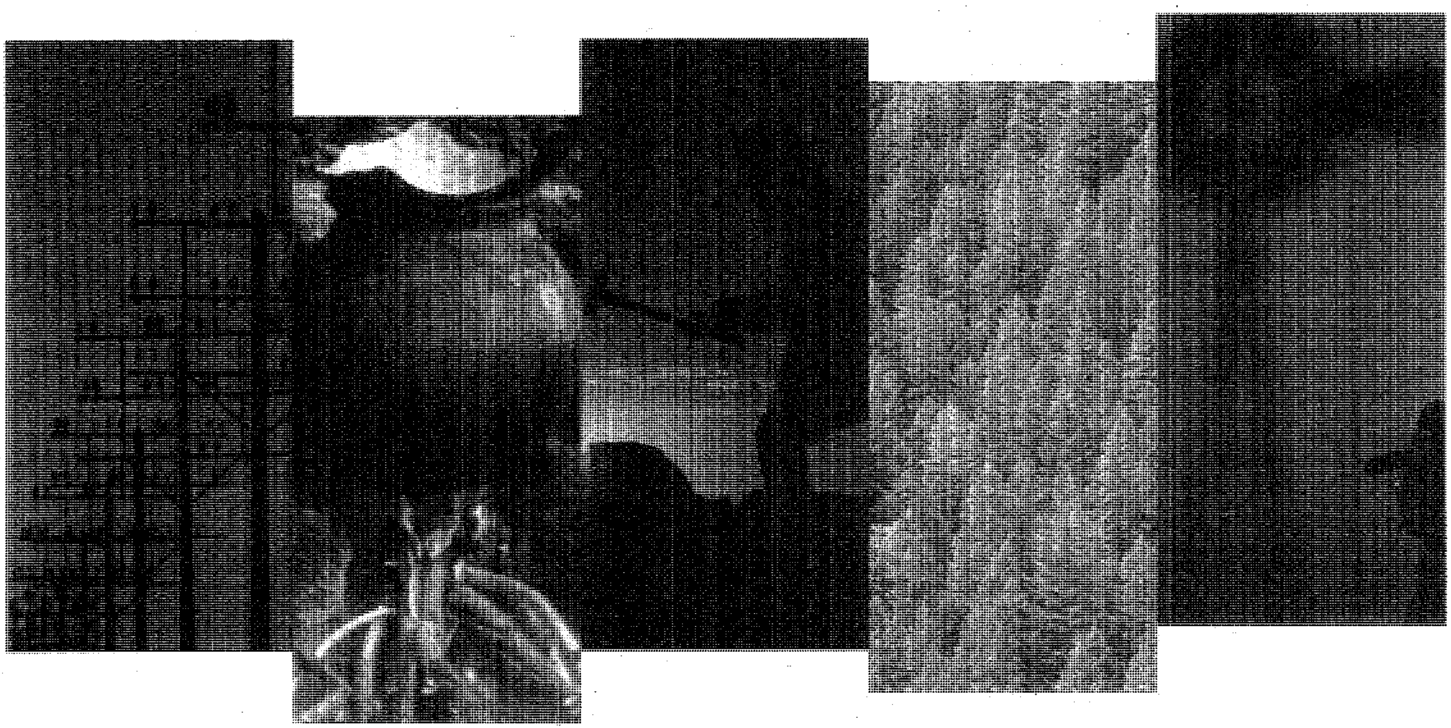
The Effect of a Shadow Price on Carbon Emission in the Energy Portfolio of the World Bank

A Carbon Backcasting Exercise

ESM212
February 1999



Energy

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ESMAP

Report 212/99
February 1999

JOINT UNDP / WORLD BANK
ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAMME (ESMAP)

PURPOSE

The Joint UNDP/World Bank Energy Sector Management Assistance Programme (ESMAP) is a special global technical assistance program run as part of the World Bank's Energy, Mining and Telecommunications Department. ESMAP provides advice to governments on sustainable energy development. Established with the support of UNDP and bilateral official donors in 1983, it focuses on the role of energy in the development process with the objective of contributing to poverty alleviation, improving living conditions and preserving the environment in developing countries and transition economies. ESMAP centers its interventions on three priority areas: sector reform and restructuring; access to modern energy for the poorest; and promotion of sustainable energy practices.

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FUNDING

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Joint UNDP/World Bank Energy Sector Management Assistance Programme
(ESMAP)

First printing February 1999

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Abbreviations and Acronyms

AIJ	Activities Implemented Jointly
CAC	Cost of avoided carbon
CAS	Country Assistance Strategy
CC	Combined cycle
CH_4	Methane
CO_2	Carbon dioxide
CT	Combustion turbine
DH	District heating
DR	Distributed resource
DSE	Demand-side efficiency
DSM	Demand-side management
EIRR	Economic internal rate of return
EPC	Energy performance contracting
EPRI	Electric Power Research Institute
ESCO	Energy services company
ESLII	Second Energy Sector Loan
ESW	Economic and sector work
FAS	Federation of American Scientists
GDP	Gross domestic product
GEF	Global Environment Facility
GHG	Greenhouse gas
ICE	Internal combustion engine
IIEC	International Institute for Energy Conservation
IPCC	Intergovernmental Panel on Climate Change
IPP	Independent power producer
IRP	Integrated resource planning
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
N_2O	Nitrous oxide
NG	Natural gas
NGCC	Natural gas combined cycle
NGO	Nongovernmental organization
NO_x	Nitrogen oxide
NPV	Net present value
NREL	The National Renewable Energy Laboratory (U.S.)
NTPC	National Thermal Power Corporation (India)
O&M	Operations and maintenance
OCC	Opportunity cost of capital
OECD	Organisation for Economic Co-operation and Development
PM	Particulate matter
PPP	Purchasing power parity
PV	Photovoltaics
SAR	Staff Appraisal Report
SEI-B	Stockholm Environment Institute—Boston
SO_2	Sulfur dioxide
SPV	Solar photovoltaic

SRTP	Social rate of time preference
SSM	Supply-side management
TA	Technical Assistance
T&D	Transmission and distribution
TSP	Total suspended particulate matter
UNEP	United Nations Environment Programme
UNFCCC	United Nations Framework Convention on Climate Change
USAID	U.S. Agency for International Development
VRA	Volta River Authority

Units of Measure

Btu	British thermal unit
CC	Combined cycle
GJ	Gigajoule
GtC	Gigatons of carbon
GWh	Gigawatt-hour
kgC	Kilograms of carbon
km	Kilometers
km^2	Square kilometers
kWh	Kilowatt-hour
m/s	Meters per second
MMBtu	Million Btu
MW	Megawatt
t	Metric ton
tC	Metric tons of carbon

Acknowledgments

The Carbon Backcasting Study was commissioned by the World Bank Global Environment Division, Global Climate Change Unit, and by the Energy Sector Management Assistance Programme (ESMAP) and was conducted by a study team consisting of Hagler Bailly Services, Inc., Stockholm Environment Institute—Boston (SEI-B), and the International Institute for Energy Conservation (IIEC). Principal investigators in the study were Joel Smith, Shannon Ragland, Carolyn Lang, Karl Spiecker, and Dave Mills (Hagler Bailly); Michael Lazarus and Bill Dougherty (SEI-B); and Karen Holmes (IIEC). Coordinating assistance and oversight was provided by Charles Feinstein, Andrew Steer, Richard Stern, Eivind Tandberg, Odil Tunali Payton, and Kerri Poore at the World Bank.

The World Bank would like to express its appreciation to the study team for assisting in the Bank's efforts to evaluate the effects of a carbon shadow price on past energy loans. The U.S. Agency for International Development (USAID) supported the scoping study, which led to the development of the analytical methods applied in the shadow price research. The governments of Norway and the Netherlands provided funding for the main study, and the government of Sweden supported the contributions of the SEI-B throughout the scoping and main studies. The Federation of American Scientists was responsible for suggesting the research idea and initially setting the range of carbon shadow values used. Numerous Bank staff, including project task managers and library staff, assisted the research by providing requisite documents and information. The task managers were particularly helpful in the difficult assignment of developing counterfactual scenarios for the analysis.

The Steering Committee for the Backcasting Study provided essential guidance and feedback on method development: Robert Watson, Ken Newcombe, Joseph Gilling, and Ann Kristin Westberg (World Bank); Chandra Sekhar Sinha (Tata Energy and Resources Institute); Kilaparti Ramakrishna (Woods Hole Research Center); Leslie Black Cordes, Alberto Salazar, and Carla Koppell (USAID); and Paul Hofhuis (Royal Netherlands Embassy). Distinguished economists also provided valuable advice and comments: Michael Tolman (Resources for the Future) and Sam Fankhauser (World Bank). Others who donated their expertise include Peter Lilienthal, Tony Jimenez, and Larry Flowers (National Renewable Energy Laboratory (NREL)).

The World Bank would also like to thank Hagler Bailly, SEI-B, and IIEC staff members who helped with the analysis and report preparation: Stephanie Lenhart, Eloise Trabka, Steve Piper, Frank Stern, Tony DeAngelis, Bill Meade, Chris Thomas, and Shana DeBault (Hagler Bailly); Michael Ruth, Steve Bernow, Semida Silveira, Max Duckworth, and Michael Brower (SEI-B); Pat Keegan, Peter Kelly Detwiler, and Debra Lew (IIEC).

Executive Summary

The World Bank has pledged to ensure that its activities are consistent with the United Nations Framework Convention on Climate Change (UNFCCC) and to assist its clients in meeting their commitments. Because energy generation is a key source of greenhouse gas (GHG) emissions, this pledge will affect the Bank's investment strategy in the energy sectors of client nations. The Bank is considering strategies that encourage investment in low and no-carbon energy alternatives, such as including a carbon shadow price in its analyses of project benefits and costs. To inform the debate over suitable strategies for the Bank, the Federation of American Scientists (FAS) recommended that the Bank examine how the economic analyses of recently approved energy projects might have been affected by including a carbon shadow price.

This carbon backcasting study was commissioned by the Bank in response to the FAS recommendation, and uses methods that were developed in a scoping study commissioned by the U.S. Agency for International Development (USAID). It had two objectives. The first was to analyze the effect of placing a shadow price on carbon emissions for a sample of recently approved energy loans to determine whether the shadow price could adversely affect their economic analyses.[1]

The second objective of this study was to conduct an analysis of whether a shadow price would encourage investment in low-carbon alternatives. A carbon shadow price can increase the relative economic attractiveness of alternative energy investments: for example, a wind-generation project that is more costly than a diesel-generation project will become more competitive when a carbon shadow price is applied to the diesel's carbon emissions. Below are the methods used to conduct the shadow price and alternatives analyses, and a discussion of the main results. Also discussed are issues and recommendations for implementing policies that will encourage lower-carbon investments.

Shadow Price Analysis

To conduct the carbon shadow price analysis, the study team reviewed Staff Appraisal Reports (SARs) for a sample of 50 randomly selected energy loans from the portfolio of 154 energy loans approved between 1990 and 1996.[2] Relying on these and other sources, the team estimated carbon emissions—and other significant GHG emissions when necessary—associated with the loans using the following definitions:

Project emissions. These are the total emissions that are generated by activities and facilities funded by the loan. For example, the project emissions from a new power plant are the total emissions of the plant.

Net emissions. These are equal to project emissions minus any emissions that would have occurred in a counterfactual scenario, which is what might have happened in the absence of the Bank's involvement. For example, net emissions from a new power plant equal its project emissions minus any emissions generated by a power plant, if any, that would have been built without Bank funding. If a smaller plant had been built, net emissions would have been positive; if a less efficient plant had been built, net emissions would have been negative.

This distinction facilitates comparisons across loans because it leads to two sets of emissions measures that are internally consistent.

To analyze shadow price sensitivity, the study team applied a range of shadow prices—\$5, \$20, and \$40 per metric ton of carbon (tC)—to the carbon emissions.[3] This range is consistent with the marginal damage estimates reported in the Intergovernmental Panel on Climate Change (IPCC) review of the literature on global impacts of climate change (Pearce et al. 1996). Literature on the impacts of global change suggests that the marginal damage of emitting carbon may rise over time because atmospheric concentrations of GHGs will be higher in future years. (Fankhauser 1995). To reflect this trend, the team applied a 2 percent annual growth rate to the $5, $20, and $40 shadow values, which is the growth rate implied by the literature.

The study team incorporated the shadow price costs in the economic analysis in the SAR for each loan, and recalculated the project's net present value (NPV) and economic internal rate of return (EIRR). To reflect uncertainty about how the marginal damage should be discounted, the team applied discount rates to each loan's shadow price costs that ranged 0 percent to about 12 percent.[4] For all other benefit and cost flows, the discount rate was the opportunity cost of capital (OCC).

For each shadow value and discount rate, the team grouped the loans into the following four categories:

1. *No effect:* Shadow price does not affect economic analysis because carbon emissions are zero.

2. *Moderately affected:* Shadow price reduces NPV, but NPV remains positive.

3. *Strongly affected:* Shadow price reduces NPV below zero.

4. *No SAR:* No economic analysis available for shadow price analysis; these tend to be restructuring loans or supplemental loans, and it is likely that they would not be affected by a shadow value.

Box S.1. A Brief Note on Methodology

The study team was aware that, especially in developing countries, an NPV based on electricity tariffs, such as has been used in this analysis, may substantially understate the economic benefits of energy projects. The team was also aware that, in Bank project analysis, a low NPV often implies that the proposed tariffs should be increased to recoup investment and operational costs. However, this exercise was *not* meant to model the real-world effects of a carbon tax. The Bank is in no way suggesting that a carbon tax be imposed on borrowing countries. In the context of this study, the team was recalculating project NPVs simply as a means of quantitatively assessing the carbon intensity of projects to identify those for which there may be low- or no-cost alternative ways to supply equivalent energy services to the borrowing country. In noting where the NPVs of projects are sharply reduced by accounting for the shadow value of GHG emissions, the study team is in no way implying that it is "uneconomic" to develop electricity infrastructure in a given country or using a particular technology. For a fuller discussion, see chapter 2.

Figure S.1
Comparison of $5 and $20 Shadow Price Effects
(0% net discount rate)

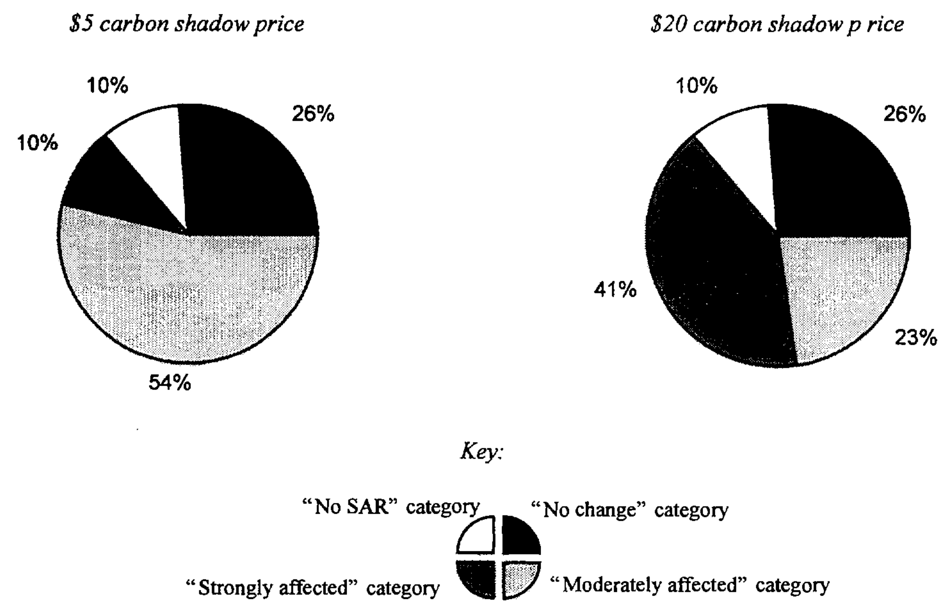
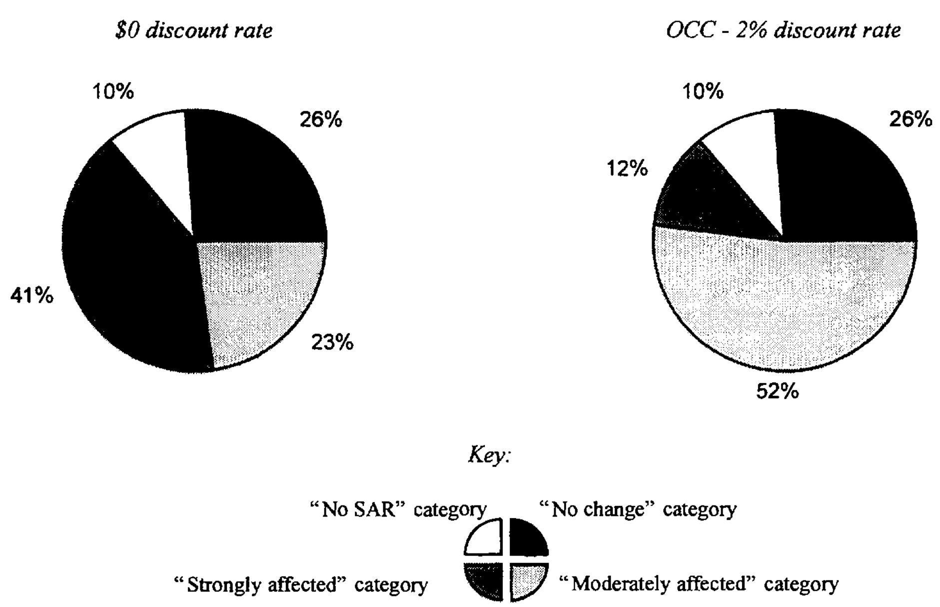


Figure S.2
Comparison of 0% and OCC minus 2% Net Discount Rates
($20 shadow price)



Based on the shadow price analysis using project emissions, almost 40 percent of the Bank's investment portfolio would not be affected by a shadow price on carbon emissions because the funded activities (for example, energy efficiency, renewable resources, sector restructuring) did not generate carbon emissions. The portfolio share affected by a carbon shadow price (approximately 60 percent) is sensitive to the price and discount rate assumptions.

Figure S.1 shows that a significantly larger share of the investment portfolio is in the "strongly affected" categories at $20 per metric ton of carbon (41 percent) compared with $5 per metric ton of carbon (10 percent). The "strongly affected" category further increases to 46 percent for a $40 per metric ton of carbon (tC) shadow price. Thus, there appears to be a decreasing effect of higher shadow prices on loans moving into the "strongly affected" category. Not surprisingly, the loans in the "strongly affected" category tend to include investments in coal generation, particularly at lower shadow prices. If the results are extrapolated for the $20 shadow price to the overall energy portfolio of 154 loans, then about $7.8 billion of Bank loan funds went to projects that are strongly affected by a carbon shadow price.

Figure S.2 illustrates sensitivity of the results to the choice of discount rate on the shadow price. The proportion of "strongly affected" loans (41 percent) is more than three times larger at a 0 percent discount rate than the proportion of "strongly affected" loans (12 percent) at a discount rate equal to OCC minus 2 percent.

Since 1994, the Bank has placed increasing emphasis on meeting the institutional, regulatory, and reform needs of client country power sectors. The study team divided the shadow price results into two periods (loans approved in 1990–93, and loans approved in 1994–96) to determine whether they are affected by the policy shift. The loans in the earlier period are more sensitive to the carbon shadow price. Figure S.3 shows that in the earlier period, about one quarter of the loans were unaffected by shadow price because they had no carbon emissions or "no SAR" (that is, no economic analysis of the data), but in the later period almost two-thirds of the loans were unaffected by the shadow price. Conversely, the share of "strongly affected" investments in the earlier period (50 percent) is much larger than the "strongly affected" share in the later period (11 percent). One effect of the Bank strategy shift is a reduction in the proportion of energy sector investments that generate carbon emissions.

Extrapolating total project emissions from the random sample of 50 loans to the energy portfolio of 154 loans suggests that the annual emissions from Bank-funded activities would range from 73 million to 88 million metric tons of carbon. This represents 1.7–2.1 percent of average annual emissions from non-OECD countries during the period 1990–2015, which is estimated to increase from 3.2 billion metric tons of carbon (GtC) in 1990 to 5.6 GtC in 2015 (Pepper 1997).

Relatively few loans in the sample have positive net emissions. Thus, applying a shadow price to net emissions has a small effect on the Bank's portfolio. Projects accounting for 64 percent of financing were in either the "no SAR" or "no emissions" categories, and at a $20 shadow price, 5 percent were in the "moderately affected" category and 9 percent in the "strongly affected" category. Projects associated with the remaining 22 percent of funds had negative net emissions, and their NPVs increased when the shadow price was added. These projects included energy efficiency and renewable resource investments that would not have occurred without Bank support. They also included some power supply projects wherein Bank funding led to a more efficient supply with lower emissions.

Figure S.3
Comparison of 1990–93 and 1994–96 Sub-samples
(0% net discount rate and $20 shadow price)

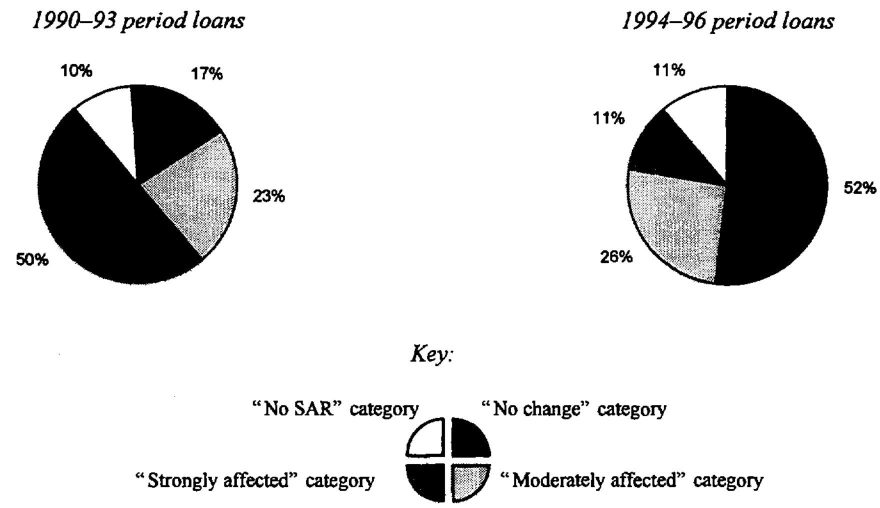
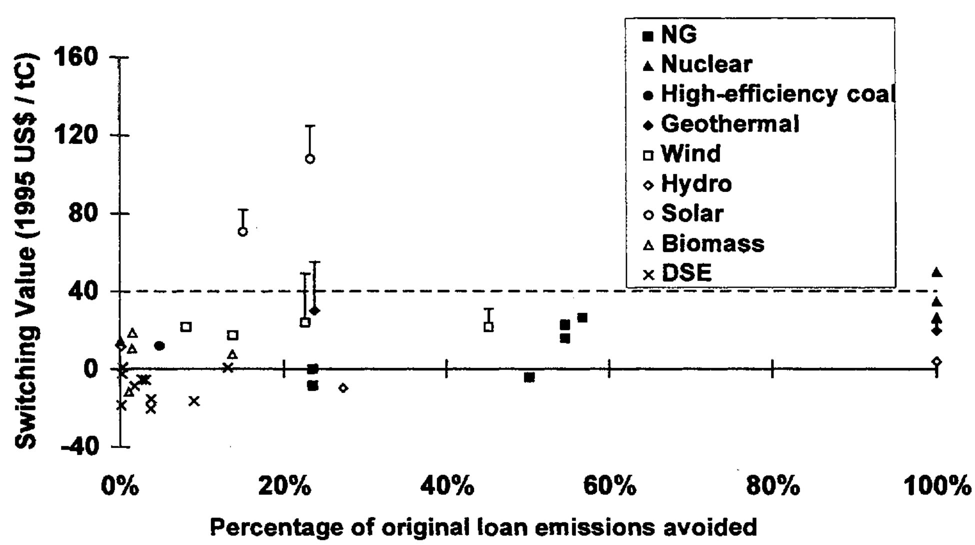


Figure S.4
Switching Values and Avoided Emissions
for Power Supply Loan Alternatives



Analysis of Alternatives

For a subset of the loans that represent a cross-section of the Bank's client regions and of its principal project types, the study team examined how a shadow price would affect the economic performance of low-carbon alternatives to the Bank-funded projects. Examples include wind power or hydropower alternatives to thermal power supply, natural gas (NG) alternatives to coal-fired plants, and demand-side efficiency (DSE) alternatives to reduce power demand. These alternatives included low-carbon investments identified in the SARs, but most alternatives were developed from other sources using site-relevant information about commercially available technologies. Because the team did not restrict the study to technologies that were available at the time of loan approval, the study has benefited from including technological advances that have occurred since then and that may be available for future projects.

The team estimated each alternative's carbon savings and incremental cost, which is the additional cost of the alternative compared to the funded project. Incremental costs were usually positive, but some "win-win" alternatives had lower costs, as well as lower carbon emissions. Dividing the net present value of incremental cost by the carbon savings generated a "switching" value that the team used to make comparisons across alternatives and with the shadow price range. Similar to the shadow price analysis, the team estimated switching values for a discounted scenario (OCC minus 2%) and an undiscounted scenario (0%).

Figure S.4 reports the switching values and carbon savings for the alternatives for power supply projects, assuming a 0 percent net discount rate on carbon emissions. These results suggest that switching values for many types of alternatives fall in the $0/tC to $40/tC range. Most alternatives offset only a portion of the original project's emissions because either resources were insufficient to completely replace the supply project (for example, wind power is too intermittent to fully replace a coal plant) or the alternative generated some carbon emissions (for example, natural gas). The figure also shows that some "win-win" investments, such as demand-side efficiency (DSE) programs, can reduce carbon emissions and cost less.

The switching values for the higher discount rate (OCC minus 2%) are about three to four and a half times higher than those shown in figure S.4. Figure S.5 shows the sensitivity of switching values to the discount rate using the example of a wind power alternative for the China Yangzhou power plant. The switching value for the 0 percent discount rate scenario is about $50 per metric ton of carbon avoided. When the net discount rate is 10 percent, the switching value is about $210 per metric ton.

Figure S.5 also shows that switching values are sensitive to assumptions made about resource availability, proximity, and cost, and project lifetime. The switching value is about 80 percent higher, and fewer carbon emissions are avoided, if the wind farm operates at a capacity factor of 20 percent rather than 30 percent, as assumed originally. On the other hand, the switching value decreases by one-third if the project lifetime is assumed to be 30 years, which is more typical of a coal plant, instead of the 20-year lifetime used in the SAR analysis. The switching value also decreases to $24 per metric ton if existing transmission networks are sufficient to transmit the added wind capacity.

Analyses of alternatives for transmission and distribution projects, rural electrification projects, and power sector reform projects also demonstrate that opportunities to reduce carbon emissions exist in the $20 to $40 shadow price range used in the shadow price analysis.

Issues and Recommendations

The issues and recommendations emerging from the shadow price analysis and the analysis of low-carbon alternatives comprise three main categories: (a) the value of incorporating these analyses into the economic analysis of proposed World Bank projects, (b) methodological issues, and (c) implications for Bank operations.

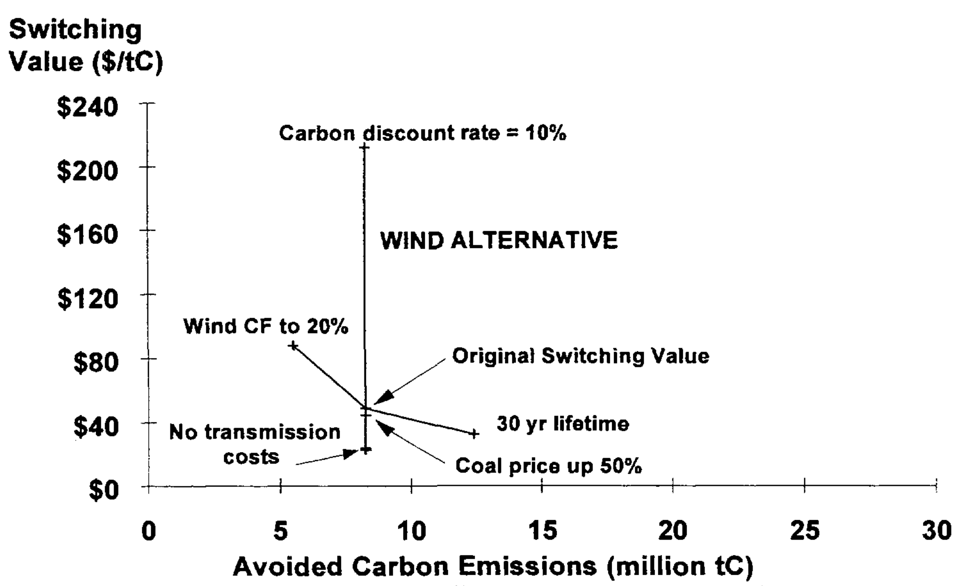
The team concludes that carbon shadow value analysis would be a useful tool in the project preparation process for World Bank energy lending. Their findings demonstrate that valuing the carbon flows produced by a project has a substantial impact on project economics. Such analysis should not be difficult or costly to carry out because it relies on data (for example, fuel type and price) that are normally gathered in the course of project economic analysis.

The extent to which the incorporation of a shadow value for carbon in project economic analysis would cause a shift in Bank energy lending toward low-carbon technologies depends on the existence of low-carbon alternative investments that are financially preferable to the borrowing country and the availability of funding from the international community to "buy down" the incremental costs of lower-carbon projects. Over the course of the analysis, the study team found little evidence of rigorous assessment of low-carbon alternatives to the projects brought to the Bank. The team developed many plausible options to reduce carbon emissions at a reasonable cost, that is, in the $0 to $40 per metric ton range.

There are numerous methodological issues that will need to be addressed if the Bank chooses to institute carbon shadow value analysis as part of the project economic analysis. The results of the analysis are sensitive to the choice of shadow price, discount rates, and project lifetimes. Given the lack of consensus on the value of climate change damage associated with greenhouse gas emissions, it is appropriate for the Bank to use a range of shadow prices (for example, we used $5, $20, and $40 per metric ton of carbon). Concerning the choice of discount rates, experts disagree on the appropriate discount rate for project carbon flows. We recommend a low or zero social discount rate for carbon to be consistent with the origin of the shadow prices and current practices at the Global Environment Facility, and testing sensitivity to a higher rate that takes into account the opportunity cost of capital.[5] The time horizon of the analysis also strongly influences results; for carbon flows, the study team recommends that the analysis address the physical lifetime of the investment, which in developing countries is typically much longer than the economic lifetime of the project.

In addition to these methodological issues, there also are several operational questions the Bank should address. At the project level, the study team recommends that carbon shadow value analysis be carried out early in the project cycle, where there is maximum scope to modify a project concept to address the same development

Figure S.5
Sensitivity Analysis of China Yangzhou Alternatives:
Inner Mongolia Wind Alternative



Note: Original switching value based on 0% net discount rate, 20 year project lifetime, 30% capacity factor, and all costs for new transmission line.

need in a less carbon-intensive manner. At the country level, assessment of the potential for low-carbon technologies should be incorporated in Bank processes that look at the entire development path, such as economic and sector work (ESW) and the Country Assistance Strategy (CAS). At the regional or global level, the Bank could review marginal sources of energy supply, their costs, and the associated emissions to identify the most favorable sites for low-carbon technology projects. Such investments should be designed to create well organized, sustainable markets for low-carbon technology, rather than just financing isolated projects. All of the above will require significant expertise on low-carbon technologies, such as energy efficiency, cogeneration, biomass, and wind. Task managers and other relevant Bank staff will need to ensure that they can identify and access such experts with specific local experience and knowledge of market conditions and resource potentials.

1. A smaller-scale study using similar methods was also conducted on transport sector loans. The results of that study became available in mid-1998.

2. During the scoping study, the team analyzed nine energy loans. Because they were not randomly selected, they were not included with the results reported for the random sample in the present study.

3. All currency units are U.S. dollars, unless otherwise specified.

4. For each loan, this discount rate initially ranged from a social discount rate of 2 percent to the country's opportunity cost of capital, which was typically between 10 percent and 14 percent. When the 2 annual shadow price growth rate was subtracted from these discount rates, the net discount rates for the shadow price costs ranged from 0 percent to 12 percent.

5. From an investment perspective, carbon savings of low-carbon alternatives will be discounted at a rate that, ultimately, the market will decide, based on the reservation prices (and, implicitly, the discount rates) of buyers and sellers in a hypothetical international carbon offsets market. The creation of such a market is contingent on what agreements emerge as protocols to the UNFCCC. This does not answer the question of what discount rate or rates should be used in Bank economic analysis to identify low-carbon options that are "win-win" or "no regrets," as well as alternatives with positive incremental costs for "shopping" to potential carbon offset or joint implementation investors.

1 Introduction

Recent scientific findings suggest that increasing concentrations of greenhouse gases (GHGs) in the atmosphere due to human activities are likely to change global climate, and this is likely to have particularly detrimental effects on developing countries. In its most recent assessment of the state of the science on climate change, the Intergovernmental Panel on Climate Change (IPCC) found that atmospheric concentrations of greenhouse gases, such as carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O), have increased, respectively, 30 percent, 145 percent, and 15 percent since the beginning of the industrial revolution. The increases in concentrations are largely attributable to human activities, particularly energy use and land use activities.The IPCC concluded that, if emission trends continue, average global temperatures will rise 1°C to 3.5°C by 2100 and sea level will rise 15 cm to 95 cm by 2100 (Houghton et al. 1996).

The IPCC found that human health and most natural ecological systems and socioeconomic systems are sensitive to climate change. Successful adaptation to climate change depends on access to technology and information, availability of financing, and responsiveness of institutions. Thus, developing countries, which tend to have less favorable economic, informational, and institutional circumstances, are more vulnerable to climate change (Watson, Zinyowera, and Moss 1996). For example, global grain production may shift from low-latitude countries, which tend to be developing countries, to high-latitude countries, which tend to be developed countries (Rosenzweig and Parry 1994). Also, many developing countries may have to devote a large portion of their financial resources to defend themselves against or adapt to a sea level rise (Hoozemans, Marchand, and Pennekamp 1993).

1.1 The Role of the World Bank

The World Bank is an important actor in promoting economic development, which includes financing the provision of energy services in developing countries. There is universal agreement that the energy needs of the developing world are great, and increased levels of energy services will be essential if living standards are to be raised. Since 1990, the Bank has approved 170 loans totaling more than $24 billion for a variety of projects in the electric power sector. [1] Most of these loans were to non–Annex I countries, which do not face reduction commitments on their CO_2 emissions.[2] Nonetheless, the impact of these projects on global emissions of GHGs over the next 30 years will be substantial. While some projects will reduce greenhouse gas emissions, for example, renewable energy projects or energy efficiency projects, other Bank loans will increase GHG emissions by increasing fossil fuel use in new power plants or as new supply for expanding electricity grids.

Given scientific consensus that increasing concentrations of atmospheric CO_2 are likely to cause global climate change, further investment in fossil fuel energy technologies, while providing developing countries with the benefits of the energy they need for economic development, also contributes to the increased risk of damage from global climate change. Although industrial countries are responsible for much of the present anthropogenic stock of GHGs, developing countries will generate the larger share of future emissions. Successful GHG mitigation will thus depend on joint efforts. However, developing countries are least able to bear the costs of GHG mitigation.
The World Bank is not the sole source of investment capital for international energy

development, supplying about 3 percent of the total financing requirements of the sector (about 5 percent of the foreign exchange requirement). The flow of private investment into this sector is substantial: private sector flows are four times as large as public sector development flows. In many developing countries, however, the Bank plays a key role in setting the standard by which other energy projects are judged, thus exerting an influence disproportionate to the size of its investment portfolio alone.

Moreover, the Bank has pledged to ensure that its activities are consistent with the United Nations Framework Convention on Climate Change (UNFCCC) and to assist its clients in meeting their commitments under the UNFCCC. Defining what policies and investments are "consistent" with the UNFCCC is a matter of some debate. Investment in GHG-intensive projects, such as fossil fuel technologies, must be judged in relation to the energy and development needs of the borrowing country. Investment in the continued growth and use of fossil fuel technologies could be consistent with the UNFCCC if there are no feasible and cost-effective development alternatives. However, there is good reason to believe that there is significant potential for the Bank's client countries to pursue lower-carbon energy paths—including improvements in energy efficiency, fuel-switching, and renewable energy technologies—while still achieving national economic development goals.

Implementing the investments that are needed to substantially reduce GHG emissions will frequently require expenditures beyond a level that is economically efficient for the borrowing country. The Global Environment Facility (GEF) was established by the international community to provide a means for transferring resources from the industrial countries to the developing countries to meet the "incremental costs" of making investments that yield global environmental benefits. Although the GEF has directed more than $400 million toward climate change mitigation projects, there most likely are additional opportunities within the Bank's energy lending portfolio for alternative, lower-carbon investments, which could attract a GEF-like subsidy from the international community.

1.2 The FAS Colloquium

During December 8–10, 1995, the Federation of American Scientists (FAS) and the World Bank co-hosted a colloquium addressing the question, "Should the World Bank decisionmaking on lending for projects that would result in the emission of greenhouse gases reflect the global damage that such emissions might cause?" The colloquium included distinguished economists and scientists.

The colloquium examined how much global warming is expected and when it will happen, what the impacts may be, whether a shadow price for carbon is appropriate and how large it should be, and whether Bank loans should be influenced by a shadow price for carbon.[3] Although there were some disagreements, the conclusions of the meeting were consistent with the summary statements about the science stated above (see FAS 1996).

The colloquium could not come to a consensus about whether the Bank should implement shadow prices for carbon. One concern raised was how the shadow price would be funded. The colloquium recommended that the Bank conduct a "backcasting" exercise to examine how a shadow price on carbon would have affected the economic analyses of recent Bank energy loans. A shadow price in the range of $5 to $40 per metric ton of carbon reflects a broad range of potential damage from the increase of greenhouse gas concentrations in the atmosphere (Pearce et al. 1996).

1.3 Objectives of the Backcasting Study

A shadow price on carbon emissions increases project costs and thereby reduces its economic internal rate of return (EIRR) and its net present value (NPV).[4] Recent Bank loans for energy that generates carbon emissions (for example, from fossil fuel use) will look less attractive economically when the additional costs of their carbon emissions are taken into account. In such cases, an alternative, lower-carbon project might have been preferred if its incremental investment costs were less than the cost of the shadow price on the original project's carbon emissions. Conversely, other loans might look more attractive economically because they have lower carbon emissions relative to what might have happened if they were not funded.

With these outcomes in mind, the carbon backcasting exercise had three main objectives:

1. *To understand how the energy portfolio of the Bank would have been affected by the incorporation of a shadow value for carbon emissions.* In general, the analysis produced three categories of results:

   - No change in NPV and, hence, no change in the investment decision: The project analyzed was already optimal with respect to CO_2 and the shadow price did not affect EIRR and NPV.

   - Reduction in NPV, but no change in the investment decision: Lower-carbon alternatives to the project existed, but the additional cost was higher than would be justified at a given shadow value for CO_2. When alternatives were not analyzed, loans that had smaller but still positive NPV with a shadow price were in this category.

   - Change in investment decision: A lower-carbon alternative would be justified at a given shadow value for CO_2.

   The aim of the Bank and research team was to simulate what would have happened to project costs, project types, project selection, and environmental impacts (including local and regional externalities) if the damage associated with global climate change had been integrated into the Bank's energy lending via the use of a shadow value for carbon emissions.

2. *To provide analytic support for the formulation of the Bank's climate change policy.* The results of this backcasting exercise are expected to contribute to the development of a Bank sector strategy paper on energy and environment. In addition, this study will form part of a presentation to the Bank's Board of Directors on issues pertaining to climate change and Bank energy loan policies.

3. *To identify priority investments for the international community.* The study identified the ways in which the Bank's recent energy lending portfolio might have been modified to reduce CO_2 emissions. However, it is not equitable to expect that associated with lower-carbon alternatives. The developed countries may wish to provide the incremental investment needed to make lower-carbon projects financially attractive to the developing countries, and they should bear the burden of any additional costs borrowing countries, as is now being done through the GEF. In essence, the study demonstrates how the GEF approach could be extended to encompass the Bank's energy lending portfolio. It also shows how the Bank's investment decisionmaking processes could stimulate mechanisms to mobilize new resources for combating climate change, including the identification of opportunities for Activities Implemented Jointly (AIJ).

1.4 Study Organization

The team of investigators for the carbon backcasting study included Hagler Bailly Services, Inc., the Stockholm Environment Institute—Boston (SEI-B), and the International Institute for Energy Conservation (IIEC). The team developed the analytical methods used in the carbon backcasting study during a scoping study implemented by USAID, which analyzed six Bank energy sector loans and one transport loan. For the main carbon backcasting study, which is the subject of this report, the methods were applied to a significant share of recent Bank energy loans to draw conclusions about the energy loan portfolio. A supplemental report on transport loans will be completed mid-1998.

The analysis approach involves three main steps:

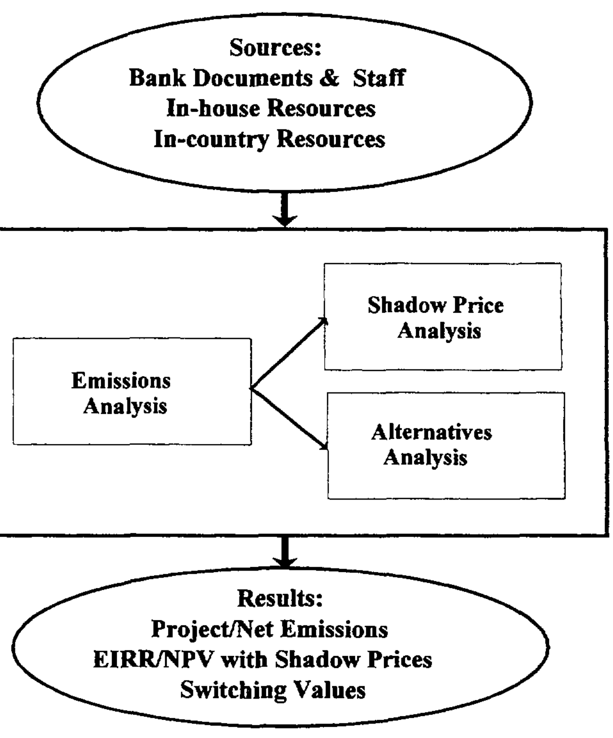
Step 1: Emissions Analysis (estimate a project's carbon emissions).

Step 2: Shadow Price Analysis (apply shadow price to carbon emissions).

Step 3: Alternatives Analysis (compare carbon savings and incremental costs of alternatives to the project).

Figure 1.1 illustrates how the analysis flows through these steps, and shows the analytical outputs for each step. First, information from the energy loan's Staff Appraisal Report (SAR) and other sources was used to estimate project and net emissions. The emissions estimates are inputs to both the shadow price analysis of the project and the alternative investment analysis. The outputs for these two steps are EIRR and NPV values adjusted for shadow price, and switching values for the alternative investments. Chapter 2 describes the methods used for the emissions analysis and the shadow price analysis, and chapter 3 presents the emissions estimates and the shadow price effects on EIRR and NPV for all loans in the sample. Chapter 4 describes the methods used for the alternative analysis, and chapter 5 presents the switching value results for the subset of loans included in the alternative investments analysis. Chapter 6 discusses the results in chapters 3 and 5 in the context of potential large-scale implications for the Bank's energy portfolio. Chapter 7 concludes the report with a discussion of implementation issues and recommendations for the shadow price and alternative analyses.

Figure 1.1
Major Components and Progression of Carbon Backcasting Analysis



[1] All currency units are U.S. dollars, unless otherwise specified.

[2] Non–Annex I countries comprise all developing countries (OECD countries plus economies in transition).

[3] A carbon shadow price can be thought of as the marginal social cost of a metric ton of carbon (Fankhauser 1995).

[4] A real-world carbon tax would likely be passed on to consumers in the form of increased electricity prices and utility revenues, as well as increasing the cost of carbon-intensive fuels. However, this study does *not* analyze a carbon tax or advocate imposing one, but merely examines the use of carbon shadow value analysis as a *potential* planning tool.

2 Carbon Shadow Price Analysis Methods

Investments in energy projects that generate GHG emissions will increase the atmospheric concentration of GHG, and potentially increase the associated damages of climate change. These damages are external costs that are not borne by the project's investors. When investment decisions do not take external costs into consideration, resources can be misallocated. The objective of the carbon shadow price analysis was to internalize these costs (that is, incorporate them into the investment analysis) and identify energy investments that are strongly affected by a carbon shadow value (that is, are likely to have low-carbon alternative investments that would be economically attractive either to the borrowing country or in a global carbon offsets market).

The carbon shadow price analysis internalizes potential damages associated with climate change by applying a shadow price to an energy project's carbon emissions, and recalculating the project's NPV and EIRR. This chapter discusses the analytical methods used to implement the shadow price analysis, which include randomly selecting a sample of loans (section 2.1), estimating carbon emissions for each loan (section 2.2), and applying a shadow price to the emissions (section 2.3). It also describes an approach for applying shadow prices to other air pollutants, such as sulfur dioxide (section 2.4).

2.1 Sample Selection

To make inferences about how a shadow price might affect the entire portfolio of recent energy loans, the study team needed to analyze a sizable and random sample of the loans. The portfolio was composed of loans that were approved between 1990 and 1996. Prior to sampling, the study team excluded the 10 loans that were reviewed as part of the scoping study sample from the portfolio. Consequently, the random sample was drawn from a portfolio of 154 loans. A random sample of 50 loans was selected from the portfolio of the Bank's recent energy sector. Table 2.1 lists the sample of 50 loans and provides descriptive information, such as loan size, project size, and approval year. This table also describes some of the project components that are relevant to GHG emissions and the shadow price analysis.

The sample was stratified by year to determine whether an increasing emphasis since 1994 on the institutional, regulatory, and reform needs of developing country power sectors affects the shadow price analysis results over time (World Bank 1993). Approximately 62 percent of the loans in the portfolio were approved during the 1990–93 period, and the remaining 38 percent were approved during the 1994–96 period. Sample proportions are roughly the same: 64 percent of the sample loans are from the 1990–93 period and 36 percent are from the 1994–96 period.

A comparison between the Bank's loan portfolio and the study sample with respect to project-type composition (table 2.2) and regional composition (table 2.3) demonstrates that the sample is representative of the portfolio. Table 2.2 lists the types of activities that a loan might include, and summarizes how many of the loans in the portfolio included each activity. For example, 56 loans or 59 percent of the 1990–93 loans included activities related to power development. Table 2.2 also reports the activities for the study sample.

Table 2.1
Energy Loans Analyzed in the Backcasting Main and Scoping Studies

Loan title	*Loan size ($ millions)*	*Project cost ($ millions)*	*Approval year*	*Project description*
Main study loans				
Albania—Power Loss Reduction	5.0	8.7	1995	Transmission and Distribution—Efficiency
Algeria—First Petroleum	64.1	122.6	1992	Fuel Production
Argentina—Hydrocarbon Engineer	28.0	40.0	1992	Fuel Development
Argentina—Pub. Entrp. Ref. Adj.	300.0	300.0 [a]	1991	Reform, Institutional
Armenia—Power Maintenance	13.7	14.5	1994	Other Efficiency
Bangladesh—LPG Distribution	67.2	94.2	1991	Fuel Distribution
Bolivia—Hydrocarbon Sector Ref. & Cap.	10.6	13.3	1996	Reform, Institutional
Brazil—Hydrocarbon Transport and Processing	293.4	633.7	1991	Fuel Distribution
Burundi—Energy Sector Rehab.	22.8	32.2	1991	Rural Electrification
Chad—Engineering	11.0	14.5	1991	Supplemental
China—Beijing Environment	—	—	—	—
China—Inland Waterways	210.0	556.8	1995	New Renewable Supply—Hydro
China—Sichuan Transmission	270.0	1,078.7	1995	Transmission and Distribution—Expansion
China—Yanshi Thermal	180.0	355.0	1992	New Thermal Supply—Coal
Colombia—Energy TA	11.0	12.4	1995	Reform, Institutional
Colombia—Power Market Development	249.3	410.0	1996	Transmission and Distribution—Efficiency
Côte d'Ivoire—Energy Sector Loan	100.0	100.0 [a]	1990	Reform, Institutional
Ghana—Power Sector	40.0	117.5	1990	Other Efficiency
Ghana—VRA/Sixth Power	20.0	156.0	1990	Rural Electrification
Guinea-Bissau—Energy	3.9	9.2	1991	New Thermal Supply—Other
Hungary—Energy Environment	100.0	242.5	1994	New Thermal Supply—Other
India—Maharashtra Power 2	350.0	957.4	1992	New Thermal Supply—Coal
India—NTPC Power Generation I	400.0	8,009.0	1993	New Thermal Supply—Coal
India—Power Grid Corporation Power System	350.0	764.0	1993	Transmission and Distribution—Expansion
India—Private Power Util. I	200.0	653.0	1990	New Thermal Supply—Coal
Indonesia—Gas Utilization	86.0	118.8	1990	Transmission and Distribution—Expansion
Indonesia—Suralaya Thermal Power	423.6	2,360.5	1992	New Thermal Supply—Coal
Indonesia—TA for Infra.	28.0	33.6	1995	Reform, Institutional
Iran—Power Sector Efficiency	165.0	413.9	1993	Other Efficiency
Jordan—Energy Sector Loan	80.0	80.0 [a]	1994	Reform, Institutional
Latvia—Jelgava Dist Heat	11.7	14.7	1995	Other Efficiency
Madagascar—Pet Sector Reform	13.8	13.9 [a]	1994	Reform, Institutional
Mauritius—Sugar Energy Development	15.0	55.1	1992	New Renewable Supply—Bagasse
Morocco—Second Rural Electrification	114.0	220.0	1991	Rural Electrification
Pakistan—Domestic Energy Resources Dev.	180.0	541.6	1992	Fuel Development
Pakistan—Pvt. Sector Egy. Dev. II	250.0	2,390.0	1995	New Thermal Supply—Other
Pakistan—Supp. Loan to ESLII	28.0	46.0	1991	Supplemental
Philippines—Rural Electrification	90.0	90.0 [a]	1991	Rural Electrification
Poland—Power Transmission	160.0	275.7	1996	Transmission and Distribution—Efficiency
Sri Lanka—Power Distribution	50.0	79.0	1992	New Thermal Supply—Other
Tanzania—Power VI	200.0	383.7	1993	New Renewable Supply—Hydro
Thailand—Second Power Sys. Dev.	94.0	2,780.0	1990	New Thermal Supply—Coal, Other
Turkey—Berke Hydro Plant	270.0	623.7	1992	New Renewable Supply—Hydro
Ukraine—Hydropower Rehab.	114.0	215.1	1995	Other Efficiency
Uruguay—Power Trans. & Dist.	125.0	228.0	1995	Transmission and Distribution—Expansion
Uzbekistan—Instit. Bldg.	21.0	25.0	1994	Reform, Institutional
West Samoa—Afulilo Hydro Power	1.0	1.0	1993	Supplemental
Yemen—Power 3	15.4	20.9 [a]	1990	New Thermal Supply—Other
Yugoslavia—Kolubara Thermal	300.0	1,314.3	1991	New Thermal Supply—Other
Zimbabwe—Power 3	90.0	1,191.1	1994	New Thermal Supply—Coal, Other
Scoping study loans				
China—Yangzhou Thermal Plant	350	1,081.4	1994	New Thermal Supply—Coal
Estonia—District Heating Rehabilitation	38.4	64.5	1994	Other Efficiency
Ghana—Thermal Power	175.6	414.3	1995	New Thermal Supply—Other
India—Renewable Resources Development	75.0	280.0	1992	New Renewable Supply—Hydro, Other
Indonesia—2nd Rural Electrification	398	841.3	1995	Rural Electrification
Peru—Electricity Privatization Adjustment Loan	150	150	1995	Reform, Institutional
Russia—Gas Distribution Rehabilitation and Energy Efficiency	106.5	131.4	1995	Other Efficiency
Thailand—Distribution System and Energy Efficiency	109.0	658.6	1993	Transmission and Distribution—Expansion

— Not available.
a. These SARs did not report total project costs. The loan was used as an estimate of project costs.

Table 2.2
Comparison of Loan Activity Distributions for Energy Loan Portfolio and Study Sample

Loan activities listed in energy portfolio	*Portfolio of 154 loans*				*Sample of 50 loans*			
	1990–93		*1994–96*		*1990–93*		*1994–96*	
	Number	*%*	*Number*	*%*	*Number*	*%*	*Number*	*%*
Reform private sector	19	20	19	32	6	19	4	22
Efficiency	44	46	25	42	12	38	9	50
Rural and household	12	13	4	7	3	9	1	6
Nonconventional and renewable	3	3	2	3	1	3	0	0
Energy and environment	13	14	11	19	4	13	4	22
Power development	56	59	25	42	19	59	8	44
Oil and gas	28	29	20	34	11	34	4	22
Heat	1	1	6	10	1	3	2	11
Other energy sector	11	12	4	7	3	9	4	22
Other energy	0	0	1	2	0	0	0	0
Other	5	5	9	15	3	9	3	17

Source: World Bank 1995.

Table 2.3 lists the major Bank regions, and the number of loans in the portfolio and the study sample in each region. For the 1990-1993 period, the regional proportions of the sample are similar to portfolio proportions except for a slight over-representation of North Africa and the Middle East and offsetting under-representation of Latin America and the Caribbean. East Asia is under-represented in the 1994–96 period sample, and Latin America and the Caribbean is over-represented. The Latin American and the Caribbean loan portfolio for that period tends to have a higher proportion of reform, efficiency, and energy and environment loans than the East Asia portfolio, so there is some possibility that the regional distribution will bias the results toward such loans. However, the sample distribution was compared by region and activity with the loans in the 1994–96 period, and it was found that reform and efficiency loans in East Asia are under-represented in the sample, and oil and gas loans in Latin America and the Caribbean are over-represented. These results tend to offset any potential bias because of the regional distribution.

2.2 Greenhouse Gas Emissions Analysis

The carbon shadow price analysis required an estimate of the carbon emissions over time that were associated with the Bank loan. CO_2 emissions are the primary source of carbon-equivalent emissions for most energy-related investments that involve hydrocarbon-based fuel sources. Other GHG emissions may occur, however. For example, fugitive methane emissions from natural gas transmission lines and pumps, methane emissions from coal mines, methane and nitrous oxide emissions from fuel combustion, various emissions from vehicles and equipment, and emissions from land use changes. Emissions from these sources can be expressed in carbon equivalents and included in the shadow price analysis because the relative

Table 2.3
Comparison of Regional Distributions for Energy Loan Portfolio and Study Sample

Region	*Portfolio of 154 loans*				*Sample of 50 lwoans*			
	1990–93		*1994–96*		*1990–93*		*1994–96*	
	Number	*%*	*Number*	*%*	*Number*	*%*	*Number*	*%*
Latin America and the Caribbean	13	14	9	15	3	9	4	22
North Africa and the Middle East	7	7	1	2	4	13	1	6
Africa	23	24	7	12	8	25	2	11
East Asia	24	25	20	34	7	22	3	17
South Asia	21	22	4	7	8	25	1	6
Europe and Central Asia	7	7	18	31	2	6	7	39

contribution of non-CO_2 gases to global warming can be compared to CO_2 using carbon equivalents from the IPCC Second Assessment Report (Houghton et al. 1996).

Most of the emissions estimates do not include incidental sources because such emissions are small compared to carbon emissions from fuel combustion. For example, during the scoping study, methane emissions from coal mining and combustion were found to be less than 20 percent of carbon emissions from combustion. Furthermore, estimating incidental emissions would have required more information than typically provided in the SARs, and the associated estimation methods are more uncertain compared to methods for estimating carbon emissions from combustion (IPCC 1995).

Nonetheless, for a few projects, fugitive methane emissions were included and converted to carbon equivalents because they made up a significant share of project GHG emissions.

2.2.1 Two Definitions of Emissions

To measure carbon emissions, two definitions of what constituted a project's carbon emissions were used. First, "project emissions" were defined as the total emissions that are generated by the project. Second, the study team defined "net emissions" as project emissions minus an estimate of what emissions might have occurred in a counterfactual scenario. Counterfactual scenarios were adopted based on "business as usual" activities, that is, what might have occurred without the Bank loan. Two examples given below demonstrate the differences between project and net emissions.

The first example is a thermal power plant. Project emissions are the plant's emissions when it is operated to generate electricity. Because project emissions are positive, a carbon shadow price will reduce the loan's EIRR and NPV. To estimate net emissions, counterfactual scenario(s) are defined as what might have happened without the Bank loan. Would the host country have built the plant anyway? Would smaller and less efficient plants with higher aggregate GHG emissions have been built? Would no thermal facility have been built? The estimate of net emissions differs significantly across these three counterfactual scenarios. If the plant were built regardless of loan approval, net emissions would be zero because the project's emissions would be the same as the counterfactual scenario's emissions. If several smaller, less efficient thermal plants were built to supply the same level of energy services, net emissions would be negative because the aggregate emissions of the smaller plants would be greater than the project's emissions. Finally, if the plausible counterfactual scenario is no thermal plant, net emissions would be positive and equal to project emissions. Depending on which of these counterfactual scenarios is more plausible, a shadow price on net emissions would increase, decrease, or not affect the project's EIRR and NPV, respectively.

As the second example, a demand-side management (DSM) program may be considered. A DSM program helps existing capacity satisfy more demand by reducing the energy requirements of end uses. Essentially, DSM is a way to increase energy benefits without consuming additional fuel. Consequently, project emissions are zero because no actual carbon emissions are associated with the program, and EIRR and NPV are unaffected by a carbon shadow price. This approach is consistent with conditions in many developing countries where the demand for energy services exceeds supply.

Supposing that the DSM program would not have been implemented without Bank support, and that the result would be greater baseline fuel consumption and carbon emissions, then the program's net emissions would be negative. The program's reduction in fuel consumption could be caused by either a reduction in the generation required to meet existing energy service demand, or a reduction in future generation capacity growth required to meet growing energy service demand. The shape of the baseline growth path of electricity demand will determine which characterization is appropriate.

Both examples illustrate the importance of distinguishing between project and net emissions when incorporating a shadow price in the economic analysis of a project. They also illustrate the difficulty in selecting a single method. Although the measure of project emissions accurately reflects a project's direct effect on the environment, it obscures the DSM project's carbon emissions reductions compared to baseline emissions. Similarly, although the net emissions analysis reflects economic benefits of reducing fuel consumption and emissions relative to baseline emissions, it is based on a hypothetical reference case because the counterfactual scenario is an educated guess about what might have happened without Bank funding. Consequently, economic results based on net emissions are potentially less defensible. In particular, it is not defensible to conclude that a thermal plant's negative net emissions accurately reflect its environmental impact.

Another way to clarify the distinction between the two emissions measures is to note that they are compatible with different mechanisms for reducing carbon emissions: the project emissions approach is suitable for an emissions permit mechanism, and the net emissions approach is suitable for a joint implementation mechanism. A permit mechanism requires that emission sources have enough permits for their emissions. Any Bank project that generates emissions would need to estimate its total emissions and obtain permits for them; projects that do not have emissions do not need permits. If the permits were purchased, project costs would increase much as they do with the shadow price on project emissions. Alternatively, a joint implementation mechanism is based on quantifying emission reductions from baseline or "business as usual" emissions, which is the same as our net emissions approach
Project alternatives can be compared against one another using either approach because emissions are ranked consistently across the approaches. However, the two approaches should not be mixed, using project emissions for some projects and net emissions for others. Mixing the two approaches is tantamount to double-counting.

To illustrate this problem, the examples of the new thermal generating unit and the DSM program may be considered again. This time, however, it may be supposed that they are alternatives under consideration to help a utility meet an increase in energy service demand. The utility can add generating capacity and increase fuel consumption to meet demand, or alter end user technologies to meet the same demand for services without increasing capacity and fuel consumption. An economic analysis for the added capacity includes fuel consumption, a shadow price would naturally be applied to the associated emissions, which are called project emissions. The economic analysis of the DSM program, however, would include avoided fuel consumption, so one would be inclined to estimate avoided or negative carbon emissions (that is, net emissions), and apply a shadow price to them. By mixing project and net emissions across the alternatives, the difference in emissions between the two alternatives has been counted twice.

2.2.2 Information Sources

The study team relied on several data sources to estimate emissions. The SARs were the primary source, but they generally did not contain estimates of carbon emissions. However, the SAR data often included information, such as fuel consumption forecasts or electricity sales and fuel mixtures that were used to derive emissions.

Additional sources of data for emissions calculations included other documents in the project file, such as feasibility studies or demand forecasts, information provided by Bank task managers, and standard conversion factors in engineering data bases. Finally, emissions factors from the *Greenhouse Gas Inventory Volume 3: Reference Manual* (IPCC 1995) were used to convert energy consumption to carbon emissions. Table 2.4 lists some of the energy sector emissions factors, which are in kilograms of carbon (kgC) per gigajoule (GJ). All noncarbon GHG emissions were converted to carbon equivalents using the most recent Global Warming Potential Index values (Houghton et al. 1996) to obtain CO_2 equivalents, and multiplying by a molecular weight factor of 12/44 to obtain carbon.

2.2.3 Project Emissions

To obtain project emissions estimates, the same basic question was asked for all of the loans: What are the actual GHG emissions from the project? Projects that emit GHG have positive project emissions; those that do not have zero emissions. Finally, projects that actively reduce atmospheric concentrations, for example, carbon sequestration projects, have negative project emissions.

Table 2.4
Selected Emissions Factors

Fuel source	*Emissions factor (kgC per GJ)*	*Fuel source*	*Emissions factor (kgC per GJ)*
Peat	28.9	Residual Fuel Oil	21.1
Lignite	27.6	Gas or Diesel Oil	20.2
Anthracite	26.8	Crude Oil	20.0
Sub-Bituminous Coal	26.2	Other Kerosene	19.6
Other Bituminous Coal	25.8	Gasoline	18.9
Bitumen	22.0	Natural Gas Liquids	15.2

Source: IPCC 1995.

Below is the general approach to characterizing project emissions by types of activities funded by the Bank loans. These activities are divided into supply-side activities (ranging from fuel development to point of service) and demand-side activities (affecting end user demands for energy services).

Supply-Side Activities

The loans in the study sample funded five main types of supply-side activities:

1. Generation capacity development, for example, new generating units.
2. Transmission and distribution development, for example, new lines.
3. Fuel development, for example, field development and refinery rehabilitation.
4. Fuel-switching, for example, retrofitting boilers to burn biomass rather than fuel oil.
5. Miscellaneous energy system efficiency improvements, for example, plant upgrades or transmission and distribution (T&D) efficiency investments. Generation Capacity Development

For projects that included new thermal units, project emissions for the units were the annual carbon emissions caused by fossil fuel combustion. Other GHGs from combustion and upstream emissions were not included, so the estimate of project emissions is conservative. During the scoping study, upstream emissions, such as methane emissions from fuel transport, were quantified and found to be small relative to fuel consumption emissions (that is, less than 20 percent of consumption emission). Consequently, the study team decided against quantifying them for thermal generation activities in the main study.

Project activities that implemented renewable energy resources, such as new hydropower facilities, had zero project emissions. Incidental emissions associated with construction and operation activities were not quantified because they would have minimal effects on project EIRRs and NPVs.

Transmission and Distribution Projects

A metric ton of carbon emitted should be assessed a shadow price only once. For combustion emissions, the natural point at which to assess the shadow price is on the project that builds the combustion unit. It is clearly double counting to include a shadow price on emissions for the new plant, and a shadow price on those same emissions for an accompanying T&D project. However, if the shadow price is not assessed on the new plant, it is appropriate to assess it on the accompanying T&D expansion. For the T&D expansion loans in the sample that included new generation units, the shadow price was assessed on the generation units. For the T&D expansion loans in the sample that only financed T&D activities, carbon emissions were estimated for the reported increases in fuel consumption, and a shadow price was applied to those emissions. One T&D loan, the India Power Grid Corporation Power System Project, was associated with another loan in the sample, which financed the generation capacity associated with the T&D expansion loan. Because a shadow price was assessed on the combustion emissions of the generation loan, those emissions were not double counted for the T&D loan. Similarly, the China Sichuan Transmission Project provided grid connections for a Bank-funded hydropower project. The methane emissions of the hydropower plant would have been considered for a Bank loan for that project, so they were not included in the T&D loan.

Fuel Development Projects

Project emissions for fuel development investments also required a determination of whether fugitive emissions and combustion emissions had been included in shadow price analyses of associated generation activities. If the analysis of a new generation unit includes upstream fugitive emissions, then those same emissions should not be included in the economic analysis of the upstream development project. Conversely, if the economic analysis of the generation unit does not include a shadow price on fugitive and fuel consumption emissions, the shadow price can be assessed on the fuel development project. This is the case for the fuel development projects in the loan sample, so both fugitive emissions and combustion emissions were estimated for domestically consumed fuel, and a shadow price was applied to total emissions. As a sensitivity analysis, the shadow price was also applied only to fugitive emissions.

Fuel-Switching Projects

Fuel-switching activities have positive project emissions when the new fuel source emitted carbon (for example, peat fuel used in the Estonia District Heating Project), and zero project emissions when the new fuel source has no emissions (for example, hydropower as in the Ghana Power System Project). Project emissions, when positive, were measured as total emissions of the new fuel source. Emissions of the original fuel source were not netted out because project emissions are the total emissions caused by the new fuel.

Efficiency Projects

Efficiency investments include many activities designed to improve generation and T&D efficiency such that electricity services require less generation capacity. For example, generation units can be repaired or maintained to decrease the fuel consumption per unit of energy output, and T&D upgrades can reduce line losses on overloaded systems. Such investments do not generate combustion emissions or significant incidental emissions, so project emissions are zero.

Demand-Side Activities

Project emissions for demand-side energy efficiency projects, such as DSM programs or metering programs, are equal to zero because no appreciable emissions are generated by activities such as selling compact fluorescent bulbs or installing gas meters. Incidental emissions, such as vehicle emissions, were too small to affect the analysis. For example, the SAR for the Brazil Hydrocarbon Transport Project provided vehicle use information that was used to estimate annual carbon emissions, which were 40 metric tons per year.

2.2.4 Net Emissions

In contrast to the project emissions analysis, net emissions were measured relative to one or more plausible counterfactual scenarios about what might have happened without Bank funding for the project. Net emissions were calculated by subtracting the emissions from the counterfactual scenario from a loan's project emissions. If the counterfactual scenario had higher emissions than the project, net emissions were negative. Conversely, if the counterfactual scenario had lower baseline emissions, net emissions were positive. Finally, projects that would have been undertaken regardless of Bank funding had net emissions of zero because the project's emissions would have occurred without Bank funding. In some instances, a range of hypothetical counterfactual emissions was considered to account for the uncertainty of estimating a hypothetical project emissions stream. Because the SARs generally contained no information about baseline emissions, loan task managers were the primary source of information for net emissions analysis.

Generation Capacity Development. As shown in the example above, net emissions for power supply projects could be either positive, negative, or zero, depending on whether the plausible counterfactual energy source generated fewer, more, or the same amount of carbon emissions. When Bank funding promoted a more efficient energy source than would have been developed in the absence of Bank funding, the less efficient sources making up the counterfactual scenario would have had higher GHG emissions than the Bank's project, and net emissions would be negative. Conversely, had Bank funding led to construction of a larger energy supply project than would have been built under more constrained capital conditions, net emissions would have been positive. However, net emissions would be less than project emissions whenever some emissions would have occurred anyway in the counterfactual scenario.

Energy Efficiency and Renewable Fuels Projects. Net emissions reductions for energy efficiency projects and renewable fuels projects would be negative (that is, signifying a reduction in emissions) as long as emissions would have occurred without the loan. For example, in the counterfactual scenario for the Latvia District Heating Rehabilitation Project, it was assumed that the program's heat losses would continue to occur without the program, and that fuel consumption would be higher. Thus the project's negative net emissions were based on its reduction in heat losses and the related fuel savings.

Fuel-Switching Projects. Similarly, fuel-switching projects could have positive, negative, or zero net emissions. Projects that switched to a fuel source that had higher project emissions than the original fuel source had positive net emissions equal to the difference in emissions across the fuels. Conversely, fuel-switching projects from higher carbon emitting fuels to low or no carbon emitting energy sources had negative net emissions.

2.3 Shadow Price Analysis

Having estimated a loan's project emissions, the next step was to incorporate the emissions and shadow prices ($5, $20, and $40 per metric ton) in the SAR economic analysis. These shadow prices represent a reasonable range of values based on the IPCC summary of global climate change damage studies, which is shown in table 2.5 (Watson, Zinyowera, and Moss 1996).

The study team applied the shadow price to project emissions rather than net emissions to show what might happen to the Bank's portfolio if the actual environmental impacts of emissions were considered. Essentially, the shadow price analysis involved multiplying the stream of project emissions over time by each shadow price to obtain environmental costs of carbon emissions (see Box 2.1). These costs were subtracted from net benefits to obtain three new net benefit streams. Finally, an EIRR and an NPV were recalculated for each new net benefits stream. However, there were two important issues to address in the analysis: the marginal damages of emissions may rise over time, and the "appropriate" discount rate on the shadow price is still a topic of debate. With respect to the first issue, one could argue that the shadow price should rise over time because the willingness to pay to avoid additional emissions rises as emissions accumulate. Atmospheric GHG concentrations will be higher in 25 years than they are now, and a marginal increase of that higher concentration might have greater damages than a marginal increase now. Willingness-to-pay values in the future could also be higher if real incomes are higher and the environmental and economic goods affected by climate change are normal or superior goods.

To address this issue, the study team reviewed per metric ton values reported for different time periods to determine a possible range of escalation rates for the shadow prices. Fankhauser (1995) summarized decennial shadow prices for 1991–2000 and 2021–30 from four benefit-cost studies of climate change. The escalation rates implied by the growth of these values between the two decades are approximately 2 percent per year. The team used this escalation rate, so the shadow prices grew by 2 percent per year over the lifetime of a project.

Table 2.5
Summary of Social Costs of CO_2 Emissions over Time
(in 1990 $ per tC)

Study	*1991–2000*	*2001–10*	*2011–20*	*2021–30*
Ayres and Walter (1991)		30–35		
Nordhaus (1994)	5.3	6.8	8.6	10.0
Best guess	12.0	18.0	26.5	n.a.
Expected value				
Cline (1992)	5.8–124	7.6–154	9.8–186	11.8–221
Peck and Teisberg (1992)	10–12	12–14	14–18	18–22
Fankhauser (1994)	20.3	22.8	25.3	27.8
	(6.2–45.2)	(7.4–52.9)	(8.3–58.4)	(9.2–64.2)
Maddison (1994)	5.9–6.1	8.1–8.4	11.1–11.5	14.7–15.2

Source: Watson, Zinyowera, and Moss 1996.

To address the discounting issue, the team conducted a bounding exercise by using discount rates from under debate (Arrow et al. 1996). At the upper end is the discount rate from the economic analysis in the SAR, or a cost-of-capital rate reported in the SAR or obtained from the task manager (for example, Munasinghe and Lutz 1993; Markandya and Pearce 1994). Taking the 2 percent escalation rate into account, the net discount rate on the shadow price is equal to the cost-of-capital rate (usually about 10 percent to 12 percent) minus 2 percent, which will differ across countries.

At the lower end of the discount rate range is a social discount rate; rates commonly used in climate change damage studies range from 0 percent to 3 percent (for example, Cline 1992; Nordhaus 1993; and Fankhauser 1994). The study team selected a social discount rate of 2 percent such that when the 2 percent escalation rate is subtracted, the net discount rate is 0 percent. This approach is similar to "cost of carbon" estimation methods such as those conducted by the GEF (Anderson and Williams 1993).[1]

For some projects, a shadow price analysis using net emissions was also conducted when the net emissions approach was consistent with the economic analysis in the SAR. For example, the SAR analysis of energy efficiency loans generally focused on fuel savings. Net emissions, that is, avoided GHG emissions, are consistent with an economic analysis of fuel savings, so the shadow price was applied to net emissions to determine how a shadow price would have affected the project's EIRR and NPV.

To standardize the EIRR and NPV across projects, and obtain comparable shadow price impacts, all monetary units were converted to 1995 U.S. dollars. In many instances, the values in the SARs were in U.S. dollars. When they were not, national currency was converted to U.S. dollars using the exchange rate quoted in the SAR. This exchange rate was for the base year in which all values were expressed, so the result was U.S. dollars in some base year between 1989 and 1995. The U.S. gross domestic product (GDP) deflator was then used to convert from base year U.S. dollars to 1995 U.S. dollars (Council of Economic Advisors 1996). For example, the economic analysis for the India Renewable Resources Project was in 1992 rupees. Rupees were converted to U.S. dollars using the 1992 exchange rate in the SAR. The 1992 U.S. dollar figure was then converted to 1995 U.S. dollars using the GDP deflator values for those years.

For all of the loans in the sample, the Bank loans partially funded the projects. This raises the issue of whether the entire project should be evaluated, or if only the Bank's "share" should be isolated and analyzed. It generally is not possible to isolate the Bank's share because

Bank monies financed portions of most or all activities. Furthermore, one objective of the shadow price analysis is to determine how it would affect the Bank's portfolio. Because the Bank's original investment decision was based on the entire project (or entire project component), the backcasting analysis similarly evaluated the entire project or component.

The SARs for several of the Bank loans contained more than one economic analysis; independent project components were analyzed separately. The study team considered combining them into a single project analysis, or developing separate GHG emissions and shadow price analyses. Combining them would have concealed the effects of the shadow price on individual components, which may have otherwise revealed that some components no longer had a positive economic benefit. Because this effect potentially reduced the value of the backcasting study, the study team developed separate analyses.

The economic analysis in many of the SARs contained costs and benefits for a larger energy development program rather than the project funded by the loan. Ideally, one would want to evaluate the effect of a carbon shadow price on the funded project, but it generally was not possible to do so because cost and benefit data for the project were not provided. Because the original loan determination was based on the economic analysis of the program rather than the project, the study team opted to conduct a shadow price analysis for the entire program. However, the team tried to indicate whether the shadow price effects on the project might differ from the effects on the program.

2.4 Shadow Prices for Other Externalities

Many of the projects that were considered have other air, water, and solid waste emissions in addition to the GHG emissions evaluated with the carbon shadow price. A new coal-fired power plant, for example, has a variety of air emissions besides carbon dioxide, including nitrogen oxide (NO_x), sulfur dioxide (SO_2), and particulate matter (PM). The environmental impacts associated with these other air pollutants are referred to as "local impacts" because they affect the local population and environment, for example, health effects from smog and fine particulate, and injuries to forests from acid rain (see, for example, Rosebrock 1994; and Rowe et al. 1996). Monetizing these impacts could have a significant effect on NPV. To estimate the relative size of these local impacts in comparison to GHG impacts, three projects in the sample were evaluated, which included estimates of these emissions in the SAR, or which included data that could be used to readily estimate emissions of NO_x, SO_2, and PM. The team focused its analysis on these pollutants because they are the precursors to ozone, fine particulate, and acid rain. Recent research has found that impacts from these pollutants (primarily health impacts) comprise the largest share of local damages from energy projects (Rowe et al. 1996).

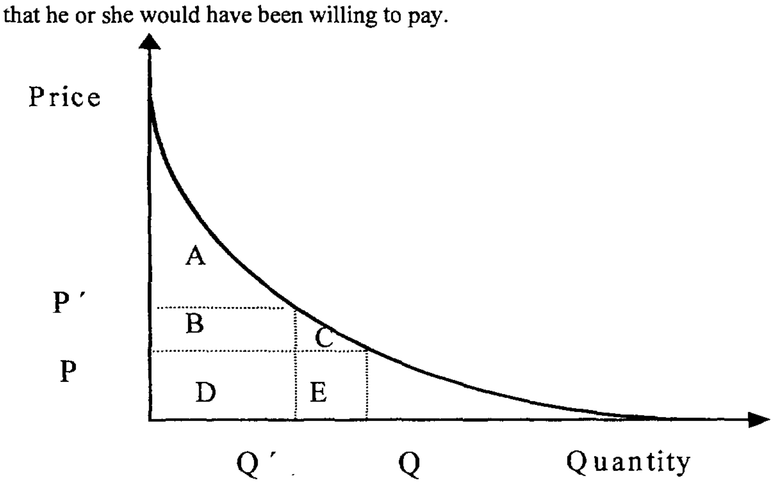
The shadow prices that were used to quantify local impacts were taken from Rosebrock (1994) and are shown in table 2.6. To adjust these values to local equivalent values, Shah and Larsen (1992) suggest using a purchasing power parity (PPP) index. The PPP index values reported in the *World Development Report: 1995* (World Bank 1995) were used.

The team used these values to estimate local benefits for the Latvia District Heating Rehabilitation Project in which several small, inefficient coal-fired boilers would be shut down. Total annual emissions reductions for the project were estimated in the SAR to be 53 metric tons of SO_2, 12 metric tons of NO_x, and 8.5 metric tons of PM. Applying the PPP index, the local shadow price values were $512 per metric ton-$SO_2$, $2,217 per metric ton-$NO_x$, and $1,362 per metric ton-PM. Including these local benefits in the project economic analysis has about the same impact as the $5 per tC shadow price. The relative magnitude of local benefits for other projects will vary with emissions rates and PPP.

Box 2.1: A Note on Methodology

This exercise is *not* meant to model the real-world effects of a carbon tax. The World Bank is in no way suggesting that a carbon tax be imposed on borrowing countries. In fact, there is currently no proposal before the Bank's Board to mandate that carbon shadow value analysis be incorporated into the Bank's project or other planning processes. Because the study does not examine a proposal to tax World Bank projects, the analytical techniques used depart significantly from the methodology that would be needed to evaluate an actual carbon tax. The study team assessed the impact of a carbon shadow value on World Bank energy lending by recalculating the net present value (NPV) of energy projects, that is, subtracting the value of the environmental damages associated with carbon emissions from a stream of tariff-based project benefits.

The study team was aware that, especially in developing countries, a tariff-based NPV may substantially understate the economic benefits of energy projects. Because of the relatively inelastic demand for electricity, electricity tariffs in developing countries may be well below consumers' willingness to pay for electric power. Where this is the case, a tariff-based NPV understates the economic value of the project by failing to account for ***consumer's surplus***, that is, the extra benefit experienced by a consumer from being able to buy a particular commodity at a price lower than that he or she would have been willing to pay.



In the figure shown above, an NPV based on the prevailing electricity tariff P measures revenues (represented by the areas D and E), but does not account for consumers' surplus, (represented by the areas A, B, and C). In the case of a rise in the price of electricity from P to P' (that is, a rise in the cost of generating electricity using high-carbon fuels, such as coal), the new quantity demanded is Q', the new revenue is represented by the areas B and D, and the new consumers' surplus would be A. B represents the loss of consumers' surplus from having to pay more for each unit of electricity consumed, and C represents the loss of consumers' surplus from consuming less electricity. In the case of a developing country experiencing power shortages, which has large amounts of pent-up demand for electricity to fuel new industries and businesses, a modest rise in price is not likely to cause consumers to consume less electricity, but rather will simply lower the level of consumers' surplus. Forecasting how these price and consumption parameters would change with shadow prices would require estimation of income and elasticity effects. Such analysis was beyond the scope of the study and, in the study team's view, would have materially contributed neither to reaching the study's objectives nor to its policy relevance.

Despite the shortcomings associated with using a tariff-based NPV, the study team concluded that it was appropriate in this instance, because the objective was not to measure the economic benefits of power projects in developing countries. Rather, examining changes in NPV is merely a means of quantitatively assessing the carbon intensity of projects in order to identify projects for which there may be low- or no-cost alternative ways to supply equivalent energy services to the borrowing country. In noting where the NPVs of projects are sharply reduced by accounting for the shadow value of greenhouse gas (GHG) emissions, the study team is in no way implying that it is "uneconomic" to develop electricity infrastructure in a given country or using a particular technology. Instead, a large drop in NPV is simply a signal indicating that it may be worthwhile to consider lower-carbon alternatives to the project in question.

Table 2.6 **Shadow Price Values for Local Benefits** (1990 $ per metric ton)			
	NO_x	SO_2	*PM*
Shadow price value	$6,500	$1,500	$4,000

Source: Rosebrock 1994.

[1] Anderson and Williams (1993) derive their 0 percent net discount by escalating the shadow price at the rate of discount, then discounting it using the same rate. The rationale for their escalation approach is based on an economic theory of the optimal "extraction" rate for depletable resources (Hotelling 1931), which holds that the value of a depletable asset should appreciate over time at the same rate as other assets. In Anderson and Williams' (1993) work, the depletable asset is carbon emissions, which are capped to meet some target of atmospheric concentration. Thus the shadow price, which is the value of the depletable asset or right to emit carbon, rises over time at the cost of capital rate.

3 Shadow Price Analysis Results

Fifty-eight energy sector loans underwent shadow price analysis. The results are discussed below.

3.1 Overview of Loan Samples

Table 3.1 reports summary statistics for the random sample of 50 loans selected for the main study and the 8 loans selected during the scoping study. As shown, the loans totaled $8,033 million and represent about 37 percent of the Bank's energy loan portfolio for fiscal years 1990–96. The loans represent about 22 percent of total spending on the projects they financed.

The loans in the main study sample financed a total of 20,805 MW of thermal generation capacity (including rehabilitation of older units) and the 9 scoping study loans financed 900 MW of new thermal generation. The primary fuel burned in the new generating units was coal (16,600 MW).

The coal units were primarily located in India, Indonesia, and China. New hydro capacity for the main study sample was about an additional 1,645 MW, and about 100 MW for the scoping study sample.

3.2 Results of Emissions Analysis

Of the 50 main study loans, 12 loans or 24 percent did not have an SAR. Only one of the nine scoping study loans did not have an SAR. Ten of the 13 loans without SARs were investments in policy reform measures, such as privatization, restructuring, or price reform. The documentation available for these loans did not include quantitative estimates of project costs and benefits, so no quantitative shadow price analyses could be conducted. Furthermore, the activities funded by these loans would only indirectly affect future fuel consumption and carbon emissions. Consequently, the team could perform only qualitative emissions analyses on these loans. Whenever the funded activities supported growth in the energy sector (for example, oil well development), the team concluded that they would tend to increase future emissions. However, such loans might generate more efficient growth in energy use compared to the growth that might have occurred without the investment, which would lead to lower carbon emissions compared to a counterfactual scenario.

Table 3.1
Summary Statistics for Loan Amounts and Project Costs

Loan Sample	*Total Loan Amount*	*Total Project Costs*[a]
Main Study (50 loans)	$6,181 million	$27,766 million
Scoping Study (8 loans)	$1,853 million	$9,194 million
Total	$8,033 million[b]	$36,960 million

a. SARs for a few policy loans did not include information about total project costs. For those loans, the loan amount was used as a proxy for project cost.
b. Detail does not add to total due to rounding.

Table 3.2
Summary Statistics for Project and Net Emissions

Loan Sample	*Total Project Emissions*[a]	*Total Net Emissions*
Main Study	1,431 million tC	134 million tC
Scoping Study	181 million tC	20 million tC

a. Project emissions include about approximately 1,000 million tC from multiyear programs, of which the Bank-funded projects account for about 20 percent of emissions.

Two of the loans without SARs were supplemental investments for earlier Bank investments. Assuming that the original Bank loan would include a shadow price on emissions, the study team determined that no emissions should be associated with the supplemental loan, even though it may have had some effect on the timing of emissions (that is, net emissions might be positive because the loan caused a project to be completed earlier than it would have been without the loan). Had it been assumed otherwise, these relatively small supplemental loans would have had large project emissions.

Table 3.2 shows total project and net emissions for the loans that provided enough information in the SARs to derive emissions. Net emissions are positive, which

means that the Bank loans generated carbon emissions that would not have occurred under the counterfactual scenarios. Net emissions, however, are significantly lower than project emissions for two main reasons:

1. Many of the projects that have positive project emissions would have been completed without the Bank loan and, therefore, have zero net emissions.

2. Some of the projects reduce carbon emissions compared to their respective counterfactual scenarios, resulting in negative net emissions that reduce total emissions across the loans.

Overall, about 80 percent of project emissions come from 16 loans that increase generation capacity, and about 66 percent of emissions come from coal facilities. The remaining 20 percent of emissions are associated with four T&D expansion projects that increase fuel consumption and carbon emissions, and five fuel development projects. Chapter 2 noted that

shadow prices were assessed on emissions associated with these activities when they were not assessed at another point of the electricity supply (for example, a new generation unit). If shadow prices were routinely assessed on all generation units, positive project emissions would not need to be associated with T&D projects, and they would only be counted on fugitive emissions associated with fuel development projects.

3.3 Results of Shadow Price Analysis

The results of the shadow price analysis on the main study loan sample are summarized below. The scoping study loans were not included in these results because they are not part of the randomly drawn sample from which inferences are drawn about how a carbon shadow price might affect the energy loan portfolio. However, the sensitivity of the results to including the scoping study loans was tested, and relatively little change was found.

Some of the economic analyses in the SARs were broken down by component. For example, the Indonesia Gas Utilization Project SAR analyzed two components separately, and the Brazil Hydrocarbon Transport Project SAR analyzed five components separately. Because each loan subcomponent was analyzed separately, 61 independent shadow price analyses were conducted for the main study sample and 10 for the scoping study loans. Although the team determined the effect of a shadow price on each loan's EIRR and NPV, the results of the shadow price analysis are presented in terms of how a loan's NPV would change.

This is necessary because in many instances the shadow price generated a net benefit stream that did not allow calculation of the EIRR term (that is, net benefits were negative in most or all periods).

For each shadow price and net discount rate, loans were placed in one of three categories based on the effect of the shadow price on the NPV:

1. *"No change" category:* Shadow price does not change NPV.

2. *"Moderately affected" category:* NPV declines, but remains positive.

3. *"Strongly affected" category:* NPV falls below zero.

For projects whose NPVs were strongly affected by a carbon shadow price, low-carbon alternatives may be supplying equivalent energy services at a low (or no) cost. Such alternatives may also exist for moderately affected projects, but are probably less likely to be found.

3.3.1 Overall Results

The charts in figure 3.1 show the effect of a shadow price on the main study sample for a net discount rate of zero. Each of the 6 pie charts in the figure includes the subset of 12 loans that did not have SARs, as well as the share of loans falling into the three categories. The first column of pie charts show the percentage of loan components in each category. The second column of pie charts show the percentage of total loan amount in each category.

At each shadow price, the percent of funding in the "strongly affected" category is larger than the percentage of loan components in "strongly affected" category. This happens because the loans that are adversely affected by the shadow price tend to be larger than the loans in the "no change" category or the "no SAR" group.

Perhaps the most important result in figure 3.1 is that the incremental effect of a $40 shadow price is relatively small compared with the incremental effect of a $20 shadow price. The number of loans in "strongly affected" category roughly triples when the shadow price increases from $5 to $20 (for example, increasing from 8 percent to 28 percent of loan components), but the number of loans in this category only increases by about 20–25 percent when the shadow price increases from $20 to $40 (for example, increasing from 28 percent to 34 percent of loan components). Consequently, a $20 shadow price achieves nearly the same effect on the loan sample as the $40 shadow price. This result is common throughout the analysis in this section.

Bank loans in the "strongly affected" category are mainly thermal capacity investments, primarily for coal-fired projects. The loans for coal-fired power plants tend to fall into this category at either the $5 or $20 shadow price, and other hydrocarbon loans tend to enter this category at the $20 or $40 shadow prices if at all. Table 3.3 shows the effect of the shadow prices on per-kWh costs for different fuels. At $5 per tC, the incremental cost for coal generation increased by 0.11¢ to 0.16¢ per kWh, which is higher than incremental costs for oil, diesel, and gas. The $40 per tC shadow price added as much as 1.3¢ per kWh to cost of generating electricity. Although per-kWh cost increases for diesel are similar to coal, the shadow prices had less effect on loans including diesel generation because some loans included small diesel generators as part of a larger energy sector project.

Figure 3.1
Effects of \$5, \$20, and \$40 Shadow Prices on Main Study Loan Sample Where the Net Discount Rate is 0%

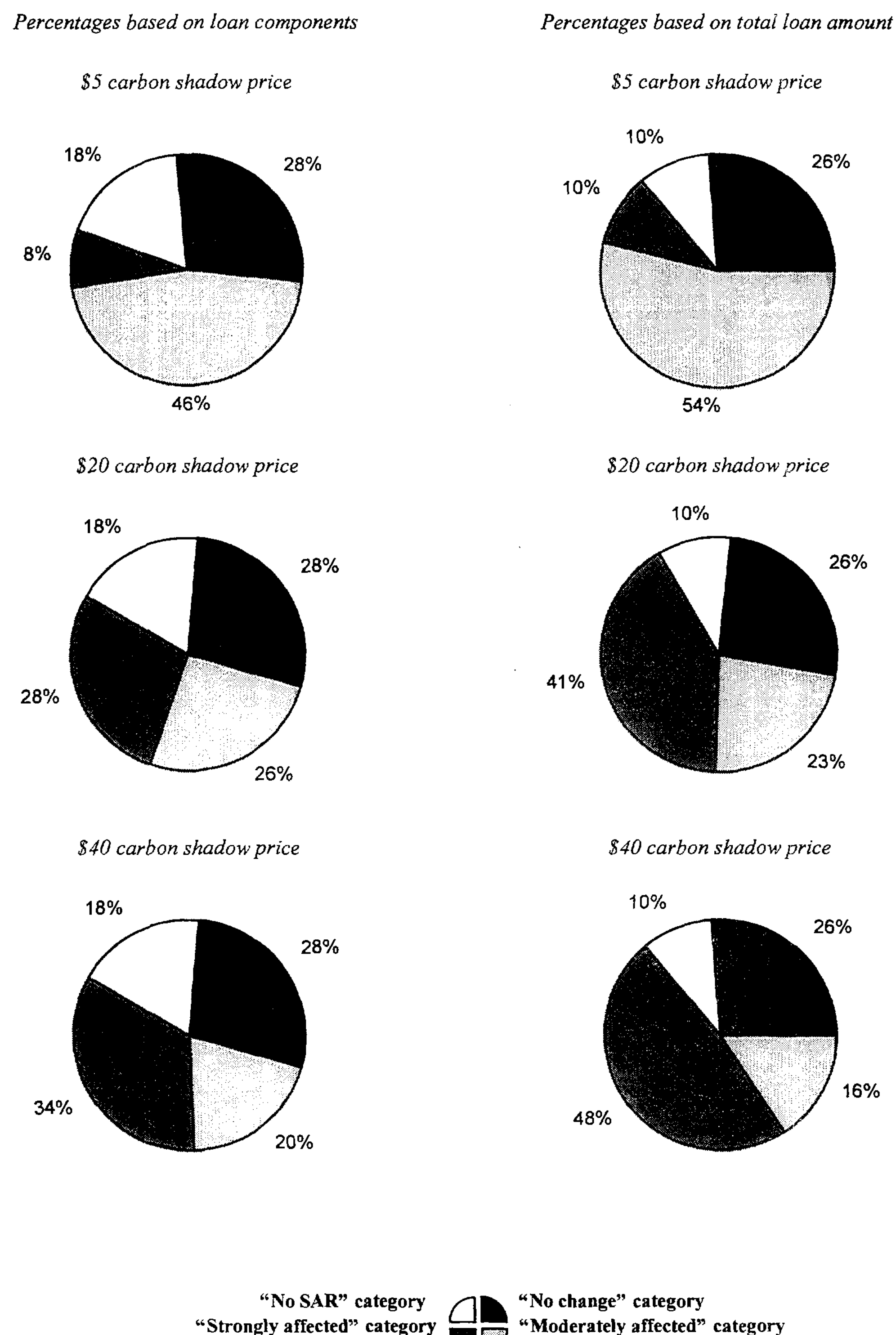


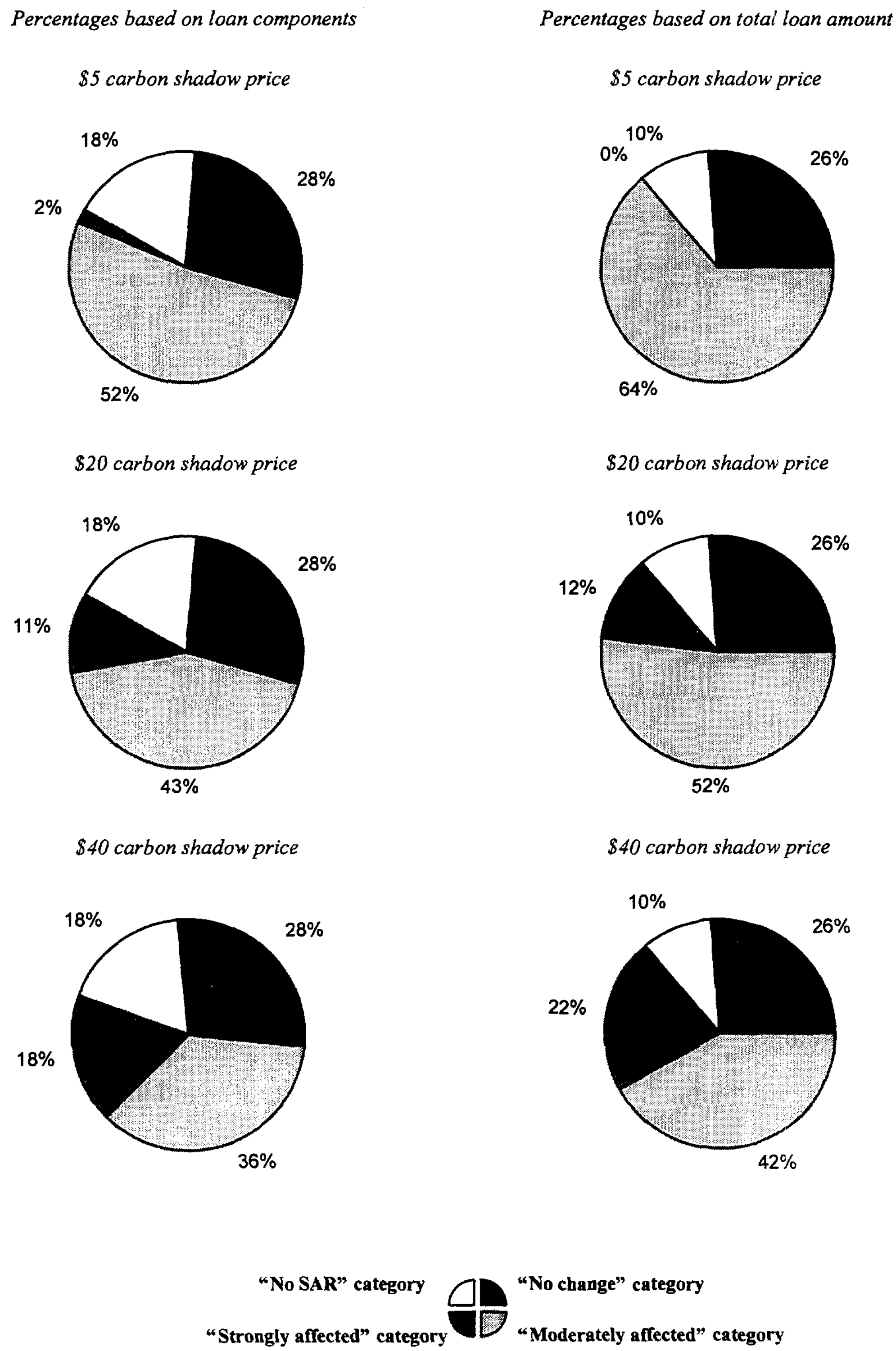
Table 3.3
Incremental Energy Generation Costs of Shadow Prices (U.S. cents per kWh)

Fuel type	*Incremental cost*		
	Shadow price of $5 per tC	*Shadow price of $20 per tC*	*Shadow price of $40 per tC*
Coal	0.11–0.16	0.42–0.65	0.84–1.30
Diesel	0.13–0.15	0.54–0.60	1.07–1.20
Oil	0.09–0.10	0.35–0.42	0.69–0.84
Gas	0.06–0.12	0.23–0.47	0.45–0.94

The pie charts in figure 3.2 illustrate how the choice of discount rate affects the distribution of loans across the "moderately affected" and "strongly affected" categories. These charts are based on the shadow price analyses with a net discount rate on the carbon shadow value that was equal to the host country's cost of capital minus 2 percent to account for annual growth in the shadow price. The net discount rates tended to be in the 8–12 percent range. The higher net discount rate diminishes the present value economic impact of the carbon shadow value in future years. The "no change" category and "no SAR" percentages are not affected because discounting does not affect those sample subsets. However, the "moderately affected" category loan amount shares are larger in figure 3.2 than they are in figure 3.1, and the "strongly affected" category shares are smaller. The "strongly affected" category loan amount shares in figure 3.2 are less than half of what they are in figure 3.1. For example, at a $20 shadow price, about 41 percent of loan amounts falls in "strongly affected" category when the net discount rate is zero (figure 3.1), but only 12 percent fall into this category when the net discount rate is higher (figure 3.2), and at $40, these shares are 48 percent (figure 3.1) and 22 percent (figure 3.2). Thus, the discount rate has a significant effect on how a shadow price alters the loan portfolio.

This effect is much more pronounced for the shares based on loan amounts than it is for the shares based on loan components. That happens because, at the higher net discount rate, some of the large loans for coal projects do not have negative NPVs at any of the shadow prices considered, and other coal projects remain in the "moderately affected" category at the $5 or $20 shadow prices that turn them into "strongly affected" category projects when the net discount rate is zero.

Figure 3.2
Effects of $5, $20, and $40 Shadow Prices on Main Study Loan Sample Where the Net Discount Rate Is the Cost of Capital minus 2%



Similar to figure 3.1, figure 3.2 shows that most of the shadow price effect is achieved by a $20 shadow price, that is, most of the loan dollars or components that fall into the "strongly affected" category are in that category at $20. The incremental effect of raising the shadow price from $20 to $40 is small relative to the effect of the $20 shadow price.

3.3.2 Results by Loan Period

The shift in Bank policy toward more institutional loans for reform and restructuring is apparent when the results are separated into the two periods that make up our stratified sample: 32 loans through fiscal year 1993 and 18 loans after fiscal year 1993. Figure 3.3 shows the shadow price results for the subset of loans from the 1990–93 fiscal years when the net discount rate is zero, and figure 3.4 shows the results for the 1994–96 fiscal years with the zero discount rate.

These figures illustrate a large increase in the share of institutional loans (that is, loans without SARs) between the two periods. Similarly, the share of loans that are not affected by a shadow price (for example, energy efficiency and renewable fuel loans) have increased over time, particularly when their dollar value is considered, which was 19 percent of the 1990–93 period subsample, and 38 percent of the later sample. Together, institutional loans and loans that do not have carbon emissions constitute less than one-third of the total loan amount in the earlier period, but almost two-thirds of the loan amount in the later period.

Also of note is a redistribution between the "moderately affected" and "strongly affected" categories over time. In the earlier period, 50 percent of the loan dollars were in the "strongly affected" category at a $20 shadow price, which represents about 68 percent or two-thirds of the loan amount in either the "moderately" or "strongly affected" categories. In the later period, however, roughly two-thirds of the loan dollars are in the "moderately affected" category. Only 11 percent of total loan dollars are in the "strongly affected" category, which represents about 30 percent of the loan dollars in either category.

Comparing results across the two discounting methods reveals different sensitivities to discounting. Figures 3.5 and 3.6 show results analogous to figures 3.3 and 3.4 for the discount rate that is close to the cost of capital. The subsample from the earlier period is very sensitive to the choice of discount rate, but the later period subsample is not sensitive. The share of the "strongly affected" category loans in figure 3.5 is less than half of what it would be for a net discount rate of zero (figure 3.3) for the 1990–93 subsample. Conversely, this category's share in the later subsample for the higher discount rate (figure 3.6) is the same as the share for the zero discount rate (figure 3.4). This may be because of the smaller sample size for the later period; a larger sample size may show more sensitivity to discounting.

Figure 3.3
Effects of $5, $20, and $40 Shadow Prices on 1990–93 Subsample Where the Net Discount Rate Is 0%

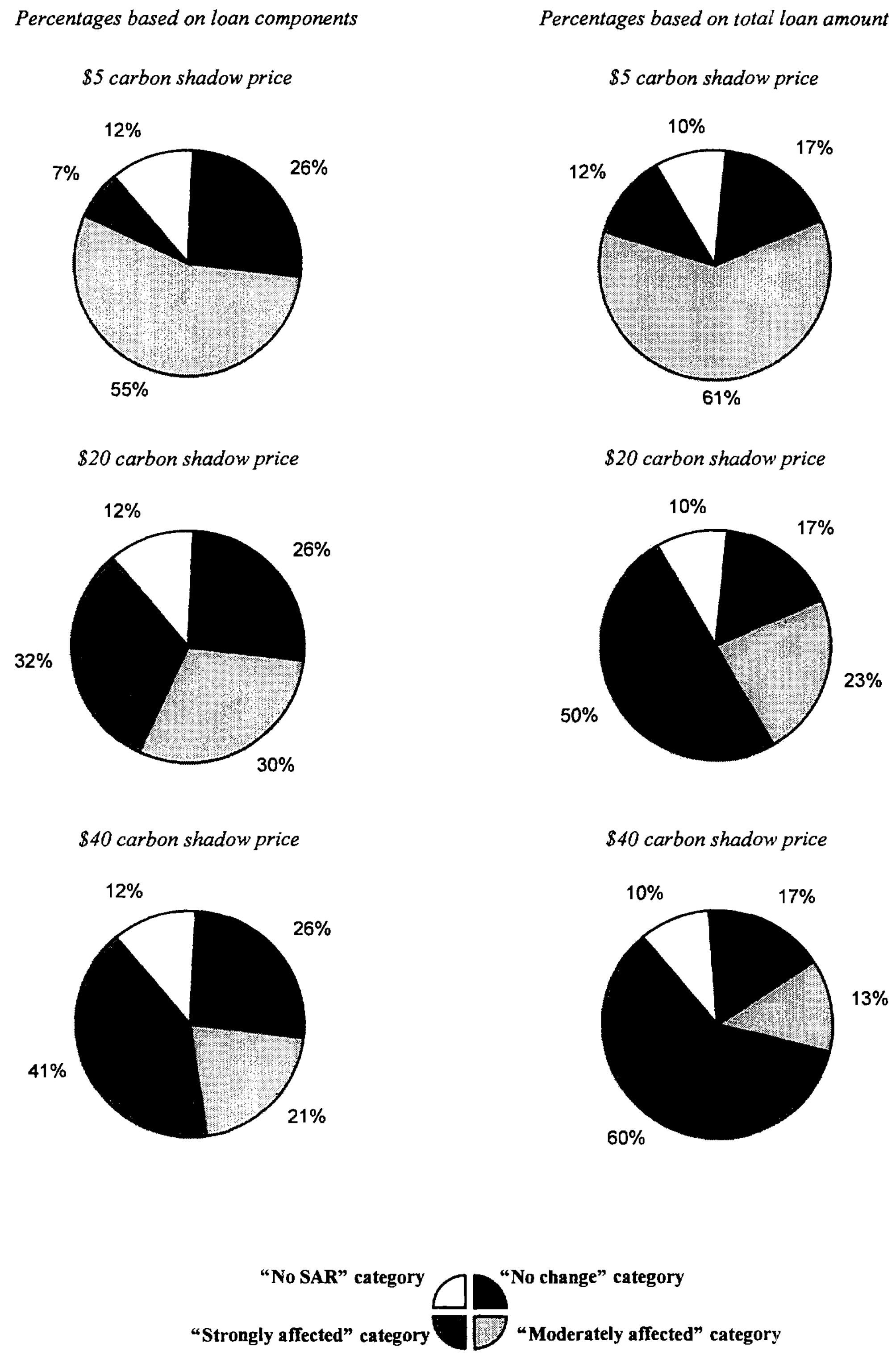


Figure 3.4
Effects of $5, $20, and $40 Shadow Prices on 1994–96 Subsample Where the Net Discount Rate Is 0%

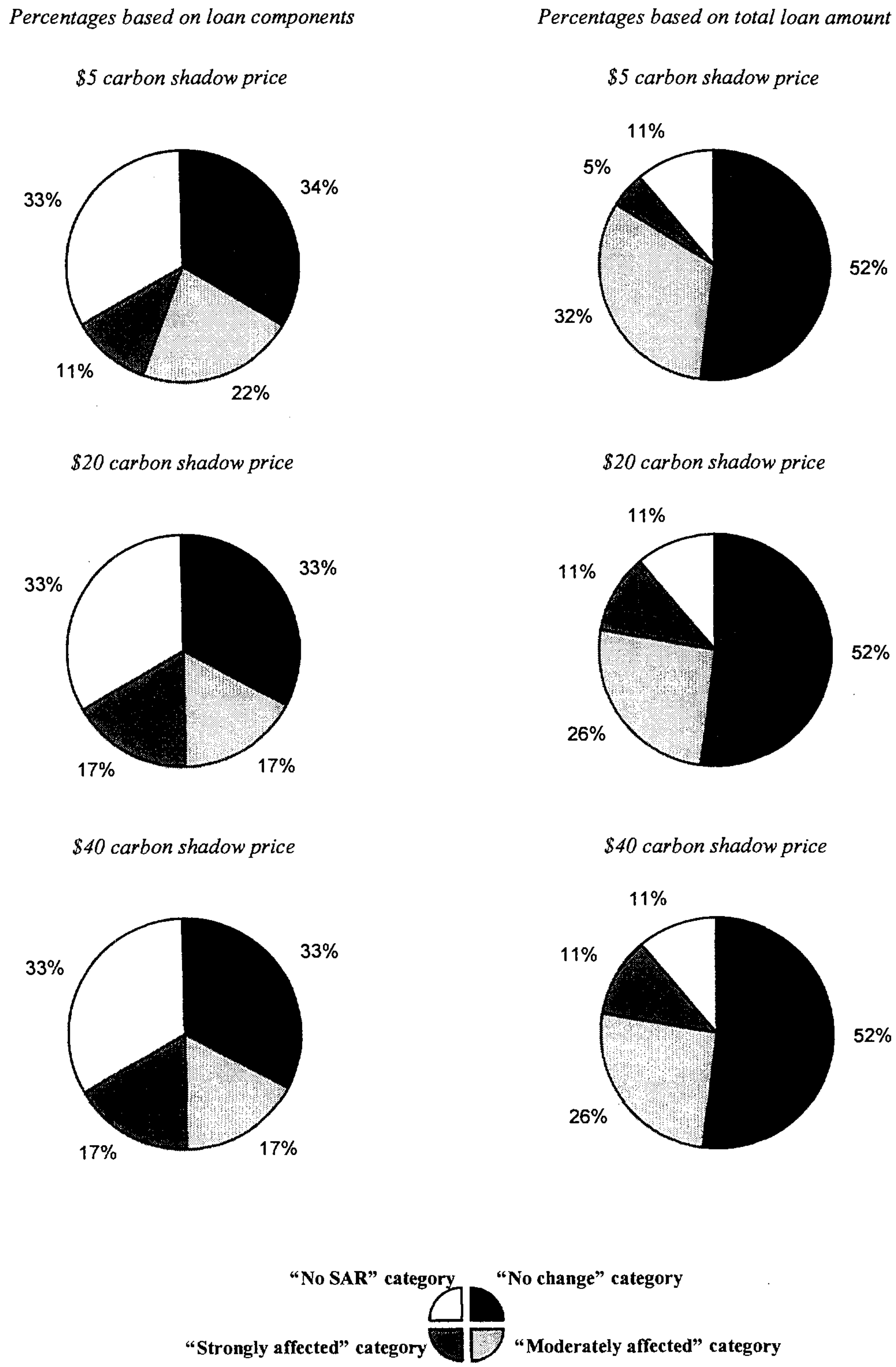


Figure 3.5
Effects of $5, $20, and $40 Shadow Prices on 1990–93 Subsample Where the Net Discount Rate Is the Cost of Capital minus 2%

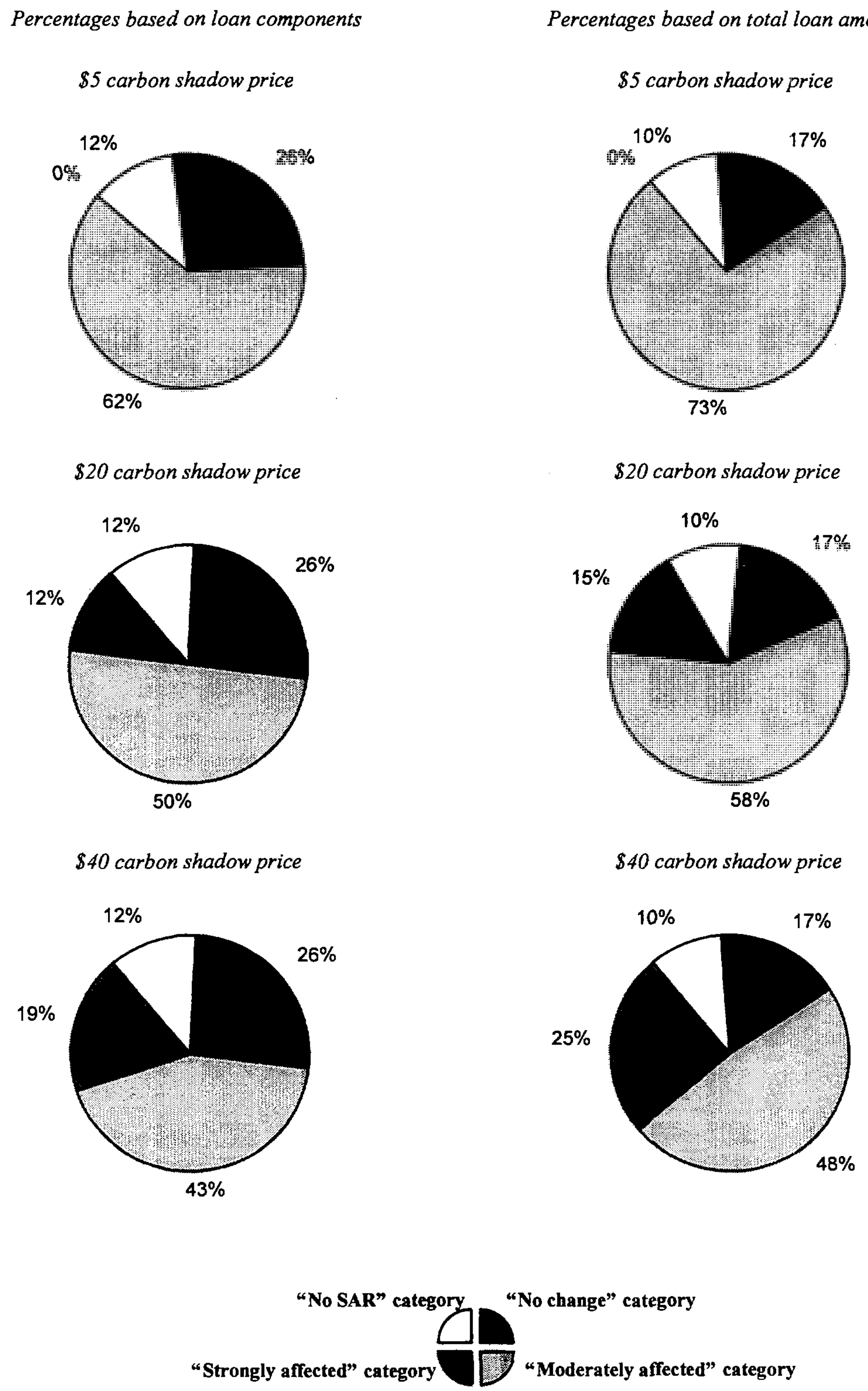
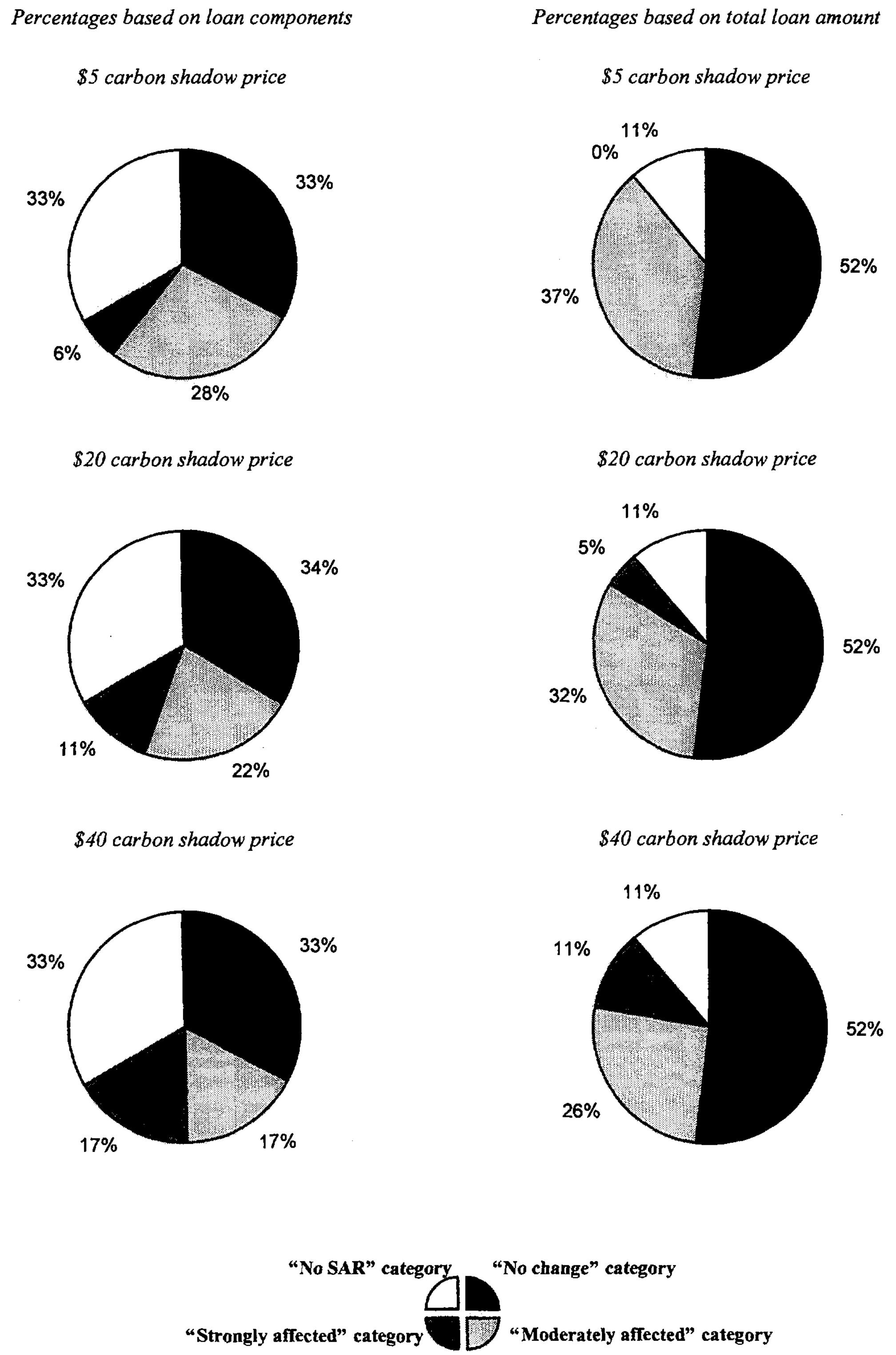


Figure 3.6
Effects of $5, $20, and $40 Shadow Prices on 1994–96 Subsample Where the Net Discount Rate Is the Cost of Capital minus 2%



3.3.3 Results for Net Emissions

Because the counterfactual scenarios for many of the loans in the main study sample of 50 loans included activities that were the same or similar to the activities funded by the Bank, a large share of the loans have net emissions equal to zero. This is evident in figure 3.7, which shows what happens to the sample of loans when a shadow price is applied to net emissions, rather than project emissions, and a zero net discount rate is used. About 35 percent of the loan components and 50 percent of the loan amount are in the "no change" category.

The pie charts in figure 3.7 include a new outcome, "positively affected" category, which comprises 11 loans that have a higher NPV when a carbon shadow price is incorporated. These are loans that have negative net emissions because they implement the following:

1. Energy efficiency measures, such as the Albania Power Loss Reduction loan, which reduced nontechnical losses.

2. Lower carbon alternatives to existing power sources, such as the Ghana Power Sector loan, which replaced small diesel generators with grid-interconnected power from hydro facilities.

About six loans that include these activities are not in the "positively affected" category on the charts because their net emissions are zero. These loans might have been in this category if the study team estimated emissions on a "with and without project" basis. This outcome is an artifact of choosing a counterfactual scenario that could have had the same activities as the Bank-funded project.

Few of the loan components fall into either the "moderately affected" or "strongly affected" categories because the counterfactual scenarios for many of the large thermal installations in India, Thailand, and Indonesia were the same as the funded activities. The shadow price analyses on net emissions are not very sensitive to the choice of net discount rate, primarily because so few loans are in these categories. Finally, the differences between the two periods are not as apparent as those discussed in the previous section. The later period still has a higher proportion of institutional loans compared to the earlier period, but the change in relative share of "strongly affected" category versus "moderately affected" category loans is not as noticeable. Again the reason is probably that so few loans have positive carbon emissions under the net emissions definition.

3.4 Results for Sulfur Dioxide, Nitrogen Oxide, and Total Suspended Particulate Matter

The study team compared the relative impact of the carbon shadow prices and shadow prices on emissions of SO_2, NO_x, and particulate matter for three projects: the Latvia District Heating Rehabilitation Project, the China Yangzhou Thermal Power Project, and the India Maharashtra Power II Project. A recent evaluation of local environmental benefits by the World Bank (Rosebrock 1994) estimated the benefits of pollution abatement for SO_2, NO_x, total suspended particulate matter (TSP). The reported shadow prices estimates were $1,500 per metric ton of SO_2, $6,500 per metric ton of NO_x, and $4,000 per metric ton of TSP in 1990 U.S. dollars. For the Carbon Backcasting Study analysis, the study team adjusted these shadow prices to 1995 dollars, and tested the sensitivity of the results using the purchasing power parity index, as suggested in Shah and Larsen (1992).

The Latvia District Heating Rehabilitation Project would reduce fuel consumption and associated air pollutants. Loan documents reported that SO_2 emissions would be reduced by 53 metric tons, NO_x emissions by 12 metric tons, and TSP emissions by 8.5 metric tons per year. The India and China projects would increase consumption of electricity generated by coal. Estimates of 0.420 lb of NO_x per MMBtu, 0.390 lb of SO_2 per MMBtu were used, and 0.032 lb. of PM_{10} per MMBtu. Table 3.4 summarizes the estimates of lifetime emissions for these local pollutants, and for carbon emissions.

The TSP emissions for the India and China projects could be higher than PM_{10} estimates reported here. If this were the case, applying the TSP shadow price to PM_{10} estimates would underestimate the shadow price impact on NPV.

Figure 3.7
Effects of $5, $20, and $40 Shadow Prices on Main Study Sample Using Net Emissions Where the Net Discount Rate Is 0%

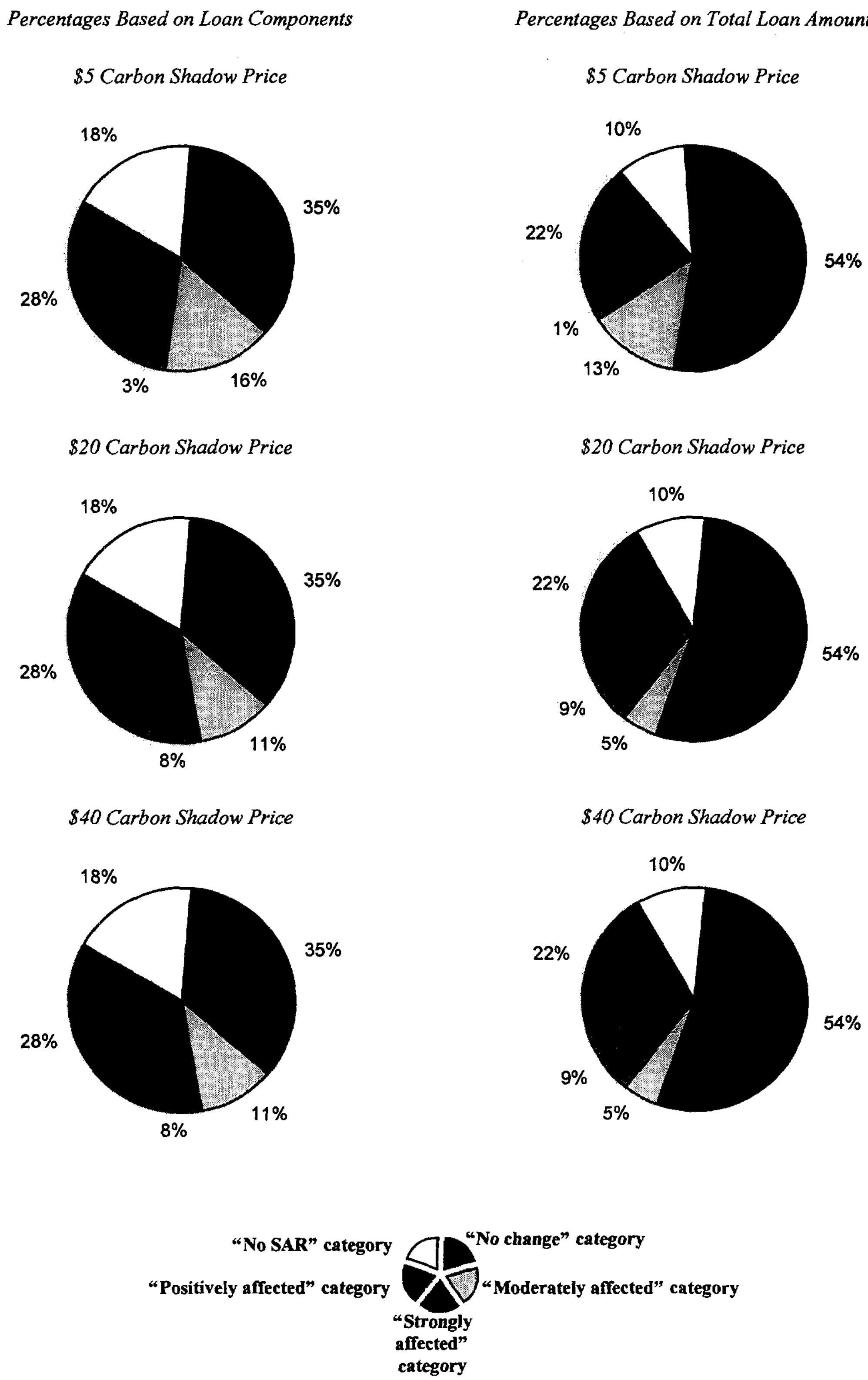


Table 3.4
Total Emissions over the Life of the Project
(millions of metric tons)

Project	NO_x	SO_2	PM_{10}	*Carbon*
Latvia (10%)	-0.000210	-0.000925	-0.000148	-0.124
China Yangzhou (12%)[a]	0.243	0.225	0.018	34.990
India Maharashtra (13%)	0.154	0.143	0.012	22.235

a. China Yangzhou SAR reported 0.263 million metric tons of NO_x and 0.482 million metric tons of SO_2 emissions.

However, if electrostatic precipitation is used to remove larger particles, then PM_{10} is a reasonable approximation for TSP.

Table 3.5 compares the combined effect of three shadow prices on local pollutants with the effects of the carbon shadow prices. This comparison is based on shadow values for local pollutants that have been adjusted for PPP. The table shows carbon shadow price results for the 0 percent net discount rate on the shadow price, and the net discount rate equal to the opportunity cost of capital minus 2 percent, which is usually in the 8 percent to 12 percent range.

When the net discount rate on the carbon shadow price is zero (top set of results), the carbon shadow price has a much larger effect than the combined effect of the shadow prices on local pollutants. For example, the shadow prices for NO_x, SO_2, and TSP reduce the NPV for the China Yangzhou project by about 25 percent from $129 million to $98 million. By comparison, a $5 per tC shadow price reduces NPV to less than zero. The effect of the shadow prices on local pollutants is more comparable to a $5 per tC shadow price when the net discount rate on the carbon shadow price is closer to the cost of capital.

Table 3.5
Comparison of Local Pollutant Shadow Price Impacts on NPV[a]
with Carbon Shadow Price Impacts on NPV[a]
Adjusted for Purchasing Power Parity[b] ($)

Project	*SAR*	*NO_X, SO_2, and TSP shadow price impacts*	*Carbon shadow price impacts, undiscounted*		
			$5 per metric ton	*$20 per metric ton*	*$40 per metric ton*
Latvia (10%)[c]	7.67	8.02	8.29	10.16	12.64
China Yangzhou (12%)[d]	129.24	97.94	(45.71)	(570.56)	(1,270.36)
India Maharashtra (13%)	294.22	282.39	183.04	(150.49)	(595.19)
			Carbon shadow price impacts, discounted		
Latvia (10%)[b]	7.67	8.02	7.95	8.78	9.89
China Yangzhou (12%)[c]	129.24	97.94	88.10	(35.31)	(199.87)
India Maharashtra (13%)	294.22	282.39	271.40	202.97	111.72

a. Values in millions of 1995 U.S. dollars. Discount rates are shown in parentheses.
b. The study team used a purchasing power parity value of 34.1 for Latvia, 7.6 for China, and 5.2 for India (World Bank 1993).
c. For Latvia, shadow prices were applied to net emissions. Project emissions were zero. For China Yangzhou and India Maharashtra, shadow prices were applied to project emissions.
d. The China Yangzhou SAR reported NO_x and SO_2 emissions. Using those values instead of the ESEERCO-based values, NPV is $89.88.

Table 3.6
Comparison of Local Pollutant Shadow Price Impacts on NPV[a] with Carbon Shadow Price Impacts on NPV[a] Not Adjusted for Purchasing Power Parity ($)

Project	*SAR*	*NO_x, SO_2, and TSP shadow price impacts*	*Carbon shadow price impacts, undiscounted*		
			$5 per metric ton	*$20 per metric ton*	*$40 per metric ton*
Latvia (10%)[b]	7.67	8.95	8.29	10.16	12.64
China Yangzhou (12%)[c]	129.24	(282.62)	(45.71)	(570.56)	(1,270.36)
India Maharashtra (13%)	294.22	66.81	183.04	(150.49)	(595.19)
			Carbon shadow price impacts, discounted		
Latvia (10%)[b]	7.67	8.95	7.95	8.78	9.89
China Yangzhou (12%)[c]	129.24	(282.62)	88.10	(35.31)	(199.87)
India Maharashtra (13%)	294.22	66.81	271.40	202.97	111.72

a. Values in millions of 1995 U.S. dollars. Discount rates are shown in parentheses.
b. For Latvia, shadow prices to were applied to net emissions. Project emissions were zero. For China Yangzhou and India Maharashtra, shadow prices were applied to project emissions.
c. China Yangzhou SAR reported NO_x and SO_2 emissions. Using those values instead of the ESEERCO-based values, NPV is ($388.75).

Table 3.6 shows that the results are very sensitive to the PPP adjustment. When the shadow prices are not adjusted downward, their combined effect on NPV is greater than the $5 per tC shadow price, but less than the $20 per tC shadow price, if the net discount rate on carbon emissions is zero. However, their combined effect can be greater than the $20 per tC or $40 per tC shadow prices when the higher net discount rate is applied to the carbon shadow price.

3.5 Findings and Conclusions

Depending on the discount rate and shadow price, the study team finds that anywhere between 0.1 percent and almost 50 percent of the sample loans are "strongly affected," that is, their NPV drops below zero. Because the sample was randomly selected from the pool of energy sector loans, and because it appears to be representative of that pool in terms of regional and activity distributions, the team concludes that similar shares of the portfolio would also be strongly affected by a carbon shadow price.

The results are very sensitive to the choice of shadow price up to $20, and less sensitive to the shadow prices between $20 and $40. About three times as many loans fell into the "strongly affected" category at the $20 shadow price compared with the $5 shadow price. At $40, about 20 percent to 24 percent more loan components or dollars fell into this category compared with $20.

Using a higher discount rate reduces the amount of lending in the "strongly affected" category by 50 percent or more, depending on the shadow price. Results generated using the lower rate had more than twice as many loans classified as "strongly affected" category loans compared with results using the higher rate.

The results are significantly different between the two periods. The subsample from the later period (1994–96) has more institutional loans and more loans that do not generate carbon emissions than the subsample from the earlier period.

Shadow prices on local air pollutants for the loans tested have a smaller effect than a shadow price of $5 per metric tonof carbon, if the net discount rate on carbon emissions is zero. This result is sensitive to the assumptions made about transferring United States–based values to developing countries. Because the shadow values were based on wages and medical costs in the United States, they should be adjusted to wage and cost conditions in developing countries. Because the largest share of these values pertains to statistical values of human life, however, there is considerable debate about the appropriateness of such downward adjustments in the values (see, for example, Watson, Zinyowera, and Moss 1996). If the values are not adjusted using a purchasing price parity index, their effect is comparable to a carbon shadow price between $5 and $20. If the carbon shadow price is discounted, then the combined effect of the shadow prices on local pollutants can be larger than a $20 or $40 carbon shadow price.

4 Approach to Analyzing Alternatives

Lower carbon fuels and technologies offer the potential to meet growing demand for energy services in the Bank's client countries while reducing global carbon emissions. In light of global efforts to reduce GHG emissions and the impact of carbon shadow prices on past Bank investments as described in chapter 3, such alternative investments are increasingly important for the Bank to consider. To get an indication of their availability, costs, and emissions savings, the study team analyzed lower carbon alternatives for several Bank energy projects. Alternatives are defined as low or no carbon options that the Bank either considered at the time of the original project analysis or that could now be envisioned as feasible alternatives to the original project.

4.1 Selection Process for Loans and Alternatives

The selection process for loans is discussed below, along with alternative loan packages.

4.1.1 Loan Selection

The alternatives analysis was undertaken for a subset of the loan sample described in the previous chapters. These loans, listed in table 4.1, fall into five broad categories: power supply, fuel switching and district heating, transmission and distribution (T&D), rural electrification, and power sector reform.

The study team selected these loans to reflect the Bank's regions and principal project types, enabling the evaluation of a wide range of alternative investments. Other factors contributing to loan selection included the ease of formulating reasonable lower carbon alternatives and the availability of information on the loan and alternative options.

4.1.2 Identification and Characterization of Alternatives

Alternatives are often considered by the Bank or the host country during the loan cycle. Few loan documents considered here, however, contained sufficient information about alternatives to analyze them. In most cases, the study team needed to create illustrative examples of alternative loan packages on the basis of research and consultation with local and international experts.

To select the feasible lower emission alternatives within the context of a past Bank loan package, the study team defined the following criteria:

1. Lower cumulative carbon-equivalent emissions than the original project.
2. Local resource availability and compatibility with local systems. For instance, wind resources were considered where sufficient wind regime exists near the demand and if the amount of resource addition (for example, percentage of capacity) was compatible with the existing system (for example, ability to manage the intermittent resource). In several cases, a resource within feasible reach of a transmission line or pipeline was also considered, and the additional transportation costs were included in the analysis.
3. Coverage of a wide range of technical and policy options. Across the range of loans considered, a wide range of potential low GHG investments was identified. More cost-competitive technologies, such as wind, gas, and efficiency improvements were analyzed more frequently than higher-cost ones, such as on-grid solar generation. Repetitive

Table 4.1
Loans Considered for Analysis of Alternatives

Loan type	*Country*	*Loan*
Power Supply	China	Yangzhou Thermal Power Project (1994)
	China	Yanshi Thermal Power Project (1991)
	Ghana	Thermal Power Project (1995)
	India	Second Maharashtra Power Project (1992)
	India	NTPC Power Generation Project (1993)
	Indonesia	Suralaya Thermal Power Project (1992)
	Thailand	Second Power System Development Project (1989)
	Yugoslavia	Kolubara 'B' Thermal Power and Lignite Mine (1991)
Fuel switching and district heating	Estonia	District Heating Rehabilitation (1995)
	Latvia	Jelgava District Heating Rehabilitation (1995)
Transmission and distribution	Mexico	Transmission and Distribution Project (1990)
	Thailand	Distribution System and Energy Efficiency (1993)
	Uruguay	Power Transmission and Distribution Project (1995)
Rural electrification	Indonesia	Second Rural Electrification (1995)
	Morocco	Second Rural Electrification (1990)
Power sector reform	Colombia	Energy Sector Technical Assistance Project (1994) Power Market Development (1995)
	Jordan	Energy Sector Adjustment (1993)
	Peru	Electricity Privatization Adjustment (1995)

analysis of similar technologies across a range of loans helped in gathering insights on the effects of local conditions and context on desirability of specific alternatives. CO_2 scrubbing technologies and emission offsets were not considered because of their generic nature and lack of specificity to loan conditions.

4. Commercial availability of technologies. Options with no commercial experience were not considered.
5. Adequacy of site-relevant information. Country-specific studies and data were used wherever possible. Where option costs and potential were highly site specific (for example, DSM potential, wind resources, or hydro costs) and local information was inadequate, potentially feasible alternatives were not considered. For this reason, relatively few demand-side efficiency options were included here, far fewer than the full demand-side potential, due to the limited availability of site-specific demand-side evaluations. The lack of systematic wind resource measurements and mapping, for example, precluded consideration of wind generation for the Ghana loan analysis. Where reasonable quantitative estimates were particularly elusive, qualitative descriptions of the alternatives were provided instead.

Thus, to develop cost and performance estimates for alternative options, the study team reviewed Bank and general literature and contacted many local and regional experts, as well as Bank staff. In a few instances, the team identified relevant alternatives that had already been studied at the preinvestment level. In most cases, however, the alternatives represent options that would require further feasibility assessment before investment appraisal.

Hindsight and Additional Loan Components

In addition to the above criteria, the alternatives analysis process had two important features.

First, since a major objective of the backcasting study was to inform future investment decisions, the definition of alternatives benefited from hindsight. Technological advances and better information about alternatives since the time of the loan appraisal were used in the analysis. Second, for several loans, it was difficult to envision a reasonable scenario under which the loan project would not go forward. Instead, the study team considered additional rather than alternative loan components. Such loans typically reflect a desirable infrastructure investment that would most likely have been made regardless of the Bank's involvement. For these loans, additional or supplementary loan components appeared more sensible to consider than alternatives that substitute for part of the loan package. By including such additional components, the Bank could leverage its investment to reduce GHG emissions and achieve other benefits closely related to the objective of the original loan. This approach is not dissimilar to current Bank lending practices. For instance, the Thailand T&D loan reviewed here—a T&D line upgrade and extension in and around Bangkok—included an additional DSM component. By adding the DSM component, the loan package more efficiently and effectively satisfied expanding electricity demand in the Bangkok area than the T&D investment alone would have.

These additional loan components are particularly relevant to T&D and power sector reform loans. Such loans rarely include GHG emitting or abating investments per se. Instead, they create networks or new systems that can augment or change energy consumption patterns. Considering additional loan components for these types of loans is also a more practical approach than suggesting alternatives. Conceiving and characterizing alternatives to these types of projects can be technically complex and involve matching a wide set of social as well as economic objectives. For example, defining an alternative distribution system configuration for the Bangkok T&D loan would have required a detailed site-specific assessment well beyond the scope of this exercise. Thus the team considered additional investments as part of the Bangkok loan, including small-scale generation resources sited closer to the load center. These distributed resource investments could reduce T&D system losses, delay the need for future upgrades, and extend the useful life of the project.

4.2 Quantitative Analysis of Alternatives

The study team calculated the incremental costs and carbon emissions relative to the original loan for each loan alternative where quantitative analysis was possible. These calculations yielded two principal measures used to compare alternatives: carbon savings and switching value. Carbon savings represent the incremental reduction in emissions achieved over the lifetime of the loan alternative, presented here as metric tons of carbon saved or as the percentage of the original loan's project emissions reduced. Switching value represents the carbon shadow price at which the loan alternative matches the original loan's net present value. The lower the switching value, the more attractive the loan alternative as a carbon reduction option. A negative switching value indicates a "no regrets" option, one that could reduce emissions while yielding net economic benefits.[1]

The calculation of switching value and carbon savings is simple in principle. First, cost streams and gross carbon emissions streams are developed for each alternative; the assumptions used to develop these estimates are described in the report appendices. Second, the cost and emission streams for the original project are subtracted from the alternative cost and carbon streams. The resulting incremental cost and carbon streams, $\Delta Cost_t$ and $\Delta Carbon_t$, respectively, are then used to calculate the switching value according to the following equation:[2]

$$\sum_{t=1}^{n} \frac{\Delta \mathrm{Cost}_t}{(1+\mathrm{i})^t} + \sum_{t=1}^{n} \frac{S * \Delta \mathrm{Carbon}_t}{(1+\mathrm{j})^t} = 0\text{, or} \qquad (4.1)$$

$$\mathrm{NPV}^{\mathrm{i}}(\Delta \mathrm{Cost}) + \mathrm{NPV}^{\mathrm{j}}(\mathrm{S} * \Delta \mathrm{Carbon}) = 0, \qquad (4.2)$$

where:

t	=	time period between first year and last (n) year.
$\Delta Cost_t$	=	$Cost_{alt,t} - Cost_{orig,t}$.
$\Delta Carbon_t$	=	$Carbon_{orig,t} - Carbon_{alt,t}$.
S	=	the switching value (in 1995 U.S. dollars).
i	=	the discount rate used for the cost streams.
j	=	the discount rate used for the carbon emission streams.
NPV^i	=	the net present value at discount rate i.
NPV^j	=	the net present value at discount rate j.

The switching value can be usefully expressed as:

$$S = \frac{NPV^i(\Delta Cost)}{NPV^j(\Delta Carbon)}, \text{ or} \quad (4.3)$$

$$S = \frac{NPV^i(Cost_{alt} - Cost_{orig})}{NPV^j(Carbon_{orig} - Carbon_{alt})} \quad (4.4)$$

As discussed in chapter 2, carbon emission streams are discounted at a lower rate (j = 0%, with a sensitivity of i - 2%) than the rate used for the standard economic cost streams (i = 10–12%, the opportunity cost of capital used in the original loan analysis).

To those familiar with the climate change mitigation literature, the switching value is equivalent to the cost of avoided carbon, cost of saved carbon, or abatement cost. Cost of avoided carbon is typically calculated for technology and policy options using the same equations as those for switching value. Readers comparing switching values reported here and costs of avoided carbon found in the literature should bear in mind two important differences: discount rates and baselines.

First, most analysts tend to calculate abatement costs by discounting both cost and emission streams at the same rates, i and j in the above equations, which is typically lower than the opportunity cost of capital used in Bank loan analyses (for example, in the range of 3–10 percent).[3] The net effect in most cases is likely to make the switching values reported here somewhat smaller than costs of avoided carbon reported in the literature.

Second, abatement costs are measured as the difference between the cost of an alternative and an assumed or modeled baseline cost. Instead of a defined Bank loan package, the baseline for abatement cost calculation reflects the analyst's assessment of the likely or least-cost marginal energy supply source(s) that an alternative would displace (for example, a coal plant technology, gasoline use in standard engines). For a common technology and country, differences between a switching value presented here and a cost of avoided carbon reported in the literature may derive from different assumed baselines.

Where reported, the NPV and the EIRR for the alternative projects are calculated using the project emissions approach described in chapter 2.

4.3 Methods Specific to Each Loan Type

Although the general quantitative analysis described above is simple in principle, its application to loan analysis presents a number of analytical challenges. These methodological issues are addressed by loan type below, beginning with power supply loans. Power supply loans presented many issues common to all loan types, thus for each subsequent loan type only the differences with the basic approach are discussed.

4.3.1 Power Supply Loans

Because a broad range of proven low carbon alternatives are widely available for power production, power sector loans are quite amenable to analysis of alternatives. Options include more efficient and lower-carbon fossil fuel plants, renewable energy projects, and demand- and supply-side efficiency improvements. Alone or in combination, these options could substitute for part or all of a planned investment. These options are occasionally considered in power supply expansion studies or in other national and local analyses.

Power supply expansion planning can be a complex exercise involving considerable effort in data collection, technology evaluation, and system modeling. The illustrative and limited nature of this backcasting study dictated a more rapid assessment approach. Instead of using power supply planning models to develop and cost optimal system configurations for each alternative, the team employed a series of approximations to yield indicative results. Approximations were needed, in particular to determine the appropriate size of intermittent and demand-side resources, and to determine the economic value of their contributions to supply expansion.

The simplest way to value alternative resources would be to assume that each kWh produced avoids the need for a kWh generated by the loan project, and each MW of added capacity avoids the need for a corresponding MW of capacity from the loan resource. Thus, the alternative would simply displace a downsized version of the Bank project. This approach, however, can ignore important differences in the timing and reliability of the kWh that an alternative resource would provide. Intermittent renewable resources, such as wind and solar, operate only 20–40 percent of the time, whereas the baseload plants typically supported through Bank loans usually have capacity factors of 60–80 percent and can be dispatched more readily to meet baseload demands.[4] To the extent that alternative resources can be expected to operate reliably at times of high or peak demand, their lower capacity factors can actually be a relative benefit. For instance, investment in more efficient lighting and air conditioning equipment, which generally operates more at high demand periods, can reduce the need for more costly peakload capacity and generation. The accurate valuation of an alternative resource thus depends on determining which existing or planned resources the alternative would avoid. The notion of avoided costs, corresponding to the costs of the displaced capacity and generation, is well accepted and used for the assessment of alternative resources.[5]

For the purposes of this backcasting analysis, the team needed a rapid assessment approach for determining the size and value of alternative resources, as well as their avoided costs. The remainder of this section describes the methods used to capture the differences in resource size, availability, and reliability between the alternative and original loan projects.

How Were Alternative Resource Sizes Selected?

Aside from conventional large-scale hydro, natural gas, and nuclear projects, few low-carbon alternatives can match the size of a Bank power sector investment. Even if the resource is available, it may be imprudent to fully substitute a 1,200 MW coal plant with wind alone, or a 300 MW oil-based combustion turbine with only agricultural residue generation. Since smaller-than-loan-project capacities make sense for many alternatives resources, a natural question is what size to evaluate.

The effective cost per kWh or metric carbon tons saved of an alternative energy resource will often vary significantly with the size of the resource and the nature of the energy system. On the one hand, economies of scale in items such as transmission, turbine size, or site preparation can favor larger investments. On the other hand, costs for some alternative resources can increase with the extent of exploitation and use. For example, with wind resources, the best sites are often exploited first. Furthermore, the intermittence of the resource becomes more problematic at higher penetration rates. Typically, where wind generation is small compared to total system loads and production matches well with times of increased demand, half or more of its rated capacity can count toward meeting system reliability and reserve requirements. As its contribution to total generation increases, however, its capacity value decreases.

It was beyond the scope of this exercise to determine an "optimal" investment size for a given alternative resource. Given sufficient time and information, one could effectively determine an optimal level of investment size (for example, MW of wind resources) that would be justified by each of the shadow price levels considered ($0, $5, $20, and $40 per tC).

Absent the data or sizing criteria needed to determine an optimal resource size, the team developed indicative resource sizes based on available studies and judgment regarding resource potential and system considerations (for example, system integration for intermittent renewables). Greater carbon savings may be available at, in most cases, higher costs. Similarly, stricter limits on achievable resource penetration may mean that only a fraction of carbon savings reported here can be achieved, possibly at lower costs.

How Were Smaller-than-Loan Investments Evaluated?

Since an alternative resource is often sized smaller than the original loan project, additional energy and capacity were often needed to match the energy services provided by the loan project at roughly equivalent reliability. To address this issue, the study team adopted a "project downsizing" approach. In general, if a loan supported a 500 MW coal plant, an alternative 50 MW biomass facility would be combined with a downsized 450 MW coal plant to produce an alternative loan package that could match the benefit stream of the original loan. The alternative loan package was then supplemented with additional capacity and generation costs, as needed, to account for any shortfalls in capacity factor and reliability.

The ideal approach to evaluating an alternative resource is a decrement approach, wherein the entire power supply plan is reoptimized to complement this resource in a least-cost fashion. In response to the addition of an alternative resource, the construction of a specific plant may be delayed rather than downsized or cancelled.[6] Thus, the downsizing approach should be viewed as a proxy for reflecting avoided costs, rather than strictly as an alternative loan package containing a smaller version of the same facility. An alternate approach would have been to evaluate the alternative resource as a net addition to the original loan. Such an "addition-to-project" approach would have the advantage of not appearing to modify the original project size and operating characteristics. It would also be a more likely outcome if the Bank were to pursue some of the smaller alternatives discussed here. However, the project team felt that, in keeping with the overall approach of the backcasting study, the benefit stream and overall objectives of the loan should be unmodified wherever possible.

In most cases, the net difference between the "project downsizing," "decrement," and "addition-to-project" approaches is small in terms of calculated switching values and carbon savings. This is true as long as the alternative resource, as configured, roughly matches the loan project in terms of operating characteristics. Most supply-side alternatives were configured in this manner. As discussed next, some demand-side efficiency investments differed significantly in their operating characteristics (that is, the timing of load reductions), and as a result, switching costs may be overestimated in options that predominantly reduce peak demand (for example, load management options).

How Were Demand-Side Efficiency Investments Evaluated?

Demand-side efficiency improvements are valued in a manner similar to investments in alternative supply options.[7] The power supply costs avoided by a demand-side efficiency improvement depend on the characteristics of the resulting demand savings. For refrigerator or industrial motors, which operate relatively constantly, efficiency improvements can be represented fairly accurately as a reduction in baseload requirements. Since most of the Bank's power supply investments are in baseload facilities, the straightforward "project downsizing" approach is reasonably accurate for this type of efficiency improvement.[8]

For those efficiency improvements with lower capacity factors than a baseload facility, the assumption of baseload avoided costs can understate their benefits. Where the timing of the reduced demand and the system's peak demand coincide, higher-cost electricity from peaking facilities is effectively avoided.[9] For DSM options with low capacity factors and high peak coincidence—air conditioning, lighting, and building shell improvements tend to fall into this category—baseload avoided costs provide a lower bound estimate.[10] For DSM options with uncertain or low likelihood of peak coincidence, such as agricultural pumping, no capacity value was assumed.

Losses between the point of electricity generation and the point of sale—T&D losses and consumption at the power plant—require that from 5 to 20 percent additional kWh must be generated for every kWh delivered to customers. As a result, every kWh saved by a demand-side efficiency improvement reduces generation requirements by 1.05–1.20 kWh. These savings were accounted for by multiplying demand savings by the system-specific T&D losses to determine total avoided generation. Achievement of demand-side efficiency savings requires the creation and implementation of DSM programs (for example, rebates, audits), promotional campaigns, codes, or standards. These in turn entail additional costs for program design, implementation, and administration. The team used a standard 20 percent adder to technology costs to reflect these costs.

How Was the Inherent Intermittence of Renewable Resources Handled?

The ease of integrating intermittent renewable resources into an existing power system is an important consideration. Because of the intermittent nature of renewable energy availability, some renewable resources, such as wind, solar, and seasonal biomass, cannot be dispatched like a conventional thermal power plant. As a result, a 10 MW windfarm is generally less valuable in terms of meeting system demands than a conventional 10 MW thermal plant. The equivalent capacity value of a renewable resource, that is, its contribution to meeting system capacity requirements, depends on how well its availability matches system loads. Where there is good coincidence in timing between maximum generation and system peak loads, and where penetration of that resource is small relative to total power system capacity (for example, less than 10–20 percent), the team assumed that the intermittent resource can have a relative capacity value of up to 50 percent of an equivalently rated thermal plant (Grubb and Meyer 1993; Bernow et al. 1994). If the resource is out of phase with the system loads, the capacity value was assumed to be lower. In the case of biomass cogeneration facilities, which do not generate electricity during several months of the year, the capacity value could be as low as zero.

The team thus "downrated" the capacity contribution of renewable resources to account for their intermittence and load matching characteristics. The team also included the costs of any additional thermal capacity and generation needed to make up shortfalls in generation.

How Were Differential Capital and Foreign Exchange Constraints Addressed?

The principal economic criterion used to compare loans and alternatives in this study, switching value, does not reflect the total borrowing and foreign exchange requirements imposed by a given project. Many renewables come at higher financing costs per unit service provided, typically with savings in annual fuel and other running costs. Although added (or reduced) financing costs can be reported to give a sense of the change in borrowing needs, it does not reflect whether this would pose any practical obstacles to financing. Similarly, foreign exchange requirements will vary in either direction, depending on the source of the fuels and the technologies involved in the project and its alternatives. No differential capital and foreign exchange costs were assumed.

4.3.2 District Heating and Fuel Switching Loans

District heating and fuel switching loans are perhaps the most straightforward of all to analyze. In most cases, these loans address boiler systems and fuel provision. Alternatives include lower carbon fuel supply, improved boilers, and reduced heat demand through efficiency improvements. Since most boiler fuels can be readily supplied and stockpiled and capacity costs tend to be relatively low compared with recurrent fuel costs, system planning and dispatching complexities are not a concern as they are for power sector loans.

4.3.3 Transmission and Distribution Loans

At least two types of alternative investments can reduce T&D losses, and thereby reduce the emissions from generation required to cover these losses. One type of alternative is improvements to the T&D system itself, for example, transformer upgrades or improved maintenance. Given the lack of local information on loss reduction opportunities for the selected loans, the team focused on another type of alternative: distributed generating resources. When small-scale generation and cogeneration facilities are sited closer to load centers, distributed resources can reduce investment and losses in T&D. Here again the availability of relevant local data is a limitation; however, by combining local fuel cost and T&D loss information with generic data on distributed resource technologies, a range of illustrative switching values can be derived.

4.3.4 Rural Electrification Loans

Rural electrification loans typically consist of investments in grid extension facilities (T&D) to previously unconnected towns, villages, and other outlying areas. In more limited circumstances, the Bank invests in off-grid resource development, such as diesel or micro-hydro systems. Lower carbon alternatives to investments in rural electrification can include substitution of wind, solar, geothermal, and micro-hydro systems for off-grid diesel systems. Hybrid systems that couple renewable resources with battery storage and a smaller back-up diesel unit can be an attractive option for introducing intermittent renewables at a village scale. Solar photovoltaic (PV) home systems present another, and increasingly popular, low carbon alternative for electrifying individual households rather than entire villages. The GEF is supporting PV home system projects in Indonesia, Sri Lanka, and Uganda as climate change mitigation activities. Each of these alternatives has distinct advantages and limitations, as discussed by Foley (1995) and by Liebenthal, Mathur, and Wade (1994).

The analysis of rural electrification alternatives is inherently complex, particularly when comparing grid connection with isolated village electrification, and even more so when comparing either with individual household electrification. Each option provides a different level and quality of electric service, and its relative attractiveness depends on current and future needs and services the electricity would provide (from household lighting to industrial motor drive), which in turn is closely linked to the path of future local development. Given these complexities and data limitations related to several of the Bank's electrification loans, the team restricted their analysis to the comparison of off-grid hybrid systems with grid connection in Morocco. In addition, the team adapted the findings of a Bank-sponsored assessment regarding the costs, benefits, and emissions savings of solar home systems in Indonesia (World Bank 1996).

For the analysis of off-grid hybrid systems, the team matched limited resource availability information with the regions undergoing electrification. Then the optimization model HOMER was run, which uses technology costs and performance characteristics together with load and resource inputs, to determine the optimal size and configuration of a hybrid system.[11] The team considered variations in several of the inputs, including capital cost, resource availability, and extent of resource penetration. Based on these analyses, the team deduced the distance from grid access—that is, the length of transmission line required for grid extension—at which the hybrid system would "break even" or match the NPV of grid extension, given a range of carbon shadow prices.

4.3.5 Power Sector Reform Loans

As in the shadow price analysis, the analysis of alternatives for power sector reform loans is inherently qualitative. For these loans the team explored possible types of carbon reduction policies that the Bank might consider promoting and financing in the context of power sector reform under a carbon shadow price regime. There are several potential powerful regulatory and pricing mechanisms at a host country's disposal that could effectively reduce carbon emissions from an economically efficient standpoint, such as the use of carbon adders or taxes for system dispatch and planning or renewable resource portfolio standards or set-asides. The team briefly reviewed the literature on possible mechanisms, and discussed with local experts the various challenges—political, ideological, and practical—such options would face. Given its different approach, the analysis of power sector reform loans is presented in the form of initial review of policy options (see section 5.6)

1. For "no regrets" options, a lower value (that is, higher negative number) does not necessarily indicate a preferable option. For two alternatives that produce the same economic benefit, the option with higher carbon savings, which is presumably preferable, produces a higher value (smaller negative number). For two alternatives that produce the same carbon savings, the option with the greatest economic benefit is presumably preferable and produces a lower value (larger negative number). The precise switching value of a "no regrets" option is thus of limited value.

2. For nearly all alternative investments analyzed, economic benefits were roughly identical to the benefits of the loan. Thus the benefit streams did not need to be considered. In the few cases where additional benefits were provided, these were valued in the same fashion as in the loan and subtracted from the cost streams.

3. The cost of avoided carbon (CAC) is often expressed as CAC = ΔLevelizedCost/ΔCarbon, where costs are levelized using a discount rate and ΔCarbon is a constant annual (or per unit energy) rate of carbon savings (Watson, Zinyowera, and Moss 1996). This equation is a special case of CAC = ΔLevelizedCost/ΔLevelized Carbon, which is mathematically equivalent to equation 4.2, where j = i. Since carbon savings for a given option are often constant over time or per energy unit, carbon streams are generally not levelized.

4. Capacity factor is the ratio of average production to peak production. For a supply option with constant production levels, this is a equivalent to the fraction of a year in which it operates.

5. The most accurate approach for calculating avoided costs is the decrement approach (Tellus Institute 1995). The decrement approach begins with an optimal power supply expansion plan. Then the generation (or demand reduction) from an alternative resource is subtracted from load projections. The power supply expansion plan is reoptimized for the decremented load. The difference in supply costs before and after the decrement is a fairly accurate estimate of the true avoided costs. Unfortunately, this method tends to be time, labor, and data intensive.

6. For this reason, the team did not consider any possible loss of economies of scale related to plant downsizing. It is important to note that the least-cost plan that includes a given alternative might not include the original loan resource.

7. For the purposes of this analysis, it was assumed that the Bank and other investors fully capitalize the efficiency investments, and all savings show up in the benefit stream. In many cases, only the incremental or program costs would need to be financed. This is essentially a social cost perspective, and avoids the need for more detailed analysis of how DSM, standards, and other programs would be set up and financed. Although such analysis would be needed to indicate financial feasibility and develop a concrete investment plan, it is beyond the scope of the present effort.

8. Both capacity and energy requirements are assumed to be avoided. If excess capacity exists, near-term avoided capacity costs can be quite low. Significant excess capacity, however, is rare in most industrializing countries.

9. Our approach did not include the extra benefits from reducing a system's reserve margin, which typically requires that approximately 20 percent more capacity than peak load be constructed to ensure system reliability. By reducing peak load by 10 MW, a demand-side efficiency measure may actually reduce capacity requirements by 12 MW.

10. To the extent that electricity generation from peak load facilities is avoided, emissions from these facilities, instead of the baseload facility, are avoided. The difference in overall emissions is likely to be insignificant in most cases. Where the baseload facility is coal and the peaking facility is oil based, as is commonly the case, emissions on a per-kWh basis are quite similar, because of the lower efficiency of the peaking facility.

11. See Lilienthal, Flowers, and Rossman. 1995. The HOMER model runs were conducted by U.S. National Renewable Energy Laboratory (NREL), the model developer.

5 Alternatives Analysis Result

Following the approach described in chapter 4, the study team evaluated a set of alternative, lower carbon investment options. This chapter presents the results of the analysis.

5.1 Loans and Alternative Options Considered

Some alternative options to loans are discussed below.

Regional Distribution of Loan Types

As illustrated in figure 5.1, each of the loan types considered in the alternatives analysis has a different regional distribution. Power supply loans are concentrated in Asia, the result of at least three factors there: rapid demand growth, high reliance on fossil fuels, and a continued government role in the power sector. Power supply loans are absent from Latin America, where the 1990s emphasis on sector reform shifted investment activity largely to the private sector in many countries. Hydro resources are abundant in Latin America, as they are in Africa, but these loans were excluded from the alternatives analysis since they leave little scope for GHG reduction. The three rural electrification loans are in two continents, Asia and Africa, and district heating loans are restricted to Eastern Europe.

The emphasis on power supply loans in the alternatives analysis is consistent with the finding that approximately 80 percent of Bank project emissions are attributable to power supply expansion loans, assuming the random sample of Bank projects evaluated in chapter 3 is representative of the full portfolio. It is also the loan type for which the largest number of well-proven low-carbon technologies are likely to exist. Oil and gas development projects, in contrast, were not included for the alternatives analysis, given the more limited availability of carbon-reducing alternatives, along with the need for detailed site-specific data.[1]

Alternatives Considered

Across all the loans evaluated, switching values were calculated for more than 60 alternatives. Among these options, many low-carbon resources were considered: natural gas, higher efficiency coal, stand-alone windfarms, isolated wind-diesel hybrid systems, solar thermal electric, solar PV-diesel hybrid systems, geothermal, biomass residue, nuclear, large- and small-scale hydro, cogeneration, and a variety of demand-side efficiency (DSE) and distributed resource options. In addition, a series of policy options was considered for the power sector reform loans, including low carbon resource standards, trading schemes, and carbon taxes and shadow prices.

Table 5.1 shows the distribution of alternatives considered across loans, by loan type and resource. DSE options were the most commonly analyzed alternative, because of both the significant potential for low-cost carbon reductions and the large number of individual technology and end-use options. Natural gas was also frequently evaluated given its wide availability and diversity of applications. Wind and biomass were the most often analyzed renewable resource options, given their widespread resource availability and cost-competitiveness in many circumstances. Fewer hydro options were considered, a reflection of loan sites with limited unexploited potential and limited data on mini-hydro and other options.

Figure 5.1
Global Distribution of the Analyzed Loans, by Loan Type

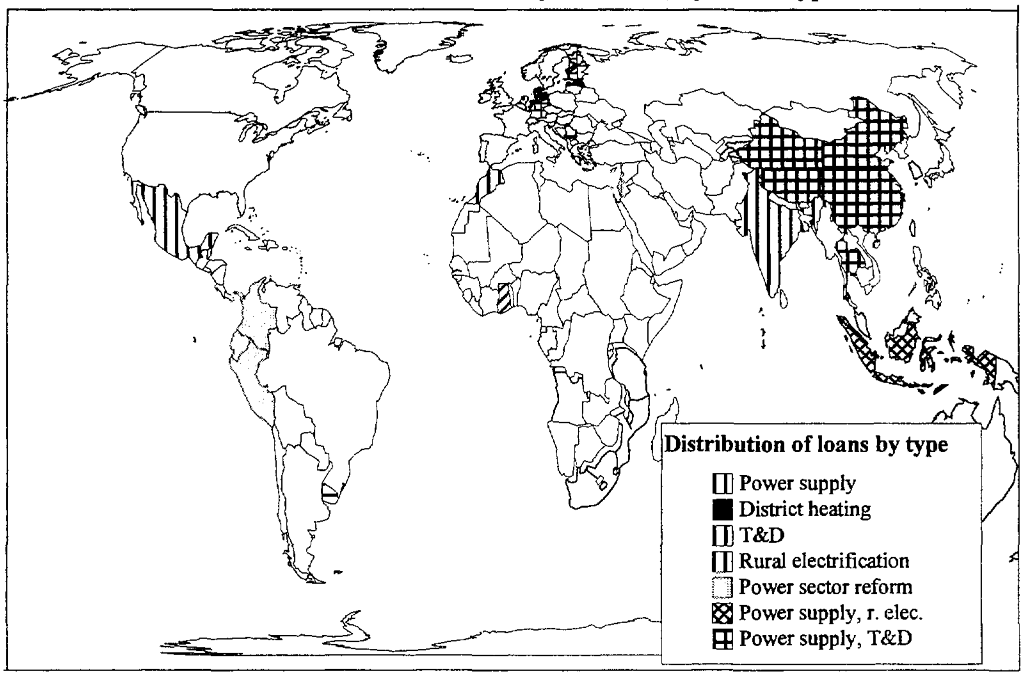


Table 5.1
Alternative Options Considered by Resource and Loan Type

Resource	*Power supply*	*District heating*	*T&D*	*Rural electrification*	*Total*
Demand-side efficiency (DSE)	11 (4)	7 (2)			18
Natural gas	6 (4)	2 (2)	3 (2)		11
Biomass	5 (4)	2 (2)			7
Wind	4 (4)		1 (3)	1 (1)	6
Hydroelectric	3 (3)				3
Solar	2 (2)		1 (3)	2 (2)	5
Geothermal	2 (2)				2
Nuclear	3 (3)				3
Higher–efficiency coal and oil	1 (1)				1
Total	37	11	5	3	56

Note: Numbers in parentheses indicate the number of loans in which the resource was considered.

5.2 Power Supply Loans

This section presents the analysis results by loan type. Given the large number of alternatives developed, only the characteristics and underlying assumptions for some of the alternatives are presented. Fuller descriptions of each of the alternatives can be found in the loan project appendices.

5.2.1 Summary of Results

Power supply loans represent the largest category of loans, and of alternatives reviewed: nearly 40 alternatives were analyzed across 8 loans. The apparent bias toward power supply in a number of loans and alternatives makes sense insofar as the potential for carbon reductions is greater here than for any other category of Bank loan. Power supply currently accounts for 40 percent of energy-related carbon emissions in non-OECD countries, and these emissions are projected to continue growing at about 3 percent per year.

Table 5.2 provides a comprehensive list of all the power supply alternatives considered and the analysis results. Carbon reductions range from a small fraction of total project carbon emissions for most DSE and biomass alternatives to full displacement of project carbon emissions for nuclear, geothermal, and some hydro options. Switching values also span a wide range, from -$19 per tC (agricultural pump improvements in India) to $125 per tC (solar thermal electricity in Ghana). These and other results presented in this chapter reflect the use of a net discount rate of zero on carbon emission streams as discussed in previous chapters. The corresponding results for power supply alternatives at a discount rate of 8 percent to 10 percent (opportunity cost of capital minus 2 percent) are presented in section 5.2.6 and figure 5.6 below.

The relationship between switching values and avoided emissions for power supply loans is shown in figure 5.2. A significant number of alternatives could yield a net economic benefit, as indicated by the points below the x axis. As in many national mitigation cost assessments, most of these "no-regrets" options are energy efficiency improvements.[2] Two of the other options below the x axis are natural gas alternatives in Yugoslavia and Ghana; these options were not originally chosen because of concerns about price volatility, supply reliability, and available infrastructure. The other two negative cost options are biomass (bagasse cogeneration in India) and hydro (Ghana) alternatives. In the latter case, the low value may reflect an underestimate of costs associated with drought susceptibility in a hydro-dominated system.

Figure 5.2
Switching Values versus Avoided Emissions for Power Supply Loans: All Alternatives

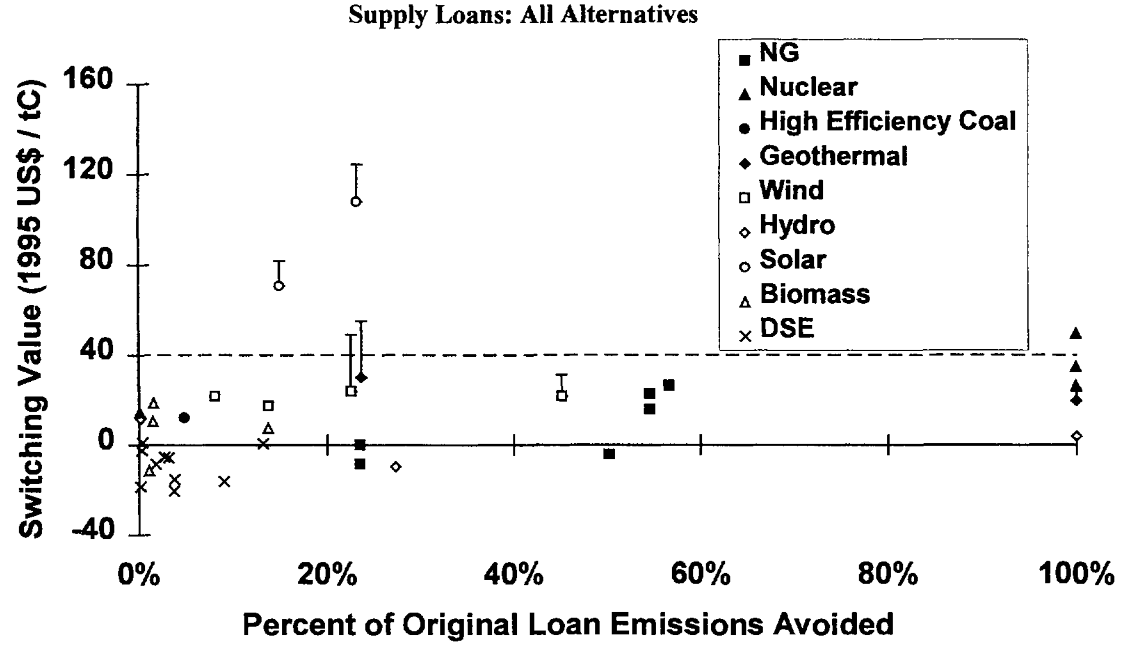


Table 5.2
Results from Analysis of Alternatives for Power Sector Loans

Loan and alternatives	*Carbon savings (million tC)*	*Switching value (1995 $ per tC)*	*Incremental costs (% of project costs)**
China, Yangzhou (coal, 1,200 MW)	*(baseline = 36.60 million tC, project costs = $1,109 million)*		
Natural gas (1,200 MW CC, pipeline)	19.98	23	41
Natural gas (1,200 MW CC, LNG)	19.98	16	28
Wind (670 MW, Inner Mongolia)	8.26	24–49	37
Wind (240 MW, Jiangsu)	2.96	22	6
Biomass (1,200 MW wood cofiring)	5.02	8	3
Nuclear (1,200 MW)	36.60	50	165
Coal (1,200 MW, supercritical)	1.77	12	2
DSE (33 MW, motors)	0.99	(5)	>-1
China, Yanshi (coal, 600 MW)	*(baseline = 24.35 million tC, project costs = $495 million)*		
Natural Gas (600 MW CC, pipeline)	13.81	26	74
Wind (670 MW, Inner Mongolia)	11.00	22–31	69
Geothermal (185 MW)	5.78	30–55	64
Ghana, Takoradi (oil CC, 300 MW)	*(baseline = 9.01 million tC, project costs = $425 million)*		
Natural gas (300 MW CC)	2.12	0	<1
Natural gas (300 MW CC, Tema)	2.12	(9)	-4
Hydro (399 MW)	2.46	(10)	-6
Solar thermal (200 MW)	2.09	108–125	61
Biomass (4.2 MW wood waste cogen)	0.14	19	1
India, NTPC (coal, 2,000 MW)	*(baseline = 87.94 million tC, project costs = $1,794 million)*		
DSE (490 GWh per year, agricultural pumps)	3.36	(15)	-3
Biomass (80 GWh per year, bagasse cogen)	1.30	11	1
Nuclear (2,000 MW)	87.94	35	171
Mini-hydro (22 GWh per year, canal drop)	0.18	12	<1
India, Maharashtra (coal, 500 MW)	*(baseline = 22.08 million tC, project costs = $602 million)*		
Wind (200 MW)	3.04	17	9
Solar thermal (100 MW)	3.31	71–82	68
DSE (163 MW, package of 8 options)	7.02	(7)	-8
Indonesia, Suralaya (coal, 1800 MW)	*(baseline = 65.52 million tC, project costs = $2,504 million)*		
Geothermal (1,575 MW)	65.52	20–24	62
Nuclear (1,800 MW)	65.52	27	69
Biomass (122 GWh per year, bagasse cogen)	0.72	(12)	>-1
Biomass (0–18 GWh per year, rice husk cogen)	0.07	15	<1
Thailand, Bang Pakong (NGCC, 614 MW)	*(baseline = 13.51 million tC, project costs = $379 million)*		
Hydro (600 MW, Laos)	13.51	4	14
Yugoslavia, Kolubara (coal, 700 MW)	*(baseline = 27.09 million tC, project costs = $1,453 million)*		
Natural gas (700 MW CC)	13.61	(4)	-4

- Project costs are as reported in SARs, and may include additional project components, such as technical assistance. In some instances where loans financed large additional loan components (India Maharashtra II), or where costs were reported as time slices of power development plans (India NTPC; Thailand), project costs for the individual power plants financed by the Bank were estimated using information in the SARs.

LNG = Liquefied natural gas.

CC = Combined cycle.

Switching values for most of the other alternatives fall within the shadow price range of $0 to $40 per tC. These include the bulk of the natural gas alternatives, two of the three nuclear options, and nearly all wind, hydro, geothermal, and biomass alternatives.

The bars extending upward from six of the points in figure 5.2 indicate the added transmission costs for remote renewable energy options. The high end of the range reflects the option cost if a new transmission line were constructed from the site of the alternative resource to the local network served by the loan resource, and if this cost were fully allocated to the alternative. If no additional transmission capacity were needed, the low end of the range would be a more appropriate estimate. Actual transmission costs, as discussed in section 5.2.4, would most likely lie somewhere in this range. As shown in figure 5.2, the addition of full transmission costs would raise the cost of two renewable alternatives above $40 per tC. The only other options above $40 per tC are a nuclear station estimate for China and the two solar thermal facilities considered. Overall, solar generation was the most expensive power supply alternative analyzed.

5.2.2 Original Loan Projects and Calculated Switching Values

The results shown in figure 5.2 are significantly influenced by the investment choices in the eight power supply loans selected for analysis. Six of these loans funded the construction of coal-fired plants; coal is the most carbon-intensive fuel and the major source of new baseload capacity in much of Asia. Nonetheless, this group of power supply loans may over-represent coal facilities relative to their share of new non-OECD electricity supply, and the reported carbon savings may thus be higher than might be achievable by an average, representative mix of new power sources.

The net effect on switching values of a coal-oriented set of loans is unclear, since their relatively high emissions and low unit costs of production have a countervailing effect. Since it increases carbon savings, comparison against coal plants tends to decrease switching values. This can be seen in equation 5.1 below; the higher the emissions of the original loan project ($Carbon_{orig}$), the lower the switching value (S):

$$(5.1)\quad S = \frac{NPV_i\,(Cost_{alt} - Cost_{orig})}{NPV_j\,(Carbon_{orig} - Carbon_{alt})}$$

At the same time, coal plants tend to be among the cheapest sources of electricity, particularly in regions with low-cost, indigenous reserves. Lower costs for coal-based electricity supply will tend to lower the cost of the original loan project ($Cost_{orig}$), and thereby increase the switching value.

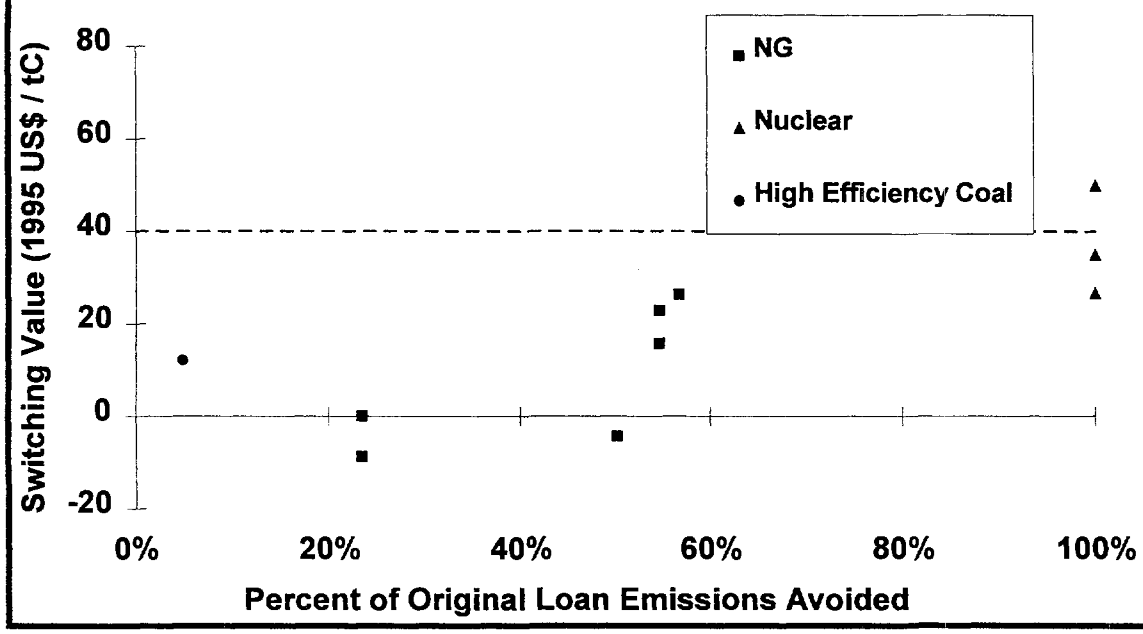
5.2.3 Natural Gas, Nuclear, and Higher Efficiency Coal Alternatives

Conventional supply options, such as nuclear and high-efficiency natural gas and coal, are the alternatives most typically evaluated in the power system planning studies referenced by loan SARs. In several cases, the team could draw assumptions for fossil-based alternatives directly from the SARs and supporting documentation.

Figure 5.3 shows three types of conventional supply options: (1) a high-efficiency coal option with limited carbon savings (5 percent) at a switching value of $12 per tC; (2) six natural gas options, two that save 25 percent of original loan emissions at zero to negative cost and four that save upwards of 50 percent at -$4 to $26 per tC; and (3) three nuclear alternatives that displace all project emissions at costs ranging from $29 to $50 per tC.

Higher-efficiency coal technologies, such as supercritical boilers, are inherently limited in their carbon savings potential. They offer carbon savings only where the original loan project is a lower-efficiency coal plant and typically only a 5–10 percent savings is possible with commercially available technologies. They nonetheless have the advantage of easy substitution: they can be sized and run similarly to the loan project, and can use the same fuel supply.

Figure 5.3
Switching Values versus Avoided Emissions for Power Supply Loans: Fossil Fuel and Nuclear Alternatives



For the two groups of natural gas alternatives, the difference in carbon savings is caused by the carbon content of the avoided fuel. Displacing fuel oil in Ghana saves about 25 percent of project emissions, whereas displacing coal elsewhere saves between 50 percent and 60 percent. The Ghana switching values are low because the delivered price of imported natural gas is almost equal to that of imported heavy fuel oil at the plant site. Natural gas prices would be even lower if the plant were sited closer to the source of natural gas (Nigeria), thereby resulting in a negative switching value. The Ghana oil thermal facility was in fact built with dual-fuel capability, recognizing the potential benefits of gas supply, which has yet to be secured from Nigeria. The cluster of three natural gas alternatives around $20 per tC represents the cost and carbon savings of switching from coal in China. The results are similar for both imported liquefied natural gas (LNG) and indigenous natural gas options. Finally, the negative cost option at 50 percent emission savings in figure 5.3 represents a natural gas alternative to a lignite plant built in the former Yugoslavia. This alternative relies on the use of Russian natural gas and may appear more economic under then-current gas prices than the lignite plant, but was not implemented in part because of overriding concerns about price volatility and supply reliability.

The difference among switching values for the nuclear plants is due to differences in cost estimates for both the nuclear plants and the coal plants they would displace. For China, the cited capital costs per kilowatt of a nuclear station are 4.5 times higher than its coal-fired counterpart; for India, estimated nuclear capital costs are only 1.5 times higher.

5.2.4 Renewable Resource Alternatives

With the exception of large hydro facilities, renewable energy alternatives were not included in the economic comparisons found in the loan SARs considered. Instead the team developed the geothermal, wind, solar, biomass, and additional hydro alternatives from available resource assessments.

Results for renewable resource alternatives are shown in figures 5.4 and 5.5. Together, these figures show that hydro and biomass resources provide the least expensive options, ranging from -$12 to $19 per tC. This finding is not surprising given that these resources are currently the two leading renewable sources of electricity worldwide.

The lone negative switching value in figure 5.4 represents the Bui hydro option in Ghana, and is most likely an underestimate of actual costs. The Takoradi oil thermal plant was built instead of the Bui hydro option to reduce susceptibility of the hydro-dominated power system to drought-induced shortages. The switching value for Bui does not account for this important risk factor.[3] The Bui hydro option is also potentially limited as a carbon saving option. The resulting reservoir would flood 400 km^2 of a national park, and aside from other potential environmental and other concerns, it would forgo future carbon sequestration potential in a high biomass growth area. Lost sequestration potential is equivalent to approximately three-quarters of the emissions of the oil-fired Takoradi facility. The other large hydro facility (100 percent carbon savings) on figure 5.4 represents the construction of a dam in Laos and the import of electricity into Thailand at a cost of about $4 per tC.

Mini-hydro installations are important potential resources in many of the Bank's borrowing countries, particularly for off-grid or poorly served areas. However, despite their resource potential, data were readily available for only one of the loan regions under consideration: irrigation canal-drop systems in India. Although irrigation-based hydro systems appear to displace only a small fraction of carbon emissions at a net cost of $12 per tC, their value could be significantly greater when compared to the higher-cost electricity supply in rural areas.

Figure 5.4
Switching Values versus Avoided Emissions for Power Supply Loans: Renewable Resource Alternatives

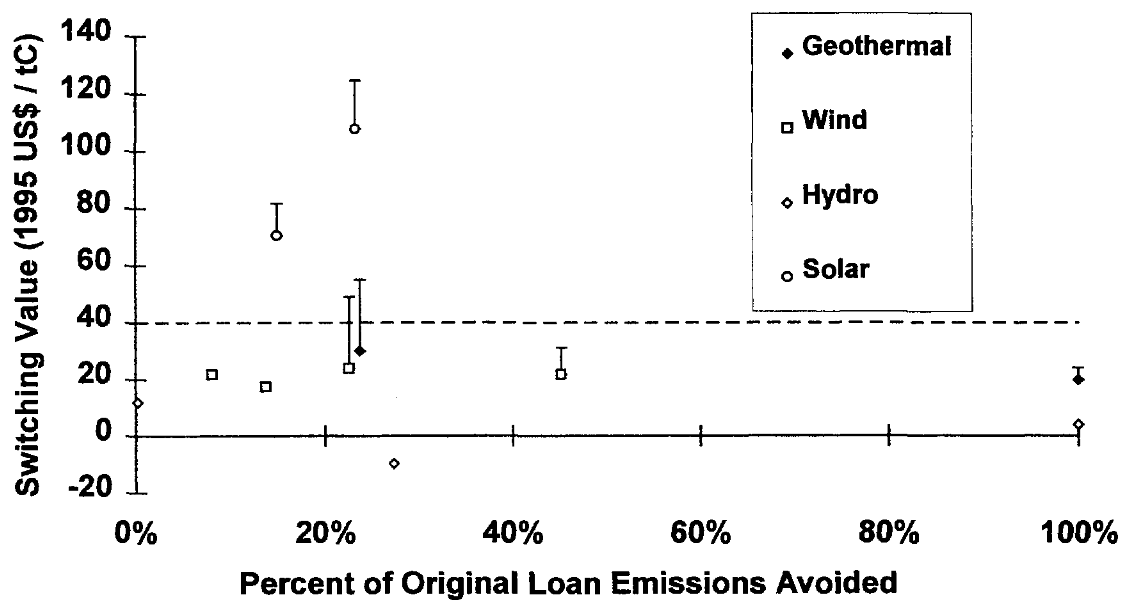
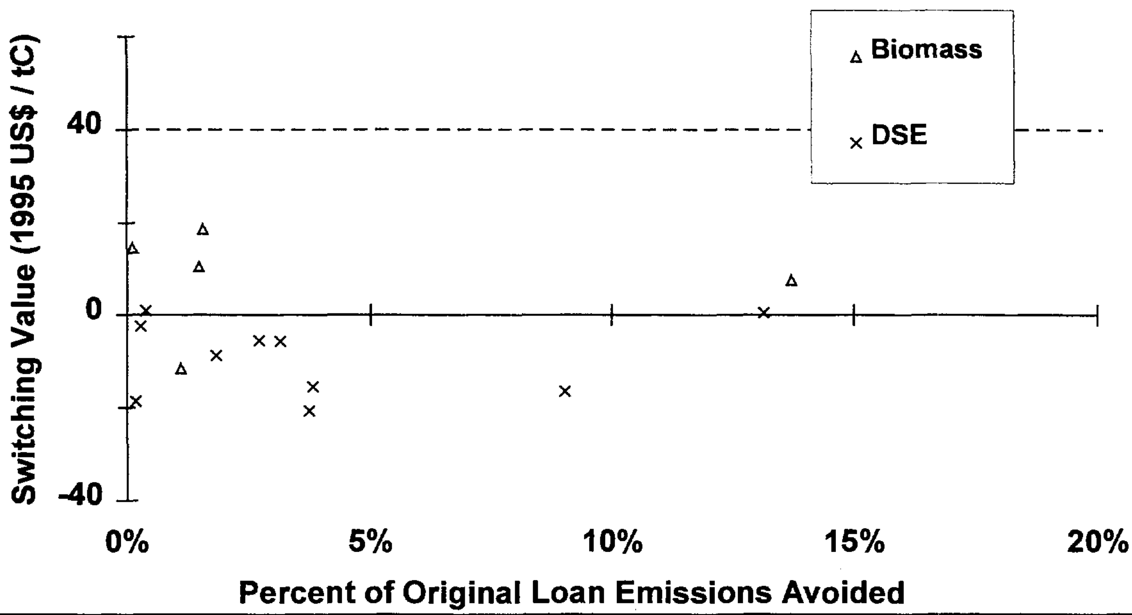


Figure 5.5
Switching Values versus Avoided Emissions for Power Supply Loans: Biomass and DSE Alternatives



Biomass alternatives, plotted separately in figure 5.5 because of their smaller scale, all have switching values below $20 per tC. Most entail more efficient use of biomass residues through cogeneration of electricity and process steam.[4] Bagasse cogeneration at sugar mills appears to be a cost-effective alternative for the Indonesia Suralaya loan, but a net positive cost option in India, because of differences in conditions and local cost estimates. Cogeneration using rice husks in Indonesia and wood wastes in Ghana has switching values from $15 to $19 per tC, but is quite limited in its overall potential to offset emissions on the scale of loan investments.

Four wind alternatives were considered: three in China and one in India. Of these, the largest carbon savings, 11 million tC or 45 percent of Yanshi loan emissions, result from large-scale exploitation of the abundant and powerful wind resource available in the Inner Mongolia region (China). The study team considered the same resource for the China Yangzhou loan. In both cases, transmission costs could be considerable, as reflected by the bars in figure 5.4. (It would probably make more economic sense to use these resources for less distant power grids, thereby reducing transmission requirements.) The other two wind alternatives represent the exploitation of more limited wind resources available closer to the loan sites in China (Yangzhou) and India (Maharashtra).

The switching values of the wind options considered fall within a range of $17 to $31 per tC; the addition of transmission costs could increase the costs for remote options by up to $25 per tC there. The lowest switching value, $17 per tC, was found in India, now the world's second leading producer of wind-based generation. Wind power in India appears to be more competitive than in China, in part because of the higher relative cost of coal-based power generation.

Absent transmission impacts, the switching values for the two geothermal alternatives, one in China, the other in Indonesia, are both approximately $30 per tC. In China, however, the geothermal resource is approximately 1,000 km from the loan region, thus entailing potentially high transmission costs.

Switching values for the solar thermal alternatives range from $71 per tC (India, no additional transmission costs) to $125 per tC (Ghana, full additional transmission costs), with respective reductions in carbon emissions of 15 percent and 23 percent of project emissions. The difference in switching values is primarily because coal generation is being displaced in India and high-efficiency oil generation is being displaced in Ghana. So although estimates of costs and resource availability for the alternative are about the same for both countries, the India alternative generates more carbon savings over the baseline than does the Ghana alternative.

Added Transmission Costs for Remote Renewables

As noted above, and as illustrated by the bars in figures 5.2 and 5.4, the exploitation of distant renewable energy resource options can entail significant transmission costs. The team considered distant resources where (a) resource assessments showed insufficient local resources, (b) resource assessments showed significantly better or more abundant resources at greater distance, or (c) the team was unable to obtain assessments for the areas surrounding the specific loan area or region. For remotely sited facilities, the incremental transmission costs are determined by the constraints of the existing transmission network between the remote site and the load center. As an upper bound, the team assumed this network was either fully constrained (no additional capacity available) or nonexistent: a new transmission line would be required to link the remote power supply with the demand center. As in the high-end estimate, the study team attributed the full costs of new transmission capacity to the alternative. This could overestimate the costs if other loads and facilities were served by the expanded transmission network. The lower bound represents zero additional transmission costs, that is, the existing transmission system has sufficient excess capacity to carry the additional load. Since neither extreme is likely, actual transmission costs would probably lie somewhere along the bars shown in the figures.

5.2.5 Demand-Side Efficiency Alternatives

Several DSE alternatives were considered, and nearly all yielded net economic benefits. This is largely a reflection of the local efficiency analyses used, which typically screened out uneconomic options (see appendix).

Consequently, the points on figure 5.5 reflect only a small fraction of the DSE options likely to be available at net cost, or those available at net economic benefit. Only for the India Maharashtra loan did the team locate a relatively comprehensive demand-side evaluation that sought to capture achievable energy savings across several demand sectors and end uses. A package of eight DSE measures identified by Banerjee and Parikh (1993) appears capable of avoiding almost a third of the carbon emissions from a 500 MW coal plant. These measures, which include improved motors, motor drives, electric arc furnaces, lighting, and housekeeping, are each plotted separately in figure 5.5. For other loan regions, detailed demand-side analyses are lacking and only assessments for selected technologies are available, for example, for motor improvements in China and for agricultural pumps in India.

5.2.6 Sensitivity Analysis

Figure 5.6 shows the switching values for all power sector alternatives when carbon emission streams are discounted at the opportunity cost of capital (OCC) minus 2 percent. A comparison of figures 5.2 and 5.6 illustrates that the two discount rates produce dramatically different results. Aside from the negative cost alternatives, which actually decrease in switching value, at the higher discount rate only two options (one hydro and one biomass) remain below $40 per tC. The higher discount rate increases switching values by a factor of about 3 to 4.5, a function of the loan-specific opportunity cost of capital and the lifetime and construction period of the loan project.

Figure 5.7 further illustrates the extent to which switching values are sensitive to the variation in discount rates, as compared with other parameters. For wind (Inner Mongolia resource) and natural gas (via pipeline) alternatives to the Yangzhou coal thermal plant in China, figure 5.7 shows how switching values deviate from those reported above, when fuel price, transmission cost, project lifetime, performance, and discount rate are varied.

The other interesting result of figure 5.7 is the effect of increasing project lifetime from 20 years, which is typically assumed for accounting purposes in Bank SARs, to 30 years, which is more typical of power plants. As the accounting period is extended by 10 years, carbon savings increase by 50 percent and the switching value decreases by 33 percent. At the higher discount rate of OCC minus 2 percent on carbon emission streams, the switching value decreases by only 10 percent, since emission reductions 20–30 years hence have much less value. The effect of using a more realistic physical lifetime is a particularly important finding: since the team was adopting all the assumptions of Bank SAR economic analyses for the analysis of power supply alternatives, total carbon savings may have been systematically and substantially underestimated, and switching values overestimated.

Figure 5.6
Switching Values for Power Supply Loan Alternatives at a Carbon Discount Rate of OCC minus 2%

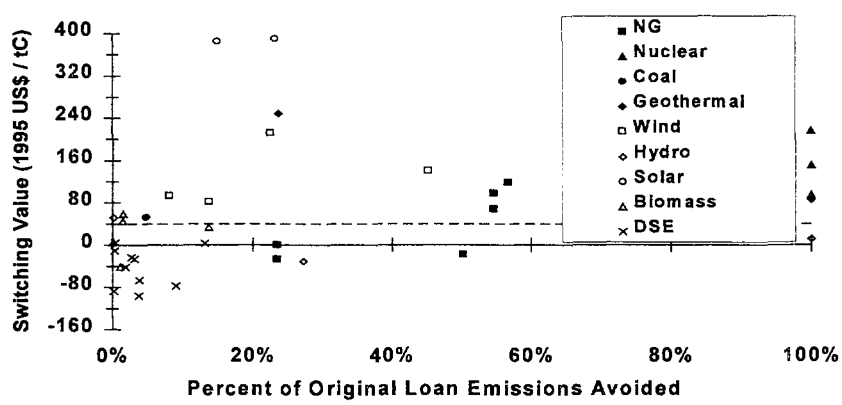
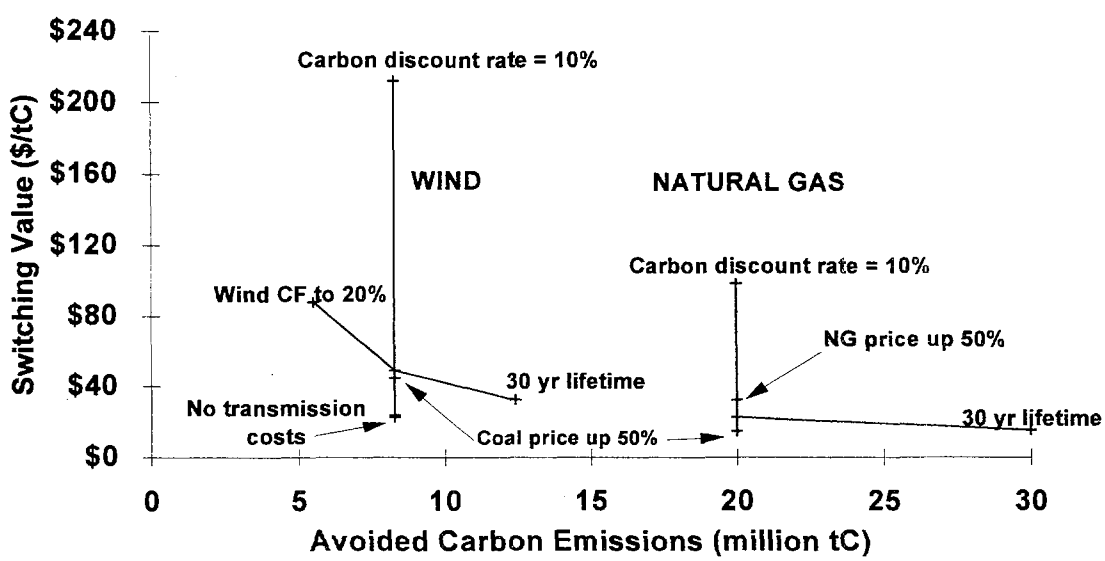


Figure 5.7
Sensitivity Analysis of China Yangzhou Alternatives: Inner Mongolia Wind and Natural Gas via Pipeline



Note: Original switching value based on 0 percent net discount rate, 20 year project lifetime, 30 percent capacity factor, and all costs for new transmission lines.

5.3 District Heating and Fuel Switching Loans

District heating and fuel switching loans are discussed below.

5.3.1 Description of Alternatives

Similar options were considered for each of the two district heating loans: fuel switching to lower-carbon fuels and improvements in building energy use. Lower-carbon fuels are available from the large indigenous wood resources of the Baltic states and from imports of Russian natural gas through existing pipeline networks.

Although the loan projects in Latvia and Estonia address the large inefficiencies in the supply of district heat, similar large inefficiencies remain on the demand side. Large residential buildings in the ex-Soviet Baltic states are poorly insulated, and the use of heat and hot water is poorly managed. The study team considered several DSE improvements, including pipe insulation, efficient windows, roof insulation, basement insulation, metering, and heat balancing controls.

5.3.2 Results

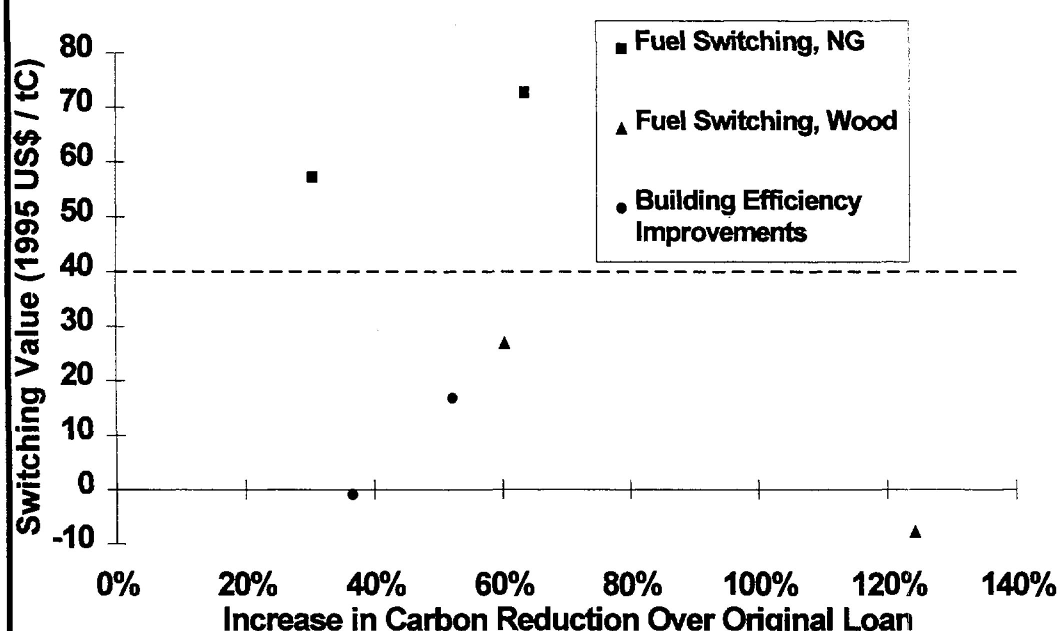
As shown in table 5.3, the team found that natural gas is an expensive carbon-reduction option in both countries, exceeding the $5 to 40 per tC shadow price range. This is largely a reflection of high natural gas prices in both countries, particularly in relation to the fuels they displace: heavy fuel oil in Latvia and peat in Estonia. High natural gas prices may also be the result of cross subsidies to other consumers, as suggested in the SARs. Natural gas prices reported in the SARs are almost 50 percent higher in Latvia than in Estonia, a surprisingly large difference given their proximity and their common source of natural gas supplies (Russia). Not surprisingly, switching from boiler fuels to wood yields considerably greater carbon savings at lower expense than switching to natural gas. Although there are substantial incremental costs associated with converting boilers to use wood chips, wood fuel is a much cheaper fuel, roughly 5–10 percent of the price of natural gas and oil, respectively, on a GJ basis. Wood use in Latvia could provide net economic benefits as suggested by its negative switching value, whereas in Estonia, the net cost could be almost $30 per tC, given that wood offers no fuel cost savings relative to the peat it would displace.[5]

The package of building efficiency improvement measures in Estonia is more ambitious and somewhat more costly than the measures reviewed for Latvia. The Estonia building improvements, which involve adding insulation and heat balancing controls to about 1,000 buildings in Tallinn at an incremental cost of $20,000 per building, reduce heat demand by 17 percent and yield a switching value of $12 per tC with carbon savings of 290,000 metric tons. The combination of five types of improvements to Latvian apartment buildings avoids 43,000 metric tons of carbon emissions at a net economic benefit of $1 per tC. As with wood fuel substitution, the efficiency improvements are more economically attractive in Latvia since they displace the use of higher-cost fuel. Figure 5.8 shows the relationship of switching values to emissions reductions for the district heating loan alternative.

Table 5.3
Results from Analysis of Alternatives for Fuel Switching and District Heating Rehabilitation Loans

Loan and alternatives	*Incremental carbon savings (thousand tC)*	*Switching value (1995 $ per tC)*	*Incremental costs (% of project costs)*
Estonia (boiler conversion)	*thousand tC saved, project cost = $5.30 million)*		
30% of boilers switch from peat to natural gas	30	57	37
30% of boilers switch from peat to wood	70	27	34
Estonia (District heating (DH) rehabilitation)	*(527 thousand tC saved, project cost = $18.8 million)*		
Building efficiency improvement (4 measures)	290	12	25
Latvia, Jelgava (DH rehabilitation)	*(123 thousand tC saved, project cost = $13.9 million)*		
45% of boilers switch from HFO to natural gas	78	73	41
30% of boilers switch from HFO to wood	152	(11)	-9
Building efficiency improvement (5 measures)	43	>(1)	>-1

Figure 5.8
Switching Value versus Emission Reductions for District Heating Loan Alternatives



5.4 Transmission and Distribution

As noted in chapter 4, the analysis of T&D loan alternatives was limited to an illustrative comparison of distributed resource (DR) options. Table 5.4 shows the shadow prices calculated for a few generic DR options across the Mexico, Thailand, and Uruguay loans, along with some generic characteristics of these technologies. It is important to emphasize that the generic comparison of five technologies—natural gas engines, turbines, and fuel cells, as well as wind and PV—does not reflect the full promise of DR options. Because of a lack of local data, cogeneration, DSE, and biomass technologies were not considered, but could be the most attractive options in many circumstances. Furthermore, an important economic benefit was not calculated: the ability of DR options to delay future T&D upgrades or extend the ability of the existing grid to service new loads. More detailed economic analyses are required to estimate these important benefits, which have been a prime motive for DR investments to date.

Among the options considered in table 5.4, several natural gas and wind options fall below $40 per tC at the low end of their cost ranges. The variance in cost estimates reflects a range of unit capital cost and operating cost and performance assumptions. The variation among countries reflects the difference in avoided costs and emissions. In Mexico, the marginal avoided resource is assumed to be fuel oil steam; in Thailand, it is coal steam; and in Uruguay, it is oil combined cycle. Furthermore, the reported T&D system losses vary considerably, from 13 percent in Mexico and Uruguay to 7 percent in Thailand, and account for much of the difference in the switching values. At the low end of their cost range, natural fuel cells present the most attractive of the five DR options. Despite this ideal niche for distributed applications, fuel cells remain a maturing technology.[6]

Table 5.4
Costs and Characteristics of Distributed Resources

DR type	*Capacity range (MW)*	*Advantages*	*Disadvantages*	*Mexico switching value ($ per tC)*	*Thailand switching value ($ per tC)*	*Uruguay switching value ($ per tC)*
NG ICE	0.5–5	• Low cap. cost • Quick startup • High reliability	• Emissions • Noise • Sensitive to temp.	21 to 76	47 to 97	—.
NG CT	5–27	• Low cap. cost • Quick startup • High reliability	• Emissions • Noise	33 to 138	61 to 151	—
NG fuel cells	0.5–10	• High efficiency • High reliability • Modular	• Less mature technology • High O&M	(2) to 187	20 to 194	—
Wind	0.5–5	• No fuel • No pollution • Modular	• Visual impact • Land requirements • Intermittency	23 to 95	40 to 109	32 to 132
Solar or PV	0.5–5	• No pollution • Can coincide with peak	• High cap. costs • Space requirement • Intermittency	253 to 398	260 to 399	350 to 551

— Natural gas is currently not available.
ct Combustion turbine.
ICE Internal combustion engine.
NG Natural gas.

Table 5.5
Break-Even Distances and Carbon Savings
for Morocco Rural Electrification Alternatives

	Wind-diesel hybrid system (wind speed: 8 m/s)	*PV-diesel hybrid system (penetration: 50%)*
Break-even grid length (km) at		
$0 per tC	25	38
$20 per tC	24	37
$40 per tC	23	35
Annual carbon savings[a]		
Relative to grid extension (%)	33	52
Total (tC per village)	188	281

Note: Illustrative village size is 220 households.

a. Carbon savings computed based on displacing diesel oil combustion turbine (marginal system resource). Village diesel generators operating at 17,000 Btu per kWh heat rate.

5.5 Rural Electrification

As noted in section 4.3.4, the direct comparison of off-grid, low-carbon alternatives with grid connection, as typically funded by Bank rural electrification loans, is complicated by several factors, such as differences in the level and quality of service provided. The study team nonetheless undertook a simplified analysis for the Morocco Second Rural Electrification loan, the results of which are shown in table 5.5

At wind speeds found in Moroccan villages, wind-diesel hybrid systems become more cost-effective than grid connection where a village is 25 km or more from the nearest grid connection point. PV-diesel hybrids, having higher costs, require a distance of 38 km or more to become competitive with grid connection. These results are highly sensitive to the number of households in a village, assumed here to be 220. This relationship, however, has little effect on a key finding of our analysis: the economics of diesel hybrid systems are relatively insensitive to the application of a carbon shadow price of $20 to $40 per tC. The net effect is to decrease the break-even distance by less than 10 percent. It is thus unlikely that a shadow price in this range would cause a significant switch in investment decisions away from grid connection and toward wind or PV hybrid systems beyond what would already be economically justified.

Solar home systems, consisting of PV, battery, controller, light fixtures, and related components, offer another low-carbon rural electrification alternative. A major Bank-supported solar home system project in Indonesia is likely to proceed soon with GEF grant support, and it is possible that such systems could have been considered as a direct alternative to grid connection in the villages electrified by the earlier Indonesia Second Rural Electrification loan (1995). The SAR for the planned Indonesia Solar Home Systems Project reports an expected carbon savings of 370,000 metric tons for the project itself, and 610,000 metric tons assuming that a multiplier effect increases market penetration of solar home systems beyond those supported by the project itself. These savings presume that 70 percent of the electricity generated by solar home systems displaces kerosene lighting, 20 percent displaces diesel-based battery charging, and 10 percent provides additional energy services (previously unmet demand). Assuming that the GEF grant of $24.3 million ($14.2 million, discounted at 10 percent) represents the incremental cost required to achieve these savings, the resulting switching value is $39 per tC, and drops to $23 per tC if the additional multiplier effects are included.

5.6 Power Sector Reform

The main study sample contained three loans dealing with power sector reform: an $80 million Energy Sector Adjustment loan to Jordan (1993); a $150 million Electricity Privatization Adjustment loan to Peru (1994); and an $11 million Energy Sector Technical Assistance Project loan to Colombia (1994, followed by a much larger Power Market Development Project loan). As described in section 4.3, the team examined various policy mechanisms that could be used to reduce carbon emissions in the restructured power sectors addressed by these three loans. The loans and policy mechanisms are described below, followed by an assessment of which mechanisms might be most appropriate in the context of these loans and similar investments.

5.6.1 Loans Examined

Analyses of the loans to Colombia, Peru, and Jordan are discussed below.

Colombia and Peru

The Colombian and Peruvian loans were analyzed in tandem, for two reasons. First, the power sectors of both countries are being privatized in a similar fashion. In this model of privatization, increasingly common in Latin America, there is a strong emphasis on a competitive, free market approach. Second, in both countries, most of the installed capacity is hydropower generation, although new construction is likely to include fossil-fired plants, especially in Colombia. Given the high reliance on hydroelectricity, changes in energy consumption may have a limited effect on carbon emissions, except to the extent that marginal generation is fossil-fired. The major element of each of these loans was helping institutions involved in power sector reform to accomplish key objectives, such as attracting private capital, rationalizing pricing policies, eliminating subsidies, and creating competition between generators.

Jordan

In Jordan, restructuring of the power sector provides for a more extensive governmental role, particularly with respect to regulation, resource planning, and promotion of energy efficiency. Jordan is dependent on imported fossil fuels for electricity generation, which has created a significant balance of payments problem. The goal of the loan was to restructure the energy sector, including the electricity subsector, to improve Jordan's balance of payments and hence enhance macroeconomic stability. The loan supported pricing reform, privatization of electric utilities, establishment of a regulatory framework for the power sector, improvement of institutional arrangements for policy formulation and planning, and strengthening of environmental protection and energy conservation measures.

5.6.2 Policy Mechanisms Considered

The impact of power sector restructuring and privatization on carbon emissions is difficult to predict. Although removing subsidies sets prices closer to long-run marginal costs, elasticities are such that consumption is not greatly affected. Meanwhile, the restructured environment is likely to minimize the value accorded to environmental and social concerns, with the result that low-carbon energy technologies may be disadvantaged. As some observers have noted, reforms under way in Latin America may result in increased investment in natural gas generation rather than hydropower resources (Suding 1996).

Thus, in the context of a shadow price for carbon emissions, it is important to consider how various policy instruments could be incorporated into power sector reform loans to produce optimal emissions reduction. The mechanisms the study team considered fall into the following five broad classes:

1. *Low-carbon resource targets*, such as resource portfolio standards requiring all power suppliers to maintain a given target level of low-carbon resources (for example, wind power, small-scale hydro) within their supply-side portfolio. A variation on this

theme is the renewables set-aside, which provides small-scale developers with an opportunity to sell into the grid at a fixed price for a fixed term, usually 10 to 15 years.

2. *Emissions taxes and shadow prices,* through which a charge is levied per unit of carbon dioxide emitted. Revenues from the charge may be collected, or simply used as an adder for planning purposes. Charges may be applied at the level of generation, distribution, or resource planning (for example, decisionmaking about system expansion), or all three.

3. *System benefits charges*, which consist of a fee levied specifically per kilowatt-hour sold. For carbon abatement, revenues could be applied to finance renewable resources or investments in energy efficiency.

4. *Integrated resource planning (IRP),* a planning methodology that holds that electric power resources should be developed in order of ascending cost and that the resource portfolio should treat supply-side and demand-side resources in the same manner.

5. *Traditional energy efficiency promotion activities,* including market development and conditioning activities, such as building an energy services company (ESCO) industry, establishing energy efficiency codes and standards, and promoting voluntary programs to encourage private firms to invest in cost-effective energy efficiency measures.

5.6.3 Results of the Assessment

When assessing which policy instruments to reduce carbon emissions would be most appropriate in the context of a given power sector reform loan, it is necessary to consider several factors. First is the degree of government involvement in the restructured setting. Some mechanisms that work well when the government is substantially involved in power sector regulation and planning would not be appropriate when the government's role is more limited, and vice versa. Other criteria are effectiveness in stimulating emission reductions; use of market-based measures to maximize economic efficiency; determination of whether the measures are "no-regrets" (that is, produce other benefits that make them economically justifiable without reference to their carbon reduction effects); and feasibility of implementation given the national political and institutional conditions. Table 5.6 presents a summary of how the policy instruments the study team considered rank in terms of these attributes.

Colombia and Peru: Policies for a Competitive Free Market Environment

For the Colombia and Peru loans, mechanisms that rely on strong government involvement in the power sector, such as shadow pricing in the resource planning process and standard IRP, would be impractical. Among those mechanisms that are suitable, the most effective in reducing carbon emissions would be carbon taxes on power generation or a resource set-aside for small-scale, nonhydro renewables. A carbon tax on generation would effectively discourage development of fossil-fired capacity, and any revenues produced by the tax could be used to reduce other taxes in the economy.[7] However, such a tax is likely to be politically and institutionally difficult to implement in most countries. A set-aside for small-scale renewable resource development could be designed not only to forestall fossil generation at the margin, but also to reduce the risk of drought-related power shortages in hydro-dominated systems. Technology-specific set-asides could be used to establish an independent power producer (IPP) market that would help Colombia and Peru diversify their power resources (for example, geothermal in Peru) without increasing their use of fossil fuels. A set-aside will usually be more feasible to implement than a carbon tax and, when coupled with a competitive bidding process, will be likely to produce considerable price reductions in renewably generated electricity.

A system benefits charge could also be effective in reducing carbon emissions, though perhaps somewhat less so than a carbon tax or a renewables set-aside. Such policies rank high in terms of political and institutional feasibility. System benefits charges have been implemented

Table 5.6
Power Sector Policy Mechanisms to Promote Carbon Reductions

Mechanism or Activity	*Competitive generation*	*Traditional generation monopoly*	*Emission reduction potential*	*Market-based?*	*"No regrets" option?*	*Politically and institutionally feasible?*
Low carbon resource targets and trading systems						
Resource portfolio standard	●	●	●	⊙	○	⊙
Resource set-asides	●	⊙	●	⊙	○	⊙
Emission taxes and shadow prices						
Tax for power generation (revenue neutral)	●	●	●	●	○	○⊙
Tax for power generation (targeted revenues)	●	●	●	⊙	○	○⊙
Shadow price in system dispatch	⊙	●	●	⊙	○	⊙
Shadow price in resource decisionmaking	○	●	●	⊙	○	⊙
System benefits charge	●	●	⊙	○	⊙	●
Integrated resource planning (IRP)						
Standard IRP	○	●	⊙a	○	⊙	⊙
Distribution-level IRP	●	○	⊙a	○	⊙	⊙
Traditional efficiency activities						
ESCOs, market transformation	●	●	⊙	⊙	●	⊙
Barrier removal activities	●	●	⊙	○	●	⊙
DSM or funded efficiency programs	●	●	⊙	○	●	●
SSM or T&D loss reduction	●	●	⊙	○	●	●
Codes and standards	●	●	⊙	○	●	⊙
Voluntary Information Programs	●	●	○	○	●	●

● practical, yes, or high ranking ⊙ partly practical, perhaps, or medium ranking ○ impractical, no, or low ranking

a. Limited to extent of "no regrets" options.

in Brazil, Mexico, the United Kingdom, and other countries where they provide a reliable and constant source of financing for sustainable energy investments.[8] However, care must be taken to ensure the economic efficiency of this mechanism. Since the charge is not directly linked to carbon emissions, it may produce undesirable fuel-switching effects if not well designed and applied. In addition, revenues should be used for cost-effective, market-based investments in energy efficiency and renewable energy.

Incorporating energy-efficiency promotion activities directly into power sector reform loans is another way to reduce carbon emissions. Some of these activities would be highly feasible to implement (voluntary programs, T&D loss reduction), whereas others may encounter some political or institutional difficulties (codes and standards, ESCO development). One great advantage of this mechanism is that it produces "no regrets" options that generate substantial national economic benefits as well as carbon emissions reduction. For maximum impact, activities should be designed to transform entire markets rather than to undertake stand-alone projects.

Although standard IRP techniques are not applicable in a competitive free-market environment, distribution-level IRP may have a role. Natural distribution monopolies remain even where generation has been opened to competition. Governments can require distribution utilities to assess the cost-effectiveness of investments in distributed renewable generation and energy efficiency as a means of avoiding costly grid extension. Such investments would directly reduce carbon emissions in a fossil-dominated power sector; in Colombia and Peru, they could displace investment in new fossil-fired generation at the margin. Distribution-level IRP ranks in the middle in potential to reduce emissions, feasibility of implementation, and "no regrets" potential.

Jordan: Policies for a More Regulated Environment

In Jordan, policy mechanisms to reduce carbon emissions would be structured somewhat differently than in Latin America, for a number of reasons. One reason is that the government retains a stronger role in power sector regulation and planning than in a more competitive environment such as in Latin America. Another is the domination of fossil fuels in Jordan rather than hydropower as in Latin America. Energy efficiency and renewables directly reduce carbon by displacing fossil generation. Moreover, energy efficiency and domestic renewables help ameliorate Jordan's negative balance of payments.

One of the most effective ways to reduce carbon emissions in Jordan's power sector would be for the government to establish a low-carbon resource portfolio standard (for example, wind and solar) for the country's privatizing electric utilities. Such a policy could be designed to use market mechanisms to keep costs down. For example, a competitive bidding process could attract private sector involvement.

Because of the government's continuing role in regulation and planning, there are many options to apply carbon taxes or adders to produce emission reductions. The most economically efficient option would be a revenue-neutral carbon tax on power generation, which would enable reductions in other taxes. Perhaps more politically feasible would be the use of carbon adders in planning processes, for example, decisionmaking on system expansion. Jordanian utilities are already responsible for adopting least-cost expansion programs, including load management and energy conservation.

Another policy option is a system benefits charge. This would not be implemented significantly differently in a more regulated environment than in a fully competitive free-market environment. (Refer to the section above for a brief description of the advantages and drawbacks of this option.) Programs to promote energy efficiency could be implemented as part of power sector reform efforts. In Jordan, utilities are already responsible for establishing efficiency targets and developing action plans.

5.7 Findings and Conclusions

The limited loan sample, the site specificity of results, and the rapid assessment approach preclude definitive conclusions about specific resources and their attractiveness. It would be misleading to suggest, for instance, that natural gas and wind resource investments require incremental cost subsidies of up to $20–$70 per tC, as some of the switching values suggest. Where avoided costs are higher and these resources are cheap and abundant, they are already economically attractive. Natural gas combined cycle facilities are one of the most common power supply investments today, and hundreds of megawatts of wind turbines are now under construction in India and elsewhere. Similarly, the carbon savings reported here are indicative rather than definitive assessments of the potential of each alternative resource to avoid carbon emissions.[9] With these caveats in mind, the analysis of alternatives revealed the following:

1. At a net discount rate of zero for carbon emissions, switching values for most types of alternatives fall in the $0–$40 per tC range. These include all of the natural gas, hydro, biomass, and higher-efficiency thermal plants considered for power supply loans; fuel switching to wood for district heating loans; and most of the wind, geothermal, and nuclear options considered. According to a recent Bank SAR, solar home systems, as alternatives to traditional rural electrification, may also fall in this range.

2. Options above the $40 per tC range included all other solar alternatives considered (power supply, distributed resources, and T&D), wind and geothermal options where new long-distance transmission is required, and high cost estimates for nuclear power. Natural gas substitution for district heating loans also fell in this category.

3. Net economic benefit ("no regrets") opportunities found here are largely demand-side investments. This finding is consistent with much of the mitigation cost literature. Several biomass alternatives also fell in this category: bagasse cogeneration in one instance, and wood use for district heating boilers in another.

4. Carbon reduction potential appears to be highest for those individual options that can be efficiently sized at the scale of large baseload power plants: geothermal, nuclear, hydro, and natural gas. However, smaller biomass, energy efficiency, wind, and solar options can be combined to produce high carbon savings as well.[10]

5. Switching values and carbon savings can vary considerably for similar alternatives analyzed for different loans. Factors accounting for these differences include the costs and emissions of the project resource; the availability, proximity, and quality of alternative resources; variations in cost estimates for similar alternative technologies; and investment lifetimes.

6. The location of a loan investment has a significant influence on switching value. Resource availability for many low carbon energy options is highly site specific, and in many cases, access to these resources may entail considerable pipeline, transmission, or other transport costs.

7. Results are highly sensitive to the choice of discount rate for carbon emission streams and assumptions about project lifetime. Increasing the discount rate from the default rate of zero to the opportunity cost of capital minus 2 percent increases switching values by factors of 3 to 4.5. This is not a surprising finding. Low discount rates for the carbon streams have the desired effect of making future emissions roughly as important as current ones, as they should be if there were a cap on carbon emissions. Higher discount rates on carbon induce a strong time preference for reducing current emissions. At a rate of 10 percent, reducing 10 metric tons of carbon 25 years from today would be less valuable than reducing emissions by 1 metric ton today. In addition, the 0 percent discount rate on carbon emissions thus magnifies the effect of SAR assumptions regarding plant lifetime, which are typically about 10 years shorter than actual. Increasing plant lifetimes from 20 to 30 years would decrease reported switching values by 33 percent.

8. Although assessment of alternatives for power and fuel supply projects (for example, district heating) are more

straightforward, opportunities for carbon reductions exist for other loan types, including T&D, rural electrification, and power sector reform loans. Power sector reform activities, in particular, provide a unique opportunity for the Bank to pursue economically efficient mechanisms to reduce carbon emissions, such as (a) carbon adders or taxes on power supply or the energy sector more broadly; and (b) low-carbon resource portfolio standards, targets, bidding, and trading schemes in the power sector.

9. Bank SARs and supporting documentation provide essential information for the analysis of low-carbon alternatives, but rarely are sufficient to evaluate the types of alternatives considered here. Only a few of the 60 alternatives described in this chapter relied exclusively on SAR and supporting documentation to define alternatives and calculate switching values.

[1] Although some options exist, for example, in the reduction of flaring and venting emissions, CO_2 reinjection, and pipeline loss reduction, their assessment requires site-specific analysis beyond the scope of this study.

[2] For developing countries, the IPCC Second Assessment Report (Watson, Zinyowera, and Ross 1996) cites the findings of United Nations Environment Programme (UNEP) studies for Brazil, Thailand, and Zimbabwe, which indicate that 10 percent to 15 percent of national emissions could be reduced at no cost or at net benefit, largely through DSE improvements (Halsnaes et al. 1994). Although cost curves for these and other studies are similar in general shape to the distribution of points in figure 5.2, the results are not directly comparable because (a) savings reported here are relative to a single power supply investment rather than an entire national energy system, and (b) technologies represented in a typical cost curve are implemented in tandem, and here many are mutually exclusive.

[3] The team were able to obtain an engineering cost estimate for Bui, but not the power planning studies that would have accounted for the economic implications of lost load because of drought.

[4] The team did not consider dedicated biomass crops or large-scale harvesting of wood resources, which could provide much greater electricity supply, because of the associated complexities of carbon accounting and land use considerations.

[5] The net benefit estimate for Latvia is somewhat uncertain because the team lacked local wood cost estimates and used those from Estonia. Nonetheless, wood prices are unlikely to differ dramatically.

[6] For instance, in the state of Minas Gerais, Brazil, a utility invested in a lighting efficiency program to decrease peak loads and thereby avoid costly upgrades to a local T&D network (Geller 1997).

[7] In hydro-dominated systems, such as in Colombia and Peru, a carbon tax on generation would operate at the margin and would mainly affect decisions concerning development of new generation. In systems with existing fossil-fired generation, such a tax would have a more direct (and most likely a larger) impact.

[8] As indicated before, the preeminence of hydropower in Colombia and Peru means that energy efficiency and renewable energy initiatives financed by a system benefits charge would affect carbon emissions principally by forestalling the development of fossil-fired generation.

[9] As noted in chapter 4, the team made illustrative assumptions about resource sizes and demand-side equipment penetration rates, and did not seek to optimize or maximize these investments.

[10] The team did not consider resource combinations since our focus was to draw out the costs and carbon savings of individual options.

6 Implications for the Energy Portfolio

This chapter discusses some implications of the results presented in chapters 3 and 5 in terms of the Bank's energy loan portfolio.

6.1 Carbon Emissions from the Energy Loan Portfolio

Lifetime carbon emissions (project emissions) for the main study sample are an estimated 490 million tC, and average annual carbon emissions for the sample are about 20–25 million tC (assuming an average project lifetime in the 20–25 year range). Extrapolating this range to the portfolio of 154 loans gives an annual range of 73–88 million tC. This extrapolation is based on the sample's 29 percent share of total portfolio value, and assumes that the sample's metric ton–to–U.S. dollar ratio is representative of the portfoliowide ratio.[1]

The IPCC (1992) projects that annual net carbon emissions from non-OECD countries will grow from 3.2 billion metric tons of carbon (GtC) in 1990 to 5.6 GtC in 2015 (Pepper 1997). The 73–88 million tC range of annual emissions from the Bank portfolio accounts for about 1.7–2.1 percent of these emissions.

6.2 Share of Energy Loan Portfolio Strongly Affected by a Shadow Price of $20 per tC

The analysis of the randomly selected sample of 50 loans indicated that approximately 40 percent of financing went to 16 loans that were in the "strongly affected" category at a shadow price of $20 per tC, a net discount rate of zero. This share declines to 14 percent when the net discount rate on the shadow price is in the 8–12 percent range. Extrapolating these results to the Bank's $20 billion portfolio of energy loans, between 14 percent ($2.8 billion) and 40 percent ($7.8 billion) was invested in projects that would be strongly affected by a carbon shadow price.

This conclusion may have limited application to the Bank's future loan portfolio because the share of "strongly affected" category loans among more recent loans tended to be much smaller than the share of such loans in earlier loans. If the future Bank portfolio tends to look more like the 1994–96 subsample, the loan amount in this category will be a smaller share of the total, that is, about 10 percent of the portfolio.

6.3 Aggregate Incremental Costs of Avoiding Carbon Emissions

For the 16 loans in the "strongly affected" category at a $20 per tC and a net discount rate of zero, the team calculated what it would cost to offset the carbon emissions enough to qualify them as "moderately affected" category loans (that is, non-negative NPV). For program loans, the team examined only the time-slice or components that involved funding from the Bank. Based on the analysis of the costs of alternative investments to reduce net carbon emissions (see chapter 5), the team assumed it would cost $20 per tC on average to offset emissions, and that the incremental cost of abatement would not accrue to the loan's economic analysis. Consequently, the NPV for the loans would be $0.

The results are displayed in table 6.1. Total carbon emissions for these 16 loans would have to be reduced by over 51 percent to increase their NPV to $0. Yet, the percentage of total carbon emissions that would need to be reduced from each loan varies widely. On one extreme, the Yugoslavia Kolubara Project would need only 3 percent of its carbon emissions offset, whereas on the other extreme, the Madagascar Petroleum Sector Refinery Rehabilitation Project would need a 97 percent reduction in emissions. It is not likely that alternative investments could replace such high carbon emission percentages, particularly for large-scale thermal projects. Additional components, such as DSM programs or carbon offsets, may be necessary to reduce overall emissions. Furthermore, if the offsets were to come by investing in the project itself (as an addition or replacement), the costs per metric ton would vary significantly. Small carbon emissions reductions might be achieved at costs of less than $20 per tC, but larger reductions could cost well over $20 per tC on average.

The total Bank contribution to these projects was $2.4 billion, and the team estimates it would cost another $3.3 billion to offset enough carbon emissions at $20 per tC to move the "strongly affected" category loans to the "moderately affected" category. About one-half of this amount would come from one loan, the India NTPC Power Project. Furthermore, the 5 loans

Table 6.1

Emissions Reductions Required to Shift Loans from the "Strongly Affected" to the "No Effect" Category

($20 tC shadow price and 0% net discount rate)

oan or loan component	*Original emissions (million tC)*	*NPV (million 1995 $)*	*Emissions reduction necessary for NPV=0 (million tC)*	*Reduction as % of total emissions*
razil Hydrocarbon-Hydrotreatment Plant	18.19	($233.27)	-11.66	-64%
Brazil Hydrocarbon-Natural Gas Pipeline	4.02	($9.97)	-0.50	-12%
China Yanshi	24.52	($201.50)	-10.07	-41%
Ghana Sixth Power-Wa Component	0.02	($0.09)	0.00	-26%
Hungary	2.76	($28.67)	-1.43	-52%
India Maharashtra*	17.09	($47.61)	-2.38	-14%
India NTPC Power	87.94	($1,611.73)	-80.59	-92%
India Private Power Utility	22.18	($101.52)	-5.08	-23%
Indonesia Suralya*	65.52	($291.01)	-14.55	-22%
Madagascar Petroleum Sector Refinery Rehabilitation	8.76	($169.66)	-8.48	-97%
Mauritius Sugar Energy Development	0.47	($0.57)	-0.03	-6%
Philippines Rural Electrification	14.85	($137.56)	-6.88	-46%
Sri Lanka Power District	9.99	($161.93)	-8.10	-81%
Thailand 2nd Power System Development Fund*	13.51	($232.82)	-11.64	-86%
Yemen Power 3	1.46	($18.76)	-0.94	-64%
Yugoslavia - Kolubara	27.09	($14.48)	-0.72	-3%
Zimbabwe Power 3 - Hwange Facility	2.49	($38.77)	-1.94	-78%
Total	320.86	($3,299.92)	-165.00	-51%

* Indicates program loans. Emissions and costs were prorated for Bank-funded activities.

needing more than $200 million in investments in offsets make up 78 percent of the total value of the 16 loans.

The study team extrapolated this result to the portfolio of 154 energy loans, assuming that 40.7 percent, or $8.1 billion, of the dollars in the total $19.9 billion portfolio would be in the "strongly affected" category. The team assumed the same ratio of offset costs per loan amount as in the sample, and that the offsets could be purchased for an average of $20 per tC, that is, that there is an unlimited supply of offsets at $20 per tC. As a result, about $11 billion would be required to offset the emissions from the Bank's portfolio of loans to shift the loans in the "strongly affected" category to the "moderately affected" category. Note that this estimate is crude and should be treated only as an indication of the potential magnitude of investment necessary to offset emissions that reduce NPV below zero.

If the loan-to-project cost ratio of about 25 percent for the sample is applicable to the entire portfolio, then the $19.9 billion Bank portfolio financed approximately $83 billion in project costs. Thus, the $11 billion incremental carbon abatement cost represents about 13 percent of total project costs.

[1] The total emissions incorporate the approximate 118 million tC from the scoping study sample.

7 Issues and Recommendations

In discussing the major technical implementation issues arising out of the Carbon Backcasting Study, this chapter focuses on four principal questions:

1. How useful is it to incorporate a shadow price for carbon emissions in the economic analysis of World Bank energy projects?

2. How should carbon shadow price analysis be implemented? For example, what are the appropriate price, discount rate, and time horizon? How should the analysis of low-carbon alternatives be carried out?

3. How would the Bank have to operate differently if carbon shadow price analysis and assessment of low-carbon alternatives were the norm in project preparation and other Bank functions?

4. How might the introduction of a shadow price for carbon affect the interactions between the Bank and its clients? Between the Bank and other stakeholders, including nongovernmental organizations (NGOs), private sector energy developers, and others?

7.1 Usefulness of Carbon Shadow Price Analysis

Issue: How useful is carbon shadow price analysis as a tool for project economic assessment?

Recommendation: Based on the results of this study, the team has concluded that carbon shadow price analysis is a useful tool in the economic analysis of World Bank projects.

A significant share of the World Bank energy sector investments examined are strongly affected by the incorporation of a shadow price for carbon emissions, that is, the project's NPV drops below zero. The only case in which carbon shadow price analysis had little effect was when a low shadow price was combined with a high discount rate for future climate change–related damages. Moreover, the analysis of low-carbon alternative investments shows that there are several options to reduce emissions at a reasonable cost, that is, in the $20 to $40 per metric ton range and below. Taken together, these results suggest that if a shadow price had been included when project alternatives were evaluated early in the project cycle, a different technology or investment mix might have resulted.

In essence, carbon shadow price analysis flags projects that are carbon-intensive and signals Bank staff and borrowing countries to try to identify low-carbon alternatives with the same or better economic benefits for all or part of the original proposed investment. This is consistent with the obligations of borrowing countries as signatories to the UNFCCC, and with the Bank's pledge of consistency with the UNFCCC in its lending policies and practices.

It need not be costly or onerous for the Bank to incorporate carbon shadow price analysis in the process of project preparation. Since 1994, Bank task managers have been instructed to assess GHG emissions associated with proposed projects (although the study team saw little evidence of this in the post-1994 projects examined). It is only one step more to assign a shadow price for carbon emissions and plug these emission flows into the stream of project costs and benefits.

It is important to reiterate that the objective of this analysis is not to shift the burden of UNFCCC implementation from developed to developing countries. There is currently no proposal before the Bank's Board to mandate the incorporation of carbon shadow price analysis. Even if such a decision were to be made in the future, lending decisions would be affected only if low-carbon alternatives could be identified that were financially preferable to the borrowing country, or if funding from the international community were available to "buy down" the incremental costs of the low-carbon alternative project.

7.2 Analytical Implementation Issues

Some key issues related to implementing investments are discussed below.

7.2.1 Methods for Measuring Greenhouse Gases

There are three key issues with regard to measuring carbon emissions for a proposed investment: defining a baseline or reference point, avoiding double-counting, and choosing which GHGs to measure.

Issue: How should the baseline for carbon shadow price analysis be established?

Recommendation: Defining a baseline case can be a difficult matter, involving numerous subjective judgments. In this analysis, the team dealt with this difficulty by adopting two different methods of measuring carbon emissions. Because of the potential for distortions, the team recommends that both these approaches be used to measure carbon emissions.

Project emissions were defined as the actual emissions from a project (see section 2.2.3), and *net emissions* were calculated by subtracting from project emissions the emissions associated with a counterfactual scenario describing what would have happened without Bank funding (see section 2.2.4). The goal in defining these two levels of carbon emissions for each project was to capture two aspects of emissions information that would be important for evaluating the carbon impact of a project.

The *project emissions* approach captures the total carbon emissions impact of a project, for example, the carbon emissions going up the stack. Project emissions are important for policies such as carbon taxes or permits, which impose a cost for each metric ton of carbon that is emitted by a project. Because project emissions are not measured against a reference case, there is little distortion to the emissions estimate caused by determining which emissions are already counted in the reference case. However, there can be distortions related to the definition of the project, such as the scope of the project, especially in "time slice" investments that provide partial funding for a variety of efforts and are related to the lifetime of a project and the number of years during which the GHG emissions are counted.

The *net emissions* approach captures the effect of the Bank's involvement in a project. Carbon emissions are measured relative to the counterfactual scenario, that is, "what would have happened" without Bank involvement. Many distortions are possible in the net emissions estimates because it is often difficult to define which aspects of a project would have changed without Bank involvement.

Issue: Where in the fuel cycle should emissions be "counted?"

Recommendation: Usually emissions are counted at the point of fuel combustion, but depending on the type of project, other approaches may be needed. The study team recommends that a consistent method for "counting" emissions be established before emissions are estimated.

Another issue raised by this analysis, especially with regard to fuel supply projects, such as oil field and refinery development, was where in the fuel cycle (development, refining, transportation, and combustion) emissions should be "counted." Usually emissions are counted at the point of fuel combustion (for fugitive emissions, at the point of release), but because the project sample was randomly selected from all types of energy projects, emissions at other points of the fuel cycle had to be considered. In the shadow price analysis, the evaluated project emissions for fuel supply were calculated in two ways. The team estimated the actual emissions for the process, such as methane or carbon emissions from an oil refinery or oil field. The team also evaluated the potential emissions for the fuel that would be produced by the refinery and oil field. Even though the point of combustion was not included in the project, the project would indeed result in higher fuel combustion.

This can lead to double-counting of emissions. For example, if the team counted potential emissions of diesel fuel for a refinery project and this fuel was used in a diesel combustion unit for electric generation for another project in the same country or in another country to which the fuel was exported, the emissions could have been double-counted. The team checked the results for double-counting in this study, but the potential exists for other studies. For countrywide sectoral analysis, double-counting is unlikely if the entire fuel cycle is evaluated and emissions are counted at the point of combustion or release. One consideration when establishing this method is how it might bias Bank investment in the area of power supply projects. For example, if the Bank decides that combustion emissions will accrue only to generation projects and not to T&D projects, client countries can propose T&D projects in a sector expansion program for Bank funding while investing other resources in power development. If this happens, the Bank may be unable to encourage investment in low-carbon generation resources.

Issue: Which greenhouse gases should be measured?

Recommendation: At a minimum, emissions of carbon dioxide and methane should be estimated.

Carbon dioxide clearly is the most important GHG because of its production during fossil fuel combustion. Methane emissions can be a significant byproduct of oil and gas production, coal mining, biomass combustion, and hydroelectric generation. Nitrous oxide (N_2O)and carbon monoxide (CO) are GHGs also associated with fossil fuel combustion, although these emissions are difficult to estimate and are probably minimal. Emissions should be estimated using IPCC-sanctioned emissions factors, and converted to carbon equivalents using the most recent values of the Global Warming Potential Index.

7.2.2 Methods for Shadow Price Analysis

Some key issues for alternatives analysis are discussed below.

Issue: At what point in the project cycle should carbon shadow price analysis and low-carbon alternatives assessment be carried out?

Recommendation: Because the rationale for undertaking carbon shadow price analysis is to identify projects or development programs that are strongly and adversely affected by a shadow price for carbon (that is, their NPV drops below zero) and to initiate a process for assessing lower-carbon alternatives, the shadow price analysis should be conducted early in the Bank's decisionmaking process, when there is maximum scope to modify project concepts to make them less carbon-intensive.

During the analysis, the team found little rigorous assessment of low-carbon alternatives to the projects brought to the Bank, which made the analysis much more difficult. Instituting shadow price analysis and low-carbon alternatives assessment within the Bank as part of the project preparation process would involve considerable changes to the project cycle. The implications of carbon shadow price analysis and low-carbon alternative analysis for the Bank's operations, including the project cycle are discussed, in section 7.3.

Issue: What value should be used for the shadow price of carbon?

Recommendation: A range of shadow prices should be used to reflect the uncertainly of future climate change impacts. These should be chosen to reflect the best available estimates of climate change damages.

The choice of a shadow price for carbon is controversial. For this analysis, the team used values of $5, $20, and $40 per metric ton, which reflect the ranges of values often found in the literature on climate changes damages. If the Bank proceeds with any future work on carbon shadow price analysis, the team recommends that the Bank use a similar approach of testing sensitivity to a range of values. The results in chapter 3 suggest that a shadow price of $20 per tC acts as a threshold because at that price, NPV was negative for most projects that were adversely affected by a shadow price. This price, or a comparable price (for example, the $10 price used to allocate GEF funding under its short-term response measures), should be the primary focus of the analysis, with higher and lower values used to test sensitivity, and to compare high- and low-carbon investments.

Issue: What discount rate should be used to evaluate project carbon flows?

Recommendation: The question of whether and how to discount damage costs from global climate change is complex and controversial. In the absence of consensus among the experts, and in advance of the development of a protocol under the UNFCCC, it is not possible to provide a definitive recommendation at this time. Instead, the study team recommends that, as an interim default method, the Bank use a low discount rate, and test the sensitivity of the results to this assumption.

The debate over how to discount social benefits or costs, such as damage costs from global climate change continues without resolution (see, for example, Arrow et al. 1996).[1] The results of the shadow price analysis were very sensitive to the discount rate. Similarly, the discount rate on avoided carbon emissions in the alternatives analysis had a considerable impact on switching values. For higher discount rates, there were fewer projects strongly affected by a carbon shadow price and fewer opportunities to invest in lower-carbon technologies at low cost.

Because all other project benefits and costs are discounted at the prevailing opportunity cost of capital in the client country, using a lower discount rate for climate change damages is awkward.[2] However, a low discount rate is consistent with the discounting methods used in the studies that estimated climate change damages. These studies discounted intergenerational damages of carbon emissions using social discount rates typically ranging from 0 percent to 3 percent (for example, Cline 1992; Fankhauser 1994). Furthermore, the GEF currently uses a 0 percent discount rate when it estimates the incremental costs of carbon abatement for projects (Anderson and Williams 1993).[3] Using a comparable discounting approach in the shadow price analysis will avoid discrepancies between its estimate of the amount of carbon reduction or offset needed and estimates conducted by GEF when it determines the incremental costs of carbon abatement.

Future discount rate signals may come from provisions of international climate change protocols or international carbon markets. In the interim, the study team recommends that the Bank develop a default method in which carbon flows are evaluated using a low, social discount rate. Sensitivity of the results to this assumption can be readily tested using a cost of capital rate. A low net discount rate—for example, in the range of 0–3 percent after the 2 percent shadow price escalation rate is subtracted—more accurately reflects the perspective of public entities trying to solve a social problem than does a private discount rate. A low discount rate also is more realistic for governments of developed countries, which are expected to be the principal parties interested in "buying down" the incremental costs of lower-carbon investments. Borrowing countries are not expected to bear the financial burdens of incremental costs.

Issue: What time horizon should be used for carbon shadow price analysis and assessment of low-carbon alternatives?

Recommendation: The time horizon of carbon shadow price analysis and of the assessment of low-carbon alternatives should correspond to the projected physical *lifetimes of projects.*

The time horizon of carbon shadow price analysis and low-carbon alternative analysis is quite important. Most of the Bank's economic analysis of projects considers an economic life of the project, which may be shorter than the typical period of actual use of energy infrastructure in developing countries. For instance, project economics for a coal-fired power plant could be based on a 20-year period for loan repayment, but the plant may be in operation for 30 years or more.

If the time horizon of emissions analysis is shorter than the actual physical lifetime of the project, it will understate, often by a considerable margin, the impact of carbon emissions from that project. Likewise, the benefits of a lower-carbon alternative will be significantly understated. As reported in section 5.2.6, the results of the analysis were sensitive to the choice of project lifetimes. Increasing the project lifetime of a coal-fired plant from 20 years to 30 years meant that the carbon savings from low-carbon alternatives increased by 50 percent, and the costs of switching to these alternative technologies were reduced by a third.

When analyzing a project, it is important to consider whether the "project lifetime" accurately reflects the anticipated physical use of the capital investment. If it is possible that an asset will continue to be used beyond the project lifetime, a sensitivity analysis similar to the one described in section 5.2.6 should be conducted.

7.2.3 Methods for Alternatives Analysis

Some methods for alternatives analysis are discussed below.

Issue: How should the sizing of low-carbon alternatives be addressed?

Recommendation: The assessment of low-carbon alternatives should be developed to encompass a wide range of investment options with respect to technologies used, as well as size and cost of carbon savings.

Many of the low-carbon technologies that task managers will most likely identify and assess as possible means to reduce carbon emissions are sized below the original proposed investment. Moreover, these technologies may have different characteristics than those featured in the original project concept, such as the intermittency of some renewable energy technologies. These issues and how they were dealt with in the analysis are discussed in detail in chapter 4.

A diversified menu of options would be of greater value to borrowing countries, as well as to potential joint implementation or offsets investors, than one in which options are limited to a particular size or price. Those options that are "no regrets," that is, options that cost less than the project component they replace, should be incorporated into the project. The alternatives that have higher costs should be presented to parties interested in purchasing carbon savings by paying for the incremental cost of low-carbon alternatives. Such parties often are interested in considerations beyond savings and price. Among the other factors that might be important to investors are capital availability, potential for market transformation, technology transfer, technology development, removal of barriers to a particular technology, and ancillary environmental benefits. Thus, a diversified set of options would be more valuable in attracting carbon buyers.

Issue: Should imports of low-carbon resources be treated in the same way as the use of indigenous resources?

Recommendation: Task managers should be encouraged to look at cross-border options, but with the recognition that many alternatives that are theoretically feasible are in fact not realistic options given the political risks and analytical complexities.

A few cross-border, low-carbon options arose in the context of the study, posing several intriguing questions: How should imported resources be treated? Does this treatment depend on the circumstances? Is importing natural gas for local electricity production (for example, Yugoslavia importing from Russia, Ghana from Nigeria) or district heat generation (for example, Estonia or Latvia from Russia) any different than building a hydro facility in a neighboring country and importing the power (for example, from Thailand to Laos)? And finally, but perhaps most relevant to this study, how should price volatility and political uncertainty associated with these options be factored into a shadow price assessment? Several of the above examples yielded negative or near zero switching values, but have not been pursued to date by project developers largely because of such concerns. These issues may merit further consideration in the context of emerging Bank strategy and practice on assessment of low-carbon alternatives to energy investments.

Issue: How should additional infrastructure investments be treated in the context of assessing low-carbon alternatives?

Recommendation: Task managers should perform some sensitivity analysis of the costs of infrastructure development to account for the larger economic benefits of infrastructure development.

As discussed in section 5.2.6, the results of the low-carbon alternatives analysis were sensitive to how the costs of transmission and other infrastructure development were treated. The crux of this issue is that some low-carbon alternatives require large-scale infrastructure development, which would provide benefits far beyond the project being analyzed. For example, wind resources from Inner Mongolia could be used to replace part of a proposed investment in coal generation in Jiangsu Province, China. However, it would not make economic sense to invest in a transmission line solely to Jiangsu without designing and constructing this new infrastructure to also serve other nearby major centers of electricity demand, such as Beijing. Hence, it is misleading to attribute to one project *all* the infrastructure development costs where that infrastructure has larger intrinsic economic relevance.

Even though some options have high infrastructure costs that must be fully attributed at the project level, they still may be preferred by investors over lower-cost options, and they may also produce larger economic benefits for the host country in the long run. Investors wishing to purchase carbon mitigation may prefer to invest in more expensive options if they believe that costs will go down dramatically as particular technologies are pushed toward commercial maturity. Investments that have the potential to remove barriers and transform markets may well be more desirable than the least-cost options.

The issue of accounting for infrastructure development costs points to the fact that low-carbon alternatives need to be assessed at a systems level, as well as at the project level. The costs of large-scale infrastructure development should be evaluated in the context of the electric power sector investment as a whole, not simply within the context of a single power project. In section 7.3, the study team suggests that the economic and sector work (ESW) and Country Assistance Strategy (CAS) processes include a rigorous assessment of low-carbon technology options. Such a national-level analysis would provide insights into where large-scale infrastructure development fits into the development priorities of the country and strengthen economic analysis of low-carbon alternatives at the project level.

Issue: How should policy reform loans be addressed?

Recommendation: Since 1994, Bank energy lending has increasingly featured "policy" loans, such as power sector reform loans. Although it is less straightforward to assess these loans for the impact of a carbon shadow price, the team strongly recommends that the Bank consider ways to maximize carbon mitigation in this context.

As discussed in section 5.6, power sector reform activities provide unique opportunities for the Bank to pursue economically efficient mechanisms to reduce carbon emissions. As countries restructure their power sectors to respond better to market forces, systematic market-based policies could promote the least-cost approach to reducing carbon emissions at a given shadow price. The Bank could use its influence and technical expertise to assist countries in crafting alternative policies, such as (a) carbon adders or taxes on power supply or the energy sector more broadly and (b) low-carbon resource portfolio standards, targets, bidding, and trading schemes in the power sector.

Arguably, such mechanisms could achieve more cost-effective emission reductions, if implemented and enforced, than the loan-by-loan approach used here for shadow price analysis of other loan types. Such mechanisms would create a stronger local market for lower-carbon options and would affect all investment decisions, not merely those in the Bank's loan cycle. At the same time, such mechanisms could face substantial political obstacles, be difficult to monitor, and pose significant challenges in calculating and reimbursing countries for their incremental costs.

Although the team was unable to make quantitative assessments of the costs and carbon emission potential for alternative reform policies, such assessments could be conducted in a more in-depth analysis. The impacts of low-carbon resource portfolio standards and carbon addersand taxes can be modeled using available analytical methods to reveal the relationship between emission reductions, carbon shadow prices, and incremental costs for a few specific reform loans.

In addition to the above mechanisms, which could require significant incremental cost support, the reform process could also promote more aggressive pursuit of "no regrets" options. Privatization can strengthen the financial health of utilities, but it can also damage the social fabric of countries where low-income people have no means to respond to the signal of rising electricity prices. Energy efficiency can be a tool for cushioning rate shock. Task managers should actively look for ways to build energy efficiency and other no-regrets options into loans for privatization support. Such loan elements should aim to transform markets toward greater penetration of energy efficiency in the economies of borrowing countries. Among the most effective tools for market transformation are developing domestic energy service company (ESCO) industries, supporting information and technical assistance programs on energy efficiency, establishing codes and standards on energy efficiency, and instituting suitable IRP processes.

7.3 Implications of Carbon Shadow Pricing for Bank Operations

The incorporation of carbon shadow price analysis in the economic assessment of Bank projects would significantly affect Bank operations. New steps would be added to the project cycle, and task managers would need access to additional information and expertise. The discussion below attempts to sketch out key implications for Bank operations.

Issue: How should carbon shadow price analysis and assessment of low-carbon alternatives be incorporated into the Bank's project cycle?

Recommendation: If the Bank chooses to institute carbon shadow price analysis, this step should be carried out early in the project cycle, when there is maximum scope to modify projects to make them less carbon-intensive. Within the project identification phase, all project concepts brought to the Bank should be screened for (a) the likely impact of carbon emissions on overall project economics, and (b) the potential to incorporate low-carbon alternative energy options.

Initially, the requirement to perform carbon shadow price analysis might apply only to proposed investments in the energy sector, which are likely to be the most carbon-intensive. However, there is no logical reason that other kinds of Bank lending—such as agriculture, health, and education—could not be similarly screened.

The data necessary to compute GHG emissions (for example, fuel consumption data) are usually required at early stages in the decision process because fuel costs are such a large component of total project or scenario costs in the energy sector. Therefore, it should be feasible and reasonable to conduct a shadow price analysis early in the project preparation process.

Assessing low-carbon alternatives can be very data- and time-intensive. However, at an early stage of the project cycle, rapid assessment techniques, such as the ones used for this study, can give indicative rather than definitive results. Once rapid assessment methodologies narrow the list of options, then more rigorous analysis should be done.

Essentially, the Bank and its clients should apply "all-source bidding" approaches to discussions concerning project identification in the electric power sector. At this early stage of the project preparation process, specific technologies should not be included or excluded from the project concept. For example, specifying a 500 MW coal plant excludes other ways to deliver equivalent energy services—such as energy efficiency and cogeneration—that are "no regrets" options; that is, they are financially preferable as well as lower-carbon.

Issue: What capabilities will be needed by task managers to implement carbon shadow price analysis and assessment of low-carbon alternatives?

Recommendation: Carbon shadow price analysis should not be difficult to implement, but specific knowledge of local market conditions and resource potentials will be needed to assess low-carbon alternatives.

Incorporating a shadow price for carbon into project economic analysis should not be difficult for task managers. Only a few data points are needed, and adjustments to spreadsheet models to incorporate a new parameter should be fairly easy.

However, rigorously assessing low-carbon alternatives is more complex. Task managers would need access to significant expertise on various low-carbon technologies, such as energy efficiency, cogeneration, biomass, and wind. Moreover, general expertise would often not suffice, but rather specific knowledge of local conditions and resource potentials would be required. For instance, to assess energy-efficiency options, a task manager would need access to local information on the profile of electricity demand by end use (for example, refrigerators, air conditioners, lighting, industrial motors); availability and cost of energy-efficient equipment in the market; potential electricity savings; determination of whether these savings are peak load or base load; and program administrative costs.

Issue: How should the assessment of low-carbon alternatives at the project level relate to the ESW and CAS processes?

Recommendation: Assessment of the potential for low-carbon technologies should begin well before the identification of specific project concepts. This analysis should be integrated in the ESW and CAS, which underlie the project identification process.

Through the CAS process, the Bank and the client look at the entire development path of the country. The ESW should explicitly and thoroughly analyze sustainable energy resource potential, and the results should be reflected in the CAS. For example, assessment of energy efficiency potential should quantify total potential national benefits in terms of energy savings, capital conservation, cost savings for utilities and customers, and reduction in health-damaging pollution. Renewable energy technologies should be similarly assessed.

This information would then be available to screen project concepts at the project identification phase. Energy sector analyses should be explicitly designed to help task managers identify technically and financially feasible ways to supply a given demand for energy services while also minimizing carbon emissions.

Issue: Should the potential for low-carbon alternatives be assessed at the regional level?

Recommendation: In addition to assessing low-carbon options at the country level, the Bank should also look at potentials on a larger (for example, regional) scale. As a step in this direction, the Bank might consider undertaking a review of marginal supply sources, costs, and emissions across borrowing countries. The results could then be compared with a review of low-carbon resource potentials and costs to identify the most promising sites for promoting cost-effective emission reduction projects.

If the Bank is looking to invest in the lowest-cost carbon-reduction options, it should actively seek out investment opportunities where low-carbon resource availability is highest and costs of exploitation are lowest. Similarly, ideal locations are those where the avoided investment options have the higher unit costs and carbon emissions. For example, wind power development may be feasible in a number of countries, but the Bank could probably have a greater impact on the total carbon emissions associated with its energy lending by focusing on a few countries with exceptional potential.

Issue: How should market transformation be treated in the context of assessing low-carbon alternatives?

Recommendation: The sectoral strategy process should focus on removing barriers to the penetration of low-carbon energy technologies. Shifting to a lower-carbon emissions trajectory means that the barriers to energy efficiency and renewable energy need to be systematically removed. Financing isolated projects is not enough.

To this end, the ESW should include a strategy for building the local market for low-carbon technologies, for example, seeding ESCOs. A first step in many countries, even those where conditions are not yet right to support private sector ESCOs, would be to encourage borrowing governments to convert the energy management of their public sector facilities (for example, office buildings, public housing) to energy performance contracting (EPC).[4] Experience with ESCO-like approaches, such as EPC, would begin to lay the groundwork for private sector expansion later on.

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1. Arrow et al. (1996) addressed two predominant discounting perspectives: a prescriptive (normative) approach, which advocates using a social rate of time preference (SRTP), and a descriptive (positive) approach, which advocates using the opportunity cost of capital. The prescriptive approach is based on equity concerns for future generations and seeks to represent the tradeoff between present and future consumption. The SRTP is a function of a pure rate of time preference between present and future consumption, and an expression that incorporates the rate of economic growth and the effect of higher income on utility. Even if one assumes that the pure rate of time preference equals zero, the SRTP can be positive if the rate of economic growth is positive.

The descriptive approach contends that preferences over intertemporal tradeoffs are revealed in observed rates of return to investment. These are the rates that are required to encourage people to forgo consumption today to invest and raise future consumption levels. Another consideration is that the present value of climate change damages is equal to the amount that could be invested today to compensate future generations for the damages they suffer (Markandya and Pearce 1993). If the investment grows at a rate equal to the rate of return on capital, this is also the appropriate discount rate. Much of the debate centers on perceptions of whether and how this compensation occurs.

2. Applying an SRTP to carbon shadow prices, but applying a cost of capital to other benefits and costs treats monetary streams in an inconsistent manner. Ideally all values would be converted to their consumption equivalents, which would be discounted using the SRTP because it applies to consumption values only (Squire and van der Tak 1975; Arrow et al. 1996). However, the economic values in the SARs are generally not expressed in consumption equivalents. Furthermore, this approach begs the question of whether the SRTP for the client country will suffice, or whether global damages should be discounted using a "global" SRTP. National SRTPs can vary widely across countries, and may be quite high—even if the pure time preference is zero—when growth rates are high or the elasticity of marginal utility is high, or both, which may be the case in poor countries.

3. As mentioned in section 2.3, this 0 percent discount rate is based on Hotelling's theory of the optimal extraction rate of a depletable resource (Hotelling 1931).

4. Through the energy performance contracting approach, a facility owner contracts with an energy management firm for a guaranteed level of energy services at a specified price. The energy management firm is paid only if the project energy savings are actually realized and maintained over time.

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Joint UNDP/World Bank
ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAMME (ESMAP)

LIST OF REPORTS ON COMPLETED ACTIVITIES

Region/Country	*Activity/Report Title*	*Date*	*Number*
	SUB-SAHARAN AFRICA (AFR)		
Africa Regional	Anglophone Africa Household Energy Workshop (English)	07/88	085/88
	Regional Power Seminar on Reducing Electric Power System Losses in Africa (English)	08/88	087/88
	Institutional Evaluation of EGL (English)	02/89	098/89
	Biomass Mapping Regional Workshops (English)	05/89	--
	Francophone Household Energy Workshop (French)	08/89	--
	Interafrican Electrical Engineering College: Proposals for Short- and Long-Term Development (English)	03/90	112/90
	Biomass Assessment and Mapping (English)	03/90	--
	Symposium on Power Sector Reform and Efficiency Improvement in Sub-Saharan Africa (English)	06/96	182/96
	Commercialization of Marginal Gas Fields (English)	12/97	201/97
Angola	Energy Assessment (English and Portuguese)	05/89	4708-ANG
	Power Rehabilitation and Technical Assistance (English)	10/91	142/91
Benin	Energy Assessment (English and French)	06/85	5222-BEN
Botswana	Energy Assessment (English)	09/84	4998-BT
	Pump Electrification Prefeasibility Study (English)	01/86	047/86
	Review of Electricity Service Connection Policy (English)	07/87	071/87
	Tuli Block Farms Electrification Study (English)	07/87	072/87
	Household Energy Issues Study (English)	02/88	--
	Urban Household Energy Strategy Study (English)	05/91	132/91
Burkina Faso	Energy Assessment (English and French)	01/86	5730-BUR
	Technical Assistance Program (English)	03/86	052/86
	Urban Household Energy Strategy Study (English and French)	06/91	134/91
Burundi	Energy Assessment (English)	06/82	3778-BU
	Petroleum Supply Management (English)	01/84	012/84
	Status Report (English and French)	02/84	011/84
	Presentation of Energy Projects for the Fourth Five-Year Plan (1983-1987) (English and French)	05/85	036/85
	Improved Charcoal Cookstove Strategy (English and French)	09/85	042/85
	Peat Utilization Project (English)	11/85	046/85
	Energy Assessment (English and French)	01/92	9215-BU
Cape Verde	Energy Assessment (English and Portuguese)	08/84	5073-CV
	Household Energy Strategy Study (English)	02/90	110/90
Central African Republic	Energy Assessement (French)	08/92	9898-CAR
Chad	Elements of Strategy for Urban Household Energy The Case of N'djamena (French)	12/93	160/94
Comoros	Energy Assessment (English and French)	01/88	7104-COM
Congo	Energy Assessment (English)	01/88	6420-COB
	Power Development Plan (English and French)	03/90	106/90
Côte d'Ivoire	Energy Assessment (English and French)	04/85	5250-IVC
	Improved Biomass Utilization (English and French)	04/87	069/87
	Power System Efficiency Study (English)	12/87	--
	Power Sector Efficiency Study (French)	02/92	140/91
	Project of Energy Efficiency in Buildings (English)	09/95	175/95

Region/Country	*Activity/Report Title*	*Date*	*Number*
Ethiopia	Energy Assessment (English)	07/84	4741-ET
	Power System Efficiency Study (English)	10/85	045/85
	Agricultural Residue Briquetting Pilot Project (English)	12/86	062/86
	Bagasse Study (English)	12/86	063/86
	Cooking Efficiency Project (English)	12/87	--
	Energy Assessment (English)	02/96	179/96
Gabon	Energy Assessment (English)	07/88	6915-GA
The Gambia	Energy Assessment (English)	11/83	4743-GM
	Solar Water Heating Retrofit Project (English)	02/85	030/85
	Solar Photovoltaic Applications (English)	03/85	032/85
	Petroleum Supply Management Assistance (English)	04/85	035/85
Ghana	Energy Assessment (English)	11/86	6234-GH
	Energy Rationalization in the Industrial Sector (English)	06/88	084/88
	Sawmill Residues Utilization Study (English)	11/88	074/87
	Industrial Energy Efficiency (English)	11/92	148/92
Guinea	Energy Assessment (English)	11/86	6137-GUI
	Household Energy Strategy (English and French)	01/94	163/94
Guinea-Bissau	Energy Assessment (English and Portuguese)	08/84	5083-GUB
	Recommended Technical Assistance Projects (English & Portuguese)	04/85	033/85
	Management Options for the Electric Power and Water Supply Subsectors (English)	02/90	100/90
	Power and Water Institutional Restructuring (French)	04/91	118/91
Kenya	Energy Assessment (English)	05/82	3800-KE
	Power System Efficiency Study (English)	03/84	014/84
	Status Report (English)	05/84	016/84
	Coal Conversion Action Plan (English)	02/87	--
	Solar Water Heating Study (English)	02/87	066/87
	Peri-Urban Woodfuel Development (English)	10/87	076/87
	Power Master Plan (English)	11/87	--
	Power Loss Reduction Study (English)	09/96	186/96
Lesotho	Energy Assessment (English)	01/84	4676-LSO
Liberia	Energy Assessment (English)	12/84	5279-LBR
	Recommended Technical Assistance Projects (English)	06/85	038/85
	Power System Efficiency Study (English)	12/87	081/87
Madagascar	Energy Assessment (English)	01/87	5700-MAG
	Power System Efficiency Study (English and French)	12/87	075/87
	Environmental Impact of Woodfuels (French)	10/95	176/95
Malawi	Energy Assessment (English)	08/82	3903-MAL
	Technical Assistance to Improve the Efficiency of Fuelwood Use in the Tobacco Industry (English)	11/83	009/83
	Status Report (English)	01/84	013/84
Mali	Energy Assessment (English and French)	11/91	8423-MLI
	Household Energy Strategy (English and French)	03/92	147/92
Islamic Republic of Mauritania	Energy Assessment (English and French)	04/85	5224-MAU
	Household Energy Strategy Study (English and French)	07/90	123/90
Mauritius	Energy Assessment (English)	12/81	3510-MAS
	Status Report (English)	10/83	008/83
	Power System Efficiency Audit (English)	05/87	070/87

Region/Country	***Activity/Report Title***	***Date***	***Number***
Mauritius	Bagasse Power Potential (English)	10/87	077/87
	Energy Sector Review (English)	12/94	3643-MAS
Mozambique	Energy Assessment (English)	01/87	6128-MOZ
	Household Electricity Utilization Study (English)	03/90	113/90
	Electricity Tariffs Study (English)	06/96	181/96
	Sample Survey of Low Voltage Electricity Customers	06/97	195/97
Namibia	Energy Assessment (English)	03/93	11320-NAM
Niger	Energy Assessment (French)	05/84	4642-NIR
	Status Report (English and French)	02/86	051/86
	Improved Stoves Project (English and French)	12/87	080/87
	Household Energy Conservation and Substitution (English and French)	01/88	082/88
Nigeria	Energy Assessment (English)	08/83	4440-UNI
	Energy Assessment (English)	07/93	11672-UNI
Rwanda	Energy Assessment (English)	06/82	3779-RW
	Status Report (English and French)	05/84	017/84
	Improved Charcoal Cookstove Strategy (English and French)	08/86	059/86
	Improved Charcoal Production Techniques (English and French)	02/87	065/87
	Energy Assessment (English and French)	07/91	8017-RW
	Commercialization of Improved Charcoal Stoves and Carbonization Techniques Mid-Term Progress Report (English and French)	12/91	141/91
SADC	SADC Regional Power Interconnection Study, Vols. I-IV (English)	12/93	--
SADCC	SADCC Regional Sector: Regional Capacity-Building Program for Energy Surveys and Policy Analysis (English)	11/91	--
Sao Tome and Principe	Energy Assessment (English)	10/85	5803-STP
Senegal	Energy Assessment (English)	07/83	4182-SE
	Status Report (English and French)	10/84	025/84
	Industrial Energy Conservation Study (English)	05/85	037/85
	Preparatory Assistance for Donor Meeting (English and French)	04/86	056/86
	Urban Household Energy Strategy (English)	02/89	096/89
	Industrial Energy Conservation Program (English)	05/94	165/94
Seychelles	Energy Assessment (English)	01/84	4693-SEY
	Electric Power System Efficiency Study (English)	08/84	021/84
Sierra Leone	Energy Assessment (English)	10/87	6597-SL
Somalia	Energy Assessment (English)	12/85	5796-SO
South Africa Republic of	Options for the Structure and Regulation of Natural Gas Industry (English)	05/95	172/95
Sudan	Management Assistance to the Ministry of Energy and Mining	05/83	003/83
	Energy Assessment (English)	07/83	4511-SU
	Power System Efficiency Study (English)	06/84	018/84
	Status Report (English)	11/84	026/84
	Wood Energy/Forestry Feasibility (English)	07/87	073/87
Swaziland	Energy Assessment (English)	02/87	6262-SW
	Household Energy Strategy Study	10/97	198/97
Tanzania	Energy Assessment (English)	11/84	4969-TA
	Peri-Urban Woodfuels Feasibility Study (English)	08/88	086/88
	Tobacco Curing Efficiency Study (English)	05/89	102/89
	Remote Sensing and Mapping of Woodlands (English)	06/90	--
	Industrial Energy Efficiency Technical Assistance (English)	08/90	122/90

Region/Country	*Activity/Report Title*	*Date*	*Number*
Tanzania	Power Loss Reduction Volume 1: Transmission and Distribution SystemTechnical Loss Reduction and Network Development (English)	06/98	204A/98
	Power Loss Reduction Volume 2: Reduction of Non-Technical Losses (English)	06/98	204B/98
Togo	Energy Assessment (English)	06/85	5221-TO
	Wood Recovery in the Nangbeto Lake (English and French)	04/86	055/86
	Power Efficiency Improvement (English and French)	12/87	078/87
Uganda	Energy Assessment (English)	07/83	4453-UG
	Status Report (English)	08/84	020/84
	Institutional Review of the Energy Sector (English)	01/85	029/85
	Energy Efficiency in Tobacco Curing Industry (English)	02/86	049/86
	Fuelwood/Forestry Feasibility Study (English)	03/86	053/86
	Power System Efficiency Study (English)	12/88	092/88
	Energy Efficiency Improvement in the Brick and Tile Industry (English)	02/89	097/89
	Tobacco Curing Pilot Project (English)	03/89	UNDP Terminal Report
	Energy Assessment (English)	12/96	193/96
Zaire	Energy Assessment (English)	05/86	5837-ZR
Zambia	Energy Assessment (English)	01/83	4110-ZA
	Status Report (English)	08/85	039/85
	Energy Sector Institutional Review (English)	11/86	060/86
	Power Subsector Efficiency Study (English)	02/89	093/88
	Energy Strategy Study (English)	02/89	094/88
	Urban Household Energy Strategy Study (English)	08/90	121/90
Zimbabwe	Energy Assessment (English)	06/82	3765-ZIM
	Power System Efficiency Study (English)	06/83	005/83
	Status Report (English)	08/84	019/84
	Power Sector Management Assistance Project (English)	04/85	034/85
	Power Sector Management Institution Building (English)	09/89	--
	Petroleum Management Assistance (English)	12/89	109/89
	Charcoal Utilization Prefeasibility Study (English)	06/90	119/90
	Integrated Energy Strategy Evaluation (English)	01/92	8768-ZIM
	Energy Efficiency Technical Assistance Project: Strategic Framework for a National Energy Efficiency Improvement Program (English)	04/94	--
	Capacity Building for the National Energy Efficiency Improvement Programme (NEEIP) (English)	12/94	--

EAST ASIA AND PACIFIC (EAP)

Region/Country	*Activity/Report Title*	*Date*	*Number*
Asia Regional	Pacific Household and Rural Energy Seminar (English)	11/90	--
China	County-Level Rural Energy Assessments (English)	05/89	101/89
	Fuelwood Forestry Preinvestment Study (English)	12/89	105/89
	Strategic Options for Power Sector Reform in China (English)	07/93	156/93
	Energy Efficiency and Pollution Control in Township and Village Enterprises (TVE) Industry (English)	11/94	168/94
	Energy for Rural Development in China: An Assessment Based on a Joint Chinese/ESMAP Study in Six Counties (English)	06/96	183/96
Fiji	Energy Assessment (English)	06/83	4462-FIJ

Region/Country	*Activity/Report Title*	*Date*	*Number*
Indonesia	Energy Assessment (English)	11/81	3543-IND
	Status Report (English)	09/84	022/84
	Power Generation Efficiency Study (English)	02/86	050/86
	Energy Efficiency in the Brick, Tile and Lime Industries (English)	04/87	067/87
	Diesel Generating Plant Efficiency Study (English)	12/88	095/88
	Urban Household Energy Strategy Study (English)	02/90	107/90
	Biomass Gasifier Preinvestment Study Vols. I & II (English)	12/90	124/90
	Prospects for Biomass Power Generation with Emphasis on Palm Oil, Sugar, Rubberwood and Plywood Residues (English)	11/94	167/94
Lao PDR	Urban Electricity Demand Assessment Study (English)	03/93	154/93
Malaysia	Sabah Power System Efficiency Study (English)	03/87	068/87
	Gas Utilization Study (English)	09/91	9645-MA
Myanmar	Energy Assessment (English)	06/85	5416-BA
Papua New Guinea	Energy Assessment (English)	06/82	3882-PNG
	Status Report (English)	07/83	006/83
	Energy Strategy Paper (English)	--	--
	Institutional Review in the Energy Sector (English)	10/84	023/84
	Power Tariff Study (English)	10/84	024/84
Philippines	Commercial Potential for Power Production from Agricultural Residues (English)	12/93	157/93
	Energy Conservation Study (English)	08/94	--
Solomon Islands	Energy Assessment (English)	06/83	4404-SOL
	Energy Assessment (English)	01/92	979-SOL
South Pacific	Petroleum Transport in the South Pacific (English)	05/86	--
Thailand	Energy Assessment (English)	09/85	5793-TH
	Rural Energy Issues and Options (English)	09/85	044/85
	Accelerated Dissemination of Improved Stoves and Charcoal Kilns (English)	09/87	079/87
	Northeast Region Village Forestry and Woodfuels Preinvestment Study (English)	02/88	083/88
	Impact of Lower Oil Prices (English)	08/88	--
	Coal Development and Utilization Study (English)	10/89	--
Tonga	Energy Assessment (English)	06/85	5498-TON
Vanuatu	Energy Assessment (English)	06/85	5577-VA
Vietnam	Rural and Household Energy-Issues and Options (English)	01/94	161/94
	Power Sector Reform and Restructuring in Vietnam: Final Report to the Steering Committee (English and Vietnamese)	09/95	174/95
	Household Energy Technical Assistance: Improved Coal Briquetting and Commercialized Dissemination of Higher Efficiency Biomass and Coal Stoves (English)	01/96	178/96
Western Samoa	Energy Assessment (English)	06/85	5497-WSO

SOUTH ASIA (SAS)

Bangladesh	Energy Assessment (English)	10/82	3873-BD
	Priority Investment Program (English)	05/83	002/83
	Status Report (English)	04/84	015/84
	Power System Efficiency Study (English)	02/85	031/85
	Small Scale Uses of Gas Prefeasibility Study (English)	12/88	--

Region/Country	*Activity/Report Title*	*Date*	*Number*
India	Opportunities for Commercialization of Nonconventional Energy Systems (English)	11/88	091/88
	Maharashtra Bagasse Energy Efficiency Project (English)	07/90	120/90
	Mini-Hydro Development on Irrigation Dams and Canal Drops Vols. I, II and III (English)	07/91	139/91
	WindFarm Pre-Investment Study (English)	12/92	150/92
	Power Sector Reform Seminar (English)	04/94	166/94
	Environmental Issues in the Power Sector	06/98	205/98
Nepal	Energy Assessment (English)	08/83	4474-NEP
	Status Report (English)	01/85	028/84
	Energy Efficiency & Fuel Substitution in Industries (English)	06/93	158/93
Pakistan	Household Energy Assessment (English)	05/88	--
	Assessment of Photovoltaic Programs, Applications, and Markets (English)	10/89	103/89
	National Household Energy Survey and Strategy Formulation Study: Project Terminal Report (English)	03/94	--
	Managing the Energy Transition (English)	10/94	--
	Lighting Efficiency Improvement Program Phase 1: Commercial Buildings Five Year Plan (English)	10/94	--
Sri Lanka	Energy Assessment (English)	05/82	3792-CE
	Power System Loss Reduction Study (English)	07/83	007/83
	Status Report (English)	01/84	010/84
	Industrial Energy Conservation Study (English)	03/86	054/86

EUROPE AND CENTRAL ASIA (ECA)

Bulgaria	Natural Gas Policies and Issues (English)	10/96	188/96
Central and Eastern Europe	Power Sector Reform in Selected Countries	07/97	196/97
Eastern Europe	The Future of Natural Gas in Eastern Europe (English)	08/92	149/92
Kazakhstan	Natural Gas Investment Study, Volumes 1, 2 & 3	12/97	199/97
Kazakhstan & Kyrgyzstan	Opportunities for Renewable Energy Development	11/97	16855-KAZ
Poland	Energy Sector Restructuring Program Vols. I-V (English)	01/93	153/93
	Natural Gas Upstream Pricing (English and Polish)	08/98	206/98
	Energy Sector Restructuring Program: Establishing the Energy Regulation Authority	10/98	208/98
Portugal	Energy Assessment (English)	04/84	4824-PO
Romania	Natural Gas Development Strategy (English)	12/96	192/96
Slovenia	Workshop on Private Participation in the Power Sector (English)	02/99	211/99
Turkey	Energy Assessment (English)	03/83	3877-TU

MIDDLE EAST AND NORTH AFRICA (MNA)

Arab Republic of Egypt	Energy Assessment (English)	10/96	189/96
Morocco	Energy Assessment (English and French)	03/84	4157-MOR
	Status Report (English and French)	01/86	048/86
	Energy Sector Institutional Development Study (English and French)	07/95	173/95

Region/Country	*Activity/Report Title*	*Date*	*Number*
Morocco	Natural Gas Pricing Study (French)	10/98	209/98
	Gas Development Plan Phase II (French)	02/99	210/99
Syria	Energy Assessment (English)	05/86	5822-SYR
	Electric Power Efficiency Study (English)	09/88	089/88
	Energy Efficiency Improvement in the Cement Sector (English)	04/89	099/89
	Energy Efficiency Improvement in the Fertilizer Sector (English)	06/90	115/90
Tunisia	Fuel Substitution (English and French)	03/90	--
	Power Efficiency Study (English and French)	02/92	136/91
	Energy Management Strategy in the Residential and Tertiary Sectors (English)	04/92	146/92
	Renewable Energy Strategy Study, Volume I (French)	11/96	190A/96
	Renewable Energy Strategy Study, Volume II (French)	11/96	190B/96
Yemen	Energy Assessment (English)	12/84	4892-YAR
	Energy Investment Priorities (English)	02/87	6376-YAR
	Household Energy Strategy Study Phase I (English)	03/91	126/91

LATIN AMERICA AND THE CARIBBEAN (LAC)

LAC Regional	Regional Seminar on Electric Power System Loss Reduction in the Caribbean (English)	07/89	--
	Elimination of Lead in Gasoline in Latin America and the Caribbean (English and Spanish)	04/97	194/97
	Elimination of Lead in Gasoline in Latin America and the Caribbean - Status Report (English and Spanish)	12/97	200/97
	Harmonization of Fuels Specifications in Latin America and the Caribbean (English and Spanish)	06/98	203/98
Bolivia	Energy Assessment (English)	04/83	4213-BO
	National Energy Plan (English)	12/87	--
	La Paz Private Power Technical Assistance (English)	11/90	111/90
	Prefeasibility Evaluation Rural Electrification and Demand Assessment (English and Spanish)	04/91	129/91
	National Energy Plan (Spanish)	08/91	131/91
	Private Power Generation and Transmission (English)	01/92	137/91
	Natural Gas Distribution: Economics and Regulation (English)	03/92	125/92
	Natural Gas Sector Policies and Issues (English and Spanish)	12/93	164/93
	Household Rural Energy Strategy (English and Spanish)	01/94	162/94
	Preparation of Capitalization of the Hydrocarbon Sector	12/96	191/96
Brazil	Energy Efficiency & Conservation: Strategic Partnership for Energy Efficiency in Brazil (English)	01/95	170/95
	Hydro and Thermal Power Sector Study	09/97	197/97
Chile	Energy Sector Review (English)	08/88	7129-CH
Colombia	Energy Strategy Paper (English)	12/86	--
	Power Sector Restructuring (English)	11/94	169/94
	Energy Efficiency Report for the Commercial and Public Sector (English)	06/96	184/96
Costa Rica	Energy Assessment (English and Spanish)	01/84	4655-CR
	Recommended Technical Assistance Projects (English)	11/84	027/84
	Forest Residues Utilization Study (English and Spanish)	02/90	108/90
Dominican Republic	Energy Assessment (English)	05/91	8234-DO

Region/Country	*Activity/Report Title*	*Date*	*Number*
Ecuador	Energy Assessment (Spanish)	12/85	5865-EC
	Energy Strategy Phase I (Spanish)	07/88	--
	Energy Strategy (English)	04/91	--
	Private Minihydropower Development Study (English)	11/92	--
	Energy Pricing Subsidies and Interfuel Substitution (English)	08/94	11798-EC
	Energy Pricing, Poverty and Social Mitigation (English)	08/94	12831-EC
Guatemala	Issues and Options in the Energy Sector (English)	09/93	12160-GU
Haiti	Energy Assessment (English and French)	06/82	3672-HA
	Status Report (English and French)	08/85	041/85
	Household Energy Strategy (English and French)	12/91	143/91
Honduras	Energy Assessment (English)	08/87	6476-HO
	Petroleum Supply Management (English)	03/91	128/91
Jamaica	Energy Assessment (English)	04/85	5466-JM
	Petroleum Procurement, Refining, and Distribution Study (English)	11/86	061/86
	Energy Efficiency Building Code Phase I (English)	03/88	--
	Energy Efficiency Standards and Labels Phase I (English)	03/88	--
	Management Information System Phase I (English)	03/88	--
	Charcoal Production Project (English)	09/88	090/88
	FIDCO Sawmill Residues Utilization Study (English)	09/88	088/88
	Energy Sector Strategy and Investment Planning Study (English)	07/92	135/92
Mexico	Improved Charcoal Production Within Forest Management for the State of Veracruz (English and Spanish)	08/91	138/91
	Energy Efficiency Management Technical Assistance to the Comision Nacional para el Ahorro de Energia (CONAE) (English)	04/96	180/96
Panama	Power System Efficiency Study (English)	06/83	004/83
Paraguay	Energy Assessment (English)	10/84	5145-PA
	Recommended Technical Assistance Projects (English)	09/85	--
	Status Report (English and Spanish)	09/85	043/85
Peru	Energy Assessment (English)	01/84	4677-PE
	Status Report (English)	08/85	040/85
	Proposal for a Stove Dissemination Program in the Sierra (English and Spanish)	02/87	064/87
	Energy Strategy (English and Spanish)	12/90	--
	Study of Energy Taxation and Liberalization of the Hydrocarbons Sector (English and Spanish)	120/93	159/93
Saint Lucia	Energy Assessment (English)	09/84	5111-SLU
St. Vincent and the Grenadines	Energy Assessment (English)	09/84	5103-STV
Trinidad and Tobago	Energy Assessment (English)	12/85	5930-TR

GLOBAL

	Energy End Use Efficiency: Research and Strategy (English)	11/89	--
	Women and Energy--A Resource Guide The International Network: Policies and Experience (English)	04/90	--
	Guidelines for Utility Customer Management and Metering (English and Spanish)	07/91	--
	Assessment of Personal Computer Models for Energy Planning in Developing Countries (English)	10/91	--

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GLOBAL (Continuation)

	Long-Term Gas Contracts Principles and Applications (English)	02/93	152/93
	Comparative Behavior of Firms Under Public and Private Ownership (English)	05/93	155/93
	Development of Regional Electric Power Networks (English)	10/94	--
	Roundtable on Energy Efficiency (English)	02/95	171/95
	Assessing Pollution Abatement Policies with a Case Study of Ankara (English)	11/95	177/95
	A Synopsis of the Third Annual Roundtable on Independent Power Projects: Rhetoric and Reality (English)	08/96	187/96
	Rural Energy and Development Roundtable (English)	05/98	202/98
	A Synopsis of the Second Roundtable on Energy Efficiency: Institutional and Financial Delivery Mechanisms (English)	09/98	207/98
	The Effect of a Shadow Price on Carbon Emission in the Energy Portfolio of the World Bank: A Carbon Backcasting Exercise (English)	02/99	212/99

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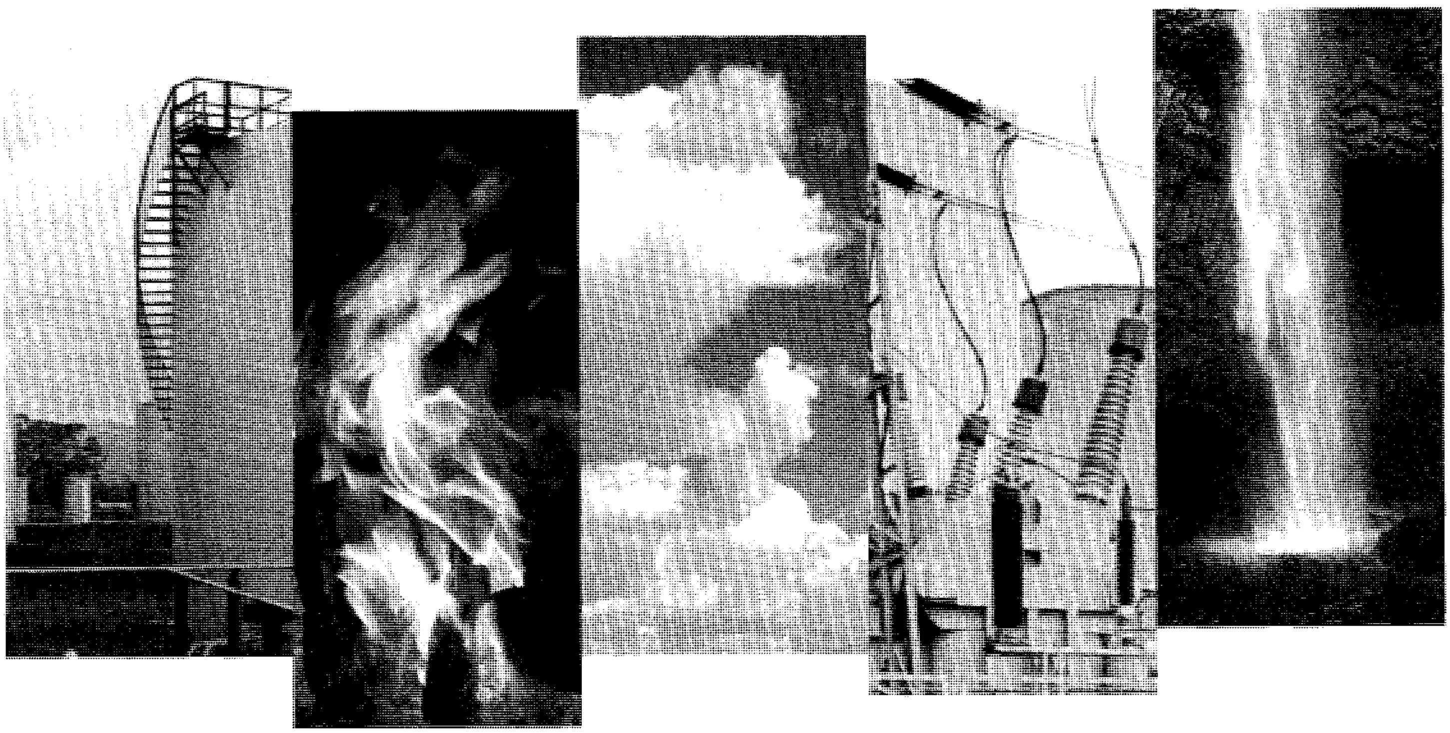

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