CHAPTER 8
CONVENTIONAL ENERGY SUPPLY

8.1 INTRODUCTION

This chapter discusses the identification and screening of mitigation options in conventional energy supplies, resource assessment and technology characterization, and the policies that might be used to implement options considered desirable. Comparative analysis of mitigation options affecting the conventional energy supply system and development of energy supply scenarios may be conducted with one of the bottom-up models discussed in Chapter 3, and not described in this chapter.

The conventional energy supply system consists of the following components:

- Oil sector
- Gas sector
- Coal sector
- Nuclear materials sector
- Electric power sector

Although the electric power sector is often the largest contributor to GHG emissions, all elements of the fuel cycle need to be considered for their mitigation potential. Table 8-1 identifies some of the GHG emission sources from the conventional energy supply system.

The application of GHG mitigation options to the conventional energy supply system is a major undertaking. The options affect large energy supply facilities (e.g., power stations, coal mines, gas distribution systems); they are complex to apply because of the highly interconnected nature of the energy supply system; and they can have major impacts on the overall economy.

The process of analyzing GHG mitigation options for the conventional energy supply system builds on the well-developed techniques of energy system planning. The addition of environmental analyses to these energy planning techniques is relatively recent but has received much attention. The addition of GHG emission calculations and the evaluation of mitigation options is an incremental analysis that can added to normal energy system planning methods.

8.2 MITIGATION TECHNOLOGY OPTIONS

GHG analyses are typically done over a long time horizon. Over a long time period, conventional energy supply systems are likely to change dramatically and so will potential GHG mitigation options. In addition to mitigation options that are commercially available at this time, this section identifies and characterizes technologies that are at various different development stages and may, at a later time, become available.

For the power sector, mitigation options are listed in three areas: technology and efficiency

Sector/Fuel Cycle Stage	Source of Emissions	Greenhouse Gas Emitted CO_2	CH_4	CO	NO_x
OIL SECTOR					
Production	Gas flaring	X	X		
Transport	Spills		X		
Refining	Distillation Fractionation Spills Storage Leaks Combustion	X	X	X	X
GAS SECTOR					
Production	Gas flaring Leaks		X		
Transport	Pipeline leaks		X		
Liquefaction/ regasification	Leaks		X		
COAL SECTOR					
Mining	Coal bed methane		X		
Transport					
Cleaning		X	X	X	
NUCLEAR MATERIALS SECTOR					
Mining		X			
Processing		X	X	X	X
ELECTRIC POWER SECTOR					
Generation	Combustion	X	X	X	X

improvements, fuel substitution, and post-combustion techniques. Mitigation options applicable to the entire energy supply system, including resource extraction and transportation/distribution, are also presented. Only a brief summary of each option is presented here. More details, including data on GHG emission reduction potential and cost, are described in the *IPCC Technology Characterization Inventory* (IPCC, 1993).

Not all of these options will be applicable in every country. In addition, countries may wish to evaluate other mitigation options not presented here. It will be necessary to screen the available options and select the most appropriate ones for detailed analysis.

8.2.1 Power Sector: Technological and Efficiency Improvements

- **Coal Beneficiation**

  The purpose of coal beneficiation (coal preparation or coal cleaning) in the energy sector is to remove impurities such as ash-forming minerals and sulfur to improve the combustion characteristics of the coal. There are three basic technology types of coal beneficiation: physical beneficiation (commercially available), chemical cleaning (under development), and biological cleaning (under development).

  Physical coal cleaning employs technologies based on physical differences between the coal and the mineral impurities. During the process, the coal is crushed and screened into different size categories to separate out impurities that are not chemically bound to the organic matter of the coal. The coal fines may either be discarded or cleaned using froth flotation. In the U.S. alone, there are several hundred beneficiation facilities in operation using physical coal cleaning. Chemical cleaning uses chemical reactions to remove impurities (e.g., sulfur) that are organically bound to the carbon in the coal. Biological beneficiation employs microbes specifically designed to selectively attack and break down impurities in the coal. Both chemical and biological cleaning have the potential for significantly higher removal efficiencies.

  Benefits of cleaning the coal prior to combustion include (1) improved boiler availability and reduced maintenance, (2) reduced SO_2 and dust emissions as well as significantly lower waste generation, and (3) increased heat content of the product coal. A higher heat content of the coal corresponds to lower CO_2 emissions per kWh electricity generated.

  Costs of coal beneficiation depend on the coal feedstock and the level of cleaning. Capital costs for physical cleaning can range from $25,000 to $100,000 per tonne/hr. Related O&M costs range from $1-5 per tonne of cleaned coal (IPCC, 1993).

- **Advanced pulverized coal combustion**

  Significant research and development efforts are directed toward improving operating characteristics of conventional pulverized coal-fired (PC) power plants. Plant efficiencies of close to 40% are targeted that will be achieved through the use of supercritical steam, higher initial steam temperatures, and multiple reheat. Better sorbent utilization and other process improvements could reduce CO_2 emissions from the flue gas desulphurization (FGD) unit as well. Table 8-2 shows cost and environmental characteristics for advanced PC plants in comparison with conventional PC technology.

Table 8-2. Cost and Environmental Characteristics for Conventional and Advanced PC Combustion

Technology	Efficiency %	Cost Information (January $1989)			Air Emissions (g/kWh)		
		Capital ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M (mills/kWh)	SO_2	NO_X	CO_2
Conventional PC, 200 MWe FGD	33.4	1,742	38.7	6.4	3.7	3.3	997.3
Advanced PC, 300 MWe advanced FGD	37.6	1,537	29.0	5.2	3.3	3.0	886.9

- **Atmospheric fluidized bed combustion**

In atmospheric fluidized-bed combustion (AFBC), a mixture of solid fuel, granulated limestone sorbent, and inert bed material such as sand or ash are suspended (fluidized) by an upward flow of air. Heat is removed from the combustion zone by producing steam in water-filled tubes passing through the fluidized bed and/or the hot gas stream. A conventional steam turbine utilizes the steam to generate electricity. The suspension provides for better fuel mixing and heat transfer and keeps the combustion temperatures low (about half of a conventional coal plant). This minimizes NO_X formation and provides for near-optimal SO_2 capture by the sorbent. Post-combustion pollution equipment is only needed for particulate control which can be achieved with electrostatic precipitators or fabric filters.

There are two types of AFBC technology: bubbling fluidized bed combustion (BFBC) and circulating fluidized bed combustion (CFBC). The combustion air flow in CFBCs occurs at higher velocities, resulting in a more turbulent bed and entrained flow, whereas in BFBCs the lower air flow velocities create a discernable and measurable bed height. Even though both technologies are commercially available, BFBCs seem to be getting more popular due to increased fuel flexibility, better mixing and heat transfer, higher SO_2 capture, and better combustion efficiency (Sondreal and Jones, 1991). Cost and environmental characteristics are given in Table 8-3.

Table 8-3. Cost and Environmental Characteristics for AFBC

Technology	Efficiency %	Cost Information (January $1989)			Air Emissions (g/kWh)		
		Capital ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M (mills/kWh)	SO_2	NO_X	CO_2
Conventional PC, 200 MWe FGD	33.4	1,742	38.7	6.4	3.7	3.3	997.3
AFBC, bubbl. 200 MWe,	34.3	1,724	34.5	7.6	3.6	1.4	972.9

AFBC, circ. 200 MWe	33.9	1,603	32.4	7.2	3.6	0.9	982.4

- **Pressurized fluidized bed combustion**

Pressurized fluidized bed combustion (PFBC) is operated at a pressure of 6-16 atmospheres. Due to the pressurized conditions and the more efficient steam production, the combustion chamber of a PFBC is generally one-third the size of a conventional furnace. The pressurized gases exiting the combustor are cleaned of particulates, alkali, and other contaminants. The gases are then expanded in a gas turbine to generate electricity and passed through an economizer to preheat the feedwater for the steam turbine cycle before being discharged to the atmosphere. The steam that is generated by the tubes immersed in the fluidized bed is expanded in a conventional steam turbine to produce additional electric power. This combined-cycle (CC) system yields an overall efficiency of up to 39% (EPRI, 1993). PFBCs also come in two different types: bubbling bed (BB) and circulating bed (CB) (see above). Cost and environmental characteristics for PFBC combustion are given in Table 8-4.

Table 8-4. Cost and Environmental Characteristics for PFBC Combustion

Technology	Efficiency %	Cost Information (January $1989)			Air Emissions (g/kWh)		
		Capital ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M (mills/kWh)	SO_2	NO_X	CO_2
Conventional PC, 200 MWe FGD	33.4	1,742	38.7	6.4	3.7	3.3	997.3
PFBC, CC. 340 MWe	38.0	1,508	40.0	6.5	3.2	0.4-0.8	877.1
PFBC, CB 250 MWe	35.2	1,464	30.6	6.5	3.5	0.4-0.8	947.8
PFBC, BB 250 MWe	33.2	1,570	29.7	6.2	3.7	0.4-0.8	1003.9

- **Advanced combustion turbines**

The combustion turbine is a prime mover that converts thermal energy into mechanical work. Inlet air is compressed in the compressor and mixed with fuel in the combustion chamber. The combustion products are then expanded through a fixed nozzle vane and the high-velocity gas stream transfers momentum at constant pressure to the blade, causing tangential rotation that drives an electrical generator. The gas travels through a series of stages (combination of nozzle and blade) in the combustion turbine before exhausting to the atmosphere. A portion of the work produced in the turbine is used to power the air compressor, which is usually mounted on the same shaft as the turbine.

Simple-cycle combustion turbines have efficiencies in the range of 30-35%. However, small (up to 50 MWe), airoderivative turbines are already being marketed with simple-cycle efficiencies of up to 41% (GTW, 1991). In combined cycle operation, the most recent turbines achieve efficiencies of 53-55% (Moore, 1993). By the end of the decade, large (150-250 MWe), heavy-frame machines are expected to operate at efficiencies of 58-61% in combined-cycle mode.

There is significant development work currently underway to design these advanced gas turbines. The advanced designs include (1) steam-injected gas turbines, (2) compressor intercooling, separately, and in combination with steam injection, (3) chemical recuperation of waste heat combined with intercooling and steam injection, and (4) humid-air turbine with an intercooled, regenerative cycle where a saturator adds moisture to the compressor discharge air. Table 8-5 compares technical characteristics of conventional turbines with intercooled steam injected gas turbines (ISTIG).

Table 8-5. Cost and Environmental Characteristics for Advanced Combustion Turbine

Technology	Efficiency %	Cost Information (January $1989)			Air Emissions (g/kWh)		
		Capital ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M (mills/kWh)	SO_2	NO_X	CO_2
Conventional Natural Gas 40 MWe	35.5	362 - 469	0.7 - 1.0	5.4 - 10.3	0.0	0.4	525
Conventional Natural Gas 140 MWe	30.3	342 - 385	0.7	5.4 - 7.6	0.0	1.8	616
ISTIG Natural Gas 50 MWe	47.0	1,142	9.7	9.2	0.0	0.04	397
ISTIG Natural Gas 150 MWe	47.0	893	6.1	5.9	0.0	0.04	397

- **Combined cycle**

Combined cycle plants consist of a combination of two or more power cycles, each using different working fluids. The most popular combined cycle is the gas and steam turbine combined cycle. In this configuration, a gaseous or liquid fuel is burned to operate a gas turbine to generate electricity. The hot turbine exhaust gases are passed through a steam boiler to produce steam for a steam turbine. The steam turbine utilizes waste heat from the turbine that, in a simple cycle, would have been rejected to the atmosphere. The additional electricity increases the overall system efficiency. Combined cycle generation is ideal for retrofit applications, as either existing combustion turbines or steam turbines can be converted into a combined cycle plant by adding the missing cycle.

- ### Integrated gasification combined cycle

In the integrated gasification combined cycle (IGCC) technology, coal is first fed to a gasifier where it is partially oxidized to form a raw fuel gas. The raw gas is cleaned to remove sulfur and nitrogen compounds, particulates, and tar. The clean gas is then fired in a gas turbine to generate electricity. The hot exhaust from the gas turbine passes through a waste heat boiler and provides steam for a conventional steam turbine. The steam turbine generates additional electricity.

There are three generic types of gasifiers. The first is the moving-bed process where large particles of coal move slowly downward through the reactor. Countercurrently, a stream of steam and oxygen (or air) moves upward, devolatilizes the coal, resulting in the two products, gas and ash. The second type is the fluidized bed gasifier. In this process, the resultant gas is desulphurized within the reactor using limestone or dolomite as sorbent. Particulates are removed downstream with cyclones. The entrained bed gasifier is the third generic type. Here, the pulverized coal and the oxidant are introduced together and move concurrently with the steam through the gasifier while they react with each other.

IGCC plants are expected to operate at efficiencies of up to 40%. By the end of the decade, IGCC plants are projected to achieve thermal efficiencies of 43% giving them ideal near-term potential for reducing GHG emissions from conventional coal-fired power plants with efficiencies of 35% (Torrens, 1989). Cost and environmental characteristics are given in Table 8-6.

Table 8-6. Cost and Environmental Characteristics for IGCC

Technology	Efficiency %	Cost Information (January $1989)			Air Emissions (g/kWh)		
		Capital ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M (mills/kWh)	SO_2	NO_X	CO_2
Conventional PC, 200 MWe FGD	33.4	1,742	38.7	6.4	3.7	3.3	997.3
IGCC Entrained bed	29.2 - 37.3	1,560 - 1,700	34.0 - 38.4	2.5 - 3.8	0.04 - 1.2	0.2 - 2.5	817 - 1,085
IGCC Moving bed	37.5 - 39.4	1,340 - 1,440	30.2	4.8	0.3 - 3.2	0.2 - 1.8	785 - 862
IGCC Fluidized bed	37.7 - 39.6	1,630 - 1,790	35.2	3.6	1.2 - 3.1	0.9 - 1.4	820

- ### Fuel cells

Fuel cells convert the chemical energy contained in a fuel directly into electricity and heat. Intermediate steps like combustion, conversion of heat to steam, to mechanical energy, and finally to electricity are not needed. Fuel cells can be classified into several categories, with the most important being molten carbonate (MCFC), phosphoric acid (PHFC), and solid oxide (SOFC). Fuel cells are similar to batteries except that the electrodes, that are consumed in a battery, are constantly replenished. Different electrochemical reactions take place, generating electricity, steam, and, depending on the cell type, CO_2. Efficiencies of up to 57% are achievable (see Table 8-7).

Table 8-7. Cost and Environmental Characteristics for Fuel Cells

Technology	Efficiency %	Cost Information (January $1989)			Air Emissions (g/kWh)		
		Capital ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M (mills/kWh)	SO_2	NO_X	CO_2
Conventional PC, 200 MWe FGD	33.4	1,742	38.7	6.4	3.7	3.3	997.3
MCFC, 500 MWe	45 - 47	1,730	27.9	6.2	0.003 - 0.25	trace - 0.08	700 - 755
SOFC, 747 MWe	48.0	1,830	58.5	included in fixed component	0.1	0.11	611 - 682

- **Combined heat and power systems - cogeneration**

A combined heat and power (CHP) system consists of an engine or a turbine to drive an alternator and a heat recovery system. In addition to the electrical power generated by the alternator, some or all of the heat from the prime mover can be used in the form of steam, hot water, or hot gases. Combined heat and power systems can reach thermal efficiencies of up to 80% and more. Small CHP systems convert about 20% of the fuel input into electric power and about 55-60% into useful heat. In larger systems, the electric power output may be as high as 40% of the fuel input. Potential applications are district heating and cooling and process heat for industrial purposes. The very high system efficiencies of CHP systems bear enormous potential for fuel savings and resulting GHG mitigation (see Table 8-8).

Table 8-8. Cost and Environmental Characteristics for CHP Systems

Technology	Efficiency %	Cost Information (January $1989)			Air Emissions (g/kWh)		
		Capital ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M (mills/kWh)	SO_2	NO_X	CO_2
Conventional PC, 200 MWe FGD	33.4	1,742	38.7	6.4	3.7	3.3	997.3
CHP, 200 MWe	80.0	na	na	na	1.5	several criteria 1.4	416.8

In back-pressure CHP plants, the steam leaving the steam turbine is condensed at conditions that generate hot water which can be directly fed into a district heating system. Heat and electric power are produced at a fixed ratio. In extraction-type CHP plants, steam is extracted from the steam turbine to heat the water for the district heating system.

This system is more flexible as it allows for a variable ratio of heat and power generation. The higher the heat demand, the more steam needs to be extracted and the lower the electric power generation.

- **Improvements in transmission and distribution systems**

  In industrial countries, power transmission and distribution (T&D) systems generally have losses that are in the range of 5-10%. In developing countries and countries with economies in transition, this number can be substantially higher. A survey of the Asian Development Bank (ADB) among its member countries showed T&D system losses ranging from 15% to 37% with an average net system loss of 21.5% (Burrel, 1991). The losses may be associated with lack of financial resources to expand and maintain the systems, chronically overloaded systems, inadequate billing and collection infrastructure, and theft.

  Reducing T&D losses provides, in essence, pollution-free power mostly at very favorable financial terms. Loss reductions can be achieved through system rehabilitation projects, use of capacitators and synchronous condensers to correct system power factors, rigorous loss reduction programs, improved billing and collection procedures, and increased security and vigilance. An ADB-financed project in Pakistan revealed that rehabilitating the distribution system can provide power at an investment cost of US$135 per kW. Power factor improvements have been shown to generate additional power at costs of US$100-200 per kW (Burrel, 1991).

8.2.2 Power Sector: Fuel Switching and Repowering

Fuel switching in the power sector is an option to reduce GHG emissions. In these cases, coal would be substituted for low- or zero-carbon fuels, namely natural gas and nuclear (hydro and other renewables are covered in Chapter 9). Natural gas emits about half the CO_2 per GJ of fuel and in many applications can replace oil or coal directly at relatively low cost. Nuclear power generation is assumed to have no GHG emissions although the fuel-processing cycle uses an extensive amount of energy, which may result in GHG emissions.

There are a number of uncertainties associated with nuclear power. Public acceptability, waste management, and financing availability are only a few of the issues that will affect nuclear power's future role. In addition, there is considerable debate about the cost of nuclear power. Cost items like decontamination and decommissioning, long-term waste management, and indirect cost for emergency evacuation planning are usually not reflected in cost assumptions of nuclear power. Including these cost items may significantly change the economic competitiveness of an expanded nuclear program.

Repowering is a somewhat different approach. Based on criteria like age, size, and control equipment, a pool of coal-fired power stations can be drawn up that may be suitable for repowering. In the repowered unit, the old firing technology is replaced with any of the new, advanced technologies.

8.2.3 Power Sector: Post-Combustion Options

The discussion of post-combustion options has, to this point, mostly centered around the mitigation of CO_2 emissions. Recent research and development work has identified a variety of technologies in this category, some of which have been derived from industrial applications. At this time, all post-combustion technologies are expensive and energy-intensive. This is due mostly to low CO_2 concentrations in the flue gas, the presence of corrosive elements, the dominance of N_2 in the flue gas that, like CO_2, is relatively inert, etc. The most promising technology for CO_2 capture from power plants appears to be the chemical stripping method. The technologies are discussed further in DOE (1993).

8.2.4 Fuel Supply: Extraction and Delivery System

- **Natural gas supply system**

  Typical components of a natural gas supply system include production wells, gas-processing plants, transmission pipelines, storage and injection/withdrawal facilities, and distribution systems. The system incurs losses at each of these steps, and as natural gas consists primarily of methane (a greenhouse gas), these losses contribute to GHG emissions.

  As shown in Table 8-9, there is a variety of emission reduction options currently available to the natural gas supply sector. In addition, development work is in process for new technologies and practices to reduce methane emissions at every stage of the supply system. Technologies that may play a stronger role in the near future include (1) installation of catalytic converters on reciprocating engines, (2) use of "smart" regulators in distribution networks, (3) use of metallic coated seals, (4) use of sealant and cleaner injections in valves, and (5) use of composite wraps for pipeline repair.

  The U.S. Environmental Protection Agency (EPA) found that the technically feasible methane emission reduction potential of the natural gas system may be as high as 33% (in 2010) using available technologies. The cost-effective reduction potential is estimated to be about 25% (in 2010) (EPA, 1993).

- **Coal mining**

  During the coalification process, gases are produced and entrapped in the coal. When the coal is mined, the gas is released to the atmosphere. The main component of the coal bed gas is methane (CH_4) (>80%) with the remainder being CO_2, N_2, O_2, H_2, and He. The heating value is comparable to natural gas. Coal rank, pressure (depth), and temperature determine the amount of gas in the coal. For the U.S., average CH_4 release factors have been determined by coal type (DOE, 1990) with the following results: 22 m^3/tonne (anthracite), 7 m^3/tonne (bituminous/subbituminous), and 0.3 m^3/tonne (lignite).

  Standard procedure in a coal mine is to collect and vent the CH_4 released into the mine shaft. Possible GHG mitigation first seeks to optimize the CH_4 release by short-, medium-, and long-hole drilling for pre- and post-drainage (Lama, 1991), and drilling of cased wells with perforations. The coal bed CH_4 is collected and utilized for on-site electric power generation. The CH_4 recovery rate of this system is estimated to be 50% (EPA, 1990). Capital costs are $690,000 per well with an annual capacity of 2,000,000 m^3 at operating costs of $80,000 per year (Kuuskraa, 1989).

Table 8-9. GHG Mitigation Options for the Natural Gas Supply Sector

Stage of Supply System	Emission Source	Mitigation Option	Comments
Production and Processing	Pneumatic devices (used on heaters, separators, gas hydrators, gathering pipelines)	Replace high-bleeding pneumatics with no- or low-bleeding devices	U.S. emission reduction potential: 7.1% Very cost-effective
	Gas dehydrators (remove H_2O from gas stream with glycol, emissions occur during glycol regeneration)	Install flash tank separator, use recovered methane as fuel in glycol regeneration unit	U.S. emission reduction potential: 7.1% Generally cost-effective
	Fugitive emissions (through leaks at damaged seals or corroded pipeline)	Implement inspection and maintenance programs	U.S. emission reduction potential: 5.7% Not cost-effective
Transmission	Pneumatic devices	Replace high-bleeding pneumatics with no- or low-bleeding devices	U.S. emission reduction potential: 3.4% Very cost-effective
	Reciprocating engines (drive compressor engines)	Use turbine engines for compression when constructing new pipeline or retiring reciprocating engines on existing pipelines	U.S. emission reduction potential: 3.7% Other operational factors must be considered when selecting compressor engines, site-by-site decision
	Venting during routine maintenance for repairs	Use portable evacuation compressors to pump gas to an adjoining section	U.S. emission reduction potential: 0.6% Cost-effective in Canada Not cost-effective in U.S.
	Fugitive emissions (through inadequately sealed valves, fittings, assemblies, or corroded pipeline	Implement inspection and maintenance programs at compressor stations	U.S. emission reduction potential: 7.1% Cost-effective
Distribution	Fugitive emissions from gate stations	Implement inspection and maintenance programs	U.S. emission reduction potential: 3.1% Cost-effective
	Fugitive emissions from subsurface piping	Replace leaking pipe or joint or insert repair material in old pipe	Very expensive Not cost-effective

8.2.5 Screening Technology Options for Analysis

A first step in conducting an analysis is to screen the available options and select a set for detailed evaluation. This screening will eliminate expending limited resources on options that will have little effect or that may not be practical for consideration in a country.

The method for screening and selecting options for analysis relies on the use of expert judgement in the consideration of a country's energy situation. It is primarily a qualitative evaluation of which options may offer the best possibilities. The basic steps that are used in the screening are discussed in the following sections.

8.2.5.1 Identify major GHG sources - current, future

First, major sources of GHG emissions from the current energy supply system need to be identified based on the inventory of GHG emissions. Mitigation options that operate on all the major sources should be considered for inclusion in the analysis.

In reviewing the information in a GHG inventory, attention should be focused not only on large individual sources (e.g., power stations, coal mines) but also on small, distributed systems (e.g., natural gas distribution lines) that may have small individual emissions but which may, in aggregate, be a major contributor.

In addition to considering current GHG emission sources, the future configuration of the energy supply system needs to be evaluated. Future major sources of GHG emissions need to be identified. Given that the planning horizon for climate change analyses may extend over several decades, the configuration of the energy supply system is likely to change significantly. Many of the existing facilities may be retired during the period. New facilities of the same type or of very different types may be brought on-line. The candidate facilities for the future energy supply system need to be included in the list of possible major GHG emission sources.

For each of the GHG sources identified, a list of mitigation options should be tabulated. This list should include options that reduce emissions from individual sources (e.g., improving combustion efficiency, fuel switching) and options that are applied on a system level (e.g., modified dispatching of electric power plants). The mitigation options identified above can be used as an initial list of possibilities.

8.2.5.2 Evaluate candidate options

Criteria that can be used to evaluate candidate options are listed in Chapter 2, Table 2-1. Here several criteria are discussed which are important for conventional supply options.

- **Applicability**

  Options that cannot be realistically considered to apply in a country's unique circumstances can be dropped from further analysis. For example, it is not reasonable to include the use of natural gas in a country that has no ready access to gas supplies either domestically or from imports. As another example, it may not be reasonable to consider a repowering program for power stations that are very old and soon to be retired.

- **Potential Effectiveness**

  The potential for a given mitigation option to have a significant impact on GHG emissions is another consideration used for screening. Options that will have only a small impact may be relegated to a lower priority when the analysis is carried out. The focus should be on those options that have the largest potential for effectiveness.

- **Potential Cost**

  Options may be screened on the basis of the potential cost to implement. While actual costs would have to be determined during the course of the analysis, there is generally enough information to identify which options would be prohibitively expensive to carry out.

- **Potential for Other Environmental and Social Benefits and Costs**

  Some options may provide other environmental and/or social benefits in addition to the reduction of GHG emissions (e.g., improved system efficiency can reduce the import fuel bill and the production of other air pollutants). These additional benefits can warrant inclusion of an option for study. Also, some options may have other environmental and/or social costs (e.g., a hydropower station that floods valuable land or displaces large groups of people) that exclude them from consideration.

- **Implementation Barriers**

  Some candidate options may be screened out on the basis of barriers (e.g., policy, regulatory, public concern) that would be very difficult to overcome. This would eliminate from the analysis those options that, while possibly effective, probably could not be implemented.

8.2.5.3 Select options for analysis

A set of mitigation options that will be subjected to more detailed analysis should be drawn up from the above considerations. This list will help focus the analysis efforts in the most productive directions.

In developing this list, several issues should be kept in mind. First, mitigation options can be considered for application both individually and in combination with other options. For example, an individual option would be to improve the efficiency of operation of electric power stations. A combined set of options would be to improve efficiency and switch from coal to natural gas. In some cases, a particular mitigation option may not be particularly effective by itself but may be very effective when taken in combination with other options.

Second, the mitigation options in the conventional energy supply system must be considered for their interactions with other sectors. What is done in one sector may have substantial effects, positive or negative, in other sectors.

Third, the analysis of mitigation options should be carried out on an iterative basis. Some options that have been selected for analysis may, on more detailed evaluation, prove to be ineffective or inappropriate. Likewise, some options that were initially screened out may, after initial results are completed, need to be reinvestigated for their potential applicability.

8.3 ENERGY RESOURCE ASSESSMENT

The investigation of the availability of energy resources determines what energy supplies are currently available and might be available in the future. The principal resources of concern here are fossil fuels: oil, natural gas, and coal. Resources other than fossil fuels (e.g., renewable energy resources) are also an important part of a resource analysis, and are covered in Chapter 9.

The resource analysis of fossil fuels is a geological determination of the location of resources, the quantity of resource available, and the economics of extraction. One method of categorizing fossil fuel resources is the procedure used by the U.S. Geological Survey. Resources are categorized into the following groups:

- Identified Resources
    - -Measured
    - -Indicated
    - -Inferred
    - -Economically recoverable
    - -Marginally economic
    - -Subeconomic

- Undiscovered Resources

When tabulating a country's fossil fuel availability, the term "reserves" is applied only to the measured and indicated resources that are economically recoverable. This gives a much more realistic picture of the availability of commercially exploitable energy.

In addition to identifying domestic resources, the resource analysis needs to determine the opportunities for importing fossil fuels. Oil, natural gas, and coal are all internationally traded commodities that can contribute to a country's supply system.

The significance of the resource analysis on the analysis of GHG mitigation options is two-fold. First, the availability of domestic fossil energy resources will determine what possibilities a country has to switch to lower carbon-content fuels. For example, a country that has large domestic coal reserves but limited natural gas will have difficulty in substituting for the coal in power generation. Second, the exploitation of fossil fuel resources (e.g., coal mining, crude oil extraction, natural gas extraction) is itself a source of GHG emissions that may require mitigation measures.

8.4 ENERGY TECHNOLOGY CHARACTERIZATION

Energy technologies that utilize the available energy resources need to be identified and characterized. A consistent and comprehensive data set for each candidate technology needs to be assembled. The technologies under consideration must cover the entire energy system, both in its current configuration and in possible future configurations.

Table 8-10 gives a typical list of energy supply system technologies that could be included. The list is intended to be illustrative and not comprehensive.

All steps of the fuel cycle should be included even though some are not significant from the standpoint of GHG emissions. Some pieces of the system, although not major contributors to GHG emissions, will affect how the system is designed. For example, the use of natural gas as a substitute for coal in power generation will be constrained by the availability of pipelines to bring the gas to power station sites.

	FUEL CYCLE STEP			
	EXTRACTION	PROCESSING	TRANSPORT	CONVERSION
OIL	On-shore Off-shore Primary recovery Secondary recovery Tertiary recovery	Refining	Pipeline Tanker Barge Truck Rail	Combustion
NATURAL GAS	On-shore Off-shore Associated Non-associated Primary recovery Secondary recovery Tertiary recovery	Well-head processing Liquefaction	Pipeline Rail (LNG) Ship (LNG)	Combustion
COAL	Underground Surface	Cleaning Solvent refining Gasification Liquefaction	Rail Barge, ship Truck Slurry pipeline	Combustion
NUCLEAR MATERIALS	Mining	Conversion Enrichment Fuel fabrication	Rail Truck	Reactor fuel

The characterization of these technologies at this stage in the analysis process consists of assembling information for each technology in a consistent fashion. The information to be gathered is illustrated on Table 8-11. Sources of this information include IPCC (1993), and also EPRI (1993).

PARAMETER	EXAMPLES
Engineering Performance Data	
Energy output	Type of products output Range of output capacity
Energy input	Input fuel Input materials Restrictions on inputs
Thermodynamic efficiency	Current Future
Performance limits	Capacity design, maximum, minimum Operational limitations
Technology status	Commercially available Research Pilot plant
Economic Data	
Capital cost	Labor, materials Interest during construction Foreign and domestic component
Non-fuel operating cost	Labor, materials Taxes
Financial data	Interest rate Return on investment Discount rate Foreign exchange
Environmental Data	
GHG emission rates	CO_2, Methane, Others Without mitigation options With mitigation options
Air pollutant emission rates	SO_x NO_x Particulates Others
Other environmental burdens	Water pollution Solid waste generation Land use Occupational health and safety

8.5 CONSTRUCTING SCENARIOS

The construction of a baseline scenario for energy supply should be conducted as part of demand/supply balancing in an energy system model. Similarly, analysis of mitigation options for conventional energy supply should be conducted in an integrated framework. This integrated analysis will identify those options affecting conventional energy supply that appear attractive. The analyst must then consider barriers to the implementation of these options and identify policies to promote their adoption.

8.6 MITIGATION POLICIES

The steps that need to be taken to encourage adoption of mitigation technology options must be identified and evaluated as part of the overall analysis. Tables 8-12 to 8-15 list several categories of implementation strategies with examples. These are adapted from DOE (1989) and are only illustrative of the many possibilities. It is not possible to select a set of implementation strategies that will be applicable to all countries. The unique situations of each country require a careful evaluation of alternative implementation techniques and the selection of the ones most suited to local conditions.

Each of the implementation options has different issues associated with its use. For example, regulations tend to be rigid and not easy to adjust to changing circumstances. They also require a large effort to enforce. Fiscal measures are more flexible, but it is not as easy to determine what level of fiscal measure (e.g., tax or subsidy) is required to produce the desired alterations to the energy system. Information measures are useful, but it is difficult to judge how effective they are. Research and development activities will generally require longer time periods to produce results. In reality, countries will need to employ a combination of implementation measures that match local conditions.

Integrated Resource Planning (IRP) is an approach that can be helpful in evaluating and encouraging adoption of mitigation options for the electric sector. Governments can encourage or require utilities to utilize IRP techniques, which provide a framework for considering demand- and supply-side options in an integrated manner.

Table 8-12. GHG Mitigation Implementation Options - Fiscal Incentives

OPTION	DESCRIPTION	EXAMPLES
Emission Fees	Fees placed on emissions of GHGs	CO_2 emission fee on energy facilities
Tradeable Emission Rights	Requiring the acquisition of rights to emit GHGs by trading with other sources; total emission quantities to be government-controlled	Reforestation project to accompany new energy facility construction Retirement of one facility before a new one can be built
Deposit-Refund System	Deposits taken on products with high GHG content or with high GHG sources used in manufacture; refunded upon proper disposal	Deposit on CFC-containing equipment
Taxes - taxes levied on GHG sources		
Excise taxes	Taxes levied on specific products	Tax on electricity generated by coal Tax on oil production
Taxes on firms	Taxes levied on companies	Tax on coal companies Tax on oil companies
Taxes on individuals	Personal income taxes	Tax credits for use of efficient equipment
Property taxes	Taxes on land and facilities	Taxes on high GHG-emitting facilities Tax credits for low GHG-emitting facilities
Tariffs	Taxes levied on imported goods and services	Taxes on imported, high carbon-content fuels
Subsidies - rebates or lower tax rates to low-GHG-emitting sources		
Direct Government Expenditures - government funding for activities		
Research and development support	Government funding of R&D programs	Energy efficient technology research GHG monitoring research
Direct government purchases	Government purchase of low GHG-emitting technology	Purchase for government use Purchase for private use

Table 8-13. GHG Mitigation Implementation Options - Regulatory Measures

OPTION	DESCRIPTION	EXAMPLES
Controls - measures that are direct controls on the development and operation of the energy system		
Bans	Strict prohibition of the use of certain technologies	Ban on new coal-fired equipment Ban on flaring gas from production wells
Emission controls	Limits on the emissions of GHG from plants in the energy system	GHG emission quotas on power plants
Input controls	Limits on the inputs to energy system facilities	Restriction on quantity of coal consumed
Consumption controls	Limits on the consumption of energy or energy-related services	Electricity use restrictions Restrictions on energy-consuming activities
Price controls	Limits on prices for energy - price ceilings/floors	Price floors on carbon-based fuels Price ceilings on non-carbon or low-carbon fuels
Rate-of-return regulation	Requirements on the rate-of-return calculation process for energy supply companies	Modification of rate base for electric utilities to allow for lower-carbon but more expensive systems
Standards - measures that set performance standards on energy supply systems		
Technology standards	Performance, process, equipment and design, and product standards for energy supply technologies	Requiring the use of specific electricity generation technologies Efficiency standards for power plants
Licensing and certification	Conditions placed on energy supply operations that must be met before they can operate	Licensing of power plant designs Site permits

OPTION	DESCRIPTION	EXAMPLES
Advertising and Labeling	Requiring GHG information on equipment	GHG emission labels on energy supply system equipment
Education	Information dissemination programs	Information programs for utility planners Information programs for the general public
Moral Suasion	Adversarial information program to persuade energy system operators	Program to promote low GHG technologies under threat of regulation
Signaling	Conveying signals to energy system operators about desired actions	Advanced notices of proposed rules Non-mandatory standards

Table 8-15. GHG Mitigation Implementation Options - Research and Development

OPTION	DESCRIPTION	EXAMPLES
Public Invention Support Programs	Providing support to commercialization of innovative technologies	Energy-efficient technology awards
Commercialization Education	Dissemination of information on commercializing innovative technologies	Information programs for private sector entrepreneurs
Provision of Specialized Information	Information program for energy operators to accelerate technology change	Extension programs
Demonstrations	Full-scale demonstrations of innovative technology	Demonstration of new electricity generating technology

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