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The SEI/UNEP Fuel Chain Project:
Methods, Issues and Case Studies in Developing Countries

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PART 1 - MAIN REPORT

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1. PROJECT OVERVIEW

With support from the United Nations Environment Programme (UNEP), the Stockholm Environment Institute (SEI), the UNEP Collaborating Centre on Energy and Environment (UCCEE), and counterparts in Venezuela and Sri Lanka have collaborated on a two-year project to develop analytical methods for incorporating environmental considerations in major fuel choice decisions.[1]

To this end, we have developed a method and software for analyzing and comparing *fuel chains*, and have implemented them through case studies in Venezuela and Sri Lanka. *Fuel chain analysis* (FCA) goes beyond the typical environmental assessment at the site of energy use or conversion to consider the "chain" of activities and environmental effects that occur elsewhere as the result consuming a unit of fuel or energy resource. In fuel chain analysis, also referred to as fuel cycle analysis or life-cycle assessment (see Section 2), the effects of mining the coal or harvesting the wood, for example, are considered along with the more commonly assessed impacts of burning these fuels for useful heat or electricity. Considering the full fuel chain in addition to on-site impacts can affect the comparative advantage of different fuel and technology choices, as we found in the case studies discussed below. Full fuel chain analysis, however, can be complex and data-intensive. Thus, the main thrust of this project has been to develop a tool that can make fuel chain analysis as straightforward as possible, and to test its applicability and usefulness in terms of policy-relevant fuel choice decisions in developing countries.

The project also placed an emphasis on improved analysis of biomass resource options. Commonly used methods for assessing biomass resource availability and impacts have simply not matched up with reality very well. So-called "gap theory" models, which predicted growing gaps or shortfalls of traditional wood energy in developing countries that never materialized, have been roundly criticized. Further, the analytical comparison of environmental implications of biomass resource use with those of fossil fuel and other energy resources has proven difficult. The nature of these impacts -- highly dispersed, site-specific, and dependent upon other activities such as agriculture -- renders them hard to quantify and generalize. As part of the SEI/UNEP project, we evaluated resource options for producing both electricity and final fuels, and the further enhanced data and methods for evaluating biomass resource options and their environmental consequences. In particular, we created a completely revised Biomass program in LEAP that now includes more realistic assessment of supply-demand interactions, better accounting for the potential for natural woodland regrowth, on-farm biomass production, modern biofuel crops, and the availability of agricultural wastes.

The final outputs of the present project -- (1) an expanded LEAP/EDB software that includes fuel chain, biomass, and environmental enhancements; (2) a database of generic fuel chains that can be used for indicative comparisons of fuels and technologies; (3) an expanded Environmental Data Base (EDB), including data developed for the generic and country-specific fuel chain assessments; (4) case study analyses directed towards fuel policy decisions in two countries; (5) in-country training workshops and seminars for analysts and policy makers; and (6) the present report -- are targeted for government and NGO planners, researchers, and decision makers with overall goal of increasing the consideration of environmental concerns in energy planning and development.

This project represents the second phase of an ongoing UNEP/SEI collaborative effort to develop and disseminate methods for bringing environmental considerations to bear on energy development in

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[1] UNEP project FP/2103-93-02 (3007) "Computerized Tool for Environmental Assessment of Energy Systems: Life-cycle Analysis and Biomass Energy". SEI-B also provided support for this project.

developing countries. In Phase 1, we developed a comprehensive Environmental Data Base (EDB). This interactive database contains extensive quantitative information on the environmental loadings associated with a wide range of energy production and consumption technologies. We also linked this database with SEI's computerized energy planning software, Long-range Energy Alternatives Planning (LEAP) system, so that the environmental loadings of specific energy scenarios could be compared. Now installed at over 100 sites in over 30 countries, the combined LEAP/EDB system is being actively used in numerous energy-environment studies. The enhancements developed as the result of this project will be available to the full network of LEAP/EDB users and other interested individuals and organizations in mid to late 1995.[2] Some preliminary ideas for future activities under a Phase 3 of UNEP/SEI collaboration are discussed at the end of this chapter.

1.1.1 Report Organization

This report is organized broadly into four parts. Part 1, consisting of Chapters 1-3, provides an overview of issues and approaches to fuel chain and biomass resource analysis. Part 2 gives detailed descriptions of the Sri Lanka (Chapter 4) and Venezuela (Chapter 5) case studies and discusses their findings.

Part 3 contains fuel chain fact sheets with background data and information on the technologies used at each stage and their environmental loadings for the four principal fuel chains considered here: biomass (Chapter 6), coal (Chapter 7), natural gas (Chapter 8), and oil (Chapter 9). Chapter 10 includes data on the production of materials used in the fuel chains and their energy requirements and environmental loadings. Together, these fact sheets are generally useful background documents for analysts looking at fuel chain impacts regardless of whether they are using LEAP or following the methods discussed here.

Chapter One continues by reviewing the overall framework for including environmental consideration in planning decisions, then reviews the stated project objectives and lists the activities undertaken. Section 1.5 summarizes the finding of the case studies and application of the new LEAP Fuel Chain program, and this chapter concludes with some suggestions for future activities.

1.2 Incorporating Environmental Considerations in Energy Decisions

Energy use is a leading cause of many of the world's most important local and global environmental problems, from local air pollution to global warming. In the absence of sound, environmentally-informed energy development, the world's growing economies will place ever greater burdens on human and ecosystem well-being. For instance, electric generation capacity in developing countries could double from current levels within 15 years, which would require construction of the equivalent one new 600 MW power plant every week. Energy requirements for transportation are likely to grow even faster.

Environmental concerns are rapidly emerging as major considerations for energy planners everywhere. Typically, these issues are confronted on a project-by-project basis, as raised by local NGOs, funding agencies, or formal government regulators. However, before reaching the project proposal and evaluation phase, many alternative options need to be compared, with their possible environmental impacts identified, if not fully studied. It is at this phase of initial project comparison, and overall energy policy formulation,

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[2] A fully completed and operational Review version of LEAP 95 -- the “beta” version in software parlance -- is currently available from SEI-B. We are awaiting final debugging and user input prior to full production of disks and manuals.

that energy planners require an expanded framework for including environmental and other *externalities*, along with the more conventional financial and economic indicators.

There are four principal stages to incorporating environmental considerations in energy decisions: *identification*, *quantification*, *valuation*, and *implementation*. The first step, identification, is essentially a scoping exercise: What are the possible types of impacts, both immediate and long-term, both on-site and distant, that might occur? Often, environmental analyses of energy use tend to identify and focus exclusively on the air pollutant emissions (e.g. SOx, NOx, CO2) associated with fuel conversion and combustion. However, these are only two of many stages in the "fuel chain" (see Figure below). Significant environmental impacts can also be associated with energy resource exploration, extraction, facility construction, transportation, distribution, storage, waste disposal, and facility decommissioning. Similarly, the impacts of hydroelectric development and biomass resource use, which are highly site-specific and difficult to quantify, are often under-emphasized.

Some Elements of the Fuel Chain for Gasoline-Powered Transport

Activity	Possible Environmental Concern
Locate oil deposit	road building in pristine areas
↓	
Drill oil well	construction, land use, accidents, solid waste
↓	
Extract crude oil	spills, gas flaring
↓	
Transport crude oil to refinery	accidents, spills
↓	
Refine oil into gasoline	air emissions, solid and hazardous wastes
↓	
Transport gasoline to filling station	accidents, spills
↓	
Fill cars with fuel	leakage from storage, evaporative emissions
↓	
Operate vehicle	evaporative and combustion emissions

The SEI/UNEP project has emphasized limited quantification of these impacts. Within the quantification process, there are several key steps. We focused on the first, and least uncertain of these steps: estimating direct on-site impact and loadings. By this, we mean the air and water emissions, waste generation, and local land use and ecosystem impacts associated with the provision of a particular final fuel, including the loadings and impacts from all major stages required to deliver the fuel to its final user. However, this level of analysis does not indicate the final damage that might occur from the energy activity. Damage estimation -- years of lost life expectancy, species lost, etc. -- requires modeling the transport, exposure, and response relationships that govern the fate and final impact of initial loadings. While damage analysis is a desirable objective, and is being pursued in a number of concurrent fuel chain research efforts (ORNL/RFF, 1992; Tellus, 1993, EC 1994), it requires far greater analytical effort and data availability, and the results may be highly site-dependent.

Similarly, the valuation and implementation processes are largely beyond the scope of the present project, but are essential to final decision-making. The valuation process involves placing a weight, in monetary or other terms, on specific damages (e.g. the dollar value of a lost human life or species) or on another, more easily determined indicator, such as on-site loadings (e.g. tons SOx emitted, hectares of land degraded). A variety of approaches have been proposed, and several recently implemented, most notably in state-level electric sector planning in the U.S. In LEAP/EDB, we have provided the capability to assign monetary values to on-site loadings. However, valuation of environmental externalities remains at early stage of development and application in most countries, with many difficult moral and analytical challenges to be faced. (See Hill and Lazarus, 1994) For now, most decision makers rely on judgmental and non-monetized assessments of the environmental costs and benefits of energy decisions.

As will be seen in the results of the Venezuela and Sri Lanka case studies, the comparison of fuel chains can present distinct tradeoffs between different local and global environmental costs and benefits (e.g. air pollution vs. global warming). Damage estimation and valuation exercises might provide one means to integrate these costs and benefits with standard financial and economic criteria to come up with an ostensibly more "objective" finding, but it might also prove overly heroic given uncertainties in the data and understanding of environmental pathways and the many factors that affect decision making. Investigation of integration and valuation techniques and inclusion in the LEAP/EDB framework is one possible follow-on activity to the present SEI/UNEP collaboration.

1.3 Objectives

As noted earlier, the long-term objective of the project is to contribute to the incorporation of environmental aspects in energy planning and policy, with an emphasis on developing countries, through the development of methods and dissemination of useful computer software tools. The nearer-term objectives have been to:

- establish a capability within the LEAP/EDB system for carrying out full fuel chain analysis of energy technologies;
- enhance the ability to analyze the resource requirements and impacts and environmental effects of utilizing biomass energy, in both traditional and modern energy systems, and provide this capability with the LEAP/EDB system;
- establish comprehensive and representative data within LEAP and EDB for a range of biomass and other fuel chains; and,
- establish expertise and experience in the extended use of the LEAP/EDB system in selected developing countries through case studies, demonstration and training workshops.

Through the activities described below, these short-term objectives have been met. A revised LEAP/EDB and representative data have been developed. Case studies have helped to evaluate these methods in Sri Lanka and Venezuela. As described below, important additional benefits have been achieved over the course of the project, including the broader dissemination of LEAP/EDB, modifications of other elements of LEAP/EDB to enhance its usefulness for environmental analyses, and the generation of case study findings of interest to the broader energy policy and research community.

1.4 Activities

The principal activities of this project have included the creation of new and enhanced software tools for fuel chain and biomass analysis within the LEAP/EDB system, the collection of comprehensive and representative data describing the environmental impacts of biomass and other fuel chains and its inclusion in LEAP/EDB, case studies to ensure that the tools are adapted to local circumstances and data availability, and local workshops to disseminate the tools and develop local expertise. Specific outputs from the project include:

1. **Fuel Chain Analysis Capability:** Based on literature reviews, modeling studies and lessons learned from case studies (described below), SEI-B has designed and implemented a new software tool for the analysis of the environmental impacts of full fuel chains. The software is designed to complement LEAP/EDB -- the existing energy-environment analysis tool designed by SEI and UNEP. While other parts of LEAP/EDB are used to evaluate the implications of integrated energy policy scenarios, the new tool enables a rapid, comparative evaluation of alternative fuel and technology choices based on full life-cycle environmental impacts. The new tool can be used to calculate the environmental loadings per unit of energy (final or useful) or per unit of energy service (e.g., per passenger-km for transport fuel chains) delivered. The tool can be used to track the environmental consequences of all energy and materials inputs in a fuel chain including the loadings associated with the construction-phase of fuel chain stages (e.g., the construction of vehicles and power plants). The tool will be disseminated to government and NGO agencies conducting energy and environmental analysis.

2. **Enhanced Biomass Analysis Capability:** As part of this project, SEI-B has enhanced the biomass analysis capabilities of the LEAP/EDB system. Designed in the light of recent criticisms of conventional "gap theory" models, the new software is now better capable of modeling the resource and environmental impacts of energy policies, and allowing full simulation of the land-use requirements and impacts, and pollution loadings associated with biomass fuel use. The new biomass program is fully capable of handling both traditional biomass issues as well as large-scale use of biomass fuels in modern renewable energy systems.

3. **Representative Data Sets:** SEI-B has established data sets in LEAP and EDB for a range of fuel chains, representative of energy systems found in both developing and industrialized nations. The data sets contained in LEAP and EDB (which will be disseminated as part of the software) are complemented by fuel chain fact sheets that provide suggested default values and a review of international sources of data. The Environmental Database (EDB) has been expanded to include more European data (from the CORINAIR database), more comprehensive default data, and new data from case studies and literature reviews carried out as part of this project. Reporting features of the EDB program have been improved to allow for easier and more flexible comparison of emission factors.

4. **Case Studies:** Case studies in Venezuela and in Sri Lanka were an essential element of the project. These case studies included training sessions by SEI-B staff in general LEAP/EDB skills, data collection missions, the additional use of local consultants for data collection, and workshops to present case study findings. The countries were in part selected to collect local data on and ensure broad coverage of four important fuel chains: oil (Venezuela), and gas (Venezuela), coal (Sri Lanka), and biomass (Sri Lanka). In each case, the new fuel chain program was employed to study the energy, material and environmental impacts of these fuel and technology choices including the greenhouse gas emissions of each fuel chain. Where applicable, the new LEAP Biomass tool was used to examine the land-use, resource and environmental implications of integrated policy scenarios based on the studied fuel chains. In particular:

   - In Venezuela**,** SEI-B collaborated with the Ministry of Mines and Energy (MEM) in examining the fuel chain environmental impacts of alternative public transport (diesel versus natural gas for buses in Caracas) and electricity generation fuel chains (residual oil versus natural gas).

- In Sri Lanka, SEI-B and UCCEE worked with the Ceylon Electricity Board (CEB) to develop fuel chain analyses for a range of alternative household fuel and electricity generation options. Biomass options were examined in both cases.

In each country, training workshops were held to establish expertise in the use of the tools and to build energy and environmental analysis capabilities in relevant organizations: government, academic and NGO. Advice and comments from local professionals working in the case study countries were used to help design the LEAP/EDB software enhancements implemented during the course of the project. For example, comments from CEB staff in Sri Lanka lead directly to revisions in the LEAP Transformation program. Local consultants also assisted in the data collection effort.

5. **Synthesis and Review Workshops:** In Caracas and Boston workshops have brought together case study and other project participants and observers near the completion of the project to identify common findings of the case studies, to assess the applicability of the analytical approach, and to develop priority areas for further research.

- **Caracas, March 1995:** The Venezuela Ministry of Energy and Mines (MEM) hosted a three day workshop for the SEI/UNEP Fuel Chain project. It included one day seminar, which reported and solicited feedback on draft results of the case study, and a two day LEAP training session for ministry personnel and other interested parties. Approximately 30 participants attended, including representatives from CORPOVEN (a subsidiary of the Petroleos de Venezuela S.A., PDVSA, the state oil company), the Metrobus system, CADAFE (the electric utility that currently operates Planta Centro, site of the case study example), the U.S. National Renewable Energy Laboratory, and the MEM.

  The case study seminar solicited several useful comments which have been incorporated into the final analysis. Suggestions were made with regard to estimated NOx emissions from Planta Centro (upward revisions), the potential global warming credit that could be assigned to the natural gas fuel chains, if the natural gas used would otherwise have been flared or vented, and the efficiency of newer natural gas bus engines. Two opportunities for future action were also discussed. The first is for the MEM to submit a proposal to the Global Environment Facility (GEF), in cooperation with PDVSA or one of its major subsidiaries, to further analyze and propose mitigation actions for natural gas that is currently flared or vented. Based on uneconomic returns, PDVSA is unlikely to adopt mitigation measures without external funding, and the fuel chain analyses could help in evaluating the potential GHG benefits of various natural gas options. The second activity will involve SEI-B support for the use of LEAP and other limited technical support for the development of a demand side management scenario to be included as part of the MEM's country study evaluation.

- **Final Project Meeting:** In April 1995, SEI-B hosted a final project review meeting, with attendees from UNEP headquarters (Project Officer), UCCEE, the Venezuelan Ministry of Mines and Energy, and the Ceylon Electricity Board. Preliminary case study findings and the fuel chain and biomass methodologies were reviewed, and suggested revisions were incorporated into the present report. In addition, directions for future activities were explored, and the outcome of these discussions are reflected in Section 1.6 below.

6. **Other LEAP/EDB Improvements:** The project also resulted in numerous other improvements to the LEAP/EDB system. These changes are reviewed in Chapter 8 of this report. They include many user-

interface improvements, better Demand program reporting features, and improved Transformation analysis and reporting capabilities. The environmental reporting features of LEAP/EDB were expanded to include the global warming potentials (GWP) of emissions and the costs of greenhouse gas mitigation scenarios. In addition, new reporting features were developed for EDB, and were used to develop the report included as Annex A.

7. **Dissemination of Software:** During the project period, SEI-B and UCCEE continued their LEAP/EDB dissemination policy in an effort to broaden the application of the tool in developing countries. In the last year, approximately 30 new users obtained LEAP and/or EDB. LEAP is now used by well over 100 organizations in more than 30 countries.

8. **Other Project Outputs:** Other project outputs include the production of software user guides, a final report, the production of a new LEAP/EDB brochure to increase access to the software (in both paper and also in electronic format on the World Wide Web of the Internet).

1.5 Findings

The following project findings were derived from the case study analyses, training and results workshops, the development process for the new fuel chain and biomass software, and other project activities. Full details of the Sri Lanka and Venezuela case studies are contained in Chapters 4 and 5 of this report respectively.

1.5.1 Venezuela Case Study

In Venezuela, the case study focused on the natural gas and petroleum fuel chains. Significant findings include:

- If the environmental objective of greenhouse gas (GHG) mitigation is considered in isolation, then, due to methane emissions from the recovery and transmission of natural gas, and the lower vehicle efficiency of compressed natural gas vehicles, natural gas is not clearly favored over diesel as a transportation fuel. Assuming low natural gas loss rates in production and distribution, the global warming impacts of the CNG bus fuel chain are approximately equal to those of the diesel fuel chain. At high natural gas loss rates, the global warming potential for the use of CNG buses is 27% greater than for diesel buses.

- A critical component of the above finding is the assumption that natural gas comes from additional production rather than the capture of natural gas that otherwise be flared, vented, or leaked from the oil and gas production, transmission and distribution system. Based on the higher economic costs of capturing natural gas from losses, this appears to be most relevant assumption. If, however, one assumed that there is causal linkage between development of CNG as a vehicle fuel and thus that captured losses would be the marginal source of natural gas in an expanded CNG vehicle program, then the CNG fuel chain could be assigned a sizable credit with respect to greenhouse gas emissions, due to the reduction in methane emission.[3]

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[3] In other words, one would have to be able to say that natural gas losses would not be reduced unless a CNG vehicle program were pursued. (e.g. say, that the increased market for natural gas were an important factor in the decision to reduce losses). The net incremental cost of natural gas loss reduction has been estimated by INTEVEP, the research arm of PDVSA. If a credit were given, it would likely make the CNG option enormously beneficial in

- In terms of greenhouse gas emissions, natural gas is the preferred fuel for electricity generation, even under the assumption of relatively high natural gas system losses. The global warming potential equivalents, natural gas-fired electricity is 12% to 27% lower than residual fuel oil per KWh. Therefore, natural gas is more effective in terms of GHG mitigation if it is used as a substitute for residual fuel oil in electric generation than as a replacement for diesel in transportation.

- With respect to emissions of local air pollutants, such as carbon monoxide, sulfur oxides, and particulates, CNG is clearly favored over diesel as a bus fuel, and natural gas is clearly favored over residual fuel oil for electricity generation.

- Upstream stages -- that is, the processes such as pipeline transport and fuel extraction, that occur prior to final fuel combustion -- represent approximately 18% to 30% of the net energy use in both of the fuel chains examined, and 15% to 35% of total fuel chain contributions to global warming emissions. In terms of local air pollutants, upstream stages can account for as much as 35% of the total fuel chain emissions (in the cases of NOx emissions for electricity generation using residual fuel oil, and SO_x emissions for the diesel bus fuel chain) or as little as 5%. Given that the overall differences in energy and emissions between fuels are often in a this range (e.g. less than 35%), the contributions of upstream stages should be considered significant and can influence the relative environmental benefits of different fuel choices.

- Upstream stages, such as off-shore oil and gas production or hydro development in indigenously inhabited or biologically diverse areas can present other, important environmental impacts that are often more difficult to quantify or compare. The future application of the fuel chain analysis framework to a broader spectrum of environmental issues (including, for example, water pollution, solid wastes, loss of biodiversity, and social impacts on indigenous cultures) can provide for a fuller accounting of fuel choice impacts. These were only covered in a qualitative fashion here, but further analysis could seek to integrate these through valuation or other multi-objective analysis approaches to yield results in a common unit.

1.5.2 Sri Lanka Case Study

Given the most likely energy policy alternatives in Sri Lanka today, the case study found, perhaps not surprisingly, that biomass presents more environmental benefits as a fuel for electricity generation than as a fuel for domestic households. In part, this is because biomass is compared to coal in the electricity sector and to LPG in the households sector in this analysis -- coal is probably the most polluting of the fossil fuels, while LPG is one of the cleanest. It should be emphasized that this case study only examined the environmental impacts of these fuel and technology options -- it did not undertake a detailed financial analysis of their viability, nor did it examine the economics and environmental impacts of alternative land-use options. Further analysis is required before firm policy conclusions can be drawn.

- The potential for use of biomass resources for electricity generation in Sri Lanka is large but remains largely untried; two examples serve to illustrate the magnitude of the resource for the purposes of this analysis. If the all of the wood presently used by the tea industry to wither and dry leaves were utilized for cogeneration of steam and electricity using a conventional steam fired plant, then the same process

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terms of global warming potential (GWP) emissions, since each tonne of methane saved avoids the equivalent of over 30 tonnes of carbon dioxide, assuming a 100-year integration period.

heat requirements could be met while also generating approximately 340 GWh of electricity, equivalent to 10% of the total electricity generated in Sri Lanka. If all of the bagasse presently utilized in Sri Lanka in the sugar industry were to be used in a similar cogeneration system, approximately 111 GWh of electricity could be produced[4].

- Another way of assessing the overall resource potential for biomass is to calculate the hypothetical land area that would need to be utilized to generate Sri Lanka's electricity requirements, now and at some time in the future. Using the assumptions for conventional biomass-steam electricity generation, about 658,000 hectares or about 10% of the total land area would need to be devoted to woodfuel plantations to generate the total electricity requirements of approximately 7000 GWh forecast for Sri Lanka in 2010. This figure is equivalent to the land areas currently devoted to paddy rice (735,000 hectares) or cereals (780,000 hectares [5]) or about 57% of the total natural forested area lost from 1956 to 1983 (1.15 million hectares), most of which is now low productive scrubland or grassland according to the Ministry of Lands.

- For the electric sector, results of the fuel chain analysis illustrate the overwhelming resource and environmental benefits of biomass fuel chains compared to coal fuel chains. Even allowing for upstream emissions from diesel fuels and fertilizer manufacture and application used in modern plantations, biomass produces much lower emissions of all pollutants. Results also show the large potential that biomass has for producing electricity both over the medium term (in which biomass generation appears economic only when low cost feedstocks are available) and over the longer term (in which the capital costs of generating plants utilizing biomass may become more competitive with fossil-fired plants). Industrial processes, in which biomass fuels are already being utilized to produce process heat, are probably the most promising first applications for biomass cogeneration in Sri Lanka. In the longer term, questions remain about how quickly high efficiency biomass systems can be developed and whether sufficient irrigation and suitable high-yielding tree species can be found for Sri Lanka's dry zones. Overall, though, modern biomass applications appear particularly promising given the absence of fossil fuel resources in the country.

- Biomass fuels are generally touted as a means to mitigate greenhouse gas emissions. The analysis for Sri Lanka, shows the assumption to be highly dependent on highly uncertain data about the sustainability of fuelwood production. For the modern fuel and electricity applications, where feedstocks are assumed to be sustainably produced from plantations or agricultural residues, the benefits over coal technologies are obviously large. However, in households, the situation differs considerably. Unless firewood is produced in a sustainable fashion then LPG, with its characteristic high end-use efficiency may actually produce lower net emissions of greenhouse gases per unit of useful energy consumed. At the same time, local policy concerns -- about the potentially harmful effects of indoor air pollutants -- point towards the promotion of cleaner burning fuels such as LPG.

- In general, upstream impacts are not very significant except in the cases of methane emissions from charcoal making, and the energy requirements of fertilizers that may be used in biomass plantations. Nonetheless, the fuel chain concept provides a useful framework for analysis, since it allows the comparison of fuel and technology choices on an equal footing (for example per KWh of delivered electricity, or per meal cooked in the household sector).

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[4] According to the CEB, small amounts of non-grid electricity are already being produced by the sugar industry.
[5] Agriculture data from FAO Agrostat database for 1990.

1.5.3 Applicability of Fuel Chain Analysis in Developing Countries

The case studies demonstrate that fuel chain analysis can be a useful tool for evaluating the environmental consequences of fuel choice decisions, enabling consideration of important upstream impacts.

- Fuel chain analysis can be data and labor intensive, and detailed fuel chain studies (even those limited to a small number of impacts) may lie beyond the analytical objectives, resource capacities and time constraints of many national energy planners. It also forces the analyst to explicitly draw boundaries around systems and to allocate impacts within and between co- and by-products of the energy system, tasks which are not necessarily simple or obvious.[6]

- A software tool like the LEAP Fuel Chain Program can help to simplify and speed up fuel chain analysis, and to overcome local data constraints with accessible default data thereby making fuel chain analysis more accessible in a wide range of applications.

- The usefulness of this approach needs to be evaluated by local planners and decision-makers.

1.6 Directions for the Future

The project workshop held in April 1995 was used in part to solicit ideas from the assembled experts on ideas for future directions. Rather than discuss the development of research methods alone, the experts emphasized the importance of capacity building, and dissemination and implementation of analyses, with the goal of improving the environmental planning capabilities of governments and organizations. The following six concepts were outlined as possible areas for future efforts:

- **Policy-relevant case studies linked to topical regional workshops.** Important topics might include energy, transport, and the environment or environmental criteria for evaluating and selecting independent power resources where electric privatization. LEAP/EDB would be used in a few countries to develop illustrative case study scenarios to indicate the likely impacts of selected policy options currently under debate (e.g. mass transit, emission controls, or pricing policies). The results would then provide a context and backdrop for analysts and policy makers, gathered in regional stakeholder meetings, to debate and share insights on the merit of various energy policies for achieving environmental goals. It would be essential at the outset to identify appropriate regional groupings and topics where a) there is a strong likelihood that policy actions will or can be taken in the near-term to address energy-environment issues; b) case study analyses can usefully contribute to the evaluation of policy options. For instance, an example could be the analysis of options for reducing urban air pollution through energy management in the transport sector in selected Asian countries.

- Development of a **guidelines document for energy-environment analysis.** Rather than a tool-specific user guide, this reference document would provide energy analysts with step-by-step procedures for conducting an energy-environment scenario analysis. The guidelines would be generic, i.e. applicable by individuals using a wide range of quantitative tools (from spreadsheets to models). At the same time, the guidelines could refer to how these steps would be implemented with LEAP/EDB, as a practical example. A good example of what such a document might look like is

[6] In Sri Lanka for example, when assessing the impacts of imported coal, an analyst must decide whether to include the impacts of the coal mining and transport stages; or when considering woodfuel sustainability, an analyst must assess the extent to which deforestation is due to fuelwood consumption pressures.

provided by Appendix IV: Mitigation Assessment Handbook of the IPCC Working Group 2 Second Assessment Report, which provides a step-by-step approach to mitigation analysis

- **Electronic networking** and information sharing among energy-environment professionals generally, and LEAP/EDB users more specifically. Options include a bulletin board system (BBS) for sharing ideas, references, and data; BBSs specializing in LEAP and EDB for rapid feedback and exchange of ideas among users; and making EDB fully and freely accessible through the Internet and/or other information networks (e.g. INFOTERRA).
- Based on comments solicited through polling of LEAP users and recipients, **a compilation of lessons learned** from over a decade of LEAP/EDB dissemination. The report/paper would enumerate some of the prerequisites for successful analyses (institutional, human resource, political will, sound data base, etc.), resources required, and long-term impacts of training and analysis efforts, soliciting frank input from LEAP users and non-users from around the world. The findings would likely be highly relevant for analysts and policy makers regardless of the analytical tools and approaches used.
- **Maintenance and Update of the Environmental Data Base (EDB).** The need for and utility of a global emission factor/environmental loading reference is well established and increasing; and, if we are to make EDB more widely and freely available, such as via the Internet (see above), this effort would become a necessity. Although it provides the broadest coverage of technologies (across regions) and references for energy-related environmental loading/emission factors, EDB could become an even more useful tool with a few important improvements. a) The data need further standardization and expansion to include items now available since the major EDB development effort almost five years ago. An international expert group could be set up to oversee the collection and quality review of additional and existing data. b) Guidance for appropriate emission factor selection could be provided on-line; c) Limited improvements to the user-interface could enable easier cross-checking and combination of data sources, expression of ranges of emission values across similar technologies, easier sharing of data between EDB users, and other items.
- **Other Areas for Research:** Other research areas suggested by the case studies include incorporation of costs into the fuel chain analysis methodology and the extension of the analysis beyond the point of environmental loadings to look at environmental impact issues such as such as pollution travel, ambient levels of pollutants, and dose-response relationships.

2. An Approach to Fuel Chain Analysis

2.1 Why Fuel Chain Analysis?

Individuals, utilities, companies, and countries are constantly faced with choices among fuels and energy technologies. An electric utility might be deciding whether the next power plant should be coal or gas-fired or an individual might be deciding whether to use an LPG stove or a traditional wood stove. Each choice has energy and environmental implications.

These implications are not restricted to site where the fuels are consumed. A decision to build a coal plant will mean that more coal needs to be mined, cleaned, and transported to the power plant. A decision to use LPG means that more crude oil must be produced and refined (or refinery operations must change) and that less wood need be harvested and collected. Each of these *stages* can have important environmental impacts: coal mining can denude hillsides and contaminate surface waters, oil refining can release harmful air and water pollutants, and wood harvesting and collection may disturb natural ecosystems or encourage land degradation. These *upstream* impacts can be overlooked unless the full *fuel chain* is considered. Therefore, in principle, *fuel chain analysis* represents the best method for making fair comparisons among energy options.

Fuel chain analysis, however, is neither simple or straightforward. In its broadest definition, fuel chain analysis should consider the effect of all incremental activities that occur as a result of an additional unit of energy required. In addition to including the *direct impacts* associated with the principal stages of a fuel chain -- primary resource extraction and preparation, transport and storage, conversion and processing, end-use services, and final disposal -- *indirect impacts* are often considered. Indirect impacts represent the effects of those activities that occur as the result of an additional unit of activity at a given fuel chain stage. In other words, where an additional unit of coal demand leads to direct impacts at the coal mining stage, additional activity at the coal mining site might lead to indirect impacts as the result of additional materials or vehicles needed for mining activities. The production of steel or cement for the power plant, coal train, or mining supports might lead to increased environmental damages near the steel mill, cement factory, or iron ore mine. The analysis of indirect impacts can obviously become very complicated and cumbersome.

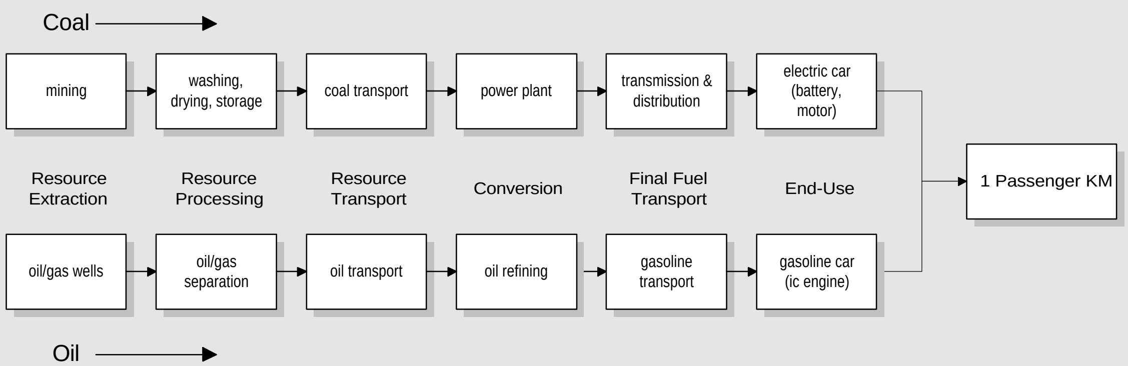
Fuel chain analysis is not new, but in recent years it has received renewed attention, particularly in industrialized countries. Along with closely related methods, its history stretches back over 20 years. Elements of the method have gone under other names, such total energy cycle analysis, total impact assessment, reference energy system analysis, fuel cycle analysis and life cycle analysis. The latter two terms are the most similar and commonly used. We have adopted the term “fuel chain analysis” because it more accurately represents the analytical process. (For reference, International Atomic Energy Agency has adopted a similar term, “full energy chain analysis” for its international program on comparative assessment of energy resources.)

Life cycle assessment (LCA) is broadest of the terms and is generally applied to the cradle-to-grave review of specific industrial processes and products, such as a cars or disposable diapers, both of which have received considerable attention in LCA circles. LCAs generally trace back through all of the emissions and impacts from materials and energy use at high level of detail, and are more truly “cycles” since there is often the potential for recycling materials used in a product. LCAs are generally more sophisticated, data-intensive, and complex than fuel chain analyses. We chose the term fuel chain rather than fuel cycle, because of the latter term’s historical association with nuclear energy, where the nuclear fuel cycle represents the various stages in processing, refinement, and reuse or disposal of the radioactive components. Furthermore, most fuel chains are not truly cycles, but linear progressions from resource extraction ending in final use.

An Example of Fuel Chain Analysis

The methods and importance of fuel chain analysis can best be illustrated with an example. Consider two alternative passenger transport fuel chains, both of which are used to provide the same energy service -- one passenger-km. In this example we will consider two types of cars, one consuming gasoline, and the other running on electricity generated by combustion of coal. At the point of end-use, the electricity car appears to be more environmentally beneficial since the electric motors used in cars produce few emissions or impacts: those of the gasoline car are well known. However, in the case of the coal-fired electric car, significant emissions and impacts may occur during the upstream conversion stages shown in Figure 6.1 below -- particularly during electricity generation and coal mining. The results of a fuel chain analysis will, for instance, show the total air pollutants or greenhouse gases that a given fuel/technology choice would imply -- a result that might differ significantly from one that a simpler approach looking only at vehicle or other end-use technologies might yield.

Two Passenger Transport Fuel Chains



In the real world, fuel chains may be more complicated than the examples shown above. In many cases, each stage in a fuel chain will be fed by a number of different technologies. For example, coal mining may consist of both surface and underground mines, each with very different energy requirements and environmental impacts. Similarly, electricity may be generated by a variety of fuels and technologies: hydro, coal, oil, natural gas, nuclear, etc. It may be important to model each of these systems separately.

Since the comprehensive early efforts of UNEP (see their Energy Report Series) and others in the 1970s, there have been a number of important fuel chain analyses. A summary of selected efforts in this field is given in the adjoining box.

Selected Recent Fuel Cycle Studies

- **US-EC Fuel Cycle Study (ORNL/European Commission, 1992-1995):** This ongoing project is developing a comparative analytical methodology and examining non-market damages and benefits for eight electric generation fuel cycles and four conservation options. The US team is examining biomass, oil, natural gas, and small hydro options; the EC is examining nuclear, photovoltaic and wind energy options. Both teams are examining coal and energy conservation options. In addition to accounting for environmental loadings, the studies are attempting to value (in monetary terms) the externalities associated with each fuel cycle.
- **Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity, Argonne National Laboratory (DeLuchi, 1994)**: This study developed detailed fuel cycles accounting for the greenhouse gas emissions of transport (gasoline, reformulated gasoline, diesel, methanol, natural gas, electric) and electricity generation fuel cycles (coal, fuel oil, natural gas boiler/turbine, nuclear, methanol and hydrogen) representative of existing and likely future US energy technologies. The study examined upstream and secondary fuel and materials inputs and their emissions, but did not attempt to examine non-GHG impacts.
- **Fuel Cycle Evaluations of Biomass-Ethanol and Reformulated Gasoline (NREL, 1993):** This study used a fuel cycle analysis approach to compare three transport fuels: reformulated gasoline with MTBE (methyl tertiary butyl ether) additives; gasohol (E10) - 10% ethanol from municipal solid waste, 90% reformulated gasoline; and E95 - 5% reformulated gasoline and 95% ethanol from biomass energy crops such as grasses and trees. For each fuel cycle, the study examined five stages: feedstock production, feedstock transport, fuel production, fuel distribution and end-use. The study did not consider alternative end-use transport technologies. Study results were in terms of emissions loadings for each fuel cycle.
- **The Environmental Manual for Power Development, World Bank/GTZ (1994-1995):** This project has focused on the development of a new software tool for fuel cycle analysis in the power sector. The tool is intended to be used to evaluate the environmental impacts of power projects, identify environmental control options and alternatives, and provide information on trade-offs between economic costs and environmental benefits. The tool is being applied in an initial case study of power sector options in the Philippines.
- **Environmental Life-Cycle Inventories of Energy Systems, Paul Scherrer Institute/Swiss Federal Institute of Technology (1993-1994):** This ongoing Swiss national research project is sponsored by the Swiss Federal Office of Energy with the aim to compute detailed environmental data for existing energy systems in Switzerland and Western Europe. Besides detailed resource depletion and emission data, the analysis also includes waste categories, detailed land-use and radioactivity emissions. All systems are describded on a "cradle to grave" basis, including construction, material use, transport of material , dismantling and disposal. A major report with all data on diskette was published in March 1994 and is now appearing in a second, revised edition.
- **Other Efforts:** Other efforts in this field include an expert workshop on “Life-Cycle Analysis of Energy Systems” organized by the IEA and OECD and held in Paris in 1992, and a report submitted to the UK department of Trade and Industry (DTI) entitled “The Social Cost of Fuel Cycles”, by Pearce, Bann and Georgiou (1992).

The present project represents one of the first attempts at fuel chain analysis for developing as well as industrialized countries. As will be seen in the case studies below, a number of methodological and practical questions arise, particularly in developing countries: Are the data sufficient or reliable? How do the results differ from those obtained by simpler methods? How can decision-makers utilize these results? Is this level of analysis appropriate for energy planners, or is it primarily for researchers? How can one overcome the methodological hurdles? (See Section 2.2 below) One of the primary objectives of the present project has been to develop a tool that makes fuel chain analysis as accessible and straightforward as possible and to try to answer some of these questions through developing country case study applications.

2.2 Some Key Methodological Considerations

This section briefly describes four methodological considerations in fuel chain analysis and how we dealt with them in the design of the LEAP Fuel Chain program. These and other methodological issues are also discussed separately in the context of the case studies in Chapters 4 and 5.

Direct and Indirect Impacts

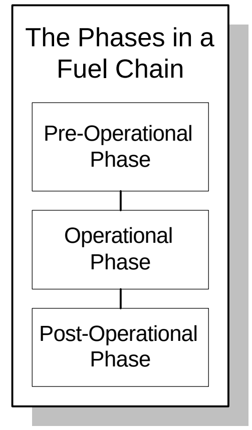
In general, indirect impacts are small in comparison with direct impacts, but this depends on the nature of the fuel and energy technology. For the coal plants, for instance, a recent report estimated that indirect emissions are two to three orders of magnitude lower than direct emissions at the power plant. (ORNL/RFF, 1994) For some capital and materials intensive fuel chains, such as solar PV and wind, the importance of indirect emissions from materials production can be considerable (see Knoepfel, 1993). They can also be important in particular cases such as the manufacture of vehicles (in transport fuel chains) or the use of fossil-based fertilizers in biofuel chains. Materials such as cement, steel, aluminum and fossil-fuel based fertilizers (used in biofuel chains) are themselves highly energy intensive to produce. For instance, the manufacture of vehicles can account for 15-20% of total greenhouse gas emissions from a typical gasoline passenger transport fuel chain. (DeLuchi, 1994)

In the user chooses to do so, the LEAP Fuel Chain program can incorporate two types of indirect impacts: (1) *indirect fuel impacts* related to the use of fuels produced off-site (e.g. the electricity used in a coal mine); and (2) the *materials use impacts* associated with materials used in construction and operation.

Indirect fuel effects occur when one energy facility (e.g. natural gas distribution) requires the energy produced by another facility (electric plant); the accounting becomes more complex when there are feedback loops (e.g. the electric plant is gas-fired). For example, if an oil refinery produces diesel to meet the needs of a diesel fired power electric plant, but the refinery itself uses some of that electricity as a process fuel, then a feedback loop is established that determines how much diesel and electricity need to be produced. We implemented an iterative solution methodology in LEAP/EDB that accurately calculates the effects of important feedback loops.

Materials use impacts can also be include the LEAP/EDB Fuel Cycle program, in terms of the energy required to produce them and the consequent environmental loadings. Some default data for materials production are included within LEAP and are described in Chapter 13 of this report.

Operational and Non-Operational Phase Impacts



Materials use is one typically important aspect of the pre-operational or construction phase impacts. Non-operational phase impacts are commonly divided into two categories. Pre-operational phase impacts occur during the manufacture of materials and equipment used in the fuel chain. Prominent pre-operational phase impacts for the above example would be the manufacture of vehicles and electricity power plants. An electric car, for instance, might require additional use of toxic materials for batteries with potentially harmful environmental impacts in their production (e.g. lead smelting). Post-operational phase impacts are most commonly associated with the decommissioning of nuclear and other power plants, the reclamation of mining lands, and the disposal of solid wastes. Averaged over the energy produced by an energy facility in its lifetime, these effects may be insignificant (e.g. <1% of the total fuel chain effects over the lifetime of the facility), however, there can be exceptions as noted above.

Allocation of Impacts Between Co-Products

For any fuel chain analysis where co- or by-products are produced -- in this case electricity and cogenerated steam -- a decision rule is needed to allocate responsibility for environmental loadings among these products. A number of different approaches can be taken. Using the LEAP Fuel Chain program, environmental loadings can be allocated (a) solely to one main energy products, electricity in this case, on the basis that a facility is built and operated primarily to produce these products, the other fuels (e.g. steam) representing a lower valued product; or (b) among two or more energy products according to the energy value produced by energy content.[7]

Boundary Issues

Boundary issues are important in defining which effects and stages to include in a particular analysis. The Sri Lanka case study provides a useful example. Since Sri Lanka will have to import all of its fossil fuels, the question arises as to whether fuel chain stages that occur outside of the country (oil production, coal mining and preparation, international transport) should be included in the analysis. The answer depends, not on any fundamental modeling question, but on the perspective of the decision makers for whom the analysis is being conducted. Other things being equal, it is unlikely that national policy planners will want to consider coal mining externalities that occur in Australia or South Africa. However, as climate change, biodiversity, and other global environmental issues become more prominent, it will be important for national levels policy makers to be well informed about both the national and international implications of their energy policy choices.

In the Sri Lanka case study, the impacts from all stages of the coal fuel chains are included, in part to provide the reader with a sense of the relative magnitude of impacts that can be expected from each stage. Results are presented for the fuel chain as a whole, and also broken down by stage. In this way, planners can utilize the results as they see fit.

Non-Quantifiable/Difficult to Quantify Impacts

Most analytical efforts in the energy sector do not include generalized models of hard to quantify effects such as the health impacts of indoor air pollution, soil erosion, soil degradation or ground and surface water pollution from agro-chemicals. At best, generalized models for these effects are not available, and at

[7] Other alternatives are possible, such as allocation by economic value, but can be analytically cumbersome.

worst the degree or even existence of these effects are controversial. LEAP also does not include any modeling of qualitative impacts. However, new features have been incorporated to encourage better documentation of these and other qualitative data for biomass and other energy technologies.

Beyond the present framework, the principal analytical challenge is to incorporate the fuel loadings identified here into cost-benefit analysis or some other decision-making framework. This is a subject requiring further analysis.

2.3 A New Tool for Fuel Chain Analysis

The new LEAP Fuel Chain program is designed to complement the integrated scenario-based tools provided in the LEAP energy scenario programs. The Fuel Chain program allows the user to compare the total energy and environmental impacts of specific fuel and technology choices per unit of energy or per unit of energy service delivered. The program comes supplied with default data representative of technologies available in both industrialized and developing countries.

The program is applied in a four step process:

1. **Build Process Database:** Processes are the basic building blocks for a fuel chain analysis. The user selects from the default data or enters data appropriate for local processes or technologies used at each stage, such as coal mining, electricity generation, oil refining, charcoal production, etc. These data are automatically shared between the Fuel Chain and Transformation programs. So, of example, if you have previously constructed an integrated scenario analysis using LEAP, then you can utilize that same data in your fuel chain analysis.

2. **Specify the Type of Fuel Chain:** You can specify three types of fuel chains:

   A) **An Energy Service Fuel Chain:** This type of fuel chain is assumed to deliver a unit of energy service (for example, a passenger-km of passenger transport, a tonne-km of freight transport, or a lumen of lighting). Comparing fuel chains based on the provision of the same service tends to be the most appropriate means of comparison in most situations. For example you might compare a passenger-km provided by gasoline cars, diesel cars, electric cars, buses and even trains.

   B) **Final Fuel Chain:** This type of fuel chain simply delivers a unit of some final energy form such as electricity, diesel, heat, etc. You can use this type of fuel chain to compare alternative supply technologies that provide the same type of final fuel or electricity. For example, you could construct fuel chains simulating alternative electricity generation technologies (coal, oil, hydro, renewable). This method of comparison is most appropriate for comparing among options for producing the same energy product, such as various electricity producing fuel chains.

   C) **Useful Energy Fuel Chain:** Similar to final fuel chains, with useful energy fuel chains you can explicitly specify the useful energy efficiency or energy intensity of the end-use device. This can be useful when, for example, considering alternative household cooking fuels. A firewood stove will have a much lower end-use efficiency (or higher energy intensity) than an LPG stove per unit of useful energy. Comparing on the basis of useful energy production would account for the differing efficiencies and enable a comparison based on the amount heat actually transferred in the cooking process. Measurement of useful energy often requires laboratory research; in contrast, one could use the energy service option above if one had survey data on the amount of firewood and LPG used to cook the same meal (i.e. the service would be "cooking a typical meal").

3. **Construct Fuel Chain Links:** Once you have defined the process building blocks name and type of the fuel chain, you can construct the links in the fuel chain. Start by selecting the conversion stage immediately preceding the end-use stage. For example, you might specify a stage describing LPG distribution for a LPG cooking fuel chain. You can then proceed to add in turn each upstream link in the fuel chain. The Fuel Chain program automatically steps you through the selection process by prompting you with options for each preceding fuel chain stage, such as LPG bottling or oil refining. A complete fuel chain will trace a final fuel through each conversion step back to the point of primary resource extraction[8]. Some sample fuel chains are shown below.

   The example shown below illustrates how fuel chains are constructed in LEAP in a modular fashion. The principal fuel chain to be analyzed is named "gasoline car", and is used to trace the gasoline used in an automobile from the end-use right back to the primary extraction of crude oil in an oil well. Diesel and electricity, are also used at various stages in the fuel chain. For example, electricity is used as an auxiliary fuel in the refining process. In LEAP you construct additional "modular" fuel chains for these fuels. Each of these second order fuel chains may in turn be linked to further fuel chains. For example, the electricity fuel chain is a branching fuel chain simulating the generation of electricity from three sources: coal, oil and natural gas, each of which are simulated by further fuel chains.

4. **Compare Fuel Chain Impacts:** Once you have created a complete set of fuel chain pathways you can then calculate and compare results for your fuel chains. A wide variety of results reports and graphs can be produced in LEAP showing the energy and materials requirements and environmental impacts of different fuel chains; many examples of these are included in the case study chapters below.

The full details of the Fuel Chain program are provided in Chapter 6.

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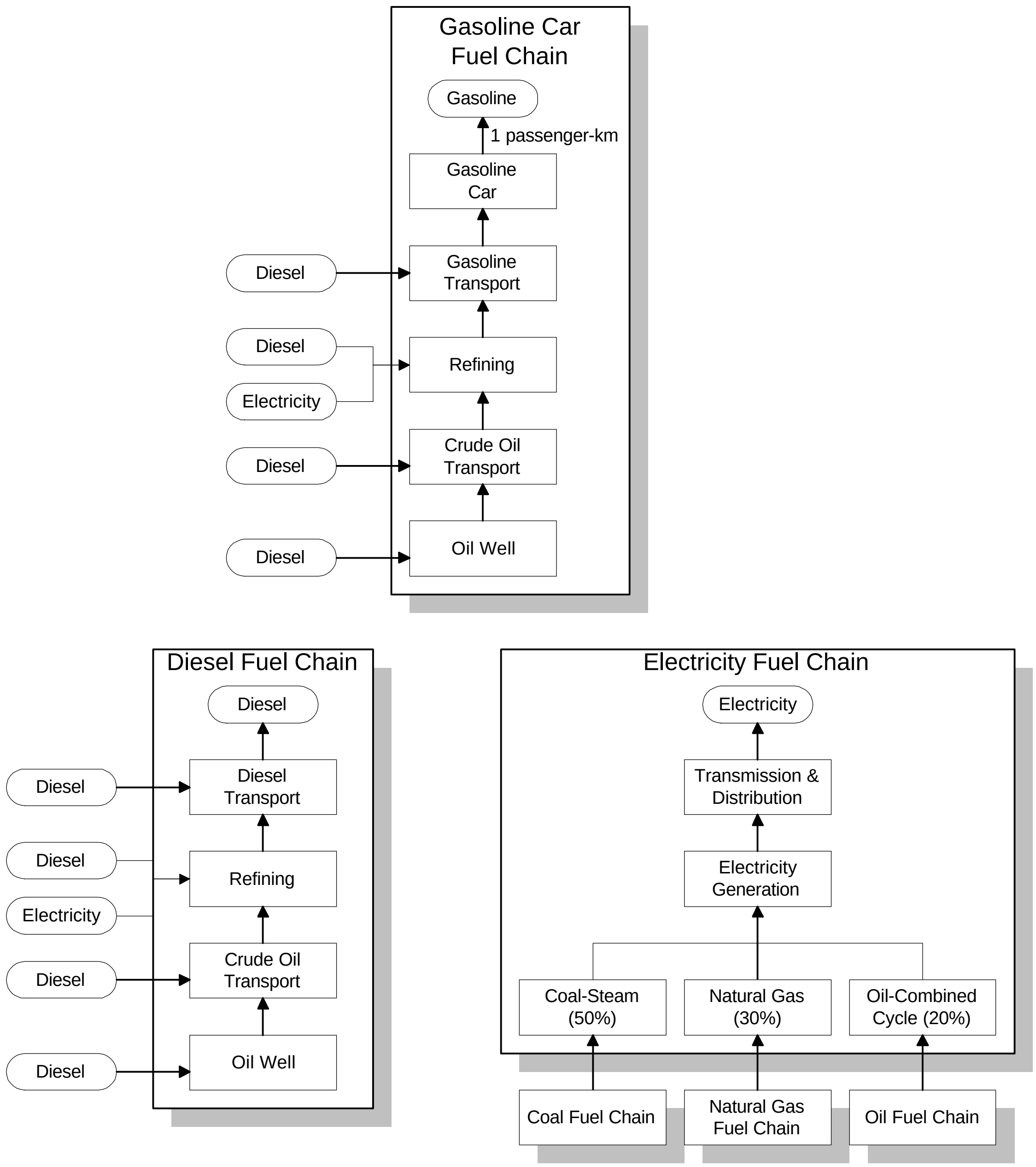
[8] In some cases you may wish to exclude analysis of stages that occur outside the boundaries of your analysis. For example, where fossil fuels are imported, you may not wish to include the environmental impacts of the resource extraction stage in your analysis.

Sample Fuel Chains in LEAP



3. AN APPROACH TO BIOMASS ANALYSIS

3.1 Introduction

Modeling of biomass energy systems is set in a context of complex issues. Overly simplistic attempts in the past have failed. These failures have greatly influenced revisions of the LEAP Biomass program carried out as part of this project.

In the 1970s, analysts and planners discovered the "other energy crisis" of woodfuel scarcities. At that time, the woodfuel crisis was perceived as a straightforward supply-demand imbalance. It appeared that population growth was leading to increased woodfuel consumption which in turn was causing widespread deforestation and desertification. "Gap theory" was adopted as the principal method for analyzing this problem and many early studies were based on this approach.

The debate has progressed since then. Through advances in the understanding of the complexities of woodfuel issues, analysts have come to recognize that, in most instances, woodfuel use is not the major cause of deforestation and moreover people can adapt in numerous ways to a declining availability of woodfuel. But if woodfuel use is not a major cause of deforestation and if people are able to adapt then just what is the value of studying woodfuel issues?

First, the issues are important both in human, and in ecological terms. Even though physical "gaps" seldom occur, people may still be suffering through woodfuel supply problems. While some of the responses to woodfuel scarcity represent improved standards of living, others represent a decline. The transition away from reliance on collected wood as a fuel and toward increased purchases of commercial (often fossil) fuels tends to occur as people's standards of living improve. Conversely, switching to lower quality fuels, changing cooking habits (possibly resulting in lower nutritional standards) or increasing the time spent in collecting woodfuel are all related to decreases in the standard of living. In terms of the ecological consequences, widespread land-use changes may be leading to varying degrees of deforestation, soil erosion, desertification, loss of habitats and even global environmental impacts (i.e. global climate change).

Second, despite rapid urbanization and a trend toward switching to fossil fuels, continuing poverty and rapid population growth in the developing world, make it evident that large numbers of people will continue to depend on biofuels for the foreseeable future. Rapid urbanization, unless carefully managed, could in fact place increasing pressures on biomass resources in some countries.

Third, different development policies whether politically interventionist or in the form of encouraging market-based transitions will have markedly different effects on woodfuel supply problems. It is important to try and assess what these effects may be.

Fourth, consideration of the environmental impact of biomass is of great importance, especially in developing countries. On the one hand, the traditional use of biomass fuels may currently cause serious human health impacts, while on the other the application of biomass fuels in modern energy systems may provide a means of supplying energy with very low associated environmental impacts.

Finally, woodfuel and other biomass resources are not only traditional fuels, but are also important locally available resources. As concerns about global environmental issues such as climate change increase, modern sustainably harvested biomass will become an increasingly attractive energy option, both for industrialized and also for developing nations. Biomass offers a potentially low cost energy source that, in more convenient forms, could substitute for more costly, imported or environmentally problematic fuels and could also act as a useful source of rural employment. If properly planned and implemented, modern biomass energy systems may prove to be an attractive option for some developing countries. The 1970s and 80s witnessed several attempts at tapping these resources including the Brazilian and Zimbabwean ethanol programs, the Philippines dendrothermal program (in which wood is grown and harvested for combustion in power plants), and current efforts to promote new efficient biomass energy technologies such as biomass integrated gasifier gas turbine and combined cycle systems (BIG-STIG/BIG-CC). A review of these technologies is provided by Williams and Larson (1992).

Thus, woodfuel and biomass energy systems must be viewed as presenting opportunities as well as problems. This section concentrates on improved understanding of the most pressing current problems associated with woodfuel supplies and demands. Important and closely related issues concerning the social costs and benefits and the land-use and environmental implications of modern biomass options also need to be fully assessed, but are touched on only briefly here.

The importance of studying these issues is made more complicated by the dearth of detailed information. For example, where biofuels consumption is concerned, Meyers and Leach (1989) state that "it is not possible to state with much certainty whether overall biofuels consumption is growing or declining in most developing countries".

3.2 Issues in Woodfuel Planning

Before attempting to model woodfuel and biomass energy systems, it is necessary to look at some of the basic questions concerning the current structure and dynamics of those systems in developing countries.

3.2.1 Who Uses Biomass Energy and How?

The term "biofuels" encompasses numerous different forms of processed and unprocessed biomass. These include firewood, charcoal, crop residues, bagasse (sugar cane residue), dung, coconut husks and shells, coco-charcoal, ethanol, methanol and producer gas. Their use varies widely both between and within individual countries. Biomass energy is used both in households for cooking, heating and lighting, and in industries and commercial establishments for end-uses such as tea, coffee and tobacco drying; brick and lime making; iron and steel production; sugar refining and a host of other small-scale end-uses.

Biomass supply pathways in developing countries are also diverse. They range from the informal collection of wood, dung and crop residues by rural people (the end-users of the fuel), to large scale industrialized operations such as the making of charcoal for iron and steel production in Brazil. These different supply pathways may have very different social and environmental impacts.

In households, the level of biomass consumption and the mix of fuels used in urban and rural areas are dependent on a range of interrelated factors. These include:

- the availability of wood and other biofuels
- the availability of modern fuels
- household income levels

- household size
- fuel prices
- costs and availability of end-use technologies (e.g. stoves)
- climate (which affects space heating/drying needs)
- cultural issues (e.g. cooking habits, social use of fires for pest control, ceremonies).

There is a dearth of statistics on biofuel consumption and it appears that the overall level of consumption and mix of fuels varies widely both between and within countries. Table 3.1 presents estimates of biomass fuels consumption for selected countries. As with most aggregate biomass data, these figures are incomplete and inaccurate.

Table 3.1: National Biofuels Consumption for Selected Countries, 1986 (PJ)

	Firewood	Wood for Charcoal	Agricult. Residue	Dung	Bagasse	Comm. Energy	Biomass % of Tot.
China	4,930		3,600	100	120	25,930	25%
India	2,365	160	430	860	190	6,114	40%
Indonesia	1,420	15		0	54	3,863	28%
Thailand	125	250	49	0	53	343	58%
Bangladesh	54	--	300	78	18	144	76%
Pakistan	220	--	34	87	29	542	41%

Source: Meyers and Leach, 1989[9]

Patterns of biomass fuel use are not static. The transition from traditional biomass fuels to fossil fuels has been fairly rapid in Latin America and many Asian cities (Sathaye and Tyler, 1991), but has been slow or non-existent in many rural areas and some cities. Income levels and the physical availability of wood and charcoal in cities and the use of other biomass fuels in rural areas remain major determinants of energy transitions. Among high income households in many developing countries, biomass consumption can still be significant. With smaller households, fuller entry of women into the (out-of-the-home) work force, and changing eating habits, clean and convenient fuels such as electricity, LPG, and natural gas become essential.

Whether rapid transitions will occur elsewhere in developing regions, particularly in rural areas, and what form this transition will take has been a subject of great debate in the literature (see for example: Leach and Gowen, 1987 or Leach and Mearns, 1988). Such changes in energy use patterns will ultimately depend on the speed and shape of economic transformations that occur. Korea provides an example of an extremely rapid transition: as recently as 1962, firewood accounted for 55 percent of total energy demand and, by implication, a large majority of household energy use (Asian Development Bank, 1991). By 1988, firewood accounted for less than 2 percent of Korea's energy demand, while oil and electricity use accounted for 64 percent, up from 10 percent in 1962.

A different story however has taken place in the Southern African region, where biomass fuels account for 80 percent of the regional energy mix (Raskin and Lazarus, 1991): "Imprecise biomass demand data, the lack of time-series data, and the highly localized nature of surveys make it difficult to track trends in biomass use. However, it is clear that a significant substitution of modern for biomass fuels - the so-called energy transition - has not occurred in Southern Africa in the 1980s. As per capita modern fuel consumption declined, there even are indications of "backward fuel switching" in recent years from modern fuels to woodfuels in urban areas and from woodfuel to agricultural residues in rural areas."

[9] Thai data includes industrial and commercial energy. Inclusion in other cases is uncertain.

Biomass energy may be purchased or collected as a "free" good. In urban households, industries and commercial establishments purchasing is common. In rural households, biomass fuels are normally collected. Again, there is little quantitative data about the scale of these activities. Biomass fuels, because they tend to be of a lower quality and are generally more abundant than woodfuels tend to be collected, more often than being commercially traded.

Table 3.2: Sources of Woodfuel

Collection of Dead Wood
Bushes & Shrubs
Lopping, Pruning of Trees
Whole Tree Harvesting
Surplus Wood From Land Clearances
Surplus Wood From Commercial Wood Harvesting & Milling
Re-growth from Fallow Lands

Woodfuel may be collected from a variety of sources. It may simply be collected from dead wood lying on the ground: branches and twigs, or it may be cut from bushes, shrubs, or trees. Another source of wood is the surpluses that arise when land is cleared for agriculture, or the wastes that arise from commercial logging of wood for non-energy purposes (e.g. lumber, pulp). Informal tree cutting practices often involve cutting live wood from trees in a sustainable way by lopping branches, pollarding or coppicing trees[10].

Estimates of tree stocks are often based on forestry department data for commercial forests or on satellite imagery. These data may only provide estimates of the biomass content of trees. They will not include the resources available from dead wood, bushes and shrubs, and often will not include trees outside of managed forest areas. Thus they may tend to severely underestimate the total biomass resources actually available.

Even in cases where whole trees are cut or land areas are cleared it is possible, depending on the presence of grazing animals, that trees will begin to re-grow. For example, charcoal cutters in Africa will often clear-fell an area of land to produce charcoal, but then will not return to the same area until the trees have grown back. Agricultural land left fallow may also be a significant source of woodfuel. It is important not to neglect the effect of tree re-growth when estimating woodfuel supplies. However, it is believed that grazing animals, fire, pests and other factors may prevent the re-growth of woody biomass, especially after large-scale land clearing (Swisher, *pers. comm.*).

[10] Pollarding is the practice of cutting branches near the trunk to stimulate a dense growth of new shoots. Coppicing referes to the ability of some species of trees to grow back from a cut stump. Coppicing trees typically produces a number of smaller shoots when the main trunk is cut.

3.2.2 Responses to Woodfuel Scarcity

Responses to woodfuel scarcity can be divided into two categories: the spontaneous adaptations in the behavior of woodfuel users, and planned policy interventions.

Users and collectors of woodfuel, when faced with scarcity, may change the ways they use and procure fuels in a number of possible ways. Their options include: better management of existing resources (by shielding fires or quenching partly used firewood, for example); reducing less essential end-uses (heating water for bathing or washing clothes, for example); spending longer times collecting wood; traveling further to collect wood; switching to other fuels (either superior or inferior depending on circumstances); increasing supplies of wood by planting trees; or changing eating and cooking habits so as to use less woodfuel (for example, using more uncooked food - possibly leading to lower standards of nutrition). Cutting standing stocks of wood is often viewed only as a last resort when faced with woodfuel scarcities. There is little more than anecdotal evidence about the scale and ranking of these responses which are likely to be highly location specific.

Table 3.3: Spontaneous Responses to Woodfuel Scarcity

Improve Wood Cutting Practices
Improve Fire Management Practices
Reduce Less Essential End-Uses
Increase Collection Times
Increase Collection Distance
Enlist More Family Members to do Collection
Change Eating Habits
Switch to Inferior Biomass Fuels
Switch to Superior Fuels
Plant Trees
Cut Standing Stocks of Trees

Planned interventions to reduce problems of woodfuel availability can take many forms. They may be direct energy policy programs designed either to increase wood resources by planting more trees (for example through agroforestry, farm forestry or community forestry projects); or to decrease the rate of growth of consumption (for example by promoting the use of new "efficient" stoves or by promoting fuel-switching or electrification schemes). Alternatively they may take the form of wider economic policies targeted at the underlying causes of woodfuel scarcities (poverty, inappropriate patterns of urbanization etc.)

3.2.3 Deforestation: Is it Occurring and What are its Causes?

The term "deforestation" is not well defined (Hosier and Boberg, 1993). In this discussion it is simply used to refer to any long-term reduction in tree cover. Deforestation, which in turn can lead to soil erosion and desertification, is a highly location specific phenomenon. Nevertheless, its principal cause throughout human history has been land clearance for agriculture. Any land clearing will have some associated costs as well as benefits (see Eckholm *et. al*., 1984), but the fear is that poverty, land distribution and land tenure inequities, coupled with the unique pressures of high population growth rates are causing rapid and uncontrolled deforestation. At the same time the poorest members of society may be unable to make the energy transition from biomass to higher quality (fossil) fuels. In some regions, most particularly Africa, this problem is exacerbated by the lack of a transition to higher intensity farming practices that require less land area, overall, to produce the same amount of food.

Table 3.4: Causes of Deforestation
Land Clearances for Agriculture
Land Clearances for Commercial Logging
Overgrazing
Pest Control
Wood for Urban Energy
Rural Woodfuel Collection

The demands for both domestic and industrial fuels in urban areas may also contribute to reduction in forest cover. Although the use of woodfuels in these areas is generally commercialized, the cutting of wood is rarely adequately regulated. Those involved in supplying wood to urban markets have little accountability for the social and environmental impacts of their trade. The problem is exacerbated in some areas because of the need to convert wood into charcoal to make its transportation over long distances cost-effective. Charcoal making in developing countries is usually carried out on an informal basis resulting in low conversion efficiencies which further increase the total amount of wood that must be harvested to meet urban fuel needs. Thus, rural woodfuel collection is only one of a number of possible causes of deforestation.

3.2.4 Constraints on Policy Interventions

The many constraints on policy interventions that would reduce the problems of woodfuel availability have been discussed widely elsewhere (see for example Leach and Mearns, 1988 and Munslow *et. al.*, 1988). Many projects, particularly those centered on large scale afforestation or on introducing new efficient stoves have failed to live up to their expectations, at least in so far as "success" was defined as saving woodfuel resources. For instance, tending agricultural land may be a higher priority than planting and tending trees, or if people do not have tenure or collection rights over the land where they are asked to plant trees, they are unlikely to be enthusiastic about tending any trees planted there.

3.2.5 Environmental Impacts of Biomass Production & Use

In addition to the deforestation concerns described in section 3.2.3, the production and use of biomass fuels also raises other environmental issues. These include:

- **End-Use Impacts:** especially indoor air pollution from biomass combustion.
- **Transportation Impacts:** Emissions from vehicles used to transport biomass fuels.

- **Conversion Impacts:** emissions from the conversion and end-use of biofuels (e.g. traditional charcoal making, or modern conversion processes such as ethanol production or biomass gasification).
- **Biomass Production Impacts:** increased soil erosion; biodiversity and habitat loss; requirements for and impacts of irrigation water and chemicals (fertilizers, herbicides, pesticides); emissions from mechanical equipment used on the plantation.
- **Greenhouse Gases:** biomass fuels raise difficult questions about how best to account for the global warming potential of biomass fuels in the energy sector while at the same time correctly accounting for net greenhouse gas emissions from land-use changes and the forestry sector.

A proper consideration of impacts must properly assign impacts between the co- and by-products of biomass plantations. For example, if electricity is produced from existing underutilized agricultural residues (such as bagasse residues from sugar cane plantations), then only part of the environmental impacts of the system should be assigned to the electricity generated by the system.

End-Use Impacts

Perhaps the most visible environmental issue for biomass fuel use is the indoor air pollution created by the combustion of biomass fuels. Smith (1987) identifies four major groups of indoor air pollutants contained in the smoke from fuel combustion: carbon monoxide, particulates, polycyclic organic matter, and formaldehyde. These pollutants are associated with a range of health impacts including: respiratory infections in young children; adverse pregnancy outcomes (including low birthweights of babies) for women exposed during pregnancy; chronic lung diseases and associated heart diseases; and cancer. Smith (1987, 1993) and Ellegard (1992) both demonstrate strong links between the use of biomass fuels in developing counties and high levels of exposure to pollutants.

There is increasing evidence of a correlation between high exposure to pollution and ill health. Quantitative assessment of the issue is complicated by the lack of reliable health data, the overlapping effect of other pollutants such as tobacco smoke and outdoor air pollution, and the lack of proper monitoring of exposure levels. The issues have been reviewed by Smith with particular reference to biofuels (1987, 1990). Smith (1993) describes a number of different studies that have found strong relationships between exposure to indoor air pollution and adverse helath impacts. However, other studies have failed to find such connections. A study of health effects in low-income urban women in Lusaka, Zambia (Ellegard, 1992) failed to find evidence that the health of biomass-fuel users was significantly poorer than those using cleaner fuels (electricity or kerosene). This negative result does not disprove the link between biomass use, indoor pollution and health, but does point to the necessity for local studies (which can correct for possible compounding factors such as smoking and socioeconomic status) and monitoring of exposure. In the particular example of Lusaka, the measured exposure levels were found to be much lower than those in other parts of the world, probably due to site-specific factors such as stove location, ventilation, mode of food preparation and type of housing.

Transport and Conversion Impacts

In both traditional and modern biomass energy systems, there will environmental impacts associated with the conversion of primary energy forms and the transport of fuels to the points where they are utilized. The principal impacts associated with transportation are related to air emissions, which will vary depending on the transport mode (truck or rail) and the efficiency and emissions controls associated with vehicles. Conversion of energy will also generate mainly air emissions impacts. Considering traditional biomass energy systems, charcoal production causes high emissions of methane, particulates and carbon monoxide. For modern energy systems, emissions will be associated with methanol and ethanol production and with biomass gasification for electricity generation.

Biomass Production Impacts

Biomass production may have major environmental impacts. These include increased soil erosion, biodiversity and habitat loss, requirements for and impacts of agricultural chemicals (fertilizers, herbicides, pesticides), and emissions from mechanical equipment used on plantations. The use of agriculture chemicals can lead to soil quality degradation, ground and surface water pollution, and mainly localized adverse human and animal health impacts. The manufacture of the agricultural chemicals itself consumes relatively large amounts of fossil fuels (particularly for fertilizers) and so contributes to air emissions.

The type of biomass crop grown will also have a major bearing on the environmental impacts of a biomass energy system. Agricultural crops may require large amounts of fertilizers and pesticides, the use of which can produce serious problems with air, ground water and surface water pollution. Intensive crop production will also require fossil energy use for fertilizer production, irrigation and operation of crop handling machinery, all of which will cause emissions of air pollutants. Siliviculture typically requires less fertilizers and energy use, little or no irrigation, and less management.

The environmental impacts of monoculture plantations may also be an important issue. The eucalyptus species in particular has a reputation for being ecologically destructive, sucking-up groundwater supplies that could be used for other crops and inhibiting the germination of seeds of other plant species (Agarwal, 1986). On the other hand, plantations may help to reduce soil erosion (depending on planting and harvesting techniques), and may provide corridors between natural forests that can actually help increase biodiversity (OTA, 1980). Because of their large land-use requirements, biomass energy schemes must also consider aesthetic changes, which may be especially important in areas where tourism is important.

Social impacts are an important consideration in biomass energy systems. In general, biomass systems will provide greater and more geographically distributed rural employment opportunities compared to a centralized energy system. Extra employment opportunities will largely arise in the agriculture or forestry sectors. This may be an important consideration in developing countries where rural unemployment and underemployment are serious problems. Because it is more dispersed, biomass energy may also help to reduce ‘enclave’ underdevelopment effects in which few of the economic benefits of an energy system flow into the surrounding economy. However, it is also possible that large scale modern biomass systems may lead to vertically integrated markets for wood since utilities normally prefer to deal with a small number of large suppliers. Small-scale land owners may be unable to compete in these types of markets. In developing countries. the social impacts of using agricultural residues, underutilized woodfuel resources, and undeveloped land areas must also be carefully considered. Resources that appear to be underutilized commercially, may in fact provide valuable but non-marketed resources to rural people. For example, tree thinnings may be used as fuel, and scrub-land may be used for animal grazing (Ackerman, 1990). Any scheme to promote modern biomass fuels should carefully consider the social impacts -- such as land tenure and distribution -- on users of traditional biomass energy forms.

Greenhouse Gas Emissions

The combustion of biomass fuels emits carbon dioxide, and the global warming impacts of these emissions will depend on the sustainability of the biomass production. For traditional biomass energy systems, such as those where rural people are collecting biomass fuels in a fully sustainable fashion, there will be no net emissions of carbon dioxide so long as wood regrowth equals removals. However, in systems where biomass stocks are being depleted, perhaps due to overcutting of firewood the system will be creating net emissions of carbon dioxide.

Considering modern biomass plantations, net carbon dioxide emissions will depend on land-use changes due to the establishment of the plantation. Where a system is based on improved utilization of existing resources (such as cogeneration using existing bagasse wastes) there will be minimal net change in carbon dioxide emissions. The net carbon dioxide emissions from newly established biomass plantations will depend on the type of biomass grown and the type of biomass it replaces. If wood fuel plantations are established on degraded scrub land there may be net carbon sequestration, whereas if the plantation replaces old growth trees there may be net carbon emissions. However, in all cases incomplete combustion of biomass leads to emissions of other non-CO_2 greenhouse gases which are not absorbed by photo synthesis, namely CO, CH_4 and certain other hydrocarbons. In certain circumstances improvement of combustion efficiency, leading to reduced CO_2 emissions can lead to more non-CO_2 emissions, with a resultant increase in global warming potential. See Smith (1992) for further discussion.

3.3 Modeling Biomass Systems

In the 1970s, analysts and planners discovered the "other energy crisis" of woodfuel scarcities. At that time, the woodfuel crisis was perceived as a straightforward supply-demand imbalance. It appeared that population growth was leading to increased woodfuel consumption which in turn was causing widespread deforestation and desertification. "Gap theory" was adopted as the principal method for analyzing this problem. Its basic tenets were as follows:

A) First, the current total consumption of woodfuels (and sometimes building poles, construction timber and other tree products) were estimated in the region under study.

B) Next, the total standing stocks of wood and the annual sustainable yield of wood in the region were estimated. Often, these were based on national forestry department estimates of commercial forestry scaled down to account for the accessibility of wood resources by assuming the wood from areas such as game reserves, controlled forests or remote areas was not accessible.

C) Consumption was then projected into the future (normally in direct proportion to the expected rate of population growth).

D) Where consumption exceeded sustainable yields, the theory assumed that "the gap" was filled by cutting into wood stocks.

E) Cutting of wood stocks was assumed to lead to a decrease in the future sustainable yield of wood. Hence the theory assumed that, without remedial action (namely planting more trees), a collapse in wood stocks would inevitably occur.

F) The final step in gap theory was to make an estimate of what needed to be done to "close the gap". Because the theory assumed an ever-widening gap, the conclusion was invariably that massive afforestation was required.

Many early studies were based on this approach including the sixty UNDP/World Bank developing country energy sector assessments conducted in the 1980s and the UN Food and Agriculture Organization (FAO) study "Fuelwood Supplies in the Developing Countries" (UN Food and Agriculture Organization, 1983). That study used gap theory to make twenty year projections, region by region, of wood resources, consumption and wood fuel gaps.

3.3.1 Criticisms of Gap Theory

The fears of imminent exhaustion of tree stocks in large parts of the world have proved to be largely unfounded, and this has led to a reappraisal of gap theory.

- A basic premise of gap theory is that woodfuel scarcities are caused by woodfuel consumption. In this respect it makes the mistake of equating deforestation and the woodfuel crisis. In fact, as noted in section 3.2.3, woodfuel problems are more often a consequence than a cause of deforestation. The cutting of live wood for fuel by rural people is only one of a number of possible responses to woodfuel scarcity. Furthermore, even where overcutting of wood does occur, this may not be because of an absolute lack of trees, but rather because of land-tenure arrangements which deny access to resources to certain parts of the community - normally the landless poor.

- By taking too aggregate a spatial perspective, gap theory ignores the reality that woodfuel supply and demand situations are highly location specific. Patterns of woodfuel consumption can vary widely within countries, within regions and even within village communities themselves.

- The data on which woodfuel consumption and tree resource projections are made are rough, but because gap theory assumes that the response to scarcity is always to cut wood stocks, it is the typically small differences between data on consumption and data on tree resources which drive the gap forecast.

- As described in section 3.2.1, woodfuel can come from a wide range of sources. Estimates of wood resources are often based primarily on forestry department data for commercial forests and so will tend to severely underestimate the total woodfuel resources actually available.

- Most gap theory projections do not account for the natural regeneration of forests. Even when whole trees have been cut or land areas cleared it is possible, depending on the presence of grazing animals, that trees will begin to re-grow.

- Gap theory methodology does not account for spontaneous responses to woodfuel scarcity. Unfortunately, as noted in section 3.2.1, there is a lack of quantitative information about the ordering and scale of these responses or as Leach and Mearns (1988) put it, there is no information about the price elasticities of demand or supply for woodfuels. In the absence of such information, gap theory makes aggregate projections on the assumption that these elasticities are all zero. That is, neither woodfuel consumption patterns nor tree planting patterns are assumed to respond to scarcity, but instead continue on their preset trends.

3.3.2 Towards a Better Approach

Bearing in mind the criticisms raised of early "gap theory" models, we can identify a range of issues which need to be addressed in any model of wood supply and demand. These issues include:

- **Land-Use Patterns:** Models must not assume deforestation is driven by woodfuel consumption. Instead of being based directly on a woodfuel supply demand balance, models needs to be based on a more complete consideration of all current land-uses and the likely changes in those land-uses over time. Furthermore, models must account for all possible sources of woodfuels: trees, bushes, shrubs and dead-wood. Including only commercial forest resources is not sufficient.

- **Disaggregation:** Because wood resource supplies, wood consumption patterns, wood management practices and responses to woodfuel scarcity are all likely to be highly location specific, any model must take a disaggregated perspective. The degree of disaggregation necessary will itself vary from area to area. Any model must therefore allow the planner the flexibility to choose where greater or lesser degrees of disaggregation are required.

- **Integration of Demand and Supply Side:** Any model must include a wide range of options and allow the planner to consider how they will interact; a demand-side policy that encourages, say LPG or kerosene, may affect the viability and economics of woodfuel plantations.

- **Wood Growth Patterns:** Any model must account for a range of wood growth patterns. It cannot, for example, be assumed that cutting into stocks will necessarily lead to lower tree growth rates. Informal wood cutting practices such as pruning or lopping may lead to higher wood growth rates. Models must account for the re-growth of trees where appropriate.

- **Data Availability:** Since data is often weak, any model needs to be flexible and user-friendly enough to (1) help make use of available data, (2) assist the user to make intelligent generic estimates where data is weak, (3) allow the user to identify priority areas where data needs to be improved (e.g. by making sensitivity analyses straight forward), and (4) be usable in-situ by planners in the developing countries so as to encourage an on-going data collection/analysis/data refinement cycle.

- **Spontaneous Responses to Scarcity:** Any model must account for a variety of responses and for a range of wood management practices. It must not simply assume that the only response to scarcity is to cut stocks.

- **Modern Biomass Options:** As concerns about global environmental issues such as climate change increase, modern sustainably harvested biomass plantations will become an increasingly attractive energy option. Any model designed to be applied to issues of woodfuel supplies and demands must be capable of analyzing the role of these options in an overall energy plan.

Two basic approaches for energy modeling are often referred to a "top-down" and "bottom-up". "Top-down" approaches attempt to capture the aggregate behavior of the energy sector by use of equilibrium or partial equilibrium models which simulate prices, demand, supply and investment interactions to seek a long-term market equilibrium. Such interdependent relationships are at best difficult to quantify and at worst an inaccurate description of the behavior of markets. This is particularly true of the markets seen in many developing countries which face severe constraints and are in any case dominated by the economies of more industrialized nations and the vertically integrated markets for many basic commodities. For example, the economies of smaller nations have little power over the prices of raw materials, especially fossil fuels.

For these reasons, a "bottom-up" or disaggregated approach is more suitable for modeling the energy systems of developing countries. This approach is not based on strict economic dogma, but instead takes a more pragmatic view of energy systems. Planners are encouraged to make demand and supply projections and investigate at a disaggregated level using available data and their own expertise and experiences of the energy system of their own country. This approach allows important (and often price-independent) effects such as technological innovations, energy transitions, market saturation and other structural shifts to be easily incorporated: something that would be virtually impossible using an econometric approach.

Economic modeling methodologies are not rejected but instead are made use of on an *ad hoc* basis only where the planner feels they are appropriate. For example: a national or regional macro-economic model may be used as the basic framework within which "bottom-up" demand and supply projections are made.

A range of different methodologies are available for modeling energy systems. These include: normative (optimizing) models, systems dynamics models, and accounting framework simulation models. Optimizing models typically use linear programming techniques to discover a system configuration which maximizes or minimizes some objective function (e.g. minimizing costs). They have found favor in such applications as least cost electricity planning studies but have generally not been seen as suitable for modeling disaggregated energy systems (such as rural biomass systems) where the planner is not generally attempting to make an optimal investment decision, but instead is attempting to quantify the economic and environmental impacts of a range of different exogenous macro-economic scenarios. Systems dynamics models makes use of engineering control theory to simulate a system as a series of interconnected stock and flow variables. They are a powerful tool for studying the interrelationships of the different parts of a system, but because their behavior is very sensitive to the feedbacks between different variables, their predictive capabilities rely upon very good knowledge both of the starting values of variables, and of the relationships between those variables. Small errors in estimates of any of these values will tend to be exaggerated as the model is run over a long planning period. To date such models have not been applied as practical tools for examining biomass or other disaggregated energy systems.

Most models of disaggregated energy systems have been based instead on a simpler approach: the accounting framework. The philosophy behind these systems is that complex and difficult to understand models are not appropriate. Instead, what the planner is provided with is a set of accounting tools for checking the consequences and consistency of a range of different scenarios. The power of these tools lies, not in a complex model, but rather in their equal emphasis on data, models and an easy-to-use user interface.

3.3.3 Modeling Environmental Impacts

Many of the environmental concerns described in section 3.2.5 can be evaluated by the preparation of fuel chains that quantify the physical inputs of energy and materials and estimate emissions and other direct impacts through linkages to environmental loadings coefficients. Land-use issues can be analyzed in models that contain a detailed and dynamic simulation of land-use changes, biomass demand and supply linkages, and biomass stock and yield relationships.

Other issues are either difficult to quantify or must be dealt with qualitatively. For example, while loadings of emissions can be quantified, no generalizable models are available that simulate the transport of pollutants, patterns of population exposure and the dose-response relationships that govern the final health impacts of the pollutant. Similarly, while simulation models can be developed to estimate biomass stocks and land-use changes, no reproducible or generalizable models are available that can take these results and use them to estimate overall soil erosion or soil quality deterioration impacts.

Considering greenhouse gases, there is some controversy in the literature about how biomass projects should be accounted for in terms of carbon sources and sinks. The conventional approach is to consider how a biomass system effects biomass carbon sequestration, and to separately account for any benefits that biomass might bring by displacing fossil fuel use. This the approach we used in the case studies. So for example, the mean stock of carbon on a new woodfuel plantation would be compared to the stock of trees on the land before conversion. Thus, converting densely stocked old growth forest to a short rotation intensive plantation could lead to net emissions of carbon dioxide. Plantations managed for maximum yield store no more than 30% of the carbon stored in a mature forest.

An alternative approach proposed by Leach (1995, *pers. comm.*) is to integrate the land use and energy accounting steps by using a concept of "supply displacement". This approach draws a wider boundary around the carbon accounting analysis to consider total energy (not just biomass) supply and consumption. While an intensive plantation itself sequesters less carbon than an old growth stock of trees, it is assumed to displace the consumption of carbon elsewhere (e.g., in the form of fossil fuels or building materials). This approach gives greater greenhouse gas mitigation credit to intensive biomass plantations and less to conventional afforestation programmes.

Whatever accounting system is used, modeling biomass fuels raises methodological questions about how best to account for CO_2 emissions from biomass fuel use in the energy system itself. One approach is to separately consider CO_2 emissions from fuelwood combustion and fuelwood conversion (e.g. charcoal making). An alternative approach is to account for all CO2 emissions, at the point of production, by making assumptions about the overall sustainability of biomass supplies and the fraction fully oxidized (e.g. 99%). In the case study analyses, we have adopted this second approach.

3.4 A New Tool for Biomass Analysis

In the light of the criticisms of biomass models summarized above, SEI-B has designed a new biomass modeling tool incorporated into the LEAP integrated planning software.

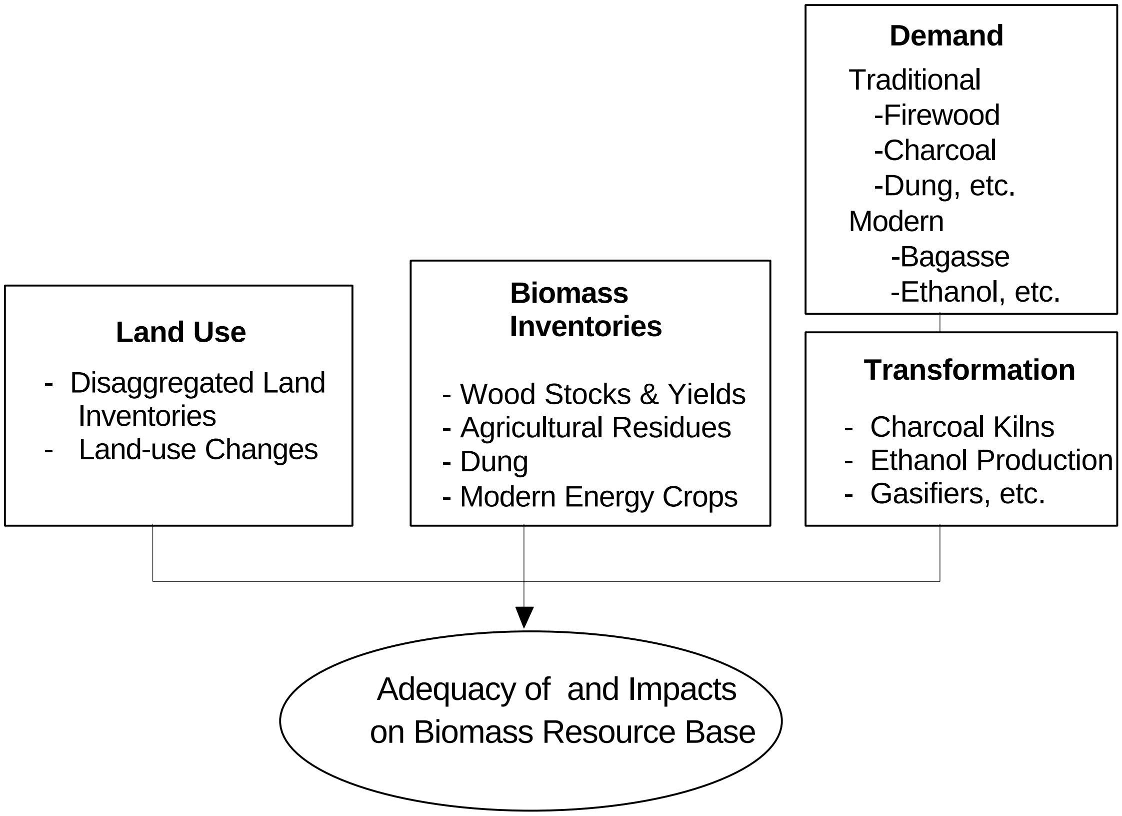
The Biomass program examines the impact of biomass consumption (both for energy and non-energy uses) and land-use changes (e.g. agricultural land clearances) on the biomass resource base. It is designed to help answer important questions pertaining to biomass energy. For example: "Will there be sufficient biomass to satisfy energy requirements?"; "Is deforestation likely to be a problem, and if so, what are its causes?"; "What are the impacts of possible afforestation programs?"; "What are the impacts of different urbanization scenarios on rural energy systems?"

The latest version of the biomass program expands the scope and flexibility of biomass analysis in LEAP, removing many of the more rigid assumptions of the previous version, expanding the scope of analysis to include dung, agricultural residues and other bioenergy resources, and improving the flexibility of the simulation of wood-growth models and land-management practices. The following section provides an overview of the new LEAP Biomass program. Chapter 7 contains a full User Guide for the new Program.

3.4.1 The LEAP Biomass Program

The basic unit of study in the new LEAP Biomass program is land. Data may be represented at whatever level of spatial detail is appropriate. An area (e.g. a country, state or province) may be further disaggregated into three levels of detail nominally labeled as subareas, zones and land types. For example, the first level could be the provinces of a country. The second level typically identifies ecological zones within a province based, for example, on the annual rainfall or zones of soil fertility. The third level identifies common land-types, generally based on land usage such as small farms, grazing ranges, natural forest, commercial forests etc.

Figure 3.1: Methodology of LEAP Biomass Analysis.



Wood stock and yield data are assigned to each disaggregated land-type and may vary from one subarea/zone to another. Different rates of growth and wood cutting practices may also be specified for each subarea, zone and land-type.

Dung resources are projected through an inventory of animals in each subarea and the dung they produce. Energy crop and agricultural residue projections are made on the basis of the land devoted to each crop and the yield of crops or agricultural residues per hectare of land.

Like the rest of LEAP, the Biomass program is demand driven. The energy demands for firewood, wood used for charcoal and any other biomass fuels are taken from the calculations of the Demand and Transformation programs. For example: a final demand for charcoal in the Demand program may be met in the Transformation program by a mix of traditional and efficient charcoal kilns. This will in turn produce a requirement for wood for the charcoal making process. As another example, demands for ethanol may be met in a Transformation module by processing appropriate biomass feed stocks.

Area-wide biomass requirements can be disaggregated to simulate the requirements for wood and other biofuels in the individual subareas used in the analysis. The effects of changing patterns of inter-subarea transportation of biofuels can be incorporated (e.g. production of wood or charcoal in a rural province for sale in an urban area). To these energy requirements are added separate estimates of the requirements for non-energy wood products: lumber, building poles, pulp and other items.

Projections of available wood resources, combined with estimates of the energy and non-energy requirements for biomass products, and scenarios describing land-use changes allow the Biomass program to simulate future wood growth and harvesting and to indicate the adequacy of wood and other biomass resources.

The Biomass program by itself, and when integrated into the rest of LEAP, addresses the requirements for an improved biomass modeling system. In particular, the following issues have been addressed:

- **Land-Use Patterns:** The Biomass program does not assume deforestation is primarily caused by woodfuel collection. Instead, its approach is based on a fundamental assessment of land-uses and land-use changes which encourages the user to explicitly account for all sources of deforestation and tree cutting. These may include cutting wood for rural woodfuel needs but will also include stocks cut during land clearing for agriculture and wood cutting for urban energy requirements.

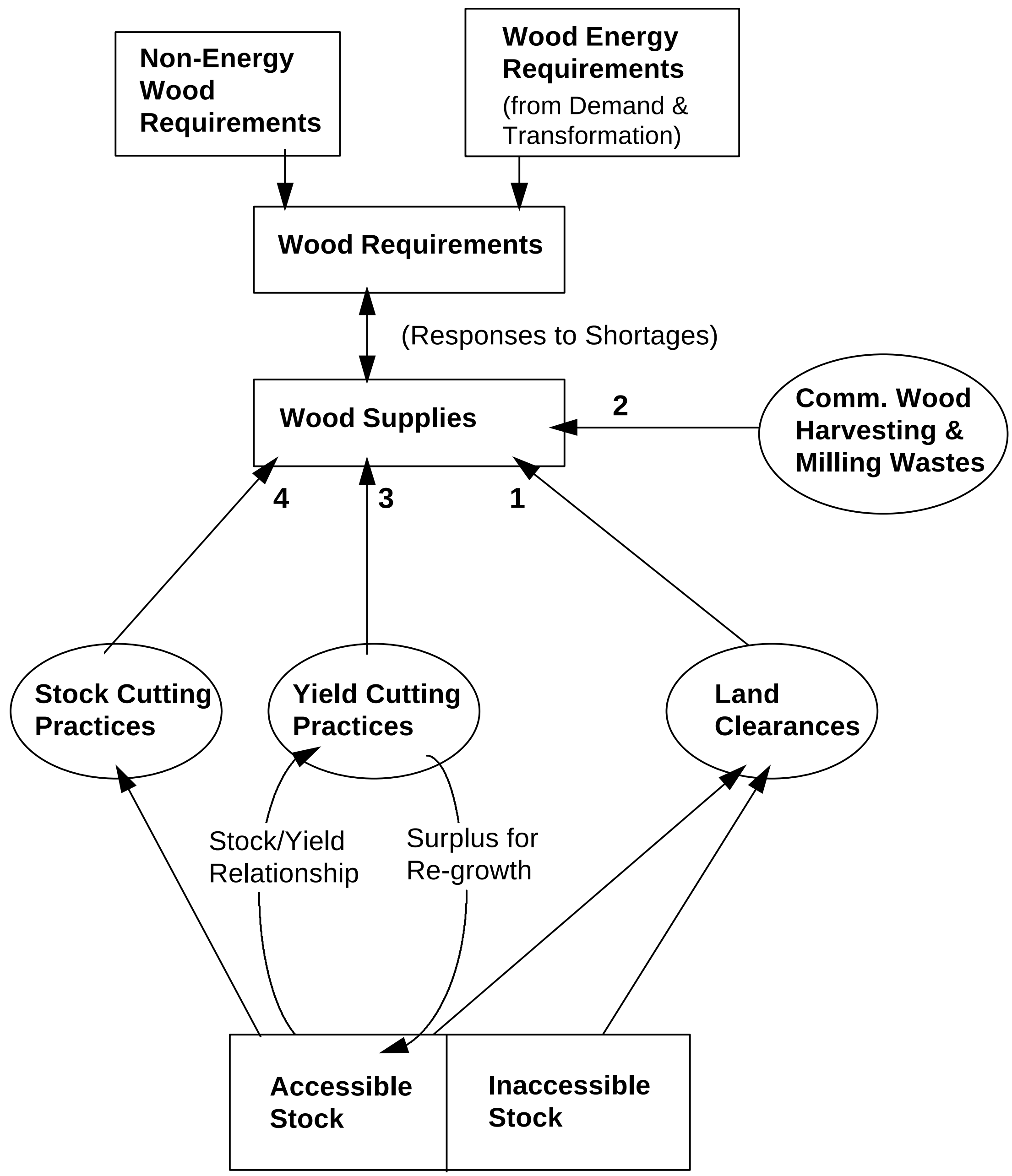
- **Disaggregation:** The Biomass program has a disaggregated perspective, which encourages the user to account for all sources of woodfuel including on-farm trees, wood from land clearances, inter-sub-area transport of woodfuels, waste wood from logging and milling as well as the cutting of trees of fuel.

- W**ood Growth Patterns:** The Biomass program allows a wide range of different land management practices and wood growth patterns to be described within its disaggregated data structure. In particular, some of the more basic assumptions of "gap-theory" models are lifted: (1) Cutting into stocks is not necessarily assumed to lead to lower tree growth rates. (2) Re-growth of wood on fallow or cleared land is allowed (but not assumed).

- **Spontaneous Responses to Scarcity:** The Biomass program does not assume that the only response to scarcity is to cut wood stocks. The user describes land-management practices on each disaggregated land-type, indicating whether or not wood stocks are cut on that land-type.

  At the present time, it has not been possible to endogenously model the wide range of spontaneous responses to woodfuel scarcity described in section 3.2.1, all of which are likely to lead to decreased consumption of woodfuel or to increased supplies. As has already been stated, these responses are likely to be highly location specific and there is little more than anecdotal evidence about their scale and ranking. To endogenously model such responses in an energy model, would require an equilibrium approach in which demands and supplies were interdependent. To solve such a system would require an iterative solution technique that would greatly increase the complexity (and time taken to solve) the system while at the same time making the structure (and results) of the model much more difficult to understand.

Figure 3.2: Schematic of Wood Demands and Supplies in LEAP



In the final analysis, like earlier "gap theory" models, the new Biomass program is still based on a supply-demand balancing approach that ultimately calculates a supply-demand "shortfall" if resources are found to be inadequate to meet requirements. This "shortfall" is not intended as a projection of a "gap". It is only intended to indicate that responses will be necessary. If sufficient data is available, assumptions about these responses can be incorporated into revised scenarios. This may involve changing the assumptions in the Demand, Transformation or Biomass programs.

3.4.2 Modeling Environmental Impacts of Biomass in LEAP

LEAP provides a generalized methodology for modeling the environmental impacts of biomass production and use. LEAP provides tools to quantify pollutant loadings, direct health and safety impacts, chemical inputs and net greenhouse gas emissions. The Biomass program described above also provides detailed estimates of the land-use requirements and impacts associated with alternative biomass energy policies.

Pollutant Loadings

By using either the Energy Scenario or Fuel Chain tools in LEAP in conjunction with the Environmental Database (EDB), air, water and solid waste emissions loadings and direct health and safety impacts can be estimated for every stage in a biomass fuel chain: end-use, conversion, transport, wood production.

Chemical and Material Inputs

The new version of LEAP developed for this project allows chemical input requirements of alternative biomass energy policies to be evaluated. Any type of chemical input can be accounted for including different types of fertilizers, pesticides and herbicides. Other material requirements relevant to environmental issues may also be studied such as irrigation water requirements.

Greenhouse Gas Inventories

LEAP provides a flexible framework for making inventories of greenhouse gases from biomass energy systems. Net carbon dioxide emissions can be accounted for in the LEAP Transformation program by simply assigning appropriate emissions factors to total sustainable and unsustainable biomass supplies. The Biomass program can be used to develop dynamic estimates about changes in biomass stocks and how the sustainability of biomass supplies in alternative scenarios.

Hard-to-Quantify and Qualitative Impacts

LEAP does not attempt to expand the boundary of its environmental analysis beyond that of loadings and direct impacts. The LEAP software does not include generalized models of hard to quantify effects such as the health impacts of indoor air pollution, soil erosion, soil degradation or ground and surface water pollution from agro-chemicals. At best, generalized models for these effects are not available, and at worst the degree or even existence of these effects are controversial. LEAP also does not include any modeling of qualitative impacts. However, new features have been incorporated to encourage better documentation of these and other qualitative data for biomass and other energy technologies.

Beyond the present framework, the principal analytical challenge is to incorporate the fuel loadings identified here into cost-benefit analysis or some other decision-making framework. One effort by Meier and Munasinghe for Sri Lanka (1994) examined how multi-criteria analysis might be used to incorporate externalities into decision making in the power sector. The incorporation of this or another type of analysis into the fuel chain framework described in this study is a subject requiring further analysis.

4. Sri Lanka: Options for Households and Electricity

Like many other developing countries, Sri Lanka is currently experiencing a transition from the predominant use of biomass fuels to the use of modern fuels. While biomass remains the dominant fuel consumed by 92% of households in 1992, the consumption of modern fuels such as electricity and kerosene for lighting and LPG for cooking is growing rapidly. Over the decade from 1980-1989 electricity consumption grew at an annual average rate of 5%, while LPG grew at 17.7%. Since that time, even higher rates of economic and energy consumption growth have been witnessed. The potential demand for modern fuels is huge. In 1989, approximately 75% of households had no access to electricity (Perera, 1992). If Sri Lanka follows the development trajectory of the rapidly industrializing countries in East and South-East Asia, modern fuel demand could double over the next 10 years.

Sri Lanka is now facing difficult choices about how to meet the needs of its growing population. It has no indigenous fossil fuel resources and, in the past, has relied on hydropower and imported oil to meet the demands for modern fuels. The remaining potential for large-scale hydro-electric development is rapidly being exhausted, and in the near future Sri Lanka will have to turn to other energy resources.

The present juncture in Sri Lanka's development provides an ideal opportunity to compare and contrast the different energy options available. Should Sri Lanka pursue an energy system that will require reliance on imported fossil fuel resources such as coal and oil, or should it seek to develop its use of indigenous renewable resources, foremost among which is biomass?

One dimension of this question is the environmental implications of different fuel choices. As outlined in Chapter 2, traditional energy planning methods often either ignore the environmental dimension, or treat it in a manner -- project-specific or sector-specific -- that does not adequately address the far reaching implications of major fuel choice decisions. New approaches can help to compare and contrast the environmental implications of choosing between different *fuel chains*. This case study presents the use of a *full fuel chain analysis method for* comparing the environmental loadings of biomass and fossil fuels in two different applications. Section 4.4 presents a comparison of biomass, coal and oil-fired electricity generation, while section 4.5 compares the environmental loadings of biomass and kerosene fuels for cooking in the household sector. In addition to the quantitative comparisons of each fuel chain per unit of delivered useful energy, we also review the important qualitative impacts of each fuel chain and examine the resource potential of each fuel chain for meeting future energy demands in Sri Lanka.

We also look briefly at the economic and institutional context in which these options are presently being debated. This study does not provide detailed costs comparisons between specific projects -- the methods of project cost-benefit analysis are well known and studies have already been conducted in many cases. Instead we examine a range of technology choices that are either currently economically viable or are likely to be so in the coming years.

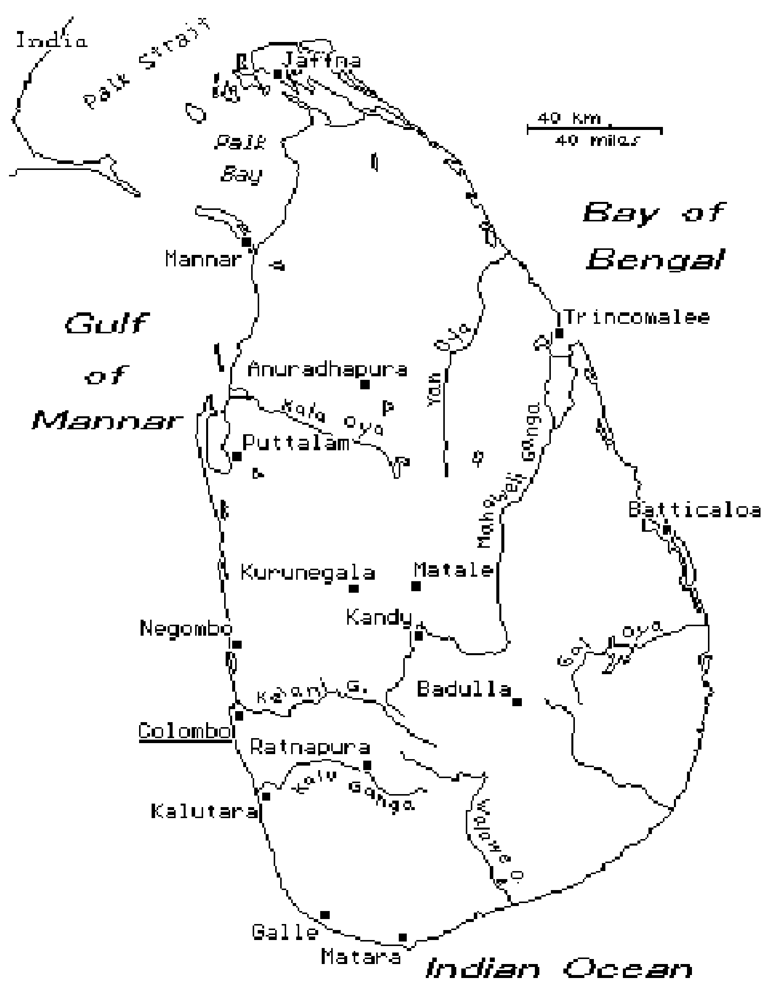
Whereas the case study of Venezuela described in Chapter 5 provides a reasonably data-rich environment to conduct a fuel chain analysis, Sri Lanka is perhaps a more typical example of developing countries, one where data availability and quality are limited. The general approach has been to develop a simple reproducible methodology that makes maximum use of locally available data, supplementing it with generic international data sources where necessary.

Beyond the present framework, the principal analytical challenge is to incorporate the fuel chain impacts or "externalities" identified here into cost-benefit analysis or some other decision-making framework. One effort by Meier and Munasinghe for Sri Lanka (1994) examined how multi-criteria analysis might be used to incorporate externalities into decision making in the power sector. The incorporation of this or another type of analysis into the fuel chain framework described in this study is a subject requiring further analysis.

4.1 Development Issues

The island of Sri Lanka is a developing country with an area of 65,610 km^2 and a population of 17.8 million in 1992. About 76% of the population lives in rural areas. The majority of the population live in the south-western 'wet zone', which receives two monsoons and comprises about one-third of the island. The remaining population lives in the 'dry zone', which receives only one monsoon. The island consists of a central hilly region surrounded by coastal lowland plains. In 1992, annual average per capita levels of GNP stood at US $494.

Figure 4.1: Map of Sri Lanka

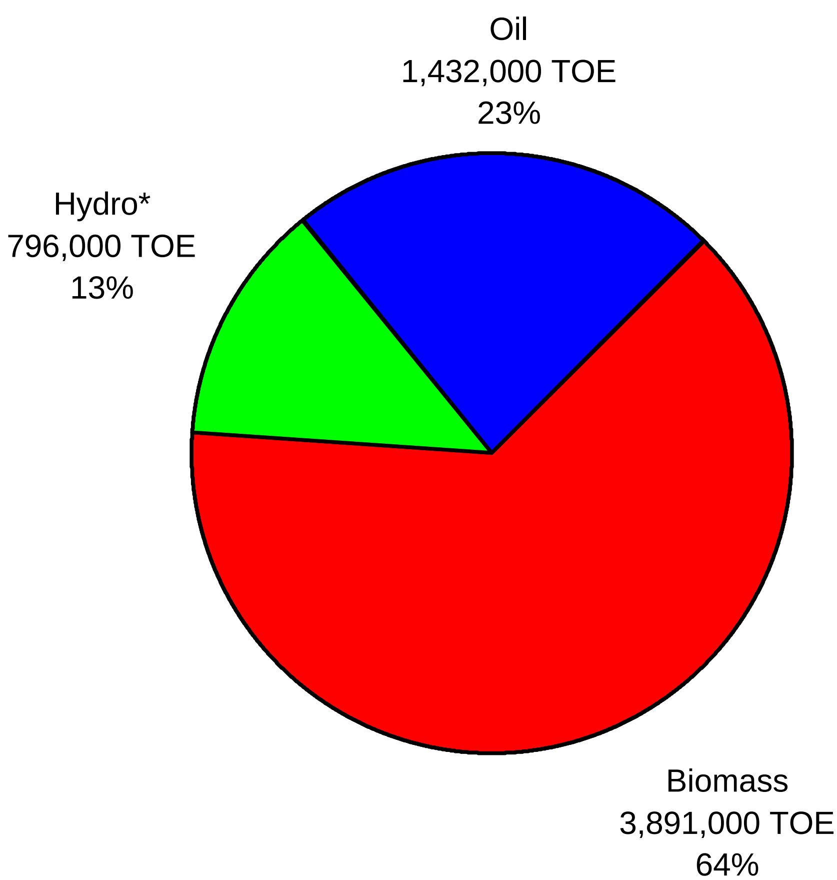


4.1.1 The Energy Sector

Sri Lanka's only indigenous energy resources are biomass and hydropower. Fuelwood and other biomass resources account for approximately 64% of primary energy supplies, as shown in Figure 4.2. Hydropower and imported crude oil and petroleum products contribute almost all of the remaining 36% of primary energy supplies. Small amounts of coal are also imported for use in rail transport. Table 4.1 shows Sri Lanka's energy balance for 1991 adapted by SEI-B from the energy balance developed by the Alternative Energy Development Branch of the CEB.

Table 4.1 shows how the household sector dominates the consumption of final energy. In 1991 they accounted for 62% of total final energy consumption. The industrial sector accounted for a further 18%, the transport sector 13% and the commercial and government sectors 5%. Agriculture and Non-Energy uses together accounted for only 1.5%. Biomass was the main fuel used in the household sector accounting for 66% of energy used there and also accounted for 51% of energy use in the industrial sector.

Figure 4.2: Sri Lanka Primary Energy Supply, 1991



Source: Sri Lanka Energy Balance 1991, CEB

4.1.2 Biomass Energy

Almost 93% of the island's population use biomass fuels for cooking, while in rural areas including people working in the estate sectors that figure is almost 99%. Firewood is the main biomass fuel accounting for approximately 69% of total biomass consumption (FPU, 94). Agricultural residues (mainly coconut fronds, husks, shells and wood, plus paddy husk used mainly in rice mills) account for a further 28%, and bagasse for 3% (FPU, 94). The main sources of firewood are the uprooting of rubber wood at rubber plantations (44%), supplies from natural forests (40%), coconut wood (7%), forest plantations (2%) and other sources (7%). These other sources include tea prunings, cinnamon and palmyrah plantations, home gardens, wayside and shade trees and shrubs from wastelands.

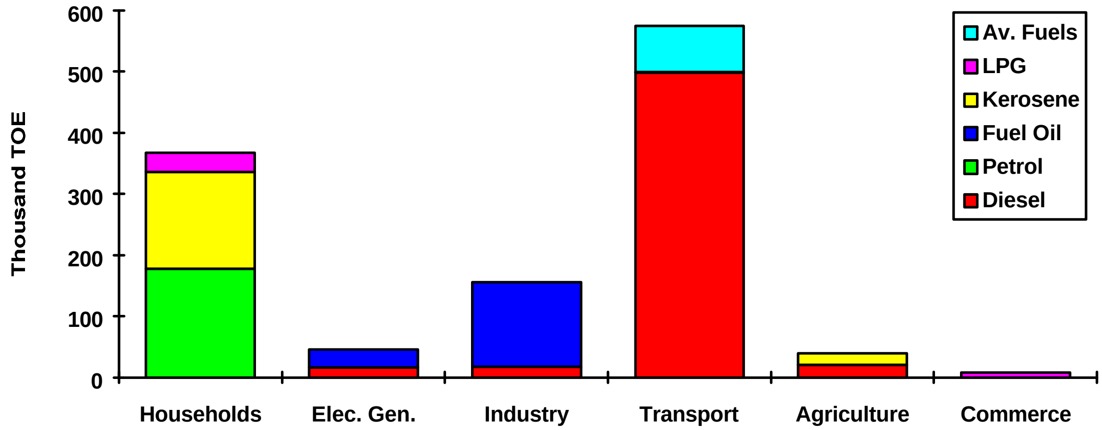
Evidence suggests that this picture may have been changing in recent years following two different events, both of which had impacts on firewood supplies. First, large-scale supplies of wood cleared from the Mahawelli redevelopment scheme have dwindled as that scheme has come to an end; and second, the poor financial position of tea and rubber plantations has meant lower than normal levels of replanting and pruning in those sectors (to maximize production in the short term at minimum cost). This in turn has led to lower than usual supplies of wood from those sectors and to increasing firewood prices being witnessed in Colombo, (Soussan, *pers. comm.*, 1994). It is estimated that, of the total firewood used by households, approximately 16% is purchased, while the balance (84%) is collected.

In households, biomass is used primarily for cooking. Smaller amounts of firewood are used in the colder hilly regions of country for space and water heating. In the industrial and commercial sectors the main consumers of firewood are the tea industry, in which firewood is used on a large scale for withering and drying tea leaves; the brick and tile making sector, primarily for firing kilns; the coconut industry, to provide heat for sterilizing and drying desiccated coconut; the rubber industry, to help cure the rubber, and other uses such as tobacco curing, food and cloth processing, ceremonies, and metal smelting.

4.1.3 Oil

Sri Lanka imports all of its oil requirements. In 1992 it imported 1.3 million tonnes of crude oil, used as a feedstock in the country's oil refinery operated by the CEYPETCO parastatal. A further 662 thousand tonnes of refined petroleum products (primarily diesel) were also imported. Petroleum products are used primarily in the transport sector (petrol and diesel); the industrial sector (fuel oil); the household sector (kerosene for lighting) and in the electricity generation sector (diesel and fuel oil). Figure 4.3 shows a breakdown of petroleum product consumption by sector.

Figure 4.3: Petroleum Product Consumption by Sector, 1991



Source: Sri Lanka Energy Balance 1991, CEB

4.1.4 Electricity

Electricity is used in households (primarily for lighting) and in the industrial and commercial sectors. In the 20 year period to 1992 electricity consumption grew rapidly averaging a growth rate of 6.8% per year. The CEB estimates that 3540 GWh of electricity was generated in 1992. The electricity generating system is dominated by hydropower. In 1992 82% of system demand was met by the system's 15 hydro power plants with a combined installed capacity of 1135 MW. The remaining gas turbine and steam thermal plants are fired with diesel and fuel oil.

The most recent Long Term Expansion Planning Study (1994-2008) conducted by the CEB indicates that the period of almost complete reliance on hydropower in Sri Lanka is now coming to an end. Although an estimated 870 MW of hydropower remains in 27 sites capable of providing about 3680 GWh/year under average conditions, in the future the electric system will require the development of new energy resources. The current CEB expansion plan calls for further hydro development and the building of new coal and diesel fired thermal plants.

4.2 Environmental Issues

Deforestation

Loss of natural forests is one of the principal environmental issues in Sri Lanka. Land area covered by natural forests has decreased dramatically in the last half century from 44% in 1956 to around 10-15% in 1990 (Hall, 1986). The main reasons for deforestation have been agricultural developments, encroachment by planned and unplanned settlements, chena (shifting) cultivation, logging and fuelwood extraction. It is not clear exactly what contribution fuelwood pressures have played in this process. In spite of the decrease in natural forests, when managed woodlands are taken into account it is estimated that around 65% of the country remains under tree cover (RWEDP, 1986).

Biodiversity and Habitat Loss

Sri Lanka is a small and relatively isolated island and has a large number of endemic species. The progressive loss of natural forests is causing concerns over habitat loss and its impact on biodiversity. The coastline of Sri Lanka with its coral reefs, mangrove swamps, nursery grounds for fish, and other ecologically important features is another area that is particularly vulnerable to environmental degradation. Given the importance of fishing and tourism to Sri Lanka's economy, the importance of protecting the environment of its coastline is already well established.

Hydro Power Impacts

Perhaps the most visible environmental issues associated with Sri Lanka's energy sector have been associated with the development of hydro power. Sri Lanka is a densely populated country (2.66 persons per hectare in 1990[11]) where land availability is an important issue. Many large dams, such as those of the Mahawelli redevelopment scheme have been built in the most densely populated wet zone, where there is less vacant land. This has led to the forced relocation of relatively large numbers of people, normally to irrigated lands in the dry zone. These lands are seen as less desirable by evacuees because of concerns over water availability.

Recent environmental impact reports conducted on proposed hydropower schemes in Sri Lanka and environmental post evaluation studies of completed projects (TEAMS Pvt Ltd., 1992 & 1993) have highlighted other environmental impacts associated with hydropower schemes. These include habitat loss, water table drawdown, removal of biomass from the area to be inundated, problems with ensuring adequate irrigation water downstream of reservoirs, and loss of archeologically and aesthetically important sites. Problems with water-borne diseases have also been associated with hydro development in Sri Lanka. For example, an evaluation of the Victoria dam project by the British Overseas Development Administration (ODA, 1987) cited problems with malaria outbreaks downstream of the dam and inadequate quantity and quality of water resources in lakeside settlements.

The benefits of hydro development also should not be neglected. In Sri Lanka dams are generally duel purpose: providing hydro power, but more importantly providing irrigation for increased crop production in otherwise dry areas. Fuel chain analysis must consider how to allocate environmental impacts between these energy and non-energy products of the fuel chain. Hydro development has also provided other important beneficial externalities including flood control, and urban drinking water supplies.

Air Emissions

The levels and effects of air pollution are generally poorly known in Sri Lanka. Table 4.2 presents a preliminary inventory of the energy-related emissions of eight selected air pollutants for 1991[12]. As would be expected in a developing country, per capita levels of emissions are very low compared to industrialized nations. Moreover, Sri Lanka's reliance on hydropower means there are very few emissions from the power sector. Nonetheless, localized air pollution problems related to fuel combustion do exist, and increased use of biomass, oil and potentially coal in the future may intensify air pollution concerns.

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[11] This figure can be compared to the population densities of other countries in 1990: USA (0.27), UK (2.37), China (1.22), India (2.87), Thailand (1.09)

[12] The inventory is based upon the 1991 energy balance shown as Table 4.1. Wherever possible emission factors appropriate for technologies used in developing countries were applied. In the case of the power sector emissions factors for thermal power plants were based on US average emission factors for plants without emissions controls.

Indoor Air Pollution

Household biomass fuels used in Sri Lanka are generally burnt on simple clay wood stoves that have no chimneys. Levels of exposure in Sri Lanka are therefore likely to be high. In the future, improving incomes and increasing levels of urbanization will lead to a transition away from the use of biomass fuels for cooking. This in turn could lead to a decrease in the problems associated with indoor air pollution.

In this case study, loadings of carbon monoxide, total hydrocarbons and particulates were quantified for a range of household cooking stoves. No attempt was made to go beyond loadings to analyze concentrations, exposures or dose-response relationships.

Local Air Pollution

While relatively little is known about ambient air quality in Sri Lanka, in most parts of the country air quality is fairly good, reflecting low levels of fossil fuel use and the strong natural ventilation of monsoon winds, (Munasinghe, 1994). An exception may be areas of Colombo where high traffic densities create high emissions of pollutants such as carbon monoxide, particulates, lead, and nitrogen oxides.

Regional Air Pollution

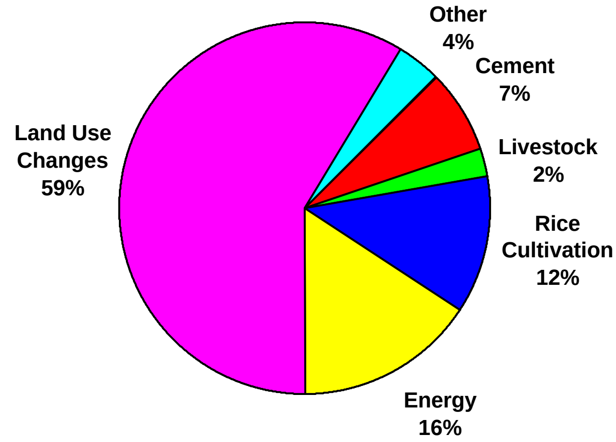
Regional environmental impacts such as acid rain are likely to become increasingly important in Asia as countries such as India and China increase their use of high sulfur coal. With virtually no coal being used in Sri Lanka, emissions of sulfur oxides, the primary acid rain precursor, are currently very low. The future potential for acid rain impacts will be related, not only to Sri Lanka's decision on whether to develop coal and other fossil fired electricity plants, but also to the pattern of transport of pollutants from India.

Global Climate Change

Global climate change is an issue that has not yet become prominent in energy policy decision making in Sri Lanka. Because of low levels of current emissions, the issue has not yet become a priority concern. However, as an island with a relatively long, densely populated and ecologically sensitive coastline, Sri Lanka would be sensitive to any rise in sea level. Climate change may also lead to an intensification of monsoon rains causing increased soil and coastal erosion.

Sri Lanka's energy related GHG emissions are currently very low. Net emissions of greenhouse gases from land use changes and rice cultivation, are currently much larger than those from the energy sector, as shown in Figure 4.4.

Figure 4.4: Sources of Net Greenhouse Gas Emissions in Sri Lanka, 1988.



Source: SEI-B, 1993 using IPCC 100 Year Global Warming Potential Factors.

As a small nation, the development of the energy sector in Sri Lanka will have only a small effect on the likely climate change impacts that Sri Lanka can expect to experience. It is therefore unlikely that Sri Lanka will formulate energy policies that restrict the growth of energy-related greenhouse gas emissions, unless those policies can be justified for other social and economic reasons. Under the Framework Convention on Climate Change, which entered into force in March 1994, industrialized countries are required to reduce their CO2 emissions to 1990 levels by the year 2000. The Convention allows countries to meet their obligations by working jointly with other countries. Low-cost greenhouse gas mitigation options exist in developing countries and these may provide a means for developing nations such as Sri Lanka to attract outside investment in newer and more efficient energy technologies.

A number of projects have already been implemented while preliminary studies are also being conducted to establish the costs of greenhouse gas abatement in developing countries. Further into the future, carbon offset, trading, joint implementation, or other schemes could bring investment funds for greenhouse gas mitigation measures to developing countries.

4.3 Fuel and Technology Choices in Sri Lanka

In the future, Sri Lankans are likely to face new fuel choices. In the electricity sector, as the potential of hydropower is exhausted, the choice will be between fossil resources (coal and oil) and renewable resources (biomass, fuels, wind, solar, etc.) In households, rising incomes will cause people to seek cleaner and more convenient forms of energy such as electricity for lighting and LPG for cooking. Biomass fuels will remain dominant for many years to come. Sri Lanka faces the challenge of finding technologies for reducing their adverse environmental and health impacts.

Each set of fuel choices will be accompanied by economic costs, environmental impacts and institutional constraints. The use of imported fossil fuels in the electricity and households sector will place a heavy burden of foreign exchange payments on the economy, while the promotion of renewable energy technologies for electricity generation will probably be more capital intensive than fossil-fired systems. In the household sector policies to promote fossil fuels (e.g. fuel subsidies) generally lead to economic inefficiencies and cross-subsidies that are both expensive and inequitable.

In this case study, environmental dimensions of these fuel choice questions for the electricity and household sectors are examined. New fuel choices will be made in the other sectors as well -- transport, industry and commerce -- but are not analyzed here.

4.3.1 Electricity Fuel Chains

The new LEAP/EDB fuel chain program was used to compare the environmental implications of three directions that new electricity supply options might take: coal, oil and biomass-fired. For each fuel chain, a range of different fuel chains were constructed to reflect both typical existing technologies as well as systems likely to be available in the future. The results for each fuel chain analysis are presented as a set of energy and environmental loadings *per unit* of electricity generated.

4.3.2 General Approach and Assumptions

For each fuel chain, assumptions were developed by combining international emissions, energy technology and materials data with available data collected in Sri Lanka. In addition to including technologies that are currently being considered as candidate electricity supply options in Sri Lanka, a number of additional technologies are included in order to demonstrate the range of impacts that can be expected with different technology choices.

All relevant fuel chain stages are covered, including primary production, transport and electricity generation. Since all fuel chains are assumed to be generating electricity for the national grid and hence have the same transmission and distribution requirements, this stage is not included in the calculations (except where electricity is used as an auxiliary input fuel in another fuel chain stage).

Facilities of a scale appropriate to the fuel chain as a whole were selected. Thus, for the coal cycle, large-scale generation facilities with capacities of over 100 MW were chosen, while for the biomass cycle, smaller scale plants capable appropriate for the likely volume of local wood or sugarcane feedstocks were considered. In addition, for those fuel chains based on biomass energy resources, the overall potential for each resource in the country was estimated.

Boundary Issues: How Should Impacts Outside Sri Lanka be Counted?

Boundary issues are important in interpreting the results of electricity fuel chains for Sri Lanka. Since Sri Lanka will have to import all of its fossil fuels, the question arises about whether fuel chain stages that occur outside of the country (oil production, coal mining and preparation, international transport) should be included in the analysis. The answer depends, not on any fundamental modeling question, but on the perspective of the decision makers for whom the analysis is being conducted. Other things being equal, it is unlikely that national policy planners will want to consider coal mining externalities that occur in Australia or South Africa. However, as climate change, biodiversity, and other global environmental issues become more prominent, it will be important for national levels policy makers to be well informed about both the national and international implications of their energy policy choices.

In this analysis, the impacts from all stages of the coal fuel chains are included, in part to provide the reader with a sense of the relative magnitude of impacts that can be expected from each stage. Results are presented for the fuel chain as a whole, and also broken down by stage. In this way, planners can utilize the results as they see fit.

For auxiliary fuel use (such as electricity use in mining), which account for a very small fraction of total energy use in the fuel chain (see results below), we have taken a simplified approach by assuming that all of the electricity is generated using the type of electricity generating plants envisaged for Sri Lanka. While this approach will inevitably produce errors in the calculation of primary energy use and environmental loadings, those errors are likely to be very small.

4.3.3 Coal-Electricity Fuel Chains

The two coal fuel chains for Sri Lanka considered all stages of the coal fuel chain: mining and preparation, long-distance transport, and combustion in electricity generation plants[13]. The first fuel chain simulates the environmental loadings of currently available technology, using data from the proposed coal-steam power plant at Trincomalee. The most recent proposals indicate that it will burn low sulfur coal, and incorporate basic NO_x and particulate control equipment. The second fuel chain assume a much cleaner and more efficient technology: integrated gasifier combined cycle (IGCC). IGCC has been included to provide a fairer comparison with the high efficiency biomass fuel chain outlined in the following sections. It illustrates the range of environmental loadings that could be expected if Sri Lanka decides to build coal-fired power plants in the next twenty to thirty years.

Coal Mining

The mining, preparation and storage of coal create a range of environmental loadings and impacts including emissions of air pollutants, water pollution, solid waste pollution, occupational hazards, and land-use impacts. Important air emissions include methane (CH_4) emitted from the mined coal seams (particularly from underground mines) and fugitive dust, in addition to the normal emissions associated with the combustion of fossil fuels used in mechanical mining and coal processing equipment.

The occupational hazards of mining (especially underground mining) are well known. The most common are accidents (fires, explosions, land subsidence, etc.), respiratory diseases such as CWP (coal workers' pneumoconiosis — "black lung" disease), and noise. Coal mining can also cause serious water pollution, principally through acid drainage, both in areas where mines are drained by pumping, and in mountainous regions where drainage is by gravity. For example, the water quality of some 17,000 km of streams in the Appalachian region of the US has been substantially altered by acid drainage from both surface and underground mines. Mining causes a range of land-use impacts (which can be particularly serious with surface mines); they include: habitat destruction, relocation of communities, visual impacts, subsidence (from underground mines), and soil degradation. Surface mining creates large amounts of solid wastes, although these are normally disposed of as the mined area is reclaimed. Spoil heaps (resulting from mining and washing wastes) as well as exposed strata from surface mining may become acidic if iron pyrites (FeS_2) are present, creating the risk of spontaneous combustion.

The environmental loadings from coal mining are often very site specific and poorly known, making it difficult to develop a generalized picture. However, the largest variations in the level of loadings and impacts occur between surface and underground mining.

Following the assumptions of the Trincomalee coal plant study, the coal used in Sri Lanka is assumed to have a 1% sulfur content and be imported from Australia or South Africa. Based on 1990 international coal production figures (IEA, 1994) for Australia, it was assumed that 32% of the coal will be from underground mines and 68% from surface mines. This ratio of surface to underground mining has an important effect on methane emissions since these are largely from underground mines and almost

[13] Losses in transmission and distribution are not considered, since that stage is common to all of the fuel chains considered here.

negligible from surface mines. In the absence of complete data, energy use in coal mining operations in Australia and South Africa is assumed to be similar to that in the US (U.S. DOE, 1983), consisting largely of electricity and diesel fuel use. Coal mining emission factors are taken from US data for underground and surface coal mines. It was assumed that all diesel is used in heavy trucks. Pre-operational phase impacts (e.g. from construction of the coal mine) and post-operational phase impacts (e.g. post-mining land reclamation) are not included in the analysis.

Coal Transport

It is assumed that coal will be transported from South Africa or Australia, a 20,000 km return trip (the distances from Sri Lanka to Australia or Sri Lanka to South Africa are both approximately 10,000 km)[14]. Since no information on energy use in international coal transport was available, we base the calculation on energy intensities for international crude oil transport (DeLuchi, 1993). From a survey of a number of different studies, DeLuchi assumes an energy intensity of 0.07 MJ per tonne/km. This is assumed to apply to both legs of the two-way trip. Emission factors for coal transport are based on US average data for fuel use in fuel oil fired shipping. Pre-operational phase impacts (from materials use in coal transport ships) are not included. The energy embodied in materials in an oil tanker accounts for less than 0.2% of the energy carried by the tanker over its lifetime (DeLuchi, 1993).

Coal-Fired Electricity Generation

The principal environmental impacts from coal-fired power generation can include air pollution (local air pollution, acid rain and greenhouse gases), and thermal pollution caused by discharges of cooling water, ash and scrubber waste disposal, and occupational health and safety risks to personnel.

In Sri Lanka, proposals to construct the country's first coal-fired power are generating some concern among local environmental groups (see for example, deSilva, 1991). The most prominent concerns regarding the plant center on air pollution and possible damage to fisheries and fragile marine ecosystems caused by thermal discharges from the plant's cooling water.

The first power plant considered is a steam cycle power plant of the type considered as a candidate at the Trincomalee site in Sri Lanka (Black and Veatch, 1988). The plant is assumed to have an efficiency of 34% (2559 kCal/kWh), and a maximum capacity factor of 75%. Emission factors for the plant are based on US EPA data for a typical large (> 20 MW) coal fired power plant with no emission controls using pulverized coal (US EPA, 1989). The other power plant considered is an advanced (IGCC) power plant that is both more efficient and produces lower emissions. IGCC technology is not yet commercially developed. It is included here to give a broad representation of a best-case scenario for coal use in the mid-term future. Emission factors for this plant were based on US EPA data for "clean-coal" technologies.

4.3.4 Biomass-Electricity Fuel Chains

Similar to the coal fuel chains, we considered two alternative biomass fuel chains to generate electricity and steam for cogeneration applications. The first chain assumes the use of a conventional steam turbine system, while the second examines the likely impacts of biomass gasification/gas turbine systems (BIG-GT). The first is representative of the types of technology already available, while the second represents the type of advanced biomass technology that will be available in the next ten to twenty years.

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[14] We assume that coal ships would return empty. In fact, shipping may be routed between a number of ports so that return journeys are made full. In such a case it would not be reasonable to allocate all impacts from this stage to the coal fuel chain.

At present, biomass-electricity generation has been widely adopted only in the US and Sweden. Largely as a result of the Public Utility Regulatory Policies Act (PURPA), almost 9,000 MW of biomass electricity had been installed in the US by 1992 (Larson & Williams, 92). All of this capacity is conventional steam fired plant, almost 6,000 MWe of which cogenerates. In developing countries, biomass electricity generation has proven economically viable only where low cost biomass fuels are readily available. It has been applied most widely in systems where cogenerating plants are used to generate electricity and also provide process steam for agricultural product processing . The sugar-cane industry in Brazil provides a major example. As many developing countries consider the deregulation of their electricity industries -- opening the way for smaller electricity suppliers to enter markets -- the prospects for more biomass fired power generation could improve. For example, in the Cote d'Ivoire, the World Bank has been encouraging the expansion of electricity cogeneration capacity in the palm oil, sugar and rubber industries as the least cost way to supply electricity to the grid (World Bank, 1994). To date only one major dendrothermal scheme -- where wood was grown in plantations solely for the purpose of electricity generation -- has been launched in developing countries. The experience of the Philippines in the 1980s was not a success mainly due to the high costs of supplying wood from plantations that produced lower than expected yields. The scheme has now been largely abandoned (see discussion in Foley, 1993).

In Sri Lanka, the most promising applications for biomass-fired electricity are in the tea and sugar cane industries where wood and bagasse are already being used very to raise large quantities of process heat. In 1991, Sri Lankan industries consumed approximately 1.05 million tonnes of firewood (FPU/FMP, 1994). The tea industry, the largest industrial consumer of firewood consumed about 40% of this, while the rubber industry consumed another 7%. In 1991, the sugar industry consumed 277 thousand tonnes of bagasse (CEB, 1991), the energy equivalent of 134 thousand tonnes of firewood.

In the tea industry, fuelwood is used on a large scale to wither and dry tea leaves. In the past, some factories used oil but due to high costs of fuel imports, most now rely on firewood as their primary energy resource. In the past, most low country tea estates have obtained their fuelwood from the low country rubber replanting schemes. In recent years, fuelwood shortages have been experienced by the tea industry, as rubber replanting has declined, although this may be a temporary phenomenon. In spite of these shortages, and largely because of the poor financial situation of the tea industry, few tea estates have planted their own fuelwood plantations and so are forced to continue using expensive oil supplies.

Most tea estates have areas of under-utilized marginal rocky lands with poor shallow soils that would be suitable for fuelwood plantations. It has been estimated that, to supply a medium yielding tea estate (with an annual yield of approximately 1500 Kg of tea per hectare), would require about 12-15% of the estate's land area, assuming existing wood burning technologies (FAO/RWEDP, 1986). The Sri Lanka Energy Managers Association (SLEMA) is developing one proposal for biomass fired cogeneration on tea estates in Sri Lanka (Walpita, *pers. comm.).* That proposal suggests growing Eucalyptus Grandis trees on 200 hectares of a 1500 hectare tea estate. The scheme would produce about 1 MW of electricity with 300 kW used by the processing plant and 700 kW sold to the grid. Process heat would be used via a heat exchanger to wilt and dry tea. Preliminary studies indicate that such a system would be financially viable if the revenue generated from sales of electricity to the grid are taken into account.

Biomass Production

In this case study, we assume that wood for biomass electricity production will be grown on dedicated plantations established specifically to meet the needs of the power plant. High yielding plantations will be necessary because they provide a guaranteed source of energy, and because they reduce the average transport distance from harvest site to power plant compared to low yielding tree species -- an important factor in the overall economics of the scheme. Short rotation times also reduce financial risks for land owners.

The biomass production stage involves land preparation, planting and harvesting of biomass. The two most important factors in determining the environmental impacts of biomass production are the change in land-use (if any) involved in establishing the energy supply chain, and the type of biomass crop grown.

Land-use changes can have a dramatic impact on the environment. Where biomass fuels are provided sustainably from existing agricultural residues or from underutilized wood fuel plantations there will be minimal impacts. For example, if electrical energy is generated from bagasse residues from sugar cane production there will be no additional environmental impacts associated with the crop production stage. On the other hand, changes in land-use can have dramatic impacts -- both negative and positive. For example, if biomass energy is provided by unsustainable logging of old growth forests there will be serious impacts including reduction of biodiversity and habitat, soil erosion and degradation, and net emissions of carbon dioxide; whereas if wood fuel plantations are established on degraded land the crop production stage may actually reduce soil erosion, improve habitats and biodiversity and sequester carbon from the atmosphere. A proper analysis of environmental impacts can only be made by considering the *change* in land-use caused by the establishment of fuel chain.

Social impacts are an important consideration in biomass energy systems. In general, biomass systems will provide greater and more geographically distributed rural employment opportunities compared to a centralized energy system. In Sri Lanka it is unclear whether the establishment of dedicated fuelwood plantations would have the effect of increasing or decreasing pressures on fuelwood supplies for rural people. However, impacts would not be due to the plantation itself, but rather to the institutional arrangements for supplying wood to the power plant. Any scheme to introduce biomass-electricity generation should carefully consider the likely impacts on rural people.

The environmental impacts of monoculture plantations may also be an important issue. The eucalyptus species in particular has a reputation for being ecologically destructive: consuming large amounts of water and sucking-up groundwater supplies that could be used for other crops and inhibiting the germination of seeds of other plant species (Agarwal, 1986). On the other hand, plantations may help to reduce soil erosion (depending on planting and harvesting techniques), and may provide corridors between natural forests that can actually help increase biodiversity (OTA, 1980). Because of their large land-use requirements, biomass energy schemes must also consider esthetic changes, which may be especially important as Sri Lanka builds it tourism industry.

Forestry yields in temperate zones are generally below about 10 dry tonnes per hectare per year. However, where wood is produced for energy purposes, yields in excess of 15 dry tonnes per hectare can be obtained, for example in Ireland and Scandinavia (IEA, 1994). In Sri Lanka, a species such as Eucalyptus Grandis can yield anywhere between 2 and 22 tonnes per hectare per annum on a 5-10 year rotation. The higher figure would probably only be obtainable on good soils with irrigation (Leach & Gowen, 1987). On arid soils (such as those in the dry zone of Sri Lanka), yields would be lower still (perhaps in the range 1-15 tonnes per hectare per annum depending on soil type and tree species. Howes (1989) estimates annual yields for a variety of major biomass fuels in Sri Lanka. Wet zone coconut, cinnamon and rubber plantations produce total biomass yields of between 6.5 and 7.7 tonnes per hectare. We assume that fertilized plantations are in the wet zone and are grown specifically to maximize fuelwood production and yield approximately 10 dry tonnes per hectare per year.

There are environmental impacts associated with planting, harvesting and maintaining a wood fuel plantation. The energy used in silvicultural machinery, the energy used by agricultural machinery and to produce three basic types of fertilizers -- nitrogen (in NH_3 and NH_4O_3), phosphorous (P_2O_5) and potash (K_2O) -- can be significant and is thus included in the analysis. There may also be important environmental impacts associated with the production of fertilizers as well. Some pre-operational phase impacts will also be associated with the energy embodied in machinery and with the preparation of crop seeds/seedlings. These effects are generally small. The environmental impacts of pesticide and herbicide use were not included, nor were the energy and environmental impacts of manufacturing those inputs.

No information was available on the intensity of fertilizer use in Sri Lankan silviculture. Assumptions are taken from DeLuchi (1993) for US short-rotation-intensive-cultivation (SRIC) wood plantations, which closely match those used in other US studies (IEA, 1994 and ORNL, 1992). It should be noted that in tropical regions, soil nitrogen is generally higher than in temperate regions so lower levels of nitrogen fertilizer may be sufficient. Also, tropical nitrogen fixing species may be available. Given evidence that irrigation produces little improvement in yields, we assumed that none is used. For each biomass-electricity fuel chain, two sensitivity analyses were conducted: including and excluding fertilizer use (The “NF” fuel chains).

Table 4.3: Fertilizer Input Assumptions for Wood Plantations in 3 different Studies

	N (kg/ha)	P_2O_5 (kg/ha)	K_2O (kg/ha)	Wood Yield
IEA (1994)	100	20	60	10 tonnes/hectare
DeLuchi (1993)	168	28	28	13.4 tonnes/hectare
ORNL (1992)	50	15	15	5-10 dry tonnes/hectare
This study	168	28	28	10 tonnes/hectare

Assumptions on diesel use for planting, managing and harvesting equipment are taken from DeLuchi (1993) and assume that the plantation is managed as a semi-automated industrial operation. In Sri Lanka, much of the energy for these processes might be provided by human and animal labor. Sri Lanka, in general, and the tea estates, in particular, suffer from chronic underemployment of labor. Fuelwood plantations could provide additional employment in an area where it is most needed.

Biomass Transport

Because biomass is much less energy dense than fossil fuels, the economics of the biomass fuel chain dictate that electricity plants must be located close to the biomass resource, and should preferably be located in the center of a biomass plantation. The economic distance for transporting wood will depend on the productivity of the biomass crop, the costs of transporting the biomass feedstock, the electricity plant amortization costs, and the costs of distributing the electricity.

All wood is assumed to be transported by diesel truck. Given the lack of infrastructure and difficult terrain in much of Sri Lanka, it was assumed that no other transport mode was capable of delivering fuelwood. We assume an average round-trip distance of 11 km (similar to conditions for US ethanol-wood plantations -DeLuchi, 1993), and an energy intensity of 4.5 MJ per tonne-km (world average energy intensity for heavy diesel trucks - SEI-B, 1994).

The environmental loadings of this stage of the fuel chain are largely related to the emissions from trucks used to haul wood to the power station, and are thus dependent on the average haul distance assumed.

Biomass Sustainability and Carbon Accounting

All wood used in the biomass-electricity fuel chains is assumed to be grown and harvested sustainably on woodfuel plantations. If established on marginal lands with present low levels of biomass stocks, managed plantations could have the effect of increasing average annual biomass stocks (above and below ground) and thus acting as a net carbon sink. If established on more mature forest lands or on lands where forests are likely to regenerate in the future, then plantations could have the opposite effect. To calculate this stock change effect one must know (a) the weighted average biomass stock on the managed plantation over the full rotation cycle and (b) the present biomass stock on the land and likely growth over an appropriate time horizon.

We have not included this potential stock change effect, but we estimate it to be relatively small. If, for instance, one assumed a 10 year rotation of even growth, complete clearing, and no fallow period, then the average above ground biomass stock on the plantation would be 10 tonnes/ha/yr x 5 years (mid-point in growth cycle), or 50 tonnes/ha. If one considers the IPCC estimate for above ground biomass stock on unproductive open Asian forests, 20 tonnes/ha, and annual long-term uptake of 0.25 tonnes/ha/yr, then over the next hundred years, the average stock would be 20 tonnes/ha + (0.25 tonnes/ha/yr x 50 years), or 32.5 tonnes/ha.[15] Thus, the net change would be 17.5 tonnes/ha or about 7 tonnes C/ha assuming 40% carbon content. This cumulative effect of 7 tonnes C over 100 years pales in comparison with the annual benefit that one ha of wood could generate in avoiding coal use, of about 3-4 tonnes C. It unlikely that any range of reasonable estimates for the stock change effect, i.e. (a) and (b) above, would alter this basic conclusion.

Biomass-Electricity Generation

Biomass is inherently cleaner than coal because it contains negligible sulfur and usually contains much less ash. However, depending on the technology used, biomass electricity generation can cause a range of mainly localized pollution problems. Important pollutants from conventional biomass combustion include carbon monoxide, hydrocarbons, particulates, methane, and hydrogen sulfide (H_2S). In the future, the use of BIG-GT technology is likely to produce very low levels of emissions, partly because of the need for clean fuels for use in gas turbines - ensuring low levels of particulate emissions, and partly because of the high temperature and high combustion efficiencies of these systems - ensuring very low emissions of carbon monoxide. Nitrous oxides emissions can arise from two sources: from thermal oxidation of nitrogen in combustion air, and from nitrogen in the biomass itself. Emissions of thermal NO_x should be very low in BIG-GT systems because of the low heating value of the biomass fuel gas and hence the low flame temperature. However, the nitrogen contained in the fuel gas may cause high levels of emissions that might need to be controlled, possibly requiring staged combustion or a catalytic converter in the turbine exhaust. The problem of NO_x emissions is similar for both coal (CIG) and biomass gas turbine (BIG-GT) systems, although biomass contains lower levels of nitrogen and so NO_x emissions are therefore likely to be less of a problem in BIG-GT systems. BIG-GT systems produce no water effluents apart from cooling water.

While wood contains fewer chemical contaminants than coal, the decentralized nature of biomass electricity production may lead to a number of institutional problems with pollution control. In decentralized systems, both the monitoring of environmental conditions and the enforcement of environmental regulations will more difficult, and the small scale of facilities will tend to eliminate capital-intensive pollution control options. On the other hand, the natural assimilative capacity of land and water

[15] See IPCC/OECD Joint Programme, GHG Inventory Reference Manual, First Draft, 1994, Tables 5-1 and 5-5. The above calculations do not include below ground biomass.

will be better able to handle the pollution from dispersed facilities. Effects that are local in nature (toxic waste disposal, depletion of water supplies, air pollution, etc.) will be less severe with small biomass plants compared to large coal facilities at one site but will occur at more sites for a given amount of electricity generated. Smaller plants with lower stack heights are likely to reduce regional environmental pollution (especially acid deposition), possibly at the expense of increased local pollution. This may, in turn, provide better incentives for local enforcement of environmental regulations.

Allocation of Impacts Between Co-Products

As noted in Chapter 2, there are several options for assigning the environmental loadings associated with biomass cogeneration to the separate products, electricity and steam, produced. For the present analysis, we have chosen to assign all loadings to electricity since all options are being compared on the basis of electricity produced and since steam is a lower valued product. One might argue that some fraction of the loadings be assigned to steam, particularly since biomass electricity is generally cost-competitive only where the overall efficiency of the cycle can be improved by cogenerating electricity and process heat (and where low-cost feedstocks are available). To assign some of the loadings to the steam would have the effect of lowering the results for upstream energy requirements and total loadings associated the biomass-electricity fuel chains reported below.

4.3.5 Results

Table 4.4 illustrates the primary energy requirements of the fuel chains analyzed in this study. The overall efficiency of each fuel chain is given by inverse of the total for each column. That is, the overall efficiency of the coal steam fuel chain is 1/3.24 = 31.2%

Table 4.4: Primary Fuel Consumption By Fuel Chain (GJ per GJ Final Energy)

FUEL	COAL STEAM	COAL IGCC	BIOMASS STEAM	BIOMASS STEAM NF	EFFICIENT BIOMASS	EFFICIENT BIO NF
NAT GAS*	0.00	0.01	0.26	0.00	0.14	0.00
CRUDE	0.18	0.18	0.06	0.05	0.03	0.03
COAL	3.04	2.76	0.02	0.01	0.01	0.00
WOOD	0.00	0.00	6.17	5.56	3.37	3.03
HYDRO	0.01	0.03	0.01	0.00	0.01	0.00
Total	3.24	2.98	6.52	5.62	3.55	3.06

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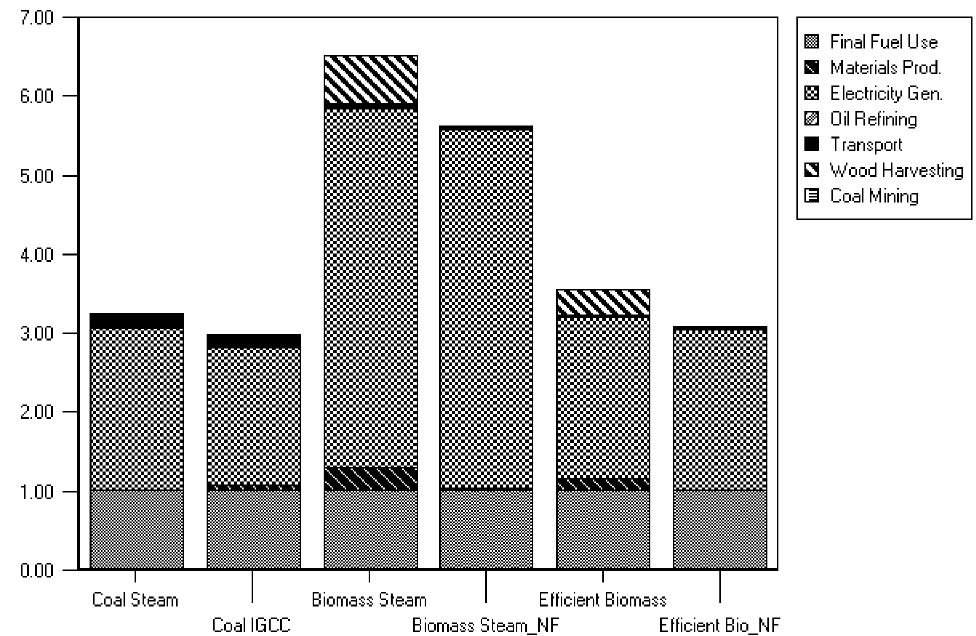
"NF" columns are sensitivity analyses for each biomass fuel chain -showing results excluding fertilizer inputs and mechanical planting/harvesting equipment.
* Note that natural gas is utilized for fertilizer production outside of Sri Lanka.

Figure 4.5: Net Energy Use: Stage By Fuel Chain (GJ per GJ Final Energy)



Graph produced by LEAP Fuel Chain Program

Figure 4.5 shows final fuel use (1 GJ of electricity) plus the losses and auxiliary fuels used in materials production and each upstream fuel chain stage. The efficiency advantages of existing coal steam systems compared to existing biomass systems lead to lower overall energy requirements. The primary resource advantages of coal compared to biomass are much less marked in the future when efficient systems are assumed to be available. However, if fertilizer is assumed to be used in biomass production, the overall energy requirements of the biomass fuel chains remain higher than those for coal.

Table 4.5: Effect By Fuel Chain: Physical Units per Thousand GJ Final Energy

EFFECT	COAL STEAM	COAL IGCC	BIOMASS STEAM	BIOMASS STEAM_NF	EFF BIOMASS	EFF BIO_NF	
CARBON DIOXIDE							
NON-BIOGENIC	297.01	270.94	17.85	3.56	9.90	2.11	(000 KG)
BIOGENIC	0.00	0.00	1115.36	1059.03	608.38	577.65	(000 KG)
CARBON MONOXIDE							
TOTAL	274.87	28.69	83.08	82.15	5.73	5.22	(KG)
HYDROCARBONS							
TOTAL	27.99	25.69	247.01	246.90	9.34	9.28	(KG)
METHANE	772.12	698.11	85.31	85.27	5.87	5.85	(KG)
NITROGEN OXIDES							
TOTAL	1155.59	663.68	492.47	488.32	147.45	145.19	(KG)
SULFUR OXIDES							
TOTAL	2129.02	698.50	7.73	1.76	4.47	1.22	(KG)
PARTICULATES							
TOTAL	4356.58	46.31	11.76	1.55	6.85	1.29	(KG)

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Table 4.5 shows the total loadings of 8 selected air pollutants for each of the fuel chains analyzed. As expected, the first coal fuel chain produces high loadings of pollutants such as sulfur oxides, particulates, nitrogen oxides and carbon dioxide. The coal-IGCC fuel chain produces much lower loadings, while the two biomass fuel chains on the whole produce the lowest of all. Nevertheless, the biomass fuel chains (especially those based on current steam-fired technologies) are likely to produce significant amounts of nitrogen oxides and hydrocarbons. The advantages of the biomass fuel chains are evident in terms of dramatic reduction in sulfur oxides and non-biogenic CO_2 emissions. In the biomass fuel chains, non-biogenic CO_2 loadings are primarily due to the consumption of natural gas for fertilizer production.

For the most part, these results reflect the overwhelming importance of the electricity generation stage as principal producer of emissions in the electric sector. However, in a number of cases, upstream emissions are important. In the coal fuel chains, the main source of methane (an important greenhouse gas) is from coal mining; in the oil fuel chains refining is important; and in the biomass fuel chains fertilizer production is important. Overall however, the coal fuel chains, because of their large production of non-biogenic CO_2, are by far the largest producers of greenhouse gases.

Based on the fuel chain data and assuming a mean annual increment of 10 tonnes per hectare from woodfuel plantations, approximately 94 hectares of land area would be required per GWh of electricity generated in conventional steam fired plants or approximately 50 hectares per GWh for efficient biomass generating systems. Thus, a 200 hectare plantation would be capable of generating approximately 2.2 GWh of electricity annually using conventional steam-fired plant. This is equivalent to 1 MW plant operating at 25% capacity factor.

Although it is difficult to make aggregate projections about the total potential biomass resource that might be available as a feedstock for electricity generation, two examples serve to illustrate the magnitude of the resource. According to the latest energy balance for Sri Lanka, the tea industry consumed 425,000 tonnes of firewood in 1991. This fuel is currently used to wither and dry tea leaves in inefficient equipment. If the same resource were utilized for cogeneration of steam and electricity using a conventional steam fired plant, then the same process heat requirements could be met while also generating approximately 340 GWh of electricity (10% of the total electricity generated in Sri Lanka from all resources). Another potential feedstock for biomass-electricity generation is bagasse. In 1991, 277,000 tonnes of bagasse were utilized in Sri Lanka to provide process heat in the sugar industry. If we assume that bagasse can be utilized in a fuel chain at the same overall efficiency as firewood, then this resource has the potential to generate a further 111 GWh of electricity (allowing for the lower energy content of bagasse compared to firewood)[16]. Obviously the total potential for biomass electricity generation in Sri Lanka is much larger.

The above two examples serve to illustrate only where existing resources could be more fully utilized. These two cases are examples of the type of application where biomass is first likely to be utilized for electricity generation in Sri Lanka. In both cases, the primary resources used as feedstocks in the fuel chain are already being utilized in industrial applications, and in both cases also their use for electricity generation will not detract from the existing provision of process heat. These two cases therefore represent low fuel cost applications of the type that will be required until such a time as the capital costs of biomass-fired cogeneration plants can become competitive with fossil-fired power plants.

[16] This is a conservative estimate since it includes only the bagasse from sugar cane (the residue left after extracting the sugar juice from the stalk). Any electricity generating system would most likely be designed to utilize the sugar cane tops and leaves or “barbojo” that are typically burnt in the field. The barbajo typically has almost twice the mass of the bagasse residue on a dry basis.

Another way of assessing the overall resource potential for biomass is to calculate the hypothetical land area that would need to be utilized to generate Sri Lanka's electricity requirements, now and at some time in the future. Using the assumptions for conventional biomass-steam electricity generation, about 658,000 hectares or about 10% of the total land area would need to be devoted to woodfuel plantations to generate the total electricity requirements of approximately 7000 GWh forecast for Sri Lanka in 2010. This figure is equivalent to the land areas currently devoted to paddy rice (735,000 hectares) or cereals (780,000 hectares [17]) or about 57% of the total natural forested area lost from 1956 to 1983 (1.15 million hectares), most of which is now low productive scrubland or grassland according to the Ministry of Lands. In fact, these land requirements are likely to be rather high since the base case demand forecast assumes high economic growth rates and no demand-side-management interventions, and the supply-side technology assumes no introduction of high-efficiency biomass systems.

4.4 Household Fuel Chains

4.4.1 Introduction

There are wide variations in the ways woodfuels are produced and consumed by households in Sri Lanka. Wood may be collected locally as a "free good" using human and/or animal labor, or it may be purchased from vendors who transport the wood between districts by truck. The source of woodfuels may be prunings from rubber and tea estates, dead-wood collected from natural forests, scrub and waste land, or wood cleared as a result of agricultural and hydro-electric schemes such as the Mahawelli redevelopment scheme. In Sri Lanka, the term "woodfuel" encompasses a range of biomass fuels including wood from various tree species; coconut husks, shells, and fronds; and paddy husk and straw. Households consume woodfuels in a variety of devices including simple three-stone fires, semi-enclosed mud stoves and improved fuelwood stoves normally constructed from fired clay. A range of different improved stoves are now on the market in Sri Lanka and appear to be gaining popularity (See for example, Wijesinghe, 1988).

This case study considers the fuel chain environmental loadings of three fuels used for cooking in households in Sri Lanka: firewood, charcoal and LPG. Of these, firewood is currently the predominant fuel, while charcoal and LPG represent two fuels which may become more widely used in the future. Because of the wide variation in technologies and practices for the supply and consumption of woodfuels in Sri Lanka, and the paucity of quantitative data on appliance efficiencies, environmental impacts and woodfuel supply pathways, no attempt is made to characterize individual technologies and practices. Instead, two representative woodfuel end-use technologies are considered: traditional and improved stoves. In addition, the effects of including and excluding wood transport and commercial woodfuel plantation impacts are estimated.

<u>Woodfuel Production</u>

The principal impacts from commercial biomass production arise from the use of mechanical machinery and the application of fertilizers, pesticides and herbicides. For household fuel chains, we assume that wood is either collected from natural forests, is a by-product of land clearances or estate plantations, or is grown on farms. We thus assume that no machinery, fertilizers or other inputs are required to produce the woodfuel[18].

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[17] Agriculture data from FAO Agrostat database for 1990.

[18] Although heavy machinery may be used for land redevelopment schemes, the impacts of these operations are not allocated to the household fuel chains since the woodfuel is a by-product of the land clearances.

Charcoal Making

The national average energy efficiency of charcoal production was 51% in 1991, according to the energy balance for Sri Lanka (CEB, 1992). This figure is high, reflecting the fact the charcoal making in Sri Lanka is a relatively industrialized operation (currently most charcoal is produced for export). No data are available on the environmental emissions from charcoal production in Sri Lanka. Calculations are based on typical emission factors for charcoal making in the developing countries from the WHO (1989) and other sources.

Woodfuel Sustainability

Assumptions regarding woodfuel sustainability are essential to estimating the net CO_2 emissions of biomass fuel chains. First, the overall sustainability of wood supplies for each resource must be estimated, then the responsibility for any decline in wood stocks must allocated among the factors -- agricultural expansion, hydro development, woodfuel demand, and others -- causing the net deforestation.

According to the last Forestry Sector Master Plan (FSMP, 1986), coconut, rubberwood, tea prunings, home gardens and forest plantations accounted for 69% of all domestic fuelwood supplies in 1986. Natural forests and other sources provided the remaining 31%. For household firewood usage, the first group are assumed to be sustainable sources of wood supplies. For the second group, natural forests and other sources, much has recently come from the Mahawelli land clearance schemes, which is clearly unsustainable but not caused by fuelwood demand. Demands for firewood are nonetheless likely to lead to some pressures on natural forests; in the absence of any other estimates, we assume a fraction of the supply from natural forests, 20%, for the purpose of the present calculations constitute a net decline in woodfuel stocks attributable to traditional fuelwood demands. Using this assumption, only 6% (20% times 31%) of total firewood supplies are unsustainable. For charcoal use, which is primarily made from wood from land clearances, we assume half of all charcoal supplies constitute a net decline in woodfuel stocks, sharing equally the responsibility for the loss of wood stocks with the other objectives of land clearance.

LPG Refining

Estimates of the environmental loadings of LPG refining are based on data provided by CEYPETCO on the products of it refinery together with international estimates of the energy used in petroleum refining and the environmental emissions from refineries. No detailed information was available on fuel use in Sri Lanka's oil refinery, therefore we had to rely on international data that suggests that refinery process energy use is about 5% of the energy embodied in the refinery products. Details of the assumptions used for oil refining are the same as those developed for the Venezuela case study and are discussed in Chapter 5.

International Crude Oil Transport

Currently the main suppliers of crude oil to Sri Lanka are Iran, Malaysia and Egypt. Iran currently supplies almost 70% of Sri Lanka's crude supplies. The average transport distance is 3500 km, and an energy intensity of 0.07 MJ per tonne/km, the same value as used for international coal transport, was assumed. The energy intensity is assumed to apply to both legs of a two-way trip. Emission factors for crude transport were based on US average data for fuel use in fuel oil-fired shipping. Pre-operational phase impacts (from materials use in oil tankers) were not included.[19]

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[19] According to DeLuchi (1994) this accounts for less than 0.2% of the energy carried by the tanker over its lifetime.

Crude Oil Recovery (for LPG)

Since the crude oil recovery stage occurs outside of Sri Lanka, international estimates of the environmental emissions and process energy use were used. DeLuchi (1993) estimates that for an onshore oil well process energy use accounts for approximately 2-3% of the energy embodied in the crude oil product. To simplify analysis and interpretation of results, all process energy is assumed to be crude oil. This figure may be much higher in offshore fields or in oil fields with difficult-to-recover reserves. For example, in some US oil fields it is as high as 9%. Refer to Chapter 5 for a detailed description of the assumptions used for this stage. Pre- and post-operational phase impacts of crude recovery are not included as they are likely to be very small.

Fuel Transport in Sri Lanka

The higher energy density of charcoal makes it a much more transportable fuel than wood with typically much higher maximum economic transport distances. Partly for this reason, charcoal is often a predominantly urban fuel in many countries, often being transported long distances from more densely wooded rural areas. In Sri Lanka, charcoal is a relatively new household fuel. The initial impetus for using charcoal has come from the need to utilize large quantities of wood cleared as a result of the Mahawelli redevelopment scheme. The State Timber Corporation has been producing charcoal from this source both for export and also for use by households. It is not clear what role charcoal will play in households in the future as these short-term supply sources dwindle.

Only one transport mode, diesel truck, was considered.[20] No other modes are likely to be available in the foreseeable future. For firewood, we examine two alternative transport scenarios, one including and one excluding wood transport. The second scenario is used to simulate firewood collected and used locally (in rural or urban) areas. We assume that all charcoal is produced in the immediate vicinity where it has been harvested and that there is no mechanical transport of wood feedstocks for charcoal making. We assume that all charcoal is transported by truck.

In the absence of detailed information on the energy intensities of freight transport in Sri Lanka, we use an energy intensity of 4.5 MJ/tonne-km . This figure is an estimate of the world average for all freight transport by truck. (SEI-B, 1994).[21] This figure is relatively high compared to estimates made for transporting different fuels in the US. Various studies make estimates of between 1.44 and 1.94 MJ/tonne-km with the lower values typical of petroleum products and the higher values typical of wood fuels.[22] The higher value for Sri Lanka reflects poorer road and transport equipment conditions.

Given the size of the country and the fact that most wood resources are located in its south-west ‘wet zone’ near to the most densely populated regions, assumed average transport distances are 80 km and 130 km for wood and charcoal, respectively. Trucks are assumed to carry full loads in both directions, and so only the energy consumed for one leg of the trip is considered. LPG transport is assumed to be more locally with an

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[20] Emissions factors for transport by truck in Sri Lanka are based on average estimates of emissions from heavy diesel trucks for eight pollutants. We have not included estimates of the materials used in transportation equipment.

[21] These values may actually be rather low. Because woodfuels are have a very low density (especially charcoal), energy use is more closely related to the volume of material transported than the mass. Thus, a truck fully loaded with charcoal may actually be capable of carrying a greater mass of wood so, for a given tonne-km load, a larger number of trucks will be required for charcoal than wood and hence the energy intensity of transporting charcoal per tonne-km is likely to be higher than for wood.

[22] A review of this data is presented in DeLuchi, 1993.

average transport distance of 20 km. LPG is both imported and produced by CEYPETCO at the country's refinery, and is distributed by the Colombo Gas and Water Company, primarily to urban households.

End-Use Technologies

Assumptions about end-use technology characteristics are based on a review of useful energy intensities of firewood stoves used in Sri Lanka, and of charcoal and LPG stoves used in other developing countries. Emission factors are based on a review of data for developing country stoves using wood, charcoal and LPG for both traditional and "improved" stoves". Estimates of materials used in stoves were not included.

Average per capita consumption of firewood by households will vary depending on many factors such as household size and income, the availability of alternative fuels, climate, how the wood is obtained (purchased or collected as a "free" good), the type of meals cooked, and the type of stove used. Data on fuelwood consumption by households is often poorly known. However, a number of measurements and estimates have been made in the Sri Lankan context. These are collected below in Table 4.6, together with the assumptions used in this study. The most notable characteristic of these values is the low fuelwood savings that appear to be yielded by "improved" stoves.

Table 4.6: Fuelwood Consumption data in Sri Lanka

	Annual Consumption (kg/person/yr.)	Efficiency	Notes:
Firewood			
This study & FSMP (1993)	500	12.5%	Traditional stove
"	449	13.9%	Improved Stove
Wijesinghe (1988)	526	11.9%	Rural Households
Howes (1988)	511	12.2%	National Average
ETC (1990)	925	6.7%	Traditional stoves on tea estates
"	548	11.4%	Improved stoves on tea estates
Charcoal			
This Study		25.0%	Metal (lined) stove, Leach and Gowen (1987)
LPG			
This Study		45.0%	Leach and Gowen (1987)
Efficiency term assumes wood energy content of 16 GJ per tonne.			

4.4.2 Results

The primary energy requirements for each of the fuel chains -- traditional firewood stoves (excluding and including fuelwood transport), improved firewood stoves (excluding and including commercial fuelwood plantations), charcoal stoves and LPG stoves -- are shown in Table 4.7. The overall efficiency of each fuel chain is the inverse of the total for each column.

Table 4.7: Primary Fuel Use for Household Fuel Chains (GJ per GJ Useful Energy)

FUEL	COLLECTED WOOD	PURCHASED WOOD	IMPROVED WOOD	WOOD PLANTATION	LPG	CHARCOAL
NAT. GAS	0.00	0.00	0.00	0.34	0.00	0.00
CRUDE OIL	0.00	0.21	0.19	0.19	2.59	0.09
COAL	0.00	0.00	0.00	0.01	0.01	0.00
WOOD	8.00	8.00	7.19	7.99	0.00	7.80
HYDRO	0.00	0.00	0.00	0.01	0.02	0.00
Total	8.00	8.21	7.38	8.55	2.62	7.89

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For reference, Table 4.8 lists the key assumptions and effects included for each household fuel chain.

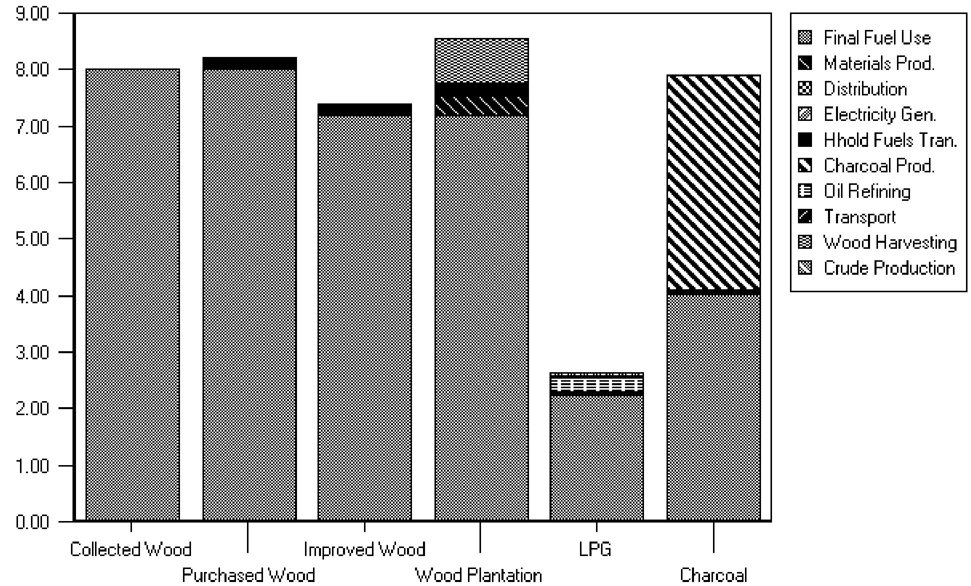
Table 4.8: Case Study Assumptions for Household Fuel Chains.

	Transport Included?	Wood Plantation Impact Included?	Assumed Woodfuel Sustainability
Collected Wood - Trad. Stove	No	No	94%
Purchased Wood - Trad. Stove	Yes	No	94%
Purchased Wood - Impr. Stove	Yes	No	94%
Wood Plantation - Impr. Stove	Yes	Yes	100%
LPG	Yes	N/A	N/A
Charcoal	Yes	No	50%

Tables 4.8 and Figure 4.6 show that for all fuel chains except charcoal, the consumption of final energy dominates the fuel chains. In the charcoal fuel chain, net energy consumption is split almost equally between energy used in the charcoal stove and energy losses for charcoal making. For all fuel chains (wood, charcoal, LPG), energy used in the transport of the fuel is found to consume no more than 1-2% of total primary energy consumption. Approximately 8 GJ of firewood are required to deliver 1 GJ of useful energy with traditional stoves. The primary energy requirements of improved wood stove chains are marginally lower for both firewood and petroleum products since less wood needs to be transported to deliver a given amount of useful energy. The use of fuelwood plantations increases the overall energy requirements for firewood used in improved stoves by approximately 1.2 GJ per GJ of delivered useful energy. This energy is used in the operation of the wood plantation and embodied in fertilizers.

For all these fuel chains, results are sensitive to assumptions on end-use and conversion process efficiencies. For example, the results indicate that the charcoal fuel chain has slightly lower primary energy requirements than the traditional firewood fuel chains. However, this result is sensitive to the assumption about the efficiency of charcoal production. If charcoal production for households is actually only 40% efficient (instead of the 51% we assumed) then the total primary energy requirements for the charcoal fuel chain would jump from 7.9 GJ/GJ to 9.0 GJ/GJ, higher than for any of the firewood fuel chains.

Figure 4.6: Final and Upstream Fuel Use for Selected Household Fuel Chains (GJ per GJ Useful Energy)



Graph produced by LEAP Fuel Chain Program

Table 4.9 shows the emissions of selected air pollutants from each household fuel chain per GJ of useful energy delivered by the fuel chain. The firewood and charcoal fuel chains show loadings for almost all pollutants are an order of magnitude higher than the LPG fuel chain. For example, comparing firewood to LPG, carbon monoxide emissions are over 1000 times, particulates emissions are 5.6 times higher and nitrogen oxide emissions are 3.8 times higher. More importantly, these loadings are concentrated at the end-use stage of the fuel chain and so result in indoor pollution since none of the firewood stoves used in Sri Lanka have chimneys. This case study does not attempt to study pollutant concentrations, dose-response relationships or likely human health impacts. Nevertheless, these results stress the dramatically higher population exposures that result from biomass fuel use compared to LPG use in households.

A comparison of firewood and charcoal loadings by fuel stage also yields interesting results. Figure 4.7 shows particulates loadings for each fuel chain. Although the charcoal fuel chain has higher total loadings of particulates, these loadings are primarily caused by the charcoal production stage of the fuel chain, and are thus likely to lead to much fewer health impacts. Similar patterns occurs when viewing loadings of the other main indoor air pollutants: nitrogen oxides and carbon monoxide.

Considering the global warming potentials of the fuel chains (which in this analysis includes CO_2 and CH_4 only), the results highlight the importance of obtaining better information on the sustainability of woodfuel use. By default we assume that 94% of firewood is produced sustainably (all coconut, rubberwood, tea prunings, home gardens and forest plantations, plus 80% of wood from natural forests and other unclassified resources). As shown in Figure 4.8, with these assumptions, total emissions from the fuelwood chain have 70% lower global warming potential than those from the LPG fuel chain. However, as the assumed sustainability of woodfuel supplies decreased, the overall global warming potential of the woodfuel chain increases. We calculate that the “breakeven” point, below which the LPG fuel chain is preferable to the wood fuel chain in terms of global warming potential, is at 78% woodfuel sustainability. It should be noted that this is substantially higher than the 69% of domestic woodfuel supplies that we know come from sustainable sources of supply. For the future, a key research question is to find out whether or not this threshold sustainability is exceeded in Sri Lanka.

The charcoal fuel chain, which in terms of energy resource requirements is similar to the firewood fuel chains, has significantly higher global warming potential both because of the lower sustainability assumed for charcoal wood resources and also because of the large amounts of methane emitted during charcoal production. It is also interesting to note that the high levels of methane emissions from charcoal making would cause the charcoal fuel chain to have greater global warming potential than the LPG fuel chain even if the wood feedstock were produced from an entirely sustainable source. Were charcoal to be produced at efficiencies lower than the 51% assumed in this case study (as is typical of household fuel chains in other developing countries), the emissions of methane would be even greater. In terms of its global warming potential, charcoal therefore appears a very unattractive option.

Table 4.9: Selected Environmental Loadings of Household Fuel Chains in Sri Lanka (kg per GJ Useful Energy)

EFFECT	COLLECTED WOOD	PURCHASED WOOD	IMPROVED WOOD	WOOD PLANTATION	LPG	CHARCOAL
CARBON DIOXIDE						
BIOGENIC	686.20	686.20	617.09	729.42	0.00	355.75
NON-BIOG	43.80	45.56	40.97	20.08	167.45	356.54
CARBON MONOXIDE						
TOTAL	40.00	40.00	35.97	35.97	0.03	60.39
HYDROCARBONS						
TOTAL	3.75	3.77	3.39	3.39	0.08	27.29
METHANE	0.28	0.29	0.26	0.26	0.16	8.11
NITROGEN OXIDES						
TOTAL	0.35	0.35	0.32	0.32	0.15	1.67
SULFUR OXIDES						
TOTAL	0.30	0.30	0.27	0.28	0.08	0.10
PARTICULATES						
TOTAL	4.50	4.50	4.05	4.06	0.18	18.75

Report produced by LEAP Fuel Chain Program

Figure 4.7: Particulates Emissions from Household Fuel Chains in Sri Lanka (kg per GJ Useful Energy)

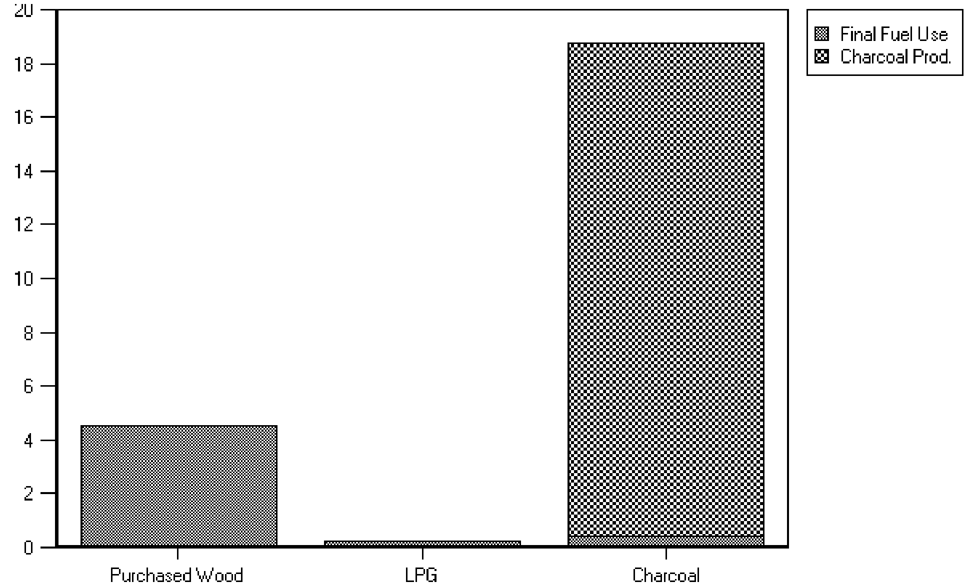
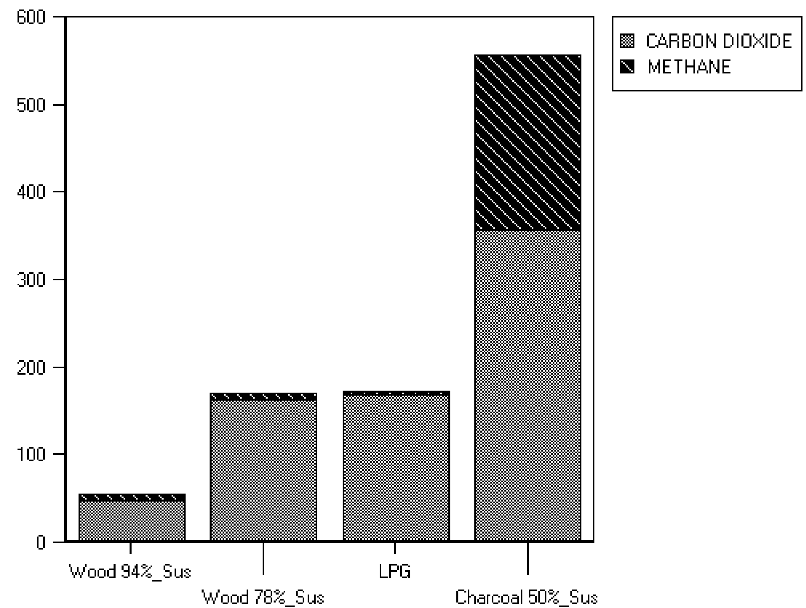


Figure 4.8: Net Global Warming Potential of Selected Household Fuel Chains in Sri Lanka (Tonnes CO_2 Equivalent per Thousand GJ Useful Energy)



Graph produced by LEAP Fuel Chain Program
NB: Uses 1994 IPCC 100 year GWPs - results for CO_2 and Methane only. Results reflect net (not total) CO_2 emissions - see text for methodology

4.5 Conclusions

Given the most likely energy policy alternatives in Sri Lanka today, the case study found, perhaps not surprisingly, that biomass presents more environmental benefits as a fuel for electricity generation than as a fuel for domestic households. In part, this is because biomass is compared to coal in the electricity sector and to LPG in the households sector in this analysis -- coal is probably the most polluting of the fossil fuels, while LPG is one of the cleanest. It should be emphasized that this case study only examined the environmental impacts of these fuel and technology options -- it did not undertake a detailed financial analysis of their viability, nor did it examine the economics and environmental impacts of alternative land-use options. Further analysis is required before firm policy conclusions can be drawn.

In general, upstream impacts are not significant except in the cases of methane emissions from coal mining and charcoal making, and the energy requirements for fertilizers used in biomass plantations. Nonetheless, the fuel chain concept provides a useful framework for analysis, since it allows the comparison of fuel and technology choices on an equal footing (for example per kWh of delivered electricity, or per meal cooked in the household sector).

For the electric sector, the results illustrate the overwhelming resource and environmental benefits of biomass fuel chains compared to coal fuel chains. Even allowing for upstream emissions from diesel fuels and fertilizer manufacture and application used in modern plantations, biomass produces much lower emissions of all pollutants. Results also show the large potential that biomass has for producing electricity both over the medium term (in which biomass generation appears economic only when low cost feedstocks are available) and over the longer term (in which the capital costs of generating plants utilizing biomass may become more competitive with fossil-fired plants). Industrial processes, in which biomass fuels are already being utilized to produce process heat, are probably the most promising first applications for biomass cogeneration in Sri Lanka. In the longer term, questions remain about how quickly high efficiency biomass systems can be developed and whether sufficient irrigation and suitable high-yielding tree species can be found for Sri Lanka’s dry zones. Overall though modern biomass uses look particularly promising given the absence of fossil fuel resources in the country.

Biomass fuels are generally touted as a means to mitigate greenhouse gas emissions. The analysis for Sri Lanka, shows the assumption is dependent on highly uncertain data about the sustainability of fuelwood production. Unless firewood is produced in a sustainable fashion then LPG, with its characteristic high end-use efficiency may actually produce lower net emissions of greenhouse gases per unit of useful energy consumed. At the same time, local policy concerns -- about the potentially harmful effects of indoor air pollutants -- point towards the promotion of cleaner burning fuels such as LPG.

Given the availability of short-term wood resources from land clearance schemes, charcoal has been used as an alternative fuel to firewood. Given the unsustainable basis of this resource, the results, not surprisingly, show charcoal to be unfavorable in terms of greenhouse gas emissions. The high level of methane emissions from charcoal production make it an unattractive fuel in terms of greenhouse gas emissions regardless of the sustainability of the wood feedstock. On the other hand, from the perspective of household emissions and indoor air pollution, charcoal is a much cleaner fuel than firewood in terms of most major pollutant categories.

5. VENEZUELA: OPTIONS FOR TRANSPORT AND ELECTRICITY

Venezuela is a good setting for case studies of the petroleum and natural gas fuel chains. As a major producer of crude oil since the 1920s, Venezuela has developed sophisticated energy planning and management infrastructures. In comparison with many developing countries, a wealth of data on the national energy economy is available. In addition, even though Venezuela is a major oil producer, alternatives to the domestic consumption of traditional petroleum products have been developed and continue to be actively considered or promoted. Using less exportable forms of energy, such as natural gas or hydropower for domestic consumption releases petroleum products for export. Environmental objectives, for example mitigating urban air pollution or the emission of greenhouse gases, can also motivate the search.

This chapter reports the results of two case studies, one comparing the use of compressed natural gas and diesel as a fuel for urban buses, and the other comparing residual fuel oil and natural gas as a primary fuel for a thermal electric generating station. The case studies demonstrate a method for estimating the environmental impacts associated with each fuel chain. No attempt is made to place a monetary value on these impacts, or to otherwise compare the environmental impacts with economic or social criteria, however, these are important areas for further analysis needed to provide decision makers with a comprehensive set of information.

Brief overviews of development issues in Venezuela, and particularly in the energy sector, are presented in Section 5.1, followed by a discussion of related environmental issues in Section 5.2. The economic, environmental and institutional dimensions of choices between fuel chains in Venezuela are examined in Section 5.3. The major assumptions supporting the analysis are discussed in Section 5.4. Results are presented in Sections 5.5 and 5.6.

5.1 Development Issues

In 1992, Venezuela had a population of 20.7 million people. With a land area of more than 912,000 km^2 the country has a relatively low population density of 22.7 persons per km^2. The population is concentrated in urban areas; the greater Caracas metropolitan area, with a population of 4-5 million, is the largest city and the national capital.

The per capita GDP in Venezuela was $2,590 in 1991, second highest in South America, after Argentina, and on the high end for most developing countries. Although the country has a wealth of petroleum and other mineral and natural resources, the national economy has been heavily dependent upon oil exports as a source of revenues, and is therefore vulnerable to the volatility of international oil markets.

Another historical challenge to economic development in Venezuela has been the economic condition commonly referred to as “Dutch disease.”[23] Dutch disease occurs when there is an over-valuation of local currency resulting from a “boom” in an exported commodity. The outcome is constrained capital flows to non-boom sectors of the economy, both as the boom sector absorbs domestic and international investment resources, and as exchange rate appreciation makes imports relatively cheap. Due to the Dutch disease,

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[23] For an expanded discussion of Dutch disease in Venezuela see Boué (1993), Chapter 9, Oil and the Venezuelan Economy.

the revenue inflow from the boom, a potential source of seed money for economic development, may create much less total economic growth than anticipated.

Another facet of the Dutch disease condition, is that revenues from an export boom, particularly in cases of natural resource extraction, come as “easy money”. The windfall can lead to government inefficiency, and postpone difficult or unpopular economic policy decisions. Highly inequitable income distribution may also arise in an economy dominated by a single export commodity.

From the 1920s through 1958, the Venezuelan government did little to implement policies to direct oil revenues towards productive investment in other sectors of the economy (Boué, 1993: p. 182). After 1958, import substitution policies, founded on high tariff barriers, were enacted in an attempt to channel oil revenues towards creating an economic take-off. Although investments in agriculture and heavy industries increased, the barriers to international market competition led to relatively inefficient development in these sectors. To defuse growing public discontent with the pace and distribution of the benefits of economic development, the government increasingly used revenues from windfalls associated with oil price increases to support large-scale subsidies of consumer goods and public employment.

To date, when oil prices decline, the rest of the Venezuelan economy has been hard pressed to take up the slack. Oil continues to dominate the economy, although to a lesser degree than in the past. Between 1987 and 1990, the petroleum sector was responsible for approximately one-fifth to one-fourth of the gross national product (MEM, 1991). In recent years, Venezuela has begun to implement policy reforms influenced by the standard economic advice dispensed by international financial institutions, and there has been a increasing trend towards privatization and reduction of government subsidies. However, these efforts can have serious social consequences. In the spring of 1989, a roll-back on subsidies for domestic fuels led to wide-spread rioting and political unrest. Today, Venezuela continues to face the question of how revenues from the oil industry can be most effectively harnessed to generate desired economic growth and social development.

5.1.1 Venezuela’s Energy Resources

Venezuela is richly endowed with a diverse slate of energy resources. Major oil and natural gas deposits are found in the west in the Lake Maracaibo basin, and in the east (Oriental basin) where there are large offshore natural gas deposits as well as onshore deposits of oil and gas, including the Orinoco oil belt (an enormous deposit of very heavy crude oils). Hydro potential is concentrated in the southeast, particularly in the Caroni river basin. Commercial deposits of coal are found in the west in the Andean foothills. Figure 5.1 illustrates the location of major energy resources within the country.

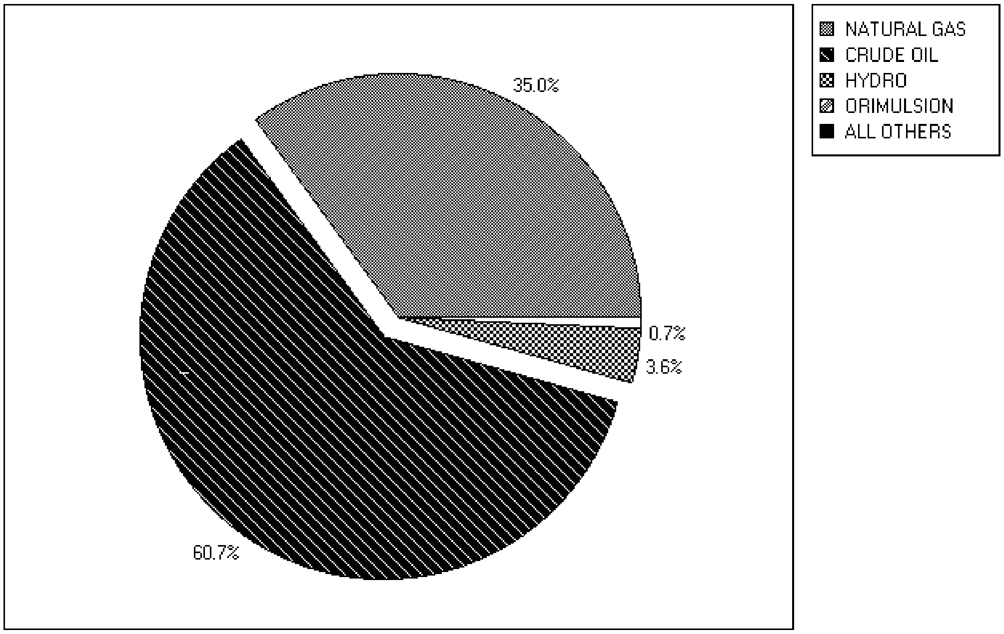
Figure 5.1 Energy Resources in Venezuela[24]

Oil

Of the energy resources found in Venezuela oil is king, both for exports and the domestic market. Over 60% of domestic energy was supplied by oil in 1990 as shown in Figure 5.2. Estimated proved reserves of crude oil are more than 63 billion barrels (approximately 6% of the global total) and cumulative historical production (at the end of 1992) was more than 44 billion barrels (*Oil and Gas Journal*, 12/27/93).

[24]Source: World Energy Council (WEC), 1992.

Figure 5.2: Venezuela Primary Energy Supplies, 1990



Large scale oil production in Venezuela began in 1914 with the discovery of the Mene Grande field, to the east of Lake Maracaibo. Total production, which rose particularly rapidly after the end of World War II, reached a peak of 3.7 million barrels per day in 1970. After 1970, Venezuela production declined, as high level/low cost output from the Middle East took market share away from Venezuela, despite efforts to impose production limits through OPEC. Production levels only began to increase once again after Iraq's invasion of Kuwait in 1990. In 1993 total production was estimated to be 2.3 million barrels per day (*Oil and Gas Journal*, 12/27/93).

Venezuela's crude resources are characteristically heavy and high in sulfur.[25] Historically, production has been concentrated on lighter crudes as much as possible. Nevertheless, over time, the constitution of the total resource dictates that Venezuela will be forced to rely on heavier crudes, which tend to result in higher environmental burdens. The trend towards a growing percentage of heavier crude production was temporarily reversed in the mid-1980s with the discovery of light and medium crude deposits in the Oriental provinces. More recently, however, the share represented by heavy crudes has started rising again, representing approximately 20% of total production in 1990 (Boué, 1993).

Orimulsion

Venezuela is thought to have the world's largest reserves of heavy crude oils suitable for the production of orimulsion. Orimulsion is a mixture of bituminous extra heavy crude oil, water, and an added emulsifier. The development of orimulsion-specific recovery, transportation, and combustion technologies has increased the likelihood of the eventual economic exploitation of the large deposits of the very heavy oils found in the Orinoco belt. The estimated 267 billion barrels of recoverable reserves add considerably to Venezuela's total estimated fossil fuel reserves (McGowan, 1990). Raising the capital needed to further

[25] Crude oil is classified according to API grade, 0-21 API is often classified as heavy, 22-30 API medium, and 30+ API as light crude. Sour crude oil contains a relatively high fraction of sulfur. These physical characteristics significantly impact crude recovery and processing costs. They also influence the mix of final products. Generally, lighter crude oils are more desirable.

develop the recovery and processing capacity required by heavier crude oils represents a challenge and opportunity for the Venezuelan oil industry. In the past, the development of these reserves has not been profitable, and uncertainty over the future of this “new” fossil fuel remains.

Orimulsion is being promoted as a cost-competitive alternative to coal for low-cost baseload electricity generation in Europe, the United States, and elsewhere. Its environmental characteristics are purported to be equal to or better than coal, however this information has remained relatively proprietary, and has received limited public scrutiny.

Coal

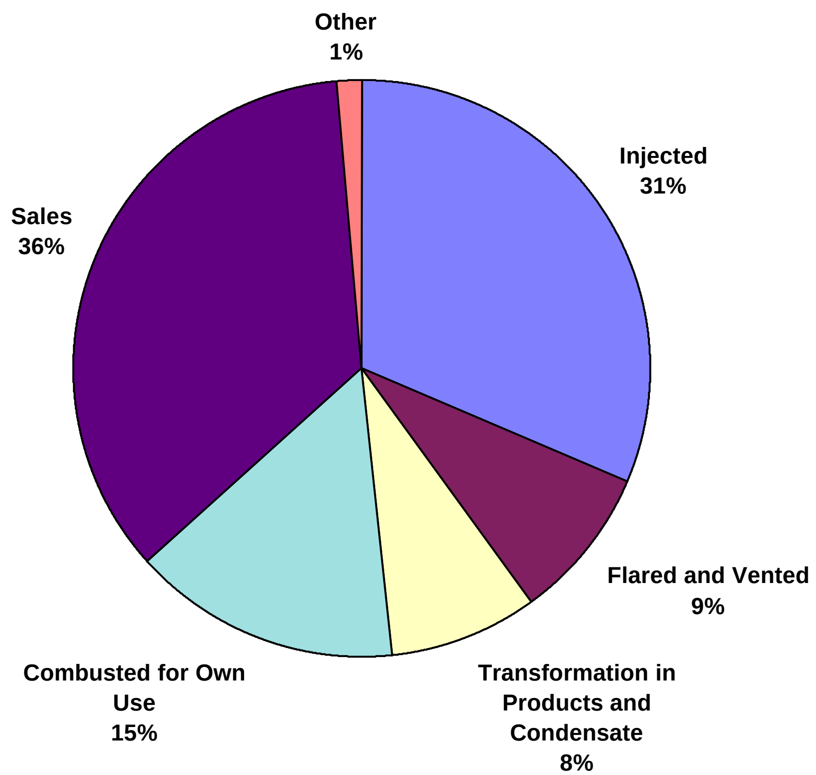
Venezuela also has estimated proven coal reserves of 697 million tons (WEC, 1992). Production in 1990 and 1991 was 2.3 million tonnes and 1.6 million tonnes. A very high percentage (98% in 1991) of the coal is exported, although some coal is used by the domestic iron and steel industries. The bituminous coal found in Venezuela has attractive characteristics for use in thermal electric generating stations, but there are no coal burning plants currently operating in Venezuela, nor are any planned. The primary target market for coal exports are electric power stations in Western Europe and the Mediterranean.

Natural gas

Venezuela has the seventh largest proven reserves of natural gas in the world (Boué, 1993). In 1990 these exceeded 3.5 trillion cubic meters (MEM, 1991), equivalent to approximately 3% of the global proven reserves. Discoveries during the mid-1980s significantly increased total proven reserves, and occurred primarily as natural gas was found in association with new crude discoveries. Gross production of natural gas in 1991 was more than 42 billion cubic meters (MEM,1991).

Early in the development of Venezuela's petroleum resources natural gas was a nuisance, rather than a resource, and prior to 1945 almost all natural gas was either flared or vented. However, from that time onwards gas has been increasingly used for reinjection (to maintain production in oil fields), as a petrochemical feedstock, and as a fuel source. Figure 5.3 represents the uses of natural gas in 1991 (MEM, 1991).

Figure 5.3 Uses of Natural Gas in Venezuela: (1991)



Total Production 42,326 Million Cubic Meters

As shown in Figure 5.2, natural gas now occupies a major role in the domestic energy market, satisfying 35% of primary energy demand. Given the size of proven reserves, and current levels of flaring and venting, the potential for further expanding domestic natural gas use, through substitution for oil products is very large.

The future development of natural gas resources in Venezuela, especially the production of non-associated gas, requires further investments in the domestic natural gas infrastructure, and on projects designed to supply export markets. Plans awaiting action include the expansion of domestic pipeline and processing capacities, the construction of an export pipeline link to Colombia, and the Cristóbal Cólon LNG project. The later, which if carried to completion will represent the largest investment undertaking in the history of Venezuela's oil industry, involves development of offshore gas reserves and the facilities to export liquefied natural gas (LNG). The Cristóbal Cólon project signifies a change in direction for Petróleos de Venezuela S.A. (PDVSA) and the government as international oil companies willing to take a major equity share in the project are actively being sought.

Another recent investment in Venezuela’s natural gas system is the repair and replacement of the gas distribution network in the Maracaibo region. A decaying natural gas distribution infrastructure, most of it in place since the late 1930s, had estimated leakage rates of 77% to 92% of total system consumption (Risø, 1994). These losses represent a large economic loss, a significant safety hazard, and approximately 10% of Venezuela’s total energy related GHG emissions in 1990. Replacement of the distribution system, projected to reduce system leakage to approximately 3%, is underway with funds made available through the Global Environment Facility.

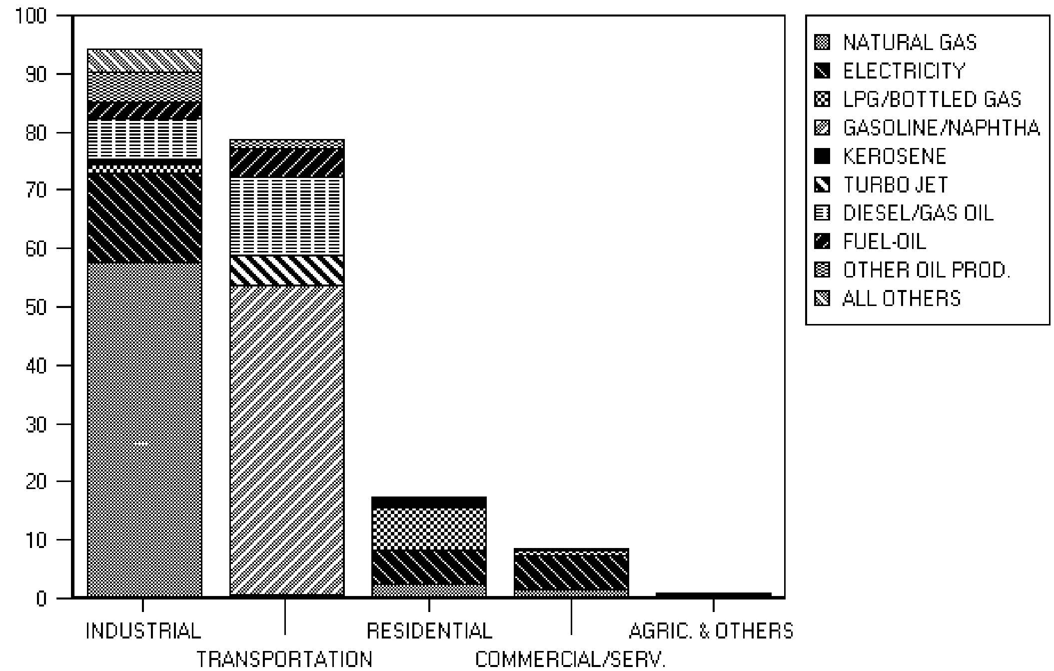
Hydro

In addition to extensive hydrocarbon reserves, Venezuela is endowed with a combination of hydrology and topography that creates one the world's largest exploitable hydropower resources. With an installed capacity of 9,025 MW, the Guri hydroelectric plant is the second largest electric generating installation in the world. The estimated total hydroelectric potential of the country is 77.5 GW. Currently planned electric expansion through 2005 is 100% hydro based.

5.1.2 Energy Demand

Industry is the largest domestic consumer of energy. Large industrial customers include aluminum production facilities, iron and steel mills, petrochemical and plastics plants, and cement factories. Transportation accounted for 38% of total final consumption in 1990 and the residential sector for 11% (MEM, 1990 Energy Balance). Figure 5.4 illustrates energy demand by fuel for each of the major sectors in the economy.

Figure 5.4: Venezuela Energy Demand by Sector, 1990
(Million Barrels Oil Equivalent)



5.1.3 Institutional Development

Until 1975 oil operations in Venezuela were primarily conducted by international companies acting as concessionaires. At first royalties and taxes on the concessions were relatively modest (in the range of 15%), but over the years these were increased until taxes on oil company profits reached 67%. In 1975 the government nationalized all oil and gas concessions and established PDVSA the national oil company. Initially comprised of 14 nationalized operating companies, created from the old concessions, PDVSA has evolved by merging and eliminating operating units so that today three main operating companies (Corpoven, Maraven, and Lagoven) remain.

PDVSA has become the third largest oil company in the world, with extensive vertically integrated operations, including refining and distribution networks in the United States and Europe (Boué, 1993, Ch. 8). One challenge facing the company is how to produce the “cleaner” fuels (reformulated gasoline and low sulfur diesel) required in many major U.S. markets as a result of the 1990 Clean Air Act Amendments. Producing reformulated gasoline and low sulfur diesel requires extensive investments in oil refineries. In Venezuela, the task is made more difficult by the resource profile skewed towards heavier and dirtier crude oils. PDVSA's response to the new market conditions has been outlined by Sánchez-Martínez (1992). One consequence is that PDVSA is likely to become more aggressive in efforts attract outside investors. Thus, in parallel to the situations with future developments in natural gas and orimulsion, it is likely that international equity investors will start being re-invited into the refining operations of the Venezuelan oil economy.

The electric power sector in Venezuela consists of five state owned (EDELCA, CADAFE, ENELVEN, ENELCO, and ENELBAR) and seven private companies. EDELCA operates hydro plants in the Caroni river basin. CADAFE operates Planta Centro, and serves most of the country’s residential customers (almost 60% of the total). Electricidad de Caracas, the largest of the private power companies, serves most of Caracas. As part of its energy policy and broader economic plans, the government is currently in the process of restructuring the electric power sector. One component of this program is the privatization of Planta Centro. The privatization is being handled by the Fondo de Inversiones de Venezuela (FIV). As of January 30, 1995, four utility affiliated companies and one independent power developer (all based in the United States) had pre-qualified to bid on the plant (*Electric Utility Week*, 12/30/95).

National energy planning and policy making are primarily the responsibility of the Ministry of Energy and Mines (MEM). Current policies are designed to continue recent trends towards the increasing the shares of hydropower and natural gas as primary sources for domestic consumption, thereby maximizing the availability of petroleum products and coal for export. Domestic energy consumption has been heavily subsidized in the past, and even today gasoline and diesel prices in Venezuela remain among the cheapest in the world. However, since 1989, energy pricing policies have been designed to eventually raise the domestic prices of tradable energy commodities to their international opportunity cost (FOB prices) and to set electricity prices equal to long run marginal costs.

Venezuela was one of the founding members (along with Saudi Arabia, Iran, Iraq, and Kuwait) of OPEC in 1960. Although at times oil output has been constrained by OPEC determined quotas, it is more likely today that market conditions, capital investment requirements, and the relatively high cost of heavier crude production and processing are more relevant as determinants of Venezuela’s total production.

5.2 Environmental Issues

National environmental policies are the responsibility of the Ministry of Environment and Renewable Natural Resources (MARNR). The MARNR regulates and monitors water and air quality as well as the management of hazardous wastes. Ambient and point source standards were established for air and water quality in the late 1980s, and, more recently, regulations concerning enforcement and penalties for non-compliance have been established (Arteaga et. al, 1992). In cooperation with the MEM, the MARNR is also involved in developing national strategies to enforce the Montreal protocol on the phaseout of ozone depleting substances, and the development of strategies to reduce greenhouse gas emissions.

Currently, some of the highest profile environmental issues in Venezuela are related to gold and diamond mining in southern, Amazon frontier, regions. The mining is commonly done in small, temporary, and sometimes illegal, camps, with little or no environmental regulatory oversight, and results in high emissions of suspended sediments and heavy metals in riverine ecosystems (MARNR, 1992). The following section presents an overview of significant, energy related, environmental issues.

Local Air Pollution

Caracas is located in a sunny natural basin. Although Caracas has wind patterns that tend to reduce the likelihood of temperature inversions, and thereby avoid the type of atmospheric conditions found in Los Angeles and Mexico City, the city is troubled by increasing levels of urban smog and air pollution, much of it caused by the operation of gasoline and diesel vehicles within the greater metropolitan area. Traffic congestion and air quality concerns were partly responsible for public investment in the subway system completed in the early 1980s.

In large metropolitan areas, such as Caracas, the health benefits of reducing particulate emissions may be quite significant. According to data collected by the Global Environmental Monitoring System (GEMS/Air) network, average particulate concentrations in Caracas from 1980 to 1984 slightly exceeded the World Health Organization guidelines of 60-90 $\mu g\ m^{-3}$ (UNEP, 1989). Research conducted in the United States has shown links between elevated exposures to diesel exhaust (a significant source of urban particulate emissions) and lung cancer, and a link between elevated ambient (PM_{10}) levels and hospital admissions for pneumonia, pleurisy, bronchitis and asthma. Studies conducted by the United States Environmental Protection Agency and the Harvard School of Public Health have suggested that as many as 50,000 to 60,000 deaths per year in the United States may be attributable to excessive levels of fine particulate matter (Skelton and Kassel, 1993).

The upstream stages of both natural gas and petroleum product fuel chains produce hydrocarbon emissions that contribute to the formation of tropospheric ozone, and to the accumulation of toxic compounds in the air shed. According to Picard and Sarkar (1993) the most prominent toxic hydrocarbons emitted by the upstream petroleum and gas sectors are benzene, toluene, ethylbenzene and xylenes.

Regional Air Pollution

Regional air pollution issues, such as acid rain, have received relatively little attention in Venezuela to date. If, as projected, natural gas and hydro power continue to be the major fuels used for electric generation, then acid rain is likely to continue as a low profile issue. Significant development of coal or orimulsion for electric generation, however, could alter this situation. The prospects for the development of Venezuela's deposits of these relatively high sulfur fuels may be limited by environmental regulations in importing countries.

Global Warming and Greenhouse Gases

The Government of Venezuela signed the United Nations Framework Convention on Climate Change in Rio de Janeiro during the 1992 Earth Summit, and it is committed to taking a lead role in international treaties and actions to protect the global environment. In the spirit of this commitment, the national Ministry of Energy and Mines (MEM) has been actively involved in several initiatives to identify and mitigate greenhouse gas (GHG) emissions. These include the Greenhouse Gas Abatement Costing Studies Project (UNEP/Risø, 1994), and the U.S. Country Studies on Climate Change.

Preliminary total GHG emissions estimates (from energy activities) for Venezuela are presented in Table 5.1 (MEM, 1994).

Table 5.1 Estimated GHG Emissions, Venezuela 1990

Emission Type	Total Emissions (Energy Activities)	Unit
CO_2	113	Million Tonnes
CH_4	1.5 to 2.3	Million Tonnes
NO_x	0.3	Million Tonnes
CO	1.5	Million Tonnes
NMVOCs	0.2	Million Tonnes
N_2O	440	Tonnes

Of the Energy activities totals, combustion emissions from liquid and gaseous fuels accounted for a total of 103 million tonnes of carbon dioxide (MEM, 1994). Methane emissions are almost entirely due to non-combustion emissions from the oil and gas sectors.

5.2.2 Deforestation and Conservation of Biodiversity

Biomass fuels are not heavily used in Venezuela, and energy development has been responsible for very little deforestation. The deforestation that has occurred has primarily been the result of hydroelectric reservoir flooding, and secondarily, the construction of oil and gas facilities. In the past, conservation of biodiversity has not been a major issue with respect to energy development in Venezuela. Typical of tropical ecosystems, Venezuela is home to a wide variety of species, and, in the future, species at risk to specific energy development plans may be identified.

5.2.3 Water Pollution

The environmental consequences of industrial development and urbanization are increasingly evident in Venezuela, as elsewhere around the globe. Deteriorating water quality in Lake Maracaibo and Lake Valencia, caused by effluents from oil production, industrial development, municipal sewage, and agricultural run-off, were incentives for the formation of the MARNR in the late 1970s.

Today, the upstream stages of the oil and natural gas fuel chains continue to be potential sources for serious emissions of water pollutants. Water found underground in association with natural gas and crude oil often has high levels of salinity, hydrocarbons, and other contaminants. The disposal or leakage of this water can damage aquatic organisms and ecosystems, and contaminate aquifers used for domestic purposes or irrigation. Oil leaks and spills also directly expose marine or freshwater ecosystems and aquifers to hydrocarbons and other pollutants.

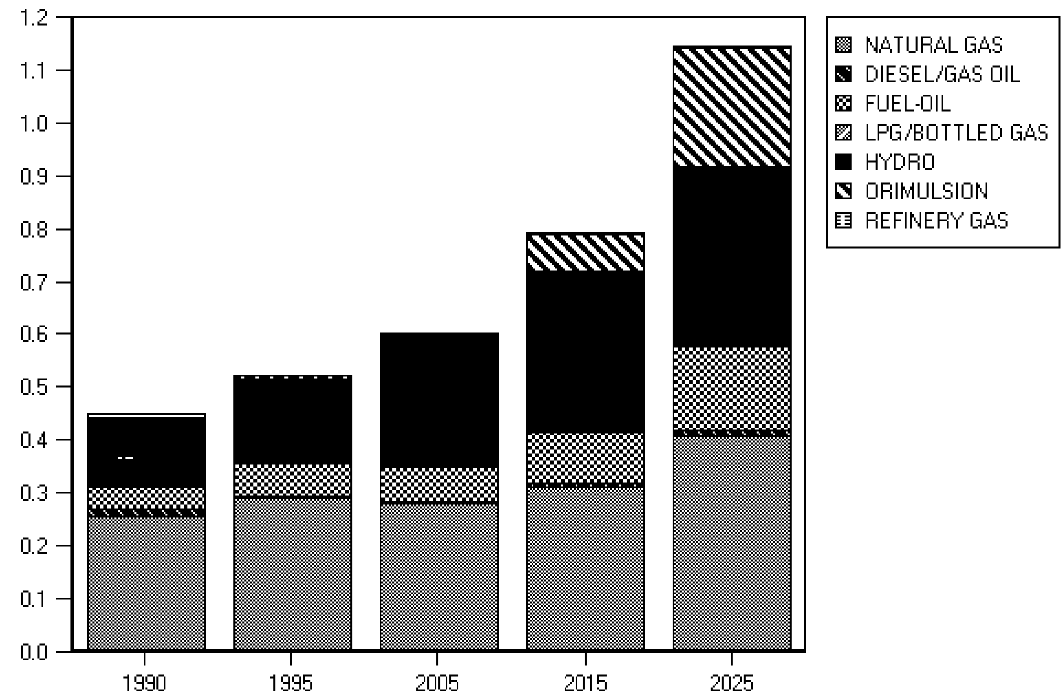
Water pollution at refineries is usually related to process water use, stormwater runoff, or groundwater contamination from leaking storage tanks. Pollution can be reduced through the use of technologies to recycle, or treat, process water, and to minimize the contamination of stormwater runoff and groundwater.

5.3 Fuel Choices in Venezuela

5.3.1 Fuel Chains for Electric Power Generation

In 1990 total electric generation in Venezuela was 56,196 Gwh. Maximum demand reached 7,959 MW, and installed capacity was 17,346 MW, of which 58% was hydro (Risø, 1994). Capacity expansion plans developed by the electric utilities indicate that, through 2005, additions will be 100% hydro, although after this time there is the possibility of expanded orimulsion, fuel oil, and natural gas fired generation. The current and projected fuel mix for electricity generation is illustrated in Figure 5.5.

Figure 5.5 Venezuela Electricity Generation 1990 to 2025
(Billions GJ)



As Figure 5.5 illustrates, the role of natural gas remains significant, accounting for the majority of Venezuela's thermal generating capacity throughout the planning period. In addition, the evaluation of the environmental fuel chain impacts of natural gas fired electric generation is important in many developing countries, where using natural gas in place of coal and oil derived fuels may be an important strategy for emissions reductions.

The total thermal electric generating capacity in Venezuela is 7,333 MW (MEM,1994: unpublished). Of this, steam turbines account for approximately 63% of the total (4,628 MW), with Planta Centro responsible for 2,000 MW. Gas turbines, which tend to be smaller, quicker to install, and cheaper than steam turbines are becoming more important, particularly for generation at industrial or remote sites.

The capacity and energy output by plant types in Venezuela for 1990 are summarized in Table 5.2.

Table 5.2 Electric Capacity and Output 1990[26]

Plant Type	Capacity Capacity (MW)	% of Total	Output Gwh	% of Total
Planta Centro, Natural Gas	400	2%	2,333	4%
Planta Centro, Fuel Oil	1600	8%	2,333	4%
Hydro	10,590	55%	36,749	63%
Other Natural Gas	6,070	32%	15,166	26%
Other Fuel Oil	435	2%	1,207	2%
All Other	135	1%	522	1%
Total	19,230	100.00%	58,310	100.00%

At the facility specific level, the choice between residual fuel oil and natural gas as a primary fuel is currently being examined at Planta Centro. With five 400 MW units, Planta Centro is Venezuela's (and Latin America's) largest thermal electric generating station. The facility is located on the coast, north of Valencia, close to the El Palito oil refinery.

Currently, four of Planta Centro's boilers are designed to burn heavy residual fuel oil as a primary fuel. The fuel oil is provided directly from the El Palito refinery by a short pipeline. El Palito is operated by Corpoven. Planta Centro has been a captive customer for the refinery's residual fuel oil, although this has not always been advantageous for CADAFE. Plant operators complain that the quality of the fuel is variable, and that it does not always meet standards, commonly because of high concentrations of vanadium and other corrosive contaminants. The standards for the residual fuel oil, and natural gas burned at Planta Centro are presented in Table 5.3.

Table 5.3 Planta Centro Fuel Specifications[27]

	Fuel Type	
	Residual Fuel Oil	Natural Gas
Minimum Calorific Value	9,600 Kcal/kg.	1012 Kcal/m^3
Max. Ash Content	0.1%	-
Max. Sulfur Content	1.5%	-
Max.Vanadium Content	300 ppm	-
Avg. Methane Content (1993)	-	82.9%
Carbon Dioxide Content	-	7.3%

Natural gas also has financial advantages over fuel oil. Table 5.4 presents estimated fuel prices, and fixed costs for various electric generation technologies in Venezuela.

[26] Source: MEM, LEAP data set, note that capacity and output figures are higher than reported in Risø, 1994.
[27] Source: Data report from CADAFE (1994), unpublished.

Table 5.4 Estimated Electric Generation Costs[28]

Plant Type	Estimated Costs	
	Total Fixed Costs US$ mills/kWh	Fuel Costs US$ mills/kWh
Upper Caroni (Hydro)	28.6	-
Lower Caroni (Hydro)	16.2	-
Natural Gas Steam	18.7	15.0 to 20.0
Fuel Oil Steam	21.8	19.2
Natural Gas Combustion Turbine	12.0	20.7 to 27.6
Natural Gas Combined Cycle	14.9	11.6 to 15.5

For CADAFE, and possible future operators of Planta Centro, natural gas is likely to be preferred over fuel oil, for a combination of financial, maintenance and environmental reasons. Unit number two was converted to burn natural gas in 1989. More recently, the pre-investment and technical assistance studies being conducted at Planta Centro as a part of the privatization process have included examination of the further fuel switching, converting units to be capable of burning either natural gas, or orimulsion. In this case study we focus on the natural gas option, since the use of orimulsion is unlikely at this time.

5.3.2 Fuel Chains for Urban Bus Transportation

Many Caracas residents confront daily transportation problems familiar to urban dwellers around the world. Increasing traffic congestion leads to longer commuting times, and higher concentrations of transport related local air pollutants. The centerpiece of efforts to improve transportation in Caracas is the Metro subway system. In 1990, the Metro accounted for approximately 2.8 billion passenger kilometers.[29] Supporting the Metro is a bus network, consisting of twenty feeder routes with a combined length of 410 km. Ridership on the Metro bus network has grown rapidly, from an estimated total of 2.4 million passengers in 1987 to more than 26.5 million passengers in 1991 (Ministry of Transportation and Communications, 1992). Total kilometers for the Metro bus system in 1993, are estimated to be more than 7.6 million (Metro de Caracas, 1994), with an average occupancy factor for large buses (>32 passenger) of 28 (MEM, unpublished). Thus, the Metro bus system accounts for approximately 212 million passenger kilometers annually, with an average passenger trip distance of slightly more than 8 kilometers. The reported diesel consumption for Metro buses in 1993 is equivalent to 15.71 E-3 litres/passenger kilometer (Metro de Caracas, 1994).

Off the Metro bus routes, buses and public vans are a dominant mode of transportation. In 1990, public vans, light duty trucks, and buses accounted for more than 60% of the 77.1 billion total passenger kilometers traveled in the country.

Recently, Corpoven has been considering the promotion of CNG as a transport fuel, particularly as an alternative for diesel powered fleets. The Metro bus system is being considered, in part, due to its high public visibility. If implemented, the program would build upon Corpoven's past experience with

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[28] Source: Fixed Costs, Data report from MEM (1994), unpublished. Fuel Costs: Actualizatcion Del Estudio De Expansion de Generacion del Sistema Electrico Venezolano: Periodo 1993-2010. June 1993. Thermal unit fuel costs converted assuming heat rates from Electric Power Research Institute (EPRI), 1989. *Technical Assessment Guide*, *Volume 1: Electric Supply*. Natural gas and fuel oil steam 10.00 MMBtu/MWh; natural gas CT 13.80 MMBtu/MWh; and natural gas combined cycle 7.74 MMBtu/MWh.

[29] MEM, 1994. Unpublished appendix to UNEP/Risø (1994) GHG Abatement Costing Studies: Phase Two.

compressed natural gas vehicle promotion. Over the past seven years, approximately 2,000 gasoline powered vehicles have been converted to be dual fuel capable, as part of the Gas Natural Para Vehiculos (GNV) program, which started with high expectations in 1988. Through the GNV program six public compressed natural gas refueling facilities and eight fleet service refueling stations were in operation by 1991 (Corpoven, 1991).

However, there have been some significant barriers to the widespread adoption of CNG as a vehicle fuel and recently the GNV program was scaled back considerably. The primary barrier to CNG as a transportation fuel in Venezuela has been the low cost of gasoline and diesel, which despite pricing reforms remain very low by international standards.[30] Other technical and convenience barriers to the adoption of CNG, particularly for private vehicles, are limited range, limited refueling infrastructure, and longer refueling times.

The primary advantages of CNG over diesel fuels for use in heavy duty vehicles are environmental. Although buses and trucks are usually significantly outnumbered by cars in most cities, they tend to contribute more than their proportional share to total emissions of transport related pollutants.[31] Exhaust from diesel buses is increasingly recognized as urban health hazard. Urban buses operate in an environment that requires frequent stopping and starting, long idling periods, and close proximity to pedestrians. Particulate emissions from diesel buses, particularly very small particles of less than 10 microns in diameter (PM_{10}) which are small enough to avoid the defenses of the human respiratory system and penetrate deep into the lungs, can carry with them a number of toxic substances, which are known to be mutagenic as well as potentially carcinogenic in humans (Skelton and Kassel, 1993).

Diesel buses are also a significant sources of nitrogen oxides (NOx) and carbon monoxide (CO) emissions, and reducing these emissions in crowded cities is also likely to produce direct health benefits. Elevated levels of NOx (greater than approx. 0.5ppm) can cause immediate symptoms, such as increased airway resistance. Long term effects may also be related to long-term exposures, at relatively low levels, particularly for children. Carbon monoxide is a toxic gas, which can cause headaches and dizziness at atmospheric concentrations of 100 ppm, and death at higher levels. Elevated levels of CO in an urban atmosphere have also been linked to loss of worker productivity and general discomfort.

In response to increased recognition of the negative health impacts of diesel engine exhaust, regulations enacted as a part of the 1990 Clean Air Act in the United States require diesel buses to reduce particulate emissions by 50% by 1996, and NOx emissions by 20% by 1998. One technology available to reduce PM_{10} and NOx emissions from diesel buses is trap oxidizers. This equipment catches particulate matter in the exhaust stream and occasionally burns the accumulated particulate build up. Trap oxidizers can be retro-fitted on existing buses, but the fleet experience of nearly 20 transit agencies in the United States has suggested that the effectiveness and reliability of trap oxidizer systems has often not been acceptable (Skelton and Kassel, 1993).

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[30] Gasoline and Diesel prices in March 1995 were 6 Bvs/ltr, equivalent to 14 cents per gallon. Increases expected to take place by July 1995 will raise prices to 15 Bvs/ltr or 34 cents per gallon.

[31] Guensler, Sperling, and Jovanis (1991) state that on a gram-per-mile basis, heavy duty diesel truck emissions are significantly higher than automobiles due to heavy operating loads and power requirements, large engine sizes, and combustion parameters. The authors do not quantify the specific amount by which heavy duty diesel emissions are higher, noting that there is a tremendous amount of uncertainty surrounding the emissions inventory for heavy-duty diesel vehicles.

An alternative for means for reducing emissions is to switch to a cleaner fuel, such as CNG. CNG buses are likely to emit less than 10% of the PM_{10}, less than one half the NOx, and less than 25% of the CO emissions of a diesel bus (Skelton and Kassel, 1993: p. 8-9). Emissions of volatile organic compounds (VOCs) are likely to be approximately 50% higher when CNG is used in place of diesel.

The economics of converting bus fleets to CNG can be attractive, particularly if the costs of adding and maintaining trap-oxidizer systems to existing diesel buses is considered. As of June 1993, nearly 70 transit companies in the United States had applied for money available from the federal government for assistance with the purchase of alternative fuel buses, or the retrofit of existing diesel buses. Large cities such as Seattle, Houston, Dallas and Cleveland have committed to converting their fleets to CNG, and the New York City Transit Authority is also considering a switch from diesel to CNG (Skelton and Kassel, 1993).

In Venezuela, additional environmental and economic factors may also favor CNG as a bus fuel. Expanding the domestic market for natural gas increases incentives to reduce natural gas flaring, venting, and transmission and distribution system leakage. By displacing diesel fuel, CNG also frees up a resource that is more easily exported.

5.4 Case Study Approach and Assumptions

5.4.1 Approach

The size and complexity of the energy economy and supporting infrastructure in Venezuela dictates that the fuel chain analysis be limited in scope to a set of specific facilities. Facilities were selected based upon data availability, potential policy relevance, geographic location, and their physical or economic ties to other study sites.

Data on facility operations and environmental impacts were collected during two visits by SEI-B staff, and through follow-up surveys conducted by an independent local consultant.[32] Meetings were held with representatives of PDVSA, Corpoven, CADAFE, the MARNR, and the MEM. In addition, site visits were made to the El Palito refinery and to Planta Centro, to discuss options with plant personnel.

The Venezuela data were compared to, and, where necessary, supplemented with, information gathered from the energy and environmental literature. For example, emissions profiles for diesel and CNG vehicles are composites built from a variety of sources. Preliminary study results were presented at a March, 1995 workshop held in Caracas, and at a fuel chain workshop held in Boston in April, 1995. Feedback and suggestions from participants at both workshops have been incorporated into the final report.

5.4.2 Major Assumptions

The upstream facilities associated with the residual fuel oil consumed at Planta Centro are the El Palito refinery, the Barinas to El Palito oil pipeline, crude oil storage facilities at Barinas, and crude oil production facilities in the Barinas/Apure oil basin.

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[32] Elba Briceño Simancas, President, Producciones Sinamaica, C.A.

The natural gas consumed at Planta Centro is assumed to be produced in the Anaco basin in eastern Venezuela, and transported to Planta Centro via the central gas pipeline grid. Gas processing is assumed to occur at the San Joaquin plant, located east of Caracas.

Crude Recovery

- Crude recovery is assumed to take place in the Barinas and Apure basins, where there are 225 operating on-shore wells, producing 115,000 barrels per day (PDVSA, 1994). The fields in Barinas and Apure are relatively small, accounting for approximately 4% of Venezuela's total crude production in 1990 (MEM, 1991). The Barinas Apure basin is selected because it is a primary supplier to the El Palito oil refinery, and the fuel oil used at the Planta Centro power station comes from El Palito.

- Auxiliary Energy Use and Fuel Combustion: The operation of oil wells requires the use of heavy duty pumps and compressors to raise oil from the ground and to inject water, steam, gases, or other materials into the well. Remote well platforms may also run diesel or gas powered generators to generate electricity used in operations. Heavy fuels, including crude, are often combusted to heat and treat crude oil, removing water or sulfur prior to transportation from the production site. The combustion of fuel for all of these activities produce air emissions that depend upon the type of fuel used, and the type and condition of the combustion equipment. Citations for emissions factors for the types of heavy duty equipment typically employed at well sites can be found in several sources including (Radian, 1992), and (USEPA, 1988).

  In the United States, onshore crude recovery operations require about 2% to 3% of the energy content of the recovered crude (DeLuchi, 1993). For offshore recovery this number can be as high as 9% (DOE, 1983). To estimate the combustion air emissions for auxiliary energy use in crude production at the Barinas and Apure sites we assumed energy consumption of 2.7%, with a mix similar to average energy consumption reported for the U.S. in 1987.[33]

- Flaring and Venting of Associated Natural Gas: Natural gas found in conjunction with crude oil deposits is called associated natural gas. The amount of associated natural gas per unit of crude oil recovered varies from site to site, and over time within a given basin. How associated natural gas is utilized, or disposed of, is a significant factor in the estimation of the environmental impacts of a petroleum product fuel cycle. There are three common fates for associated natural gas. One is that it is used as an energy resource, either at the well site or by some other end use in the economy. The second is that the gas is re-injected into the oil well. Re-injection stores the gas for potential future use and it helps to maintain pressure in the oil field and facilitate the flow of crude. Third, if the natural gas is not marketed, used directly, or re-injected, it can be vented or flared.

  Although for accounting purposes flared and vented gas are often treated equally, there are significant differences between the two when environmental impacts, such as contribution to global warming, are assessed. Venting is the direct release of natural gas (the primary component of which is methane a potent greenhouse gas) to the atmosphere, or under water. Flaring refers to the controlled combustion of natural gas at the well site. Air emissions from flaring depend upon the combustion efficiency of the burners and the composition of the flared gas. Generally, flaring results in much lower methane emissions than venting, but higher emissions of CO_2, NO_x and to a lesser degree N_20, CO and NMVOCs. Flaring, through thermal oxidation is a simple and moderately priced means of destroying

[33] DeLuchi (1993), Vol. II, Table H-2, Energy use for crude recovery by type is estimated as: natural gas 50%, electricity 18%, crude oil 13%, diesel 10%, gasoline 4%, and other 5%.

toxic materials in waste gas streams and reducing the radiative impact of methane streams by more than 91% (Picard and Sarkar, 1993).

The majority of air emissions from the flaring and venting of associated natural gas should be assigned to crude oil production rather than to natural gas production, because when gas can be used as a fuel or marketed, flaring and venting will be significantly reduced.

In the Barinas Apure basin associated natural gas is not reinjected or commercially recovered, and over 99% is flared or vented (MEM, 1993). Following Barns and Edmonds (1990) we assume that 80% of this gas is flared and 20% vented. All of these emissions are assigned to crude oil production.

- Process Efficiency and Oil Spills: PDVSA (1994) reports that the highest annual volume of spills for the Barinas Apure production camps between 1990 and 1994 was 582 barrels in 1991. With average production levels of 115,000 barrels per day, these spills represent a negligible percentage of total production. Therefore, the efficiency of the recovery process is assumed to be 100%. Although larger spills would create significant environmental impacts, such non-routine events are not included in this analysis.

- Water and Land Use, Solid Wastes: Water pollution at crude recovery sites can be caused by the disposal of water that comes from the well in association with the oil, or from the accidental leakage of hydrocarbons. Brine is often associated with the production of oil and gas. Brine disposal or leakage can alter salinity levels and may damage aquatic organisms and ecosystems, or contaminate aquifers used for domestic purposes or irrigation. Oil leaks and spills also directly expose marine or freshwater ecosystems to hydrocarbons and other contaminants.

  Significant amounts of water are often used to create drilling muds which are injected into a drill hole to lubricate the drill bit and shaft and transport residue materials. Drilling mud water contains dissolved solids and a range of other contaminants depending on composition of the geologic materials overlying the crude reservoir. The daily use of production water for the Barinas Apure basin is reported to be 339 MBD (PDVSA, 1994). With total crude production from the two basins of 115 MBD, production water use is equivalent to approximately 3 barrels of water per barrel of crude recovered. Analysis of liquid effluents for 11 sites in the Barinas district indicate that maximum standards established by the MARNR are sometimes exceeded for total solids (1500mg/L), suspended solids (60 mg/L), Phenols (0.5 mg/L), Sulfur (0.5mg/L), and temperature (30^o C.), but that reported concentrations are generally below the established limits.

  Oil exploration and development often occurs in remote or pristine environments, and recovery may therefore require the construction of roads, pipelines, and other supporting infrastructure. These activities can have a range of adverse impacts on local wildlife, or on indigenous human populations. In addition to direct air and water pollution, these include: deforestation; loss of species and/or habitats; disturbance of wildlife migratory patterns; and damage to aquatic or terrestrial ecosystems that support the hunting, fishing or agriculture activities of indigenous populations. The type and scale of these impacts is difficult to generalize.[34] DOE (1983) reports land use for an on-shore oil production site with a production capacity approximately equal to that of the Barinas Apure basin of 376 acres per million tonnes of crude production.

[34] Examples of regions that were relatively "undisturbed" prior to the development of oil resources include the north slope of Alaska, and the Ecuadorian Amazon (Kimerling et al., 1991) and (Friends of the Earth, 1994).

Solid wastes produced at oil recovery sites include drill cuttings and drilling muds. These can contain a range of minerals and toxic materials that may present a localized environmental hazard, or be transported off-site by leaching or direct transport in runoff water. DOE (1983) reports approximately 34,000 tonnes of cuttings per million tonnes of crude recovered, for an onshore oil field with 100,000 barrels per day production capacity.

Natural Gas Recovery

- Natural gas recovery is assumed to take place at the Santa Rosa production camp in the Anaco District. Production at the field is 7.7 million cubic meters per day, with daily venting of approximately 17,000 cubic meters, and flaring 71,000 cubic meters per day (Corpoven, 1994). Because these flaring and venting estimates are low, in comparison to international estimates, we conduct a sensitivity analysis for the natural gas fuel chains assuming higher flaring and venting emissions.[35]

- Auxiliary Energy Use and Fuel Combustion: Energy use for natural gas recovery is based on an average of estimates by DeLuchi (1993) for natural gas recovery in the United States.[36] We assume auxiliary energy requirements of 2.4% of the energy content of the recovered gas. DOE (1983) estimates energy use for natural gas recovery of 7.2% for onshore recovery, and 2.9% for offshore recovery. No explanation is provided for the higher estimate of energy use for onshore production.

- Flaring: At sites where commercial recovery of natural gas is occurring there is likely to be relatively little flaring of “excess” natural gas. Instead, as discussed above, flaring (and venting) are more likely at crude production sites where no infrastructure to support the sale or other uses of the associated natural gas is available. Nevertheless, some flaring and venting from natural gas production sites is expected, primarily to control gas pressure. The flaring data reported by Corpoven indicate that at the Santa Rosa field flaring is equal to approximately 1% of total production. For high emissions natural gas recovery estimates we used data reported from the Barcelona jurisdiction (MEM, 1994) that indicates 6.4% of the total natural gas recovered is flared or vented. Lacking data on the proper share of flaring and venting we assign 80% of these emissions to flaring and 20% to venting. Thus, in the high emissions case, flaring is equal to 5.12% of total production.

- Venting and Other Fugitive Emissions: Wilson (1990) reports that literature estimates of venting and leakage from natural gas production and distribution are roughly 2%-3% of production for Europe, and 3%-4% on a global average, while gas industry estimates are much lower, ranging from 0.05% to 1% for new systems (Mercado, 1993). Wilson applies a global leakage rate of 3.5% of production and conducts a sensitivity analysis with a lower rate of 1%. DeLuchi (1993) notes that earlier emission estimates of 3% to 4% for the U.S. system may be as much as an order of magnitude too high. The earlier estimates based on the amount of unaccounted gas, assumed that leakage represented all unaccounted-for gas, when in fact measurement and accounting discrepancies (for over a quarter of a million wells) are likely to be responsible for a large share of the unaccounted-for gas.[37]

  Venting and leakage estimates generally incorporate production, transmission and distribution. The

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[35] Barns and Edmonds (1990) estimate that natural gas extraction losses are approximately 5% of total production, although there are large differences between sites (As cited in EPA, 1993).
[36] DeLuchi Vol. 2, Table G.1 gives estimates of natural gas recovery energy consumption. Table G-2 provides estimates of the shares of recovery energy by fuel type.
[37] Greenpeace (1993) and Mercado (1993) also debate how much unaccounted for gas should be assigned to venting and leakage.

data reported by Corpoven for Santa Rosa (production only) indicate losses of approximately 0.2%. In our fuel chain analysis venting for the high losses natural gas case is estimated to be 1.28% of total production.[38]

- Water and Land Use, Solid Wastes: The impacts for natural gas recovery are comparable to those for oil recovery, discussed above.

Crude Transport

- Distance and Transport Mode: For this case study crude oil is assumed to be transported via a 337 km pipeline that links the Barinas-Apure oil districts with the El Palito refinery. Internationally, the most common mode of transport for crude oil is marine tanker.

- Energy Required for Crude Transport: The energy intensity of crude oil transport is dependent upon a number of parameters, which are difficult to generalize. For example, pipeline energy requirements will depend upon the type of prime mover chosen, the efficiency of pumps, the physical characteristics of the pipeline (such as elevation change, diameter, and operating pressure), and the physical characteristics of the crude oil. The average distance the crude must be transported is also site dependent and difficult to generalize. The data required to support a detailed analysis of the energy use in the crude transport stage of a fuel chain will often not be available. In this case study an average energy intensity of pipeline crude transport in the United States of 75 Btu/ton-mile is assumed (DeLuchi, 1993).[39] Electricity is assumed to be used as the primary mover for the pumps used to transport the crude through the pipeline. Diesel engines and turbines can also be used to drive pipeline pumps.[40]

- Estimated emissions for crude transport are based upon DeLuchi's (1994) estimates for average international and domestic crude transport for the United States. This may over-estimate emissions from the Barinas to El Palito pipeline, since pipeline emissions are likely, on average, to be lower than emissions for other forms of crude transportation such as marine tankers and tank trucks. However, lacking superior data specific to emissions from crude oil pipeline operations, the U.S. average (which includes domestic and international transport) was used as a conservative proxy.

Refining

- The El Palito oil refinery is located on the coast in Carabobo state to the west of Caracas. It is the sole source for the residual fuel oil burned at Planta Centro, which is 5 km west of the refinery. El Palito also provides petroleum products to the central region of the country, serving industries and transportation needs in Valencia and Maracay. In 1993 total capacity at El Palito was 194,000 barrels per operational day, and average inputs averaged 169,000 barrels per calendar day in 1989 (Corpoven, 1994). El Palito is the fourth largest refinery in Venezuela, ranking behind Amuay, Cardon, and Puerto La Cruz.

- Refining Processes: Refining is based on several major technologies, that can be roughly categorized into three types according to the manner in which hydrocarbon molecules are manipulated. These are,

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[38] Based on the total venting and flaring estimate of 6.4%, and an assumed 20% share for venting. 6.4% * .20 = 1.28%.
[39] Vol. 2 p. E-9 table E-2.
[40] Kennedy (1984) Chapters 4 through 6 provides a discussion of pipeline pump and compressor options and relative efficiencies.

distillation (sorting the hydrocarbon molecules into various types), cracking (breaking the molecules apart), and reformulation (combining the molecules). A large number of processes are used to accomplish these basic tasks. The technologies and processes employed by a specific refinery depend upon a number of technical and economic factors, including the composition of the crude oil inputs, and the desired slate of petroleum product outputs. Because a wide range of technologies (including environmental control technologies) are employed to process and produce a heterogeneous mix of refinery inputs and outputs, "generic" refinery operations and emissions figures should be checked with facility specific data, whenever possible.

Refineries are often classified into three types, simple, complex and very complex. The driving force behind increasing the complexity of a refinery is produce higher value products. Simple refineries generally produce less gasoline (roughly 30%) and more lower value fuels, such as residual fuel oil, while a complex refinery produces relatively more gasoline (approximately 50% of total output), and less of the lower value fuels. Very complex refineries produce an even higher percentage of gasoline (65% or more) as well as specialized petrochemicals and lube oils (Leffler, 1985). As refineries become more complex they generally require more capital investment, more energy use, and more steps in the refining process. Depending upon the environmental control technologies installed, more complex refineries can produce more emissions per unit of product output than simpler refineries. El Palito, with an output of approximately 45% gasoline/naphtha is best classified as a complex refinery.

- Auxiliary energy use for refining depends upon the technologies utilized, the characteristics of crude oil inputs, and the desired slate of output products. Producing more highly refined products, such as reformulated gasoline, or low sulfur diesel requires more energy per unit output than the production of residual fuel oil. One study that apportions refinery energy use to various end products indicates that energy use for gasoline refining is more than four times higher than for residual or diesel fuel (DeLuchi 1993). For this case study the auxiliary energy use required for diesel fuel production (equivalent to 4.7% of the energy content of product output) has been used to represent the auxiliary energy consumption of refining for all fuels.[41]

- Emissions from the refining process depend upon the processes used, the characteristics of feedstock materials, and installed pollution control devices. Data on total annual air emissions from the El-Palito refinery were divided by total annual inputs to the refinery to estimate emissions (Corpoven, 1994).

Natural Gas Processing

- Natural gas processing for the case study is assumed to occur at the San Joaquin natural gas processing plant. Total production at San Joaquin is approximately 28 million cubic meters per day.

- Purification Processes: In addition to methane, raw natural gas usually contains recoverable natural gas liquids as well as contaminants such as water, hydrogen sulfide, carbon dioxide, and nitrogen. The natural gas liquids are commonly condensed, collected and sold separately from the natural gas, since these have a higher value as individual fuels.

  At the well site raw natural gas is usually passed through field separators to remove hydrocarbon condensate and water. The two major components of the purification process are dehydration and desulfurization. Natural gas is considered to be "sour" when it has a sulfur content so high as to make it impractical to use without purification, due to its corrosive effect on piping and other equipment.

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[41] DeLuchi (1993), Volume II, Table H-7.

Major pieces of equipment used to purify gas are heaters, condensers, pumps and compressors. Occasionally the raw natural gas mix recovered does not contain significant water or hydrogen sulfide ("dry" or "sweet" natural gas) and it therefore does not require further purification.

Additional processing, at a natural gas plant is needed to recover natural gasoline, butane, and propane and ethane, and other condensable constituents. The major sources for air emissions from natural gas processing facilities are combustion emissions from compressor engines and acid gas wastes from gas sweetening plants. If the waste gas is flared the major pollutants of concern are sulfur dioxides (U.S. EPA, 1993). Often, however, waste gas is processed by commercial sulfuric acid plants, or sulfur recovery plants. In addition to combustion emissions, processed and unprocessed gas may also be vented or leaked from processing plants.

- Auxiliary Energy Use and Plant Efficiency: Our energy use estimate is based upon DeLuchi (1993) which indicates an average use of 2.2% of gas produced. Almost all of the energy consumed (98%) of the energy consumed at the natural gas processing plant is assumed to be natural gas. Plant efficiency at San Joaquin is reported to be 93.65% (Corpoven,1994).

- Emissions estimates for natural gas processing are based on DeLuchi (1994). Emissions data from natural gas processing plants in Venezuela were more limited than for other fuel cycle stages, but the available data indicated that this stage of the fuel chain is responsible for a relatively minor share of total fuel chain emissions. For example, emissions data for the Jose fractionation plant were reported in $\mu g\ m^{-3}$, and the concentrations for SO_2, NO_2, particulates (PST), O_3, CO, and HC were all well below the maximum concentrations permitted by the MARNR.

Petroleum Products Distribution

- The transport modes for diesel fuel transport from El Palito to Caracas are assumed to be 90% tank truck and 10% product pipeline are based on DeLuchi (1993) estimates for average petroleum product transport in the United States. Emissions are also based upon U.S. averages.

Natural Gas Transmission and Distribution

- Natural gas is assumed to be transported via the central grid natural gas pipeline, which connects Caracas, and El Palito with the major gas producing fields and processing facilities located in the Anaco District.

- The energy requirements for natural gas transmission and distribution are assumed to be 3.65% of gas transmitted based upon an average of figures cited for the U.S. natural gas system (DeLuchi, 1993).[42] The same caveats discussed under crude oil transport apply here, system losses and energy requirements are site specific, depending upon pipeline topography and other parameters, such as pipeline operating pressure.

- Corpoven (1994) estimates for the Anaco-Barquisimeto natural gas distribution system an overall pipeline efficiency of 98%, average routine emissions of 7.44 million cubic meters per year, and

[42] Note that due to the compression requirements of natural gas transportation the energy required to transport an energy unit of natural gas by pipeline is higher than the energy required to move a comparable energy unit of crude oil.

average maintenance emissions of 85.4 million cubic meters per year.[43] With the volume transported during the first quarter of 1994 estimated to be approximately 32.3 million cubic meters per day, the emissions estimate is equivalent to 0.73% of the total transported, in line with other emissions estimates for new natural gas transportation systems.

We have conducted a sensitivity analysis by assuming 3% losses (assigning all of these to emissions) for the natural gas transmission and distribution system. While there are systems in Venezuela where losses are much higher, extremely high estimates should only be used in specific cases, where the fuel chain directly includes the leaky systems. For example, although the estimated losses for the Maracaibo natural gas distribution system are as high as 77% (UNEP/Risø, 1994), our fuel chains do not include the Maracaibo region, and so these extremely high losses are not appropriate. Accounting for losses from the Maracaibo system heavily influences estimates of a national average for gas transmission and distribution losses in Venezuela.

CNG Filling Stations

- Natural gas must be compressed before it is useful as a vehicle fuel. There are two general types of CNG filling stations, slow fill and rapid fill. As the names imply, refueling at a slow fill facility requires more time, and usually less compression energy, than a rapid fill station. For fleet operations, slow fill technologies may be sufficient, since vehicles can be returned to a central station and left to refuel overnight. For CNG stations serving the general public, rapid fill technology is necessary to avoid unreasonable filling times.

  USEPA (1990) reports on four CNG filling stations that ranged in output from 20 to 178 standard cubic feet of compressed gas per minute. The average energy use for these stations is equivalent to 0.3074 kWh per cubic meter. This figure, which is consistent with DeLuchi (1993), is used in the Venezuela case study.[44]

- Emissions from the natural gas filling station are estimated to be negligible. DeLuchi (1993) reports that little or no gas leakage is expected from the CNG nozzle/vehicle port interface.

Electric Generation

- CADAFE (1994) reports annual thermal efficiency by unit for the last five years at Planta Centro. The average for unit 2, which has operated on natural gas since 1989, is 35.4%. The average for the other units, assumed here to represent the efficiency of residual fuel oil operations, is 34.4%.

- Emissions from Planta Centro for natural gas and residual fuel oil operations are estimated based on a composite of the data reported by CADAFE (1994), Planta Centro (1994), and U.S. averages.

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43 Note that for natural gas pipelines, operating efficiency and emissions are not exactly the same. As noted by DeLuchi (1993) and Mercado (1990), unaccounted for gas is not always lost to the atmosphere. Metering discrepancies, condensation, and accounting losses are reflected by system efficiency estimates, although these losses do not result in emissions.

44 DeLuchi's literature review found a range of 0.015 to 0.073 Btu-power/Btu-CNG (DeLuchi, 1993: Volume II, Table G-6). Site specific compressor efficiencies and operating conditions are important, as the stations with the highest delivery capacities did not, contrary to expectations based on strictly physical principles, consistently require higher compression energy. The USEPA (1990) average of 0.3074 kWh per cubic meter, is equivalent to 0.0322 Btu-power/Btu-CNG.

- Electricity used in fuel chains as an auxiliary input fuel is assumed to be composed of an average mix of generation capacity for the national Venezuela electric system in 1990. The 1990 average mix is primarily dependent upon hydro which accounted for over 63% of total output (MEM, 1994: LEAP data set). Hydro generation is assumed to have an efficiency of 38.5% (WEC, 1993: p. 14) for comparison to other primary energy sources.

Diesel and CNG Buses

The per passenger kilometer efficiency of a CNG bus is estimated to be 15% less than that of a diesel bus. Table 5.5 summarizes estimates of the comparative efficiency of diesel and natural gas vehicles.[45]

Table 5.5: Comparative Thermal Efficiency of Diesel and CNG Buses[46]

Study	CNG Thermal Efficiency compared to Diesel
EPA (1990)	-25%
Goetz et. al (1988)	-18% (bus engines)
Lawson (1988)	-10% to -20%
Unpublished EPA	-13%
Rele and Seppen (1990)	-15%
Klimstra (1990)	-15%

- Emissions estimates for CNG and diesel buses are composites based upon estimates for average U.S. and European emissions.

5.5 Electric Fuel Chain Results

5.5.1 Energy Use

Primary fuel consumption by each fuel chain is illustrated in Table 5.6. This table indicates that the energy demands for delivering a unit of natural gas are almost entirely met by natural gas, whereas the residual fuel oil chain requires other forms of energy input, equivalent to approximately 9% of the total primary energy. The overall efficiency of the two fuel chains is represented by the inverse of the total for each column. For example, the fuel chain efficiency for residual fuel oil is 1/3.53 = 28.3%. For the natural gas fuel chains the efficiencies are 29.6%, and 27.8% for the low and high loss cases respectively.

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[45] Compressed natural gas engines are generally expected to have an efficiency advantage over gasoline in spark ignition engines. However, for heavy duty compression ignition engines, diesel designs are expected to have an efficiency advantage over compressed natural gas. For more discussion of the relative efficiency of natural gas and diesel heavy duty engines, see DeLuchi, Johnson and Sperling (1988), Taylor, Mahmassani, and Euritt (1992), and DeLuchi (1993).

[46] Source: As cited in DeLuchi (1993) Volume II, Appendix B.2.8.

Table 5.6 PRIMARY FUEL CONSUMPTION BY FUEL CHAIN
(GJ PER GJ ELECTRICITY[47])

FUEL	P.CENTRO RFO ELEC.	P.CENTRO NG ELEC.	P.CENT.NG-Hi LOSS
NATURAL GAS	0.21	3.37	3.59
CRUDE OIL	3.18	0.00	0.00
HYDRO	0.12	0.00	0.00
Total	3.53	3.38	3.60

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The details of upstream and downstream energy use, by stage, are presented in Figure 5.6 and Table 5.7. Upstream energy consumption is significant in comparison with the energy used for electricity generation and the electricity produced (bottom two bars, Figure 5.6). For each GJ of electricity produced, 0.44 GJ is used for upstream processes in the residual fuel oil chain. For the low losses natural gas fuel chain energy use in the non-electric generating stages is equal to 0.54 GJ per GJ of electricity produced. For the high losses natural gas fuel chain 0.77 GJ per GJ of electricity produced is used in non-generating stages. These amounts account for between 22% and 42% of the energy used at the power station.

Table 5.7 NET ENERGY USE: STAGE BY FUEL CHAIN
(GJ PER THOUSAND GJ ELECTRICITY)

STAGE	P.CENTRO RFO ELEC.	P.CENTRO NG ELEC.	P.CENT.NG-Hi LOSS
Final Fuel Use	1000.00	1000.00	1000.00
Trans. Losses & Aux. Fuel Use:			
Elec.Distributio	15.70	0.59	0.61
Electricity Gen.	2065.06	1830.82	1830.96
Pprod. Dist.	0.01	0.00	0.00
NGPipe SnJose-Ca	3.51	160.76	194.05
Refinery ElPalit	288.72	0.42	0.43
Gas Treatment	5.89	269.84	278.52
NG Recovery	4.03	115.26	294.88
OlPipe Barinas-E	31.19	0.05	0.05
Crude Rec. Barns	112.78	0.16	0.17
Total	3526.88	3377.90	3599.66

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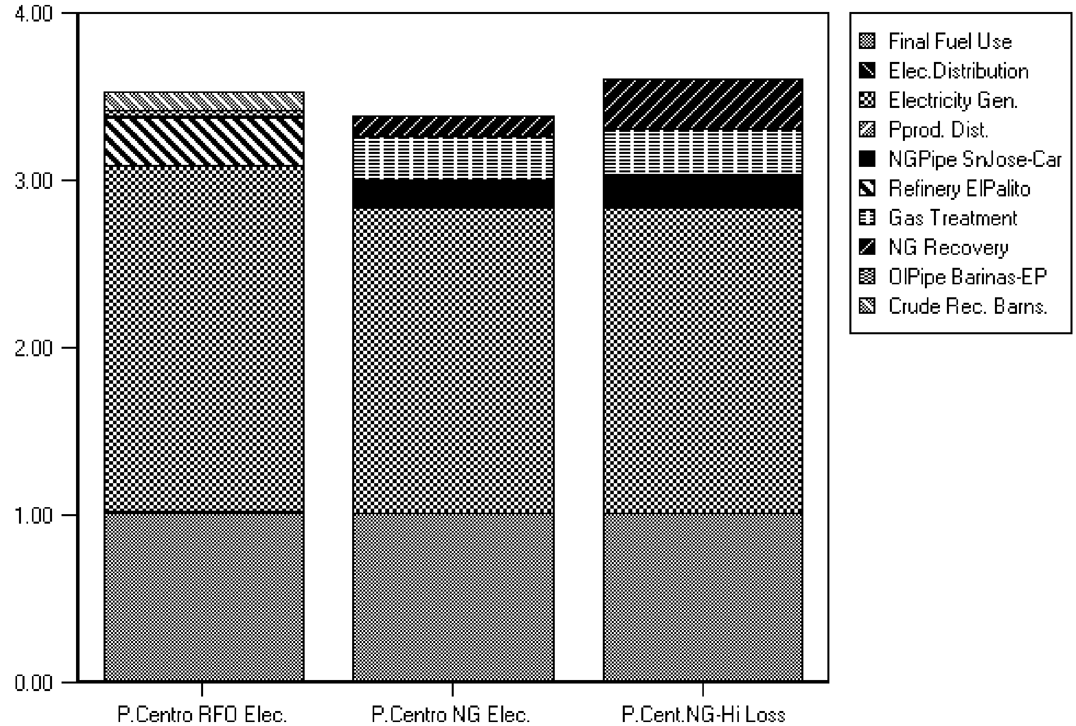
[47] Totals may not sum due to rounding.

Figure 5.6: Net Energy Use, Stage by Fuel Chain
GJ per GJ Electricity



Not surprisingly, these findings indicate that the efficiency of electric generation technologies remains a critical parameter in a comparison of total energy consumption by the fuel chains. However, the lower efficiencies of residual fuel oil boilers at the power plant may be partially or wholly offset by higher upstream energy use in the natural gas fuel chain. In this case, the final comparison hinges upon the losses assumed in the natural gas fuel chain. In the high loss natural gas fuel chain, the recovery stage requires more than twice as much energy as the recovery stages of the other two chains, due not to higher energy use per unit of gas recovered, but to higher loss rates. The effect is to make the high loss natural gas chain more energy intensive per unit of electricity produced than the residual fuel oil chain. Note that for both natural gas and residual oil fuel chains, a large share of upstream energy consumption occurs at the processing stages, either gas treatment or refining. The transportation of crude oil by pipeline is relatively energy efficient, requiring significantly less energy per unit of electricity produced than the natural gas pipeline.

5.5.2 Environmental Impacts

The comparative environmental impacts of natural gas and residual fuel oil electric fuel chains indicate that natural gas is preferred, both in terms of global warming potential (GWP), and other air pollutants. The global warming results are presented in Figure 5.7. The right hand bar in the graphic represents the high loss natural gas chain. Even when high losses are assumed for the natural gas chain, the GWP of the residual fuel oil chain is clearly higher. Figure 5.8 disaggregates the GWP impacts for each chain by type of gas, indicating that the methane emissions of the natural gas chains do not completely offset the higher CO2 emissions associated with the combustion of residual fuel oil at the power plant.

Figure 5.7: Greenhouse Gas Emissions by Stage, IPCC 100 Year Integration (kg CO_2 Equivalent per GJ Final Energy)

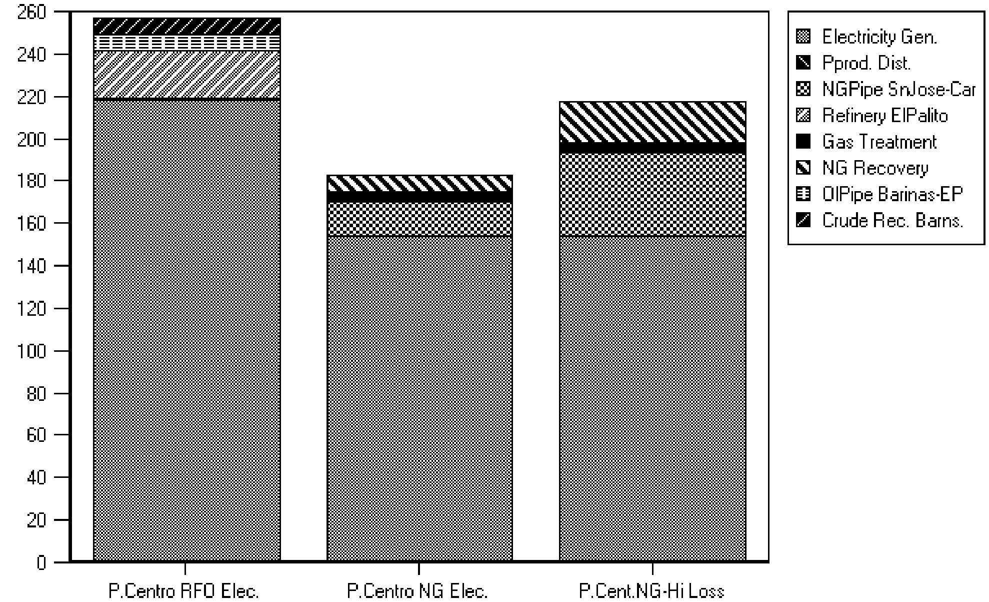
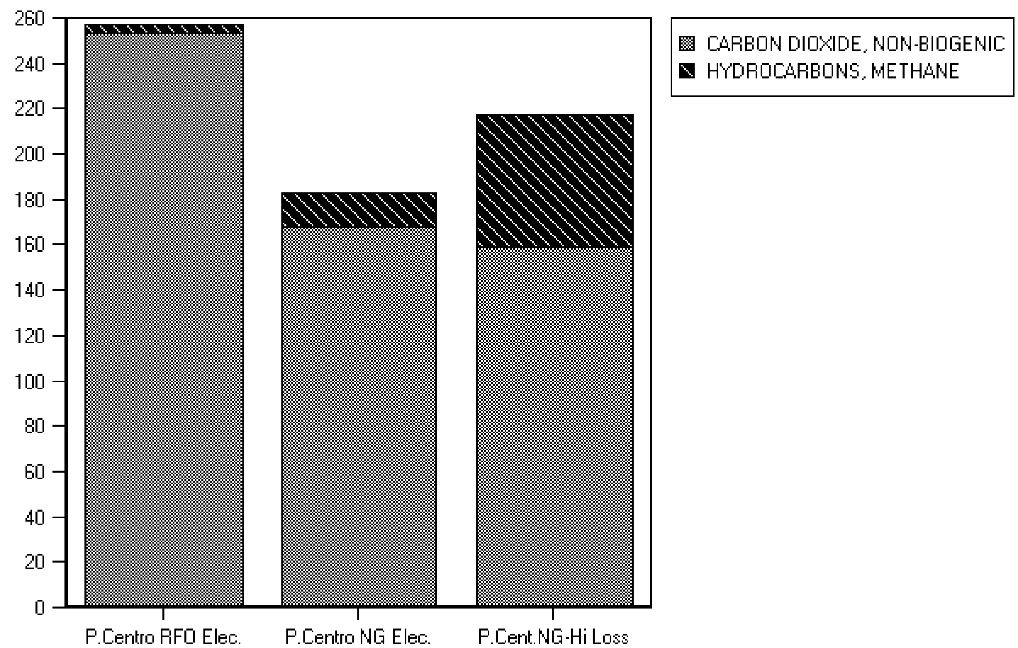


Figure 5.8: Greenhouse Gas Emissions by Gas, IPCC 100 Year Integration (Kg CO_2 Equivalent per GJ Final Energy)



Global warming impacts are not the only air emission of concern. Fuel chains for electricity generation can also result in large emissions of local and regional air pollutants. The comparative emissions of the electric fuel chains with respect to other critical air pollutants are presented in Table 5.8 and Figure 5.9.

Table 5.8 EFFECT BY FUEL CHAIN:
(PER THOUSAND GIGAJOULE FINAL ENERGY)

EFFECT	P.CENTRO RFO ELEC.	P.CENTRO NG ELEC.	P.CENT.NG-Hi-LOSS	
CARBON MONOXIDE				
TOTAL	965.34	43.56	43.62	(KILOGRAMS)
HYDROCARBONS				
TOTAL	48.37	4.88	4.89	(KILOGRAMS)
NITROGEN OXIDES				
TOTAL	672.97	707.04	707.22	(KILOGRAMS)
SULFUR OXIDES				
TOTAL	1690.74	5.24	5.24	(KILOGRAMS)
PARTICULATES				
TOTAL	57.80	8.95	8.95	(KILOGRAMS)

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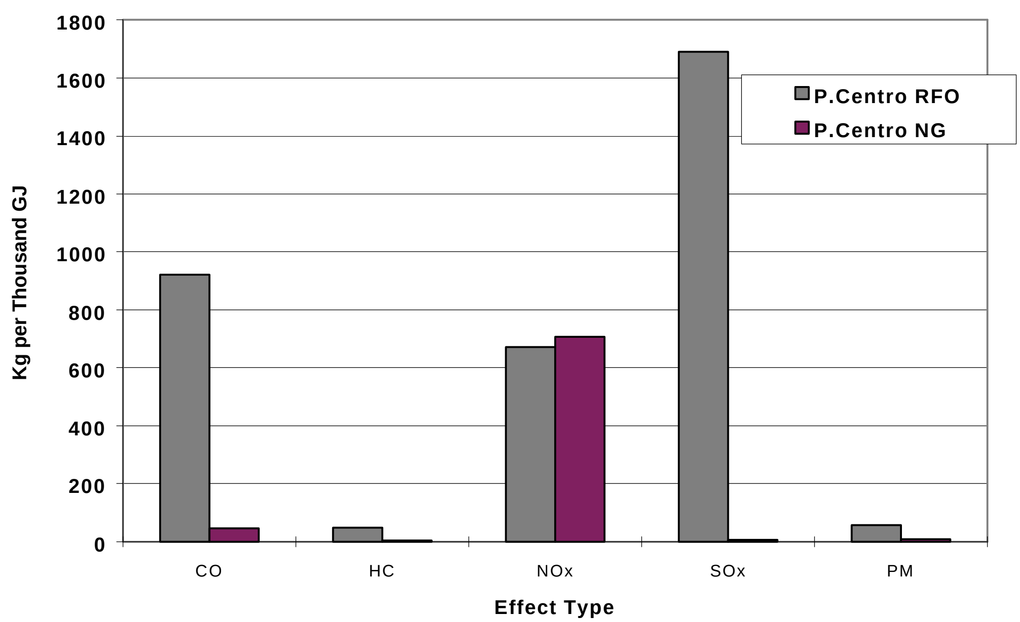
Figure 5.9 Comparative Emissions of Other Air Pollutants from Electric Fuel Chains



5.5.3 Summary Findings for Electric Fuel Chains

The natural gas fuel chain has clear environmental advantages, in terms of global, local, and regional air emissions, over the residual fuel oil chain. These results hold true even under the assumption of high losses which make the natural gas fuel chain less energy efficient than the residual fuel oil chain. Given the current, and projected, composition of thermal generating capacity in Venezuela, where natural gas is the clearly predominant fuel, these are encouraging findings.

For operational and economic reasons, the new owners and operators of Planta Centro are likely to explore the option of further conversion to natural gas. The chances of maintaining the status quo, where 80% of the total plant capacity is primarily fueled by residual oil appears to be small. Conversion of the plant is likely to impact operations at the El Palito refinery, which, as noted earlier, has benefited from having a large domestic customer for its residual fuel oil output, located only 5 km from the refinery. While PDVSA and Corpoven will gain a large natural gas customer if there is further conversion of the boilers at Planta Centro, they also lose the largest domestic customer for residual fuel oil, one of their least marketable products (MEM, 1994: Balance Energetico de Venezuela, 1991).[48] Other interest groups, such as the MEM, the MARNR, the new operators of the plant, CADAFE (previous owners who want to see the highest selling price based upon a positive outlook for future operations), and local residents, are all likely to support the conversion of the plant to natural gas.

Opportunities for reducing emissions exist at several stages in the natural gas fuel chain. As reported in USEPA (1993) there are profitable opportunities to reduce methane emissions from natural gas transmission and distribution systems by approximately 32%, through improved inspection and maintenance procedures at compressor and distribution (gate) stations, the replacement of high bleed pneumatic valves, and recovery of gas currently vented during routine pressure relief (blow down) operations. Similar opportunities for methane emissions reductions are likely to exist in Venezuela, and the implementation emissions reduction technologies, or the use of natural gas that would otherwise be flared or vented at the power station will further increase the advantages described above.

5.6 Transportation Fuel Chain Results

The fuel chains delivering diesel fuel and compressed natural gas to busses on the Metro feeder network in Caracas are similar to the chains described for electric generation with the addition of stages representing the transport of diesel fuel from the refinery to Caracas, and compressed natural gas filling stations.

5.6.1 Energy Use

Primary fuel consumption by each fuel chain is illustrated in Table 5.9.

[48] Electric generation accounts for more than one half of total domestic consumption of residual fuel oil, with the majority of this consumption occurring at Planta Centro. While exports of fuel oil are greater than internal consumption by a factor of more than 10 to 1, the maintenance or growth of the internal fuel oil market has been an objective pursued by PDVSA in the past.

Table 5.9: PRIMARY FUEL CONSUMPTION BY FUEL CHAIN
FUEL CHAINS: TRANSPORT
(GJ PER THOUSAND PASSENGER-KM)

FUEL	DIESEL BUS	CNG BUS	CNG Bus Hi-LOSS
NATURAL GAS	0.04	0.83	0.87
CRUDE OIL	0.63	0.00	0.00
HYDRO	0.02	0.05	0.05
Total	0.70	0.88	0.93

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The diesel bus fuel chain has a higher overall efficiency than the CNG fuel chain, primarily because of the assumption that diesel busses have a 15% fuel efficiency advantage over a comparable bus fueled by CNG. The higher efficiency of the diesel bus is due to engine characteristics, and additional vehicle weight due required for on-board CNG storage tanks. Table 5.10 displays the energy requirements for delivering the respective end use fuels.

Table 5.10: PRIMARY FUEL CONSUMPTION BY FUEL CHAIN
FUEL CHAINS: FINAL FUELS
GIGAJOULES PER GIGAJOULE FINAL ENERGY

FUEL	CNG	DELIVERED DIESEL	DELIVERED NG
NATURAL GAS	1.24	0.07	1.19
CRUDE OIL	0.01	1.10	0.00
HYDRO	0.07	0.04	0.00
Total	1.32	1.21	1.20

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In Table 5.10 we see that, before the energy required for compression at the CNG filling station is included, the energy required to deliver diesel and natural gas are roughly similar. Thus, the efficiency advantage of the diesel bus fuel chain over the CNG bus fuel chain is due a combination of the end-use efficiency advantage, and the energy requirements for natural gas compression.

Table 5.11 indicates that the proportion of total energy use represented by the end use stage ranges from 72% for the high loss CNG chain to 82% for the diesel chain. Thus, similar to the electric fuel chain findings, end use energy efficiency remains a critical parameter in the comparison of the total fuel chain energy consumption. Therefore, efficiency improvements in CNG busses, which may be expected as lean burn heavy duty engine technologies are further developed, will have significant impacts on total fuel chain energy consumption. Reducing losses in the upstream stages of the natural gas fuel chain will also yield fuel chain efficiency gains.

Table 5.11: NET ENERGY USE: STAGE BY FUEL CHAIN
FUEL CHAINS: PASSENGER TRANSPORT
GIGAJOULES PER MILLION PASSENGER-KM

STAGE	DIESEL BUS	CNG BUS	CNG Bus HI-LOSS
Final Fuel Use	577.23	663.81	663.81
Trans. Losses & Aux. Fuel Use:			
Elec.Distributio	3.12	5.71	5.71
CNG Filling Stat	0.00	20.90	20.90
Electricity Gen.	31.42	57.46	57.47
Pprod. Dist.	0.61	0.00	0.00
NGPipe SnJose-Ca	0.70	37.78	44.76
Refinery ElPalit	57.39	0.35	0.35
Gas Treatment	1.17	63.41	64.04
NG Recovery	0.80	27.09	69.22
OlPipe Barinas-E	6.20	0.04	0.04
Crude Rec. Barns	22.42	0.13	0.13
Total	701.05	876.66	926.42

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5.6.2 Environmental Impacts

A comparison of the environmental impacts shows that if high losses are assumed for the natural gas fuel chain, the global warming impacts of diesel busses are less than for CNG busses, but that CNG is favored over diesel with respect to other critical urban air pollutants. If low natural gas system losses are assumed the global warming impacts of the two fuel chains are approximately equal. Thus, unlike the situation for the electric fuel chains, where there are consistent environmental advantages associated with natural gas, the comparative environmental merits of the diesel and CNG transportation fuel chains are mixed. The global warming impacts of the two fuel chains are presented in Figures 5.10 and 5.11.

Figure 5.10: Greenhouse Gas Emissions by Stage, IPCC 100 Year Integration (Tonnes CO_2 Equivalent per Million Passenger-KM)

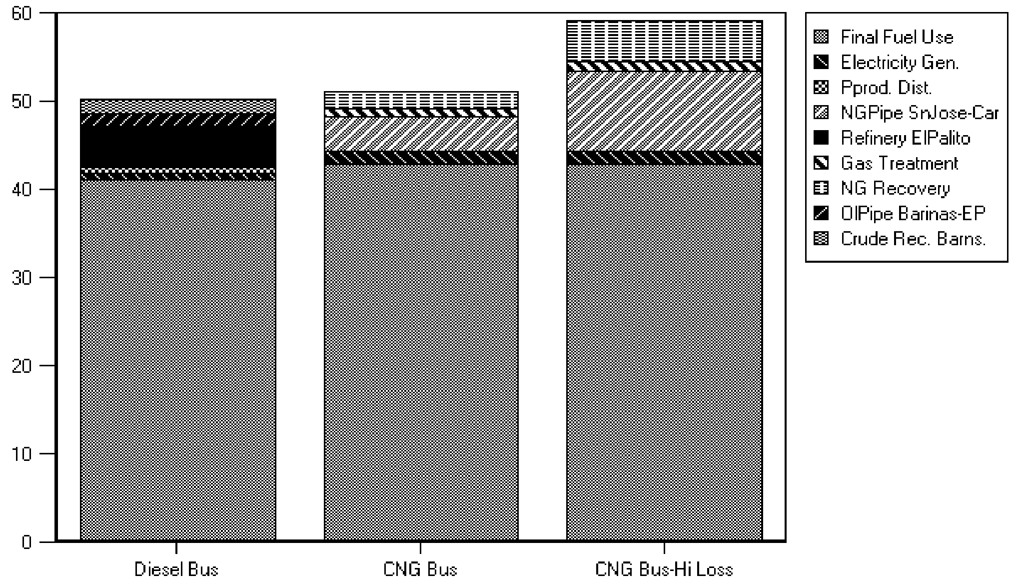
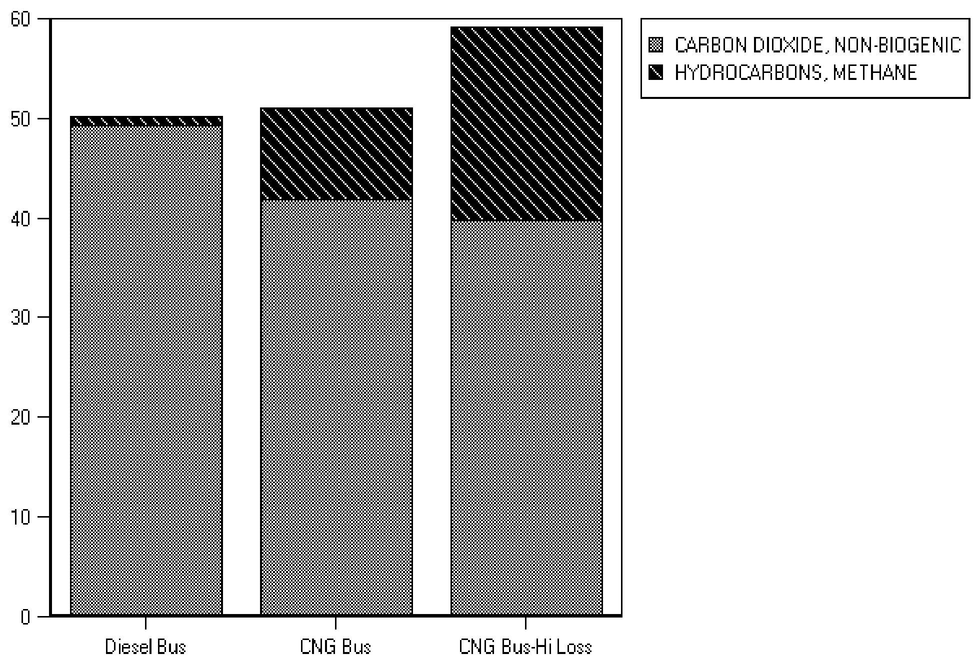


Figure 5.11: Greenhouse Gas Emissions by Gas, IPCC 100 Year Integration (Tonnes CO_2 Equivalent per Million Passenger-KM)



Emissions of other air pollutants are represented in Table 5.12 and Figure 5.12.

Table 5.12: EFFECT BY FUEL CHAIN: PHYSICAL UNITS
FUEL CHAINS: PASSENGER TRANSPORT
PER MILLION PASSENGER-KM

EFFECT	DIESEL BUS	CNG BUS	CNG Bus HI-LOSS	
CARBON MONOXIDE				
TOTAL	1351.57	301.58	301.59	(KILOGRAMS)
HYDROCARBONS				
TOTAL	84.63	7.33	7.33	(KILOGRAMS)
NITROGEN OXIDES				
TOTAL	613.28	110.01	110.02	(KILOGRAMS)
SULFUR OXIDES				
TOTAL	32.20	2.48	2.35	(KILOGRAMS)
PARTICULATES				
TOTAL	151.58	3.06	3.06	(KILOGRAMS)

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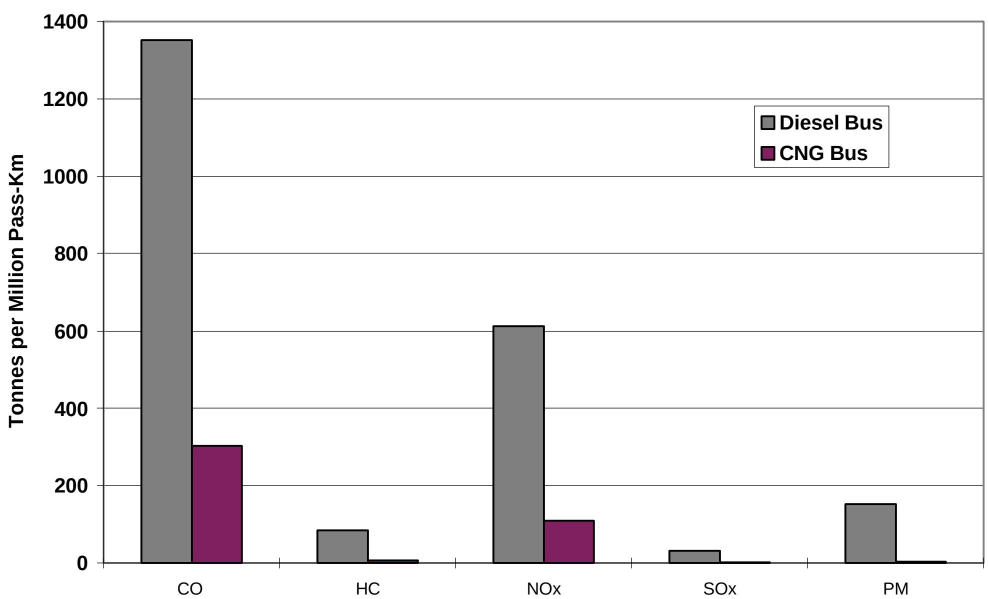
Figure 5.12: Other Air Pollutant Emissions from CNG and Diesel Transport Fuel Chains



The CNG bus option results in significant reductions in particulates, sulfur oxides, nitrogen oxides and carbon monoxide. In the context of urban air quality these reductions are very desirable. However, as indicated in Figure 5.10, reductions in these emissions involves a trade-off in terms of global warming emissions, particularly under the case of high natural gas system losses.

5.6.3 Summary Findings for Transportation Fuel Chains

The results indicate that the CNG fuel chain requires 25% to 32% more energy per passenger kilometer depending upon the assumed losses for the natural gas system. As a result, the CNG fuel chains are expected to produce higher global warming emissions than the diesel fuel chain. However, the CNG chains have significantly lower emissions of other air pollutants that are critical in determining urban air quality. As mentioned earlier, recent literature in the United States indicates that reducing fine particulate matter, a major emission from diesel busses, is likely to have significant public health benefits (Skelton and Kassel, 1993). As Corpoven continues to promote compressed natural gas as a vehicle fuel in Venezuela the Metro bus system appears to be a wise choice for conversion, due to its operation in congested urban surroundings, its highly visible public profile, and its high passenger volume. The rationale for promoting CNG busses is strengthened if natural gas system losses are relatively low, or if improvements in CNG heavy duty engine efficiency are realized.

5.7 Conclusions

- If the environmental objective of greenhouse gas (GHG) mitigation is considered in isolation, then, due to methane emissions from the recovery and transmission of natural gas, and the lower vehicle efficiency of compressed natural gas vehicles, natural gas is not clearly favored over diesel as a transportation fuel. Assuming low natural gas loss rates in production and distribution, the global warming impacts of the CNG bus fuel chain are approximately equal to those of the diesel fuel chain. At high natural gas loss rates, the global warming potential for the use of CNG buses is 27% greater than for diesel buses.

- A critical component of the above finding is the assumption that natural gas comes from additional production rather than the capture of natural gas that otherwise be flared, vented, or leaked from the oil and gas production, transmission and distribution system. Based on the higher economic costs of capturing natural gas from losses, this appears to be most relevant assumption. If, however, one assumed that there is causal linkage between development of CNG as a vehicle fuel and thus that captured losses would be the marginal source of natural gas in an expanded CNG vehicle program, then the CNG fuel chain could be assigned a sizeable significant credit with respect to greenhouse gas emissions, due to the reduction in methane emission.[49]

- In terms of greenhouse gas emissions, natural gas is the preferred fuel for electricity generation, even under the assumption of relatively high natural gas system losses. The global warming potential equivalents, natural gas-fired electricity is 12% to 27% lower than residual fuel oil per kWh. Therefore, natural gas is more effective in terms of GHG mitigation if it is used as a substitute for residual fuel oil in electric generation than as a replacement for diesel in transportation.

- With respect to emissions of local air pollutants, such as carbon monoxide, sulfur oxides, and particulates, CNG is clearly favored over diesel as a bus fuel, and natural gas is clearly favored over

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[49] In other words, one would have to be able to say that natural gas losses would not be reduced unless a CNG vehicle program were pursued. (e.g. say, that the increased market for natural gas were an important factor in the decision to reduce losses). The net incremental cost of natural gas loss reduction has been estimated by INTEVEP, the research arm of PDVSA. If a credit were given, it would likely make the CNG option enormously beneficial in terms of global warming potential (GWP) emissions, since each tonne of methane saved avoids the equivalent of over 30 tonnes of carbon dioxide, assuming a 100-year integration period.

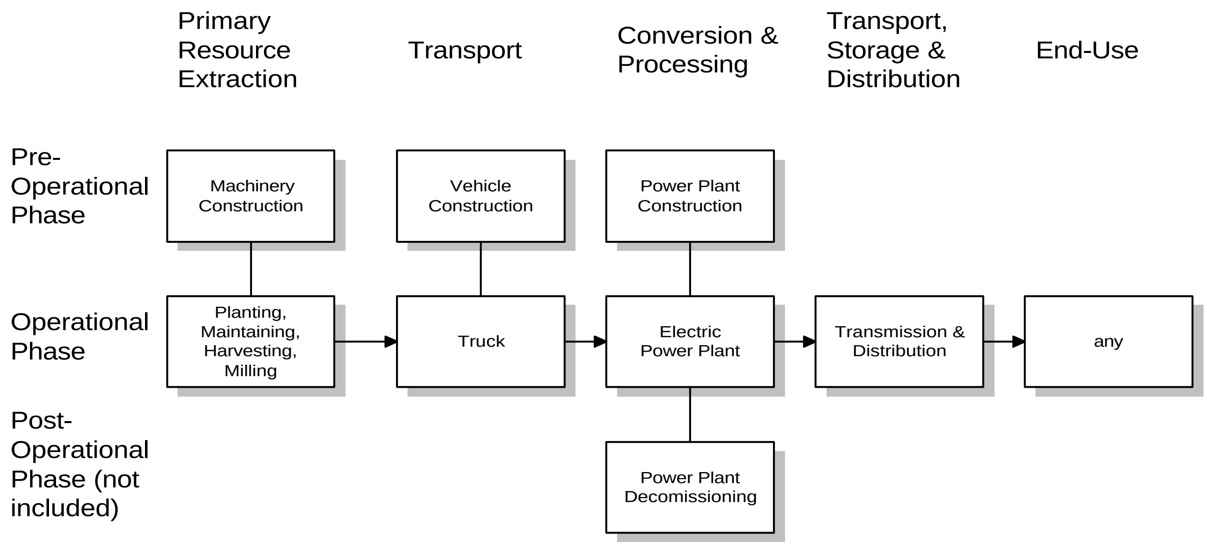
residual fuel oil for electricity generation.

- "Upstream stages" -- that is, the processes such as pipeline transport and fuel extraction, that occur prior to final fuel combustion -- represent approximately 18% to 30% of the net energy use in the fuel chains examined, and 15% to 35% of total fuel chain contributions to global warming emissions. In terms of local air pollutants, upstream stages can account for as much as 35% of the total fuel chain emissions (in the cases of NOx emissions for electricity generation using residual fuel oil, and SOx emissions for the diesel bus fuel chain) or as little as 5%. Given that the overall differences in energy and emissions between fuels are often in a this range (e.g. less than 35%), the contributions of upstream stages should be considered significant and can influence the relative environmental benefits of different fuel choices.

- Upstream stages, such as off-shore oil and gas production or hydro development in indigenously inhabited or biologically diverse areas can present other, important environmental impacts that are often more difficult to quantify or compare. The future application of the fuel chain analysis framework to a broader spectrum of environmental issues (including, for example, water pollution, solid wastes, loss of biodiversity, and social impacts on indigenous cultures) can provide for a fuller accounting of fuel choice impacts. These were only covered in a qualitative fashion here, but further analysis could seek to integrate these through valuation or other multi-objective analysis approaches to yield results in a common unit.

6. Biomass Fuel Chain Fact Sheets

Figure 6.1: The Biomass-Electricity Fuel Chain.



This fact sheet reviews available international data that can be applied in analyzing biomass fuel chains.

6.1 Biomass Production

The biomass production stage involves land preparation, planting and harvesting of biomass. In this fact sheet we quantify the energy used in silvicultural machinery, the energy used to produce three basic types of fertilizers: nitrogen (in NH_3 and NH_4O_3), phosphorous (P_2O_5) and potash (K_2O), and the environmental impacts associated with the operation of machinery and with the production of those fertilizers. In some operations lime may also be used as fertilizer, although none is included here. Some pre-operational phase impacts will also be associated with the energy embodied in machinery and with the preparation of crop seeds/seedlings. These effects are small and are not included here.

Table 6.1: Direct Fuel Use for Wood Production			
Fuel	**per tonne wood produced**	**Reference:**	**See note:**
Diesel	33.79E-3 tonnes	DeLuchi (1993)	1

Notes:

1. Includes energy used to apply fertilizer and plant, harvest and chip wood (reported as 0.074 GJ per GJ of wood, assuming 8,350 Btu/pound wood energy content).

Table 6.2: Fertilizer Requirements for Wood Production			
Fertilizer	**Use per tonne wood produced**	**Reference:**	**See note:**
Nitrogen	12.5 kg	DeLuchi (1993)	1
Phosphorous (P_2O_5)	2.08 kg	DeLuchi (1993)	1
Potash (K_2O)	2.08 kg	DeLuchi (1993)	1

Notes:

1. Based on assumption of 13.44 tonnes wood produced per hectare (after harvest losses) using short rotation intensive cultivation (SRIC) for maximum production and minimum cost. Harvest efficiency approximately 90%.

Table 6.3: Energy Requirements per Kg of Fertilizer				
Fertilizer	**electricity**	**Natural Gas**	**Reference:**	**See note:**
Nitrogen	0.50E-3 GJ	57.60E-3 GJ	DeLuchi (1993)	
Phosphorous (P_2O_5)	2.60E-3 GJ	4.37E-3 GJ	DeLuchi (1993)	
Potash (K_2O)	2.36E-3 GJ	4.61E-3 GJ	DeLuchi (1993)	

6.2 Biomass Transport

The environmental loadings of this stage of the fuel chain are largely related to the emissions from trucks used to haul wood to the power station, and are thus dependent on the average haul distance assumed. Looking at silvicultural systems used to supply wood-to-Ethanol or Methanol conversion facilities, DeLuchi (1993) assumes an average intensity of 2216 BTU/ton-mile (1.6 MJ/tonne-km) and an average 14 km one-way trip. This figure is based on calculations for an optimally sized plantation in which approximately 50% of the land is planted with high yielding trees. DeLuchi also notes that other studies have shown that longer trip distances (and larger plantations) may also be economic. The energy intensity can be compared to a world average estimate for freight transport of 4.5 MJ/tonne-km (SEI-B, 1994).

For developing countries it may be reasonable to use a higher energy intensity given that trucks will typically be older and smaller, and road conditions will be worse. However, average truck loadings may also differ between industrial and developing countries. Economic wood transport distances may well be higher in developing countries partly due to lower labor, maintenance and depreciation costs (the latter due to the use of older vintage vehicles). Woodfuel for urban use is often carried as a partial load on return trips, so giving it a low opportunity cost (although this would probably not apply to the transport of wood from dedicated plantations). These issues are reviewed in more detail in Leach and Gowen (1987). In many countries, distances of 100 km or more may (one way) be economic for firewood, while distances of 600 km or more may be economic for charcoal.

Table 6.4: Energy Use for Biomass Transport			
Diesel Truck	**Intensity**	**Trip Distance**	**Notes:**
US Biomass Plantation	1.6 MJ/t-km	14 km	
Developing Country Biomass	4.5 MJ/t-km	up to 100 km?	

Table 9.5: Biomass Transport: Loadings and Direct Impacts			
Loading/Impact	**per tonne of diesel consumption**	**Reference:**	**See note:**
CO_2	3.10E+0 t	EPA-ASF (1989)	1
CO	2.68E-2 t	EPA-ASF (1989)	1
HC Total	3.58E-3 t	EPA-ASF (1989)	1
CH4	3.57E-4 t	EPA-ASF (1989)	1
NO_x	5.36E-2 t	EPA-ASF (1989)	1
SO_x	3.86E-3 t	EPA-NEDS (1989)	1
Particulates	7.3E-3 t	EPA-NEDS (1989)	1

Notes:
1. EDB coefficients for “generic heavy diesel trucks”.

6.3 Electricity Production

In this section we examine two systems. The first represents a typical biomass fired steam plant, representative of technologies available today. The second is an example of the type of biomass technology that is likely to be available in coming years.

6.3.1 Steam Turbine Systems

Biomass fired steam systems have inherent disadvantages compared to coal systems. The high cost of transporting wood limits the size of biomass plants, typically to less than 100 MWe. Unfortunately, there are large economies of scale in the construction of steam turbines. To reduce the dependence of cost on scale, biomass systems typically use lower grade steels that require more modest steam conditions, but also lead to lower efficiencies than coal-fired plants. While modern coal-steam plants may operate with an efficiency of 35%, a typical biomass system might have an efficiency of only 14-18%.

This has so far limited the application of biomass for electricity generation to no-cost or low-cost feedstock fuels (agro-residues and forest product-residues and urban refuse). A number of technologies have or are currently being explored which may improve the economics of biomass-steam systems. For example, one system examined by EPRI that burns whole trees and uses a reheat-steam cycle is projected to achieve an efficiency of 34%. The improved efficiency of this system is largely due to its larger scale (approximately 100 MWe): such a system would not be suitable for use with dispersed biomass feedstocks because of high transport costs.

Table 6.5: Wood-Fired Steam Electricity: Loadings and Direct Impacts			
Loading/Impact	**per tonne of wood consumed**	**Reference:**	**See note:**
CO_2	1.59E+0 t	SEI-B	1
CO	2.35E-4 t	EPA-NEDS (1989)	2
Total Hydrocarbons	7.00E-4 t	EPA-NEDS (1989)	2
CH_4	2.35E-4 t	EPA-NEDS (1989)	2
NO_x	1.40E-3 t	EPA-NEDS (1989)	2
SO_x	7.50E-5 t	EPA-NEDS (1989)	2
Particulates	7.76E-4 t	EPA-NEDS (1989)	2

Notes:
1. Derived from first principles, SEI-B.
2. Coefficients taken from EDB data for wood and wood/bark generic utility boilers.

Table 6.6: Wood-Fired Electricity Efficiencies			
Technology	**Efficiency (for max elec)**	**Ref:**	**Notes:**
Conventional Steam	14%-18%	1	
CEST	21%	1	Condensing Extraction Steam Cycle
Whole Tree	34%	1	Reheat Steam Cycle
BIG/STIG	34%	1	
BIG/ISTIG	43%	1	

1. Source: Williams and Larson, 1992.

6.3.2 Gas Turbine Systems (BIG-GT)

Biomass Integrated Gasifier-Gas Turbine systems (BIG-GT) are a promising alternative to biomass steam systems. They provide high efficiency conversion at a low capital cost, and at the modest scale that is suitable for the dispersed nature of biomass feedstocks. Because they are based on gas turbine technology they also promise much lower pollutant emissions than conventional biomass steam systems and, where the biomass is grown sustainably, very low levels of CO_2 emissions.

BIG-GT systems are based on the integration of gas turbine and biomass gasifier technologies. The former is already a mature technology for natural gas and clean liquid fuels (used in the electricity generation and maritime and air transport sectors), the latter can be based on gasifiers developed for use with coal. Although there are currently no commercial BIG-GT plants in operation, a pilot plant has been developed in the US by the Batelle laboratory in Columbus, Ohio funded by the US Department of Energy, and a commercial application is planned in Burlington, Vermont.

Because gas turbines have a much higher peak inlet temperature than steam turbines, their thermodynamic efficiencies are potentially much higher. Aeroderivative gas turbines are particularly attractive because of their small scale, high efficiency, and low capital cost. Moreover, their modular design facilitates easy maintenance which may be particularly attractive in developing countries where on-site maintenance is not available.

Because gas turbines cannot be fired directly by solid fuels, a gasifier must be used to create fuel gas from the solid fuel. Most gasifier designs combine a gasifier unit with a hot gas cleanup system to remove alkalis and particulates. The development of biomass gasifier systems will be based on existing coal gasification systems. However, biomass systems are likely to be simpler than coal systems because hot-gas sulfur removal needed for coal will not be required in biomass systems since most biomass has negligible sulfur, and also biomass is more reactive than coal so easier to gasify.

At some point in the biomass fuel chain, wood-fuel must be dried before it is gasified. This can be done before it is transported, or immediately before gasification. Wood drying can consume large amounts of energy. In this study, all wood drying is assumed to be done using the excess process heat produced in the BIG-STIG system. Hence, energy for wood drying is not explicitly accounted for.

A second approach to improving electricity generation efficiency is the combined cycle, which combines a gas turbine unit with a steam turbine unit. Exhausts from the gas turbine are used to heat the steam for the steam turbine. The gas turbine produces approximately two thirds of the power and the steam turbine approximately one third. This system can also potentially produce very high efficiencies. However, because of the poor economies of scale of steam turbines and the need to use industrial (as opposed to aeroderivative) gas turbines with higher outlet temperatures experts consider it is unlikely to be the best candidate for use in decentralized biomass systems. However, this may change in the future as new gas turbine technologies emerge.

Table 6.7: BIG-GT Electricity: Loadings and Direct Impacts

Loading/Impact	per tonne of wood consumed	Reference:	See note:
CO_2	4.94E-3 t	SEI-B	1
CO	2.52E-5 t	CEC (1989)	2
Total Hydrocarbons	3.78E-5 t	CEC (1989)	2
CH_4	1.89E-5 t	CEC (1989)	2
NO_x	7.57E-4 t	CEC (1989)	2
SO_x	negligible	CEC (1989)	2
Particulates	1.39E-4 t	CEC (1989)	2

Notes:

1. Derived from first principles - see EDB for details.
2. Because of the newness the technology, no primary data is currently available on emissions from BIG-GT systems. Non-CO_2 coefficients are assumed to be the same as for integrated coal gasification combined cycle plant (IGCC) with data taken from California Energy Commission recommendations on emissions factors for generic power plants.
3. BIG-STIG systems operating in cogeneration mode (producing maximum process steam) and using wood with a 50% moisture content are assumed to produce 38.3 MWe at an electrical efficiency of 29.5%, with a further 28.9% of energy converted to process steam. When operating for maximum electric power they are assumed to produce 50.8 MWe at an electrical efficiency of 33.5% (source: Williams and Larson, 92)

Table 6.8: Biomass Power Plant Construction Materials & Land Use

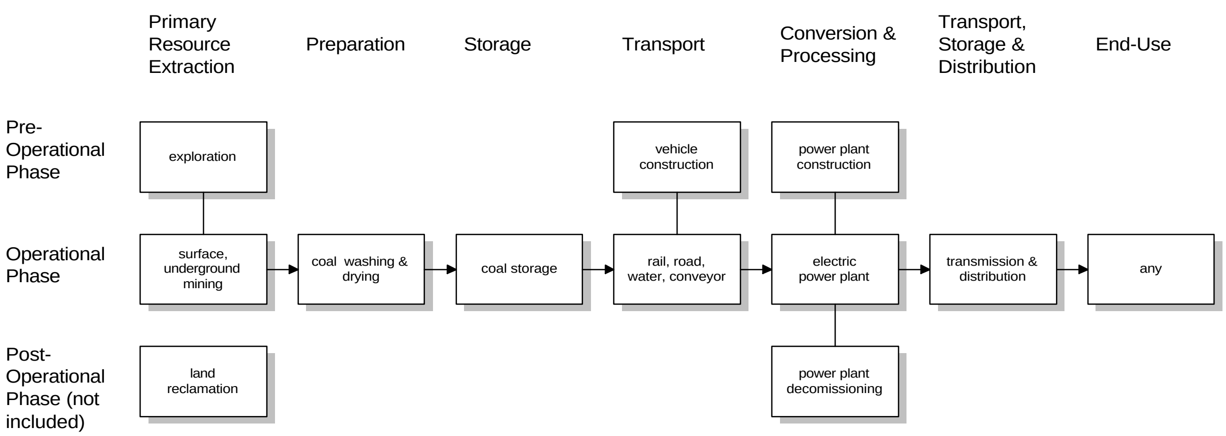
Material	Amount/MW Capacity	Reference:	See note:
Concrete	180.6 tonnes	DOE (1983)	1
Steel	68.3 tonnes	DOE (1983)	
Copper	1.61 tonnes	DOE (1983)	
Aluminum	0.58 tonnes	DOE (1983)	
land Use	0.66 Hectares	DOE (1983)	

Notes:

1. Assumptions on materials used in the construction of biomass power plants are taken from DOE Energy Technology Handbook for wood-fired steam plant. No information is available on the construction materials used in BIG-GT systems. In this analysis use of construction materials per MW are assumed the same as for conventional wood-fired systems.

7. COAL FUEL CHAIN FACT SHEETS

Figure 7.1: Schematic of the Coal Electricity Fuel Chain



7.1 Mining, Preparation And Storage

The environmental loadings from coal mining are often very site specific and poorly known, making it difficult to develop a generalized picture. However, the largest variations in the level of loadings and impacts occur between surface and underground mining. In the interest of developing a fact sheet that is as widely applicable as possible, we have developed simplified information for these two characteristic technologies.

7.1.1 Surface Mining

The following fact sheet is based on information for one USA western region surface coal mine (principle source: DOE, 83), with additional data either derived from first principles, or drawn from international sources. Western region surface coal mining is characterized by the following processes, for which data and qualitative information is included in this section: exploration (pre-operational phase), clearing & grubbing, topsoil removal, overburden removal, spoil storage, coal removal, backfilling and regrading, topsoiling, coal storage, coal transport (to preparation plant), coal preparation, waste storage, and coal loading.

Overburden removal is by dragline and stripping shovels, while bulldozers are used for backfilling and regrading. Before coal and overburden are removed they must be drilled and blasted using blasting compound. A shovel or front end loader loads the broken coal into haul trucks. Raw coal sometimes may be dumped onto a temporary storage pile and later rehandled by a front end louder or bulldozer. An on-site enclosed preparation plant is used for crushing and screening coal. Preparation plant fugitive dust emissions are minimal because the preparation plant is enclosed and uses water to reduce fugitive dust emissions.

During mine reclamation, which proceeds throughout the life of the mine, overburden spoils piles are smoothed and contoured by bulldozers. Topsoil is placed on the graded spoils, and the land is prepared for revegetation by furrowing, mulching, etc. From the time an area is disturbed until the new vegetation emerges, all disturbed areas are subject to wind erosion.

Table 7.1: Loadings and Direct Impacts			
Loading/Impact	**per tonne of coal produced**	**Reference:**	**See note:**
Air Emissions			
CO_2	4.94E-3 t/t.	SEI-B derived from DOE (1983)	2
CO	1.69E-5 t/t	DOE (1983)	
Hydrocarbons	5.23E-6 t/t	DOE (1983)	
Aldehydes	1.38E-6 t/t	DOE (1983)	
CH4	low: 3.00E-1m^3/t high: 2.00E+0m^3/t	IPCC (1994)	3
NO_x	8.36E-5 t/t	DOE (1983)	
N_2O		Not avail	
SO_x	5.58E-6 t/t	DOE (1983)	
Particulates	4.53E-6 t/t	DOE (1983)	
Fugitive Dust	1.22E-5 t/t	DOE (1983)	
Solid Wastes			
Total Solid Waste	1.10E-1 t/t	DOE (1983)	4
Occupational Health & Safety			
Deaths	7.14E-9 Deaths/t	DOE (1983)	
Injuries	1.71E-6 Injuries/t	DOE (1983)	

Table 7.2: Auxiliary Fuel Use and Other Inputs			
Input	**per tonne coal produced**	**Reference:**	**See note:**
Fuels			
Electricity	2.92E+0 kWh/t	DOE (1983)	5
Fuel (Diesel)	1.59E-3 t/t	DOE (1983)	5
ANFO	1.43E-4 t/t	DOE (1983)	5

Notes:

1. DOE (1983) information is based on information for one USA western region surface coal mine with the following operational characteristics: capacity =8.8E6 t/year (raw coal mined); production = 7.92E6 t/year (clean coal); efficiency =90% (on weight basis; or on energy basis if mined material assumed for notational simplicity to have same energy content as prepared coal); lifetime= 40 years; capacity factor =85-90% (apx.); coal characteristics: not specified.

2. CO_2 data derived by SEI-B from total fuel consumption quoted in DOE (1983) for drill rigs, bulldozers, scrapers, trucks and front-end loaders. Based on default EDB coefficient for generic heavy trucks using diesel — 86.5% C by weight, 99% of carbon oxidized during combustion, and CO_2/C molecular weight ratio(44/12), less C as CO: (0.865 * .99 * 44/12) - (0.0268 * 44/28) — the CO_2 emissions factor is 3.10 tonnes per tonne diesel consumed. Hence, CO_2 mining emission factor is: 3.1 x 1.593E-3 = 4.94E-3 t CO2/tonne coal produced. This figure is likely to be an underestimate of total mining CO_2 loadings because it ignores any non-fuel emissions (e.g. from the ammonium nitrate/fuel oil mixture used for blasting, from any soil carbon release caused by the mining land disturbance, and from any long-term biomass loss—for example, if a wooded area is mined and then, after reclamation

replaced by agricultural land). CO_2 releases from the mines themselves are not documented are therefore assumed to be insignificant.

3. CH_4 emissions depend on age, depth, structure of coal bed, mining technique, rank and quality of coal. Emissions increase with the depth of the mine, the rank of the coal and the carbon content of the coal. Surface mines emit much less methane than underground mines (due to lower methane content of the coal). Most of methane is released by the pressure drop as mined coal is exposed. Most of the remaining methane is released when the coal is cleaned, crushed and prepared. Little methane remains in prepared coal. Methane is normally mixed with air and vented for safety reasons. In some underground mines, methane is recovered and either vented or used as fuel. DeLuchi (1993) estimates that by 2005, up to 5% of methane may be vented and 5% used as in-mine fuel. Methane emissions can be higher than methane content of coal, since mining only recovers part of coal reserves, but leads to nearly all of stored methane being released. The IPCC (1994) suggests low and high emission factors of $0.3m^3/t$ and $2.0m^3/t$ respectively for surface mines (compared to values of $10m^3/t$ and $25.0m^3/t$ respectively for underground mines).

4. From DOE definition, solid waste is the total material mined that is not usable coal, defined as (1-mine efficiency). This material is returned as backfill as the mined are is reclaimed. This fraction (0.11) appears to conflict slightly with quoted efficiency of 90%.

5. Auxiliary fuel inputs (electricity, fuel and blasting compound) do <u>not</u> contribute to the overall energy efficiency of the mining process. Mining emission factors include the emissions from the use of these additional fuel inputs. Electricity is used in the preparation plant. All fuel use is assumed to diesel. ANFO blasting compound used to loosen overburden and coal. NB: loadings do not include data on emissions from combustion of this compound.

7. According to DeLuchi (1993) “less than 1% of energy available in the coal” is used to mine and prepare it.

7.1.2 Underground Mining

Two techniques are available for underground coal mining: room and pillar or long-wall. The following fact sheet is based largely on information for one USA eastern surface coal mine (source: DOE, 83), with additional data derived from first principles or drawn from international sources. The environmental loadings include a coal preparation plant and water spray dust control for the mine, preparation plant, roads and coal storage piles. The mine also includes on-site solid waste disposal and on-site water treatment and recycling to minimize discharges and water makeup requirements.

Table 7.3: Loadings and Direct Impacts			
Loading/Impact	**per tonne of coal produced**	**Reference:**	**See note:**
Air Emissions			
CO2	5.71E-4 t/t	SEI-B derived from DOE (1983)	2
CO	2.16E-6 t/t	DOE (1983)	
Hydrocarbons	5.41E-7 t/t	DOE (1983)	
CH4	low: 1.00E+1m^3/t high: 2.50E+1m^3/t	IPCC (1994)	
NO_x	8.38E-6 t/t	DOE (1983)	
SO_x	8.11E-7 t/t	DOE (1983)	As SO_2
Particulates	6.37E-7 t/t	DOE (1983)	
Fugitive Dust	negligible	DOE (1983)	
Solid Wastes			
Total Solid Waste	3.93E-1 t/t	DOE (1983)	
Occupational Health & Safety			
Deaths	4.49E-7 Deaths/t	DOE (1983)	
Injuries	7.12E-5 Injuries/t	DOE (1983)	

Table 7.4: Additional Fuel Use and Other Inputs			
Input	**per tonne coal produced**	**Reference:**	**See note:**
Fuels			
Electricity	5.77E+1 kWh/t	DOE (1983)	3
Fuel (Diesel)	1.84E-4 t/t	DOE (1983)	3

Notes:

1. DOE (1983) information is based on information for one USA eastern region surface coal mine with the following operational characteristics: capacity =1.40E6 t/year (raw coal mined); production = 1.02E6 t/year (washed coal); efficiency =72.9% (on weight basis); lifetime= 23 years; capacity factor =60-85%; coal characteristics: bituminous.

2. CO_2 data derived by SEI-B from total fuel consumption quoted in DOE (1983) for mine and preparation plant mechanical equipment. Total diesel use = 1.84E-4 tonnes. Based on EDB generic diesel trucks emissions factor for CO2 of 3.10 t/t diesel consumed: CO2 emission factor is: 3.1 x 1.84E-4 = 5.71E-4 t CO2/t coal produced. This figure ignores any non-fuel emissions.

3. Additional fuel inputs (electricity, fuel and blasting compound) do <u>not</u> contribute to the overall energy efficiency of the mining process. Mining emission factors include the emissions from the use of these additional fuel inputs. Electricity is used in the preparation plant.

7.2 Beneficiation

The following fact sheet is based on DOE (1983) information for wet circuit beneficiation, with additional data derived from first principles, or drawn from international sources. Beneficiation is used to remove ash and sulfur and improve the energy content of coal using crushers, screens, rotary breakers, jigs, thickeners, concentration tables, flotation circuits and thermal drying. It is capable of removing up to 40%-50% of sulfur and 65%-75% of ash. It does not involve any chemical separation of sulfur. The amount of pollutant loadings depend on the amount and type of coal processed and the size to which the coal must be prepared.

Table 7.5: Loadings and Direct Impacts			
Loading/Impact	**per tonne of coal produced**	**Reference:**	**See note:**
Air Emissions			
CO2	1.368E-3 t/t	SEI-B	2
CO	5.49E-6 t/t	DOE (1983)	
Hydrocarbons	5.49E-7 t/t	DOE (1983)	
CH4	Underground coal: low: 0.90E+0m³/t high: 4.00E+0m³/t Surface coal: low: 0.00E+0m³/t high: 0.20E+0m³/t	IPCC (1994)	3
NO_x	1.65E-5 t/t	DOE (1983)	
SO_x	1.10E-7 t/t	DOE (1983)	As SO_2
Particulates	2.19E-5 t/t	DOE (1983)	
Solid Wastes			
Total Solid Waste	4.22E-1 t/t	DOE (1983)	
Water Effluents			
Total dissolved solids	9.06E-4 t/t	DOE (1983)	
Iron	1.65E-7 t/t	DOE (1983)	
Manganese	8.24E-7 t/t	DOE (1983)	
Aluminium	1.10E-6 t/t	DOE (1983)	
Zinc	1.10E-7 t/t	DOE (1983)	
Nickel	8.24E-8 t/t	DOE (1983)	
Total suspended solids	1.65E-5 t/t	DOE (1983)	
Iron	1.65E-6 t/t	DOE (1983)	
Ammonia	1.10E-6 t/t	DOE (1983)	
Sulfates	4.95E-4 t/t	DOE (1983)	
Occupational Health & Safety			
Deaths	2.00E-7 Deaths/t	UNEP (1979)	
Injuries	1.3E-6 Injuries/t	UNEP (1979)	

Table 7.6: Auxilliary Fuel Use			
Input	**per tonne coal produced**	**Reference:**	**See note:**
Fuels			
Electricity	6.04E+0 kWh/t	DOE (1983)	4
Fuel	4.50E-4 t/t (assumed to be fuel oil)	DOE (1983)	4

Notes:

1. Operational characteristics: capacity =2.6E6 t/year (run of mine coal inputs); production = 1.82E6 t/year (prepared coal); efficiency =70.2% on weight basis or 87.5% on energy basis; lifetime= 20 years; capacity factor = 83% (230 days/yr); coal characteristics: not specified.

2. CO_2 data derived by SEI-B from total fuel consumption quoted in DOE (1983) for plant equipment. Based on EDB emissions factor for generic industrial fuel oil engines for CO_2 of 3.04 t/t oil consumed: CO2 emission factor is: 3.04 x 4.50E-4 = 1.368E-3 t CO2/t coal produced. Ignores any non-combustion emissions.

3. Includes all post-mining activities. Necessary to distinguish between coal from surface and underground coal because of their different methane contents. Little methane remains in prepared coal.

4. According to UNEP (1979), most air pollution arises from the use of burning coal to produce hot combustion gases to dry coal (dust, NO_x, SO_x etc.) No coal use is specified in the DOE (1983) data. Furthermore, it is not clear how the efficiency term is defined: is it (1) energy content of clean vs. run-of-mine coal, or (2) does it include the own-use of coal for drying.

7.3 Transport

The following description of the impacts of coal transport stage are based on energy intensities contained in DeLuchi (1993). Emissions data are taken from DOE (1983) data and are also derived from first principles.

Table 7.7: Loadings and Direct Impacts

Loading/Impact	per tonne-km of coal transported	Reference:	See note:
Air Emissions			
Rail (diesel - from western coal unit train)			
CO2	1.42E-5 t/t-km	SEI-B	
CO	7.71E-8 t/t-km	DOE (1983)	2
Hydrocarbons	6.08E-8 t/t-km	DOE (1983)	2
Aldehydes	1.30E-8 t/t-km	DOE (1983)	2
NO_x	7.38E-8 t/t-km	DOE (1983)	2
SO_x	8.69E-8 t/t-km	DOE (1983)	2
Particulates	2.34E-6 t/t-km	DOE (1983)	2
Road (diesel)2			
CO2	1.09E-4 t/t-km	SEI-B	
CO	5.89E-8 t/t-km	DOE (1983)	2
Hydrocarbons	9.39E-9 t/t-km	DOE (1983)	2
Aldehydes	4.27E-10 t/t-km	DOE (1983)	2
NO_x	3.72E-8 t/t-km	DOE (1983)	2
SO_x	5.97E-9 t/t-km	DOE (1983)	2
Particulates (TSP)	6.99E-7 t/t-km	DOE (1983)	2

Table 7.7: Fuel Use			
Mode	**Amount/Unit (tonne-km)**	**Reference:**	**See note:**
Rail	4.58E-6 t/t-km (diesel) = 0.195 MJ/t-km	DeLuchi (1993)	4
	0.322 MJ/t-km	SEI-B	4 UNEP-US study
	0.248 MJ/t-km	US-DOE(1983)	4
Road	3.51E-5 t/t-km (diesel) = 1.495 MJ/t-km	DeLuchi (1993)	5
	2.04 MJ/t-km	SEI-B	5 UNEP-US study

Notes:

1. Emissions data are calculated per tonne-km of coal delivered. In most cases they purport to include combustion and fugitive emissions. An alternative approach would be to use standard transport emissions factors for different transport modes (rail, road, water) and estimate the fugitive emissions separately.
2. Average emissions quoted in DOE (1983) for Eastern and Western coal unit trains (i.e. trains devoted solely to coal transport). This data appears to include emissions from the fuel used in trains as well as fugitive emissions.
3. Taken from DOE (1983) for eastern coal transport by truck. This data appears to include emissions from the fuel used in trucks as well as fugitive emissions.
4. DeLuchi also quotes comparisons three other studies with ranges between 348 and 791 Btu/ton-mile.
5. DeLuchi also quotes comparisons with US-DOE(1983) and 3 other studies with ranges between 1342 and 2800 Btu/ton-mile.

7.4 Electricity Generation

This section describes electricity generation from coal. The environmental impacts of thermal power generation include air emissions of pollutants, including SOx, NOx, CO2 and hydrocarbons, and thermal pollution caused by discharges of cooling water. Other impacts include the occupational health and safety risks to personnel. Information is based on emissions factors contained in EDB, DOE(1983) and other sources.

EDB (SEI-B, 88-94) currently contains detailed emissions coefficients for the following technologies and coefficients, as well as average emissions coefficients for a range of more aggregate existing and candidate future plant types in the US.

Table 7.8: Technologies:	Non-zero Effects
1. Steam-Bituminous Coal Plants	
atmospheric fluidized bed * no ec	CO_2, HCs, CH_4, NO_x, SO_x
fluidized bed boiler	CO_2, CO, CH_4, NO_x
cyclone furnace * pulverized bitum * no ec	CO_2, CO, HC, CH_4, Pb, NO_x, SO_x, Partic, <10ug
us * electrostatic precipitator and sox scrubber	CO_2, CO, HC, PB, NO_x, SO_x, Partic
cyclone boiler * pulverized bitum	CO_2, CO, CH_4, NO_x
dry-bottom boiler * pulverized bitum * no ec	CO_2, CO, Pb, NO_x, SO_x, Partic, <10ug
dry-bottom tangentially fired boiler * pulverized bitum	CO_2, CO, HC, NO_x, SO_x, Partic, <10
wall-fired boiler * pulverized bitum * no ec	CO_2, CO, CH_4, NO_x
wall-fired boiler * pulverized bitum * low nox burner	CO_2, CO, CH_4, NO_x
tangentially fired * pulverized bitum	CO_2, CO, CH_4, NO_x
wet-bottom boiler * pulverized bitum * no ec	CO_2, CO, HC, Pb, NO_x, SO_x, Partic, <10
spreader-stoker boiler	CO_2, CO, HC, CH_4, Pb, NO_x, SO_x, Partic, <10
spreader-stoker boiler * no ec	CO_2
traveling grate (overfeed) stoker boiler * no ec	CO_2, CO, HC, Pb, NO_x, SO_x, Partic, <10
2. Coal - Combined Cycle	
Fluidized Bed	CO_2, CO, CH_4, NO_x
Fluidized bed * selective catalytic reduction	CO_2, CO, CH_4, NO_x

Sources: US EPA (AP-42/NEDS) 1989 , SEI-B, US EPA (ASF) 1989, DOE (1983), 1983

Table 7.9: Power Plant Construction Materials			
Material	**Amount/Unit**	**Reference:**	**Note:**
Concrete	1.374E2 t/MW	DOE (1983)	1
Steel (carbon + alloy + stainless)	4.01E+1 t/MW	DOE (1983)	
Aluminum	3.48E-1 t/MWe	DOE (1983)	
Copper	1.14E+0 t/MWe	DOE (1983)	
Manganese	2.94E-1 t/MWe	DOE (1983)	
Cast iron	5.22E-1 t/MWe	DOE (1983)	
Chromium	1.76E-1 t/MWe	DOE (1983)	
Nickel	2.8E-2 t/MWe	DOE (1983)	

Notes:
1. Denominator is plant capacity (500MWe).

8. NATURAL GAS FUEL CHAIN FACT SHEETS

Although historically overshadowed by oil and coal, there are a number of reasons why natural gas likely to grow in relative importance over the next couple of decades, in terms of both absolute share of primary energy supplies and percentage growth. One reason is that while natural gas is more difficult to transport than coal or oil, commercial natural gas deposits are distributed more evenly throughout the world than the other main fossil fuels. By 1987 eighty-five countries claimed to possess commercially exploitable natural gas reserves (OTA, 1992). For some countries striving to reduce energy imports, due to either security or economic reasons, natural gas can offer a domestic alternative.

Other advantages are that natural gas technologies, in particular those for the generation of electricity, have become the most efficient, least costly, and “cleanest” fossil fuel options available. In other end uses, such as transportation, natural gas also offers the promise of being a relatively “clean” alternative.

While proven natural gas reserves are smaller than proven oil reserves on an absolute energy basis (natural gas 4.2 million PJ, oil 5.2 million PJ), proven natural gas reserves are expected to last longer based on 1989 rates of consumption (Natural Gas 60 years, Oil 40 years)(WRI, 1992:p. 148). If natural gas consumption rates increase significantly, the expected lifetime of proven reserves will decline, but at the same time further exploration may add to the estimated resource.

Energy policy makers may thus wish to consider the development of natural gas for economic, environmental and national security reasons. The exploitation of natural gas resources requires the development of a supporting infrastructure, commonly based on pipelines, or possibly on electric transmission grids, if generating stations are located near the natural gas fields. A fuel chain analysis can help to inform an analysis of the costs and benefits of investing in the development of natural gas resources, by further clarifying the upstream environmental impacts associated with the exploitation of natural gas, and providing mechanism for comparing these to impacts from alternative fuel chains.

8.1 Natural Gas Recovery

Natural gas is a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in porous geologic formations beneath the earth’s surface. The chemical composition of natural gas varies from site to site. The principal component of natural gas is methane (CH4) often representing between 70% and 95% of the raw mix (Baumeister and Marks, 1967).

The non-energy uses of natural gas include the production of ammonia, which is used as a source of nitrogen in the production of fertilizers, and as a secondary feedstock for manufacturing other chemicals including nitric acid and urea. Natural gas is also used to produce ethylene, a important base material for the production of a number of plastics.

Natural gas is often, but not always, recovered in association with crude oil. The percentage of natural gas recovered in association with crude production varies from site to site, dependent upon geology, the economics of recovery, and the supporting infrastructure. For example, in the United States, where the natural gas market and infrastructure are well developed, less than one fourth of all gas is produced in association with crude oil (EIA Natural Gas Annual 1990; as cited in DeLuchi, 1993). In Venezuela, on the other hand, in 1987 97% of the gas produced is associated with the production of crude oil, and 31% of the total was into wells to improve crude oil production and for future use (CEPET, 1992: 3-383).

Whether or not natural gas and oil are co-produced, similar drilling technologies are used to drill and develop well sites. Therefore, many crude oil recovery impacts are applicable to the recovery of natural gas.

Although it may still require assistance, natural gas tends to flow to the surface more readily than crude oil, so less process energy and equipment are required to lift natural gas from the earth. Emissions from the operational phase of natural gas recovery are therefore more closely related to possible fugitive emissions than to combustion emissions from process energy use. It is generally assumed that flaring and venting does not occur at commercially productive natural gas sites, and that flaring and venting emissions should be assigned to the production of petroleum products.

Natural gas fields may contain CO_2 that is either reinjected into the field, or vented to the atmosphere. If CO_2 is vented, this emission should be attributed to the natural gas fuel cycle.

Based on data gathered by the U.S. Minerals Management Service, DeLuchi (1993: Appendix M.3.1) concludes that venting and flaring emissions from the United States gas industry are negligible in comparison (respectively) to system leakages and the combustion emissions from the use of natural gas as a process fuel.

DeLuchi notes that earlier estimates of flaring and venting equal to 3% to 4% of gross production may be as much as an order of magnitude too high for the U.S. system (DeLuchi, 1993: M-15). The higher estimates, based on records of unaccounted-for gas, assumed all unaccounted-for gas was leaked, when in fact measurement and accounting discrepancies (for over a quarter of a million wells) were likely to represent a large share of the unaccounted-for total. Unaccounted-for gas is more accurately described as a balancing category, rather than a category representing physical losses, illustrated by the fact that in 1988 the amount of unaccounted-for gas was negative 0.4%. The American Gas Association (Mercado, 1993) used the same argument to counter claims made in an environmental critique of natural gas published by Lazarus et. al. (1992).

Barns and Edmonds (1990) cite a study by the American Petroleum Institute that included an inventory of twenty one production and processing sites. The estimated range of natural gas losses, from production and processing sites combined, was 0.25% to 2.0%. Based on this Barns and Edmonds selected a value of 0.5% of total production, and assign this value to both United States and global production.

For fugitive and other routine maintenance emissions from gas production, not including venting and flaring, the IPCC (1994) estimates a range of 46 to 96 tonnes of methane/PJ of gas produced. The average of 71 tonnes methane/PJ gas produced roughly consistent with the other estimates reported in Table 8.1

Table 8.1 summarizes estimates of air emissions from the recovery stage of the natural gas fuel cycle.

Table 8.1 Air Emissions from Natural Gas Recovery kg/000 cubic meters natural gas recovered							**Reference:**	**See Note:**
CO2	CO	NOx	SOx	HC	PM	CH4		
1.07E+02	6.08E-02	2.71E+00	4.58E+01	1.92E-02	6.08E-02	3.17E-01	USDOE (1983)	
na	na	na	na	na	na	2.18E+00	Lazarus et. al. (1992)	
na	na	na	na	na	na	3.45E+01	IPCC (1994)	1
9.40E+01	3.79E-01	1.09E-01	na	1.71E-02	na	4.31E+00	DeLuchi (1994)	2
na	na	na	na	na	na	2.46E+00	EPA (1993)	3
na	na	na	na	na	na	1.45E-03	CORPOVEN Data Report (1994)	4

Notes:
1. IPCC (1994) Average of Emission Ranges Reported for Other Oil Exporting Countries (Fugitive Emissions Only)
2. DeLuchi (1994), adjusted by own use factor of 1.092. Additional own use of 1.027 to be applied to transportation end-uses.
3. Total for estimated combustion and fugitive emissions in 1990.
4. Emissions from Santa Rosa Production Camp

8.2 Natural Gas Purification

In addition to methane, raw natural gas usually contains recoverable natural gas liquids as well as contaminants such as water, hydrogen sulfide, carbon dioxide, and nitrogen. The natural gas liquids are commonly condensed, collected and sold separately from the natural gas, since these have a higher value as individual fuels.

At the well site raw natural gas is usually passed through field separators to remove hydrocarbon condensate and water. The two major components of the purification process are dehydration and desulfurization. Natural gas is considered to be “sour” when it has a sulfur content so high as to make it impractical to use without purification, due to its corrosive effect on piping and other equipment. Major pieces of equipment used to purify gas are heaters, condensers, pumps and compressors. Occasionally the raw natural gas mix recovered does not contain significant water or hydrogen sulfide (“dry” or “sweet” natural gas) and it therefore does not require further purification.

Additional processing, at a natural gas plant is needed to recover natural gasoline, butane, and propane and ethane, and other condensable constituents. The major sources for air emissions from natural gas processing facilities are combustion emissions from compressor engines and acid gas wastes from gas sweetening plants. If the waste gas is flared or vented the major pollutant of concern is sulfur dioxides (USEPA, 1993 b). Often, however, waste gas is processed by commercial sulfuric acid plants, or sulfur recovery plants. In addition to combustion emissions, processed and unprocessed gas may also be intentionally vented or leaked at processing plants.

Table 8.2 presents estimates of emissions from the processing stage of the natural gas fuel cycle.

Table 8.2 Air Emissions from Natural Gas Processing kg/000 cubic meters natural gas processed							Reference:	See Note:
CO2	CO	NOx	SOx	HC	PM	CH4		
na	na	na	na	na	na	4.20E-01	EPA (1993)	1
9.25E+00	2.21E-02	1.40E-01	na	3.60E-03	na	2.75E-03	Lazarus et. al. (1992)	2
4.82E+01	1.39E-02	5.58E-02	na	na	na	3.49E-03	DeLuchi (1994)	
na	1.15E-04	1.31E+00	1.73E-04	1.15E-02	5.19E-03	na	DOE (1983)	3

Notes:
1. Total for estimated combustion and fugitive.
2. Assuming Losses of 0.5%.
3. Energy Technologies Handbook. Estimates for reference natural gas purification plant.

8.3 Natural Gas Transmission and Distribution

Pipelines are the most common mode used to transport natural gas from well sites and processing plants to end users. Emissions sources for this stage of the fuel cycle are the internal combustion or turbine engines used to drive the compressors that push the gas through the pipeline, leaks, and intentional venting for maintenance.

Modern pipeline technologies include the use of continuous welded steel transmission pipelines, and polyethylene distribution piping. These can reduce fugitive emissions to trivial levels. However, in many areas of the world older pipeline networks, especially those in bad repair, can be the source of much higher emissions. In Venezuela, replacing the gas distribution system in the Lake Maracaibo region is one of the countries most cost-effective strategies to control greenhouse gas emissions (Risø, 1994). In addition to being a large source of methane emissions over the years, leakage from the Maracaibo system was also a potential safety hazard.

The routine storage of gas products results in relatively minor fugitive emissions, although there is a potential for accidental emissions or explosions.

Table 8.3 presents estimated air emissions for the transmission and distribution stage of the natural gas fuel cycle.

Table 8.3 Air Emissions from Natural Gas Transmission and Distribution kg/per 000 cubic meters natural gas input to T&D system							Reference:	See Note:
CO2	CO	NO_x	SO_x	HC	PM	CH_4		
na	na	na	na	na	na	7.20E+00	IPCC (1994)	1
na	na	na	na	na	na	3.38E+00	EPA (1993)	2
na	na	na	na	na	na	8.58E+00	Lazarus et. al. (1992)	3
8.03E+01	2.32E-01	5.00E-01	na	2.85E-02	na	3.68E-01	DeLuchi (1994)	
na	na	na	na	na	na	9.65E+00	SEI-B (1990)	3
na	na	na	na	na	na	9.18E+00	Barns and Edmonds (1990)	3
na	4.60E-02	1.21E-01	2.00E-04	8.40E-03	na	na	DOE (1983)	4
na	na	na	na	na	na	5.15 E+0	Corpoven (1994)	5

Notes:
1. Average of emissions reported for Other Oil Exporting Countries, including natural gas processing. Fugitive emissions only.
2. Total of estimated combustion and fugitive emissions in 1990.
3. Assuming losses of 1.5%.
4. Energy Technologies Handbook. Estimates for reference natural gas transmission pipeline.
5. Estimated Emissions for the Anaco-Barquiemeto pipeline system.

8.4 End Uses

Unless there are high leakage rates from gas transmission and distribution systems, the end use stage is likely to account for the majority of the air emissions from the natural gas fuel cycle. The environmental advantages of natural gas over coal and oil are most pronounced at the end use stage. Natural gas produces virtually no particulates or sulfur dioxide when burned, and less NOx or CO_2 than either of the other fossil fuel alternatives. Tables 11.4 and 11.5 present end use emissions estimates for natural gas and residual fuel oil steam boiler electric generation technologies. Table 8.6 presents estimates for diesel and compressed natural gas fueled heavy duty vehicles.

Table 8.4 Air Emissions from Natural Gas Steam Electricity Generation (kg/tonne) fuel input							Reference:	Note:
CO_2	CO	NO_x	SO_x	HC	PM	CH_4		
1.86E+03	6.40E-01	8.80E+00	9.60E-03	2.24E-02	4.80E-02	na	USEPA (1989)	
1.85E+03	6.63E-01	8.82E+00	na	3.90E-03	na	2.35E-01	Lazarus et. al. (1992)	
1.98E+03	6.74E-01	9.47E+00	na	na	na	3.50E-03	IPCC (1994)	
na	na	4.06E+00	na	na	na	na	CADAFE (1994)	1

Notes:

1. Planta Centro Data Report

Table 8.5: Air Emissions from Residual Fuel Oil Steam Electricity Generation (kg/tonne) fuel input

							Reference:	Note:
CO_2	CO	NO_x	SO_x	HC	PM	CH_4		
3.06E+03	6.31E-01	8.45E+00	2.01E+01	9.59E-02	1.64E+00	na	USEPA (1989)	
3.06E+03	6.10E-01	8.46E+02	na	2.11E-01	na	3.05E-02	Lazarus et. al. (1992)	
3.08E+03	6.03E-01	8.07E+00	na	na	na	2.81E-02	IPCC (1994)	
3.03E+03	na	5.14E+00	1.93E+01	na	1.61E+00	na	Pace (1990)	
na	na	5.80E+00	3.65E+01	na	6.05E-01	na	CADAFE (1994)	1
na	1.31E+00	1.45E+00	3.34E+00	na	1.45E-01	na	CADAFE (1994)	2

Notes:
1. Planta Centro Data Report.
2. Planta Centro Technical Report.

Table 8.6: Emissions from Diesel and CNG Heavy Duty Vehicles grams/mile

						Reference:
Diesel						
CO2	CO	NOx	HC	PM	CH4	
1.65E+03	1.08E+01	8.05E+00	2.05E+00	na	1.00E-01	DeLuchi (1994)
na	7.93E+00	1.10E+01	2.39E+00	na	na	Guensler et. al (1991), USEPA
na	7.93E+00	1.27E+01	3.36E+00	1.11E+00	na	Guensler et. al (1991), CARB
1.80E+02	5.19E+01	2.61E+01	3.35E+00	na	na	EDB, Diesel Bus Avg. U.S.
CNG						
1.46E+03	7.00E+00	8.05E+00	6.00E-01	na	1.20E+00	DeLuchi (1994)
6.12E+02	6.50E+00	5.90E+00	2.30E+00	na	na	USEPA (1990)

8.5 Pre and Post Operational Impacts

In comparison to the operational phases of the natural gas fuel cycle, the pre and post operational phases will probably produce negligible emissions. Compared to oil, it is likely that the environmental impacts of developing natural gas production sites, and eventually decommissioning the equipment used to produce, process and deliver natural gas will be approximately similar to, or less than, the pre and post operational impacts of the petroleum products fuel cycle. The natural gas fuel cycle is also likely to compare favorably in terms of pre and post operational impacts with the coal fuel cycle.

9. THE PETROLEUM PRODUCTS FUEL CHAIN

Petroleum based energy products, derived from crude oil, are the predominant source of commercial energy in the world. In 1991 petroleum products accounted for approximately 45% of worldwide total final energy consumption (IEA, 1993). The petroleum industry is one of the largest industries in the world, dominated by large multi-national corporations, and state owned enterprises. Petroleum products are a critical input to modern economies, and as a result, establishing and maintaining a reliable supply of crude oil and refined petroleum products has been a consistent, although occasionally elusive, foreign policy objective for most nations since the early part of this century. Globally, proven commercial reserves of oil are estimated to be equal to 40 years of consumption at 1989 levels (WRI, 1992: Table 10.2).

Petroleum fuel combustion, and the petroleum industry are also significant sources of global and local environmental impacts. Estimates of global CO_2 emissions from fossil fuel combustion indicate that since the late 1960's liquid fuels have been responsible for more carbon emissions than either solid or gaseous fuels (ORNL, 1989 /CDIAC-25, Figure 1, p.8). Increased international transportation of petroleum products has resulted in large marine spills. The combustion of petroleum fuels for transportation is an important factor contributing to air pollution problems in many metropolitan areas. As a result, environmental concerns are playing an increasingly visible role, in determining policies for the development and use of petroleum resources.

The petroleum products fuel cycle consists of five operational stages. The first is crude oil recovery. Crude oil transport, from the recovery site to a refinery is the second stage. The third operational stage in the fuel cycle is refining. Petroleum product distribution is the fourth stage, and end use is the fifth stage. In addition, there are pre and post operational fuel cycle stages. Pre-operational stages include exploration, drilling and well development, as well as refinery and pipeline construction. Post-operational stages include the decommissioning and disposal of facilities utilized in the fuel chain.

This chapter covers each operational fuel cycle stage individually. Each section begins with a descriptive overview of the stage, followed by a discussion of environmental impacts and energy use.

9.1 Crude Oil Recovery

Crude oil is a liquid mixture consisting of hydrocarbons and relatively small amounts of sulfur, nitrogen and oxygen. It is found in porous geologic formations beneath the earth's surface. Natural gas deposits are often associated with crude oil. Comprised of a large number hydrocarbon compounds, crude oil is the basic feedstock for the variety of energy and non-energy products produced by the petroleum industry. Recovered crude can vary a great deal in terms of physical characteristics and chemical composition, and the unique composition of each crude plays a part in determining how it can be used and its market value.

Oil wells are located onshore and offshore. The majority of commercial oil recovery has been concentrated in a relatively small number of large deposits. The 300 largest oil fields in the world contain about three fourths of the total discovered resource. Offshore recovery, or recovery from remote sites on land, is likely to be much more energy intensive than recovery from an average onshore well. A number of techniques are used to recover crude oil. The techniques employed at a particular site depend on a number of factors including, the physical properties of the crude, the length of time the site has been producing, the location and geology of the reservoir, market and general economic conditions, and the availability of specific technologies and infrastructure.

Crude recovery methods are generally classified into three categories: primary, secondary and tertiary recovery. Primary recovery techniques use pumps to draw oil from the ground. As the reserves in an oil field become depleted, or if the crude is viscous, additional means, such as the injection of water, gas, or steam into the oil field can be used to increase the flow of oil. These methods, called secondary and tertiary (steam injection) recovery, consume more energy per unit of crude oil recovered than primary recovery techniques. Most fields will only yield one fourth to one third of their oil through primary recovery techniques, depending upon rock porosity and the viscosity of the petroleum. Based on data collected in Alaska and the lower continental United States, DeLuchi (1993) estimates that approximately six times more energy is required to reinject a standard cubic foot of natural gas than to recover a standard cubic foot of gas to be marketed.

Some types of crude oil have high sulfur or water content. These oils need to be processed before transport to prevent the rapid corrosion of transportation equipment. Any gathering and pre-transportation processing of the crude feedstock should be included in the crude oil recovery stage of a fuel cycle analysis if data are available.

Finding and developing productive oil reserves is a risky and expensive business. In the late 1970's approximately one in ten exploratory oil wells resulted in the discovery of sufficient resources to justify production (Ecoscience, 1977 p. 413). Since that time, improvements in exploration and drilling technologies, such as remote sensing, seismic exploration, and horizontal drilling techniques have increased average success rates, but many "dry holes" are still drilled. Theoretically, the environmental impacts of developing both the productive and non-productive wells should be included in a fuel cycle analysis of petroleum products, but the data may be lacking.

Oil exploration and development often occurs in remote or pristine environments, and recovery may therefore require the construction of roads, pipelines, and other supporting infrastructure. These activities can have a range of adverse impacts on local wildlife, or on indigenous human populations. Possibilities include: deforestation; loss of species and/or habitats; contamination of ground or surface water; combustion or fugitive air emissions; the disturbance of wildlife migratory patterns; and damage to aquatic or terrestrial ecosystems that support the hunting, fishing or agriculture activities of indigenous populations. The type and scale of these impacts is difficult to generalize. Examples of regions that were relatively "undisturbed" prior to the development of oil resources include the north slope of Alaska, and the Ecuadorian Amazon (Kimerling et al., 1991) and (Friends of the Earth, 1994). This report does not consider the valuation of environmental impacts, but we note that impact valuation in remote settings can be particularly difficult and controversial.

Historically, the development of petroleum resources has tended to occur in boom and bust social-economic cycles. "Boom-town" development is often characterized by extremely rapid infrastructure development, weak or non-existent environmental, regulatory, or judicial guidelines, the availability of fortunes for those who are lucky and act quickly. Accompanied by uncertainty over how long resources and investments will be productive, these factors can combine to create a situation characterized by a high degree of environmental and social disruption.

Significant amounts of water are often used to create drilling muds which are injected into a drill hole to lubricate the drill bit and shaft and transport residue materials. Drilling mud water contains dissolved solids and a range of other contaminants depending on composition of the geologic materials overlying the crude reservoir. Drill cuttings are the materials removed from the well hole. The disposal of drilling muds or drill cuttings in aquatic environments can disrupt food chains and aquatic ecosystems by altering the physical or chemical characteristics of the water (UNEP, 1979). Drilling generally continues during the operational phase of an oil fields development, both to maintain production levels and to explore for further deposits.

The operation of oil wells requires the use of heavy duty pumps and compressors to raise oil from the ground and to inject water, steam, gases, or other materials into the well. Remote well platforms may also run diesel or gas powered generators to generate electricity used in operations. Heavy fuels, including crude, may also be combusted to heat and treat crude oil, removing water or sulfur prior to transportation from the production site. The combustion of fuel for all of these activities produce air emissions that depend upon the type of fuel used, and the type and condition of the combustion equipment. Citations for emissions factors for the types of heavy duty equipment typically employed at well sites can be found in several sources including (Radian, 1992), and (EPA, 1988).

When the sulfur content of crude oil is high, flaring or venting of hydrogen sulfide gas can produce significant air emissions at the recovery site. While sulfur recovered from crude treatment can be used for fertilizer production and other applications, venting and flaring of H_2S gas is most likely at remote or smaller fields, where the recovery of sulfur is not economically justified.

Natural gas found in conjunction with crude oil deposits is called associated natural gas. How associated natural gas is used is a significant factor in the estimation of the environmental impacts of a petroleum product fuel cycle. There are three common fates for associated natural gas. One is that it is used as an energy resource, either at the well site or by some other end use in the economy. The second is that the gas is re-injected into the oil well. Re-injection stores the gas for potential future use and it helps to maintain pressure in the oil field and facilitate the flow of crude. Third, if the natural gas is not marketed, used directly, or re-injected, it can be vented or flared. The air emissions from the flaring and venting of associated natural gas should be assigned to crude oil production rather than to natural gas production, because when gas can be used as a fuel or marketed, flaring and venting are unlikely.

Venting is the direct release of natural gas (the primary component of which is methane a potent greenhouse gas) to the atmosphere, or under water. Flaring refers to the controlled combustion of natural gas at the well site. Air emissions from flaring depend upon the combustion efficiency of the burners and the composition of the flared gas. Flaring generally results in much lower methane emissions than venting, but higher emissions of CO_2, NO_x and to a lesser degree N_20, CO and NMVOCs.

Estimates of venting and flaring are generally reported in terms of a percentage of gross gas production, rather than in relationship to total crude production. In countries where markets and supporting infrastructure for natural gas are established the amount of flared and vented natural gas may be less than 1% of total production, while on a global basis flaring and venting are more likely to account for approximately 5% of total production (DeLuchi, 1994, Wilson, 1990, and Barns and Edmonds, 1990). How much of the total is vented versus flared is rarely recorded, but several studies have used a mix of 20% vented and 80% flared as a rough approximation (Barns and Edmonds, 1990, and Wilson, 1990).

Although for accounting purposes, flared and vented gas are often treated equally, there are significant differences between the two when assessing the environmental impacts, such as contribution to global warming. Thermal oxidation is a simple and moderately priced means of destroying toxic materials in waste gas streams and lowering the radiative impact of methane streams by more than 91% (Picard and Sarkar, 1993: p. iii).

Water pollution at crude recovery sites can be caused by the disposal of water that comes from the well in association with the oil, or from the disposal or accidental leakage of hydrocarbons. Brine is often associated with the production of oil and gas. Separated brine can be re-injected into wells. The disposal or leakage of brine can alter salinity levels and may damage aquatic organisms and ecosystems, or contaminate aquifers used for domestic purposes or irrigation. Oil leaks and spills can also directly expose marine or freshwater ecosystems to hydrocarbons and other contaminants, although in terms of total tonnage, spills from production sites are relatively minor in comparison to other sources of direct hydrocarbon water emissions (see Table 9.2).

Oil and gas deposits underground can be under extreme pressure. A “blow-out” or “gusher” is the uncontrolled release of oil or gas from a production site. The quantities of oil or gas released in a blow-out can be significant and they may result in the direct pollution of aquatic or terrestrial ecosystems. The Ixtoc I blowout in the Gulf of Mexico in 1979 released an estimated 3 million barrels of oil over a period of many months.

Table 9.1 summarizes estimates of air emissions from the recovery stage of the petroleum products fuel chain.

Table 9.1 Air Emissions from Crude Recovery
kg/tonne crude recovered

CO_2	CO	NO_x	SO_x	HC	PM	CH_4	Reference:	Note:
2.56E+01	1.89E-02	7.05E-01	5.15E-01	4.01E-01	1.33E-01	2.09E-01	USDOE (1983)	1,2
na	na	na	na	na	na	3.58E+00	Lazarus et. al. (1992)	3
na	na	na	na	na	na	1.11E-01	IPCC (1994)	4
1.44E+02	1.48E+00	4.09E-01	na	5.31E-01	na	2.07E+00	DeLuchi (1994)	5
1.72E+01	na	na	na	na	na	1.40E+00	MEM (1994)	2,6

Notes:

1. DOE (1983) *Energy Technology Handbook;* p.106-107. Primary Crude Production Onshore, US mainland. Reference energy system is a 400 well field. 195 unproductive wells are plugged with cement. Gathering pipeline routes oil to field processing facility for gas-water-oil separation. Success ratio for exploration wells is 27.4% and for production wells, 67.2%.
2. The CO2 estimate is made according to IPCC (1994) methodology. Calculation based on 15.3 kg C/Gj of petroleum, 99.5% of C oxidized, and 44/12 molecular weight ratio of CO2/C. 1 bbl crude equals 0.136 tonnes.
3. Lazarus et. al. (1992) Table 4.5, p. 36., Oil Production, Latin America.
4. IPCC (1994) Reference Manual. Table I-47., p. 1.121. Average of range for other Oil Exporting Countries. Figures are for fugitive emissions only. Add flaring and venting.
5. Source, Data Sheet from M. DeLuchi, 7/29/94. Diesel feedstock recovery. Includes CO2 from oil wells and gas leaks and flares.
6. MEM (1993). 99.18% of associated gas in Barinas district is flared or vented. Gas production 6 mmpcd.

9.2 Crude Oil Transportation and Storage

Areas of crude oil production rarely coincide with areas of processing capacity and demand. Therefore, crude oil usually needs to be transported over significant distances. Pipelines and tankers are the predominant carriers of crude oil, with rail and trucks being less important. Marine tankers account for the bulk of international crude oil transportation, while domestic transport is more dependent on pipelines. Tankers are a more flexible investment, since they can carry oil on a number of routes, adapting to shifting demand and supply patterns. In contrast, the fixed capacity of an oil pipeline requires confidence in the long term production capacity of a specific region and the demand or processing capacity at the other end of the pipeline.

The construction of pipelines, and their presence in the environment, may alter the migration patterns of animal populations. For example, there was concern that the Alaska pipeline, connecting the north slope oil fields to the port of Valdez, a distance of several thousand kilometers, might disrupt the migration and mating behavior of large caribou herds.

The routine operation of tankers and pipelines produce combustion and fugitive air emissions of greenhouse gases and other air pollutants. The level and types of emissions depend upon the type of fuel and technologies employed. Fuel oil is the most common fuel for tankers. The pumps used to transport crude oil along pipelines can be powered by electricity, diesel engines, natural gas compressors, or dual fueled diesel/natural gas engines. Total air emissions from this stage are dependent on the distance over which the crude is transported, the volume transported, and the technologies employed.

Tankers release hydrocarbons to aquatic environments, both in the course of normal operations and in the event of accidental spills. Estimates of annual global hydrocarbon emissions into marine environments are presented in Table 9.2.

Table 9.2: Sources of Petroleum Hydrocarbons in the Marine Environment (million tons/year)

Source	Probable Range	Best Estimate
Natural Sources	0.03-2.5	0.25
Atmospheric Pollution	0.05-0.5	0.3
Marine Transportation	1.00-2.60	1.45
Offshore Oil Production	0.04-0.06	0.05
Municipal and industrial wastes, including runoff	0.59-3.21	1.18
Total	1.7-8.8	3.2

Source: Hollander (1992: p. 111)

Table 9.2 suggests that marine transportation is responsible for close to one half of total marine emissions, and that the transportation stage is a much larger source of direct emissions than the feedstock recovery stage. Further disaggregating marine transportation emissions, it appears that tanker spills account for between one quarter and one fifth of the total, while routine leakage and cleaning are responsible for a much greater share, equal to approximately 70% (Hollander, 1992). Measures employed to reduce routine emissions of hydrocarbons from marine transportation are the separation of ballast water from crude cargo tanks, and the use of crude, rather than water, to wash out cargo and storage tanks.

The crude transportation stage is likely to produce relatively minor amounts of solid wastes. One potential source of solid waste is sludge occasionally cleaned from tankers or storage facilities.

Although spills and accidents are responsible for a smaller share of total emissions than routine operations, they are more concentrated and therefore likely to cause relatively more severe environmental impacts. Double hulled vessels reduce the chances of large releases of oil in the event of a tanker grounding or collision. Oil spills from pipelines can impact both terrestrial and marine ecosystems.

Table 9.3 presents air emissions estimates for the crude transport stage.

Table 9.3 Air Emissions from Crude Transport kg/tonne crude transported							Reference:	Note:
CO2	CO	NOx	SOx	HC	PM	CH4		
9.48E+01	2.24E-01	5.63E-01	na	7.45E-02	na	1.04E-01	DeLuchi (1994)	1

Notes:
1. Data Sheet from M. DeLuchi, 7/29/94. Diesel feedstock transportation. Final figures based on average distance, and mix of pipeline and tanker transport of crude in the U.S. Corrected by own use factor of 1.05.

9.3 Petroleum Refining

The refining process transforms crude oil into the variety of petroleum products used by modern economies. Worldwide there are more than seven hundred oil refineries operating with a combined capacity of over 73 million barrels per day (Rhodes, 1993).

Refining is based on several major technologies, that can be roughly categorized into three types according to the manner in which hydrocarbon molecules are manipulated. These are, distillation (sorting the hydrocarbon molecules into various types), cracking (breaking the molecules apart), and reformulation (combining the molecules). A large number of processes are used to accomplish these basic tasks. The technologies and processes employed by a specific refinery depend upon a number of technical and economic factors, including the composition of the crude oil inputs, and the desired slate of petroleum product outputs. Because a wide range of technologies (including environmental control technologies) is employed to process and produce a heterogeneous mix of refinery inputs and outputs, “generic” refinery operations and emissions figures should be checked with facility specific data, whenever possible.

Refineries are often classified into three types, simple, complex and very complex. The driving force behind increasing the complexity of a refinery is produce higher value products. Simple refineries generally produce less gasoline (roughly 30%) and more lower value fuels, such as residual fuel oil, while a complex refinery produces relatively more gasoline (approximately 50% of total output), and less of the lower value fuels. Very complex refineries produce an even higher percentage of gasoline (65% or more) as well as specialized petrochemicals and lube oils (Leffler, 1985). As refineries become more complex they generally require more capital investment, more energy use, and more steps in the refining process. Depending upon the environmental control technologies installed, more complex refineries can produce more emissions per unit of product output than simpler refineries.

The construction of an oil refinery, like the construction of any major industrial facility, can have significant local environmental impacts, but in comparison to emissions from the operational phase of the fuel cycle stage, the pre-operational impacts are likely to be relatively minor.

Emissions from oil refineries depend upon a number of factors including the physical and chemical properties of the crude feedstock, the refining processes used, and the environmental control technologies employed. The impacts from refinery emissions range from slight nuisances to highly toxic.

Combustion and fugitive air emissions are produced at many individual points in the refining process. Distillation requires heating feedstocks to boil-off fractions and separate the individual crude constituents. As fractions are boiled-off evaporative emissions may occur depending upon the design of the fractionating tower. Catalytic and thermal cracking subject feed material to heat and pressure to break apart heavy gas-oil. This requires heating feedstocks and catalysts, the regeneration of catalytic materials, and additional distillation. Heaters, fractionators, and chillers are also used in reformulation and other processes conducted in complex refineries. Throughout a refinery pumps, powered by electricity or petroleum fuels, are used to transport feed materials, and processed products. Flaring, venting, and equipment leaks can also contribute fugitive emissions of methane and other greenhouse gases. Table 9.4 summarizes the principal sources of air emissions from oil refineries.

Table 9.4 Principal Sources of Refinery Air Emissions

	Emission Type				
Source	**PM**	**SO_2**	**CO**	**VOC**	**NO_x**
Boilers and Process Heaters		X	X		X
Compressor Engines		X	X	X	X
Vapor Recovery Systems and Flares		X	X	X	X
Vacuum Distillation Columns and Condensers				X	
Fluidized Catalytic Cracking Units (FCC units)	X	X	X	X	X
Coking Units	X	X	X	X	X
Sulfur Recovery Units		X	X		X
Waste Water Treatment Plants				X	
Storage Tanks				X	

Source: Bechtel Corp. as cited in *Oil and Gas Journal*, 11/29/93, p. 42.

Water pollution at refineries is usually related to process water use, stormwater runoff, or groundwater contamination from leaking storage tanks. Technologies to recycle, or treat process water, and to minimize the contamination of stormwater runoff and groundwater can be used to minimize these impacts.

Petroleum refining produces a large amount of oily sludges (sometimes referred to as K-wastes) that are a significant source of solid and liquid emissions. K-wastes contain a range of compounds that have been classified as hazardous according to U.S. environmental regulations, including benzo(a)pyrene, toluene, xylenes and cyanide (*Oil and Gas Journal*, 11/2/92, p.52) K-wastes generally must be managed to recover hydrocarbons and minimize risks posed to human health and the environment. The uncontrolled or untreated disposal of these wastes can lead to groundwater and soil contamination. Two technologies being promoted for the treatment of refinery K-wastes are thermal desorption, and bioremediation.

Catalysts used in refining processes are usually recycled a number of times but eventually they must be replaced. Spent catalysts, often contain heavy metals, such as cobalt, nickel and vanadium. Storing or disposing of these wastes without treatment can contaminate ground water and soils. Technologies for removing the hazardous or reactive compounds from the spent catalysts and stabilizing the remaining residues can be used to reduce the risks posed by these materials.

Accidents at refineries can cause injury or death to facility personnel, and result in uncontrolled emission of pollutants. However, for the industry as a whole, the total impact of routine emissions is likely to be more significant than emissions and impacts from non-routine events.
Table 9.5 presents a summary of quantitative impact estimates for the refining stage.

Table 9.5 Air Emissions from Refining
kg/tonne crude refined

CO_2	CO	NOx	SO^x	HC	PM	CH_4	Reference:	Note:
1.52E+02	1.72E-01	7.20E-01	8.40E-01	9.20E-01	na	8.87E-02	UNEP (1979)	1
1.82E+02	1.72E-01	7.20E-01	na	9.20E-01	na	1.20E-01	Lazarus et. al. (1992)	2
na	na	na	na	na	na	3.12E-02	IPCC (1994)	3
2.29E+02	5.38E-01	4.75E-01	na	2.95E-01	na	3.07E-01	DeLuchi (1994)	4
na	8.69E-02	5.21E-01	1.74E+00	5.21E-01	1.09E-01	5.21E-01	DeLuchi et al (1988)	5
na	1.14E+01	2.85E-01	5.47E-01	4.70E-01	2.03E-01	3.39E-04	CORPOVEN (1994)	6

Notes:
1. UNEP (1979) Fossil Fuels, page 37.
2. Lazarus et. al. (1992) Table 4.5, p. 36. Existing Refinery, efficiency 94%.
3. IPCC (1994) Reference Manual. Table I-47., p. 1.121. Other Oil Exporting Countries. Average of ranges presented is used for calculations. Figures are for fugitive emissions only. 745 kg methane/PJ refined, 23.88 kg/GJ crude oil.
4. Data Sheet from M. DeLuchi, 7/29/94. Diesel fuel production. Own use factor of 1.04.
5. DeLuchi et al. (1988). Fluidizied catalytic cracking unit with environmental control.
6. CORPOVEN (1994). El Palito Data Report, p. 10, Table 2 and p.3 annual inputs.

9.4 Product Transportation and Distribution

Processed petroleum products are transported from refineries to end users by a number of means, including tank trucks, pipelines, marine tankers, and rail cars. The energy use and emissions associated with this stage of the fuel cycle depend upon the distances to be covered and the technologies employed.

In comparison to the other stages of the petroleum products fuel cycle, impacts and emissions from product transportation and distribution are likely to be relatively minor. Evaporative and combustion air emissions can be released during product transport, transfer, and storage. Filling stations can be a significant source of volatile organic carbons (VOCs).

The potential for water and solid waste emissions from this stage are similar in type, although likely to be less severe, than those discussed for crude transportation and storage.

Table 9.6 presents a summary of air emissions estimates for the product distribution stage.

Table 9.6 Air Emissions for Petroleum Products Distribution kg/tonne products into distribution system							Reference:	Note:
CO_2	CO	NO_x	SO_x	HC	PM	CH_4		
na	na	na	na	5.00E+00	na	2.50E-01	Lazarus et. al. (1992)	1
5.32E+01	1.80E-01	2.38E-01	na	4.60E-02	na	5.02E-02	DeLuchi (1994)	2
na	na	na	na	4.83E+00	na	6.20E-02	EPA (1988)	3

Notes:
1. Lazarus et. al. (1992) Table 4.5, p. 36. Petroleum products transmission and distribution. Original emissions estimate stated in terms of per unit loss. Estimate stated here based on assumed losses of 0.5%.
2. Data Sheet from M. DeLuchi, 7/29/94. For diesel distribution, adjusted by own use factor of 1.04.
3. EPA (1988) Original emissions estimate stated in terms of per unit loss. Estimate stated here based on assumed losses of 0.5%.

9.5 End Uses

Petroleum products are primarily used as transportation fuels. The transportation sector represented almost 60% of the total final consumption of petroleum products in industrialized countries in 1990 (IEA, 1993). Although worldwide data are not available, the relative share of the transport sector is likely to be comparable, or even higher, in developing countries. A combination of economic, political, and environmental factors has led to an increasing interest in the development and use of alternative transportation fuels, including electricity, biomass derived fuels, and natural gas.

Petroleum products are also used as industrial fuels, as petrochemical feedstocks, as fuels for electric generation, for commercial and residential heating, and for agriculture. For most fuel cycles it is likely that environmental emissions and other impacts from the end-use stage will dominate upstream impacts. Therefore, carefully exploring the range of available end use technologies and their related impacts is an important component of any fuel cycle analysis. End use emissions estimates for natural gas and residual fuel oil steam electric generation technologies are presented in Tables 11.4 and 11.5. Table 8.6 presents emissions estimates for heavy duty vehicles powered by diesel and compressed natural gas.

9.6 Allocation of Fuel Cycle Impacts to End Products

There are a number of fuel and non-fuel outputs from the petroleum products fuel cycle. The emissions and impacts of the fuel cycle need to be allocated between these final products. This can be done according to the volumetric or energy content share of each product, but this simplification may over or under estimate the emissions of a specific product by a significant amount. On the other hand, the petroleum fuel cycle is so complex that a completely accurate allocation of emissions may not be feasible. In this section the problems with the volumetric and energy contents approach are briefly reviewed, and a “default” method for impact allocation is suggested.

There are two problems with allocating emissions based on share of total volume or energy content. First, refining requires different amounts of energy depending on the product. DeLuchi (1991) estimated that, at the refinery stage, the process energy requirements of gasoline can be four times higher than for residual fuel oil and diesel.[50]

Second, because the final products have different densities they require different amounts of feedstock. Proportionally more crude oil is required to produce a unit of residual fuel oil (density of 3575 gms/gal.) than to produce a unit of reformulated gasoline (density of 2749 gms/gal.).[51] To simplify these relationships a bit, gasoline, in comparison to diesel and residual fuel oil, tends to require less process energy in the feedstock production, feedstock transportation and product distribution stages, (due to its lower density), and more process energy in the refining stage. Note that these factors tend to be offsetting (i.e. gasoline is responsible for a relatively larger share of emissions from refining, but a relatively smaller share of total emissions from the other stages).

The preceding discussion suggests that estimating a "generic" set of fuel cycle emissions for all petroleum products entails some loss of accuracy. If it is necessary to apply one set of emissions factors to all types of petroleum products, the best choice is to choose a medium density, medium refined product. Diesel fuel is therefore a good choice, since in comparison to residual fuel oil and gasoline it represents the "middle ground". In the Venezuelan case study we make individual emissions estimates for residual fuel oil and diesel, and compare the two.

[50] See DeLuchi (1991), Volume II Appendices, Tables H-6 and H-7. The requirements for diesel are estimated to be higher than for residual fuel oil, by factors ranging from 1.06 to 1.46.
[51] DeLuchi (1991), Volume II Appendices, Table C-1.

10. MATERIALS PRODUCTION FACT SHEETS

The environmental loadings of materials production are only considered in this report in cases where the energy embodied in materials is likely to be a significant fraction (> 1%) of the energy throughput over the lifetime of the fuel chain. The energy embodied in materials is likely to be significant in only a few fuel chains. Examples include biomass fuel chains (due to the energy embodied in fertilizers), transport fuel chains (due to the energy embodied in manufacturing and assembling vehicles) and fuel chains based on low density renewable energy forms: solar and wind (due to the energy embodied in solar panels, wind turbines, etc.).

DeLuchi (1993) contains information on the energy intensity and fuels used in materials manufacturing, plus the energy intensity of vehicle manufacture. He also includes estimates of the materials content of vehicles (shares by type of vehicle and type of material) and the energy embodied in different types of large energy facilities based on DOE, (1983) data.

Table 10.1: Energy Use for Materials Manufacture

Material	Energy Intensity (thermal equiv.)	Reference:	Note:
Steel	5.81E+1 GJ/t	DeLuchi (1993)	1
Concrete	1.15E+0GJ/t (500Btu/lb)	DeLuchi (1993)	2
Aluminum	2.90E+2 GJ/t	DeLuchi (1993)	
Iron	2.32E+1 GJ/t	DeLuchi (1993)	
Copper/Silicon	1.16E+2 GJ/t	DeLuchi (1993)	

1. Total energy consumption based on thermal energy equivalents with electricity assumed to be generated with thermal power plants (32.5% efficiency).
2. Direct energy use of energy is about 500 Btu/lb (for cement manufacture), but DeLuchi includes an additional 500Btu/lb to represent the "equivalent" use of energy for CO_2 emissions resulting from the conversion of $CaCO_3$ to CaO during concrete manufacture. This approach tends to overstate energy consumption, but give a more accurate estimate of total CO_2 emissions.

Table 10.2: Fuel Shares for Materials Manufacture (%)

Material	Coal	Oil	Nat Gas	Electricity	Reference:	Note:
Steel	59%	6%	23%	13%	DeLuchi (1993)	3
Concrete	70%	2%	3%	25%	SEI-B	4
Aluminum	4%	5%	60%	31%	DeLuchi (1993)	3
Iron	65%	6%	25%	4%	DeLuchi (1993)	3
Copper/Silicon	56%	19%	13%	11%	DeLuchi (1993)	3

3. May not sum to 100% due to rounding.
4. Based on global average fuel shares across all industries in the stone, glass, and clay industries. Data taken from Polestar/Energy 2050 project assumptions.

Table 10.3: Combustion Emissions loadings for fuel use in Materials manufacture. (t/unit of fuel consumed)					
Fuel	CO2	CO	CH4	HC	NOx
Oil	3.08E+0 t/t	6.31E-4 t/t	4.74E-6 t/t	3.33E-5	6.06E-3
Natural Gas	1.85E-3 t/m3	6.42E-7 t/m3	1.26E-8 t/m3	2.25E-8 t/m3	8.82E-6 t/m3
Coal	2.71E+0 t/t	2.5E-3 t/t	2.92E-5 t/t	3.5E-5 t/t	9.59E-3 t/t

5. SEI-B estimates using assumptions of SEI-B technical assessment in Lazarus et al (1993). These loadings do not include non-combustion related emissions associated with the manufacture of materials (e.g. CO_2 emissions from the chemical reaction durting cement manufacture, which doubles the CO_2 emissions from combustion emissions alone).

6. Note: this data, when combined with the materials requirements of the fuel chain stages listed above can be used include in the total fuel chain, the energy embodied in materials (e.g. steel in vehicles or concrete in power plants). Howeever, it does not include (for example), the energy used in the assembly of vehicles or the assembly of power plants. These appear to be significant only for vehicle assembly.

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