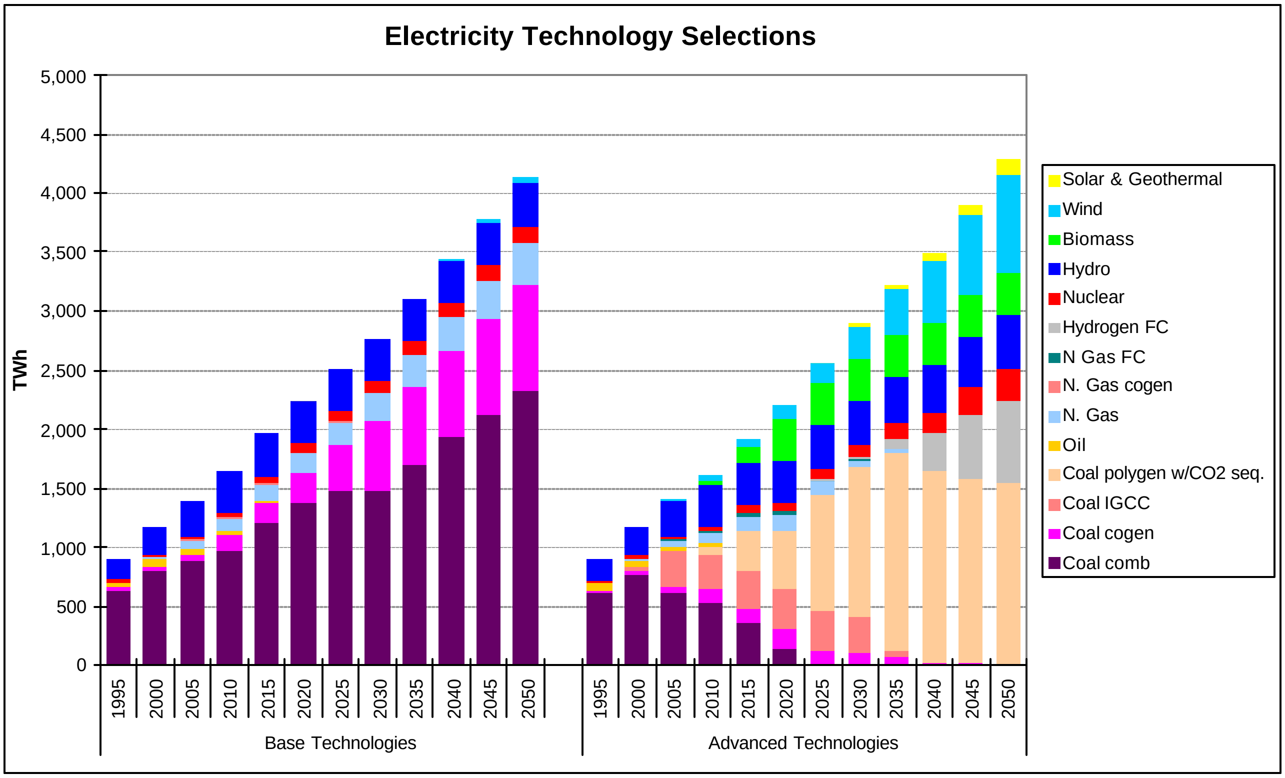
Future Implications of China's Energy-Technology Choices



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Cover Figure Note

The figure on the cover page (based on work reported here) depicts a mix of electricity generation technologies in China for a future that follows a "business-as-usual" approach (on the left) and one that stresses clean and renewable energy technologies and efficiency (on the right).

Abstract

This report summarizes results of an assessment of future energy-technology strategies for China built on analytical work carried out during the past several years by the Working Group on Energy Strategies and Technologies (WGEST) of the China Council for International Cooperation on Environment and Development (CCICED). The assessment identifies and highlights key implications of different advanced-energy technology strategies that could allow China to continue its social and economic development while ensuring national energy-supply security and promoting environmental sustainability. The MARKAL energy-system modeling tool was used to build a simplified model representing China's energy system. Different scenarios for the evolution of energy supply and demand in China from 1995 to 2050 were explored with the model, enabling insights to be gained into different energy development choices that China might make. The overall conclusion from the analysis is that there are plausible energy-technology strategies that would enable China to continue social and economic development through at least the next 50 years while ensuring security of energy supply and improved local and global environmental quality. Remarkably, except for the case when very major reductions in carbon emissions are sought, the model predicts that such energy strategies would not involve significantly higher cumulative (1995-2050) discounted costs for the energy system than "business-as-usual" strategies. Furthermore, "business-as-usual" strategies, which were also modeled, will not enable China to meet all of its environmental and energy security goals. To meet these goals, an energy development strategy that relies on the introduction of advanced technologies is essential. To realize such strategies, policies are needed in China that will *i)* encourage utilization of a wider variety of primary energy sources (especially biomass and wind) and clean secondary energy carriers (especially synthetic fluid fuels from coal and biomass), *ii)* support the development, demonstration and commercialization of radically new clean energy conversion technologies to ensure that they are commercially available beginning in the next 10 to 20 years, and *iii)* support aggressive end-use energy efficiency improvement measures.

1 Introduction

This report summarizes results of an integrated assessment of future energy-technology strategies for China. The assessment builds on ideas and analyses generated by the Working Group on Energy Strategies and Technologies (WGEST) of the China Council for International Cooperation on Environment and Development (CCICED). Over the past nine years WGEST has investigated many advanced technologies with potential long-term strategic significance to China. This assessment is intended as only an initial effort to provide an integrated, comprehensive look at the potential of these advanced technologies and to identify and highlight the key implications of different energy-technology strategies that could allow China to continue social and economic development of both urban and rural sectors while ensuring national energy-supply security and promoting environmental sustainability. The time horizon for this assessment extends from 1995 to 2050.

In 1995, total commercial energy consumption in China was 38.4 EJ, or 1,312 million tonnes of standard coal equivalent (Mtce),[1] of which coal accounted for 74.6%, oil 17.5%, hydroelectricity 6.1%, and natural gas 1.8%.[2] The sector-wise breakdown of energy consumption is characteristic of a country at a relatively early stage of economic development, with industry accounting for about 75% of consumption, the residential sector accounting for 12%, and transport and agriculture each accounting for about 4%.

For future development of its energy system, China faces several major challenges. Coal is China's largest fossil fuel resource, and it likely will continue to be the dominant fossil fuel used in the future. However, coal use today already contributes to very serious air pollution that exacts a high toll on human health. Respiratory illness is the 4th most common cause of death in urban areas of China, where it accounted for 14% of all urban deaths in 1998. In rural areas, where cooking is done largely by direct combustion of coal or biomass, respiratory illness represents the single most common cause of deaths, accounting for 25% of all rural deaths. While correlating air pollution with the cost of illness and death involves large uncertainties, the efforts that have been made to develop such correlations suggest that costs in China are high. The World Bank[3] has estimated that the air-pollution related health cost to China in 1995 was $48 billion (7% of GDP), with 2/3 of this attributed to urban areas. The Bank projects the cost of urban air pollution will rise to $390 billion (13% of GDP) by 2020 under "business-as-usual" energy development.

Aside from energy-related air pollution, China also has concerns that its domestic energy production capability will be insufficient to meet projected energy demands for 2050 and beyond under "business-as-usual" development of the energy sector.[4,5] Even with such growth in total energy use, per-capita energy use in China in 2050 would still be far below present-day US and European levels. Thus, China's need for energy is likely to continue to grow significantly even after 2050.

China has particular concerns over increasing oil imports, which are rising rapidly in step with the growth of its transport sector. In 2000, oil imports accounted for 30% of oil consumption, a sharp increase from less than 10% in 1995. Domestic natural gas resources are also limited, with the most optimistic estimate that gas would be able to provide 10% of total primary energy supply in 2030,[6,7] up from 2% today.

Ensuring energy supply security and reducing energy-related air pollution are high priorities for China, but growing emissions of carbon dioxide are also of some concern. In 1995, China emitted slightly more than half as much CO_2 to the atmosphere as the world's leading emitter, the United States, although on a per-capita basis, Chinese emissions were one-eighth of those from the U.S. With "business-as-usual" growth of the energy system in China, carbon emissions are projected to rise to over 20% of global fossil-fuel-related emissions in 2020 and surpass the United States as the highest carbon-emitting country on an absolute basis. However, China's per-capita carbon emissions would then still be only one-quarter of the U.S. level.[8]

While China faces some major energy-related challenges, the early-developmental stage of its energy infrastructure provides the opportunity to make energy-technology choices that directly address these challenges, while enabling continued economic and social development of the country. The objective of the work reported here is to assess the implications of different technological choices that China might make. In this context, four specific questions are addressed:

1) How can China meet its projected demand for energy services in an affordable manner, given that conventional projections show a significant shortfall in domestic energy resources in 2050?
2) Are there plausible scenarios by which China could meet its projected needs for liquid fuels, especially for transportation, while not becoming overly dependent on imported energy?

3) Are there plausible scenarios by which China could substantially reduce urban and rural air pollution while meeting its projected demand for energy services?
4) Are there conceivable energy-technology scenarios by which China could meet requirements for lower carbon emissions that may arise from global warming concerns?

To address these questions, the MARKAL energy-system modeling tool was used to build a simplified, but representative model of China's energy system and to explore different scenarios for the development of energy supply and demand in China from 1995 to 2050. These scenario results provide insights into energy development choices. They are not forecasts of the future.

This paper will first briefly describe the MARKAL tool and then more fully describe the MARKAL model for China that was developed for this work, including a description of the overall framework and the extensive input data set. Key results from the analysis are then summarized, and some implications for technology policy are discussed.

2 MARKAL Modeling

MARKAL was developed starting in the late 1970s as an energy-planning tool.[9] Application of the model involves first defining the system geographic boundaries (e.g., a city, a province, a country, etc.) and then building a representation of the energy system for that region by specifying material and energy flows in and out of each technological component in the system. Figure 1 shows an example of a technological component and the input specifications required by MARKAL.

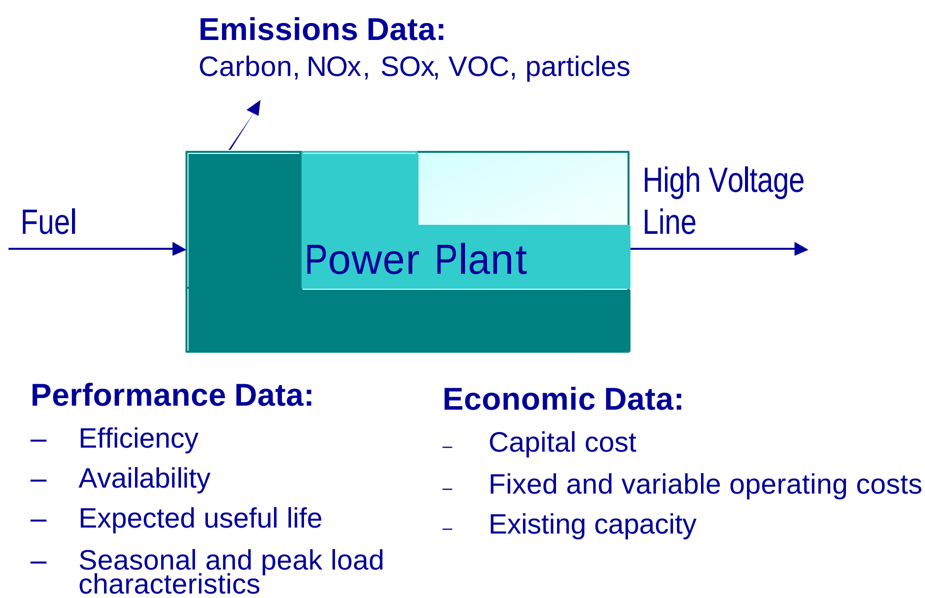


Figure 1. Example MARKAL Component Block

In addition to component-level specifications, the user must also specify inter-component connections. Figure 2 is a simplified representation of the connections in our China MARKAL model. Details are discussed in Section 3, but the row of boxes across the top part of Figure 2 describes conceptually the inter-connections in any MARKAL model. Working from left to right: primary energy resources are either mined, imported, or renewable; these resources are processed through a variety of conversion technologies to create final energy carriers; the final energy carriers are consumed to meet energy service demands.

In its standard version, which is used in this work, MARKAL requires the user to initially generate a set of projected energy service demands and input them to the model for every interval in the analysis period. The user must also input the costs for primary-energy production and delivery, specify primary-energy resource supply limits, and create profiles for all current and new energy supply and demand technology options available to the model (capital, operating costs, energy efficiencies, pollutant emissions, availability, seasonality characteristics, growth constraints, and others). MARKAL finds the combination of energy resources and conversion technologies that minimizes the overall energy-system cost (including investment and operating costs) for meeting the specified energy service demands throughout the economy over the entire analysis period. The model uses a linear programming solver (GAMS) to simultaneously solve the energy supply and demand balances at each interval over the analysis period (eleven five-year periods between 1995 and 2050 in this work). The model monitors capital stock turnover and, as required, it introduces new primary energy resources, new capacity for primary-to-final energy conversion, and new end-use capacity for converting final energy into energy service demands.

The user may also specify environmental or other constraints under which the model must satisfy the energy supply/demand balance. The design of the model enables a wide variety of "what if" analyses to be carried out, e.g., considering alternative sets of policy, technology, or environmental constraints.

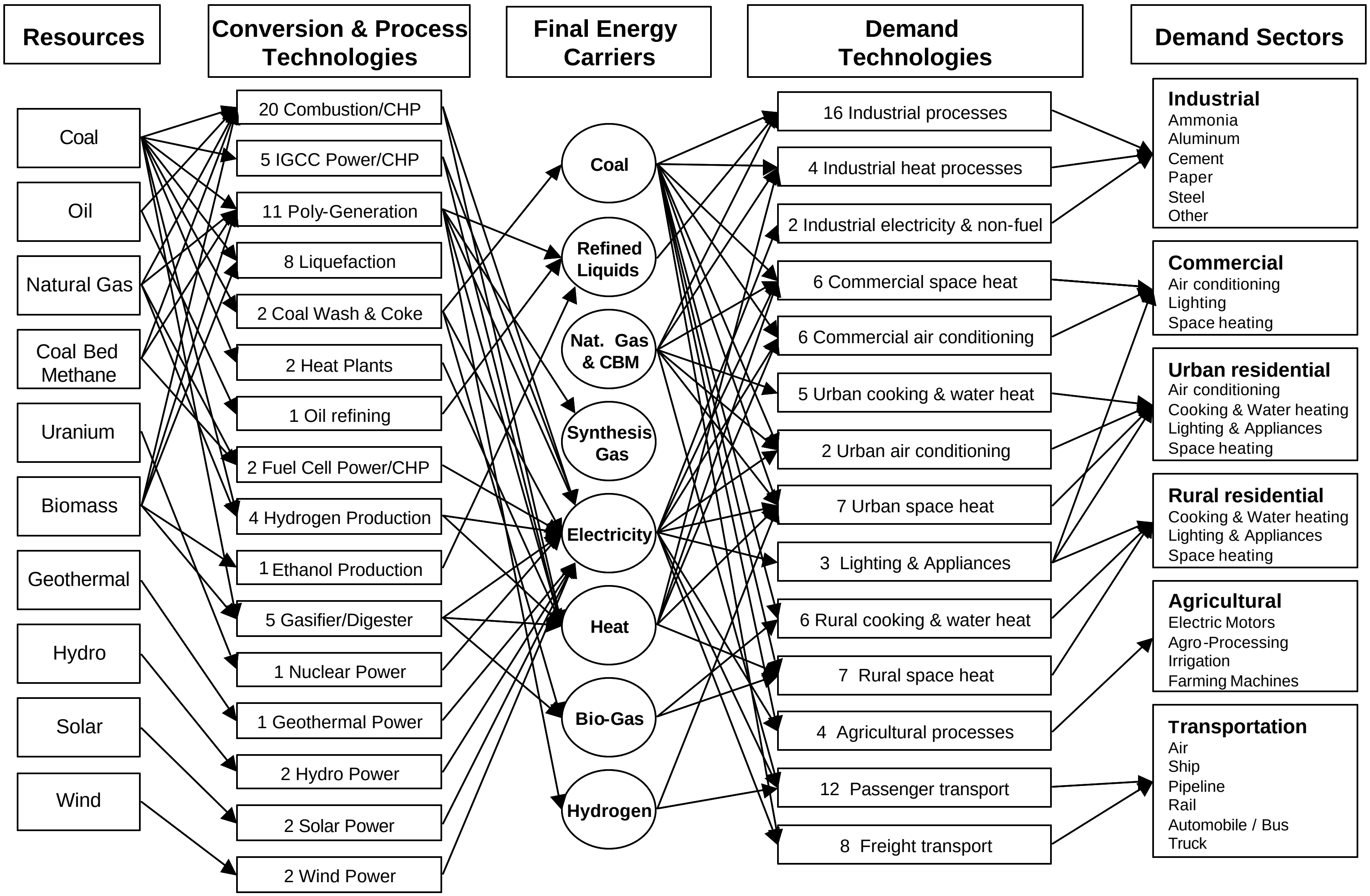
3 The China MARKAL Model

The China MARKAL model developed for this assessment builds on previous MARKAL modeling work at Tsinghua University.[10,11] This assessment expands the earlier Tsinghua model to include an extensive set of advanced energy technology options. A major effort in this assessment was the development of input data for the model. Three basic sets of input information are required for each time step over the entire period of the analysis: 1) energy service demands, 2) the potential supply and the cost of primary energy resources, and 3) the cost and performance characteristics of technologies potentially available for use in the energy system. The following section discusses some key general input assumptions, and this is followed by summaries of the three sets of required input data.

3.1 General Assumptions

Several general assumptions are critical to proper understanding of our China MARKAL model. First, China is treated as a single geographic region with six major energy service demand sectors (Fig. 2). While greater geographic detail may be desirable, it would make the model considerably more complex and require considerably more input data. Since input data must be provided for a 50-year time horizon, uncertainties associated with the results would increase, and achieving the basic objective – understanding the broad implications of different technology choices – would not be significantly enhanced. One disadvantage of not using geographic disaggregation in the model is that locally significant energy-development opportunities cannot be highlighted, e.g. gas-to-liquids projects in the Tarim basin of Xinjiang Province or enhanced coal-bed methane extraction in Shandong Province. Nevertheless, by including characteristics of technologies relevant to such local opportunities and placing appropriate constraints on the potential market size for such opportunities, the model can provide some insight into the general viability of such opportunities.

Figure 2. Simplified Representation of China MARKAL Model Structure



Second, estimates of commercially-mature performance and cost (investment and O&M) are used for all component technologies, including those that are either not yet commercial today or which have not yet reached commercial maturity. Given the 50-year time horizon and the advanced-technology focus of the WGEST, many of the technologies included in the model fall into these categories. For each such technology, we specify a first-introduction date at which the technology could plausibly be available for commercial introduction into China. Since MARKAL picks technologies to minimize total system cost, it would be unlikely to pick technologies that have not reached commercially mature cost levels. Thus, specifying technology costs that would characterize early-introduction units would, in general, be equivalent to excluding these technologies from the model. Assuming commercially mature costs for technologies from the start of market introduction may imply in some cases that actual costs are "bought down," either through subsidy of early units introduced in China or through earlier market introduction in other countries.

Third, upper bounds on domestic production of primary energy resources are specified, as discussed in detail in Section 3.3. Imports of most energy resources are allowed, with two key exceptions: no imports of coal and no imports (or exports) of electricity. While these options are possible in reality between now and 2050, they were excluded to allow for a clearer analysis of the technology choices facing China. Imports of coal would remove some of the pressure on domestic coal resources that appears in some of the model results, but it would not fundamentally change what technologies the model chooses for using coal to meet China's energy demands.

Fourth, growth-rate caps are imposed for the introduction of new technologies into the energy system. These caps do not necessarily dictate how fast a technology will expand in the market. However, for technologies that the model finds attractive, the growth rate cap often provides an upper bound on its market expansion. The allowed growth rate caps are often relatively high, especially in the early years of a new technology -- generally 20-30% per year in the first couple of decades after introduction. This is plausible because the technologies start from a small base, and historically such growth rates have been achieved by such technologies as wind and nuclear electricity. However, while not implausible, such growth rates do imply that market mechanisms are augmented by policy-drivers. [12]

Fifth, the model explicitly calculates the added cost of limiting environmental emissions relative to allowing no constraint on emissions, as discussed later. However, the environmental and public health benefits of reduced emissions (the avoidance of environmental externality costs) are not calculated. A precise determination of these benefits is difficult, but based on studies that have been done for China[3] and for other countries,[13] these avoided externality costs are likely to be very significant.

A final key assumption is the discount rate used by the model to calculate the total discounted energy-system cost (the objective function that MARKAL minimizes). Several sources were contacted, and based on these discussions a discount rate of 10% was selected as most appropriate for analyses of China's long-term technological choices, such as are being investigated in this assessment.[14]

3.2 Energy Service Demands, 1995-2050

We developed projections of the future demands for energy services at five-year intervals to 2050, based largely on comparisons with historical data for various OECD countries at similar levels of GDP per capita. Future levels of energy demand were specified based on the assumption that by 2050 China as a whole will have developed to the levels of energy services that characterized key OECD countries in the mid-1990s. Considerable thought was given to the appropriate choice of the cross-country comparisons in order to minimize the differences in economic structure, demographics, geography, culture, development path, etc. This methodology was selected because the Chinese economy is expected to undergo significant structural changes during the assessment time period,[15] and this approach does not presume what type of technology choices will be made to supply the projected demand. The methodology ties the projection of demands for energy services to the level of economic development toward which China aspires in the future.

Table 1 presents the general economic assumptions underlying the energy service demand projections.[16] The population projections and GDP projections are based on official data from China's State Economic Information Center and represent their baseline population projection and their lower bound GDP growth projection. The lower GDP projection was selected as being more consistent with recent trends in China's energy consumption.[17] The urbanization trend shown in Table 1 should be understood in the Chinese context, where it does not mean that a person migrates to a city. Instead, it means that the person transitions from some form of land-based employment and non-commercial energy use to some form of industrial or service-based employment and that they make commercial purchases for energy and other services.

Table 1. General Economic Assumptions

	1995	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Population (billion)[a]	1.211	1.294	1.340	1.386	1.441	1.495	1.528	1.560	1.575	1.590	1.583	1.575
Population GR (%/yr)	1.3%	0.7%	0.7%	0.8%	0.8%	0.43%	0.43%	0.2%	0.2%	-0.1%	-0.1%	
Urbanization (%)[b]	31.4%	34.4%	38.4%	42.4%	46.9%	51.4%	54.9%	58.4%	61.7%	65.0%	67.5%	70.0%
Urbanization GR (%/yr)	1.8%	2.2%	2.0%	2.0%	1.8%	1.3%	1.2%	1.1%	1.0%	0.8%	0.7%	
GDP (billion US$)	709	1,104	1,549	2,172	2,839	3,710	4,849	6,338	7,711	9,382	11,414	13,887
GDP GR (%/yr)[c]	9.3%	7.0%	7.0%	5.5%	5.5%	5.5%	5.5%	4.0%	4.0%	4.0%	4.0%	
Per capita GDP (US$)	585	853	1,156	1,567	1,971	2,482	3,175	4,063	4,896	5,901	7,213	8,817
Per capita GDP GR (%/yr)	7.8%	6.3%	6.3%	4.7%	4.7%	5.0%	5.1%	3.8%	3.8%	4.1%	4.1%	
ppp factor	5.005	4.430	3.930	3.460	3.080	2.730	2.380	2.055	1.830	1.625	1.415	1.230
Per capita ppp GDP (US$)[d]	2,930	3,780	4,542	5,422	6,069	6,775	7,555	8,347	8,958	9,586	10,203	10,845
pppGDP/cap growth (%/yr)	5.2%	3.7%	3.6%	2.3%	2.2%	2.2%	2.0%	1.4%	1.4%	1.3%	1.2%	

(a) State Economic Information Center internal report.
(b) IEA: Link Between Energy and Human Activity, ISBN 92-64-15690-9.
(c) Chinese government social development goal from State Economic Information Center internal report.
(d) World Bank: Key World Energy Statistics.

Given these general assumptions, the energy service demands were developed according to the following sectors: 1) Industrial, 2) Urban residential, 3) Rural residential, 4) Commercial, 5) Agricultural, and 6) Transportation, as summarized below and described in detail in Appendix A. For some of the sectors, energy service demands were projected based on final energy data rather than energy service data, due to a lack of comparative data on energy services in OECD countries. Figure 3 reflects the overall changes in supply of energy services to the Chinese economy that results from the energy service demand assumptions discussed in detail in the immediately following sections. The greater-than-tripling of final energy use between 1995 and 2050 reflects a similar increase in the supply of energy services, and the sectoral breakdown of energy use evolves from one typical of a developing country to one that more closely resembles an industrialized country.

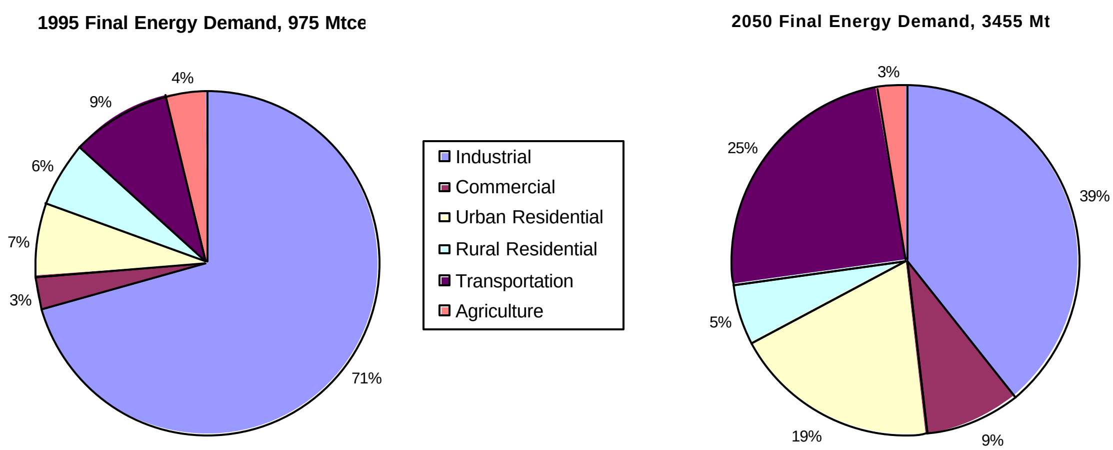


Figure 3. Final Energy Use, 1995 and 2050. The 1995 figures are actual data. The 2050 figures are illustrative of the sectoral energy demand distribution found in the scenarios discussed later in this report. The magnitude of projected total final energy demand in 2050 varies in different scenarios as a result of differing end-use technology choices.

3.2.1 Industrial Sector

China has a large industrial base with an energy intensity that is several times higher than that of most other countries. The principal reason for the high energy intensity is that the product mix is weighted towards relatively low-value goods, which are relatively energy-intensive to produce. In addition, out-dated and low-efficiency process technologies are widely used, which leads to higher energy use per output relative to other countries. Finally, many industrial plants are small and fail to achieve critical economies of scale.[18] The structure of China's industrial sector is expected to change significantly over the next 50 years. Greater diversity in the output of industrial goods, improvements in product quality and value, industrial modernization and restructuring, and classical industrial efficiency improvements will all lead to a significant improvement in the industrial sector energy intensity. We assume that the overall level of industrial energy intensity per unit of GDP decreases from the 1995 value of 1.99 kgce/US$ to a value in 2050 of 0.25 kgce/US$. The latter value is equivalent to the 1995 industrial energy intensity in the USA and South Korea, but it is higher than the 1995 values in Western Europe and Japan.

We projected energy service demands for the industrial sector by a combination of two methods. Industrial output for the five major energy consuming industries (steel, paper, cement, ammonia, and aluminum) was projected, and a variety of demand technologies providing different levels of output per unit of energy input (discussed in Section 3.4.2) were modeled in MARKAL. The "Other Industries" sector – comprised of light manufacturing, machinery, electronics, building products, and other industries – was modeled as a single entity with final energy demands for three energy carriers (electricity, process heat and non-energy feedstocks.)

3.2.2 Urban and Rural Residential Sectors

The urban and rural residential sectors were projected separately in order to account for their significantly different energy service demands, and to allow for the trend of urbanization to be included in the model.

We divided urban residential sector energy demands into four categories: air conditioning, cooking & water heating, lighting & electric appliances, and space heating, which were projected independently. The urban residential space heating demands were determined from projections of the urban population and the per capita floor area, assuming that 51.1% of urban floor space requires heating. The per capita floor area was projected to increase to a value of 35 m^2 in 2050, which compares to 1995 levels of 36 for Japan, 40 for Europe, and 58 for the USA. The percentage of urban residential floor space requiring heating was based on the current geographic distribution of urban centers and was assumed to remain the same into the future. Because the current overall level of space heating per unit floor area in China is modest, the space heating energy intensity was projected to grow slowly from 9.4 kgce/m^2 in 1995 to 11.3 kgce/m^2 in 2050 in spite of building and heating efficiency improvements.

The urban cooking and water heating energy service demands were projected from the per capita energy demand, which in 1995 was 52 kgce/person. This value was projected to increase at a constant annual rate of 1.5% to a value of 118 kgce/person in 2050. This compares to today's values of 138 for Japan, 140 for Europe, and 245 for the USA. The energy demand for urban air conditioning was about 1 kgce/person in 1995, and this energy demand was projected to reach 9 kgce/person in 2050. The urban electricity demand for lighting and appliances was 350 kWh per household in 1995. This demand was projected to grow at a constant 2.7% per year to reach a level of 1,515 kWh per household in 2050. This value is equivalent to Japan in 1995 (1,500 kWh per household) but low relative to other OECD countries, where it ranges from 2,500 to 6,500 kWh per household.

We divided rural residential sector energy demands into three categories: cooking & water heating, lighting & electric appliances and space heating. The expected growth in air conditioning use in the rural sector was included in the lighting & electric appliance category assuming it will all be electrically powered. In 1995, this sector consumed 61.8 Mtce of commercial final energy, which included 43 TWh of electricity. Use of traditional, non-commercial biomass-based fuels is not included in this figure. Although these energy sources are important to rural China, they were not explicitly included in the assessment because MARKAL will always select a free non-commercial resource over a commercial resource. However, the transition of the rural population from traditional to modern energy carriers was included in the model through both the projection of rural residential energy use and in the urbanization trend that shifts population from the rural energy sector to the urban energy sector. The total per capita use of commercial energy in the rural sector was projected to grow in proportion to the GDP growth rate according to an historical elasticity of about 0.6. Similarly, the per capita electric energy consumption was projected based on a demand elasticity of about 0.8. In 1995, 8.6% of the final energy demand was used for lighting and electric appliances, and the remaining final energy was evenly split between space heating and cooking and water heating. In 2050, the final energy proportions are 35% for cooking and water heating, 15% for lighting and electric appliances and 50% for space heating.

3.2.3 Commercial Sector

Energy demand in the commercial sector is expected to grow quite rapidly in China over the next several decades. We projected commercial sector floor area requirements according to the ratio of commercial sector floor area to urban residential floor area. Typical ratios for developed countries today include 0.31 for Japan and 0.41 for the USA. China was projected to reach 0.40 by 2015 and then remain constant. As a check, the ratio of commercial floor area to commercial GDP share decreases from a 1995 value of 9.65 m^2/1000$US to a value of about 2.0 m^2/1000$US in 2050. Values for this ratio today in other countries include 1.5 for Japan, 1.2 for Italy and 2.8 for the USA. We projected commercial sector energy intensity to grow from the 1995 value of 13.8 kgce/m^2 to a value of 20 kgce/m^2 in 2050, based on an assumed increase in energy service demands as this sector develops. We characterized commercial sector energy demands according to air conditioning, space heat and water heating, and lighting and appliances. The proportions of these demands were developed in a similar manner to those in the residential sector.

3.2.4 Agricultural sector

In 1995, the agricultural sector consumed 39.4 Mtce, which was comprised of 18.3% electricity, 37% coal and 44.7% petroleum products. Future final energy demands for this sector were projected from historical data that indicates an energy demand elasticity of 0.5 to the agricultural share of GDP growth. The energy demand projections were divided into four categories: electric motors, agro-processing (heat), irrigation and farm machines.

3.2.5 Transportation Sector

Energy use in China's transportation sector is expected to increase significantly in the future as improvements in living standards increase the demand for goods that must be transported to market, and as the increasing population requires more and better quality passenger transportation. Transport activity was projected for both freight and passengers. These were developed from the projections of GDP growth, population growth, and expected changes in transport modes.

In 1995, freight transport intensity for China was 1.01 t-km/US$ ppp, and we projected this value to decrease to 0.7 t-km/US$ ppp in 2050, which compares to 1995 values of 0.8 for the USA and 0.75 for Australia. The ppp-normalized GDP is used to project freight transport because it gives a better measure of the overall demand for goods. Thus, the total freight activity increases from 3,573 billion t-km in 1995 to almost 12,000 billion t-km in 2050. Freight transportation demands were modeled according to the following five categories: air, pipeline, ship, rail and truck. The 1995 proportion of activity for each mode is shown in Table 2. The activity in the air, truck and pipeline sub-sectors was projected to increase relative to the others as also shown in the table.

Passenger transportation in China in 1995 consumed 11.2 Mtoe in providing about 900 billion-passenger-km. The per capita travel activity was 743 passenger-km/person. We projected future per capita passenger transport activity based on a demand elasticity of 0.8 between the GDP growth rate and the per-capita transport growth rate. Even with this relatively rapid increase, the projected per capita passenger travel for China in 2050 remains a factor of 2 to 3 below the current activity levels in the USA and Western Europe.

We modeled passenger transport demands in five categories: automobile, bus, rail, air and ship. In 1995 the proportion of activity for each mode is shown in Table 2. We projected that the automobile share would increase significantly based on comparisons of per capita automobile transport in Japan, Western Europe and the USA. Assuming that China's per capita ppp GDP will reach US$10,000 in 2050, we projected that the percentage of the population owning cars would reach the same level (between 10 and 15%) as countries today with the same level of GDP, e.g. South Korea. Assuming that China has approximately 100 cars per 1000 people in 2050, that the annual travel is 15,000 km (reference: Japan at 12,500 km and the USA at 18,000 km), and the occupancy is 1.5 people per car, the 2050 passenger travel activity was estimated at 3,357 billion passenger–km, which is 32.4% of the total. The proportion of air transport increases slightly, while the other categories decrease.

Table 2. Transportation Projections

Freight Transport					Passenger Transport				
	1995		2050			1995		2050	
	10^9 t-km	%	10^9 t-km	%		10^9 p-km	%	10^9 p-km	%
Air	1.8	0.05	48	0.40	Air	68	7.6	932	9.0
Pipeline	61	1.7	466	3.9	Car	55	6.1	3357	32.4
Ship	1754	49.1	4866	40.7	Ship	17	1.9	104	1.0
Rail	1286	36.0	3587	30.0	Rail	355	39.4	2590	25.0
Truck	472	13.2	2989	25.0	Bus	405	45.0	3378	32.6
TOTAL	3575	100	11956	100	TOTAL	900	100	10361	100

3.3 Primary Energy Resources & Constraints

MARKAL requires that the cost of all primary energy resources (for extraction or import) be defined along with any constraints on their availability. Tables 3 and 4 summarize the projected costs and annual maximum allowable production limits for all primary energy resources used in the model. Each resource is discussed in detail in this section.

3.3.1 Coal

China has at least 118 billion metric tonnes of proven recoverable reserves of coal[19] and estimated reserves of about 1,000 billion tonnes (714 billion tce).[20] Total estimated coal resources in the ground are 5700 billion tonnes. In 1995, the average cost of coal in China was US$19.6 per tonne ($0.94 /GJ). We have projected the cost of coal to increase at a constant rate of 0.5% per year to reach 1.33 US$/GJ in 2050. The projected increase in cost is small because the reserves of coal are very large compared to the projected supply. The increase accounts for higher mining costs due to the expected increase in future mine depths (offset largely by improvements in mining technology) and due to expected stricter environmental regulations.[21] Coal production in 1995 was 1417 million tonnes (Mt), or 1,012 Mtce. We have projected production capacity to grow about 1.5% annually to reach 3,380 Mt (2415 Mtce) in 2050 (Table 3). The upper bound on coal production accounts for expansion constraints on the industry due to infrastructure development, water requirements, and transportation constraints. The projected maximum capacity is about 10% higher than typical projections of production capacity in China, on the assumption that an increasing fraction of coal will be converted at the mine mouth into energy carriers for which transportation infrastructure constraints are less severe than for coal, e.g., electricity or liquid fuels. The cumulative amount of coal mined from 1995 to 2050, if

Table 3. Primary Fossil Energy Resource Upper Production Bounds and Costs[a]

	1995	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	Cum[b]
Domestic Coal													
Upper bound (EJ)	29.62	32.0	34.9	38.1	41.5	45.3	48.8	52.5	56.6	61.0	65.7	70.8	2884
(million tonnes)	1,417	1,531	1,669	1,823	1,986	2,167	2,335	2,512	2,708	2,919	3,144	3,388	138,039
Cost ($/GJ)	0.94	1.04	1.07	1.09	1.12	1.15	1.18	1.21	1.24	1.27	1.30	1.33	--
($/metric tonne)	19.6	21.7	22.4	22.8	23.4	24.0	24.7	25.3	25.9	26.5	27.2	27.8	--
Domestic Crude Oil													
Upper Bound (EJ)	6.27	6.64	7.00	7.36	7.65	7.65	7.65	6.96	6.26	5.57	4.88	4.18	390
(million toe)	150	159	167	176	183	183	183	166	150	133	117	100	9336
Cost ($/GJ)	2.70	2.86	3.04	3.23	3.43	3.64	3.86	4.10	4.35	4.62	4.91	5.20	--
($/bbl)	16.13	17.09	18.16	19.30	20.49	21.75	23.06	24.49	25.99	27.60	29.33	31.06	--
Imported Crude Oil													
Cost ($/GJ)	3.00	3.18	3.38	3.59	3.81	4.04	4.29	4.55	4.83	5.13	5.45	5.78	--
($/bbl)	17.92	19.02	20.19	21.43	22.75	24.15	25.63	27.21	28.88	30.66	32.54	34.54	--
Imported Oil Product Costs													
Diesel ($/GJ)	3.99	4.24	4.50	4.77	5.07	5.38	5.71	6.06	6.43	6.82	7.24	7.69	--
Gasoline ($/GJ)	4.86	5.16	5.48	5.81	6.17	6.55	6.95	7.38	7.83	8.31	8.82	9.37	--
Kerosene ($/GJ)	4.62	4.90	5.21	5.53	5.86	6.23	6.61	7.01	7.44	7.90	8.39	8.90	--
LPG ($/GJ)	4.62	4.90	5.21	5.53	5.86	6.23	6.61	7.01	7.44	7.90	8.39	8.90	--
Fuel oil ($/GJ)	2.37	2.52	2.67	2.83	3.01	3.19	3.39	3.60	3.82	4.05	4.30	4.57	--
Domestic Natural Gas													
Upper bound (EJ)	0.702	1.46	2.19	2.93	3.58	4.24	4.75	5.27	5.71	6.14	6.49	6.84	252
(billion m^3)	18	38	56	75	92	109	122	135	147	158	167	176	6466
Cost ($/GJ)	2.31	2.48	2.65	2.85	3.05	3.27	3.51	3.76	4.03	4.32	4.63	4.96	--
($/1000$m^3$)	89.9	96.4	103.3	110.7	118.7	127.3	136.4	146.2	156.8	168.1	180.2	193.1	--
Imported Natural Gas													
Cost ($/GJ)	2.57	2.76	2.95	3.17	3.39	3.64	3.90	4.18	4.48	4.80	5.15	5.52	--
($/1000 m^3)	100	107	115	123	132	142	152	163	174	187	200	215	--
Conventional Coal Bed Methane													
Upper bound (EJ)	0.023	0.039	0.144	0.360	0.723	1.17	1.63	2.09	2.42	2.80	3.09	3.42	90
(billion m^3)	0.6	1.0	3.7	9.2	18.6	29.9	42.0	53.6	62.1	72.0	79.5	87.8	2300
Cost ($/GJ)	1.60	1.60	1.72	1.84	1.97	2.11	2.27	2.43	2.60	2.79	2.99	3.21	--
($/1000 m^3)	62	62	67	72	77	82	88	94	101	109	116	125	--
Coal Bed Methane recovered by CO_2 injection/sequestration													
Upper bound (EJ)				0.100	0.371	0.924	1.49	1.90	2.42	3.09	3.95	5.04	96
(billion m^3)				2.6	9.5	23.7	38.2	48.8	62.3	79.5	101	130	2478
Cost ($/GJ)				1.20	1.29	1.38	1.48	1.58	1.70	1.82	1.95	2.09	--
($/1000^{m3})				47	50	54	58	62	66	71	76	81	--
Domestic Oil by recovered by CO_2 injection/sequestration													
Upper bound (EJ)			0.70	0.74	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	38
(million toe)			17	18	18	18	18	18	18	18	18	18	904
Cost ($/GJ)			1.70	1.82	1.95	2.09	2.24	2.41	2.58	2.77	2.96	3.18	--
($/toe)			71	76	82	87	94	101	108	116	124	133	--

(a) Costs are in 1995 US dollars. Upper bound refers to the limit on annual production specified in the model and is not necessarily the level at which the resource is used in the model.

(b) Maximum cumulative resource utilization allowed in the model, 1995-2050. No limits on imported resources are indicated here, but some scenarios (discussed later) involve limitations on imports.

mined at the upper bound annual rate, would be 98.6 billion tce, or 10% of the current estimated reserves.

In many industrialized countries, most coal is washed after mining to reduce impurities, especially ash and sulfur. In China today, 18% of coal is washed. We assume that the fraction of coal washed in China grows to 80% by 2050. Washing is assumed to reduce the sulfur content by 50% and to improve coal use efficiency by 10%.[22] The average sulfur content of unwashed Chinese coal is taken to be 1.2%.

3.3.2 Oil

China's estimated proven recoverable reserves of oil are approximately 10 billion tons, and estimated total resources are about 102 billion tons.[23] In the early 1990's, the rate of growth in oil production increased dramatically, reaching 150 million tonnes in 1995. We projected the upper bound on oil production to continue growing slowly to peak at about 180 million tons per year between 2015 and 2025, after which production decreases to a level of 100 million tons in 2050 (Table 3). The cumulative oil production over the period, if extracted at the upper bound annual rate, would be 9.3 billion tons, or roughly the present estimate of proven reserves. Given that estimated reserves are ten times proven reserves, this level of oil production in 2050 is plausible.

Imports of crude oil and refined oil products (gasoline, diesel, jet fuel and fuel oil) are considered energy resources by MARKAL, and their treatment was an important aspect of this assessment. In general, no restrictions were placed on the level of imports except as identified in specific import constraint cases. The cost of oil and imported oil products was pegged to world market prices. In 1995, the average cost of crude oil in China was 17.9 US$/bbl. The cost was projected to increase at a rate of 1.2% annually[24] to reach 35 US$/bbl in 2050. We did not attempt to model the inevitable upward and downward fluctuations in world oil price. Given the long-term view being taken, the 1.2% average annual price increase is consistent with historical behavior of oil prices.[25] The cost of domestic crude oil was set at 90% of cost of imported crude to give a slight preference to domestic oil over imported oil. US historical data on the ratio of refined product cost to crude oil cost were used to set the cost of the imported refined products.[26] The costs of domestic refined products are calculated internally by the model based on the refinery costs specified as inputs (discussed in Section 3.4.1).

3.3.3 Natural Gas

China has approximately 1.4 trillion cubic meters (Tm^3) of proven natural gas reserves[19] and estimated total resources [20, 23] are from 47 to 62 Tm^3. In 1995, domestic production of natural gas was 17.6 billion m^3. We project natural gas production to grow rapidly through 2020 and then more slowly, reaching an upper bound level of 170 billion m^3 in 2050 (Table 3). The average annual growth rate over the entire period is 4.1%. The rapid increase in the natural gas upper bound reflects a projection based on the recent spurt of new exploration and currently planned pipeline additions. The cumulative natural gas production over the period, if used at the upper bound annual rate, would be 6.4 Tm^3, or about 4.5 times the estimated proven reserves in 1998. Given that estimated resources are as much as 44 times the current level of proven reserves, it is reasonable to expect this level of natural gas production by 2050. In 1995, the cost of natural gas in China was $90/1000 m^3, or US$2.3/GJ. We projected this to increase 1.4% per year to 2050.

3.3.4 Coal Bed Methane

Production of coal bed methane (CBM) associated with coal mining has started recently in China. In 1995 some 0.6 billion m^3 (Bm^3) were produced,[27] and the estimated resource is 30 to 35 Tm^3 up to a depth of 2000 meters.[22,27] Several commercial ventures were formed in the late 1990's to exploit this resource, and estimated production was 1.0 Bm^3 in 2000, with a projection of 10 Bm^3 in 2010. We based the projected upper bound production level in the model on these industry projections in the near term, and growth rates of 5% annually for later years. If produced at the upper bound rate, the cumulative production of CBM associated with coal mining from 1995 to 2050 would be about 2.3 Tm3, or no more than 15% of the estimated resource.

The concept of producing CBM from deep unmineable coal beds in China by injecting CO_2 into them has been proposed . There is some field experience with CBM recovery by CO_2 injection in other countries.[29] We developed a projection of the upper limit on the annual production of CO_2-enhanced CBM for the first year of availability (assumed to be 2010) based on industry estimates of the minimum practical size of a commercial installation (injecting one million tons of CO_2 per year). This corresponds to an estimated CO_2-coupled CBM production of 2.6 billion m^3. We assume this grows to 130 Bm^3 in 2050. There are no reliable estimates of the actual size of this potential CO_2-coupled CBM resource. One reference[30] estimates that there are 30 Tm^3 of CBM resources at depths of 2000 meters or greater. If produced at the upper limit rate, the cumulative production of CO_2-coupled CBM production from 2010 to 2050 would be about 2.5 Tm^3. There is considerable uncertainty in this upper bound estimate. In particular, conventional wisdom in the CBM community is that deep coals will have low permeabilities (and thus be unproductive),[28] and the permeability of the deep coal seams in China is not well known in any case. However, one hypothesis cited by Williams,[28] suggests that it will often be feasible to recover up to 90% of CBM in a homogeneous coal seam regardless of permeability down to quite low levels. Empirical work in China is needed to improve confidence in the estimate of recoverable CBM resources.

3.3.5 Hydroelectric Power

The estimated exploitable capacity for hydroelectric generation is 378 GW, of which 76 GW represent small plants of less than 25 MW each.[19] In 1995, the installed capacity of hydroelectric power plants was 52.2 GW, of which small plants comprised 15.6 GW.[20] We projected the upper bound in capacity for large plants initially to be set by the expected operation of the Three Gorges project and by modest growth rates after that to a maximum capacity of 300 GW in 2050 (Table 4). Similarly, the upper bound for small hydroelectric plants is assumed to grow to 65 GW in 2050. We have further stipulated that a minimum of 103 GW of hydroelectric capacity is in place in any given year between 2010 and 2050.

3.3.6 Nuclear Power

In 1995, the installed nuclear power capacity in China was about 2 GW. In the model, we specified both a lower and upper bound for the installed nuclear capacity. The lower bound was used to reflect a government commitment to a minimum level of nuclear power growth. In this case, the minimum installed nuclear capacity reaches 19 GW in 2050. An upper limit on possible installed capacity was set by applying a varying growth rate (approximately 15% to 2015 and approximately 5% after 2015.) In this case, the maximum possible nuclear capacity reaches 216 GW in 2050 (Table 4).

3.3.7 Biomass

Biomass is an important energy resource in rural areas of China. While traditional use of non-commercial biomass resources for cooking and heating were not included in this assessment, the commercial use of biomass energy resources and the conversion of biomass to modern energy carriers was an important element of this assessment. Two forms of biomass resource were modeled: crop residues and cuttings from managed forests (Table 4). The cost and availability of crop residues was taken from recent studies on crop straw gasification projects.[31] The cost and availability of fuelwood cut from managed forests was taken from the China Energy Statistical Yearbook.[2] For both resources, the upper bound on availability was set equal to the amounts available in 1995 on the basis that agricultural activity in China will only increase slightly in the future, and that 1995 fuelwood cutting was at a non-sustainable and was on a downward trend, but that an increase in managed forests would reverse that trend.

Biogas production for rural household use was included in the model at relatively modest levels (Table 4). No attempt was made to include landfill gas or municipal solid waste as energy resources. While these could be locally important energy resources, they are unlikely to have a major impact on the energy system of China as a whole.

Table 4. Primary Renewable and Nuclear Energy Resource Upper Bound Assumptions. [a]

	1995	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Hydro Electric Capacity (upper bound, GW)												
Small (< 25 MW)	17	18	20	23	26	30	35	40	46	52	58	65
Large (> 25 MW)	38	57	72	90	115	140	170	200	225	250	275	300
Nuclear Electric Capacity												
Upper bound (GW)		10	19	30	45	60	80	100	125	150	180	216
Agricultural Residues												
Upper bound (EJ)	7.98	7.98	7.98	7.98	7.98	7.98	7.98	7.98	7.98	7.98	7.98	7.98
(million tonnes)	466	466	466	466	466	466	466	466	466	466	466	466
Cost ($/GJ)	0.52	0.55	0.58	0.61	0.64	0.67	0.70	0.74	0.78	0.82	0.86	0.90
($/tonne)	8.7	9.2	9.6	10.1	10.6	11.2	11.8	12.4	13.0	13.6	14.3	15.1
Fuel Wood												
Upper Bound (EJ)	2.93	2.93	2.93	2.93	2.93	2.93	2.93	2.93	2.93	2.93	2.93	2.93
(million tonnes)	175	175	175	175	175	175	175	175	175	175	175	175
Cost ($/GJ)	1.37	1.47	1.57	1.69	1.81	1.94	2.08	2.23	2.39	2.56	2.75	2.94
($/t)	22.9	24.5	26.3	28.2	30.2	32.4	34.7	37.2	39.9	42.8	45.9	49.2
Biogas												
Upper Bound (EJ)	0.032	0.033	0.038	0.045	0.060	0.075	0.098	0.120	0.150	0.180	0.207	0.234
Million m^3	1.6	1.7	1.9	2.3	3.0	3.8	4.9	6.0	7.5	9.0	10	12
Wind Electric Capacity (upper bound, GW)												
Small wind		1.0	1.8	2.6	3.8	5.0	7.0	9.0	11.5	14	17	20
Large remote farms		1.0	5.0	10	20	32	52	84	132	186	237	300
Geothermal Electricity Capacity												
Upper Bound (GW)	0.030	0.040	0.050	0.060	0.080	0.100	0.120	0.140	0.150	0.160	0.170	0.180
Solar Energy [b]												

(a) Costs are in 1995 US dollars. Upper bound refers to the limit on annual production specified in the model and is not necessarily the level at which the resource is used in the model.
(b) The installed capacities of solar photovoltaic electricity systems and solar thermal energy systems are allowed to grow at a maximum rate of 30% per year during the full analysis period.

3.3.8 Wind Power

The exploitable wind resource in China has been estimated to be 400 to 450 GW,[19] with an installed capacity of 345 MW in 2000.[32] The availability of this resource is not constrained by the resource size. Rather, it is constrained by the growth rate for the wind industry in China, and by the fact that many of the good wind resources are located in remote areas such as Inner Mongolia and Xinjiang Province. The upper limit of possible installed large-scale wind farm capacity is assumed to be 1 GW in 2000, with allowed growth averaging about 17% per year until 2025 and about 7% per year from 2025 to 2050, reaching 300 GW in 2050 (Table 4). For comparison, wind electric capacity worldwide has been growing at close to 30% per year since the early 1990s.

3.3.9 Solar Energy

China has abundant solar energy resources, and as with wind, the real constraint on this resource is the growth rate for the solar industry. By 1999, there were 15 million m^2 of solar water heaters installed and a local industry with an annual production capacity of 2.5 million m^2 was in place.[33] In addition, there are about 19 MW of distributed solar PV systems installed throughout China and an emerging local industry. Given the small size of the solar industry and the relatively high cost of solar power, a 30% upper bound on the growth rate was used throughout the analysis period. Table 4 does not show the potential upper bounds, as these are very large, if growth actually occurs at 30% per year. The maximum amount of capacity operating in any of the scenarios discussed later in this report is 350 GW of solar PV systems and 10 EJ/yr of solar thermal systems, and figures are considerably smaller than these in most of the scenarios.

3.4 Technology Characteristics

Characteristics for two classes of technologies must be provided to the model. Conversion technologies convert primary energy sources into final energy carriers. Demand technologies convert final energy carriers into energy service demands.[34] While the emphasis in our modeling work has been on conversion technologies (due to the emphasis given by the WGEST to these technologies) a sufficiently comprehensive and diverse set of demand technologies has been included to adequately represent all major energy using activities in present and future Chinese society.

3.4.1 Conversion Technologies for Primary Energy to Final Energy

We developed a reasonably representative set of conversion technologies that included a total of 71 distinct technology types. For each technology type, a particular physical plant configuration was selected as representative of that class of technology. While multiple configurations of a particular technology could have been modeled, the data requirements would quickly grow unwieldy and the effort expended in the process would yield questionable returns given the broad objectives of the work. For each of the 71 conversion technology types, values are specified for energy input per unit energy output (lower heating value basis), capital investment per unit of production capacity, fixed and variable O&M costs, plant availability,[35] NO_x and SO_2 emissions per unit energy output, and the first year in which the technology can be introduced. For technologies that produce multiple products, the energy ratio between products is also specified. Two main bodies of literature have been drawn upon for the values used to define technologies. One is China-based[10,11] and one is United States-based. The US-based studies by engineering firms, technology vendors, and knowledgeable energy analysts are all available in the open literature. The most reliable studies were selected and evaluated to yield as consistent a set of cost data as possible.

3.4.1.1 Base Technologies

Conversion technologies were categorized as either "Base" or "Advanced". The Base set includes 36 technologies that share the common feature of being either commercially available today or at very advanced stages of commercial demonstration. This set includes 20 coal conversion systems, nine renewable energy systems, three natural gas conversion systems, three oil conversion systems, and one nuclear electric technology (Table 5). The coal conversion systems include 11 that produce electric power only, one that cogenerates electricity and industrial process heat, two that cogenerate electricity and district heat (for building space heating), two that produce industrial process heat only, one that produces town gas, one that produces coke, and one that co-produces town gas and coke. The renewable energy technologies include two hydroelectric technologies (one larger and one smaller than 25 MW), one grid-connected wind farm, one stand-alone combustion-based crop residue-to-electricity plant, one gasification-based technology for village-scale co-production of electricity and fuel gas from crop residues, one geothermal electric technology, one solar residential photovoltaic electric technology, and two village-scale cooking gas production systems from biomass (biogas digester and producer gas generator). Natural gas technologies include a simple-cycle (peaking) gas turbine, a gas turbine combined cycle, and a gas turbine combined cycle cogenerating electricity and industrial process heat. The oil conversion systems include an oil refinery and two electric power plants (steam plant and gas turbine combined cycle).

3.4.1.2 Advanced Technologies

The set of Advanced technology types includes 35 technologies that share the common feature of not being commercially mature at present (Table 6). In some cases, these technologies are at relatively advanced stages of development. In other cases, the technologies are quite far from commercialization. The "year first available" in Table 6 indicates when the model first has the option to select specific technologies. These values were based on our estimates of the plausible time for first commercial introduction in China considering the level of development for the technology around the world as well as the level of pre-commercial activity in China. The Advanced technologies set includes 18 coal conversion systems, 9 natural gas conversion systems, 7 renewable energy systems, and one hydrogen conversion technology (a fuel cell for distributed applications to co-produce electricity and space heat).

The coal technologies all involve oxygen-blown gasification as part of the process. Several of the technologies have two variants, one with carbon dioxide released to the atmosphere and one with the CO_2 captured for sequestration. The coal technologies include five for stand-alone electricity production, including conventional integrated coal-gasifier combined cycles (IGCC) with and without CO_2 capture, a modified IGCC concept (using a novel hydrogen separation membrane reactor) with and without CO_2 capture, and a solid-oxide fuel cell with CO_2 capture. An additional seven coal technologies produce electricity (via a variant of IGCC) together with one or more co-products. These technologies are called "polygeneration" systems, and the co-products from these systems include industrial process heat, process heat and methanol, process heat, methanol and town gas, dimethyl ether (DME) (with and without some CO_2 capture), and hydrogen (with and without CO_2 capture).[36] An additional six coal conversion systems produce fluid fuels only (without electricity). These include four indirect liquefaction processes – for production of Fischer-Tropsch (F-T) fuels (with and without some CO_2 capture), DME, and methanol – and two hydrogen production technologies – one involving conventional concepts, and one involving H_2 production from coal augmented by additional H_2 produced from coal-bed

Table 5. "Base" Technologies for Converting Primary Energy into Final Energy[a]

Conversion Technology	First Year Available	Efficiency % LHV	Installed Capital Cost	Fixed O&M Cost	Variable O&M Cost	SO_2 Emission	NO_x Emission
Stand-alone electricity production			**$/kW**	**$/kW-yr**	**$/kWh**	**gr/kWh**	**gr/kWh**
Coal-steam <=100MW	1995	0.265	676	20.3	0.005	14.0	5.00
Coal-steam, 100-200MW	1995	0.285	650	19.5	0.004	13.0	4.50
Coal-fired, 200-300MW, ESP	1995	0.34	625	18.8	0.004	10.9	4.00
Coal-fired, >=300MW, ESP	1995	0.34	600	18.0	0.004	10.9	3.00
Coal-fired, >=300MW, ESP & dry FGD	1995	0.33	709	23.8	0.005	4.5	3.00
Coal-fired, >=300MW, ESP & wet FGD	2000	0.33	764	28.8	0.005	1.1	3.00
Coal-fired, >=300MW, ESP & SO_2/NO_x	2005	0.33	788	28.8	0.005	1.1	1.20
Coal pulverized, 500 MW, FGD	2000	0.37	1090	16.1	0.002	0.5	0.87
Coal, atm. pressure fluid bed combustion	2000	0.37	900	27.0	0.009	1.6	0.60
Coal, pressurized fluid bed combustion	2000	0.42	1025	33.8	0.005	1.6	0.60
Coal, ultra-supercritical steam	2005	0.44	1114	22.3	0.003	0.5	0.87
Oil, traditional steam	1995	0.35	530	15.9	0.003	1.5	2.50
Oil, combined cycle	1995	0.40	600	18.0	0.003	1.0	1.65
NG, simple-cycle gas turbine, peaking	1995	0.40	543	20.0	0.008	0.0	1.25
NG, combined cycle	2000	0.58	445	16.1	0.002	0.0	0.10
Biomass FCB power	2000	0.165	427	0.0	0.031	0.0	0.69
Solar PV, residential	1995	1.00	2500	25.0	0.000	0.0	0.00
Wind, small-scale local turbines	1995	1.00	550	14.4	0.002	0.0	0.00
Hydropower (>25MW)	1995	1.00	1500	15.0	0.001	0.0	0.00
Small Hydropower (<25 MW)	1995	1.00	1300	19.5	0.001	0.0	0.00
Geothermal steam plant	1995	1.00	1556	23.3	0.000	0.0	0.00
Nuclear	1995	0.33	2000	40.0	0.008	0.0	0.00
Co-production of electricity and heat		**kJ_e/kJ_{fuel}**	**$/k$W_e$**	**$/k$W_e$-yr**	**$/k$Wh_e$**	**gr/kWh_e**	**gr/kWh_e**
Coal, district heat and power (traditional)	1995	0.34	721	36.0	0.012	10.9	4.50
Coal, district heat and power (advanced)	2000	0.35	750	36.0	0.012	0.5	0.87
Coal pulverized, industrial cogeneration	1995	0.32	995	19.9	0.003	0.5	1.00
NG, combined cycle industrial cogeneration	2005	0.46	485	9.7	0.001	0.0	0.12
Biomass, village gasifier/IC engine	2000	0.0667	2819	128.7	0.031	0.0	1.34
Production of non-electric energy carriers			**$/GJ/yr**		**$/GJ**	**kg/GJ_{out}**	**kg/GJ_{out}**
Coal, central station district heating plant	1995	0.72	3.6		1.07	1.4	0.57
Coal, central station district heat, advanced	2000	0.90	10.1		0.49	0.1	0.28
Coal, coke production	1995	0.90	1.48		0.11	-	-
Coal, town gas + coke, current gasifier	1995	0.87	8.03		0.71	-	-
Coal, town gas, advanced gasifier	2000	0.78	18.07		0.72	-	-
Oil refinery	1995	0.94	1.17		0.25	-	-
Biomass, village-scale biogas	1995	0.63	5.51		0.48	-	-
Biomass, village-scale producer gas	2000	0.63	26.73		1.74	-	-
Coal washing	1995	0.90	0.18		0.22	-0.258	-

(a) All costs are in mid-1990s U.S. dollars. The characteristics shown in this table are performance and cost levels input to the model for 2050. For most of the technologies, the performance and cost levels are assumed to be constant over the full analysis period. Availability factors were 0.85 for all coal and biomass technologies, 0.9 for oil, gas and nuclear technologies, and 0.5 and 0.4 for large and small hydropower , respectively, and 0.27 for solar and wind technologies. The model determines the utilization, or capacity factor for any technology. The table notes (Appendix B) give the primary source material used to develop the input values.

Table 6. "Advanced" Technologies for Converting Primary Energy into Final Energy[a]

Conversion Technology	Year first available	Efficiency % LHV	Installed Capital Cost	Fixed O&M Cost	Variable O&M Cost	SO_2 Emission	NO_x Emission
Stand-alone electricity production			$/kW	$/kW-yr	$/kWh	gr/kWh	gr/kWh
Coal, IGCC	2000	0.47	1114	22.3	0.003	0.075	0.082
Coal, IGCC with CO_2 capture	2005	0.43	1977	39.5	0.006	0.075	0.082
Coal, SOFC with CO_2 capture	2025	0.45	1524	30.5	0.004	0.000	0.082
Coal, HMSR-IGCC	2010	0.43	1154	23.1	0.003	0.000	0.000
Coal, HMSR-IGCC with CO_2 capture	2010	0.40	1489	29.8	0.004	0.000	0.000
Biomass, village SOFC-microturbine	2015	0.47	1511	37.8	0.006	0.000	0.000
Solar, Centralized PV	1995	1.00	1500	15.0	0.000	0.000	0.000
Wind, remote large-scale	2000	1.00	625	5.0	0.002	0.000	0.000
Polygeneration, electricity + co-products		kJ_e/kJ_{fuel}	$/kW$_e$	$/kW$_e$-yr	$/kWh$_e$	gr/kWh$_e$	gr/kWh$_e$
Coal, IGCC, el + industrial process heat	2000	0.38	1343	26.9	0.004	0.087	0.095
Coal, IGCC, el + DME	2010	0.344	1454	29.1	0.004	0.059	0.082
Coal, IGCC, el + DME, with CO_2 capture	2010	0.321	2234	44.7	0.006	0.059	0.000
Coal, HMSR-IGCC, el + H_2	2010	0.07	4563	91.3	0.013	0.000	0.000
Coal, HMSR-IGCC, el + H_2 with CO_2 capture	2010	0.04	10122	202.4	0.029	0.000	0.000
Coal, IGCC, el + methanol + process heat	2005	0.23	1750	35.0	0.005	0.075	0.082
Coal, IGCC, el + methanol + heat + town gas	2005	0.18	1958	39.2	0.006	0.075	0.082
NG, combined cycle with CO_2 capture	2010	0.51	1008	18.1	0.003	0.000	0.109
NG, comb. cycle el + F-T liquids	2005	0.074	4937	50.1	0.011	0.000	0.099
NG, distributed fuel cell, el + heat	2005	0.310	350	14.0	0.000	0.000	0.000
H_2, distributed fuel cell, el + heat	2010	0.410	300	12.0	0.000	0.000	0.000
Biomass, IGCC, el + F-T liquids	2010	0.20	1659	33.2	0.005	0.000	0.063
Biomass, IGCC, el + DME	2010	0.16	2241	44.8	0.006	0.000	0.052
Biomass, village microturbine, el + heat + gas	2005	0.21	2013	71.3	0.024	0.000	0.000
Production of non-electric energy carriers			$/GJ/yr		$/GJ		
Coal, methanol	2000	0.55	47.28		1.89		
Coal, F-T liquids	2005	0.56	33.63		1.35		
Coal, F-T liquids with CO_2 capture	2010	0.56	41.13		2.28		
Coal, DME	2010	0.64	20.91		0.84		
Coal, H_2	2005	0.56	35.28		1.41		
Coal, H_2 (CBM enhanced, with CO_2 capture)	2010	1.23	13.89		1.68		
NG, Methanol	2000	0.65	20.23		0.81		
NG, F-T liquids	2000	0.599	20.74		0.83		
NG, F-T liquids with CO_2 capture	2005	0.599	21.58		0.86		
NG, DME	2005	0.69	19.42		0.78		
NG, H_2	2005	0.78	13.78		0.55		
NG, H_2 with CO2 capture	2010	0.84	15.04		0.60		
Biomass, ethanol	2000	0.399	22.45		0.90		

(a) Costs are all in mid-1990s U.S. dollars. The characteristics shown in this table are performance and cost levels input to the model for 2050. For all of the technologies, the performance and cost levels are for commercially mature technology (as discussed in the text) and are assumed to be constant over the full analysis period. Availability factors are 0.85 for all coal and biomass technologies, 0.9 for gas technologies, and 0.4 for large, remote windfarms (due to oversizing of the farm relative to the transmission line size), and 0.27 for solar. The model determines the utilization, or capacity factor for any technology. The table notes (Appendix B) give the primary source material used to develop the input values.

methane extracted by injecting by-product CO_2 into deep unmineable coal beds where it would remain sequestered.[28]

The renewable energy technologies include six relatively large-scale technologies: remote large-scale wind farms with long-distance electricity transmission to load centers, central-station solar photovoltaic electricity production, polygeneration systems co-producing F-T liquids and electricity or DME and electricity from biomass, and ethanol from lignocellulosic biomass. Additionally two village-scale biomass technologies are included: gasifier-microturbine for cogeneration of electricity, space heat, and cooking fuel; gasifier solid-oxide microturbine hybrid for electricity production.

The nine natural gas technologies include gas turbine combined cycles (GTCC) for electricity production with CO_2 capture; F-T liquids production with co-production of electricity in a GTCC; a reformer/fuel cell for distributed co-production of electricity and space heat; F-T liquids production (with and without some CO_2 capture); methanol production; DME production; and hydrogen production (with and without CO_2 capture).

3.4.2 Technologies for Final Energy Conversion to Energy Services

Demand technologies use the final energy carriers to satisfy the energy service demands. Most of the demand technologies were developed in detail and are described below, but in some cases a dummy technology was used, which simply converts final energy directly into an energy service with efficiency set to 100%. Dummy technologies were used in those areas where end-use technologies are both diverse and use the same final energy carrier (usually electricity). To model, for example, a variety of lighting technologies within this analysis would not have added to the exploration of the broad energy technology strategies being analyzed, so a dummy technology was use to account for lighting energy use. An additional set of technologies, referred to as conservation technologies, were modeled to account for measures that reduce final energy demand, e.g., thermally-tighter building envelopes, improved steam traps and energy efficient motors in industry, enhanced day-lighting in commercial buildings, drip-irrigation systems in agriculture, etc. In the development of the energy demand inputs, it was generally assumed that by 2050 China as a whole will have developed to a level of energy service and energy efficiency similar that that of many industrialized countries in 1995. The conservation technologies are included as options, because while the 1995 industrialized-country level of development and improvement is significant, it is far from the efficiency potential that exists. Just as industrialized countries have significant room for improvement, China can improve end-use efficiency beyond the level assumed in the development of the energy service demands. Including the conservation technologies allows for this possibility. Demand and conservation technologies were included for six demand sectors: industrial, urban residential, rural residential, commercial, agricultural, and transportation, as summarized below. (See also Appendix C.)

3.4.2.1 Industrial Demand Technologies

In general, the industrial demand technologies were characterized in three classes: *i)* existing - representing the current inventory of plants, *ii)* modern - representing the best available in China in 1995, and *iii)* advanced – representing future high-efficiency technology that is not available commercially at present.[37] The value of the efficiency for many of these demand technology classes was not maintained as a constant over the analysis period. Instead, it was varied over time to account for the impact of expected efficiency improvements in the total inventory of each technology class. Consistent with the projections of industrial demands for energy services

(Section 3.2.1), industrial demand technologies were developed for five major energy-intensive industries, plus the "other industry" sector. These technologies are summarized in Table 7 and discussed in the following section. Where "none used" is indicated, a dummy technology is the only demand technology option available to the model, and no cost data needed to be provided to the model.

3.4.2.1.1 Steel Industry Demand Technologies

In 1995, the Chinese steel industry produced about 14% of its output from open-hearth furnaces (OHF). However, these are rapidly being phased out. Continuous casting techniques accounted for about 50% of steel production in China, compared to over 90% in all OECD countries. The

Table 7. Industrial Demand Technologies

Industrial Sector Demand Technology	Year First Available	Energy Efficiency (tonnes/GJ) [a]				Capital Cost	O&M Cost	Average Utilization Factor	SO_2 Emissions (kg/GJ fuel)	NO_x Emissions (kg/GJ fuel)
		1995	2010	2030	2050	$/t/yr	$/t			
Ammonia Production										
Coal	1995	0.015	0.017	0.019	0.021	433	87	0.86	1.03	0.44
Oil	1995	0.017	0.018	0.019	0.020	361	72	0.86	0.30	0.22
Gas	1995	0.026	0.031	0.033	0.036	260	58	0.86	0.00	0.11
Aluminum Production										
Conventional	1995	0.016	0.016	0.016	0.016	1803	72	0.85	0.00	0.00
Modern	1995	0.021	0.024	0.028	0.033	2404	91	0.85	0.00	0.00
Advanced	2010	0.025	0.028	0.033	0.039	2404	91	0.85	0.00	0.00
Cement Production										
Wet	1995	0.171	0.171	0.171	0.171	96	24	0.73	1.03	0.44
Dry current	1995	0.253	0.325	0.325	0.325	138	30	0.73	1.03	0.44
Small	1995	0.190	0.190	0.190	0.190	72	24	0.73	1.03	0.44
Dry advanced	2005		0.325	0.456	0.456	138	25	0.73	1.03	0.44
Paper Production										
Conventional	1995	0.021	0.021	0.021	0.021	1442	288	0.81	1.03	0.44
Modern	1995	0.057	0.057	0.057	0.057	1442	288	0.81	1.03	0.44
Advanced	2010		0.085	0.085	0.085	1627	325	0.81	1.03	0.44
Steel Production										
Existing BOF	1995	0.026	0.031	0.034	0.038	421	120	0.9	1.03	0.44
Existing DRI/EAF	1995	0.034	0.040	0.053	0.068	421	120	0.9	1.03	0.44
Adv smelt reduction	2005	0.062	0.066	0.072	0.078	273	108	0.9	1.03	0.44
Other industry		(GJ out/GJ in)				($/GJ/yr)	($/GJ)			
Electric	1995	1.00	1.00	1.00	1.00	N.U.	N.U.	1	0.00	0.00
Coal boiler	1995	0.65	0.65	0.65	0.65	3.16	0.164	0.8	1.03	0.44
Oil boiler	1995	0.70	0.70	0.70	0.70	2.50	0.144	0.8	0.30	0.22
Process heat	1995	0.80	0.80	0.80	0.80	2.78	0.000	0.8	0.00	0.00
Gas boiler	2000		0.75	0.75	0.75	2.00	0.120	0.85	0.00	0.11
Non-fuel	1995	1.00	1.00	1.00	1.00	N.U.	N.U.	1	0.00	0.00

(a) For the Aluminum, ammonia, cement, paper and steel industries, efficiency is tonnes of industrial output per unit of energy input.
N.U. = none used.

use of a near-net shape casting technique called thin slab casting, is just beginning to emerge. Recently-built modern integrated steel works, such as the plant at Baogang are almost as efficient as state-of-the-art mills in OECD countries, and the efficiency of the existing inventory of plants as a whole can be expected to continue to improve.[38] Steel production in China is primarily from pig iron produced in OHFs and basic oxygen furnaces (BOFs) and from sponge iron produced from direct reduction of iron ore (DRI). There is a general shortage of scrap steel, and the percentage of electric arc furnaces (EAF), which can very efficiently use scrap steel, has been constant over the past few decades at about 20% of total production. However, over the long term increased consumption of steel will lead to more scrap being available. This will eventually lead to more scrap use in primary steel-making, and also to the growth of EAF plants.

The existing technology category used in the model is based on the current inventory of key plants that use near-state-of-the-art BOF technology in integrated mills and smaller inefficient BOF and OHF plants. The OHF plants are expected to be completely phased out by 2005, and new plants will be of the key-plant type. Since existing key plants consume about 800 kgce/t, this means that average plant efficiency will improve over time. Characteristics of the current inventory of plants were taken from Liu, *et al*.[39] and expected improvements over time from Worrell[38] and DeBeer, *et al*.[40] Additional improvements in this technology category are expected to come from increased use of near-net-shape casting techniques and higher scrap steel inputs.

The modern technology category is based on current EAF plants using DRI sponge iron input.[38] The average specific energy consumption is assumed to improve over time based on installation of more efficient plants and based on higher uses of scrap steel. By 2010, advanced EAF plants using 100% scrap steel could use as little as 400 kgce/t of primary energy.[41]

The advanced technology category is based on smelt reduction technology, which combines coal gasification with direct reduction of iron and eliminates the need for coke. This technology is already in use in Japan, Europe and the USA, and it could be introduced in China as early as 2005. The technology offers lower capital and operating costs and reduced environmental impacts.[38] Capital costs are reported to be 35 to 55% lower than for BOF technology, and operating costs are reported to be 5 to 25% lower.[40] For China, we have estimated these at 35% and 10%, respectively.

3.4.2.1.2 Cement Industry Demand Technologies

In 1995, the average energy intensity of the Chinese cement industry was 189 kgce/ton. Four demand technologies are included as model inputs: small, wet, dry, and advanced-dry processes. The "small" cement plants are vertical shaft plants that are very energy intensive and highly polluting. The "wet" plants are wet-process rotary kilns that are also energy intensive. When existing plants of this type are retired, they are likely to be replaced with more advanced technology.[42] The "dry" plants are based on a dry-process rotary kiln, the likely choice for new plants in the near term. The efficiencies for these plants were taken from Price, *et al*.[37] The advanced dry cement process technology is a fluidized bed kiln. An important option relative to energy consumption in the cement industry is the production of blended cement, reducing the share of clinker in the cement. For example, blast furnace slag cement may have an energy intensity as low as 40 kgce/ton, assuming 65% blast furnace slag. In 1995 the share of clinker in cement was roughly 82% in China. Using different additives (slags, fly-ash, ground limestone), the share of clinker could easily be reduced to 65%, which would reduce the energy consumption for a ton of cement. This is assumed to occur for both the "dry" technology plants.

3.4.2.1.3 Paper Industry Demand Technologies

In 1995, the Chinese paper industry consumed 44.8 Mtce, and had an average energy intensity of 1,600 kgce/ton, which is very high because of the use of low-grade raw materials and outdated technology. Modern paper plants in China have an energy intensity of about 600 kgce/ton.[43] Three demand technologies – existing, modern, and advanced – were used to model energy consumption in pulp and paper manufacture. The advanced process is expected to be available in 2010, and it would have an energy intensity of about 400 kgce/ton.

3.4.2.1.4 Ammonia Industry Demand Technologies

Both in terms of total use and per hectare of farmland, the use of chemical and nitrogen fertilizers in China is much higher than world average levels.[43] In 1995, the ammonia industry consumed 57.1 Mtce, and had an energy intensity of 2,066 kgce/ton, which is a composite of the current mix of large, medium and small manufacturing plants. Three demand technologies, characterized by feedstock (coal, oil and natural gas), are included in the model. The energy intensities for plants using coal and oil as feedstocks are expected to improve to 1,600 and 1,700 kgce/ton, respectively.[42] The energy intensity of the large plants using natural gas is currently within the range of those found in OECD countries (1,340 kgce/ton[37]), and it is projected to improve to 950 kgce/ton[42] by 2050.

3.4.2.1.5 Aluminum Industry Demand Technologies

In 1995, the aluminum industry consumed 11.2 Mtce and had an average energy intensity of about 6,000 kgce/ton. Conventional plants require about 17,000 kWh/ton, or 6,270 kgce/ton based on the primary energy content of the fuel required to produce the electricity. Modern plants can reduce energy consumption to 13,000 kWh/ton.[44] Advanced processes for primary aluminum reduction, which can reduce energy intensity to about 11,000 kWh/ton, are expected to become available in 2010.[44,45]

It is important to note that aluminum can also be produced from scrap by secondary processes that are much less energy intensive than primary production. In 1995, China's share of secondary aluminum production was only seven percent.[37] As this fraction increases, overall energy intensity will decline, and for this analysis, that effect was captured through efficiency improvement in the "modern" and "advanced" technologies. For the baseline scenario, the fraction of aluminum recycle was projected to increase by 2050 to current levels in the USA and Germany (44%).

3.4.2.1.6 Other Industry Demand Technologies

The other industry category was modeled using eight demand technologies to satisfy the energy demands for electricity, heat and non-energy feedstocks. The other industry electricity demands were modeled using a dummy technology. An other industry electric conservation technology was used to model reductions in the projected demand attributable to conservation measures, such as high-efficiency motors and lighting, variable speed drives, etc. that go beyond the level of efficiency improvement incorporated in the development of the demand data. Coal-fired, liquid-fuelled, and gas-fuelled boilers along with co-generated heat and a conservation technology were available as demand technologies to supply heat demands in the Other industry category. The conservation technology accounted for efficiency improvements such as better steam traps, and for process improvements that would reduce the overall heat demand. Non-energy feedstocks were modeled with a dummy technology.

Where there are competing demand technologies for the model to select from, the conservation technologies are modeled with investment and O&M cost data to allow the model to make cost-effective choices between supply and conservation. Where the final energy demand is modeled using a dummy technology (e.g. the lighting and appliance demands) the conservation technology is also a dummy, so that the model implements the conservation automatically (because it reduces demand and hence system cost). Assumptions regarding the conservation technologies for all end-use sectors are listed in Table 8. The cost and savings potentials shown in the table are based on Jochem *et al.*'s estimate of the economic potential for savings in China.[46] We assumed that the level of potential energy savings increased gradually until reaching the predicted economic potential for savings at the end of the analysis period. This is a fairly aggressive assumption, because the level of economic efficiency improvements, while lower than the technical potential, are not currently met in most industrialized countries due to market and institutional barriers.

Table 8. Conservation Technologies

Conservation Technology	Energy Saved (PJ)			Economic Potential[a]	Capital Cost ($/GJ/yr)	O&M Cost ($/GJ)
	2010	**2030**	**2050**			
Other industry electric conservation	132	430	1514	15%	N.U.	N.U.
Other industry heat conservation	719	1751	4040	25%	4.60	0.24
Commercial cooling conservation	9	61	216	15%	4.68	0.19
Commercial lighting conservation	30	160	399	25%	N.U.	N.U.
Commercial heating conservation	92	461	1195	20%	4.68	0.19
Urban cooling conservation	2	15	44	15%	9.35	0.38
Urban cooking & hot water conservation	37	214	628	30%	N.U.	N.U.
Urban lighting conservation	25	162	556	25%	N.U.	N.U.
Urban heating conservation	142	795	2084	20%	4.41	0.19
Rural cooking & hot water conservation	31	116	261	30%	N.U.	N.U.
Rural lighting conservation	22	93	207	25%	N.U.	N.U.
Rural heating conservation	81	304	706	30%	3.34	0.14
Agricultural electric conservation	20	77	160	20%	N.U.	N.U.
Agricultural process heat conservation	32	94	149	20%	N.U.	N.U.
Irrigation conservation	18	59	107	35%	N.U.	N.U.
Farm machinery conservation	8	25	46	5%	N.U.	N.U.

(a) This is the maximum economic savings potential as indicated by Jochem *et al.*[46] We have assumed that the maximum percentage is reached in 2050. Percentage savings are smaller in earlier years.
N.U. = None used.

3.4.2.2 Residential Sector Demand Technologies

Urban residential energy demands (Table 9) were divided into the same four categories used to project energy service demands in this sector: air conditioning, cooking & water heating, lighting & electric appliances, and space heating. Air conditioning and lighting & appliances were modeled as dummy technologies using electricity as the final energy carrier. Conservation technologies were also used for both categories (Table 8). Technologies for meeting urban cooking & water heating demands were coal, LPG/DME, electric, and gas stoves, solar water

Table 9. Commercial, Residential and Agricultural Demand Technologies

Demand Technology	Year First Available	Energy Efficiency (GJ/GJ)	Capital Cost ($/t/yr)	O&M Cost ($/t)	Average Utilization Factor	SO_2 Emissions (kg/GJ fuel)	NO_x Emissions (kg/GJ fuel)
Commercial Sector							
Air conditioning - chillers-coal	1995	1.00	6.75	0.34	0.3	1.03	0.44
Air conditioning - chillers-oil	1995	1.00	5.62	0.28	0.3	0.30	0.22
Air conditioning - chillers-gas	1995	1.00	5.62	0.28	0.3	0.00	0.11
Air conditioning - chillers-LTH	1995	1.00	3.46	0.23	0.3	0.00	0.00
Air conditioning - compressors	1995	1.00	4.48	0.22	0.3	0.00	0.00
Air conditioning - solar w/gas backup	1995	1.00	10.68	0.28	0.3	0.00	0.00
Lighting & appliances	1995	1.00	N.U.	N.U.	1.0	0.00	0.00
Space & water heating - coal boiler	1995	0.65	3.16	0.16	0.3	1.03	0.44
Space & water heating - gas boiler	1995	0.75	2.00	0.12	0.3	0.00	0.11
Space & water heating - electric heater	1995	1.00	2.88	0.16	0.3	0.00	0.00
Space & water heating - oil boiler	1995	0.70	2.50	0.12	0.3	0.30	0.22
Space & water heating - LTH	1995	0.80	0.00	0.00	0.3	0.00	0.00
Space & water heating - solar w/gas	1995	0.80	7.29	0.39	0.3	0.00	0.00
Urban Residential Sector							
Air conditioning - electric	1995	1.00	4.48	0.22	0.16	0.00	0.00
Air conditioning - solar w/gas backup	1995	1.00	13.82	0.28	0.16	0.00	0.00
Cooking & hot water - coal	1995	0.30	0.96	0.10	0.16	1.03	0.44
Cooking & hot water - gas	1995	0.50	2.67	0.12	0.16	0.00	0.11
Cooking & hot water - electric	1995	0.80	2.88	0.16	0.16	0.00	0.00
Cooking & hot water - LPG/DME	1995	0.50	2.67	0.12	0.16	0.00	0.11
Cooking & hot water - solar w/LPG backup	1995	0.50	6.24	0.15	0.16	0.00	0.11
Lighting & appliances	1995	1.00	N.U.	N.U.	1.0	0.00	0.00
Space heating - central boiler	1995	0.65	3.16	0.16	0.3	1.03	0.44
Space heating - scattered boiler	1995	0.60	2.88	0.14	0.3	1.03	0.44
Space heating - coal stove	1995	0.50	1.27	0.10	0.3	1.03	0.44
Space heating - electric	1995	1.00	2.88	0.16	0.2	0.00	0.00
Space heating - LTH	1995	0.80	0.00	0.00	0.3	0.00	0.00
Space heating - gas boiler	2000	0.75	2.00	0.12	0.3	0.00	0.11
Space heating - solar w/gas backup	2000	0.80	7.29	0.29	0.3	0.00	0.00
Rural Residential Sector							
Cooking & hot water - coal	1995	0.30	0.96	0.10	0.16	1.03	0.08
Cooking & hot water - biomass	1995	0.50	1.13	0.02	0.16	0.00	0.00
Cooking & hot water - biogas/producer	1995	0.70	1.81	0.12	0.16	0.00	0.11
Cooking & hot water - solar w/gas backup	1995	0.50	4.16	0.15	0.16	0.00	0.11
Cooking & hot water - LPG/DME	1995	0.70	1.81	0.12	0.16	0.00	0.11
Cooking & hot water - village CHP	2005	0.90	0.00	0.05	0.16	0.00	0.00
Lighting & appliances	1995	1.00	N.U.	N.U.	1.0	0.00	0.00
Space heating - coal	1995	0.50	1.27	0.10	0.3	1.03	0.44
Solar house design with coal backup	1995	0.80	7.57	0.05	0.3	0.00	0.00
Space heating – biogas/producer gas	1995	0.80	1.15	0.12	0.3	0.00	0.11
Space heating - DME	1995	0.80	2.67	0.12	0.3	0.00	0.11
Space heating - biomass	1995	0.80	1.13	0.02	0.3	0.00	0.00
Solar heating panels-w/coal backup	1995	0.80	4.42	0.52	0.3	1.03	0.44
Space heating - village CHP	2005	0.90	0.00	0.02	0.3	0.00	0.00
Agricultural Sector							
Electric motors	1995	1.0	N.U.	N.U.	1.0	0.00	0.00
Agro-processing	1995	1.0	N.U.	N.U.	1.0	1.03	0.44
Irrigation	1995	1.0	N.U.	N.U.	1.0	0.30	0.22
Farm machines	1995	1.0	N.U.	N.U.	1.0	0.30	0.22

N.U. = none used

heaters with gas backup, and conservation. Urban space heating technologies consisted of centralized and scattered coal boilers, coal stoves, gas boilers, electric heaters, solar panels, co-generated heat and conservation.

The rural residential sector energy demands were divided into three categories: cooking & water heating, lighting & electric appliances and space heating. Lighting & appliances were modeled using a dummy technology to satisfy the energy demand using electricity as the final energy carrier and a conservation technology to model additional efficiency improvements beyond those incorporated in the development of the demand data. The cooking & water heating demand technologies included four stoves: coal, biomass, biogas/producer gas, and LPG/DME; solar, co-generated heat, and conservation. Rural space heating technologies included coal, biomass, biogas/producer gas, and DME stoves, co-generated heat, passive solar homes, solar panels with coal backup, and conservation.

3.4.2.3 Commercial Sector Demand Technologies

Commercial sector energy demands (Table 9) were divided into three categories: air conditioning, lighting and appliances, and space and water heating. As in other demand categories, lighting and appliances were modeled by a dummy technology and conservation. Air conditioning technologies included electric compressors, absorption chillers, and conservation. Space heating technologies consisted of coal, liquid and gas boilers, electric heaters, co-generated heat and conservation. Energy efficiency improvements for this sector include such things as improved building envelopes (wall and roof insulation, thermal pane window, and better building designs), improved building controls, compact fluorescent lighting, new HVAC technologies, and improved boiler designs.

3.4.2.4 Agricultural Demand Technologies

The agricultural sector energy demands are relatively small, and so they were modeled using dummy technologies to satisfy their energy demands using the appropriate final energy carriers (Table 9). Conservation technologies were used in all four of the agricultural demand categories (Table 8).

3.4.2.5 Transport Demand Technologies

Demand technologies for the freight and passenger transport categories are listed in the Table 10. Gasoline and diesel truck energy efficiency was increased over time to reach vehicle energy efficiencies projected for 2020 for Europe and the USA.[47] Ship energy efficiencies for freight transport were also projected to increase and keep pace with projected worldwide improvements. Conventional bus energy efficiency was projected to decline until 2010 as near-term improvements in passenger comfort are expected to outweigh increases in engine efficiency. After 2030, bus energy efficiency increases to keep pace with worldwide averages. The cost and efficiency values for hybrid electric and fuel cell vehicles were developed from Ogden, *et al.*,[48] and the CNG bus fuel economy was taken from the LEAP database.[47] In most cases, the efficiencies of different vehicle types was kept constant over the period of the analysis, because the size and amenities associated with the vehicles are assumed to grow with time. The energy efficiency of the transport sector as a whole increases over time as larger fractions of the more efficient vehicles enter the fleet.

Table 10. Transportation Demand Technologies

Transportation Demand Technology	Year First Available	Energy Efficiency 1995	2010	2030	2050	Capital Cost	O&M Cost	SO2 Emissions (kg/GJ fuel)	NOx Emissions (kg/GJ fuel)
Freight		**1000 t-km/GJ**				**$/1000 t-km**			
Air	1995	0.042	0.042	0.042	0.042	N.U.	N.U.	0.08	0.29
Pipeline	1995	1.50	1.50	1.50	1.50	N.U.	N.U.	0.08	1.65
Ship - diesel & fuel oil	1995	1.52	1.76	1.95	1.99	N.U.	N.U.	0.08	0.62
Rail - coal	1995	3.48	3.48	3.48	3.48	N.U.	N.U.	1.03	0.08
Rail - diesel	1995	9.69	9.69	9.69	9.69	N.U.	N.U.	0.08	1.65
Rail - electric	1995	25.39	25.39	25.39	25.39	N.U.	N.U.	0.00	0.00
Truck - gas	1995	0.445	0.558	0.717	0.877	N.U.	N.U.	0.00	0.23
Truck - diesel	1995	0.593	0.690	0.763	0.778	N.U.	N.U.	0.08	0.67
Passenger		**1000 passenger-km/GJ**				**$/1000 p-km**			
Airplane	1995	0.469	0.476	0.486	0.495	N.U.	N.U.	0.08	0.29
Bus - diesel	1995	1.84	1.71	1.71	1.89	86.8	2.59	0.08	1.00
Bus - hybrid electric	2005		3.68	3.68	3.68	94.6	2.59	0.00	0.00
Bus - CNG bus	2000		1.91	1.91	1.91	104.2	2.59	0.00	0.21
Bus - fuel cell[a]	2010		4.35	4.35	4.35	104.2	1.04	0.00	0.00
Car - gasoline	1995	0.578	0.578	0.578	0.578	666.7	43.9	0.00	0.54
Car - diesel	1995	0.598	0.598	0.598	0.598	666.7	43.9	0.08	0.51
Car - hybrid electric	2005		1.21	1.21	1.21	726.3	43.9	0.00	0.54
Car - fuel cell[a]	2010		2.11	2.11	2.11	776.0	43.9	0.00	0.00
Rail – diesel	1995	5.83	5.83	5.83	5.83	N.U.	N.U.	0.08	1.65
Rail – electric	1995	15.3	15.3	15.3	15.3	N.U.	N.U.	0.00	0.00
Ship - diesel & fuel oil	1995	1.20	1.20	1.20	1.20	N.U.	N.U.	0.08	0.62

(a) Fuel costs calculated by MARKAL for these technologies include H_2 transmission, distribution cost of $2.8/GJ and refueling station cost of $1.9/GJ.

(b) Energy efficiency for many passenger vehicle types was kept constant over the analysis period, because vehicles size and amenities are assumed to grow with time and to offset the improvements in efficiency.

4 Results and Discussion

In keeping with the overall objective of the work – to understand at a broad level the implications for China of different energy-technology choices – as well as the specific objective of answering the four questions raised in Section 1, the framework for our application of the China MARKAL model consists of two basic sets of technology scenarios, overlaid by one or more of the following constraints: *i)* limits on emissions of SO_2; *ii)* limits on imports of oil and natural gas; and *iii)* limits on emissions of CO_2 to the atmosphere.

One set of model runs used only the Base set of energy conversion technologies (Table 5). These runs represent a continuation of current energy-supply technology trends, with incrementally improved technologies (having higher efficiency and or lower emissions) available for introduction into the economy, but without the possibility of introducing fundamentally different technologies. For example, in the case of coal-electric technologies, more efficient coal combustion technologies are available in the Base set, but gasification-based technologies are not. The Base set of technologies might be described as those that would result from a "laissez-faire" approach to energy-supply planning and development, with little incentive provided for the development and introduction of technologies that would provide "leap-frog" rather than incremental improvements.

A second set of model runs added the Advanced set of energy conversion technologies (Table 6) to the Base set, thereby providing leap-frogging opportunities. The model chooses the advanced technologies to meet environmental or energy import constraints whenever they minimize total system cost. While the model does choose advanced technologies under a variety of conditions, many of the advanced technologies represent radically new technologies that will not necessarily be introduced into the Chinese economy without focused government policies and support for technology research, development, demonstration, and commercialization (in China and/or in other countries). Some policy implications of the scenario results are discussed in the final section of the paper.

In all model runs with either the Base or Advanced energy-supply technologies, the model chooses the subset of energy conversion, demand, and conservation technologies that minimizes the total discounted cost of meeting the energy service demands. In many cases, conservation and the more efficient technology options will lead to the minimum total system cost. This is consistent with the generally accepted notion that there are considerable cost-effective energy efficiency improvements possible in most economies. One indication of the aggressiveness of energy efficiency improvements calculated in the model is the rate of decline in primary energy intensity (primary energy use per $ of GDP). Between 1995 and 2050, in most of the cases discussed below, the primary energy intensity falls from 58 MJ/$GDP to about 8 MJ/$GDP, which is an average of about 3.5% per year. For comparison, over the period 1980 to 1997, primary energy intensity fell an average of 1.2%/year in Japan (from 8.2 to 6.9 MJ/$GDP), 1.4%/year in the USA (from 18.6 to 15.5 MJ/$GDP), and 1.8% per year in the UK (from 13.1 to 9.7 MJ/$GDP).[49] Given China's high starting point, this level of improvement in primary energy intensity is aggressive, but not implausible.

For the Base and Advanced energy-supply technology sets, we explored various levels of constraints on emissions of SO_2, oil and gas imports, and carbon emissions. Emissions of SO_2 are taken as an indicator of local air pollution generally. We considered only a single profile of SO_2 emission cap over time. Annual emissions were capped through 2020 at levels officially targeted by the Chinese government, which plans to reduce emissions from the current level of about 24 million tonnes/year of SO_2 to 16.5 million tonnes in 2020. For 2050, we selected an allowable level of SO_2 emission that would give China an average SO_2 emission per unit of coal consumed that is roughly comparable to the level found in the United States today. We connected the 2020 and 2050 target levels with a smooth curve, and the total allowed annual SO_2 emission reaches 10.4 million tonnes in 2050. Under the SO_2 emissions cap, the maximum cumulative emissions allowed between 1995 and 2050 are 987 million tonnes of SO_2.

We explored limits on the allowable imports of oil and natural gas. The percentage of oil and of natural gas that could be imported in any given year were each separately constrained to values as low as 20%. For comparison, oil imports to China in 2000 accounted for about 30% of oil consumption. The United States imports about 50% of its oil today.

We developed alternative carbon emission caps from IPCC estimates of cumulative global carbon emissions to the atmosphere between 1990 and 2100 that would enable stabilization of atmospheric concentrations of CO_2 at 350 ppmv (380 GtC allowed globally), 450 ppmv (750 GtC), 550 ppmv (1100 GtC), or 750 ppmv (1400 GtC).[50] The level of emissions attributable to China over this period was calculated to be proportional to its share of year-2000 global population (21.5%). The algorithm we used to determine the cumulative allowable emissions to

2050 is as follows: the annual growth rate in Chinese CO_2 emissions between 1990 and 2100 was assumed to be constant at the level that results in China reaching its cumulative proportion of global emissions in 2100. With this trajectory, the cumulative allowable emissions to 2050 were thereby calculated to be 89, 80, 66, and 46 GtC for a 750, 550, 450, and 350 ppmv world, respectively.

In Section 4.1, we present a broad summary of the Base and Advanced energy-supply technology case results within the framework of scenario constraints described above. This summary is intended to give a picture of the full set of scenarios that were explored, but does not provide detailed discussion of any of the scenarios. In Section 4.2 we examine two scenarios in detail, which provides greater insight into the operation of the model and highlights the fundamentally different technology and fuel choices being made in the Base and Advanced sets of scenarios.

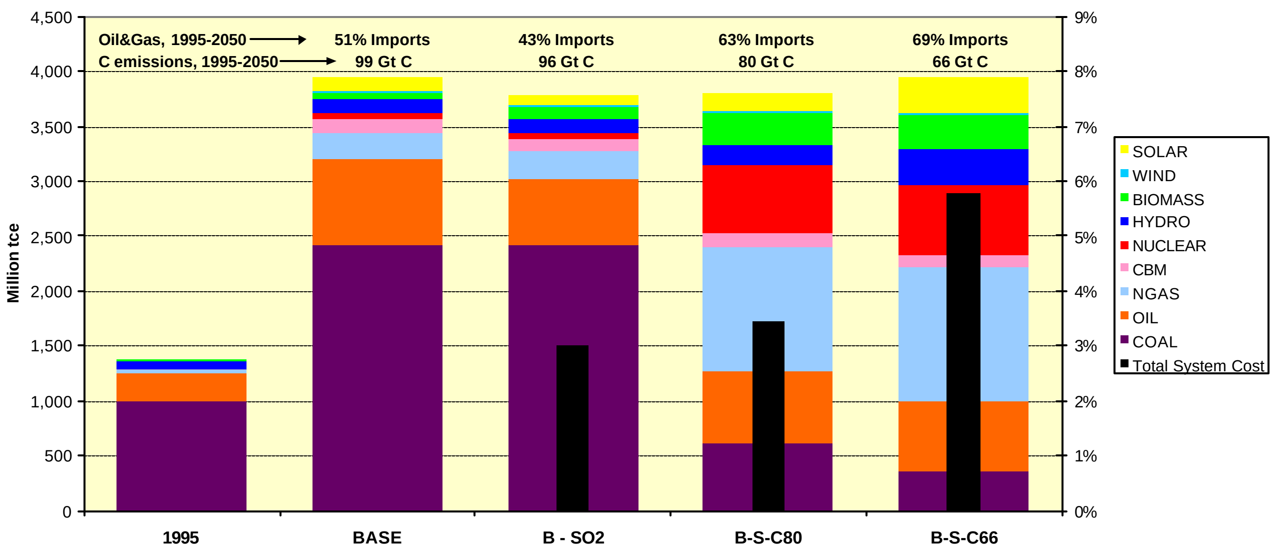
4.1 Summary of All Model Results

To summarize the extensive detailed results generated for each of a number of different scenarios by the China MARKAL model, we have chosen the primary energy mix in 2050 as the principal metric. This provides a good indication of the types of choices made by the model to meet the various constraints imposed. In the primary energy representations, we have converted nuclear, hydro, wind, solar, and geothermal electricity to "fossil-fuel equivalents" by multiplying by 3.03.

We begin with a summary of the scenarios that use the base set of energy-supply technologies (Figure 4). The colored bars give the breakdown of primary energy use. The numbers above each bar indicate the percentage of the cumulative (1995-2050) oil and gas energy use that is imported and the total cumulative emissions of CO_2 (expressed in carbon terms – GtC). The center black bar in the three scenarios on the right in this figure shows the change in cumulative (1995-2050) discounted total system cost relative to the scenario labeled BASE. The discounted total system cost for a given scenario, which we refer to below as the "system cost," represents the total cost in that scenario for the period 1995-2050 for investments in energy conversion and demand technologies, for fuel, and for O&M and other costs, discounted to 1995 dollars. Due to the large uncertainties in this kind of analysis, we use the difference in system cost between the various scenarios as the measure of the cost impact of the changes imposed by each scenario. The system cost for the BASE case is the reference cost in all cost comparisons shown in this section.

In the BASE case, no constraints were placed on emissions of SO_2, on oil/gas imports, or on carbon emissions. The other cases in Figure 4 show the impact of adding constraints. The bar labeled B-SO_2 is the BASE case with the SO_2 emissions cap (defined earlier) imposed. The bars labeled B-S-C80 and B-S-C66 represent BASE cases with the SO_2 emission constraint imposed and cumulative (1995-2050) carbon emissions limited to 80 GtC and 66 GtC, respectively. Primary energy use in 2050 ranges from 111 to 116 EJ (3790 to 3950 Mtce), or roughly triple 1995 energy use.[51] Coal is the dominant energy source in the BASE and the SO_2–constrained scenario (B-SO_2) and is used at the maximum allowed rate throughout the analysis period. Primary energy use decreases in the B- SO_2 case because of substitution of coal for more efficient natural gas use in the industrial sector. In the electric sector, cleaner and more efficient coal combustion technologies such as ultra-supercritical-steam power plants with flue gas

Figure 4. BASE Technology Scenarios. 2050 primary energy use and change in cumulative (1995-2050) discounted total system cost. Also indicated are the cumulative (1995-2050) percent of oil and gas use that is imported and the total carbon emissions.

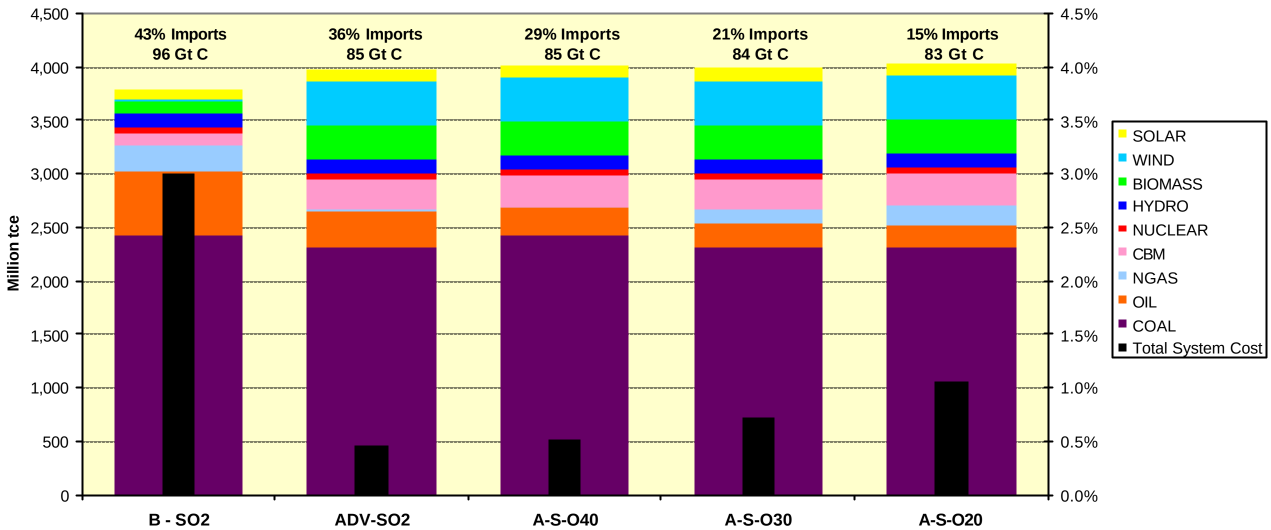


desulfurization are selected in B-SO_2 in place of less costly but more-polluting and less-efficient technologies, enabling some reduction in oil use, but contributing to a 3% increase in total cumulative discounted system cost from 1995-2050. Oil and gas imports average 280 Mtoe/year in the BASE scenario during the 55-year analysis period, peaking at 450 Mtoe in 2050. Cumulatively, 51% of oil and gas is imported. In the B- SO_2 scenario, oil and gas imports average 203 Mtoe/year and peak in 2050 at 329 Mtoe. Cumulatively, 43% of oil and gas is imported during 1995-2050, the lowest achievable oil/gas import level with the base technologies.

Cumulative carbon emissions are 99 GtC in the BASE scenario and fall slightly in the B-SO_2 scenario. To achieve greater reductions in carbon emissions with the base technologies, coal use must be dramatically reduced and imports of oil and gas must be substantially increased, e.g., reaching 988 Mtoe in 2050 for the scenario with 80 GtC cumulative carbon emissions (B-S-C80). Furthermore, the lower carbon emission cases requires an increase in the exploitation of hydroelectric resources – by about 33% in the B-S-C80 case relative to the B-SO_2 case and to the maximum allowed amount in the B-S-C66 case. Moreover, nuclear energy increases by an order of magnitude over the B-SO_2 scenario, reaching the maximum allowed installed capacity in 2050 (216 GW) and supplying about 40% of all electricity in 2050 in both the B-S-C80 and B-S-C66 scenario. The use of biomass resources also reaches its limit, with most of the biomass being used in village-scale systems co-producing electricity and producer gas for cooking and heating. Solar energy contributions also grow significantly in the carbon-constrained cases, reaching almost 200 GW of solar PV capacity. Primary energy use increases in the B-S-C66 case relative to the B-S-C80 case because of the decrease in cogenerated heat from coal (driven by the need to decrease coal use) that is largely replaced by renewables. To achieve the 80 GtC emission limit, the total discounted system cost increases insignificantly compared to the B-SO_2 case, and to reach the 66 GtC limit, the system costs increases only slightly (6% higher than the BASE case) . It is not possible to reach the 46 GtC limit with the base set of technologies.

Figure 5 summarizes scenarios that meet the SO_2 emissions cap using advanced energy-supply technologies, with varying levels of constraints on oil and gas imports. Because the advanced technologies can provide clean substitutes for oil and gas, cumulative imports as low as 15% can be achieved, with insignificant increases in the system cost relative to the unconstrained BASE scenario. Furthermore, the change in total system cost in all advanced-technology cases shown in Figure 5, is a factor of three to six lower than the change in total system cost to meet the SO_2 cap with the base energy-supply technologies (B-SO_2). The lower cost of achieving SO_2 reductions in the advanced case is also reflected in the marginal cost of emission reductions calculated by the model. For example, in 2010 the marginal cost is \$370/tSO2 for the B-SO_2 case compared to \$100/tSO_2 for the ADV-SO_2 case.

Figure 5. Advanced Technology Cases. 2050 Primary energy use and change in cumulative (1995-2050) total discounted system cost. Also indicated are the cumulative (1995-2050) percent of oil and gas use that is imported and the total carbon emissions.



Unlike the base-technology cases in Fig. 4, coal is not used at its maximum allowed rate in any of the advanced technology scenarios shown in Fig. 5. Increased electricity production from biomass and wind reduces pressure on coal use, and the tight oil and gas import constraints are satisfied by converting coal and biomass via polygeneration into synthetic liquids and gases. Additionally, the advanced technology set includes the option of enhanced production of coal-bed methane by injecting into deep, unmineable coal seams the CO_2 captured at coal gasification facilities. (This is in addition to conventional coal bed methane from coal mines, which is also available in the base scenarios.) The added CBM further reduces pressure on coal use and natural gas imports.

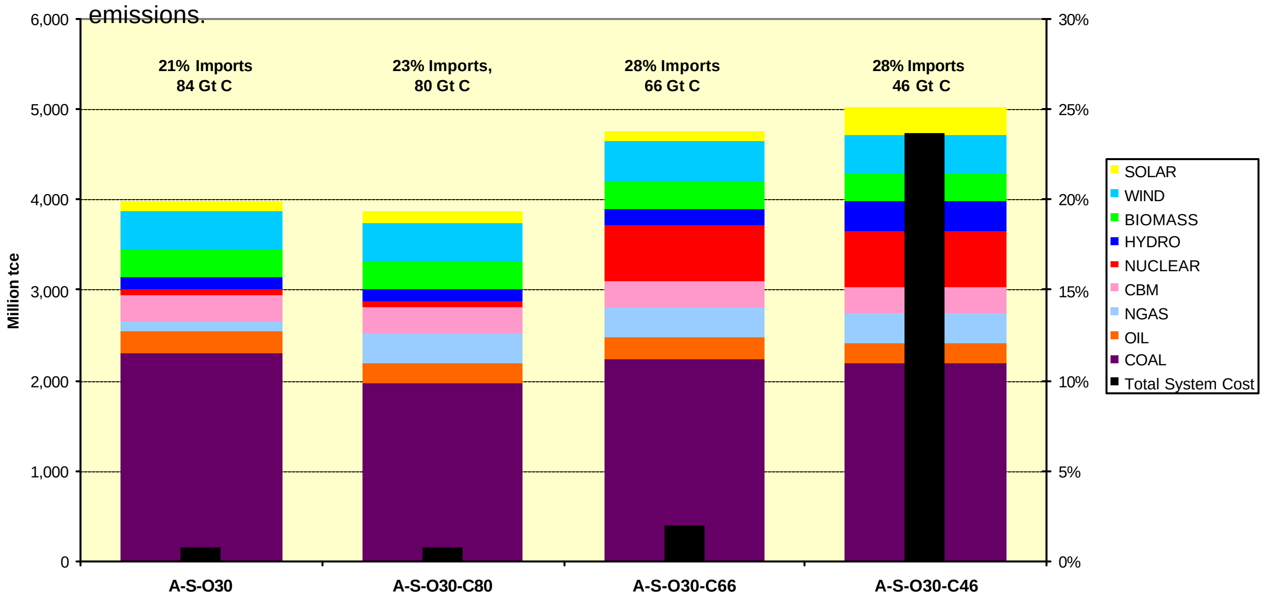
The wind energy technology selected under these scenarios is remote, large-scale wind farms with long-distance transmission to load centers, and the model selects this option up to the maximum allowed level. Electricity from these large wind farms is less costly than nuclear or hydro electricity, so the contributions of the latter two options are limited to modest levels. Under these scenarios, the model also uses the maximum allowed level of biomass resource, and the preferred use of the biomass is for co-production of electricity and dimethyl ether, a fuel that is used like LPG for cooking and heating and also as a diesel substitute in transportation.

Very noteworthy is the fact that all of the advanced technology scenarios in Fig. 5 reduce cumulative carbon emissions by between 11% and 14% compared to the B-SO_2 scenario. Thus, carbon emissions can be reduced from 96 GtC to 85 GtC or less as a byproduct of satisfying the SO_2 and oil import constraints with the advanced technologies. Most of the carbon reductions come as a result of using CO_2 for enhanced recovery of CBM and oil. Due to the relatively low cost of these indigenous resources, they are used from 2010 on at the maximum allowed levels (Table 3) in all of the advanced-technology scenarios described in this report. The amount of carbon sequestered in association with enhanced resource recovery (ERR) reaches 142 million tC in 2050, of which 136 MtC is for enhanced CBM recovery.

Given uncertainties surrounding the size of the potential CBM resource, we made a sensitivity run with the cumulative conventional CBM resource limited to half the value shown in Table 3 and the CO_2 –enhanced CBM resource limited to one-third the value in Table 3. With this constraint, the model selected more hydrogen and more methanol from coal polygeneration processes with CO_2 sequestration to replace CBM. Coal use increased by about 70 Mtce in 2050, but was still over 100 Mtce below the maximum allowed amount for that period.

To examine the impact of carbon emissions constraints applied with the advanced technologies, we ran the A-S-O30 case (advanced technologies with SO_2 cap and 30% oil/gas import limit) with varying levels of carbon constraints. Without any carbon constraints, the 1995-2050 cumulative carbon emission is 84 GtC, as shown in Fig. 5 and reproduced in Figure 6. Only minor changes in the primary energy mix relative to the unconstrained A-S-O30 are needed to meet the 80 GtC target. The most significant change is a small decrease in coal use and a compensating increase in natural gas use. Total system cost is insignificantly different from the A-S-O30 scenario. An important difference in the 80 GtC scenario that does not show explicitly

Figure 6. Advanced Technology and Carbon Constraint Cases. 2050 Primary energy use and change in cumulative (1995-2050) total discounted system cost. Also indicated are the percent of oil and gas use that is imported and the total carbon emissions.



in Fig. 6 is carbon sequestration that is not related to ERR. Non-ERR sequestration begins in the early 2040s, and 1.3 GtC are sequestered in the final decade of the analysis period. This nearly matches the 1.4 GtC that are sequestered during this period in association with ERR.

To meet the 66 GtC target, there is a major transition to electric technologies in the commercial and residential sectors starting in 2035, and that increased electrical demand is supplied largely by nuclear power, which is used to the maximum level allowed. This causes the total primary energy use, as depicted in Figure 6 to increase by 20% relative to the unconstrained case (A-S-O30). However, total fossil primary energy use increases only about 5% relative to the A-S-O30 case (due primarily to the efficiency penalties associated with CO_2 sequestration). Sequestration activities begin in 2010 at a modest level (5 million tC/year) and increase thereafter, averaging 0.6 GtC/year in the second quarter of the century and reaching a maximum of almost 1.1 GtC sequestered in 2050.

We made one sensitivity run to examine the extent to which nuclear power is needed to reach the 66 Gt cumulative level of carbon emissions. Future investments in nuclear capacity were not allowed, and the currents plants were allowed to run for their economic life. In this scenario, the model replaces all the new nuclear capacity that it selects in the A-S-O30-C66 case with advanced coal gasification and advanced hydrogen production technologies that sequester CO_2. The use of hydroelectric power also increases to the limit of the exploitable resource. The other technology choices remain essentially unchanged. Total coal use in 2050 is about 100 Mtce below the maximum allowed. Over the entire period, cumulative coal use increases by about 2,200 million tonnes, reaching 92% of the maximum allowed cumulative production (compared to 88% of maximum in the A-S-O30-C66 case). The total system cost of this "no nuclear" case was identical to that of the A-S-O30-C66 case, and (as shown in Figure 6) the percentage difference in cost between the BASE and A-S-O30-C66 case (2%) is not very significant.

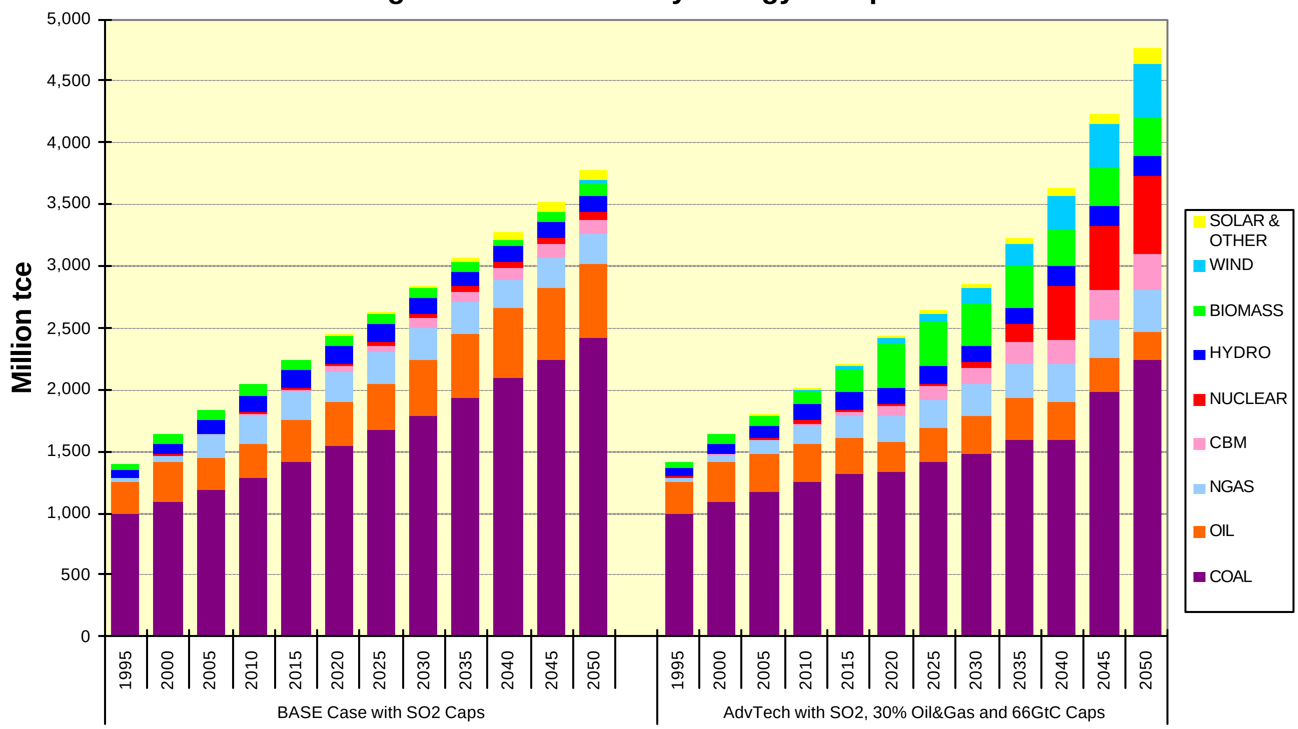
The cumulative carbon cap of 46 Gt C can also be met with the advanced technologies (Figure 6). However, the increase in system cost is substantially greater (24% relative to the BASE) than for the 66 GtC case, and 20 Gt of additional carbon must be sequestered during the analysis period. The electrification of the commercial and residential sectors starts about 2015, and by 2040 these sectors have no direct fossil fuel used as final energy. In addition to nuclear power, the model maximizes hydroelectric capacity and adds large-scale grid-connected solar electric power systems to meet the electrical demands.

4.2 Detailed Results for Two Scenarios

Figures 4 to 6 in the previous section summarize key characteristics of the principle scenarios that we explored. In this section, we compare in detail the B-SO_2 scenario with the A-S-O30-C66 scenario to provide a more complete understanding of the fundamental features of an advanced-technology energy-supply strategy as contrasted with features of a "business-as-usual" energy-supply strategy. As a shorthand in this section, we refer to the B-SO_2 scenario (base energy-supply technologies meeting SO_2 constraint) as the B scenario and the A-S-O30-C66 scenario (advanced energy-supply technologies meeting SO_2 constraint, with maximum oil/gas imports of 30% in any given year, and cumulative carbon emission limit of 66 GtC, 1995-2050) as the A scenario.

Primary energy use in the B scenario grows from about 1,400 Mtce (41 EJ) in 1995 to about 3800 Mtce (110 EJ) in 2050 (Figure 7). Total primary energy growth is similar in the A scenario

Figure 7. Total Primary Energy Comparison



until the latter part of the analysis period, when primary energy use grows more rapidly than in the B scenario due mostly to the switch to electric end-use technologies in the commercial and residential sectors as explained above. However, the growth in fossil-fuel primary energy is significantly lower in the A scenario, especially up until 2035, when there is a spurt in coal to the electric sector to support the electrification in the commercial and residential sectors. Total primary energy use reaches 4760 Mtce (139 EJ) in 2050, but fossil primary energy use is 280 Mtce lower than in the B scenario. Coal contributes importantly in both scenarios. Natural gas has a modestly more important role in the A scenario, while oil plays a less significant role. The most significant increases in energy supplies in the A scenario come from CBM, biomass, wind energy, and (in the later part of the period) nuclear power. Each of the primary energy resources is discussed next by way of explicating the A and B scenarios.

Coal maintains its dominance in the B scenario throughout the 55-year period. It is used at the maximum allowed level (see Table 3), falling only modestly as a fraction of total energy use from 71% in 1995 to 64% in 2050. The fraction of coal used for electricity production increases gradually from about 30% in 1995 to 41% in 2050. Direct use of coal is forced out of the industrial, residential, and commercial sectors over the analysis period (Figure 8) in order to meet the SO_2 emissions cap. Coal is increasingly used instead for production of town gas for industrial, commercial, and residential uses (Figure 9).

A striking feature of the A scenario is the much lower percentage of coal in the primary energy mix at the end of the analysis period (Figure 7). Coal use does not reach the maximum allowed level and represents only 47% of primary energy use in 2050. Direct use of coal in industry, commercial, and residential sectors declines, as in the B scenario, but coal to the electricity sector increases to a much more substantial level (60%) by 2050 (Figure 8). The increasing fraction of coal going to the electricity sector is primarily a consequence of two related factors: *i)* electricity generation provides the least costly means for capturing and sequestering carbon, which is required to meet the 66 GtC cap, and *ii)* the demand for hydrogen grows in the second quarter, as discussed below, and the least costly source of hydrogen is from coal at facilities that co-produce electricity and hydrogen.

Figure 8. Distribution of Coal Use by Sector

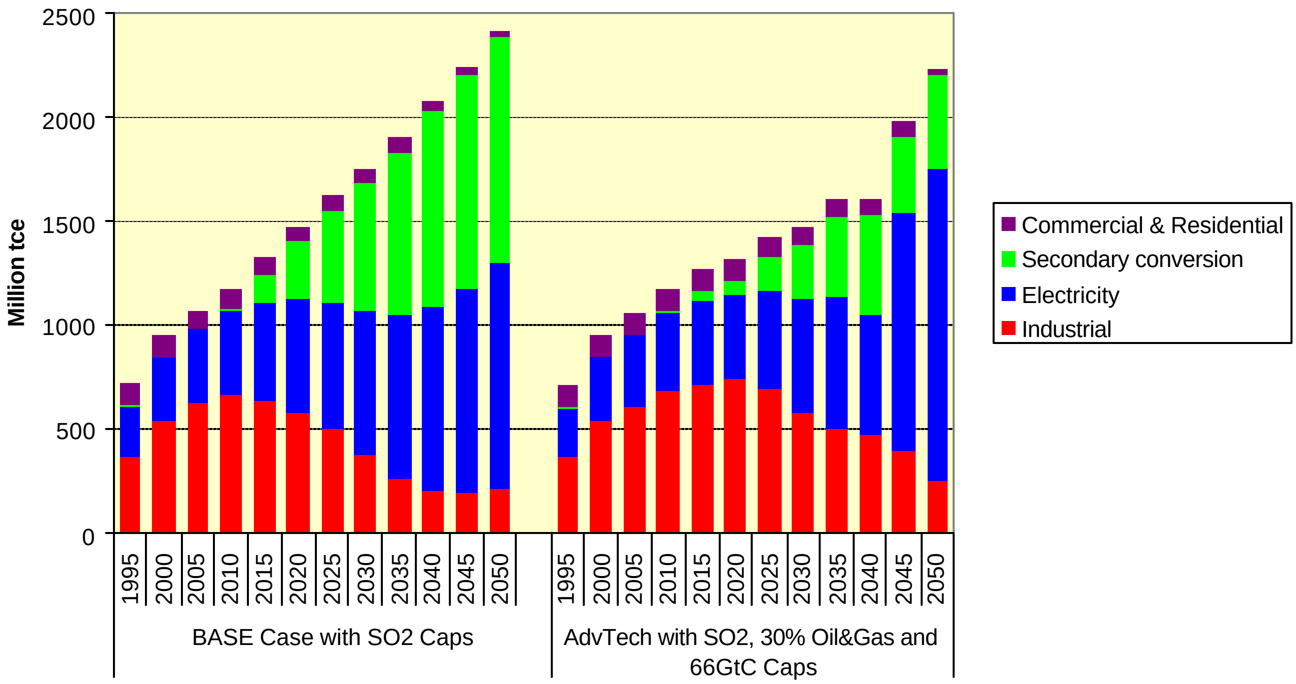
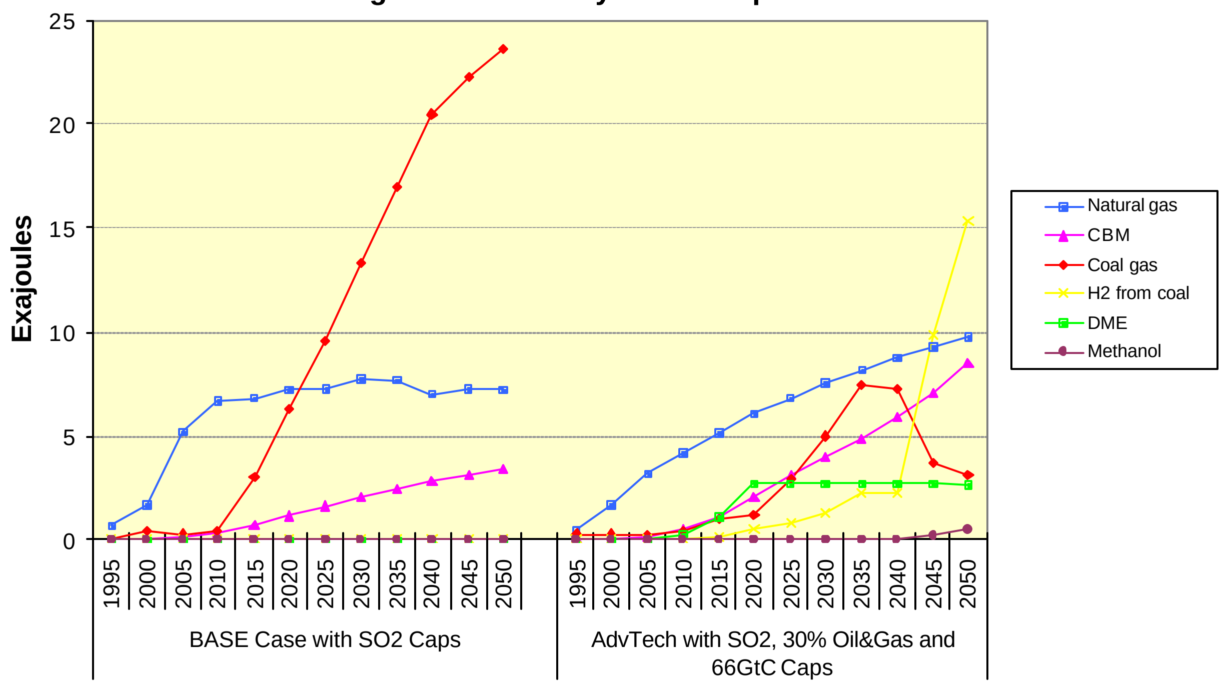


Figure 9. Gas & Synthetic Liquid Fuels



The share of oil and natural gas in the primary energy mix stays nearly constant over the analysis period in the B scenario, but the absolute consumption of these resources grows from 8.5 EJ in 1995 to 25 EJ in 2050 (Figure 7). After domestic oil production peaks in 2020, oil imports grow rapidly, reaching 320 million tonnes in 2050, when they account for 76% of total oil supply (Figure 10). Imports of gas peak early in the period in the B scenario, reaching 97 billion m^3 in 2010, when they account for 56% of total gas use (Figure 11). On average over the analysis

Figure 10. Domestic and Imported Oil Use

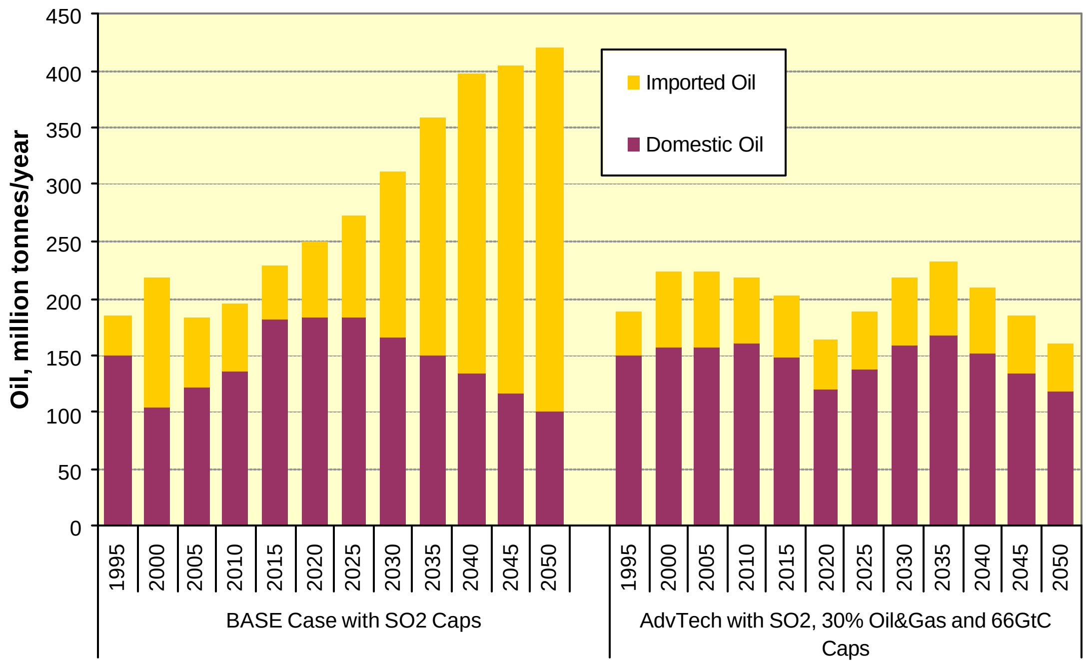
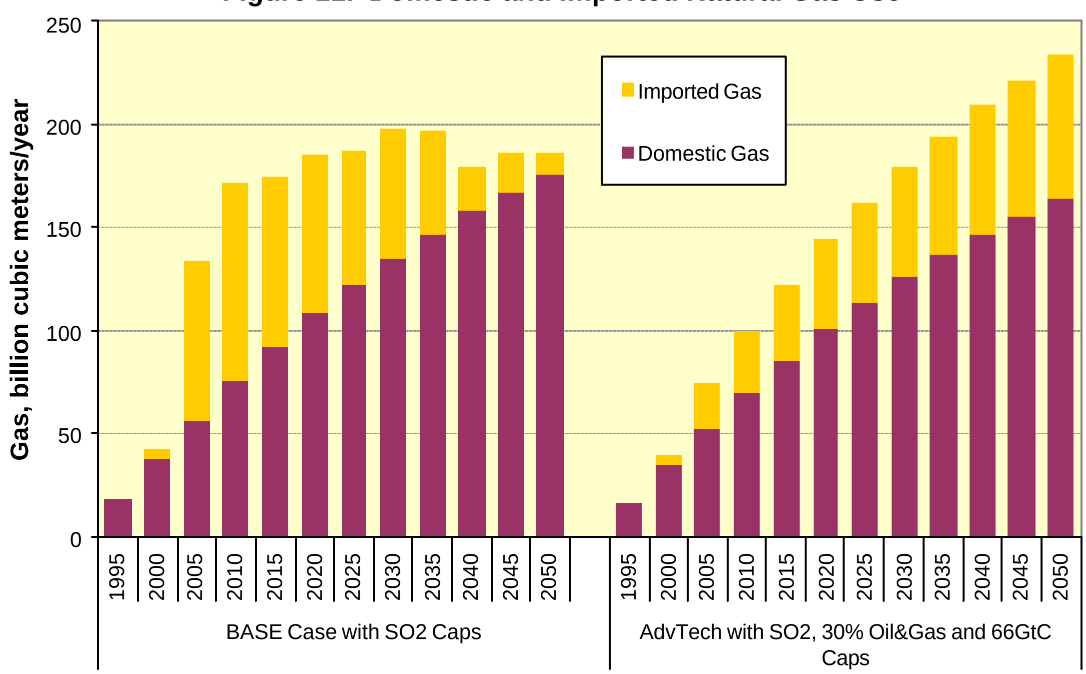


Figure 11. Domestic and Imported Natural Gas Use



period, natural gas is used at half the rate that oil is used, because lower-cost substitutes are available for gas, but not for oil. In particular, the use of town gas from coal increases significantly after 2010 along with a steady increase in the use of coal-bed methane (Figure 9). As a result of the unconstrained oil imports and the significant use of coal gas, natural gas imports are sharply reduced after 2040.

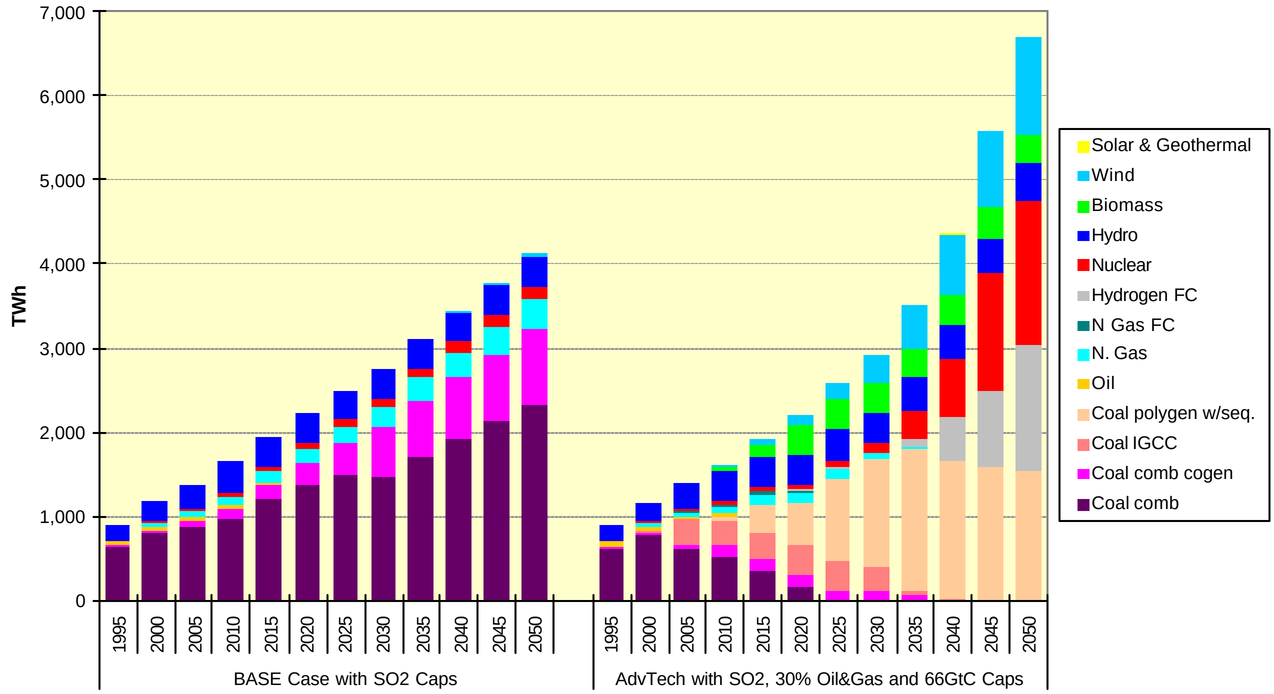
In the A scenario, the oil and gas share of primary energy falls from 21% in 1995 to 12% in 2050, with oil use staying in the range of 150 to 200 million tons per year throughout the period. The reduced need for oil in the A scenario compared to the B scenario arises primarily as a result of increases in the efficiency of petroleum-fueled vehicles in the transport sector early in the period (with a switch from conventional petroleum vehicles to hybrid-electric vehicles), the increasing adoption of fuel cell vehicles in the second quarter using coal-derived hydrogen, and the availability of petroleum fuel substitutes made from coal or biomass, including DME and methanol (Fig. 9).

Natural gas use in the A scenario grows steadily, and imports account for 30% of use throughout the period (Fig. 11). Natural gas supplies are augmented by town gas and conventional CBM, as in the B scenario, and additionally by CO_2-enhanced CBM and hydrogen (Fig. 9). In stationary applications, hydrogen is used in the second quarter of the century for combined heat and electricity production in distributed fuel cells. In the last decade of the analysis period, these fuel cell power sources account for 15 to 20% of all electricity supply in the A scenario.

In the B scenario, nuclear and renewable energy sources together account for 275 Mtce, or 7%, of primary energy supply in 2050 (Fig. 7). Installed nuclear power grows from 2 GW in 1995 to 19 GW in 2050. Hydroelectric power grows until 2010 when 87 GW of capacity are in place, and remains at that level thereafter, as lower-cost electricity options become available. In the A scenario, nuclear power grows to its maximum allowed level (216 GW) in 2050, and hydropower capacity reaches 107 GW. The model selects nuclear over hydropower because of strict economics, and it could be argued that the hydropower should have a higher priority. However, interchanging nuclear and hydro capacity would not change any other results of the model. Wind and biomass resources are used at the maximum allowed levels, and contribute 430 Mtce and 314 Mtce, respectively, or a total of 16% of primary energy supply. A total of 320 GW of wind-electric capacity (almost all as large-scale remotely-sited wind farms with HVDC transmission of power to load centers) is operating in 2050, providing 17% of China's electricity supply.

Figure 12 shows a full picture of electricity production by fuel and technology class. In the B scenario, electricity production is dominated by coal combustion technologies, which provide 72% of electricity in 1995 (653 TWh) and 78% in 2050 (3225 TWh). Stand-alone coal-fired power production shifts increasingly over the period from pulverized coal plants to ultra-supercritical or advanced fluid-bed combustion technologies to achieve SO_2 emission reductions. Also, the share of coal-derived electricity that is cogenerated increases from 3% to 28%, reflecting the generally attractive economics of cogeneration and the many available heat loads in China that could provide a sink for cogenerated heat. Coal use is constrained by limits on the availability of coal, so that other electricity sources are required to meet demand. Hydroelectric capacity, a major contributor to electricity supply in the early part of the model period, peaks in 2010 at 87 GW of installed capacity and remains level thereafter. In later years nuclear and natural gas capacity grow. Natural gas combined cycle capacity begins growing around 2020 in proportion to the total supply of natural gas and CBM. In later years, natural gas cogeneration is displaced by coal cogeneration. Installed nuclear power capacity grows from 2 GW in 1995 to 11 GW in 2025 and to 19 GW in 2050.

Figure 12. Comparison of Electricity Production Fuel/Technology Selections



In the A scenario, the electricity supply mix evolves in a markedly different fashion (Fig. 12). Coal remains the most important fuel for electricity generation, but direct combustion technologies are phased out by 2025 in favor of electricity production from gasification-based systems. The gasification-based systems not only yield reduced SO_2 emissions, but they also provide the capability for hydrogen production, with capture and sequestration of the by-product CO_2. Installed coal gasifier-based electric power capacity peaks at about 250 GW in 2030. Either directly or through distributed fuel cells, coal provides 45% of the electricity supply by 2050 in the A scenario. In total, nearly 7000 TWh of electricity are generated in this scenario, which is over 60% more than in the B scenario. The large electricity supply in the A scenario reflects the greater electrification of the economy: by 2050, electricity accounts for nearly 30% of all final energy use in the A scenario compared to 17% in the B scenario.

Total natural gas use for electricity in the A scenario is lower than in the B scenario (which helps enable gas to displace coal and oil in the residential and commercial sectors). Distributed natural gas fuel cells contribute to electricity generation between 2010 and 2025, but are then overtaken by hydrogen fuel cells. Nuclear power grows significantly in the later years, reaching 216 GW of installed capacity in 2050. (However, the "no nuclear" sensitivity run discussed in Section 4.1 indicated that advanced coal gasification and hydrogen production technologies with CO_2 sequestration could be expanded to replace all nuclear capacity.) Contributions of hydroelectricity are relatively constant through the analysis period at about one-third of the maximum allowed exploitation rate. Electricity from biomass is produced as a byproduct of the production of DME that is consumed largely in rural households for cooking. Electricity from large wind farms grows to be very substantial as noted earlier.

Figure 13 shows total emissions of SO_2 and CO_2 for the B and A scenarios. The SO_2 emissions follow the imposed SO_2 constraint. Total CO_2 emissions in 2050 are 2.3 Gt C in the B case and 0.9 Gt C in the A case, with cumulative emissions over the full analysis period totaling 99 Gt C and 66 Gt C, respectively. The carbon emissions level in the A scenario is achieved by a combination of more efficient transportation technologies, greater contributions from renewable energy sources, and the sequestering of 18 Gt C between 2010 and 2050. Carbon sequestration in 2010 amounts to 9 MtC as a by-product of enhanced resource recovery (ERR) and an additional 5 MtC without ERR. Total sequestration reaches 110 MtC in 2020, 450 MtC in 2040, and 1.2 GtC in 2050.

Figure 13. Total Emissions of SO2 and CO2

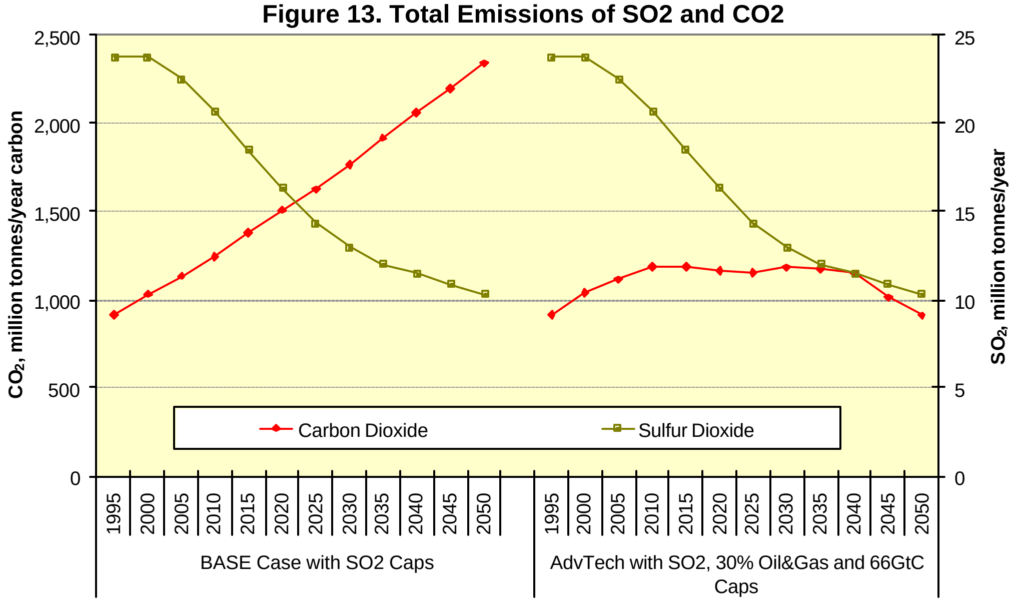
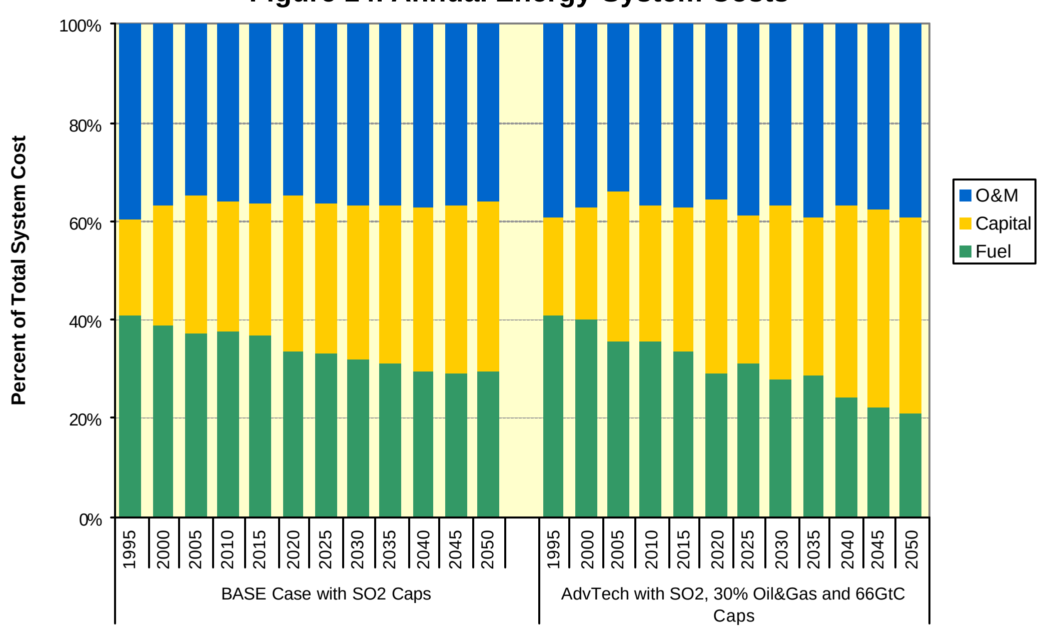


Figure 14. Annual Energy-System Costs



Finally, Figure 14 shows the annual percentage of total system cost attributed to capital investment, fuel, and O&M. In the first half of the analysis period, the A and B scenarios show a similar trend of decreasing fuel cost share and increasing capital investment share. In the second half of the period, the trend accelerates in the A scenario. In absolute terms, the calculated annual capital investments in the A scenario average only about 5% higher than in the B scenario through 2035 and increase to 25-35% above the B scenario thereafter. The fuel cost for the A scenario decreases to about 90% of the fuel cost in the B case in 2015 and to 80% of the B case fuel cost in 2050. Overall, the higher capital investments required in the A scenario are more than offset by the lower fuel costs arising from the generally higher efficiencies of the technologies selected in the A scenario, so that the total system cost for the A scenario (shown in Fig. 6) is slightly lower than for the B scenario (shown in Fig. 4).

5 Conclusions and Policy Implications

An important conclusion from our analysis is that if a "business-as-usual" approach to energy supply is followed that relies on the current set of conventional technologies (the Base technologies), China will be unable to achieve its economic development aspirations over the next 50 years while simultaneously meeting energy-security and local air pollution reduction goals. This is true even if end-use energy efficiency improvements are aggressively pursued and a high level of nuclear electricity enters the economy during this period. Moreover, a business-as-usual energy-supply strategy does not provide the possibility for achieving meaningful reductions in carbon emissions without very high levels of energy imports.

While the "business-as-usual" energy supply approach is unsustainable, our analysis suggests that there are plausible advanced-technology strategies that would enable China to continue social and economic development through at least the first half of the 21st century while ensuring security of energy supply and improved local and global environmental quality. Our modeling exercises have highlighted the fact that the fundamental attractiveness of the advanced-technology strategies arises as a result of interactions between all the energy demand and conversion sectors (not simply the electricity supply sector) and the ability of the advanced technologies to provide a variety of clean final energy carriers. Furthermore, our model results suggest that there would be essentially no added cost to society over the long-term for pursuing an advanced-technology strategy relative to a "business-as-usual" approach, except in the case when very deep reductions in carbon emissions are sought. Indeed, implementing advanced technologies solely for the purpose of reducing air pollution and oil and gas imports will achieve important reductions in CO_2 emission with no added cost (Figure 5).

However, if China does pursue an energy strategy that allows it to achieve its development aspirations under increasingly cleaner skies and with reasonable energy security, it will need to make significant investments to help develop and commercialize radically new conversion and demand technologies within the next 10 to 15 years. As noted in Section 3.1, these near-term costs were not explicitly accounted for in our analysis. However, the environmental, social, public health and balance-of-payments benefits that would accrue over the long term from implementation of the advanced-technology strategies were also not included in the analysis. It seems likely that these benefits will far outweigh the needed near-term technology and infrastructure development investments, but we have not done detailed analysis of this tradeoff.

In any case, practical realization of the advanced-technology strategies identified in this report will require policies in China that *i)* encourage utilization of a wider variety of primary energy sources (especially biomass and wind) and secondary energy carriers (especially synthetic fluid fuels from coal and biomass), *ii)* support the development, demonstration and commercialization of new clean energy conversion technologies, especially for coal conversion, to ensure that they are commercially available beginning in the next 10 to 20 years, and *iii)* support aggressive end-use energy efficiency improvement measures. Some specific technology policy recommendations are offered in the final section of this report.

It is further worth noting that in addition to helping China toward its air pollution and energy security goals, near-term investments in advanced technology and infrastructure would also set China up to be able to meet possible CO_2 emission reductions in the future. Because of their development-driven energy growth, implementing advanced technologies will not lead to absolute reductions in CO2 emissions, but they will set the stage for significant reductions below what those emissions would be without implementation of advanced technologies. Perhaps this insight can provide a new approach to the Kyoto Protocol, where the investments in absolute emission reductions by industrialized countries are balanced by the investments of developing countries to adopt advanced-technology pathways that will significantly reduce their future CO_2 emissions.

Finally, the analysis presented in this report should be viewed as the starting point for further detailed analysis. Our conclusions are broad and based on analysis with many simplifying assumptions, including those discussed in Section 3. We believe that more detailed analyses should be pursued, especially including regional aspects of energy technology and fuel choices, but we also believe the overall conclusions presented in this section will not change significantly as a result of more detailed analyses.

5.1 Technology and Resource Conclusions

Based on our modeling, we draw several broad conclusions regarding advanced technologies and energy resource choices that would enable China to meet future demands for energy services while limiting energy import dependence and environmental impacts.

First, end-use efficiency improvements are the least-costly option for meeting energy service demands and thus should be pursued regardless of what energy-supply strategy is adopted. If energy efficiency implementation falls short of goals for any reason, an advanced-technology energy-supply strategy would likely still enable energy-security and air pollution reduction targets to be met, primarily because several liquid energy carriers made from coal or biomass are available as oil substitutes, and because coal is used in the advanced-technology scenarios at less than the maximum possible production rates.

Second, coal can continue to be the dominant primary energy resource for China. However, its use must shift from coal combustion technologies to coal gasification-based technologies, which have intrinsic capabilities for removal of SO_2 and offer the option of producing clean liquid and gas fuels as alternatives to petroleum and natural gas fuels. Gasification-based technologies also facilitate lower-cost capture and sequestration of CO_2, an option that additionally provides for coupling with enhanced resource recovery – especially stimulation of coal-bed methane (CBM) recovery from deep unmineable coal beds. While some coal combustion technologies can effectively reduce SO_2 emissions, they cannot produce fluid fuels, and capturing CO_2 from combustion flue gases is more costly than from gasification systems due to low CO_2 concentrations in flue gases from coal combustion technologies.

Third, gas and liquid fuels will need to play increasingly important roles in a sustainable energy future. Coal-derived town gas replacing direct burning of coal in the industrial sector is one key to achieving SO_2 limits, and natural gas is an important substitute for coal and oil in the residential and commercial sectors. CBM associated with coal mining and also CBM recovered from deep unmineable coal beds by CO_2 injection could become especially important in meeting residential and commercial sector energy demands. Hydrogen production from coal begins in the second quarter of the century to provide fuel for fuel cells in vehicles and in combined heat and power plants (CHP) in commercial and urban residential buildings. This further contributes significantly to reducing SO_2 emissions and to limiting the need for oil and gas imports. Methanol from coal becomes an important oil substitute toward the middle of the century as petroleum prices increase. DME from biomass grows to become an important fuel for cooking and compression-ignition engine vehicles in the second quarter of the century.

Fourth, renewable energy sources take on important roles. Wind power is an especially important contributor to electricity supply in all of the advanced technology cases, with most of the contribution coming from large-scale wind farms in remote wind-rich areas connected by long-distance high-voltage DC transmission lines to major load centers. Modern biomass technologies are essential to meeting the energy needs of rural populations. The village-scale producer gas systems that appear in the base technology cases and larger-scale polygeneration systems co-producing electricity and DME that appear in the advanced technology cases are constrained only by the availability of agricultural residues. Solar heating is an important contributor in the residential sector, where it is used in most scenarios for water and space heating in urban and rural homes. When oil import constraints are especially tight, solar appears in the commercial sector for water heating and air conditioning. Hydropower is important in all scenarios, but only about half of the exploitable hydropower resources needs to be tapped, even if the fraction of oil and gas imports is limited to as little as 30%. Only in the low CO_2 emission cases (66 Gt C for the base technologies, and 46 Gt C for the advanced technologies) is the full hydropower resource used. As with hydropower, solar photovoltaic systems on rural homes and at centralized, grid-connected sites are important contributors to electricity supply only when low CO_2 emission levels are sought.

Fifth, key technologies for achieving reductions in carbon emissions in the advanced-technology cases involve carbon capture and sequestration. Significant amounts of carbon are sequestered for enhance resource recovery (ERR) in all advanced-technology cases. For the cases with CO_2 constraints, carbon sequestration without ERR also occurs (Table 11).

Sixth, modest contributions from nuclear power can help achieve the desired energy-security and air pollution reduction goals, but with the advanced-technology strategies, nuclear power is not

Table 11. CO_2 Sequestered (Million tonnes carbon per year)

Case	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Sequestered with Enhanced Resource Recovery[a]										
	0	9	16	31	46	57	72	90	113	142
Additional Sequestration without Enhanced Resource Recovery										
ASO30C80	-	-	-	-	-	-	-	-	80	186
ASO30C66	-	5	58	79	169	220	343	359	778	1,049
ASO30C46	41	297	510	724	815	884	908	918	972	1,021

[a] The amount of CO_2 injected for enhanced oil and CBM recovery is the same for all advanced-technology cases.

essential. This is in contrast to the Base case, in which nuclear power is important for achieving reduced levels of CO_2 emissions (80 Gt C and 66 Gt C cumulative). The nuclear contribution is not essential to achieving 80 GtC or 66 GtC with the advanced technologies, because there is sufficient coal, which if used with CO_2 sequestration technologies can meet the electrical demands otherwise satisfied with nuclear power.

Seventh, as discussed in Section 4.1, the changes in total cumulative discounted system cost calculated by the model are quite small except for the very lowest CO_2 emission reduction case (46 Gt C cumulative).

5.2 Implications for Technology Policy

5.2.1 Technology Development and Demonstration Needs

Based on the technology choices made by the model to minimize total discounted system cost, we have identified a set of technology development and demonstration recommendations for speeding up commercialization of these technologies.

1. Demonstrations of efficient end-use energy technologies should be pursued in all sectors of the economy.

2. Coal gasification is an enabling technology that can be used for coal integrated gasification combined cycle power plants (IGCC) or a variety of coal poly-generation plants. Research, development, commercial demonstration, and capacity building in China in this field should be increased.

3. Several coal polygeneration technologies should be demonstrated, especially technologies that co-produce electricity and fluid fuels such as DME. Intermediate technology steps, such as co-production of electricity and DME from remote natural gas fields should be encouraged.

4. Remotely-cited large-scale wind farms with long-distance transmission of power to demand centers should be demonstrated in the near term in anticipation of implementing a major wind energy program based on such systems.

5. Village-scale modernization of biomass energy conversion and use should be demonstrated and replicated widely.

6. Biomass polygeneration technology for co-production of electricity and DME should be commercially demonstrated.

7. Efforts to improve the exploration and extraction of coal bed methane should be expanded, and the development of new processes and technologies for stimulation of CBM resources should be pursued, including by CO_2 injection.

8. Improved technology for CO_2 capture, compression, and geologic sequestration should be investigated and demonstrated in combination with coal gasification. Intermediate steps to geologic sequestration, such as enhanced oil recovery using CO_2 injection should be encouraged.

9. Hydrogen production with coal gasification and membrane separation reactor technology should be developed and demonstrated.

10. Hydrogen fuel cell technology should be demonstrated for two key applications: urban transport (buses) and CHP systems for urban buildings.

5.2.2 Commercialization Incentives

Technology research and demonstration is not usually sufficient to ensure commercial market availability of radically new technologies, such as many of the advanced technologies described in this report. Market introduction incentives are usually needed to buy-down early high engineering and construction costs, mitigate technology performance risks, and provide initial manufacturing volumes to help reduce the technology cost. Also, markets have inertia, which is not a factor that was represented in the model. One feature of this inertia is a reluctance to accept new technology despite prospectively competitive costs, unless there is a strong incentive. Therefore, government policy must address the issue of how to provide proper incentives for market introduction of these technologies to ensure their commercial availability.

In addition, the model selected several technologies, such as energy conservation technologies for buildings, large-scale remote wind farms and solar hot water systems that are nearly commercially available or in the early stages of commercialization. However, these technologies face serious market barriers that will prevent them from reaching the potential identified in the model unless these market barriers, which are often institutional and regulatory in nature, are addressed. The following set of recommendations addresses these issues of technology commercialization.

1. Implement a renewable energy portfolio standard, such as is recommended in the 10th Five-Year Plan, to create a set-aside, but still-competitive market for electricity from wind, solar, biomass, and small-hydro power plants. This program could be implemented in concert with a power purchase program (see next bullet) to promote developments in all regions.

2. Create a special power purchase program that will stimulate the market for clean energy technologies with guaranteed power purchases at attractive rates. This type of model was successfully used in California in the 1980s to jump-start an industry for wind, biomass and cogeneration technologies. The Germans, Danish and Japanese have used a similar approach to grow wind and solar industries in their countries. Such a program in China would ensure rapid and robust industry growth for the advanced technologies identified in this paper.

3. Promote end-use efficiency (conservation) technologies as they are often the lowest cost solution to meeting future energy demand increases.

4. Develop a program of lease-concessions to stimulate the development of large-scale wind-farms in remote regions with high winds that will provide developers and investors with a strong incentive to commit to large-scale wind farm deployments and cooperate on construction of long-distance transmission lines to bring the power to market.

5. Reduce the VAT levels for solar water heating systems and other renewable energy technologies in order to make their tax burden comparable to that of conventional systems.

6. Provide some form of buy-down grants or tax incentives to stimulate early commercial introduction of technologies as they emerge from successful demonstration projects.

5.3 Closing Remarks

Our work suggests that China can support its social and economic development objectives for the next 50 years and beyond with clean and renewable energy that is derived mostly from its indigenous resources. If China aggressively pursues the advanced-technology energy strategies identified in this report, it will likely be able to ensure energy-supply security and improve local and global environmental quality. Furthermore, it appears that there would be essentially no added cost over the long-term to pursue this sustainable energy path. This is a remarkable conclusion. On the other hand, if China follows (or allows to happen) a "business-as-usual" energy development strategy (relying on the Base technologies alone), it will be unable to achieve all of its development, air quality, and energy security goals.

Our promising conclusions regarding the implications of an advanced-technology energy strategy for China suggest that it would be prudent for China to begin considering efforts toward implementing such a strategy. As we noted earlier, however, the work reported here should be viewed only as the starting point for much more detailed analyses that are needed to understand the full dimensions and implications of an advanced-technology energy future and to explore and evaluate specific steps that could be taken in the near term. Multi-disciplinary, technology-focused analyses are needed, for example, *i)* to better understand the spectrum of demand and conservation technology options in the industrial, transportation, and residential sectors, *ii)* to better understand the characteristics of advanced electric power technologies and the best strategies for integrating them into the electric power system, and *iii)* to explore and develop regional (province-level) strategies for implementing advanced-technologies. Also needed are detailed analyses of the potential impacts of alternative incentive structures on the development, commercialization, and widespread dissemination of specific advanced energy supply and energy demand technologies. The potential long-term benefits to China of all such efforts appear to be considerable.

End Notes

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later in this report involve such early investments, and accordingly we have not assumed any discontinuities in oil prices.
[26] The price of imported refined petroleum products was based on the historical average from 1983 to 1999 in the ratio of (a) price of product sold by U.S. refiners to resellers to (b) the average U.S. refiner acquisition cost of crude oil (Energy Information Administration, 1999, *Annual Energy Review*, US Dept. of Energy, Washington, DC).
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[35] Plant availability was assumed to be 85% for all solid-fuel conversion systems and 90% for all gas and liquid fuel conversion systems. Small Chinese coal-fired power plants today often have availabilities much lower than 85%, but assuming high availability for these units does not affect the model results in any substantial way since these technologies play a relatively small role in the energy system, especially when environmental constraints are assumed.
[36] The polygeneration processes producing liquid fuels (methanol, DME, of F-T liquid) all involve a "once-through" synthesis reactor, in which the synthesis gas is passed once through a catalyst-filled reactor to make the liquid fuel, with unconverted gas being burned to drive a gas turbine combined cycle for electric power production.
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[51] The 2050 primary energy projection for the Base scenario and many of the other scenarios run with this China MARKAL model are well within the upper and lower bounds of primary energy projections found in other studies. See endnote 5 for a summary of some other studies.