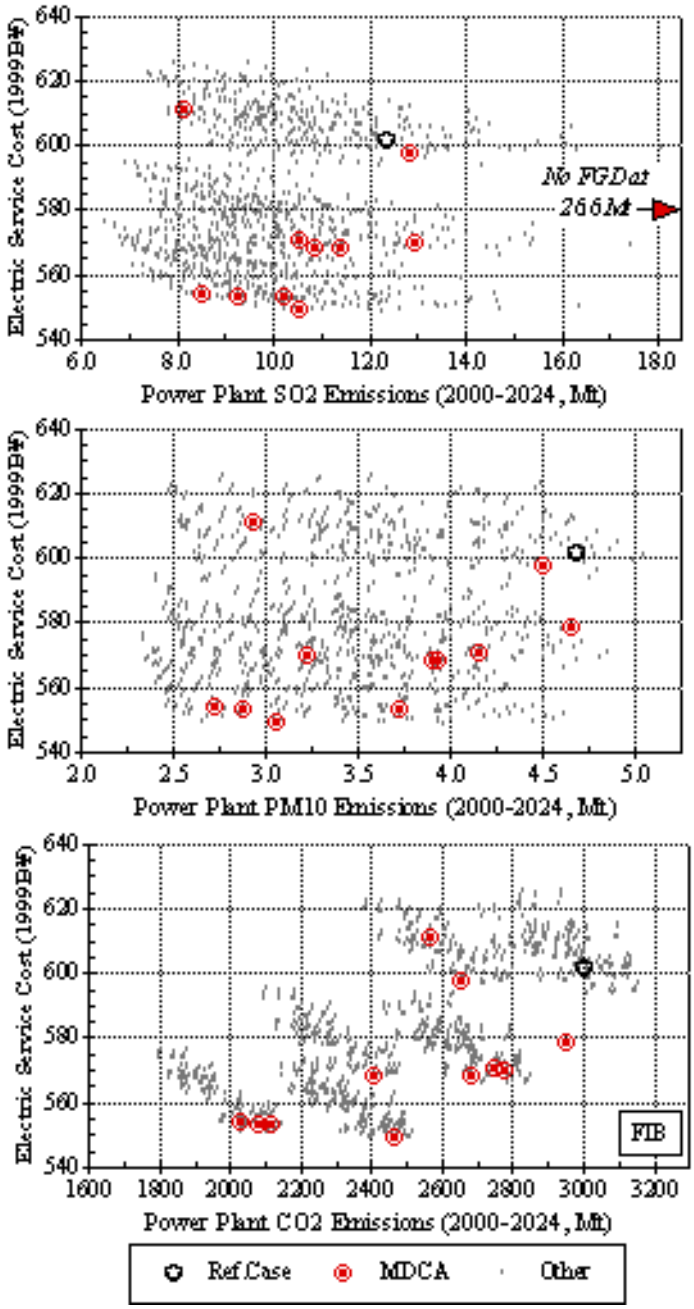
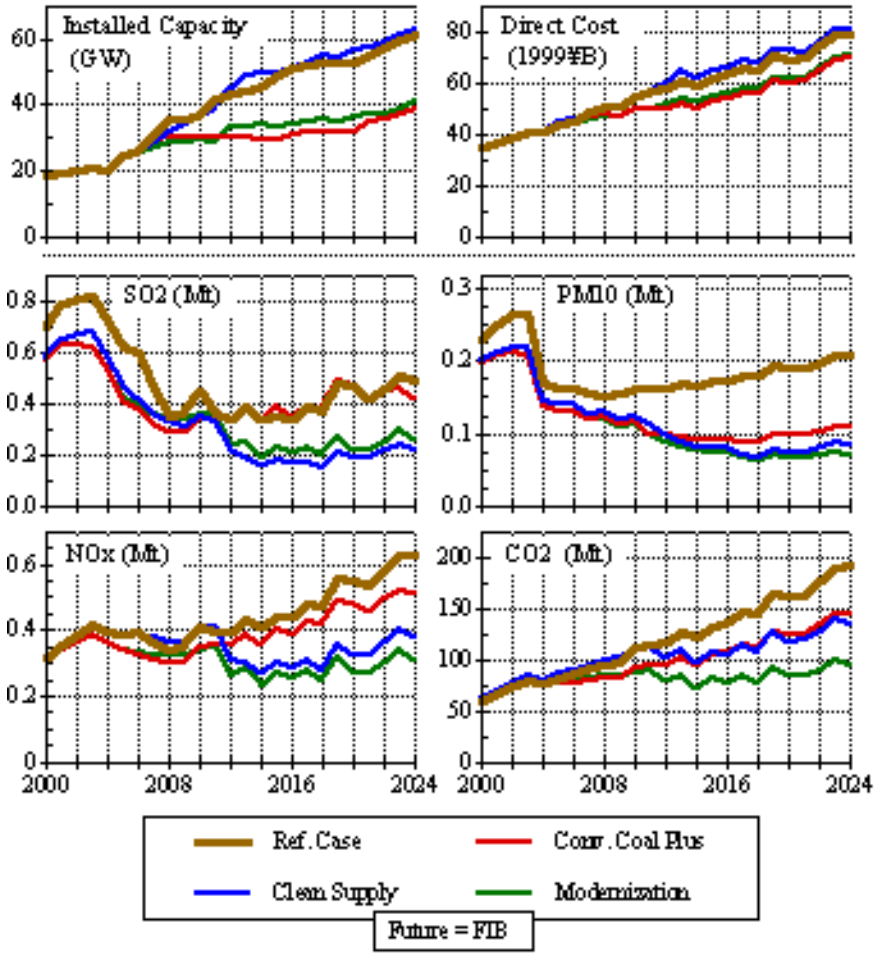


Figure 6.34: Annual Performance of Select MCDA Strategies




To better understand the dynamics behind these trends Figures 6.35 and 6.36 show capacity additions, utilization, and costs for the same four strategies. Figures 6.37 and 6.38 do the same for power plant emissions. Here the dispatch effect is clearly evident. In the Reference Case and Clean Supply strategies, new generation displaces nearly all of the generation from older units. In the Conventional Coal Plus and Modernization strategies, while total generation is substantially lower, much more of it comes from older units, even after many of the dirtier ones have been retired. This is especially true for the Conventional Coal Plus strategy. Expect for SO2 emissions, even in this case, there is enough a reduction in all generation to offset the increased emissions from the older units. Of the four, only the Modernization strategy sustains the reductions of all four emissions.

Figure 6.35: Generation Expansion, Utilization and Electric Sector Costs for the Reference Case and Clean Supply Strategies

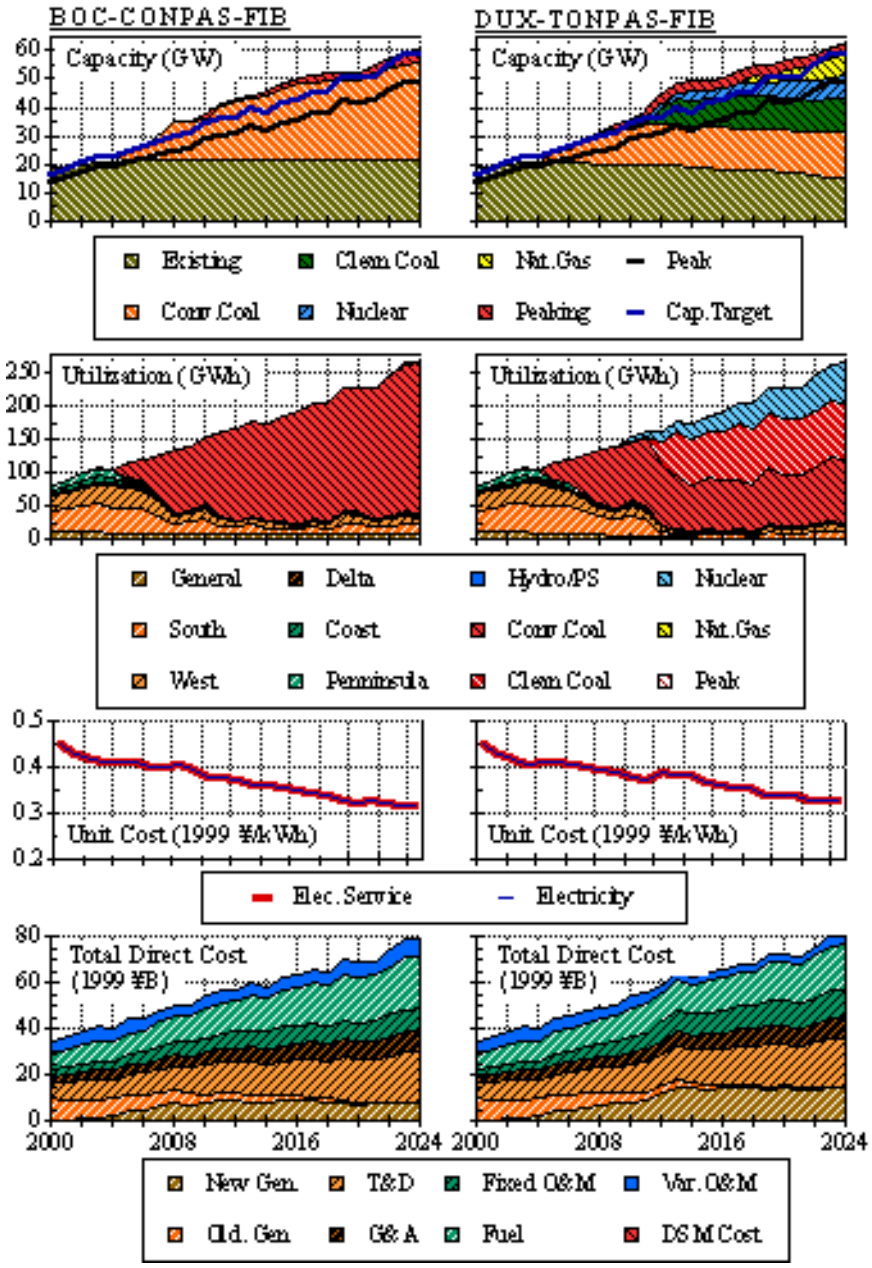


Figure 6.36: Generation Expansion, Utilization and Electric Sector Costs for the Conventional Coal Plus and Modernization Strategies

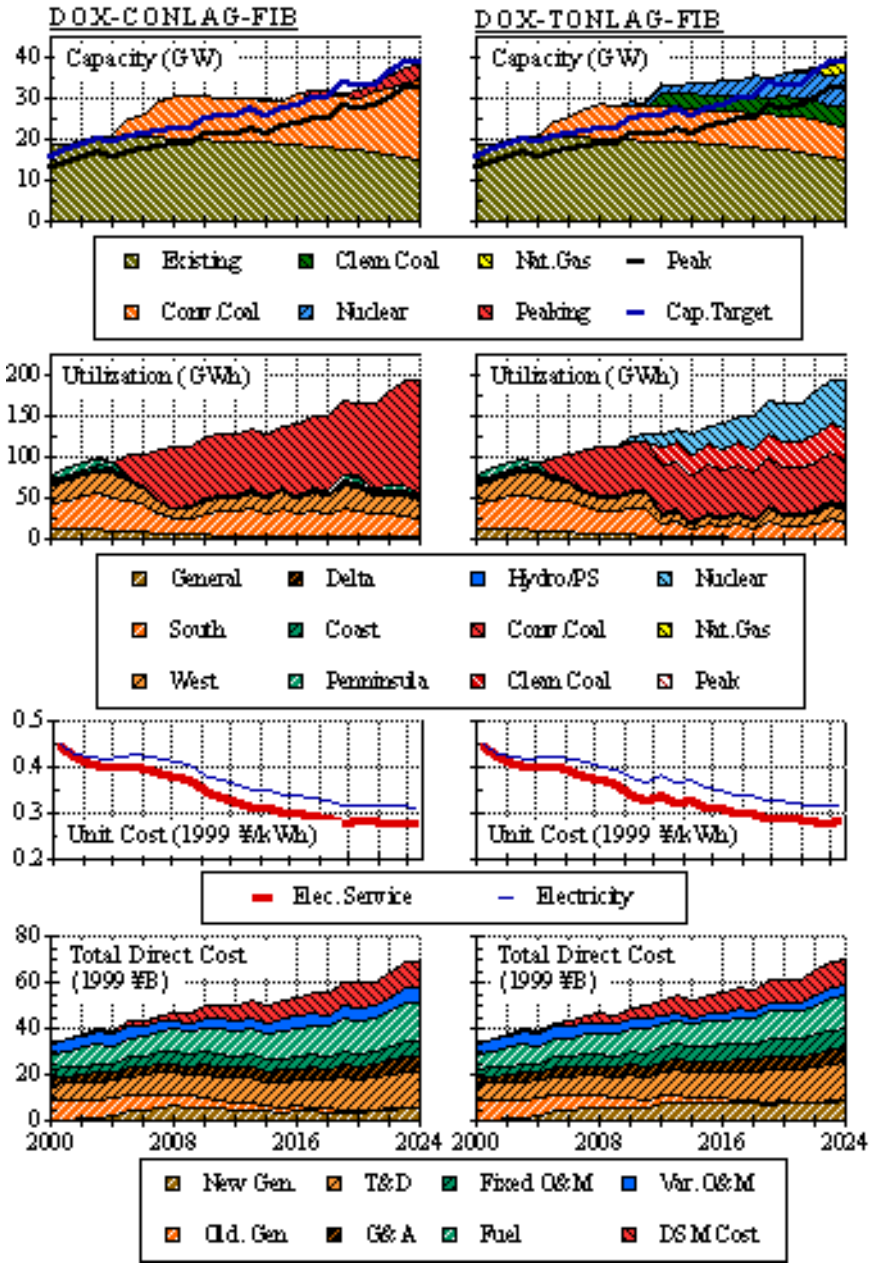
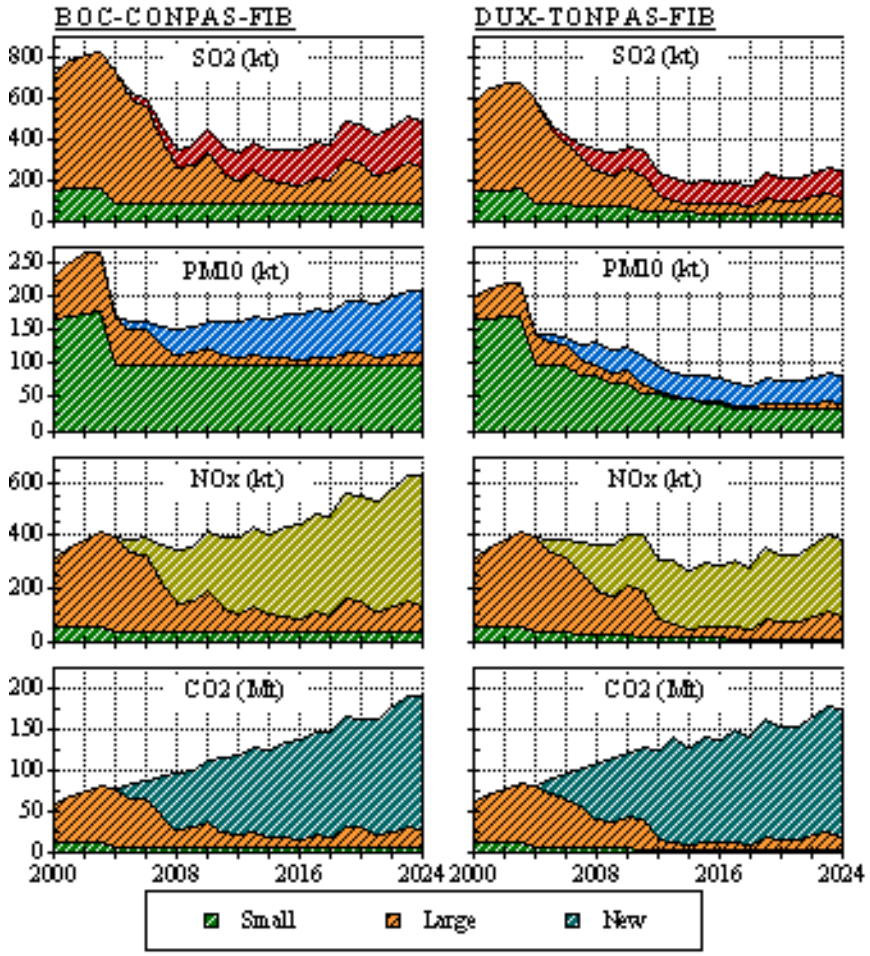
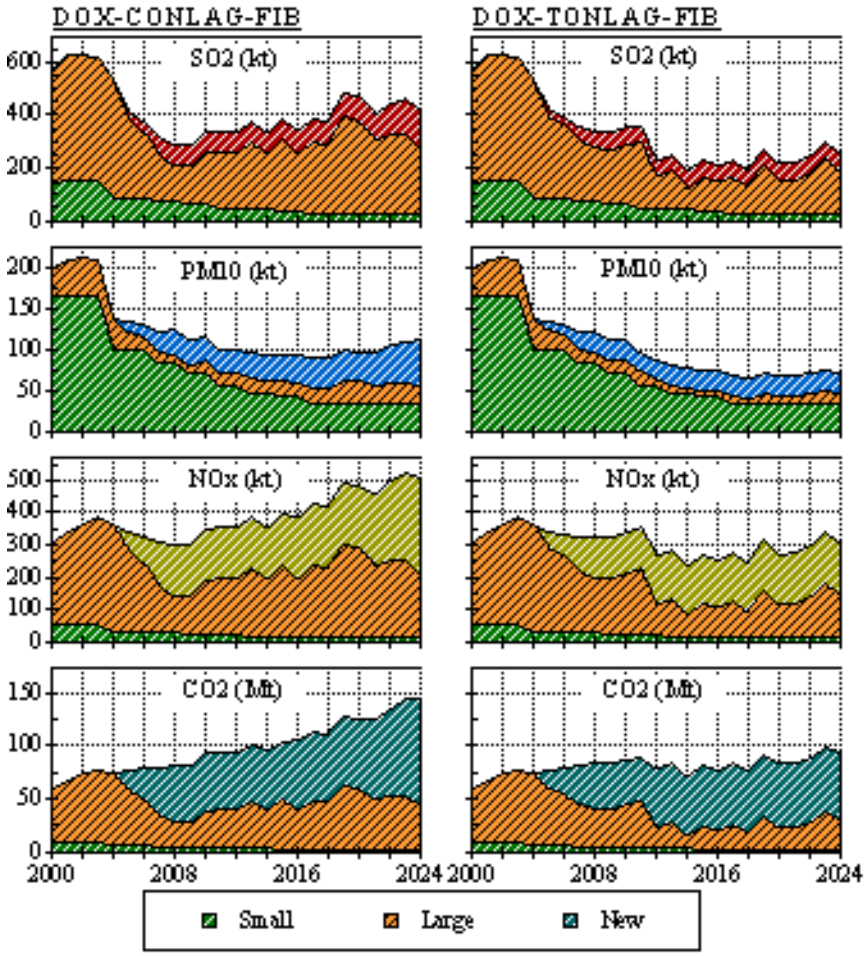


Figure 6.37: Annual Pollutant Emissions by Size and Vintage of Generation for the Reference Case and Clean Supply Strategies



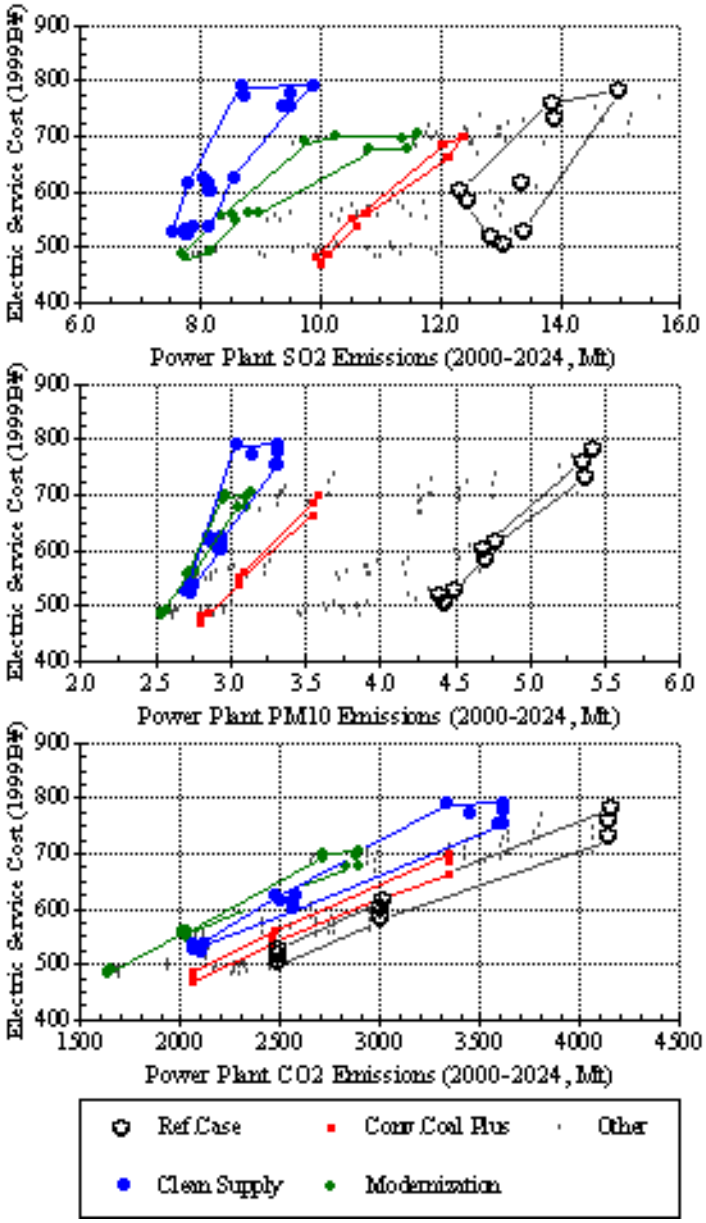

How robust are these strategies? Figure 6.39 shows the twelve MCDA strategies plotted for all eighteen futures. Highlighted are the four named strategies shown in detail above. The lines circumscribe the "performance envelope" of these strategies across the different load growths and fuel costs, and give us a sense of how their costs and emissions change across with changes in electricity demand and fuel costs.

Figure 6.38: Annual Pollutant Emissions by Size and Vintage of Generation for the Conventional Coal Plus and Modernization Strategies



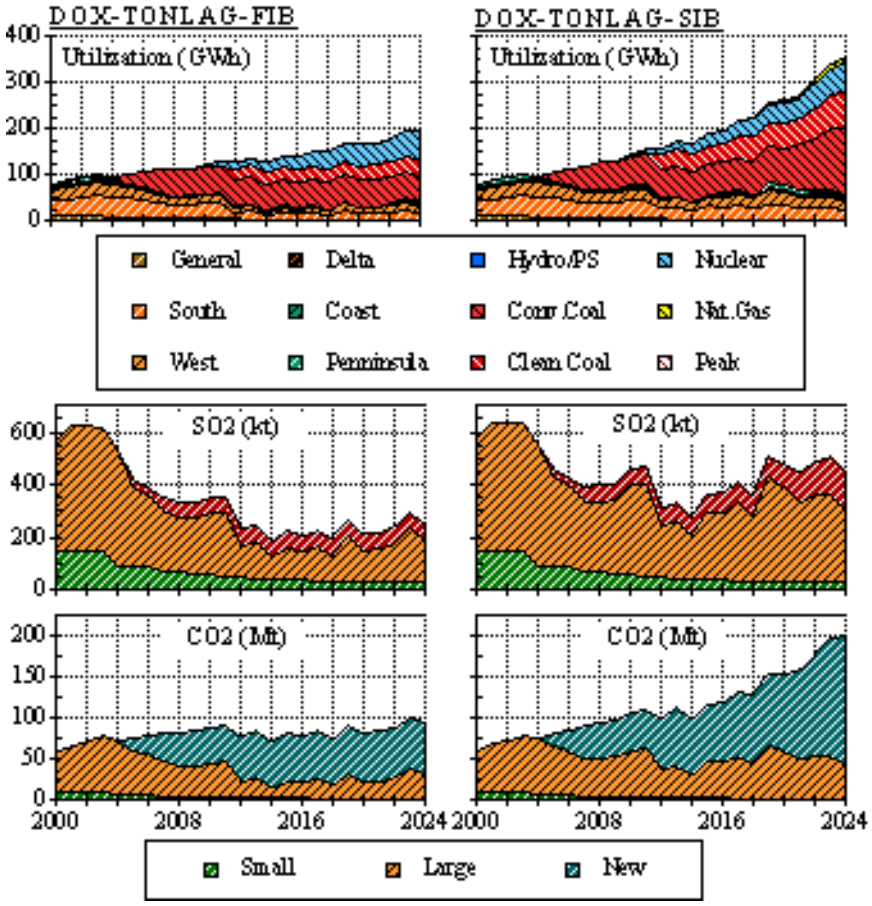

Several things are apparent from Figure 6.39. First is that the high DSM Conventional Coal Plus and Modernization strategies' costs are less sensitive to an increase in electricity demand. This is due, in part, to the fact that the 20% reductions in electricity demand from efficiency programs "scale up" as electricity demand increases. This is in no way a problem. In fact, it may be argued that rapidly rising demand for electric service provides greater opportunities for the deployment of more efficient electrical appliances, since the increased affluence, and therefore purchasing power, may increase the turnover of refrigerators, lamps and air conditioners.

Figure 6.39: Select MCDA Strategy Performance Across All Futures




Also in Figure 6.39, we see that the Modernization strategy's SO2 emissions increase more than the other strategies'. There are two reasons for this. First is that the nuclear option is fixed at eight 1000 MW power plants whether load grows fast or not. This means that the emissions displacement potential of the nuclear option, as it was modeled, does not scale with the increase in demand. Second is that if load grows faster than new capacity additions, then older generation will be used more. Figure 6.40 shows these impacts on capacity utilization, SO2 and CO2 emissions for the Modernization strategy under moderate and strong electricity demand growth.

Figure 6.40: Performance of the Modernization Strategy Under Moderate and Strong Load Growth Uncertainties




## Extending the Range of Options

Even though a broad range of options were incorporated into the full scenario set run by Electric Sector Simulation analysis team, from a sustainable energy viewpoint, there are some omissions. Most noticeable is that of renewable energy sources. As mentioned early in the chapter, hydropower potential in the province is severely limited. Although one of China's major rivers, the Yellow River, flows through the province, it cannot be considered a possible source of hydropower. Not only is the topography rather flat as the Yellow River approaches its delta, but upstream utilization of the water often prevents it from reaching the Bo Hai Sea at all. In 1997, the lower reaches of the Yellow River ran dry for a 226 days. (Kirby, 1999) Since the first time the Yellow River ran dry in 1972, the event has reoccurred roughly four out of every five years. (Liu, 2001) The demand for what water resources there are is intense, whether for irrigation, industry, power production or petroleum refining. (Singer, 1998) Even now, officials are still considering additional diversions of river water to some of Shandong's population centers (Qingdao, Yantai, Weihai) far away from the river. (China Daily, 2002) It was

with this knowledge in mind that the Electric Sector Simulation team placed such an emphasis differentiating new inland and coastal generators.

Other prospective renewable resources are wind and sun. These options were not included in the Electric Sector Simulation's scenario set since adequate resource data was not available. The cost and quantity of generation from renewable technologies is directly attributable to the size and dynamics of the renewable resource (McGowan and Connors, 2000).

Dong et. al. suggest that substantial wind resources may be present in Shandong. (1998). At the end of 2000 there was roughly five and a half megawatts of wind generating capacity installed in the province, primarily on the northeast coast including islands. The Chinese government is actively pursing this option, with both small and large wind turbine technologies, and is considering numerous mechanisms for providing incentives–including wind resource concessions–to those wishing to develop wind farms. (Raufer and Yang, 2002)

Even so, the location, quantity, and seasonal and daily distribution of wind needs to be known in order to estimate whether wind farms along Shandong's mountains and coasts can displace both the investment in, and the use of, fossil generation, either old and new. Several dozen additional scenarios were run looking at three levels of windpower deployment. 1500 MW of onshore wind was analyzed, phased in from 2005 to 2019, as was 3000 MW of offshore wind, deployed from 2010 through 2019, and then the two together. Onshore windpower was given a 25% capacity factor, while offshore wind was assumed to have a 35% capacity factor. (Hansen, 2002) Both represent fair wind regimes given current technology costs.

The performance is these strategies are reported in Hansen. (2002) In general they perform like the DSM strategies above. As a non-dispatchable resource, conventional generation sees the impact of wind and other uncontrollable generation resources as a reduction in demand that power system operators normally use dispatchable generation to meet. As such, the amount of emissions reduction is scaled to amount of non-dispatchable generation deployed. Whether this generation avoids the need for new dispatchable generation, or displaces the operation of old versus new controllable generation, can only be determined with a solid understanding of not only the renewable resource, but how it matches the demand for electricity as well. The historical hourly demand for 1998 through 2000, shown earlier in Figure 6.10, suggests that Shandong's electricity demand has strong late day and summertime peaks. This shows promise for both wind and solar, but only a detailed study of these renewable resources can show for sure whether they are both well timed, and exist in sufficient enough quantities, in order to have a large potential impact. Both wind and solar technologies are progressing rapidly on both a cost and performance basis, especially offshore wind. Both should be considered for a future detailed study.

Also examined as additional technological sensitivities were waste-to-energy and advanced nuclear technologies. A long standing issue, when looking at energy from municipal solid waste in developing and emerging economies is its energy content. Such waste in developing countries is often high in inorganic materials, making it a poor fuel. Food wastes are also poor energy candidates for conventional "mass burn" waste-to-

energy technologies, due primarily to their moisture content. Hansen, therefore looked at performance of strategies including methane production from bio-reactor type landfills. Again, the contribution to emissions reduction on a provincial level is a function of how much of the waste "resource" there is that can used to generate fuel for power production. As an alternative to the 1000 MW advanced light water reactors included in the scenarios above, modular high temperature gas reactors were also examined. These HTGR, or pebble-bed, reactors are still under development, but if successfully commercialized have numerous advantages in cost, modularity (113 MW), ease of deployment, and the utilization of uranium fuels. These also are discussed in Hansen (2002).

## Encompassing Greater Uncertainties

One of the reasons Shandong Province was selected for study is that the province and its electric grid are geographically and institutionally the same, making interactions with stakeholders, the search for pertinent information, and its incorporation into a coherent study, that much easier. As power exchanges with neighboring provinces have historically been small, it also makes setting the "boundary" of the study far easier.

However, China is currently in the process of reforming its electric sector. One of the largest changes that power sector reform is expected to bring is that of regionalizing the country's power grids, and separating generation–ownership-wise–from transmission and distribution, and inviting more investment by independent power producers. (Hillis, 2002.) Also anticipated is a consolidation of existing state owned generation companies, including SEPCO. (China Business, 2002)

In addition to policies directly affecting the structure of the electric sector are changes in the fuel sector and the economy in general. The strategies examined here assumed unconstrained access to new, advanced technologies, including the fuels they consume, and that these will be available at reasonable cost, including financing. With China's recent admission to the World Trade Organization (WTO), these seem reasonable assumptions. However WTO ascension also raises issues regarding the degree of subsidization–especially borrowing rates–that China may make in certain sectors, increased scrutiny in licensing and the use of intellectual property, as well as greater harmonization of rules and regulations, including accounting and environmental performance. Barker (2001) explored several of these topics using the ESS scenarios as a baseline, and the results indicate that these may influence the cost and choice of technologies in different ways. Government policies regarding other infrastructure investments, fuel and water supplies for example, all suggest that there are a broad range of uncertainties that need to be considered as both Shandong and China examine their long-term electric power choices.

## Electric Sector Simulation Conclusions

This analysis shows that Shandong Province has numerous opportunities to simultaneously meet its future electricity needs, and substantially reduce both criteria pollutants and greenhouse gas emissions (CO2). However, in order to achieve these combined goals, it must embark on a strategy which targets the emissions from older, dirtier power plants, and balances this with a well coordinated effort which manages the

growth in electricity demand, and introduces new generation technologies. Furthermore, Shandong may be able to implement such a coordinated strategy at equivalent or even lower direct costs than other alternatives. While the future costs of generation, fuels and DSM are quite uncertain, the general trends in relative costs should hold true.

Specifically, the feasibility of providing lower-ash, lower-sulfur prepared coals should be explored in earnest. This not only lowers the pollution from coal combustion, but extends the capabilities of the coal transportation infrastructure by having more fuel energy transported per tonne of coal shipped. Lower ash coal also improves the performance of conventional power plants by reducing the slagging of boilers, thereby extending the period between scheduled maintenance and increasing unit availability.

The select retirement or retrofitting of smaller, dirtier, older generation should also be considered. Historical emissions data show that there are some units that emit very high levels of SO2 and particulates, even though they only see limited use on an annual basis. Older generation units are usually quite small (≈ 100 MW), compared with the much larger ones (300 – 1000 MW) being built today. Given the continued rapid expansion of power generation in the province, the "extra" investment required to replace these units does not appear provide any significant cost pressure to providing the people of Shandong with electric service.

While continued use of pulverized coal, but with flue gas desulfurization, looks cost-effective, the development of newer, higher efficiency, lower emissions technologies and fuel supplies looks like a solid long-term option. China is gaining considerable experience in the area of nuclear. Greater expertise in the development, deployment and integration of other technologies such as clean coal–especially IGCC, natural gas combined-cycle, and windpower should also be pursued. What contribution niche technologies such as waste-to-energy, cogeneration, biomass and solar may make should also be explored.

Finally, great attention should be paid to the demand side. While "moderate" growth of 5% per year in electricity demand is much smaller than what the province has experienced over the past quarter-century, it will still result in electricity demand tripling over the next twenty-five years. With growing urban populations, and individual purchasing power, growth in peak electricity demand may be even larger. Opportunities for using electricity more wisely need to be identified, and policies ensuring their timely deployment implemented.

The above scenarios, formulated in conjunction with the CETP's Stakeholder Advisory Group, indicate that the greatest benefit to the province will come when all three elements of these robust strategies; managing old generation and the fuels it uses; promoting the efficient use of electricity; and encouraging investment in advanced generation technologies, are deployed in concert.

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