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DIRECTIONS IN DEVELOPMENT
Energy and Mining

The Design and Sustainability of Renewable Energy Incentives

An Economic Analysis

Peter Meier, Maria Vagliasindi, and Mudassar Imran
with contributions by Anton Eberhard and Tilak Siyambalapitiya

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Executive Summary

Several factors—including the growing demand for energy to fuel economic development, the need to diversify into environmentally sustainable supply sources and ensure energy security, and climate change considerations—have contributed to a need for accelerating public and private investment in renewable energy (RE). Many countries have designed incentive structures to induce private investment in renewables, especially those that involve higher or incremental costs. There remains much debate, however, on the cost-effectiveness—from an economic and financial perspective—of various incentives to promote renewables around the world, and on how to best address issues related to regulatory design and affordability.

In an attempt to contribute to the lively debate, this study provides a global taxonomy of the economic and financial incentives provided by RE support schemes. It summarizes economic models of the sustainability and affordability of such support schemes, alongside operational advice on how the regulatory design may need to be modified to minimize the impact on the budget and be affordable to the poor, as well as how to identify—and fill—the financing gap.

In line with its objectives, the study examines a range of issues associated with RE development that fall under the following broad categories: the effectiveness of incentive mechanisms, the details of tariff design, the integration of climate finance considerations into existing regulatory processes, and financing and affordability issues. Under each category the report represents the first systematic attempt to respond to questions such as: What types of incentive schemes have proven to be the most successful in attracting private investment in renewable generated electricity? How do feed-in tariffs (FITs) compare with renewable portfolio standards (RPSs), quota systems, avoided-cost-based tariffs, funds, and auctions? How important are the details of FIT system design, which may include capping (government-established limits on installation)? From a broader policy perspective, how cost-effective are RE solutions in reducing or controlling greenhouse gas (GHG) emissions? What are the incremental costs of renewables, who pays for them, and what is the impact of RE support mechanisms on consumers?

The novelty of this work is the fact that it introduces a rigorous and objective economic perspective on current RE support mechanisms and an empirical analysis of the strengths and weaknesses of these mechanisms—both of which are much needed in a debate often dominated by widespread misconceptions. The economic rationale for RE is straightforward: the optimum amount of RE for grid-connected generation is given by the intersection of the RE supply curve with the avoided cost of thermal electricity generation.

The proposed analytical framework (a) differentiates and illustrates trade-offs—among local, regional, and national impacts, in the short and long run; (b) captures distributional impacts (since subsidies to cover the incremental costs of RE may have very different beneficiaries); and (c) captures externalities and compares (where possible) alternative projects based on equivalent output and cost (comparing, for example, RE and energy efficiency projects against those using fossil fuels). Accordingly, the study advocates for the need to get the economic, financial, and institutional basics right for the deployment of RE.

The study's integration of RE subsidies with fossil-fuel subsidies is another novel and important contribution. This allows important comparisons. For example, to reduce carbon intensity in the economies of developing countries, is it more efficient to deploy RE or implement alternative options, such as eliminating subsidies on fossil fuels? It is easily shown that both social and global welfare increases as a result of eliminating subsidies; any reduction in fossil-fuel subsidies is a win-win situation. But the political economy of such reforms represents a major challenge.

The work is based on case studies of Vietnam, Indonesia, Sri Lanka, South Africa, Tanzania, the Arab Republic of Egypt, Brazil, and Turkey, selected to provide a representative sample of varied energy endowments (coal, natural gas, and hydro-based systems) and policy incentives (from FITs to auctions). The case studies compare the incremental cost of RE (from wind to mini-hydro, solar, and biomass) with the average cost of generation (again, highly dependent on the energy resource endowment) and determine the impact of alternative support mechanisms on the government budget and residential consumers. An analytical framework provides the underpinnings of the case studies, and provides the background for the principal research hypothesis of this report: more attention to the principles of economic analysis and market efficiency leads to more sustainable and effective policies. The main premise is that the economic rationale for RE lies at the heart of effective incentive mechanism design.

The main lessons emerging from the case studies are clear and inescapable; successful RE policies:

- Will only be effective once the state-owned utilities who are the buyers of grid-connected RE are themselves in good financial health (in all of the case study countries, the power utilities are under financial duress).
- Need to be grounded in economic analysis and accompanied by the application of market principles to ensure economic efficiency.
- Require a sustainable, equitable, and transparent recovery of incremental costs.

These points are elaborated as follows:

1. The first and arguably most important conclusion about sustainable incentives for RE relates to the financial health of the power utilities. Until such time as these utilities are in good financial health, and operate under a transparent regulatory system that sets electricity tariffs on a sustainable basis—and allows for the incremental costs of RE to be passed to the consumer—they will continue to oppose what they see as unnecessary costs that will worsen their already poor financial situation. The idea that one can achieve sustainable recovery of incremental costs for RE where utilities are in financial distress is unrealistic.
2. Although numerous studies have advocated using economic principles as a basis for RE targets, few countries have in fact done so. The lack of intellectual rigor in setting RE targets lies at the heart of the slow uptake of RE generation in most of the case study countries. Targets that bear no relationship to the economic realities of the incremental costs of RE are rarely achieved; even worse are those targets (and associated support tariffs) issued in the complete absence of knowledge about the magnitude of the incremental costs implied (the most notable recent example of which is the 2012 Indonesian geothermal FIT).
3. Incentives can be successful in enabling significant private sector investment in RE. But this is merely a necessary condition, not a sufficient condition. To be successful, such a tariff needs to be transparent in its methodology, be accompanied by a nonnegotiable power purchase agreement; propose clear arrangements for transmission costs, and be clear about the magnitude of expected incremental costs and how these will be recovered. Transparency is important because private developers and their lenders require assurance about the evolution of the tariff in the future, and need to understand the methodology of its derivation so that they can themselves make an assessment of future cash flows. Transparency in setting and adjusting a support tariff will necessarily support its acceptance.

Abbreviations

ACT	avoided cost tariff
ADB	Asian Development Bank
AfD	French Development Assistance
AfDB	African Development Bank
ANEEL	Brazilian Electricity Regulatory Agency
ASEAN	Association of Southeast Asian Nations
ASTAE	Asia Sustainable and Alternative Energy Programme (World Bank)
AWDR	average weighted deposit rate (Sri Lanka)
BBBEE	broad-based black economic empowerment
bbl	barrel
bcm	billion cubic meters
BEP	best efficiency point (hydro turbine)
BM	build margin (CDM methodology)
BNDES	Brazilian Development Bank
BNE	best new entrant
BO	build, operate
BoI	Board of Investment
BOO	build, own, and operate
BOOT	build, own, operate, transfer
BOT	build, operate, transfer
bp	basis point
bpd	barrels per day
BTU	British thermal unit
BWEA	British Wind Energy Association
CAPM	capital asset pricing model
CCCT	combined-cycle combustion turbine
CCGT	combined-cycle gas turbine
CDCF	Community Development Carbon Fund

CDM	clean development mechanism
CEB	Ceylon Electricity Board (Sri Lanka)
CEPEL	Centro de Pesquisas de Energia Elétrica
CER	certified emission reduction
CF	capacity factor
CFB	circulating fluidized bed
cif	cost insurance freight
CNPE	National Energy Policy Council
CO_2	carbon dioxide
COD	closure of development
COP	Copenhagen Conference of Parties
CPC	Central Power Company (Vietnam)
CPC	Ceylon Petroleum Corporation (Sri Lanka)
CPI	consumer price index
CRESP	China Renewable Energy Scale-up Program
CS	consumer surplus
CSP	concentrated solar power
CTF	Clean Technology Fund
cumec	cubic meter per second
CV	compensating variation
DC	direct current
DFCC	Development Finance Corporation of Ceylon
DSCR	debt service cover ratio
DSI	Directorate of State Hydraulic Works
DSM	demand-side management
dwt	dead weight ton
ECX	European Carbon Exchange
EdL	Electricite de Laos
EEA	European Environment Agency
EEG	Erneuerbare-Energien-Gesetz (Renewable Energy Sources Act)
EEHC	Egyptian Electricity Holding Company
EETC	Egyptian Electricity Transmission Company
EgyptERA	Egyptian Electric Utility and Consumer Protection Regulatory Agency
EIA	Environmental Impact Assessment
EIPS	Environmental Issues in the Power Sector (Sri Lanka, World Bank study)
EMA	Energy Market Authority (of Singapore)
EME	Exempt Micro Enterprise

EML	Electricity Market Law
EMRA	Energy Market Regulatory Authority
EMRRP	Estate Micro Hydro Rehabilitation and Re-Powering Project
EPC	engineering, procurement, and construction (contract)
ERAV	Electricity Regulatory Authority of Vietnam
ERPA	Emissions Reduction Purchase Agreement
ERR	economic rate of return
ESDP	Energy Services Delivery Project (Sri Lanka)
Eskom	Electricity Supply Commission of South Africa
ESMAP	Energy Sector Management Assistance Program (World Bank)
ESP	electrostatic precipitator
EU	European Union
EUA	EU Allowance Unit of one ton of CO_2
EU-ETS	European Union Emission Trading Scheme
EV	equivalent variation
EVN	Electricity of Vietnam
EWURA	Energy and Water Utilities Regulatory Authority
FERC	Federal Energy Regulatory Commission (U.S.)
FGD	flue gas desulphurization
FIDIC	International Federation of Consulting Engineers
FIRR	financial internal rate of return
FIT	feed-in tariff
fob	free on board
FOREX	foreign exchange
FS	feasibility study
FTP2	second fast-track program
GDP	gross domestic product
GEF	Global Environment Facility
GHG	greenhouse gas
GoV	Government of Vietnam
GTZ	Gesellschaft für Technische Zusammenarbeit (Germany)
GW	gigawatt = 1,000 MW
GWh	gigawatt-hour
ha	hectare
HCMC	Ho Chi Minh City
HFO	heavy fuel oil
HHV	higher heating value
HRSG	heat recovery steam generator

HSFO	high sulphur fuel oil
HX	heat exchanger
IBRD	International Bank for Reconstruction and Development
IDA	International Development Association
IDC	interest during construction
IEA	International Energy Agency
IEC	International Electrotechnical Commission
IFC	International Finance Corporation
IFI	international financial institution
IMF	International Monetary Fund
IoE	Institute of Energy (Vietnam)
IPCC	Intergovernmental Panel on Climate Change
IPP	independent power producer
IRP	integrated resource plan
IRR	internal rate of return
ISCC	Integrated Solar Combined Cycle
ISO	International Standards Organisation
IUP	Izin Usaha Panas Bumi (geothermal business license)
JCC	Japan Crude Cocktail
JICA	Japan International Cooperation Agency
JSC	Joint Stock Company
KCal	kilocalories
KfW	German Development Bank
kg	kilogram
kW	kilowatt
kWh	kilowatt-hour = 3,412 BTU
LCOE	levelized cost of energy
LDU	local distribution utility
LECO	Lanka Electricity Company (Private) Limited (Sri Lanka distribution company)
LF	load factor
LFG	landfill gas
LHV	lower heating value
LIBOR	London inter-bank offer rate
LNG	liquefied natural gas
LoI	letter of intent
LR	licensing regulation
LRMC	long-run marginal cost
LV	low voltage

m/sec	meter per second
m^2	square meter
m^2/yr	square meter per year
MADA	multi-attribute decision analysis
MAE	Wholesale Electric Energy Market
MARD	Ministry of Agriculture and Rural Development (Vietnam)
MEM	Ministry of Energy and Minerals
MEMR	Ministry of Energy and Mineral Resources
MENA	Middle East and North Africa
MENR	Ministry of Energy and Natural Resource
mmBTU	million British thermal units
MME	Ministry of Mines and Energy
MMS	mandated market share
MNES	Ministry of Non-conventional Energy Sources (India)
MoE	Ministry of Energy
MOEE	Ministry of Electricity and Energy
MoF	Ministry of Finance
MoIT	Ministry of Industry and Trade (Vietnam)
MoNRE	Ministry of Natural Resources and Environment (Vietnam)
MoU	memorandum of understanding
MSWI	municipal solid waste incineration
Mt	metric ton
MT	million tons
mtpa	million tons per annum
MUV	manufacture unit value (index)
MV	medium voltage
MW	megawatt = 1,000 kW
MWh	megawatt-hour
MWL	minimum water level
NCRE	nonconventional and renewable energy (Sri Lanka)
NERSA	National Energy Regulator of South Africa
NIF	Neighbourhood Investment Facility (European Union)
NLDC	National Load Dispatch Centre (Vietnam)
NO_X	nitrogen oxide
NPC	National Power Corporation
NPV	net present value
NREA	New and Renewable Energy Authority
NREL	National Renewable Energy Laboratory
NTF-PSI	Norwegian Trust Fund for Private Sector and Infrastructure

O&M	operation and maintenance
OCCT	open-cycle combustion turbine
OCGT	open-cycle gas turbine
OECD	Organisation for Economic Co-operation and Development
OLS	ordinary least squares
OM	operating margin (CDM methodology)
OPEC	Organisation of Petroleum Exporting Countries
OPEX	operating expenses
ORB	OPEC Reference Basket (crude oils)
PA	Privatization Administration
PAD	Project Appraisal Document (of the World Bank)
PC	pulverized coal
PDA	project development agreement
PDD	project design document (of the UNFCCC)
PDP	Power Development Plan (Vietnam)
PDP7	Seventh Power Development Plan (Vietnam)
PGE	Pertamina Geothermal Energy
PLN	Perusahaan Listrik Negara (Indonesian State Electric Utility Company)
PM-10	particulate matter (no greater than 10 microns in diameter)
PPA	power purchase agreement
PPIAF	public-private infrastructure advisory facility
PPP	purchasing power parity
PPPs	public-private partnerships
PROINFA	program for the promotion of renewable energy
PS	pumped storage
PSO	public service mechanism
PTC	production tax credit
PUCSL	Public Utility Commission of Sri Lanka
PURPA	Public Utilities Regulatory Policy Act (United States)
PV	photovoltaic
QF	qualifying facility
QSE	qualifying small enterprise
R&D	research and development
RE	renewable energy
REAP	Renewable Energy Action Plan (Vietnam)
REDP	Renewable Energy Development Project (World Bank, Vietnam)
REIPPP	Renewable Energy Independent Power Producer Procurement

REL REPA	Renewable Energy Law Wind Energy Potential Map of Turkey
REMP	Renewable Energy Master Plan (Vietnam)
RER Certificate	Renewable Energy Resource Certificate
RERED	Renewable Energy for Rural Economic Development
RESPP	renewable energy small power producer
RfP	request for proposals
ROE	return on equity
RoR	run-of-river
RPS	renewable portfolio standard
RSA	Republic of South Africa
SBV	State Bank of Vietnam
SC	supercritical
SCADA	supervisory control and data acquisition
SCC	social cost of carbon
SCF	standard conversion factor
SCF	statement of cash flow
SEFI	Sustainable Energy Finance Initiative
SEIERP	System Efficiency Improvement, Equitization and Renewables Project (World Bank)
SGD	Singapore dollars
SHP	small hydro project
SIDA	Swedish International Development and Cooperation Agency
SLF	system load factor
SLPUC	Sri Lanka Public Utilities Commission
SLSEA	Sri Lanka Sustainable Energy Authority
SMO	system market operator
SMS	Turkish State Meteorological Service
SO	system operator
SO_2	sulphur dioxide
SPDF	special purpose debt facility
SPP	small power producer
SPPA	standardized power purchase agreement
SV	switching value
T&D	transmission and distribution
TA	technical assistance
TANESCO	Tanzania Electric Supply Company
TCM	thousand cubic meters
TEAS	Turkish Electricity Generating and Transmission Corporation
TEDAS	Turkish Electricity Distribution Company

TEK	Turkish Electricity Authority
TGC	tradable green certificate
TJLP	long-term interest rate
TKB	Turkish Development Bank
TOE	tons of oil equivalent
TOOR	transfer of operating rights
ToR	terms of reference
TRY	Turkish Lira
TSKB	Turkish Industrial Development Bank
TSO	transmission system operator
TSP	total suspended particulates
TWh	terawatt-hour
U.S.	United States (of America)
UAE	United Arab Emirates
UK	United Kingdom
UNEP	United Nations Environment Programme
UNFCCC	United Nations Framework Convention on Climate Change
UREA	Uttranchal Renewable Energy Agency (India)
USC	ultra super critical
VAT	value added tax
VCGM	Vietnam competitive generation market
VEPF	Vietnam Environmental Protection Fund
VM	volatile matter
VND	Vietnamese dong
VSL	value of statistical life
VSPP	very small power producer
WACC	weighted average cost of capital
WASP	Wien Automatic System Planning
WKP	Wilayah Kerja Pertambangan Panas Bumi (geothermal work areas as known in Bahasa, Indonesia)
WTI	West Texas Intermediate (crude oil)
YEGM	Yenilenebilir Enerji Genel Müdürlüğü (General Directorate of Renewable Energy)
YOLL	years of life lost

All monetary amounts are in U.S. dollars (US$) unless otherwise indicated.

CHAPTER 1

Introduction

Background

Rapid urbanization and economic growth, new demographic trends, and climate change are key challenges that developing countries must face as they strive to meet growing energy demand. These and other challenges call for an acceleration of public and private investment in renewable energy (RE).

The adoption of the Kyoto Protocol in early 2005 spurred exponential growth in mainstream RE investment around the world. In 2008, for the first time, RE—including large hydropower projects—attracted more power sector investment globally than fossil-fuel-based technologies (UNEP, SEFI, and Bloomberg New Energy Finance 2012). Contributing to this exponential growth was an alignment of global factors: rapid growth in energy demand in emerging economies such as those of China and India, increased competition for energy resources, geopolitical tension and energy security concerns, rising oil and gas prices, as well as the entry into force of the Kyoto Protocol, and the rise of climate change in the political agenda more generally.

The traditional functions of energy policy and regulation are to ensure access to adequate and reliable supply, protect consumers from high prices, and ensure that private sector entities will be able to recoup their investment. A fourth goal—decreasing environmental impact—is often added. These goals sometimes conflict with one another. Improved access to reliable, secure, affordable, climate-friendly, and sustainable energy can represent a formidable challenge.

Changes can be particularly costly if a move toward a low-carbon solution is implemented through an increasing proportion of RE. Most renewable sources of energy are more expensive than conventional ones; in most cases this is because of high capital costs, spurring changes in the level and composition of investment. In addition, most forms of renewable generation—though good substitutes for conventional sources of energy—are poor in providing capacity at peak time.

A recent review of private sector investment in RE draws several important conclusions about the effectiveness of incentive mechanisms:[1]

- Developing countries that have introduced feed-in tariffs (FITs) are almost four times more likely to attract private investment in RE—resulting in about seven times more total investment—than countries where such support mechanisms have not been introduced.

- The introduction of FITs (and, more broadly, of other support mechanisms) is positively and significantly associated with the introduction of public-private partnerships (PPPs)[2] in renewable electricity generation, controlling for several variables (including supply and demand factors), economy-wide governance indicators, and sectoral controls. FITs affect both the entry and the level of investment in renewable-based energy, though they became much less significant when it comes to determining the amount of investment. This second point suggests the need to revisit the implied allocation of risks between the public and private sectors over time to ensure that FITs produce the desired volume of investment.

- In contrast, broader economy-wide governance factors, including the degree of corruption and political competition, are most often considered by private investors as they decide whether to invest in renewable-based generation. This reinforces the hypothesis that private investors seem to be adequately protected against risk: once they have entered the market, they can accommodate the governance environment.

- Countries that have enhanced transmission investment have also paved the way for attracting more investment in renewables. This confirms that attracting more private investment depends on the broad policy environment, and not just financial support or incentive mechanisms. Avoiding costly construction delays due to regulatory uncertainties, and lack of transmission and infrastructure access pose significant obstacles to timely, successful project development.

The effectiveness of FITs and renewable portfolio standards (RPSs) in deploying RE can be framed within the pioneering debate between the use of quantity versus price instruments. In the absence of market imperfections, both policies have the same welfare outcome (Weitzman 1974, 477–91). In the presence of market failures, however, each policy has its relative merits. The key advantage of a FIT is that it reduces investor risk by offering a guaranteed price. On the other hand, a FIT that is too generous can stifle innovation and unnecessarily increase procurement costs. The advantage of an RPS is that it typically stimulates cost-effective procurement by inducing competition between suppliers. On the other hand, such competition may deter the entry of risk-averse RE suppliers and limit the ability to foster technologies that require time to become more competitive. Functional form choices for the independent variable range from binary indicators (a policy exists, or it does not) to nominal measures (level of FIT or RPS target) to more nuanced measures that aim to better capture the incentives that the policies provide. Other dimensions, along which these regression approaches differ in scope (in terms of countries and years), are relevant to policy design and range-of-control variables.

Overall, there is still a lack of consensus among studies about whether, which, and in what way renewable policies have been successful in stimulating RE. Case studies and cross-sectional regressions typically find that FITs and RPSs are most effective in RE deployment (del Rio Gonzalez 2007, 994–1012; 2008, 2917–29; Haas and others 2011, 2186–93; Lesser and Su 2008, 981–90; Lipp 2007, 5481–95; for RPSs, see Allegappan, Orans, and Woo 2011, 5099–104; Menz and Vachon 2006, 1786–96). But econometric studies using panel data do not confirm these results. For example, in the case of RPS studies, the presence of an RPS has been found to increase, not affect or even reduce, RE penetration (Carley 2009, 3071–81; Shrimali and Kniefel 2011, 4726–41; Yin and Powers 2010, 1140–49). Some discrepancy between findings is due to the different methodologies that have been used. For example, between cross-sectional and panel data, the ability of panel data to control for time-invariant unobservables encourages greater confidence in the robustness of results. Another reason for discrepancy between findings depends on the different extents to which different studies take account of policy design and policy contexts. The many dimensions of policy design and context are difficult to capture by simple quantitative indicators.

Major progress may be observed in the econometric literature, however. Zhang (2013), for example, models several FIT design elements and finds that high feed-in rates do not necessarily lead to an increased uptake of wind power in European countries, but guaranteed grid access and length of feed-in contracts are crucial policy characteristics for RE deployment (Delmas and Montes-Sancho 2011). Several studies, including those of Delmas and Montes-Sancho (2011) and Zhang (2013), attempt to account for the existence of a lag between the enactment of policy and measured policy output. This lag arises because it takes time for investors to respond to incentives and is particularly relevant for technologies with high up-front capital costs, such as RE.

Existing studies focus almost exclusively on the United States and the European Union (EU). This focus undoubtedly reflects not only the prevalence and experience of RE policies in developed countries, but also the difficulty of assembling data for quantitative analysis in developing countries. There is limited understanding of renewable policy design considerations that are specific and important to developing countries.

Studies also focus on effectiveness as a measure of policy success, rather than cost-effectiveness or efficiency. For example, Zhang (2013) suggests that high subsidies in Europe's FIT program may have driven up investment costs by allowing installation at low-wind-speed sites. Similarly, Menz and Vachon (2006) suggest that an effective RPS can facilitate the adoption of renewable capacity in states with low resource potential. These results are critical to ensure sound spending of public funds in support of RE generation.

Key Issues

From these general observations follow the main questions to be considered by the case studies included in this report:

- *Effectiveness and efficiency of incentive mechanisms*. What types of incentive schemes prove to be the most successful in attracting private investment in renewable-generated electricity? How do FITs compare with RPSs, quota systems, and auctions in terms of effectiveness and efficiency? How can the combination of different incentive schemes (see the taxonomy outlined in table 1.1) (Mitchell, Bauknecht, and Connor 2006; Rickerson and Grace 2007) be used to maximize effectiveness, while reducing the cost burden on the budget and on vulnerable consumers (Cory, Couture, and Kreycik 2009)?

- *Details of tariff design*. How important are the details of the FIT system design, which may include capping (government-established limits on installation); tariffs differentiated by technology; tariff inflation-indexation; duration; and the methodology used to determine tariff levels and to revise tariffs, purchase obligations, the introduction of tariff degressions, and the specific "burden-sharing" system? Which of these design factors will make the business environment for renewables more or less attractive to private investors?

- *The broader energy policy environment*. How effective is the deployment of RE in reducing the carbon intensity of developing country economies, relative to alternative options, such as eliminating subsidies on fossil fuels? What is the evidence from several of the case study countries that provide large subsidies to coal and gas generators (the Arab Republic of Egypt, South Africa, Indonesia, Vietnam)?

- *Financing and affordability issues*. What is the incremental cost of RE relative to that of fossil fuels? *Who pays* for it? Are donor grants, concessionary loans, and carbon finance provided by the global community, consumers, or taxpayers? What is the impact of RE support mechanisms on consumers? Is it equitable and affordable for poor consumers in developing countries to contribute? Can the costs be passed on to just large customers (rather than poorer residential customers)? Yet in some countries (including Germany), it is the large customers who are *exempt* from consumer levies to recover the incremental costs.[3]

Objectives

The main objectives of this study are to offer (a) a global taxonomy of the economic and financial incentives provided by renewable support schemes and (b) an economic modeling of the sustainability and affordability of such support schemes. Also included is operational advice on how the regulatory design may need to be modified to minimize budgetary impact and be affordable to the poor, with an aim to identify—and fill—the financing gap.

Table 1.1 Taxonomy of Financial Incentive Mechanisms for Renewable Energy

Category	*Type of instrument*	*Who pays*	*Examples*
Price	Production cost-based feed-in tariffs (FITs)	*Design decision*	Algeria (since 2002) Austria (since 2002) Belgium Brazil (since 2002 until 2010) Bulgaria (since 2007) Canada (Prince Edward Island, since 2004; Ontario, since 2006) China (since 2005) Cyprus (since 2003) Czech Republic (since 2002) Estonia (since 2003) France (since 2001) Germany (since 1990) Greece (since 1994) Hungary (since 2003) Ireland India (since 1993) Israel (since 2004) Italy (since 1992) Kenya (since 2008) Korea, Rep. (since 2003) Latvia (since 2001) Lithuania (since 2002) Luxembourg (since 1994) Malaysia (since 2010) Malta (since 2010) Netherlands (since 2011) Nicaragua (since 2004) Norway (since 1999) Pakistan (since 2006) Philippines (since 2008) Portugal (since 1999) Slovak Republic (since 2003) Slovenia (since 1999) Spain (since 1994) Sri Lanka (since 2011) South Africa (since 2009—not implemented) Switzerland (since 1991) Tanzania (since 2008) Thailand (since 2006) Turkey (since 2005) Uganda (since 2008) United Kingdom (since 2010) United States (California since 1978; Hawaii since 2008; Oregon and Vermont since 2009)
	Avoided cost tariffs (ACTs)	*Design decision*	Indonesia (2012 geothermal tariff) Sri Lanka (1998–2010) Vietnam

table continues next page

Table 1.1 Taxonomy of Financial Incentive Mechanisms for Renewable Energy *(continued)*

Category	*Type of instrument*	*Who pays*	*Examples*
	Premiums over generation market price ("adders")	*Design decision*	Czech Republic Denmark (premium only) Estonia Italy Netherlands (premium only) Slovenia Spain Thailand ("adders")
	Premiums over retail price ("green tariffs")	Consumers, voluntarily	China-Shanghai ("jade" tariff)
Quantity	Direct auctions for price	*Design decision*	Brazil (since 2007) China (wind concessions until 2009) Egypt, Arab Rep. Indonesia (price-based tenders for geothermal work areas) Morocco Peru (since 2009) South Africa (since 2009) Turkey (since 2008)
	Auctions for subsidy	*Design decision*	Thailand (funded from the tax on petroleum products)
	Renewable portfolio standards (RPSs)		Australia (since 2001) Belgium (Flanders since 2002; Walloon since 2003; Brussels since 2004) Canada (Nova Scotia, Ontario, and Prince Edward Island, since 2004) Chile (since 2008) China (since 2007) Italy (since 2001) India (at a state level, Maharashtra since 2003; at a national level, since 2008) Japan (since 2003) Korea, Rep. (since 2012) Latvia Lithuania Poland (since 2005) Philippines (since 2008) Romania (since 2008) Sweden (since 2003) United Kingdom (England, Wales, and Scotland, since 2002; Northern Ireland, since 2005) United States (30 states and the District of Columbia, with Iowa the first, since 1983)
Direct	Grants and capital subsidies	Government	Belgium Cyprus Czech Republic Egypt, Arab Rep. Finland Greece Hungary Jordan

table continues next page

Table 1.1 Taxonomy of Financial Incentive Mechanisms for Renewable Energy *(continued)*

Category	*Type of instrument*	*Who pays*	*Examples*
			India Latvia Lithuania Malta Morocco Philippines (grants to consumers for photovoltaic systems) Tunisia
	Sale of carbon credits (for example, CDM)	Global community	Most developing countries
	Grants	Global community	Egypt, Arab Rep. (EU Neighbourhood Investment facility, grant for CSP) Many countries (grant component of IDA loans, for example, Nepal hydro rehabilitation project)
Indirect	Preferential taxes	Taxpayers	Belgium Finland Greece India (accelerated depreciation on wind farms) Spain Tunisia United States (PTC) Most developing countries (import duty and VAT concessions)
	Preferential domestic financing	Government	Bulgaria Brazil (low-cost loans to RE producers by BNDES) Estonia Germany Malta Netherlands Poland Slovenia Thailand
	Preferential foreign financing and loan guarantees	Global community	Indonesia (Carbon Trust Fund support to geothermal projects) Most developing countries have access to the Carbon Trust Fund

Source: Authors' elaboration.
Note: BNDES = Brazilian Development Bank; CDM = clean development mechanism; CSP = concentrated solar power; EU = European Union; IDA = International Development Association; PTC = production tax credit; PV = photovoltaic; VAT = value added tax. The taxonomy is not meant to be exhaustive, but to provide a few representative examples in each category.

Why Is Renewable Energy Important for Poor Countries?

To date, few World Bank discussions about the need for increasing RE in developing countries have directly confronted one of the fundamental realities of the global climate change debate: governments in poor, developing countries believe that they should not bear the incremental costs of RE in the same way as the governments of, say, Germany, Switzerland, and Sweden. Such beliefs are fundamental to the question of who pays.

Everyone prefers to be seen as "green," so there are countless examples of RE targets promulgated as political statements that have little realistic chance of being achieved, or of governments going through the motions of introducing RE incentive schemes that at first glance appear to be based on wishful thinking, but in fact are based on a great reluctance to do anything that results in increases of the electricity tariff.

An example from our case studies underscores this point. Vietnam has at best a modest wind resource, and what it does have is highly seasonal (and more seasonal than that of Europe or Latin America).[4] Given that wind is very high up on the RE supply curve, and that Vietnam has significant small hydro and biomass resources that can be exploited at a much lower cost, there is no economically rational reason for Vietnam to pursue wind power. Only years of relentless donor advocacy have persuaded the government to introduce a wind FIT—but one set at such a low level (7.8 cents/kilowatt-hour, kWh) as to have no realistic chance of enabling any wind farms.

Understandably, the Government of Vietnam is reluctant to introduce a wind FIT at a level comparable to other Asian countries (16 cents/kWh in the Philippines, 19 cents/kWh in Sri Lanka). With inflation and already sharply increasing electricity tariffs being a real problem in Vietnam, the idea of imposing a consumer levy to recover incremental costs of wind power has been politically unattainable, with the result that the draft Renewable Energy Master Plan, which was submitted in 2009 and which proposed such a consumer levy, has little chance of eventual approval. Yet at the same time, Vietnam has implemented a highly successful small hydro program, with 800 megawatts (MW) enabled since 2009 through its avoided cost tariff (ACT) and standardized power purchase agreement (SPPA). The program has been successful precisely because one could demonstrate that small hydro was economically efficient, with costs at or below the avoided social cost of the thermal alternative.

This highlights one of the main themes of this report: namely, that economic rationality lies at the heart of any successful RE program, and that the single most important issue is the transparent recovery of incremental costs. We know of no successful RE program based on attempts to bury incremental costs in nontransparent subsidies. The most expensive RE program in the world—in Germany—has been achieved by a transparent consumer levy. In 2012 residential customers paid 25 cents/kWh for electricity, of which the surcharge for the FIT levy accounted for 3.59 cents/kWh, or 13.9 percent of the average bill (see box 1.1). This surcharge will rise to 5.28 cents/kWh in 2013 (excluding value added tax, VAT).[5]

Taxonomy of Financial Incentive Mechanisms

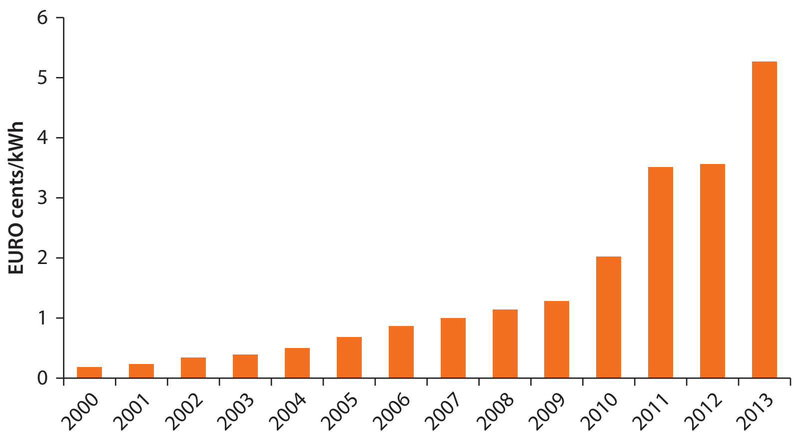
The economic rationale for RE lies at the heart of the design of incentive mechanisms. Our proposed taxonomy of incentive mechanisms recognizes four general categories:

- *Price incentives*, as when the government intervenes to provide RE generators with preferential output prices, with the result that the market determines the

Box 1.1 A Paradox in the Design of the Erneuerbare-Energien-Gesetz (EEG) Surcharge, German Renewable Energy Sources Act 2000

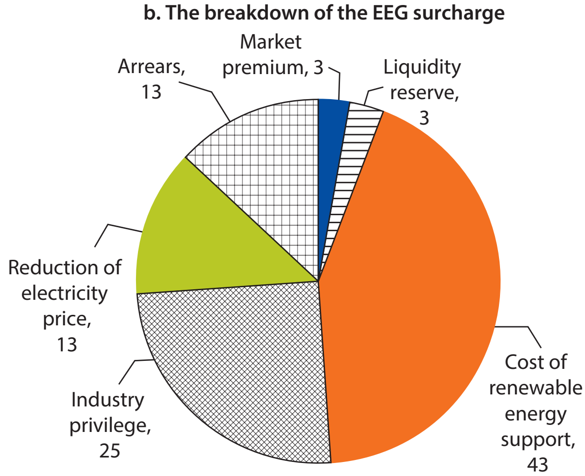
Renewable energy (RE) has had a price-curbing impact on wholesale prices in recent years, as additional supply has shifted the demand curve, particularly in the case of wind (Sensfuß, Ragwitz, and Genoese 2007). Because the surcharge is calculated as the difference between the feed-in tariff (FIT) and spot market prices, lower prices mean an increased surcharge (see the figure B1.1.1, panel a). Exempted industrial consumers are net beneficiaries: because of RE they pay lower electricity prices, and almost no surcharge. Households and other small consumers do not benefit from lower prices (due to the merit order effect), as these are not passed on to them (for lack of effective competition among distributors). By contrast, their surcharge payments are increased since they also pay for the "extra cost" share of the exempted industry (see figure B1.1.1, panel b).

a. The development of the EEG surcharge, 2000–13



Note: kWh = kilowatt hour.

b. The breakdown of the EEG surcharge



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Box 1.1 A Paradox in the Design of the Erneuerbare-Energien-Gesetz (EEG) Surcharge, German Renewable Energy Sources Act 2000 *(continued)*

Is it true that all costs are passed through to users? The answer is no, as there are other costs attributable to RE sources. These include, for example, the additional cost for basic and balancing energy that is needed because of the fluctuating input of electricity from photovoltaic (PV) and especially wind energy systems. Other factors are grid expansion due to the integration of power from renewables, and administrative costs incurred by grid operators for implementation of the EEG. These additional cost factors are difficult to quantify. They have been estimated to total between €300 million and €600 million, the dominant share of which is due to basic and balancing energy. On the other hand, the expansion of renewables also involves a number of beneficial effects that are not reflected in the operating cost factors so far considered.

Apart from the reduction in wholesale electricity prices effected by the EEG, the external costs of electricity generation from fossil fuels that are avoided by using RE sources are particularly important from a macroeconomic point of view. If these costs were allocated in strict accordance with the "polluter pays" principle, the price of electricity from non-RE sources would be much higher. In this connection a study for the Federal Ministry for the Environment, Nature Conservation, and Nuclear Safety of Germany (Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit, BMU) came to the conclusion that the external costs saved by EEG electricity, between €5.84 billion and €20.44 billion in 2012, were more or less equal to the additional procurement costs for the EEG.

Electricity generation from RE sources also results in a significant reduction in imports of coal and natural gas into Germany. In 2012 this reduced Germany's bill for fuel imports by about €25 billion. One must also remember the positive effects of RE on growth and employment. The basis for this positive trend is the rise in domestic sales of RE that has been in progress for years and—to an increasing extent—the export success of the German renewables sector. The latter is profiting considerably from the fact that the EEG has set in motion a technological development that has given Germany a leading position on the world market in various fields in the renewables sector. The fact that the EEG itself is increasingly proving to be an export hit, reflects this trend and is one of its main driving forces.

Source: Lauber 2013.

quantity of RE provided at the stipulated price (though in some countries a cap is placed on the quantity).

- *Quantity incentives*, as when the government sets a target for the *quantity* of RE to be provided, with the result that the marketplace determines the price (for example, through an auction for a given quantity of megawatt-hours [MWh] to be delivered some years hence).
- *Direct support*. Cash support is provided directly to RE generation projects, either as direct cash subsidies from governments, or as cash from the sale of carbon credits (clean development mechanism, CDM).

- *Indirect support*. Support is provided to developers through tax rebates and incentives, low-cost loans from government-owned development banks, or concessionary carbon financing.

Within each category there are many different specific mechanisms, as listed in table 1.1. Moreover, most countries have in place more than one such mechanism, which makes policy interaction and compatibility important issues, since the combined impact may result in inefficient outcomes.[6]

In some cases, who pays is defined by the nature of the incentive mechanisms. For example, a preferential rate of income tax is necessarily carried by taxpayers, and green tariffs are necessarily carried by consumers. But for those incentives identified in table 1.1 as a "design decision," who pays must be decided by the government as a matter of policy design. The incremental costs of a FIT can be paid by consumers or from several different sources (as in the case of Vietnam's wind FIT, by the utilities and the Vietnam Environmental Protection Fund, VEPF).

Table 1.1 lists the policies directly aimed at increasing RE generation. But this list excludes the policies that are not expressly directed at promoting RE, but which may in fact have a much greater impact on RE by removing the distortions that lead to the need for RE incentives in the first place. The two main policies in this regard are:

- Subsidies on fossil fuels, which make RE appear more expensive than it really is (as in Vietnam and Indonesia).
- Subsidies on the retail tariff, whose elimination would (other things being equal) reduce all electricity generation and greenhouse gas (GHG) emissions far more than is achieved by the policies listed in table 1.1 (illustrated by Indonesia, where the Ministry of Finance subsidy to the Indonesian utility Perusahaan Listrik Negara [PLN, or Indonesian State Electric Utility Company] runs to several billions per year).

These are important questions for countries whose subsidies are large: from both the Vietnam and Indonesia case studies it can be concluded that removing fuel subsidies would have a far greater impact on GHG emissions—and the amount of RE that would become competitive without subsidy—than the additional RE likely to be enabled by the proposed FITs.

Meanwhile, the removal of institutional barriers often unlocks much more RE than attempts to introduce price incentives. This is well illustrated by the Indonesian example: in fact the main barrier to achieving the geothermal targets is not inadequate tariffs, but the barriers faced by private developers in dealing with an often-dysfunctional permitting system in the provinces, and tender committees that lack technical capacity and have awarded tenders at unrealistic prices by developers who lack technical and financial capacity.[7] On the other hand, in Vietnam, it is relatively easy to build a small hydro project (SHP), but provincial authorities' capacity for reviewing SHPs is *weak*, resulting in widespread allegations of environmental damage and the perception that too many SHPs are being built.

Economic vs. Financial Incentives

The different incentives listed in table 1.1 all relate to the *financial engineering* of projects in an attempt to achieve bankable projects by reducing the financial costs (or increasing the financial benefits through preferential tariffs). Together with reducing subsidies on fossil fuels and on power tariffs, these measures can be advocated on economic efficiency grounds by bringing financial costs closer to economic costs and thereby improving the allocation of resources in the economy.[8]

But none of these incentives does anything to change the realities of the underlying *economic* costs and benefits. A quite different set of policies is required to provide incentives to reduce economic costs, or improve the technical efficiency of RE. Examples of such incentives include:

- *Domestic manufacture of RE equipment*. The foremost example of this is China, whose low-cost equipment has done far more to promote bankable RE projects in Asia than all of the financial incentives listed in table 1.1. In Vietnam hydro- and wind-turbine generators manufactured in China cost 60 percent of the equipment manufactured in Europe.[9] Many countries have attempted to promote domestic manufacture through domestic content provisions (for example, eligibility for low-cost loans from government-owned development banks as in Brazil, or the bonus in the Malaysian FIT for biomass equipment manufactured locally and the bonus in the Turkish FIT and the South Africa local content provision for RE auctions).

- *Operational optimization*. Many hydro projects are not based on a clear understanding of how reservoir-operating rules and flow-discharge decisions affect generation, resulting in operation at points quite distant from the so-called best efficiency point (BEP), with significant generation penalties (amounting to as much as 5 percent in total annual net generation).[10]

- *Institutional transaction costs*. The original Global Environment Facility (GEF) that funded many RE projects between 1995 and 2005 expressly recognized the importance of reducing institutional barriers. Experience over the past decade has shown that the costs of delay attributable to institutional dysfunction have a major impact on economic returns: excellent examples are the mini hydro projects funded by the Philippines Rural Power Project (if the 2.5 MW Sevilla project implemented by the Boheco Rural Electricity cooperative had been built over two years rather than the actual four years, its economic rate of return [ERR] would have increased from 21 percent to 26 percent) (World Bank 2013a).

- *Support for transmission integration*. Twenty percent of China's installed wind capacity is reported to be idle for lack of transmission connection or transmission system bottlenecks.

Organization of the Rest of the Report

Chapter 2 presents the analytical framework that underpins the case studies, and provides the background for the principal research hypothesis of this report, which is better attention to the principles of economic analysis and market efficiency leads to more sustainable and effective policies.

Chapters 3–10 present country case studies for Vietnam, Indonesia, Sri Lanka, South Africa, Tanzania, Egypt, Brazil, and Turkey.

The conclusions of the study are presented in chapter 11. Each of the main issues presented above is discussed, and appropriate conclusions are drawn. The main lessons for those who design RE support mechanisms are clear and inescapable. Successful RE policies:

- Need to be grounded in economic analysis and the application of market principles to ensure economic efficiency.
- Will only be effective once the state-owned utilities that are the buyers of grid-connected RE are themselves in good financial health (in all of the case study countries, the power utilities are under financial duress).
- Require a sustainable, equitable, and transparent recovery of incremental costs.

Finally, some appendixes illustrate the application of useful techniques in economic analysis (taken from World Bank practice) that have been found effective in communicating analytical ideas to policy makers and stakeholder consultation meetings. Appendix A (setting RE targets in Croatia) illustrates basic tools from decision analysis; appendix B (multi-attribute decision analysis in Vietnam) shows how trade-off plots are useful in comparing RE generation with other options for reducing GHG emissions; and appendix C (estimating incremental costs in Indonesia) shows how RE supply curves can be used for estimating subsidies.

Notes

1. See Vagliasindi (2013) for the overall report and Vagliasindi (2012) for the statistical analysis, which is based on panel data analysis.
2. The public-private partnership (PPP) requires careful definition. In some countries (for example, Indonesia) PPPs are simply independent power producers (IPPs) with sovereign guarantees. In others, PPPs imply equity contributions from a government or international financial institution (IFI) (for example, the International Finance Corporation, IFC).
3. It is often supposed that the incremental costs of the German feed-in tariff (FIT) are spread to all consumers in Germany through a levy, but power-intensive industrial consumers (and the railways) benefit from various degrees of exemption. See, for example, Neuhoff and others (2013).
4. For a detailed discussion of this point, see chapter 3 on Vietnam, section "Renewable Energy Resource Endowment: The Supply Curve."
5. See Neuhoff and others (2013, 42). The transmission system operators publish the level of the FIT surcharge every October for the following year. But it may well be

noted that given the high level of the surcharge, public support is beginning to wane, and calls for a more competitive system are growing.

6. See, for example, conclusions of the Bank's 2011 review of the design of policy instruments (Azuela and Barroso 2011).
7. As noted below, another reason for failure to reach targets is that the targets themselves were established as political statements rather than being grounded in economic analysis, with the result that targets were in any event unachievable at a reasonable cost.
8. As we see in chapter 2, the financial supply curve for renewable energy (RE) lies above the economic supply curve, so all other things being equal, the point of intersection with the avoided costs of thermal generation will be at a lower quantity of RE.
9. See chapter 3 for further discussion of this question: it is true that low-cost Chinese hydro turbines for small hydro projects often have lower efficiencies and higher outage rates than their European counterparts, but these are far outweighed by the lower up-front costs (provided that equipment is sourced from reputable manufacturers).
10. See, for example, Kali Gandaki Hydro Rehabilitation Project Appraisal Document (World Bank 2013b).

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CHAPTER 2

The Economic Rationale for Renewable Energy

Analytical Framework

The *economic* rationale for renewable energy (RE) is straightforward: the optimum amount of RE for grid-connected generation is given by the intersection of the RE supply curve with the avoided cost of thermal electricity generation (figure 2.1). Very little RE will be competitive with the avoided thermal cost if that cost is based on financial prices: in almost all Asian countries that have their own fossil-fuel resources, subsidized prices to power utilities are widespread. Only where the marginal thermal resource is imported (unsubsidized) oil is RE competitive (as was the case in Sri Lanka in the early 2000s); where the thermal generation price is based on coal, little if any RE is competitive.

If thermal energy is correctly valued at the border price P_{ECON} (which equals = $P_{FIN} + \alpha$, the subsidy), then the optimal quantity of RE increases, as depicted in figure 2.2.

These principles constitute the basis for the original avoided cost tariffs (ACTs) for RE in Sri Lanka, Indonesia, and Vietnam. In Sri Lanka, which has no domestic fossil resources, the marginal thermal production cost was set by imported diesel fuel, so the acceptance of an RE tariff set at this avoided cost was easily achieved in 1998. In Vietnam this was more difficult, since at the time of its introduction in 2009, the avoided financial cost of thermal generation to the state-owned utility (Electricity of Vietnam, EVN) was based on extensive subsidies to coal and domestic gas used for power generation. But as additional gas-fired combined-cycle-gas-turbine (CCGT) plants came online, with prices linked to international prices,[1] EVN accepted a tariff based on the cost of the marginal thermal project. This is discussed further in chapter 3.

But even if the cost of fossil energy is correctly valued at the border price, this needs to be further adjusted to reflect the local environmental damage costs of fossil energy—that is, the damage caused by local air pollutants (PM_{10},[2] SO_X,[3] NO_X[4]), or the environmental damage costs associated with coal mining (to the

Figure 2.1 Economic Rationale for Renewable Energy: Optimal Quantity (Q_{FIN}) at Financial Cost of Thermal Energy (P_{FIN})

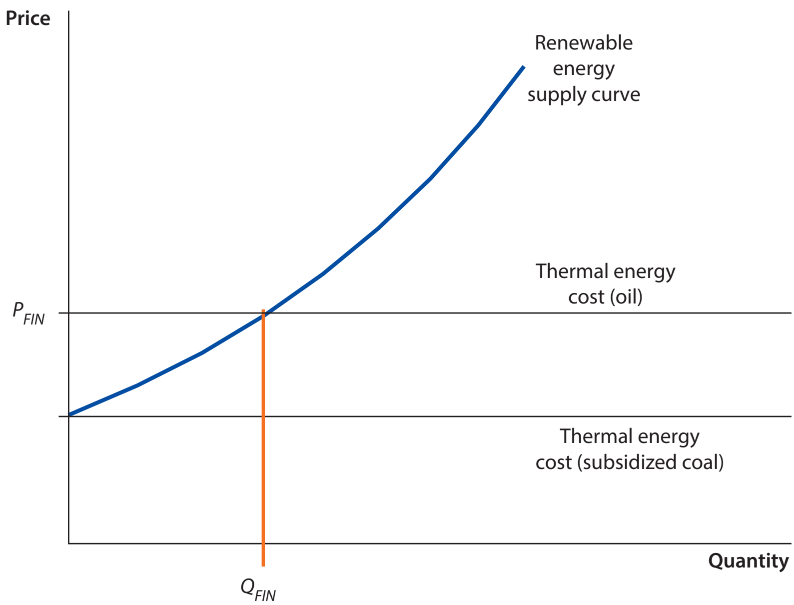


Figure 2.2 Optimal Quantity (Q_{ECON}) at the Economic Cost of Thermal Energy (P_{ECON})

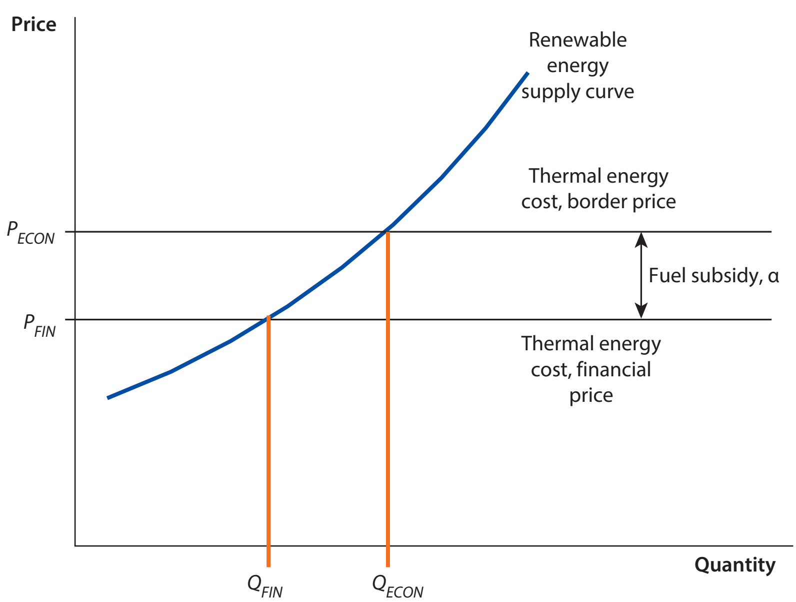


Table 2.1 Externality Costs of Coal Generation

	Rand cents/kWh	*US cents/kWh*
Positive externalities	18.00	2.40
Negative externalities		
Combustion air pollution	−1.35	−0.18
Biodiversity loss	−0.70	−0.09
Acid mine drainage	−2.10	−0.28
Fuel production health impacts (coal mining)	−0.36	−0.05
Total negative externalities	−4.51	−0.60
Net benefit	13.49	1.80

Source: Edkins and others 2010.
Note: kWh = kilowatt-hours.

extent these are not already reflected in the economic cost of coal supplied to a coal-burning project).

As shown in the example of South Africa, in the case of coal these externality costs may be substantial (table 2.1). Nevertheless, there are also positive externalities to be included, which as shown in this table exceed the negative externalities—these benefits derive mainly from the avoidance of the health effects from indoor air pollution associated with kerosene lighting and diesel self-generation. However, while these net benefits are relevant for evaluation of the no project alternative, when comparing coal with RE alternatives these same benefits also accrue to RE, so it is only the comparison of the *negative* externalities that matter.

Such environmental damage costs represent real economic costs to the national economy, and their avoidance should be reflected as a benefit in the economic analysis of RE. In effect, the real social cost of thermal generation is its economic price (that is, without subsidy) plus the per kilowatt-hour (kWh) local environmental damage cost. As shown in figure 2.3, at this cost $(P_{ENV}) = P_{ECON} + E$, the economic quantity of RE increases further, to Q_{ENV}.

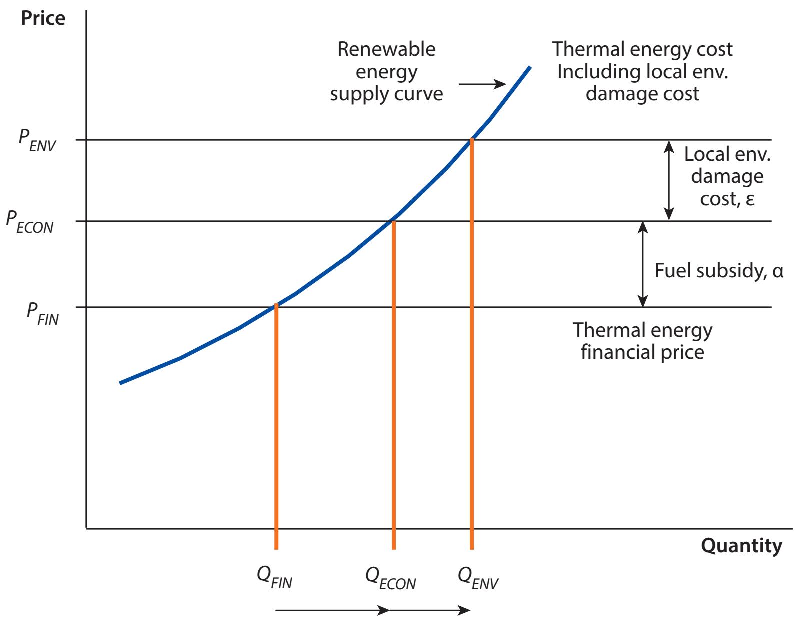
Just this framework was used to underpin the case for RE in China, as is summarized in figure 2.4. The quantity of additional RE increases from 79 terawatt-hours (TWh) to 89 TWh when the environmental damage cost of coal, estimated at 0.4 yuan/kWh (0.48 cents/kWh), is added to the economic cost of coal-fired generation.[5] Appendix C shows how such supply curves can be used in practice to illustrate and estimate incremental costs.

Local Environmental Damage Costs

Table 2.2 summarizes estimates of the environmental damage costs of thermal projects in several developing countries.

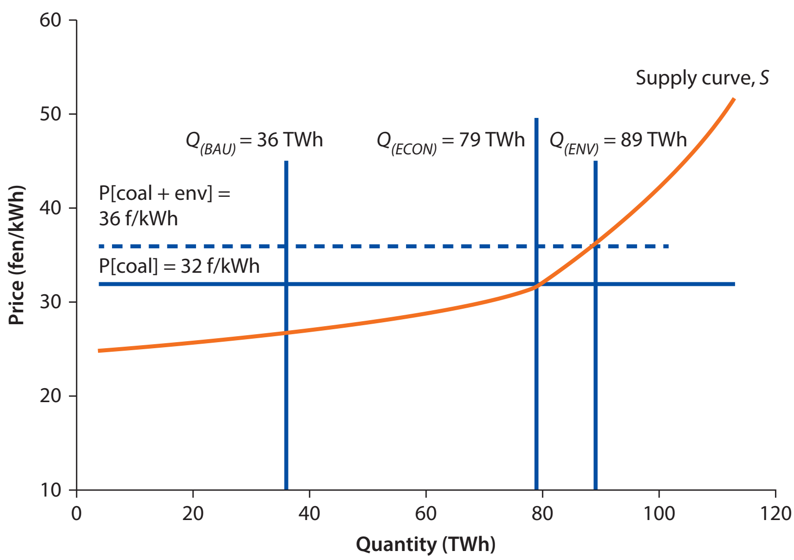
The difficulty with such aggregate damage cost estimates is that they are not transparent with respect to a whole range of important assumptions: the population affected, per capita income, the quality of the fuel (and the efficiency with

Figure 2.3 Optimal Quantity of Renewable Energy, Taking into Account the Environmental Damage Cost



Note: env. = environmental.

Figure 2.4 The Economic Rationale for Renewable Energy: China



Source: Spencer, Meier, and Berrah 2007.
Note: kWh = kilowatt-hours; TWh = terawatt-hours.

which it is burnt), the height of the stack at which the pollutant is emitted, and the pollution control technology in place. Therefore, application of such aggregate per kilowatt-hour emission factors to any specific project comparison, or policy evaluation, can be very misleading. Compounding the difficulty, a significant part of the damage cost from the air pollutant is related to the cost of mortality—how to value the cost of human life is the key question. This is recognized in the latest European Union (EU) studies, which show damage costs based on two main methodologies: the value of statistical life (VSL), and years of life lost (YOLL).[6] Thus, for example, the damage cost estimate per kilogram (kg) of PM-10 (particulate matter no greater than 10 microns in diameter) emissions in Germany varies from €28.9/kg using YOLL, to €81/kg using VSL (EEA 2011).

Perhaps it is not surprising that even using the same methodology across all countries (or across provinces in the large countries), the damage cost estimates for specific pollutants vary widely. In both Europe and China (figure 2.5) regional variations in damage costs span an order of magnitude.

EU and U.S. estimates of health damages are often scaled by per capita gross domestic product (GDP) figures, adjusted by purchase-power parity when transferred to developing countries (the so-called benefit-transfer method).

Table 2.2 Local Externality Damage Costs in Selected Countries

		Cent/kWh	*Date of estimate*	*Source*
India	Coal	1.21	2010	See box 2.1
South Africa	Coal	0.60	2010	See table 2.1
China	Coal	0.1–1.0	2006	World Bank (2005)
Indonesia	Coal	0.32	2010	(1)
	Gas	0.087	2010	(1)
	Heavy fuel oil	2.2	2010	(1)
Egypt, Arab Rep.	Gas CCGT	0.03	2013	NO_X only

Note: (1) see box 5.2 (in chapter 5 of this report) for details. CCGT = combined-cycle gas turbine; CRESP = China Renewable Energy Scale-Up Program; NO_X = nitrogen oxide.

Box 2.1 The Renewable Energy Supply Curve in India

A good example of an renewable energy (RE) supply curve is that prepared by a recent World Bank study for India (Sargsyan and others 2011). The production cost of coal is 5.65 cents/kWh (3.08 rupees [Rs]/kWh), to which is added the estimated local environmental damage cost of 1.21 cents/kWh, which intersects the RE supply curve at about 38 gigawatts (GW). The additional global environmental premium is 2.24 cents/kWh (based on a carbon valuation of \$32/carbon dioxide, CO_2), which enables an additional 13 GW—to bring the total to 51 GW (see figure B2.1.1). This would constitute a rational basis for setting an all-India target for RE.

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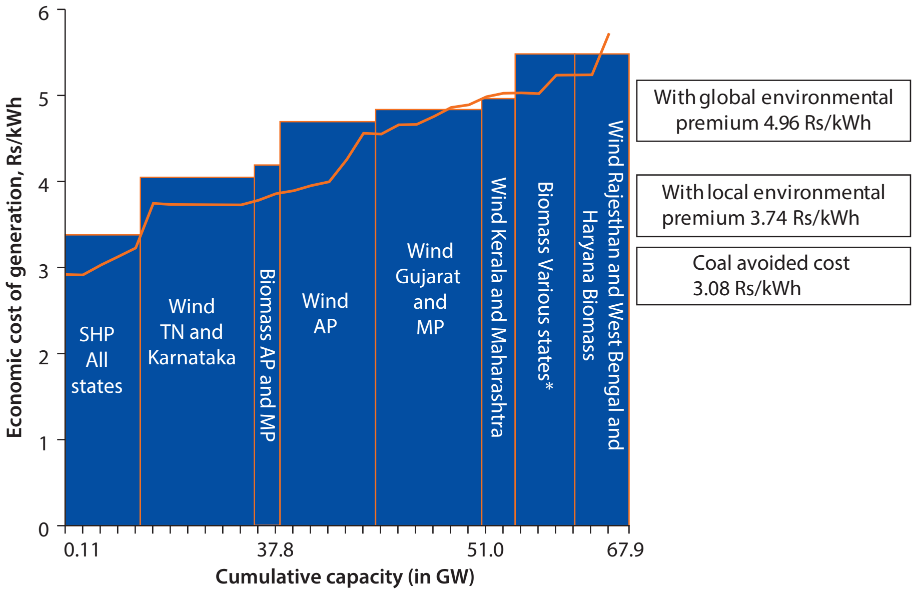
Box 2.1 The Renewable Energy Supply Curve in India *(continued)*

Figure B2.1.1 Renewable Energy Supply Curve in India, by States and Energy Source



Note: SHP = small hydro project; TN = Tamil Nadu; MP = Madhya Pradesh; AP = Andhra Pradesh. $1 = Rs. 54.5.

In the case studies presented in this report, some of the issues associated with such supply curves will be discussed in more detail. For example, India in particular suffers from low (and declining) average load factors in its wind projects, so gigawatt-hours rather than megawatts is the preferred unit of comparison. And different RE technologies also have very different capacity values, which require some adjustment to the RE cost if expressed simply as Rs($)/kWh. But whatever the difficulties, such an analysis is always a better basis for setting an RE target than mere political statement of aspirational goals.

Source: Sargsyan and others 2011.

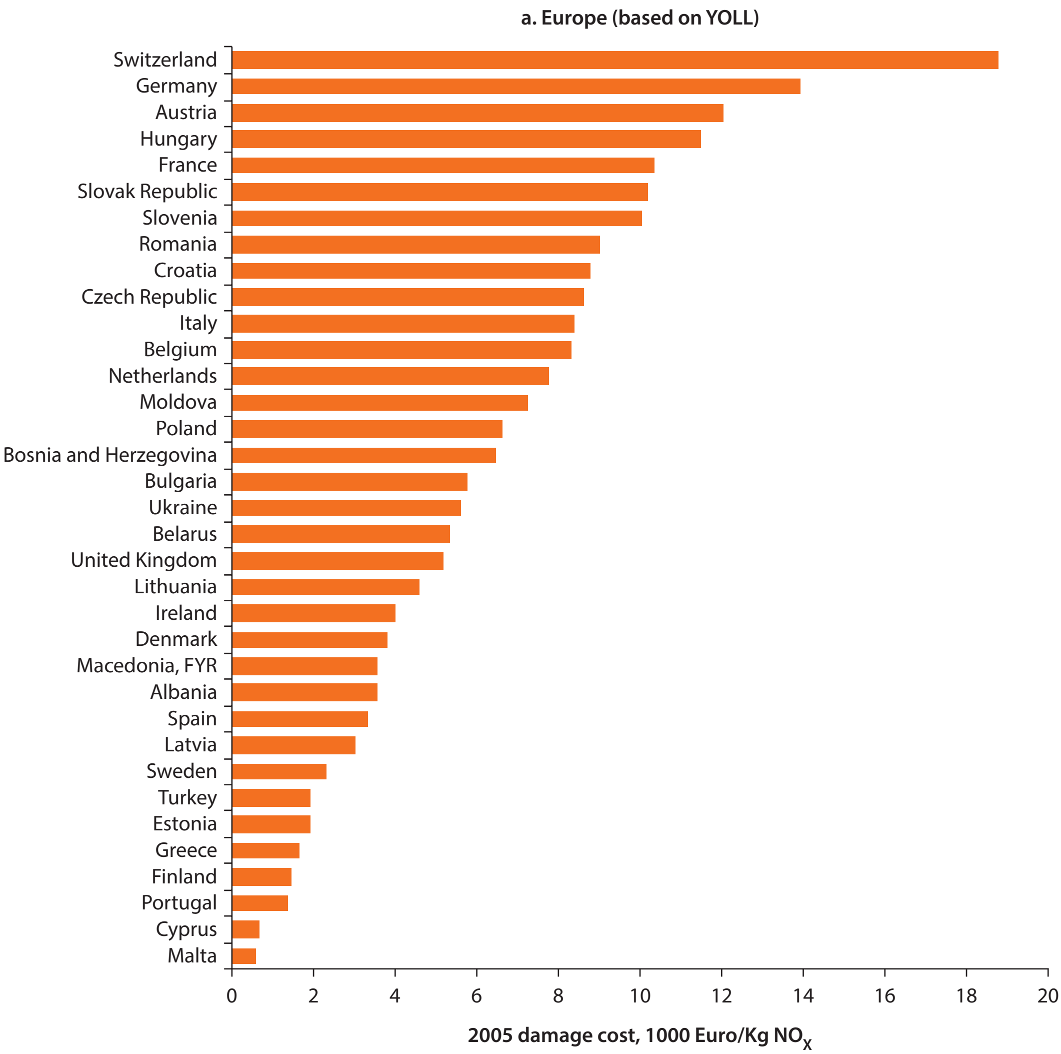
Table 2.3 shows such an exercise for NO_X emissions in the Arab Republic of Egypt, estimated at about 0.1 cent/kWh using the U.K. damage costs. Had the calculation been based on German damage costs, the estimate would be three times higher.[7]

The rationale for such adjustment is therefore doubtful. Figure 2.6 shows the relationship between damage cost estimates for NO_X (as €/kg) versus per capita GDP for European countries. There is little evidence of correlation. The practice of scaling by per capita GDP would certainly not work within Europe, so there is little reason to suppose it would work across developing countries.

These problems were recognized in a 2000 World Bank study that estimated health damage costs from air pollution across six major cities in developing countries. As shown in table 2.4, damage cost estimates varied by two orders of magnitude across (a) ground-level emissions, typical of self-generation, and (b) large-scale utility projects, which have high stacks and are typically located in areas remote from densely populated cities.

The damage cost estimates of table 2.3 are recalculated in table 2.5, using the average values for medium-stack-height emission factors (CCGTs rarely have the sort of high stacks used at coal projects). The damage cost per kilowatt-hour is one-tenth of the benefit transfer estimate listed in table 2.2.

Figure 2.5 Variation in Damage Cost Estimates



Source: EEA 2011.
Note: YOLL = years of life lost; kg = kilogram; NO_X = nitrogen oxide.

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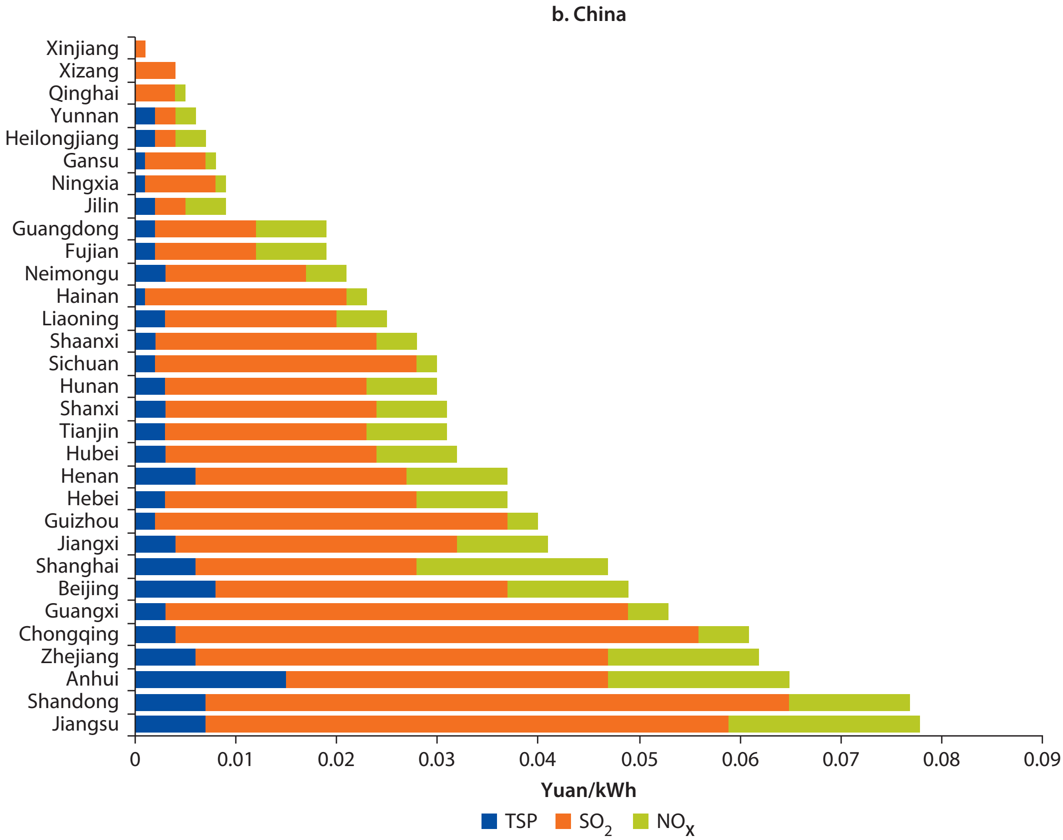
Figure 2.5 Variation in Damage Cost Estimates *(continued)*



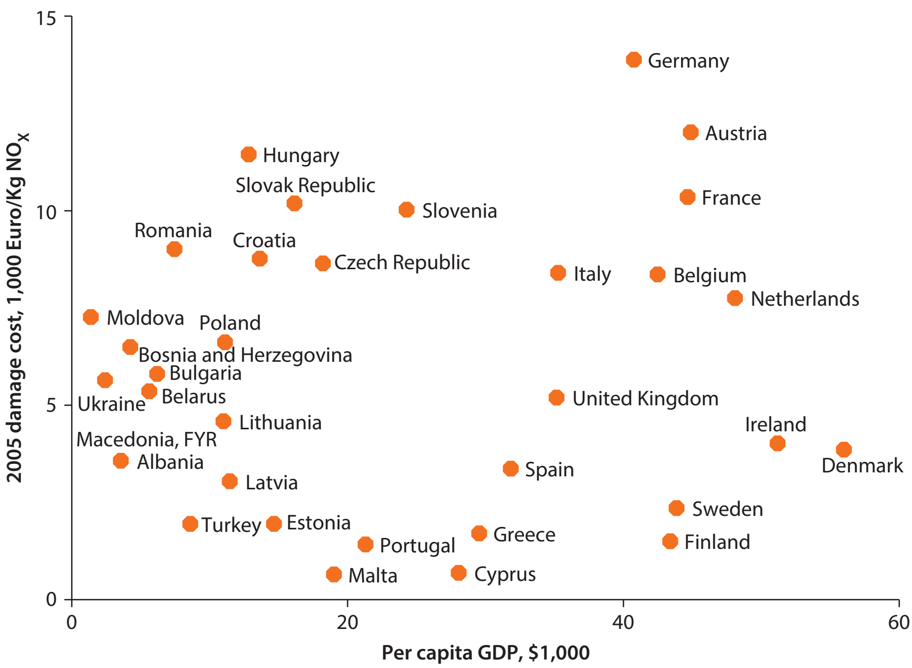
Source: World Bank 2005.
Note: (in 2005, $1 = 8.25 Yuan). The total damage cost in Shandong of around 0.08 Yuan would be (in 2005) 0.97 cent/kWh. In Yunnan the damage cost is one-tenth of this, about 0.1 cent/kWh. NO_X = nitrogen oxide; SO_2 = sulfur oxide; TSP = total suspended particulates.

Table 2.3 Damage Cost of NO_X Emissions from Combined-Cycle Gas Turbines in the Arab Republic of Egypt

		Unit	*CCGT*
1.	NO_X damage cost, utility emissions	2005 €/ton	5,181
2.	NO_X damage cost, utility emissions	$/ton	6,735
3.	Adjusted to 2013 prices	$/ton	8,206
4.	Emission factor	gms/kWh	0.71
5.	EU damage cost	cents/kWh	0.6
6.	PPP Euro zone, per capita GDP	$	35,657
7.	Country PPP	$	7,057
8.	Local damage cost	$/ton	1,333
9.	Egypt, Arab Rep., damage cost	cents/kWh	0.095

Source: World Bank 2013.
Note: CCGT = combined-cycle gas turbine; EU = European Union; GDP = gross domestic product; gms = grams; kWh = kilowatt-hours; NO_X = nitrogen oxide; PPP = purchasing power parity.

Figure 2.6 Damage Costs of NO_X Emissions vs. Per Capita GDP in Selected European Countries



Source: Data from EEA 2011.
Note: GDP = gross domestic product; kg = kilogram; NO_X = nitrogen oxide. Three outliers—Switzerland, Norway, and Luxembourg—have been removed, as their economic conditions are unique in Europe.

Table 2.4 Damage Cost Estimates ($/ton Emissions per Million People per $1,000 of Per Capita GDP Income)

	High stack (modern power plants)	*Medium stack (large industry)*	*Low stack (small boilers and vehicles)*
PM-10			
Range	20–54	63–348	736–6,435
Average	42	214	3,114
SO_2			
Range	3–8	10–56	121–1,037
Average	6	33	487
NO_X			
Range	1–3	3–13	29–236
Average	2	9	123

Source: Lvovsky and others 2000.
Note: GDP = gross domestic product; PM-10 = particulate matter (no greater than 10 microns in diameter); NO_X = nitrogen oxide; SO_2 = sulphur dioxide.

Table 2.5 Damage Costs of NO_X Emissions from Combined-Cycle Gas Turbines in the Arab Republic of Egypt

		NO_X
Damage cost	\$/ton/million population/\$1,000 GDP	9
GDP (PPP)	\$1,000/capita	7.1
Population	Million	2
Cost per ton	\$/ton	127.8
Emission factor, CCGT	gm/kWh	0.71
Damage cost	Cent/kWh	0.009

Source: World Bank 2013.
Note: CCGT = combined-cycle gas turbine; GDP = gross domestic product; gm = grams; kWh = kilowatt-hours; NO_X = nitrogen oxide; PPP = purchasing power parity.

The point is simply that there is high uncertainty in the cost estimates for local environmental externalities. This means that, in turn, targets for RE set on the basis of such estimates are also associated with similar uncertainties—though the impact in practice will also depend on the slope of the RE supply curve.

Discount Rate

Supply curves are based on a ranking of potential projects according to their levelized cost of energy, defined as:

$$LCOE = \frac{\sum_{i=1,..n} \frac{C_i}{(1+r)^i}}{\sum_{i=1,..n} \frac{E_i}{(1+r)^i}}$$

where

r = Discount rate
$LCOE$ = Levelized cost of energy
E_i = Net energy generation in year i
C_i = Economic cost incurred in year i
n = Economic life

The levelized cost is thus critically dependent upon the choice of the discount rate. RE is generally more capital intensive than fossil energy, for which a greater part of the cost (of fuel) lies in the future. Consequently, the lower the discount rate, the more favorable RE appears by comparison—which is quoted by some as a reason for using lower discount rates when evaluating RE alternatives.[8]

Discount rates across countries vary: as shown in table 2.6, discount rates in the Bank's RE project portfolio have varied from 8 percent to 15 percent. For example, in the Philippines the rationale for the high 15 percent discount rate (as used in the solar PV program) is that public sector projects ought not to crowd out private sector investment, and that therefore public sector hurdle rates (at least in the energy sector) should be *higher* than the typical weighted average cost

Table 2.6 Discount Rates in World Bank Renewable Energy Projects

Country	*Rate (%)*	*Renewable energy technologies evaluated*
Philippines	15	Solar homes (PV)
Peru	14	Small hydro, solar homes (PV) (Peru Rural Electrification Project)
India	12	Solar homes (PV), small hydro
China	12	Small hydro, wind, bagasse, landfill gas
Vietnam	10	Large and small hydro
South Africa	10	Landfill gas, small hydro, pulp and paper cogeneration: Renewable Energy Market Transformation Project (carbon finance for renewables)
Sri Lanka	10	Small hydro, wind, village (micro) hydro, solar homes
Cape Verde	10	Wind
Croatia	8	Biomass (combined heat and power), wind, small hydro

Note: PV = photovoltaic.

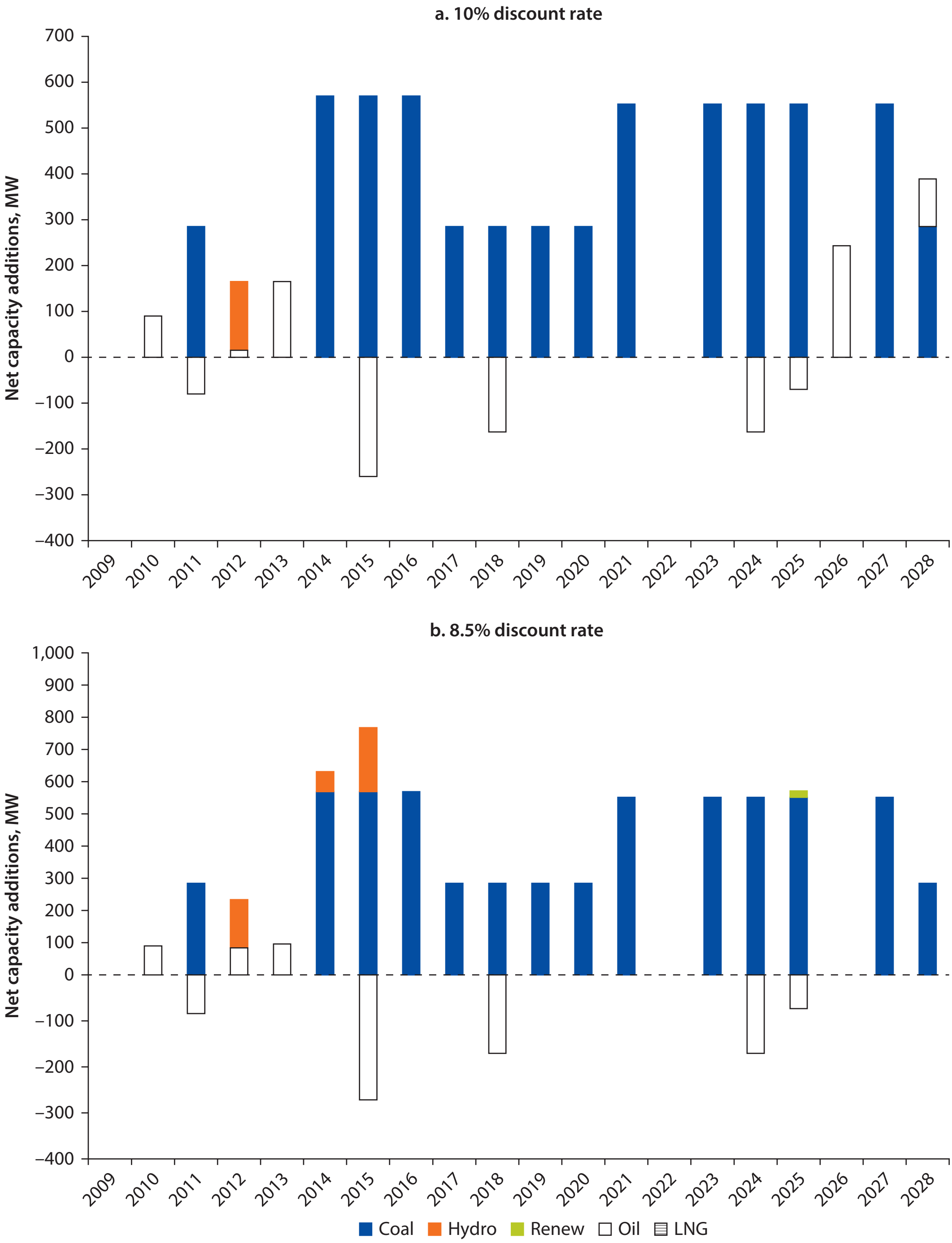
of capital (WACC) for private sector companies. If one argues that the optimal quantity of RE is given by the intersection of the RE supply curve with the avoided social cost of thermal generation (that is, including the cost of externalities), the same discount rate should be used for both sets of calculations. If the discount rate used in the least-cost expansion plan is 10 percent, one cannot justify a comparison with an RE option whose levelized costs are calculated on the basis of a 6 percent discount rate.

Low discount rates should be used with caution, and should not be used merely as a substitute for attempting quantification of environmental impacts. At the same time, they do need country-by-country scrutiny. For example, almost every country that uses formal capacity expansion planning models (such as WASP or EGEAS) use 10–12 percent as the discount rate. At least in theory, the discount rate used for power sector planning should reflect the Government's actual opportunity cost of capital (OCC)—which may or may not be 10–12 percent as is often assumed.

That such a rate is not always appropriate is illustrated by the recent example of the economic analysis for the proposed Noor II & III concentrated solar power (CSP) projects in Morocco (World Bank 2014), where the state-owned Morocco power utility ONEE has long used 10 percent (real) for its discount rate in its least-cost planning studies. One measure of the Government's actual OCC is the cost of recent bond issues in foreign currency,[9] for which a nominal rate of 6 percent would be reasonable.[10] Given an inflation assumption of 2 percent (for both Morocco inflation and trade-weighted FOREX), the corresponding real rate would be 4 percent. Now it might be argued that *additional* $2 billion bond issue earmarked expressly for CSP would require a somewhat higher coupon rate, a reasonable assumption for the real discount rate used for economic analysis would be 5 percent. That is significantly lower than the standard 10 percent assumption, and has a correspondingly large impact on the results. The main lesson here is simply that an economic analysis needs to examine a range of discount rates.

Figure 2.7 illustrates the impact of the discount rate on Sri Lanka's capacity expansion plan. Much as expected, at the lower discount rate of 8.5 percent, the

Figure 2.7 The Impact of a Discount Rate on an Optimal Capacity Expansion Plan: Sri Lanka



Source: World Bank 2010a.
Note: Negative numbers indicate retirements. LNG = liquefied natural gas; MW = megawatts.

planning model chooses to build additional medium-scale hydro projects in 2014 and 2015, reducing the need for additional combustion turbine capacity. In the later years of the planning horizon, the model builds additional coal capacity, rather than the combustion turbines built in the reference case using a 10 percent discount rate.

The Social Cost of Carbon

In economic analysis, the relevant global environmental premium is not the financial revenue that may be obtained from the sale of carbon credit on global carbon markets, but the global *social* cost of carbon (SCC) that reflects the actual damage costs of increasing atmospheric concentrations of greenhouse gases (GHGs).

The literature on the SCC is growing, with estimates ranging from a small net *benefit* to costs of several hundred dollars a ton. Thus almost any estimate would find some support. Tol's (2008) meta-analysis of peer-reviewed literature—which updated an earlier 2005 meta-analysis (Tol 2005)—cites 211 studies, and finds an average estimate of $120/ton carbon ($33/ton CO_2) for studies published in 1996–2001, and $88/ton carbon ($24/ton CO_2) for studies published since 2001. Tol concludes in the 2005 study that "it is unlikely that the marginal damage costs of emissions exceeds $50/ton carbon ($14/ ton CO_2) and are likely to be substantially lower than that."

Much of the economics literature on the subject is highly technical, particularly with respect to the choice of discount rate and assumptions about future global economic growth and income inequalities: in general one can say that the lower the discount rate, the higher the SCC (a value that may also change over time). The high valuation given in a report by Stern (2007) ("the current SCC might be around $85/ton CO_2") is largely a consequence of the use of a very low discount rate.[11] A 2007 Intergovernmental Panel on Climate Change (IPCC) report highlighted the wide range of SCC estimates, given in the literature as $4–$95/ton CO_2. In the United States, regulatory impact analysis requires consideration of the SCC[12] using a range of discount rates (from 2.5 percent to 5 percent), with carbon values that increase over time. For example, at a 5 percent discount rate the valuation is $12/ton in 2015, rising to $27/ton by 2050; at a 2.5 percent discount rate the valuation rises from $58/ton to 98$/ton by 2050. In the United Kingdom the Department of Environment recommended, in 2007, a value of £25/ton ($37/ton) CO_2[13]; this was subsequently updated to a time-dependent system ranging from £23/ton CO_2 in 2015 rising to £48/ton by 2025 ($36–$76/ton CO_2).

The World Bank—like other international financial institutions (IFIs), such as the Asian Development Bank (ADB) and African Development Bank AfDB)—does not publish an official estimate of the value of the SCC to be used in economic analysis. In the typical economic analysis of RE projects, recent practice has been to calculate the economic rate of return (ERR) with and without consideration of GHG emissions. The choice of valuation is left to the economist assigned the task of estimating the economic returns (table 2.7).

The approach taken in this study is not to choose any particular value for the SCC, but to calculate the *avoided cost of carbon* associated with a particular RE option. This is the value of CO_2 that makes the cost of an RE project exactly equal to the least-cost thermal alternative. What is particularly important about such calculations is that they *only* have meaning relative to the option against which the RE is being compared. For example, in South Africa, where concentrated solar power (CSP) would be compared to coal (which has a high GHG emission factor), the avoided cost of carbon for CSP is much lower than in Egypt, where the comparison is with natural gas, whose emission factor per net kilowatt-hour (in a highly efficient CCGT) is just one-third that of coal (table 2.8).

In this report the calculations presented for the avoided cost of GHG emissions are based on discounted GHG emissions (using the same rate as costs and benefits are discounted): in this definition, the avoided cost, in $/ton, is defined as the value that must be given to a ton of avoided GHG emissions (i.e., a benefit)

Table 2.7 Carbon Valuations in World Bank Studies and Project Appraisals

Country	*\$/ton CO_2*		*Reference*
India	32		Sargsyan and others 2011
Indonesia	30	Geothermal project appraisal	PAD
Vietnam	30	Trung Son hydro project	PAD
Egypt, Arab Rep.	5–50	Wind Power Development Project	PAD
South Africa	29	Medupi coal project	PAD
Morocco	30	Ourzazate I CSP	PAD
Central Asia	13–43	CASA-1,000 transmission project	PAD
EEA	44		
IPCC	4–95		

Note: EEA = European Environment Agency; ton CO_2 = ton of carbon dioxide; PAD = Project Appraisal Document (of the World Bank); CASA-1000 = HVDC transmission project to export summer hydro surplus from the Kyrgyz Republic and Tajikistan to Afghanistan and Pakistan.

Table 2.8 The Avoided Cost of Carbon for Concentrated Solar Power

Country	*Technology*	*Production cost, cents/kWh*	*Carbon shadow price, \$/ton CO_2*
South Africa	Medupi coal = least cost	5.8	0
	CSP no storage, 25% LF	14.8	115
	CSP storage, 40% LF	17.0	143
	CSP storage Eskom estimate	17.9	155
Egypt, Arab Rep.	Kom Ombo (1) (against Gas CCGT)	—	267

Source: South Africa: World Bank 2010b, 2013.
Note: CSP = concentrated solar power; CCGT = combined-cycle gas turbine; CO_2 = carbon dioxide; Eskom = Electricity Supply Commission of South Africa; kWh = kilowatt-hours; LF = load factor; ton CO_2 = ton of carbon dioxide; — = not available.
(1) see chapter 8 for a detailed discussion of the Kom Ombo project.

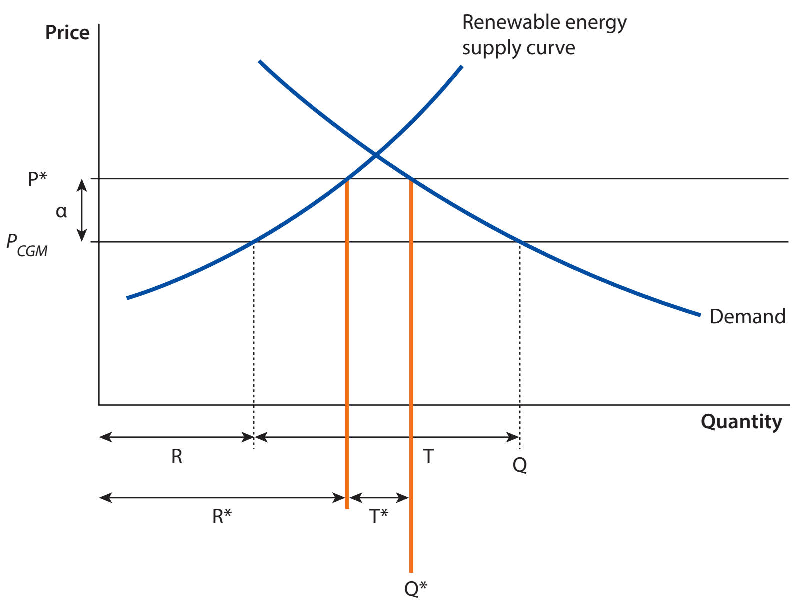
to bring the incremental costs of a RE option to the hurdle rate. It could also be termed the *switching value* as used in sensitivity analysis and risk assessment. Note that this differs to the term "marginal abatement cost" of GHG as used by the CTF and GEF, in which the net present value of costs and benefits (at the discount rate used) is divided by the undiscounted lifetime GHG emissions (i.e., assuming a zero discount rate). In general one should avoid arithmetic operations on quantities based on different discount rates. The calculation based on undiscounted emissions will typically be 50–60 percent lower than in the switching value definition.[14]

Fossil-Fuel Price Subsidies

The impact of fuel subsidies is readily illustrated. Consider figure 2.8, which shows the demand for electricity, the RE supply curve, and the price of thermal energy in a competitive generation market, P_{CGM}, assuming that the coal price is subsidized in the amount α. The quantity consumed at this price, Q, is given by the intersection of the demand curve with P_{CGM}. The quantity of renewables will be R (namely that quantity whose production cost is less than P_{CGM}), and the balance will be fossil generation, T ($R + T$ = Q).

Now suppose that the subsidy on domestic coal is removed, which increases the price to P^*. At this higher price, the demand curve intersects at Q*. More RE will be economic at the higher price P^*, and the quantity of fossil energy reduces to T^* ($R^* + T^*$ = Q*).

Figure 2.8 Impact of Coal Price Subsidies



Thus there are three important consequences of reducing the subsidy on coal:

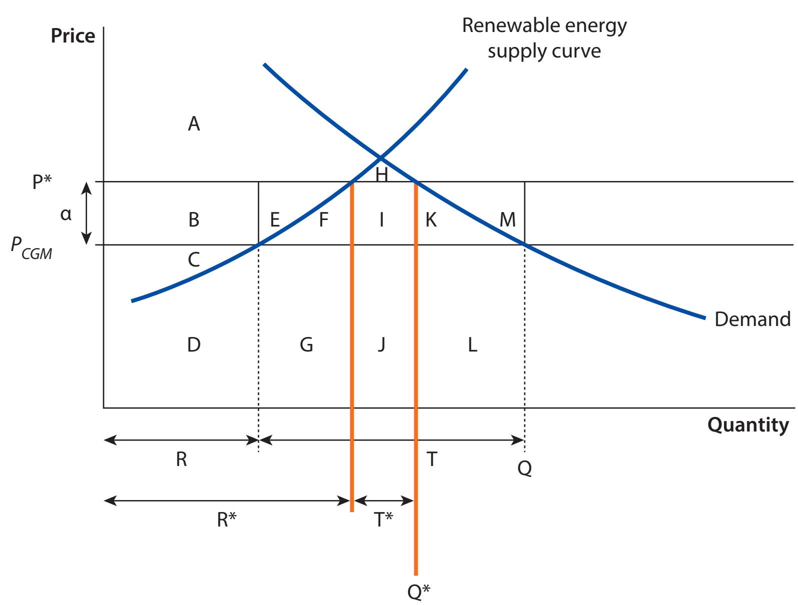
- Less electricity is consumed.
- The amount of fossil energy, and hence GHG emissions, is reduced.
- The amount of RE increases.

It is easily shown (in box 2.2) that both social and global welfare increases as a result of the elimination of the subsidy: the reduction in fossil-fuel subsidies is a win-win.

The International Energy Agency (IEA 2012) Energy Outlook[15] estimates subsidies on energy consumption in the largest countries outside the Organisation for Economic Co-operation and Development (OECD) at \$523 billion in 2011—almost \$110 billion higher than in 2010, based on the IEA's price-gap methodology (figure 2.9). This applies to several of this report's case study countries (Egypt, Vietnam, Indonesia, South Africa, and Brazil). Most countries

Box 2.2 The Welfare Impacts of Fuel Subsidies

The cost of a fuel subsidy to a government is ***Tα***, equal to the area ***E*** + ***F*** + ***I*** + ***K*** + ***M***. At the subsidized level of consumption ***Q***, consumers enjoy a net benefit equal to the area under the supply curve less their cost, the so-called consumer surplus, equal to the area ***A*** + ***B*** + ***E*** + ***F*** + ***I*** + ***H*** + ***K***. RE producers enjoy the producer surplus **C**. And GHG emissions are ***Tα*** where ***α*** is the relevant emission factor.



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Box 2.2 The Welfare Impacts of Fuel Subsidies *(continued)*

Once the subsidy is eliminated, the government benefits by the amount of that subsidy. The consumer surplus shrinks to ***A* + *H***, but RE producers increase their surplus to ***C* + *B* + *E***. So the balance of costs and benefits can be shown as in table B2.2.1.

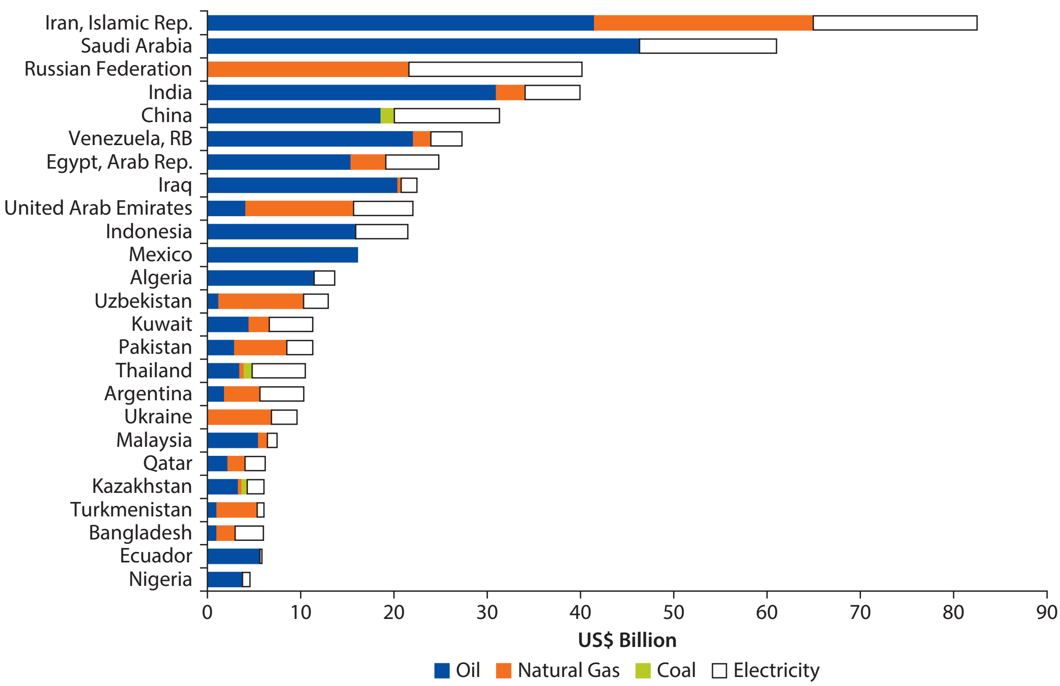
In other words, society gains (because the cost of the subsidy *exceeds* the increase in consumer surplus enjoyed under the subsidy), *and* the global environment gains (because there is less fossil generation).

Table B2.2.1 The Welfare Impact of Subsidy Removal

	With subsidy	*No subsidy*	*Net impact*
Government (subsidy cost)	−E − F − I − K − M	0	+E + F + I + K + M
Consumers	+A + B+ E + F + H + I + K	A + H	−B − E − F − I − K
RE producers	+C	C + B + E	+B + E
Society	A + B + C + H − M	A + B + C + B + E + H	+E + M
Global environment	Tα	T*α	α(T − T)

Note: RE = renewable energy.

Figure 2.9 Energy Subsidies, by Fuel, in Non-OECD Countries



Source: IEA 2012.
Note: OECD = Organisation for Economic Co-operation and Development.

have declared policies to eliminate these subsidies, but implementation is almost always slower than the announced schedule, for sudden removal of subsidies often has significant political repercussions. Vietnam is a case in point: notwithstanding the declared intention of removing subsidies for fuels used in power generation, and the commitment to market principles declared in the Electricity Law, both domestic coal and natural gas prices for power generation remain subsidized.[16]

Renewable Energy and Employment

A widely cited benefit of RE is employment creation.[17] But assessment of the benefits of increased employment requires caution. Economic analysis normally treats the cost of labor as an *input*, not as an output. A highly labor-intensive biomass technology may create local employment, but if the economic costs of the biomass project are above the avoided social costs, then employment in the economy as a whole may fall (because if households spend more on electricity, they will spend less on other goods and services).

The argument that RE development will create "green jobs" is frequently heard in the United States, European countries, and some developing countries (such as China). Generalizations from limited country experience, mainly in RE equipment manufacturing in the OECD countries, are no substitute for careful country-specific analysis; more research is needed to better understand the issue of green jobs.

The large employment benefits noted in such countries are a consequence of RE technology manufacture, particularly in countries that manufacture and export equipment, such as Spain and Denmark in the case of wind power (see box 2.3). So the question is: what is the extent to which these job gains apply to countries that do not have domestic manufacturing capacity for renewable generating equipment or reasonable prospects for doing so?

Another question that needs to be answered is whether such studies on the job creation benefits of RE also include the loss of jobs in those energy industries that are displaced by the RE. In countries where there are large benefits from RE replacing coal, more RE could mean fewer coal miners, and lower employment in factories that manufacture gas turbines and coal-fired steam generators.

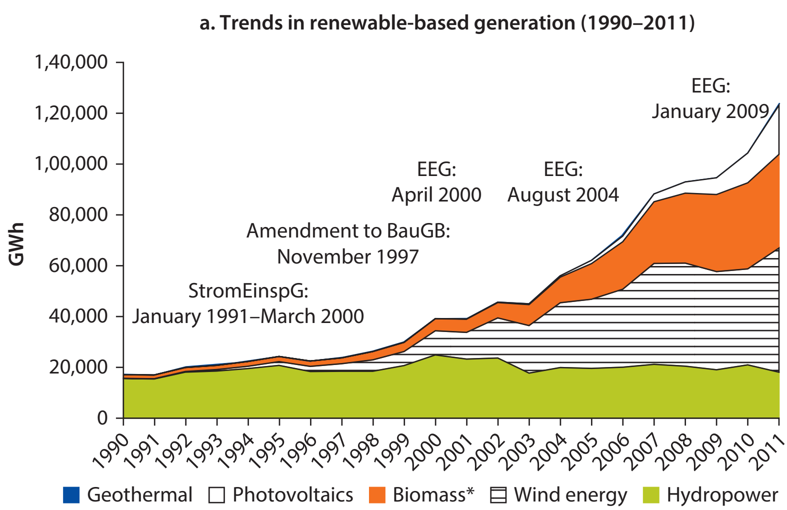
Within this context it is important to build a methodology to (a) contribute to a better understanding of the main effects/mechanisms to depict employment impacts and (b) provide a clear definition of gross impact studies (sectoral) and net impact studies (economy wide). Even if some comparisons indicate that RE and energy efficiency projects generated more employment than fossil fuels, such comparisons fail to consider both the costs of delivery of equal outputs using different fuel mixes and the cost of public funds. Such simplifying assumptions may lead to misleading estimates. First, the lack of evidence on the cost of using alternative energy sources to generate the same

Box 2.3 Lessons Learned from the German *Energiewende* (Energy Transition)

The ideas presented in a book titled *Energiewende* (Energy Transition) by Öko-Institut Freiburg found fertile soil in 1980 in Germany, in the context of anti-nuclear protests, two oil crises, fears of acid rain, and the emerging climate-change problem. It made the case for a change—a transition from fossil fuels over to renewables and energy efficiency. This thinking inspired the Erneuerbare-Energien-Gesetz (EEG or the Renewable Energy Sources Act) of 2000 and its 2004 amendment. Both were adopted by Social Democratic-Green parliamentary groups against intense Conservative-Liberal opposition that came back to power in 2009. In the meantime, the EEG had a strong impact: (a) it was highly effective in stimulating RE with growth and investment, increasing new renewable energy (RE) output (other than hydro) by a factor of five from 2000 to 2011 (see figure B2.3.1); (b) it created a strong wind power, biomass, and photovoltaic (PV) industry, which generated new employment for about 365,000 persons by 2012 (see figure 2.3.2, panel b); and (c) over 50 percent of new RE generation capacity is owned by private persons and farmers (see figure B2.3.2, panel b). All utilities together own from 2 percent to 7 percent (PV, wind)—only for hydro does this go up to 90 percent (see figure B2.3.2, panel a).

There were three Conservative-Liberal attempts to slow down Energiewende in 2010, by scrapping the nuclear phase-out (a bridge technology for renewables), planning caps and steeper degressions for RE, and introducing a flexible cap for PV energy to limit new PV installations to 3 GW per year. In 2012 a plan for new, more drastic caps on PV and other technologies was implemented, and in 2013 there was a proposal to cap the EEG surcharge. From the Conservative-Liberal perspective several emerging issues needed to be addressed. First, the extraordinary deployment of PV since 2009, which surpassed all expectations and cost estimates; the dramatic increase in the EEG surcharge from €1.3 to

Figure B2.3.1 Development of Renewables-Based Electricity Generation and Investment



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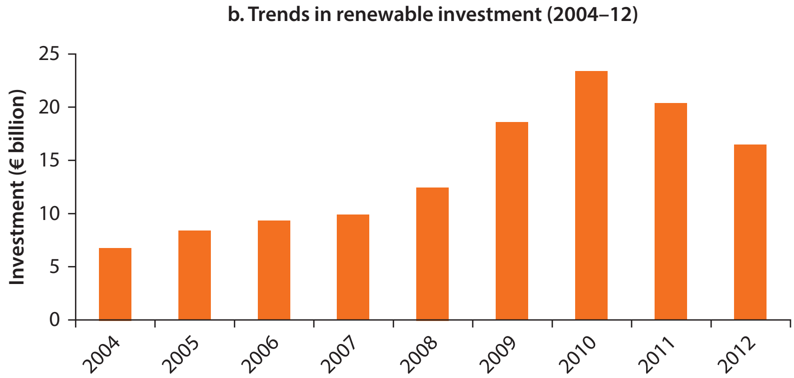
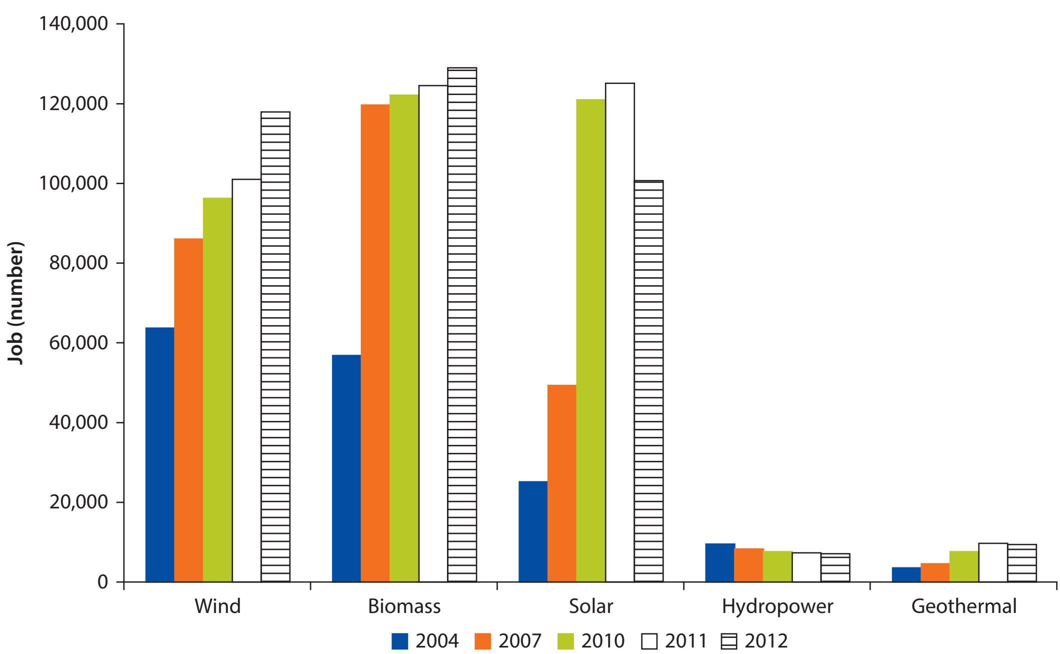
Box 2.3 Lessons Learned from the German Energiewende (Energy Transition) *(continued)*

Figure B2.3.1 Development of Renewables-Based Electricity Generation and Investment *(continued)*



Note: EEG = Renewable Energy Sources Act; GWh = gigawatt-hour.

Figure B2.3.2 Development of Renewables-Based Jobs and Ownership, 2012



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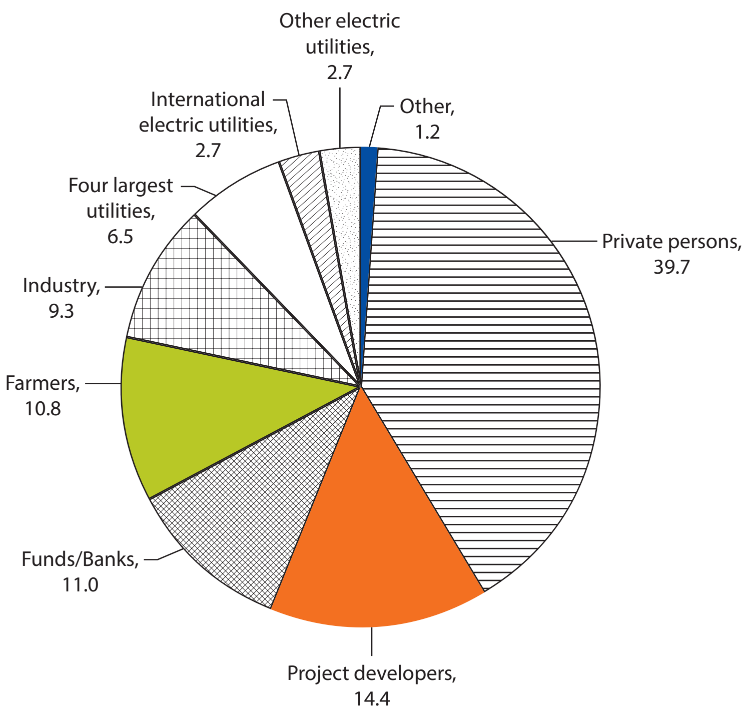
Box 2.3 Lessons Learned from the German Energiewende (Energy Transition) *(continued)*

Figure B2.3.2 Development of Renewables-Based Jobs and Ownership, 2012
(continued)



€5.28 cents from 2009 to 2013; an "imminent" grid congestion from PV and wind technologies; damage to profitability of needed fossil-fuel generation due to the priority dispatch for RE, which implies that hard coal and gas plants lose lucrative operating hours (the noon peak demand is now increasingly covered by PV); and gas generation being affected by cheap coal due to low U.S. shale gas and Emission Trading System (ETS) prices.

Source: Lauber 2013.

output may lead to overestimating the net benefits of job creation by RE and energy efficiency projects (relative to fossil-fuel projects), by not including their cost. A rigorous methodology should first differentiate and illustrate trade-offs among (a) local, regional, and national impacts and (b) short- and long-run impacts. Second, it should illustrate the extent to which classic economic project analysis does not adequately reflect the employment-creation objectives of the government. Third, it must capture distributional impacts (since subsidies to cover incremental costs of RE may have very different beneficiaries) and employment-related externalities. Fourth, it might compare, where possible, alternative projects based on equivalent output and cost between

(a) renewable-energy and energy-efficiency projects and (b) fossil-fuel projects. To our best knowledge, no study reviewed to date compares projects costing the same amount (or producing the same output) along both employment and cost metrics.

Of course, it is perfectly valid for governments to stimulate employment in disadvantaged areas of a country, even at the cost of lower employment in richer urban areas, if this is viewed in the context of social equity. But an important distinction might be noted: promoting employment in specific regions reflects the ***equity*** objective of the government, and not the economic-efficiency objective.

The correct approach for economic analysis is to shadow-price labor costs.[18] For example, the economic cost (or the *opportunity* cost) of employing otherwise unemployed rural workers is zero—and different to the actual wage rate that would be used in the financial analysis. But few RE projects will have much need for unskilled labor, whether during construction, or during operation (when unskilled labor, at best, would extend to the security staff at a wind farm or a CSP project).

Specific Questions for the Case Studies

The analytical framework requires that the effectiveness of incentive mechanisms be assessed and compared by a set of rational criteria, as follows:

- *Economic efficiency*. How close is an RE support tariff to the avoided social cost of thermal energy (which for developing countries means economic cost + avoided local externalities)? How close is the target quantity to the economic optimum (intersection of the economic supply curve with the avoided social cost of thermal energy)?
- *Market principles.* Does the design require the application of market principles? An auction meets this criterion perfectly (provided there are safeguards against collusion and abuses). Access to a subsidy on the basis of first come, first served, or "all come" (as in Germany's feed-in tariff, FIT) does not meet market principles (and constitutes the worst possible way of providing access to support).
- *Transparency.* Is the methodology of preferential pricing published? Can developers and their lenders come to their own conclusions about the future evolution of the tariff level? Does the mechanism provide for adjustment to changes in the law?
- *Sustainable recovery of incremental costs.* Are the incremental costs known? (In a surprising number of cases they are not!) Is the mechanism for recovery of these costs sustainable (that is, is the mechanism for raising the necessary funds, and for disbursing them, seen as credible by developers and their lenders)?
- *Adaptability.* Is there a predictable mechanism for updating the tariff and adjusting it for external changes (changes in technology costs, changes in tax rates, changes in fossil energy prices in the case of ACTs)?

The evaluation of the policy framework should similarly follow a set of rational criteria:

- *Targets.* Are the targets set as political statements, or on the basis of a rational economic analysis (supply curve methodology, or affordability)? Are targets reasonably achievable, and are they in harmony with the support measures necessary to achieve them? In the case of renewable portfolio standards (RPSs) and mandatory renewable shares, are the penalties for not meeting them reasonable?
- *Energy subsidies.* How does the additional quantity of RE—made economic by reducing fossil-fuel subsidies—compare with the quantity of RE to be supported by RE incentives? How does the quantity of thermal energy that would not be required if retail tariff subsidies were eliminated compare with the quantity of RE supported by targeted RE incentives?

Methodology

For each of the case study countries, the following set of calculations will be presented:

- From the current least-cost power sector development plan, the expected generation mix for 2020, the generation shares and gigawatt-hours of each major fuel and technology, and the gigawatt-hours of retail sales.
- Estimate of the consequences if 1 percent of generation were replaced by RE. What would be replaced is the most expensive of the thermal generation, by some RE whose tariff could be calculated to provide the developer with a target financial internal rate of return (FIRR) based on typical commercial lending rates. This allows a calculation of the total financial incremental costs—and the impact on consumers were this amount to be recovered from them.
- An estimate of the tariff (and incremental cost) decrease prompted by the various incentives listed in table 1.1 (taxonomy of incentives): a clean development mechanism (CDM), carbon finance, subsidized loans from government-owned development banks, tax incentives, and so on.
- A comparison of the impact on the consumer from reducing any fossil-fuel subsidies. Reducing fossil-fuel subsidies would increase the generation cost passed to the consumer, for which there is also a GHG emission reduction benefit. How does this compare with the cost to the consumer if the consumer is charged with a levy to recover RE generation costs?
- Finally, a comparison of the residual incremental cost, as may need to be covered from the direct government budget, with government spending on education and health (or some other appropriate indicator of spending for poverty alleviation). This question is core, as developing country governments are reluctant to incur the incremental cost of RE in the face of the overriding objectives of poverty alleviation and economic growth.

Notes

1. Gas delivered to the Ca Mau CCGT project in Vietnam is indexed to the Singapore fuel oil price.
2. Particulate matter (no greater than 10 microns in diameter).
3. Sulphur oxides.
4. Nitrogen oxides.
5. The additional quantity Q_{BAU} is the much lower quantity of renewable energy likely to be implemented in the absence of explicit RE policy, due mainly to institutional and regulatory constraints (such as problems in negotiating PPAs, obtaining permits, and obstacles imposed by utility buyers who have traditionally opposed the emergence of IPPs for fear of losing market share).
6. VSL (value of statistical life) is used in most U.S. and European studies as a basis for mortality and is based on contingent valuation methods typical in American accident liability lawsuits. Most development economists argue that valuations based on YOLL (years of life lost) are more appropriate for the premature mortality typically associated with pollution-aggravated respiratory diseases.
7. The damage cost of $1,333/ton NO_X is consistent with the $473/ton (at 2002 prices) cited in the Bank's 2003 Energy/Environmental Review (though the derivation of that estimate is unclear) (World Bank/EEAA 2003).
8. For example, a study on wind energy in Vietnam (Global Green Energy 2004) argues that "OECD uses a discount rate of 6 percent as standard, thereby justifying a 7 percent rate" (rather than the 10 percent actually used by the Government of Vietnam).
9. In the case of an open economy, capital can be considered a tradable good, and the EOCC will be the world supply price of capital (U.S. treasuries, or long term LIBOR plus some country specific risk premium). Many developing countries now have domestic bond markets which can provide further information.
10. Morocco issued $500 million, 30-year 144a/Regulation S bonds in December 2012 at a coupon of 5.5 percent. The issue was reopened in May 2013 to increase the issue to $750 million for a tap of 237.5 basis points over U.S. Treasuries, and is currently trading at a discount. As such, a nominal discount rate of 6 percent for modeling purposes seems reasonable.
11. For a good discussion of these issues, and a review of the assumptions in the Stern Review, see, for example, Hope and Newbery (2007). See also Grubb, Jamasb, and Pollitt (2008).
12. Interagency Working Group, *Technical Update of the Social Cost of Carbon (SCC) for Regulatory Impact Analysis under Executive Order 12866*, May 2013.
13. DEFRA, *The SCC and the Shadow Price of Carbon*, December 2007; Department of Energy and Climate Change, *Carbon Appraisal in UK Policy Appraisal: A Revised Approach: A Brief Guide to the New Carbon Values and their Use in Economic Appraisal.*
14. The rationale for *not* discounting GHG emissions is that it is the cumulative stock of GHG emissions in the atmosphere that matters, not the time at which it is emitted. However, there is an emerging consensus that the economic benefit of a ton of avoided GHG emissions *increases* over time as the concentration of atmospheric GHGs reaches the tipping point (recall the discussion of SCC, above, and the valuations being used by the U.S. Interagency Working Group on the SCC, and others).
15. The subject first received detailed analysis by the IEA in 1999 (IEA 1999).

16. Whether the use of subsidized fuel prices also distorts power sector investment decisions is unclear. An assessment of the use of financial prices rather than economic prices in Vietnam's Sixth Power Development Plan found little impact on the optimal capacity mix as proposed by the plan (Economic Consulting Associates 2006).
17. An argument made, for example, by Kammen, Nozafari, and Prull (2012).
18. A related problem is the extent to which the cost of accidents and deaths to coal miners should be separately considered as an additional externality and added to the social cost of coal generation (as are included, for example, in the South African damage cost estimates of table 2.1). In economic theory higher occupational health hazards should be reflected in higher wage rates for miners, compared to other potential occupations that experience lower rates of occupational mortality, and hence do not classify as an externality. But this would be true only in a perfectly competitive and mobile labor market. For example, whether miners in the mining areas of northern Vietnam have real alternative employment opportunities (whether in the mining areas or elsewhere in Vietnam) may be debated.

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CHAPTER 3

Case Study: Vietnam

Sector Background

Vietnam has seen major economic growth over the past three decades, and significant progress in reducing poverty. It is a densely populated country that, in the past 30 years, has had to recover from the ravages of war, the loss of financial support from the old Soviet Bloc, and the rigidities of a centrally planned economy. The seeds of this expansion were planted more than two decades ago, with the 1986 launch of the renovation process known as *Doi Moi*.[1] Vietnam has since witnessed a rapid transition to a globalized, market-based economy.

The progress is reflected in the growth of electricity use and the electrification rate. In 1976, the first year after unification, just 2.5 percent of rural households had access to electricity; per capita electricity consumption was 45 kilowatt-hours (kWh)/year, and aggregate consumption was 2,300 gigawatt-hours (GWh). This rose to just 65 kWh/capita in 1985, before the start of *Doi Moi*. But since 1986, average growth has been a dramatic 9 percent: by 2009 consumption reached 72 terawatt-hours (TWh) and by 2012, 105 TWh—an increase of 11.25 percent over 2011 (Gencer and others 2011). Per capita annual consumption has grown from less than 50kWh/capita in 1976 to over 1000 kWh/year in 2013. While there is much uncertainty about future growth rates, especially in light of expected tariff increases, even at a modest 7 percent growth rate, 2020 sales should reach 180 TWh. The electrification rate is now close to 98 percent.

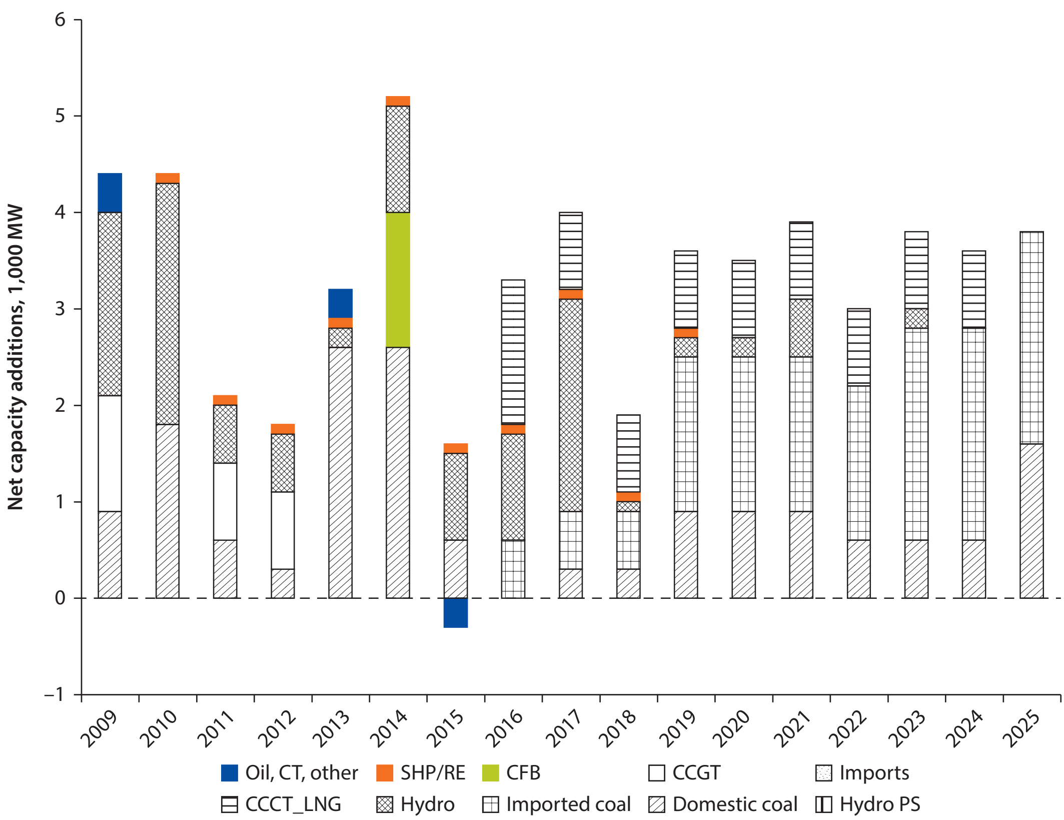
Power Sector Development

Two large hydro projects, Hoa Binh (1,920 megawatts, MW) and Yali (720 MW), both built with Russian assistance, provided the impetus for large-scale electrification of the country. Most of the domestic hydro resources are in the North (and in the Central highlands); all of the domestic coal (anthracite) resources are also in the North, while natural gas is exclusively in the South. These regional disparities were accommodated by the construction of the 500 kilovolt (kV) grid, which connected the major generating projects to the major load centers in Hanoi and Ho Chi Minh City (HCMC). Several large gas-fired combined-cycle combustion turbines (CCCT) have also been built in the South over the past 15 years, some as independent power producers (IPPs).

Figure 3.1 illustrates the least-cost capacity expansion plan by technology. Net capacity retirements are shown as negative entries. This shows that the projected increases in demand will be met by a combination of hydro, gas, and coal—with coal, in particular, playing an increasingly important role, albeit with increasingly sophisticated technologies new to Vietnam (such as supercritical pulverized coal). The domestic anthracite resource is nearing its end, and so the first imported coal-fired generating station is expected by 2017. Most of the large hydro projects, however, will be completed by 2017—the 2,400 MW Son La and the 1,200 MW Lai Chau projects are the last major hydro projects expected in Vietnam itself—and Vietnam is looking to several medium-sized hydro projects in the Lao People's Democratic Republic to supply additional peaking power in the 2015–20 period.

Beyond 2020 the main uncertainties include whether additional gas can be found to fuel combined-cycle gas turbines (CCGTs), whether the energy to gross

Figure 3.1 Vietnam's Capacity Expansion Plan



Source: Meier 2011.
Note: Negative values indicate plant retirements. CCCT = combined-cycle combustion turbine; CCGT = combined-cycle gas turbine; CFB = circulating fluidized bed; CT = combustion turbine; LNG = liquefied natural gas; PS = pumped storage; RE = renewable energy; SHP = small hydro project.

domestic product (GDP) elasticity can be reduced, and whether (and when) Vietnam should commit to nuclear power.

Renewable Energy Development

Vietnam (like China) was one of the leaders in small hydro development long before the linkage of renewable energy (RE) to climate change, the principal motivation being remote rural electrification. But with the expansion of the national grid to even the most-remote provinces, most of these older off-grid small hydros were abandoned during the 1990s (see box 3.1).

The seminal work on RE is the 2001 *Renewable Energy Action Plan (REAP)*, a joint study by the World Bank, the Ministry of Industry and Trade (MoIT), and the electric utility (Electricity of Vietnam, EVN) (Bogach and others 2001). It called for new grid-connected small hydro projects (SHPs), community isolated hydro grids (to electrify up to 90,000 off-grid households), resource data development (especially for wind), 25,000–50,000 household scale systems (photovoltaic [PV] and improved pico-hydro units), and extensive technical assistance (for example, in the development of a standardized power purchase agreement, SPPA) for grid-connected small power producers.

The effort to promote off-grid electrification using RE must be judged a failure—not least because of the much faster expansion of the national grid: by

Box 3.1 Development of Small Hydro in Vietnam

Small hydro development in Vietnam falls into five main phases:

- *1960–75 and 1981–85* saw extensive construction of small hydro projects (SHPs) in remote areas to service mini-grids. Most were built with funds from the state budget for construction of civil works, with equipment imported from China and Eastern Europe.
- *1985–90* saw a diversification of the forms of investment: some projects were funded by the central budget, and many others were built by military units, cooperatives, and local communities (most with provincial assistance).
- *1990–95:* SHP development slowed down due to lack of investment capital for construction of new stations and lack of equipment and spare parts for replacement and repair. At the same time, the national power grid began to expand rapidly into rural areas. The use of pico-hydro units expanded greatly during this era—by some estimates as many as 150,000 such units, each less than 500 watts (W), had come into use.
- *1995–2002:* SHP development slowed down further, and as the grid expanded into remote areas previously served by SHPs, these were abandoned. Some 200 stations of 5–50 kilowatt (kW) capacity stopped operation, many at multipurpose facilities (power and irrigation).
- *2002–present:* There was significant expansion of larger grid-connected SHPs in the 2–30 MW size range, most developed by private developers, particularly provincial construction companies. Pico units have now all but disappeared.

Source: MoIT 2011.

2008 just one district (Muong Te) in the remote province of Lai Chau remained unelectrified. Off-grid projects assisted by the World Bank, the Japan International Cooperation Agency (JICA), and the Swedish International Development and Cooperation Agency (SIDA) made little progress in the face of rapid escalation of civil costs and the difficulties of construction in remote areas.

But the prospects for grid-connected small hydro were much better, and by the end of 2011, the Electricity Regulatory Authority of Vietnam (ERAV) estimated some 590 MW of small hydro had been connected to the grid, greater than the 175–251 MW target established by the Action Plan (see as a counterfactual the small hydro development in Lao PDR summarized in box 3.2).[2] This compares to just a few thousand households electrified by SHPs in off-grid areas, compared to the 10-year target of 90,000–150,000 households.

In 2009, with the assistance of the World Bank, the MoIT prepared a draft Renewable Energy Master Plan (REMP). This plan established targets and proposed to recover the incremental costs of RE by a consumer tariff levy funded

Box 3.2 Counterpoint: Small Hydro Development in the Lao People's Democratic Republic

Small hydro development in the Lao People's Democratic Republic serves as the perfect counterfactual for Vietnam. Notwithstanding the significant potential for small hydro, very little has been accomplished: as of the date of writing, the few grid-connected small hydro projects (SHPs) operating in Lao PDR have a total generation of just 11 megawatts (MW). To date, government policy has been to promote the role of independent power producers (IPPs) through an incentive-based system. Potential developers carry out feasibility studies under a memorandum of understanding (MOU) with the Government of Lao PDR. Yet, while there are currently over 30 active MOUs across the country for small hydropower, few developers have been able to raise adequate finance. Some MOUs are held by speculators, holding attractive sites dormant. Concession agreements are power purchase agreements (PPAs) negotiated on a case-by-case basis.

In 2012 efforts were made to introduce a new approach, following Vietnam's example, with a standardized power purchase agreement (SPPA) and a published tariff, to be issued every five years, and inflation adjusted every year: the tariff proposed a time-of-day structure differentiated by season (compare the tariff in tables B3.2.1 and B3.2.2 with table 3.2 for Vietnam). The tariffs are linked to the utility's (Electricity of Lao) 22 kV tariff, ranging from 95 percent of the tariff for 1 MW projects, to 80 percent for 10–15 MW projects.

The SPPA and new tariff would be available to all SHPs no smaller than 15 MW in size. The approach calls for the government to prepare batch projects (with Asian Development Bank [ADB] assistance), and award to developers by competitive tendering (with awards based on highest royalty). The projects are designed for high heads and minimal storage and based on dry-season flows. The first four projects have the following design parameters: high plant factors and high heads. Costs are in the range of $1,600–$2,100/kW (considerably higher than for Vietnam).

box continues next page

Box 3.2 Counterpoint: Small Hydro Development in the Lao People's Democratic Republic *(continued)*

Table B3.2.1 Standardized Tariffs

Connection capacity (MW)	*Jan–Jun peak*	*Jan–Jun off-peak*	*Jul–Dec Peak*	*Jul–Dec off-peak*	*Weighted average*
0–1	0.1324	0.0543	0.0659	0.0420	0.07631
1–5	0.1254	0.0518	0.0624	0.0398	0.07229
5–10	0.1067	0.0503	0.0611	0.0458	0.06827
10–15	0.1005	0.0474	0.0575	0.0431	0.06426

Note: Exchange rate: $1 = KN 8,055. KN = kip; MW = megawatts.

Table B3.2.2 Project Characteristics

Project		*Nam Hong*	*Nam Hao*	*Nam Long*	*Nam Pe*
Province	*Units*	*Borikhamxai*	*Houaphan*	*Houaphan*	*Phongsaly*
Average flow	m^3/s	12	7	3	4
Design flow	m^3/s	6.1	4.3	1.8	1.6
Gross head	m	237	210	285	380
Net head	m	224	197	267	343
Canal length	m	10,800	11,000	7,279	21,433
Penstock length	m	530	520	966	938
Permanent road	km	8.6	2.4	3.4	3.5
Transmission lines	km	28	0.3	8.7	7.6
Generator output	kW	11,660	7,100	3,800	4,500
Plant factor	%	0.79	0.71	0.73	0.85
Production/year	GWh/year	80	44.2	24.1	34
Overnight cost	$	18.8	12.4	7.3	9.2
Investment per kW	$	1,630	1,740	1,950	2,070
Levelized cost/kWh	$	0.037	0.044	0.048	0.043
Tariff per kWh	$	0.064	0.068	0.072	0.072

Note: GWh = gigawatt-hour; km = kilometer; kW = kilowatt; kWh = kilowatt-hour; m = meter; m^3/s = cubic meters per second.

As of the time of writing, the proposal for an SPPA and a published tariff has not been acted on, and they face opposition both from the developers and the utility. Yet without these essential reforms, it is hard to see substantive progress.

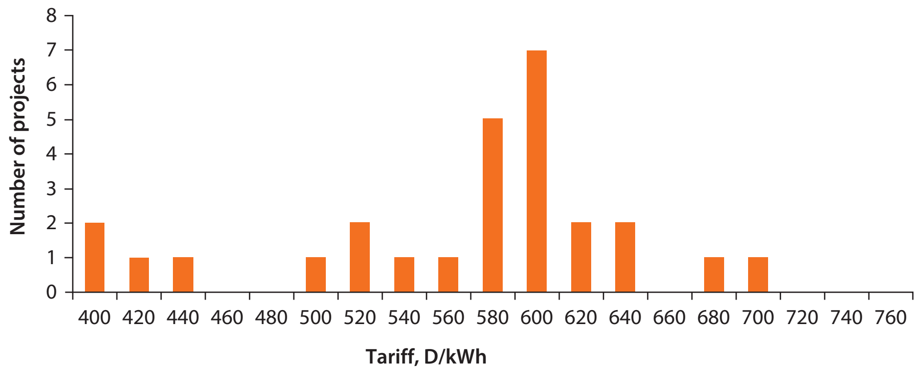
Source: Anderson 2012.

by a Renewable Energy Fund.[3] But both the fund and the consumer levy did not find favor with the government, and the REMP has yet to be approved.

Prior to 2009 small hydro tariffs were negotiated between developers and EVN on an *ad hoc*, project-by-project basis, with tariffs in the range of D575–D625/kWh (2.8–4.4 cents/kWh) (figure 3.2). The process did not work well, as developers gamed the system in the expectation of being negotiated down to a 12 percent rate of return on equity.

January 2009 saw the start of a new system, with the introduction of an SPPA for qualified RE facilities not greater than 30 MW, which provided for an avoided cost tariff (ACT) to be published by the MoIT every year. In the recognition that such a tariff would be mainly of interest to small hydro, the tariff was expressly

Figure 3.2 Distribution of Tariffs, and Individually Negotiated Tariffs



Source: MoIT Survey of Small Hydro developers 2007.
Note: At the 2007 average exchange rate $1 = D15,740. kWh = kilowatt-hour.

designed to reward daily peaking projects rather than pure run-of-river (RoR) projects, by providing a capacity charge for peak-hour dry-season production (table 3.1).[4] This is calculated as the avoided capacity cost of a gas-fired CCCT. Other important characteristics include:

- *Regional differentiation* (across the three main regions of Vietnam). The small regional variations in tariff arise because of differences in avoided transmission losses. For example, the output of an SHP in the North results in less gas-fired generation in the South (which is otherwise imported into the North across the 500 kV network), so the amount of generation reduction in the South (the benefit of RE) is larger than the injection of RE in the North when transmission losses are taken into consideration.
- *Surplus energy charge* (which applies to wet season energy produced in excess of monthly load factors greater than 90 percent). This was introduced as a concession to the distribution companies, which (under must-take provisions of the SPPA) are obliged to accept small hydropower in wet years even though they are already in surplus from large hydro.
- *Transmission connection*. The SPPA requires that developers be responsible for the costs of the connection to the nearest substation, or to the nearest passing transmission line.

With this tariff, a typical RoR SHP could in 2009 achieve an average tariff of just D563/kWh (3.2 cents/kWh)—not much of an increase compared to the old tariff regime (table 3.2). By 2010 this had increased to D686/kWh (3.3 cents/kWh). Just 20 percent of the total remuneration (row [20]) is from the capacity charge (a reflection of the low value of such projects to the EVN system).

Table 3.3 summarizes the calculations for other types of RE projects. In 2012 a typical daily peaking hydro could achieve a tariff of 5 cents/kWh, as compared to just 3.3 cents/kWh for a RoR project. Realization from wind farms is just 4 cents/kWh—obviously not a level at which wind farms would be profitable.

Table 3.1 The 2009 Avoided Cost Tariff, D/kWh

	Dry season (November–June)			*Wet season (July–October)*			
	Peak hours	*Normal hours*	*Off-peak*	*Peak hours*	*Normal hours*	*Off-peak*	*Surplus energy*
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
North	435	419	415	483	472	470	235
Center	403	411	418	418	427	439	220
South	428	427	426	453	451	447	223
Capacity charge	1,674						
As cents/kWh							
North	2.5	2.4	2.4	2.8	2.7	2.7	1.3
Center	2.3	2.3	2.4	2.4	2.4	2.5	1.3
South	2.4	2.4	2.4	2.6	2.6	2.6	1.3
Capacity charge	9.6						

Source: Decision No. 74/QD-DTDL, dated December 24, 2008.
Note: At the 2009 exchange rate $1 = D17,490. kWh = kilowatt-hour.

Table 3.2 Realization of the Avoided Cost Tariff, Run-of-the-River Project, North Vietnam

	GWh	*[%]*	*2009 tariff, D/kWh*	*2009 revenue, D (million)*	*[%]*	*2012 tariff, D/kWh*	*2012 revenue, D (million)*	*[%]*
Dry season								
Peak [capacity]	3,928	n.a.	1,674	6,575	*21.9*	1,805	7,090	*19.4*
Peak [energy]	3,928	7	435	1,709	*5.7*	619	2,431	*6.7*
Normal	10,214	19	419	4,280	*14.3*	596	6,088	*16.7*
Off-peak	4,714	9	415	1,956	*6.5*	554	2,612	*7.1*
Total	18,856	35	n.a.	14,520	*48.4*	n.a.	18,221	*49.8*
Wet season								
Peak	7,165	13	483	3,461	*11.5*	596	4,270	*11.7*
Normal	18,628	35	472	8,792	*29.3*	557	10,376	*28.4*
Off-peak	5,113	10	470	2,403	*8.0*	538	2,751	*7.5*
Surplus	3,485	7	235	819	*2.7*	269	937	*2.6*
Total	34,391	65	n.a.	15,475	*51.6*	n.a.	18,334	*50.2*
Total	53,247	100	n.a.	29,995	*100*	n.a.	36,555	*100*
Average load factor	43.4%							
Average, D/kWh				563.3			686.5	
Exchange rate				17,490			20,690	
Cents/kWh				3.2			3.3	
Capacity charge, D m				6,575			7,090	
Average capacity remuneration, D/kWh				123			133	
(as % of total)				21.9			19.4	
Average energy remuneration, D/kWh				440			553	

Source: ERAV 2012.
Note: n.a. = not applicable. kWh = kilowatt-hour.

Table 3.3 Tariff Realizations for Different Types of Projects, 2009–12

		2009	*2010*	*2011*	*2012*
Run-of-the-river small hydro	D/kWh	563	565	646	687
	Cents/kWh	3.2	3.0	3.2	3.3
Daily peaking small hydro	D/kWh	877	870	979	1,029
	Cents/kWh	5.0	4.6	4.8	5.0
Wind farm	D/kWh	655	683	802	828
	Cents/kWh	3.7	3.6	3.9	4.0
Rice husk gasifier	D/kWh	668	677	794	862
	Cents/kWh	3.8	3.6	3.9	4.2

Source: Meier 2013.
Note: kWh = kilowatt-hour.

By the end of 2011, 88 new projects for 572 MW had signed SPPAs under the new tariff, of which 30 projects (256 MW) were already in operation. The tariff itself was set on the basis of EVN's avoided cost of the marginal thermal generator (which is CCGT, as discussed further). This success in enabling small hydro at such low tariffs was made possible only by the extensive use of Chinese equipment, with costs about one-third less than that of European equipment.

Despite the success of the ACT in enabling small hydro, as expected by the tariff's designers, no wind projects have been enabled by the tariff; and only in late 2012 did two bagasse projects (at existing sugar mills) join the tariff. There is presently just one wind farm in operation in Vietnam, the 20 MW project in Binh Thuan.[5] This has led to calls for feed-in tariffs (FITs) to support biomass and wind generation; several proposed biomass projects based on rice husk combustion have languished, awaiting a new biomass FIT. But much of the rice husk is already productively used, mainly as a heat source for brick making and ceramics.

Following years of unrelenting pressure from donor advocacy (including countless field trips to developed countries and several major studies rehearsing the arguments for a wind FIT), in June 2011 the MoIT issued a wind FIT of 7.8 cents/kWh.[6] One cent/kWh was to be provided by the Vietnam Environmental Protection Fund (VEPF), the balance of 6.8 cents would be paid by the buyer (most wind resources are in the southern part of central Vietnam, and would be connected to the Central Power Company).

This tariff has been widely criticized by developers as providing inadequate remuneration, and indeed no *new* wind projects have been enabled by the tariff.[7] Nor is it clear whether the VEPF has a sustainable source of funding for this purpose.

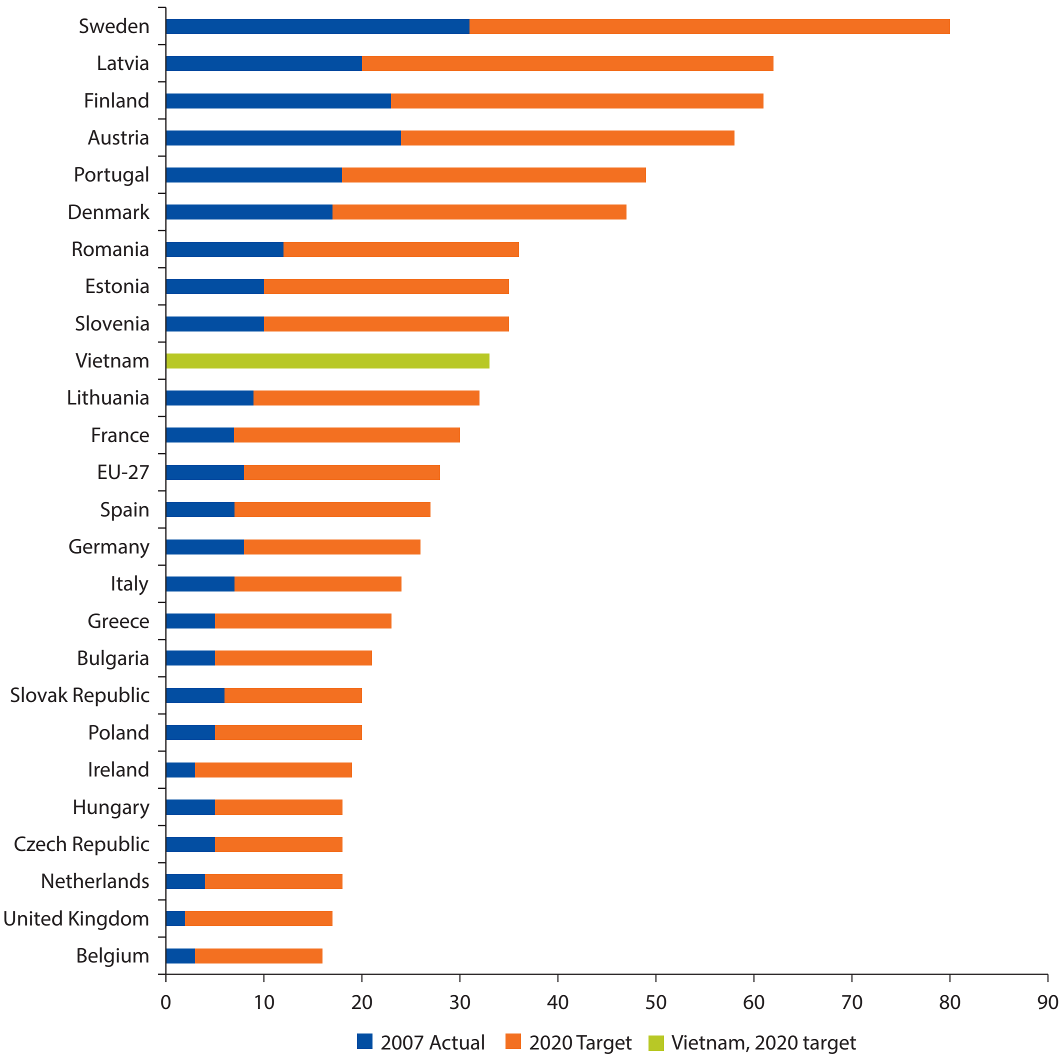
At the time of writing, the government is considering the issuance of a FIT for biomass, and is assessing the desirability of a FIT for solar PV. The government is also preparing a Renewable Energy Decree (or possibly a law) to codify the government's approach to supporting RE development.

The absence of wind and biomass generation notwithstanding, it is worth noting that in 2009 Vietnam generated 39 percent of its electricity from RE.

While this includes large hydropower, members of the European Union (EU) also include large hydro in their RE targets (figure 3.3). In Vietnam this percentage is set to decline with the significant increase in coal generation expected in the next 15 years, and by 2020 the fraction of electricity generated by RE will fall to 33 percent. But as evident from figure 3.4, even at this lower level, Vietnam's renewables share will be greater than most EU countries, including Germany.

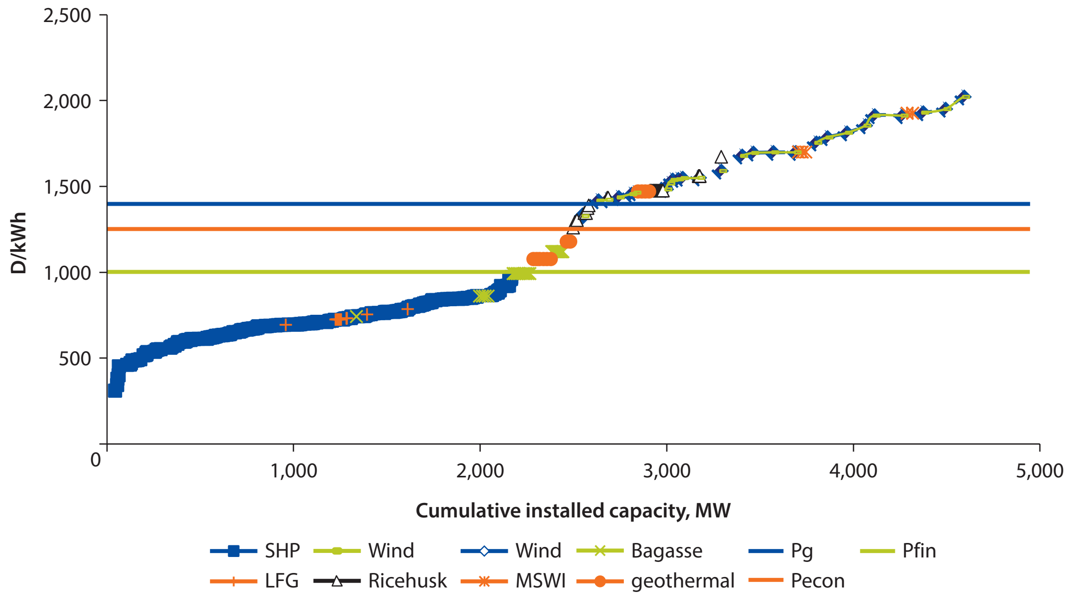
Vietnam's average power sector emissions per kilowatt-hour generated also compares well by international standards, as shown in table 3.4. Emissions are low because of the high proportion of hydro and gas in Vietnam's power generation mix.

Figure 3.3 2020 RE Targets for Electricity Generation: Vietnam and the European Union



Source: Meier 2013.
Note: EU = European Union; RE = renewable energy.

Figure 3.4 The 2025 RE Supply Curve for Vietnam: Installed Capacity
GW



Source: MoIT 2011.
Note: GW = gigawatt; kWh = kilowatt-hour; LFG = landfill gas; MSWI = municipal solid waste incineration; SHP = small hydro project.

Table 3.4 CO_2 Emissions per Kilowatt-Hour Generated in Selected Countries, 2008

	gms CO_2/kWh
South Africa	895
China	745
Indonesia	726
Malaysia	656
United States	535
Thailand	529
Global average	**502**
United Kingdom	487
Philippines	487
Germany	441
Sri Lanka	430
Vietnam	413

Source: IEA 2010.
Note: Includes industrial process heat. gms CO_2 = grams of carbon dioxide; kWh = kilowatt-hour.

Renewable Energy Resource Endowment: The Supply Curve

Other than for small hydro, for which a detailed master plan is available (PECC1 2001), and for agricultural wastes (biomass, which can be reliably inferred from official data on agricultural production), the other RE resources suitable for grid-connected projects are either largely unknown (if not quite speculative, as in the case of geothermal), too small to make any significant contribution (such as landfill gas), or vastly overestimated in light of existing evidence (as in the case of wind, where estimates of "physical potential" have little practical meaning).

The small-hydro master plan identified some 2,925 MW in 408 potential SHPs in a size range of 5–30 MW, with average costs of $1,283/MW. This is somewhat less than the results of the 2007 MoIT survey that identified 3,443 MW in 319 projects that were at some stage in the project pipeline. How much of this capacity is actually economic is debatable, but according to the REMP, some 2,000 MW of small hydro was considered economic at EVN's avoided financial cost.

The size of the wind resource is subject to the usual meaningless estimates of gross physical potential. According to one early World Bank–supported study, the potential in areas identified as having average annual wind speeds of 7–8 meters per second (m/sec) is 102 GW (plus another 9 GW in areas of wind speeds > 8 m/sec) (TrueWind Solutions 2001). But the first official study in 2007 estimated the actual technical potential (at sites with wind speeds >6 m/sec at 60 meters above ground) at just 1,785 MW (EVN 2007). More recent assessments show as much as 5,200 MW has been proposed at various stages of the project pipeline, concentrated in just two provinces (Ninh Thuan and Binh Thuan) (table 3.5). Since the planning process in Vietnam encourages early

Table 3.5 Status of Wind Power Development in Vietnam

				Status				
	Province	*Number of projects*	*Installed capacity*	*IR*	*IP*	*TD*	*UC*	*IO*
1	Lang Son	1	200	1				
2	Quang Binh	3	n.a.	3				
3	Quang Tri	1	30	1				
4	Binh Dinh	3	251	1		2		
5	Phu Yen	1	45	1				
6	Dak Lak	2	n.a.	2				
7	Gia Lai	1	41		1			
8	Lam Ding	2	330		2			
9	Ninh Thuan	16	1,105	9	6	1		
10	Binh Thuan	20	1,541	17		1	1	1
11	Ba Ria	2	112	1	1			
12	Tien Giang	2	150	1	1			
13	Ben Tre	2	280	2				
14	Tra Vinh	2	123	2				
15	Soc trang	6	690	6				
16	Bac Lieu	1	99				1	
17	Ca Mau	2	300	2				
	Total	67	5,297	49	11	4	2	1

Source: Meier 2013.
Note: Status: IR = investment report; IP = investment project; TD = technical design; C = under construction; IO = in operation. n.a. = not applicable.

inclusion of projects in the officially approved list, this list is not necessarily an indication of actually bankable projects.[8]

Vietnam has a plentiful endowment of potential biomass, rice husk, rice straw, bagasse, coffee shells, wood fuel, and wood waste. An estimated 60 percent of the rural population uses biomass to meet the needs of heat for cooking, agricultural processing, and small-scale food production. In addition, biomass is used as fuel for producing heat and electricity in rural industrial production, such as rice husk for firing bricks, firewood or woody biomass for firing ceramics (in the South), and electricity and steam production in sugar mills from bagasse. Much biomass use is still based on old, outdated, and inefficient technologies. Several rice husk gasification and combustion projects are under development, but progress has been slow in the absence of an adequate tariff. None have been enabled under the existing subsidy scheme offered by the VEPF or the ACT.

Vietnam has been successful in developing small-scale household biogas systems, with nearly 200,000 biogas systems installed in households with an average digester capacity of about 7–10 cubic meters (m^3) per system, and used for cooking, lighting, and running small electricity generators. But the potential for biogas development in Vietnam remains significant—especially at the medium and large scale—not only to handle animal waste but also waste from food processing. Another important potential biomass source for fuel in Vietnam is rice *straw* (one ton of paddy produces 1 ton of straw) estimated at some 40 million tons in 2010, 54 percent of which is produced in the Mekong River Delta region.

Bagasse is used for cogeneration of heat (steam) and power in sugar mills: the current installed capacity of cogeneration systems in all sugar mills is around 150 MW. But only three sugar mills—Son La sugar mill (Son La province), La Nga sugar mill (Dong Nai province), and Bourbon Tay Ninh sugar mill (Tay Ninh province)—are selling their surplus electricity to the grid. The Bourbon sugar mill has installed the largest bagasse cogeneration plant in Vietnam, with a capacity of 24 MW, of which 9–10 MW is used for the sugar mill, and the rest is sold to the grid. Several new projects are under development but, absent an appropriate support tariff, progress has been slow.

The most careful and detailed assessment of the RE resource for grid-connected energy generation is found in the 2008 Draft Renewable Energy Master Plan, which evaluated all projects in the plausible development pipeline (except for small hydro, whose resource potential was extrapolated from the small hydro master plan). Figure 3.4 shows the 2025 supply curve for installed capacity: about 2,400 MW is enabled by the 2008 estimate of economic cost, of which 220 MW is available at the avoided financial cost (that is, at the ACT). Just a single 30 MW wind farm is economic when the carbon benefit is included (table 3.6).

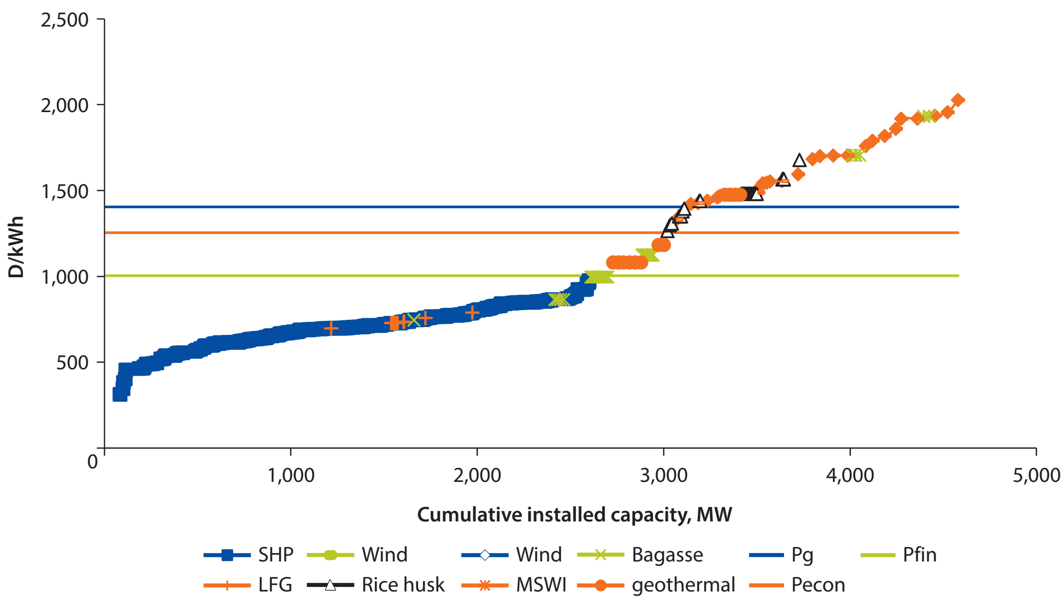
The corresponding supply curve in terms of generation is shown in figure 3.5 and table 3.7. At the 2008 estimate of the avoided economic cost (P_{ECON}), some 11 TWh are economic by 2025, likely to be around 5 percent of generation.

Table 3.6 Economically Optimal Renewable Energy: Installed Capacity

	MW enabled by ACT (P_{FIN})	*MW enabled by support to P_{ECON}*	*MW enabled by CDM (P_G)*	*Total*
SHP	2,030	0	0	2,030
Rice husk	0	0	69	69
Bagasse	185	65	0	250
LFG	52	0	0	52
MSWI	0	0	0	0
Geothermal	0	152	0	152
Wind	0	0	30	30
Total	2,267	217	99	2,583

Source: MoIT 2011.
Note: ACT = avoided cost tariff; CDM = clean development mechanism; LFG = landfill gas; MSWI = municipal solid waste incineration; MW = megawatt; SHP = small hydro project.

Figure 3.5 The 2025 RE Supply Curve for Vietnam: Generation



Source: MoIT 2011.
Note: kWh = kilowatt-hour; LFG = landfill gas; MSWI = municipal solid waste incineration; MW = megawatt; RE = renewable energy; SHP = small hydro project.

Based on this assessment of the supply curve, the REMP developed four scenarios:

- *Scenario 1:* economic quantity of grid-connected renewables, household electrification completed in 2025.
- *Scenario 2:* economic quantity of grid-connected renewables, rural electrification completed in 2020.

Table 3.7 Economically Optimal Renewable Energy in Vietnam Generation (GWh): Projected to 2025

	Generation at P_{FIN}	*Generation at P_{ECON}*	*Generation at P_G*
SHP	8,814	8,814 (81.7%)	8,814
Rice husk	0	0	299
Bagasse	667	896 (8.3%)	896
LFG	214	214 (2.0%)	214
MSWI	0	0	0
Geothermal	0	862 (8.0%)	862
Wind	0	0	91
Total	9,694	10,785 (100%)	11,175

Source: MoIT 2011.
Note: GWh = gigawatt-hour; LFG = landfill gas; MSWI = municipal solid waste incineration; SHP = small hydro project.

- *Scenario 3*: scenario 1 + wind development demonstration program (630 MW by 2020).
- *Scenario 4*: scenario 1 + all identified grid-connected renewables (maximum grid-connected potential).

The main assumptions for the evaluation of incremental costs included a wind FIT of 10 cents/kWh, no subsidy for SHPs, and biomass and geothermal at the estimated cost of generation (capped at P_{ECON} of D1,200/kWh). The incremental costs were assumed to be raised by a consumer levy. The REMP assumed that the electricity levy would also be used to fund the off-grid rural electrification program,[9] and to fund subsidies for household-scale biogas and solar water heating. Figure 3.6 shows the results of scenario 3 (economic quantities plus a wind demonstration program of 630 MW by 2020). Subsidies for rural electrification peak in the period 2015–20, then fall off as the goal is achieved (here in 2025). The subsidy for wind is about $125 million per year, but the impact on the tariff is just D20/kWh (0.1 cent/kWh).

One reason for the low tariff levy is the very high demand forecast used in 2008: that is, 128 TWh in 2012 (compared to the actual 2012 consumption of 105 GWh), though this is partially offset by underestimating the consumer tariff (2012 estimate of D1,012/kWh compared to the actual D1,361/kWh). When the levy is recalculated under currently more realistic assumptions, it more or less doubles to around D40/kWh (0.2 cents/kWh).

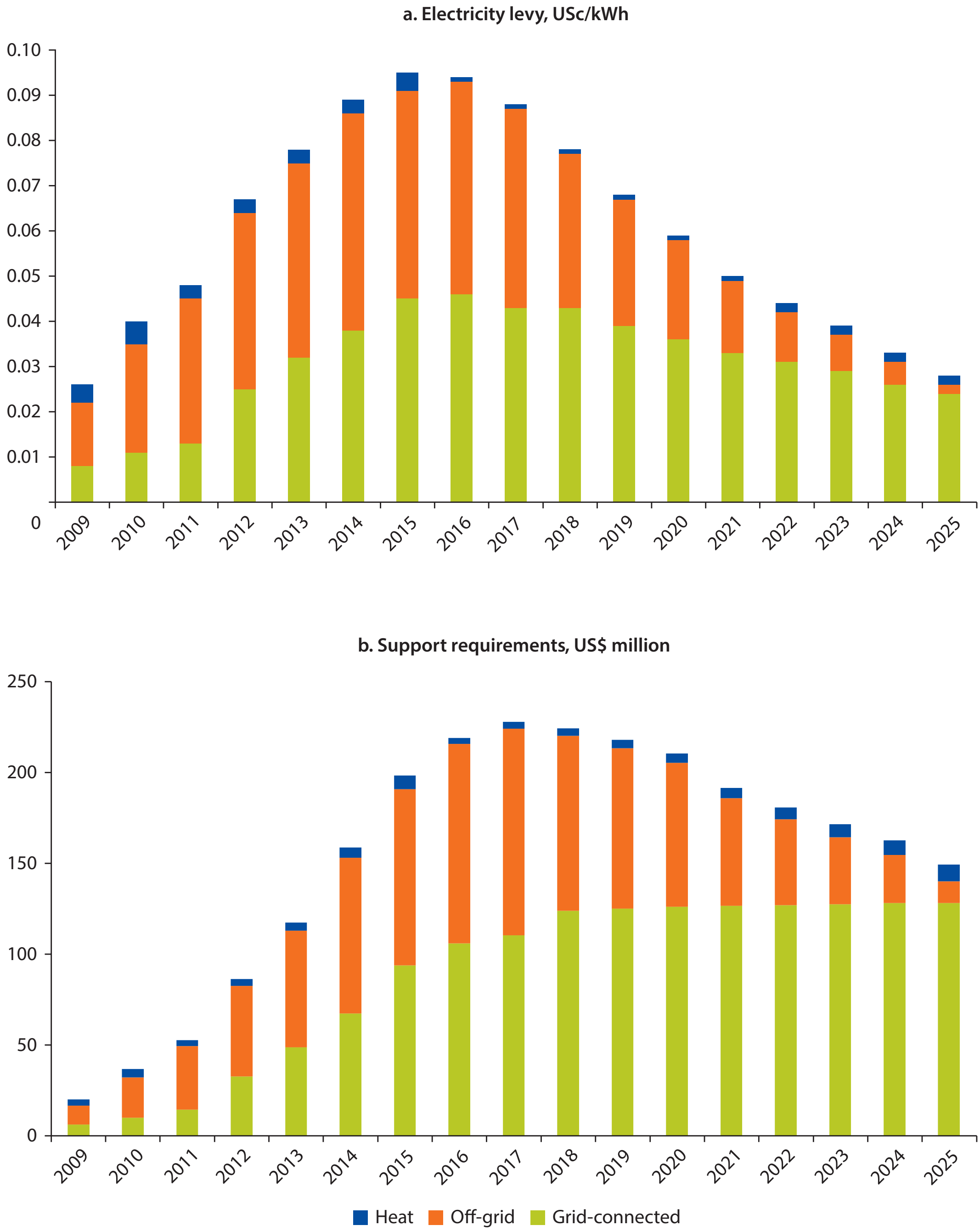
Production Costs

Wind

For the baseline estimate of wind production costs, we make the following assumptions:

- Capital cost $1,750/kW (based on the 2011 Institute of Energy, Vietnam [IoE] assessment of Chinese wind turbine prices; wind farms based on European turbine prices are assessed at $2,250/kW).[10]

Figure 3.6 Impact of the REMP Development Scenario: Economic + Wind Demonstration Program, 2009–25



Source: MoIT 2011.
Note: USc = U.S. cents.

- Average annual plant load factor of 26.7 percent (based on the IoE evaluation of wind speed data of 7 meters per second [m/sec] at 85 meters hub height).
- Financing 25 percent equity/75 percent debt (the state-owned Vietnamese Development Bank stipulates a minimum of 15 percent equity, but commercial banks would want to see much higher equity).
- Local commercial financing: end 2012 Vietnamese prime rate (14 percent) + 2 percent = 16 percent; term 7 years including 2 years grace (during construction).
- Balance sheet financing (so project debt service cover ratio [DSCR] is not a binding constraint).
- Annual operation and maintenance (O&M) costs (2 percent of capital cost).
- Two-year construction period.
- Domestic inflation 6 percent, dollar inflation 2 percent, and exchange rate depreciation 3.9 percent.[11]
- Target financial internal rate of return (FIRR) after tax = 15 percent (nominal).
- Corporate tax rate is 28 percent, depreciation over 20 years (no tax holidays or accelerated depreciation).[12]

The model calculates the required tariff in cents/kWh to meet this target FIRR, under the assumption that the U.S.-denominated tariff remains constant (that is, adopting the way in which the present wind FIT is adjusted). The required tariff under the above assumptions is 11.3 cents/kWh. For European wind turbine costs, the required tariff is 14.6 cents/kWh.[13]

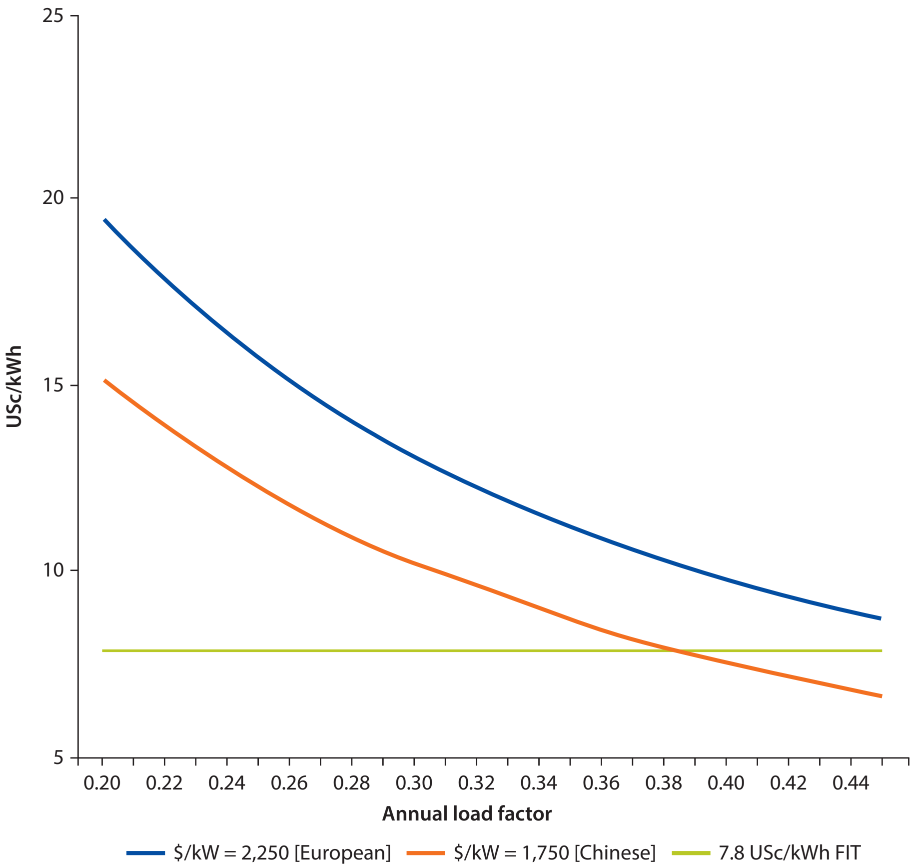
As shown in figure 3.7, it is evident that the current wind FIT of 7.8 cents would require an annual load factor of 38 percent using Chinese equipment, and almost 50 percent using European equipment. Such load factors are simply not achievable given the actual wind regime.

Table 3.8 summarizes wind power support tariffs in other Asian countries. Note the wide range in support levels, from Vietnam's 7.8 cents/kWh to 24 cents/kWh in the Philippines. This wide range cannot be explained by the differences in assumptions about the cost of wind turbines, which is certainly much less than a factor of 3. Chinese wind turbines may cost 70–80 percent as much as machines from European turbine manufacturers, but not as little as 20–25 percent. This illustrates the difficulty of the government setting a production-cost-based FIT in the face of great information asymmetry: government officials only rarely have access to the relevant current market information, so assumptions about production costs are often little more than guesses or judgments as to what might be reasonable.

Capacity Value

The calculations above simply reflect the tariff required of the developer. But this is not necessarily the same as the cost to the buyer, because wind energy is not dispatchable, and contributes little reliable power during peak hours. In short, it has little *capacity* value.[14] The general rule of thumb is that the capacity credit

Figure 3.7 Required FIT to Maintain 15 Percent FIRR vs. Capital Costs



Source: Meier 2013.
Note: FIT = feed-in tariff; FIRR = financial internal rate of return; kW = kilowatt; kWh = kilowatt-hour; USc = U.S. cents.

Table 3.8 Wind Support Tariff Comparisons

	Assumed load factor	*Cents/kWh*
Vietnam	26.9%	7.8
Thailand		17.6[a]
China	30–35.6%	8.1–9.7
Philippines	Not provided	24
Sri Lanka	36%	~20 (in 2009) 15 (2012 proposal)

Note: kWh = kilowatt-hour.
a. 11 cent adder + 6.5 off-peak base rate.

may be approximated by the ratio of annual average capacity factors. If a wind project of x MW with a load factor of 25 percent displaces coal generation with a load factor of 75 percent, it should be given a capacity credit $\gamma = 0.33x$ [MW]. This means that the capital cost of the wind project should be burdened with the fixed costs of open-cycle gas turbine (OCGT) capacity (the cheapest form of capacity) in the amount of (1 – γ) [MW]. The British Wind Energy Association (BWEA) estimates that the capacity credit for wind is around 33 percent at 5 percent wind penetration, falling to 20 percent at 15 percent penetration.[15] As shown in box 3.3, studies in China showed capacity values for wind and small hydro of 43 percent and 47 percent, respectively.

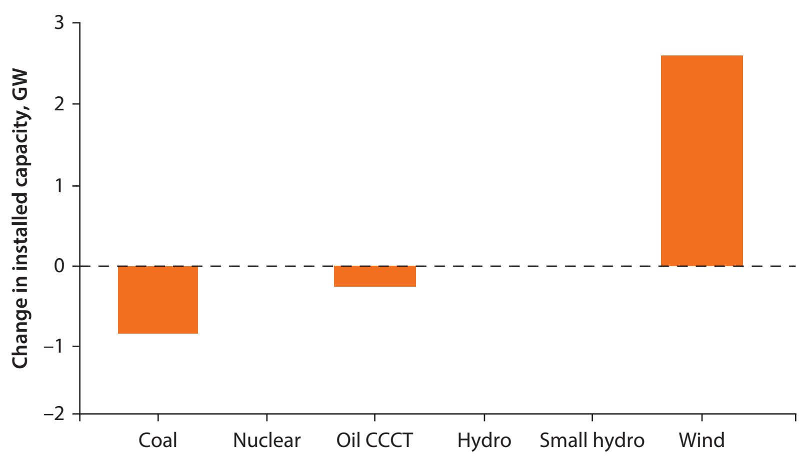
Therefore, a Vietnamese wind power project with a 26.8 percent load factor has a capacity credit of 32 percent. With OCGT at $350/kW, this means that EVN incurs an additional capital cost of $239/kW, or 1.192 cents/kWh

Box 3.3 The Capacity Value of Renewables in China

Rules of thumb are all very well, but do they have any basis in reliable studies? The only way the capacity impacts can be realistically assessed is in a capacity expansion optimization model, in which the least-cost plan is perturbed by forcing in renewable energy (RE) and evaluating how much thermal capacity is actually avoided (or deferred). There are few such studies; one was part of the economic analysis conducted for the China Renewable Energy Scale-up Program (CRESP) project in China. In an initial modeling study, the impacts of a wind development plan of 2,600 MW of additional wind capacity over 10 years in the North China grid were assessed: as shown in the figure below this resulted in a displacement of 836 MW of coal and 256 MW of oil-fired combined-cycle gas turbine (CCGT)—in effect a capacity credit of 43 percent (see figure B3.3.1).

A second modeling study examined 1,000 MW of additional small hydro in the Zhejiang grid: this resulted in a 402 MW decrease in coal capacity, and 60 MW in oil-fired CCCT, a capacity credit of 47 percent (see figure B.3.3.2).

Figure B3.3.1 Capacity Displacements in the North China Grid

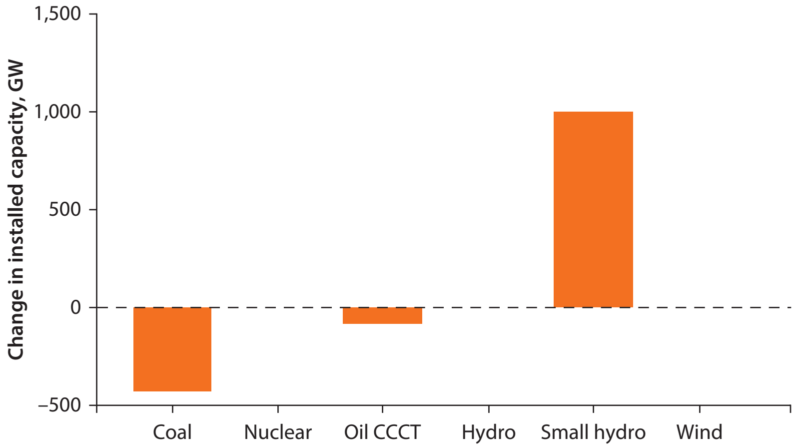


Source: World Bank 2005.
Note: CCCT = combined-cycle combustion turbine; GW = gigawatt.

box continues next page

Box 3.3 The Capacity Value of Renewables in China *(continued)*

Figure B3.3.2 Capacity Displacements in Zhejiang



Source: World Bank 2005.
Note: CCCT = combined-cycle combustion turbine; GW = gigawatt.

Table 3.9 Capacity Penalty, Wind Project with Annual Load Factor of 26.9 Percent

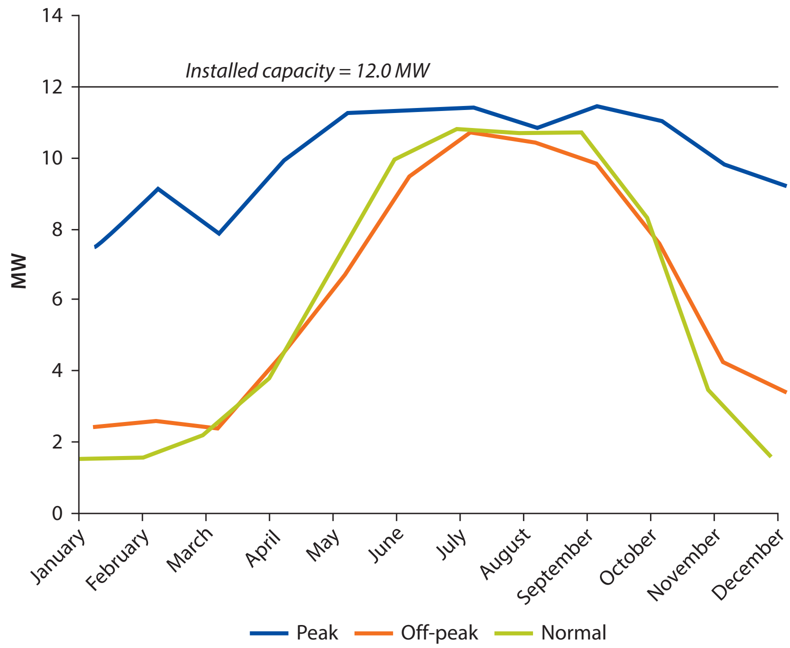
		Units	
1	OCCT cost	$/kW	350
2	Capacity credit	[proportion]	0.32
3	Capacity penalty	$/kW	239
4	Capital recovery factor	[proportion]	0.12
5	Annual cost	$/year/kW	28.1
6	Annual generation	kWh/year	2,356
7	Cost per kWh	Cents/kWh	1.192

Source: ERAV 2012.
Note: kW = kilowatt; kWh = kilowatt-hour; OCCT = open-cycle combustion turbine.

(table 3.9). This additional cost needs to be considered in incremental cost calculations.

Detailed studies of how RE projects are operated in Vietnam provide additional insights. Figure 3.8 shows the average monthly dispatch for each of the three tariff blocks (peak, normal, and off-peak) for the 12 MW Nam Mu daily peaking SHP. This shows that even during the dry season, the average monthly dispatch during peak hours is around 8 MW; during the system peak in November it is 10 MW. During the wet months of July–August, the plant runs more or less at its full capacity of 12 MW throughout the day. Of course, there is little or no generation in the dry season during off-peak hours—but the economic motivation to build daily peaking capacity rather than pure RoR is clear. And, clearly, Nam Mu is dispatchable and has significant capacity value.[16]

Figure 3.8 Operation of the Nam Mu, Daily Peaking, Small Hydro Project



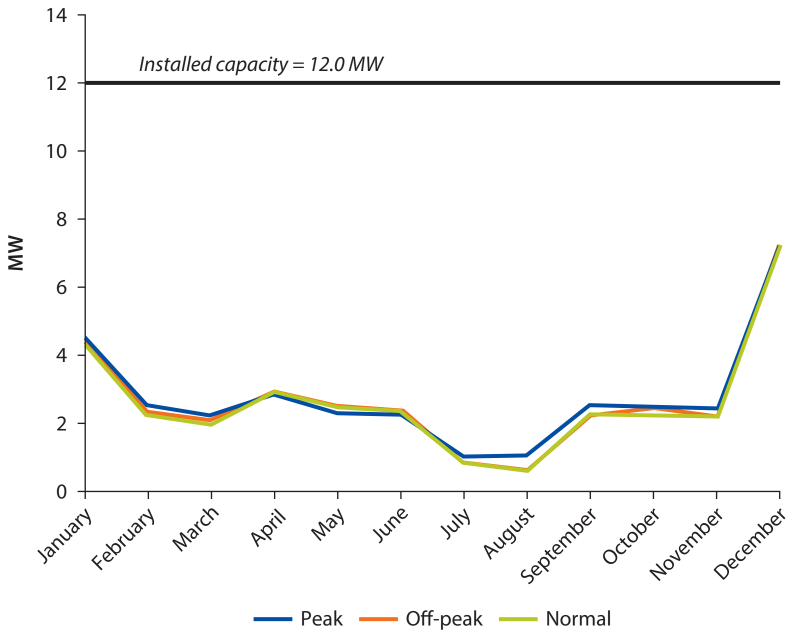
Source: ERAV 2012.
Note: MW = megawatt.

This may be compared to the analogous evaluation of a wind project proposed for Ly Son Island, (poorly) served by old diesels (figure 3.9).[17] The output is strongly seasonal: just 2 MW on average for most of the year, and just 7 MW in the peak month (December) and a little less than 5 MW in January (for an annual average load factor of 22 percent). In short, such a project has very little capacity value, especially when compared to daily peaking hydro.

For small hydro, then, the capacity value is much more significant. For 2009 we have examined monthly dispatch data for a portfolio of 11 SHPs for which we have individual hourly data, representing an installed capacity of 89.5 MW (figure 3.10). With heavy representation of central region projects, the contribution of the portfolio to the coincident peak month is high:[18] the average dispatch in the peak hours of this month is 82 MW, and the average peak-hour contribution in the dry season is 62 MW. Even in the dry season of January–April, the portfolio has a capacity value of around 50 MW for the five peak hours of the day.

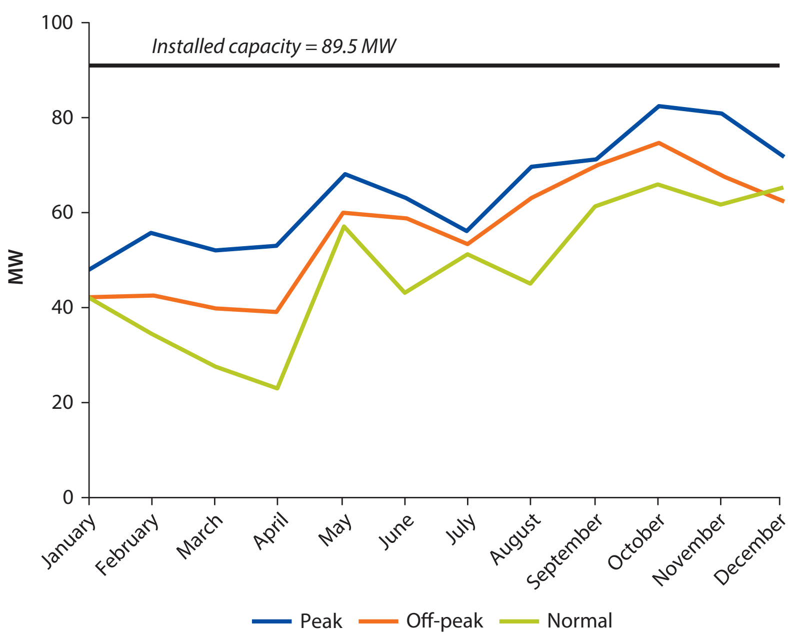
The same is true for the EVN system as a whole, for which we have aggregate hourly data from the regional load dispatch centers (but not at the individual project level). This shows significant contribution during the peak hours of the dry season throughout the year, and is a clear demonstration of the capacity value of a portfolio of SHPs. Strictly speaking, capacity value can be gauged by the contribution to the November coincident system peak: as is clear from figure 3.11, the SHP portfolio as a whole contributes about 85 percent of its installed capacity to the November system peak.

Figure 3.9 Operation of the Proposed Ly Son Island Wind Project



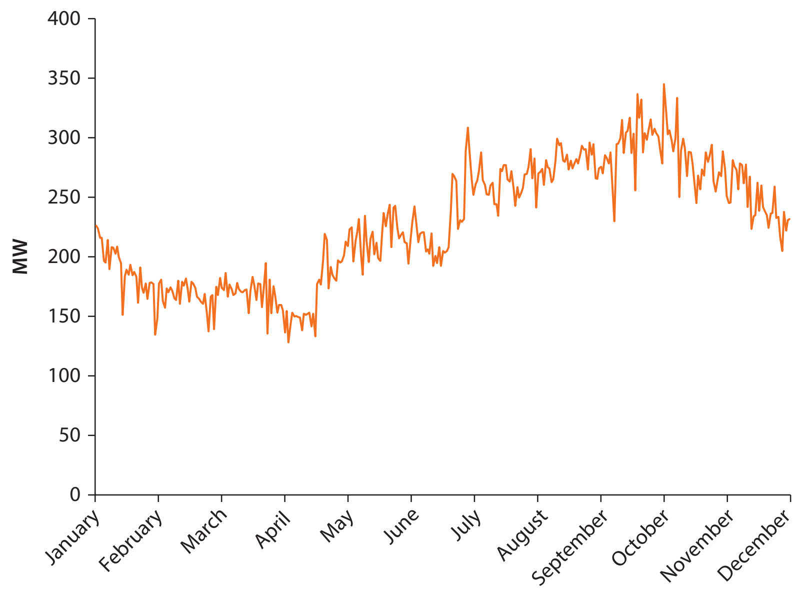
Source: ERAV 2012.
Note: MW = megawatt.

Figure 3.10 Dispatch of a Portfolio of Small Hydro Projects



Source: ERAV 2012.
Note: MW = megawatt.

Figure 3.11 Average Contribution of Small Hydro during the Five Peak Hours of the Day, 2009



Source: National Load Dispatch Centre (NLDC) daily reports.
Note: MW = megawatt.

Biomass

A technology-based FIT for biomass has two critical assumptions: capital cost and fuel cost. The MoIT will need to make estimates for both to be able to issue a technology-specific FIT. Table 3.10 shows the tariff required to achieve a 15 percent FIRR (posttax), under the following assumptions:

- Rice husk combustion: 20 MW.
- No carbon revenue, or ash sales.
- Domestic inflation, 6 percent; Organisation for Economic Co-operation and Development (OECD) inflation, 2 percent.
- Two-year construction time.
- Thirty percent equity, 70 percent debt (domestic loan, 16 percent interest, 7 years including a 2-year grace during construction, interest during construction [IDC] capitalized).
- Own use: 9 percent.
- Fuel rate: 1.5 kg/kWh.
- No real escalation in rice husk prices (that is, increase at assumed rate of domestic inflation).
- First year fixed operation and maintenance (O&M) costs: 4 percent of capital costs, increasing to 5 percent in year 6 and 7 percent in year 11.
- Annual tariff adjustment to allow for exchange rate depreciation (similar to the wind FIT mechanism).

Table 3.10 Tariff Required for 15 Percent FIRR (Post Tax)

	Rice husk price, $/ton									
Capital cost, $/kW	*18*	*20*	*22*	*24*	*26*	*28*	*30*	*32*	*34*	*36*
1,200	6.36	6.75	7.13	7.52	7.91	8.30	8.69	9.07	9.46	9.85
1,300	6.60	6.98	7.37	7.76	8.15	8.54	8.93	9.31	9.70	10.09
1,400	6.83	7.22	7.61	8.00	8.39	8.78	0.16	9.55	9.94	10.33
1,500	7.07	7.46	7.85	8.24	8.63	9.01	9.40	9.79	10.18	10.57
1,600	7.31	7.70	8.09	8.48	8.86	9.25	9.64	10.03	10.42	10.81
1,700	7.55	7.94	8.33	8.71	9.10	9.49	9.88	10.27	10.66	11.04
1,800	7.79	8.18	**8.56**	8.95	9.34	9.73	10.12	10.51	10.89	11.28
1,900	8.03	8.41	8.80	9.19	9.58	9.97	10.36	10.74	11.13	11.52
2,000	8.27	8.65	9.04	9.43	9.82	10.21	10.59	10.98	11.37	11.76
2,100	8.50	8.89	9.28	9.67	10.06	10.45	10.83	11.22	11.61	12.00

Feasible at the same tariff as wind (7.8 USc/kWh)
Feasible at the avoided social cost of thermal generation (10.8 USc/kWh)
Requires tariff higher than the avoided social cost (uneconomic)

Source: ERAV 2012.
Note: kW = kilowatt; kWh = kilowatt-hour; USc = U.S. cents.

Table 3.11 Tariff Required (in Cents): 3 Percent Annual Real Price Escalation for Rice Husk

	First year rice husk price, $/ton									
Capital cost, $/kW	*18*	*20*	*22*	*24*	*26*	*28*	*30*	*32*	*34*	*36*
1,200	7.3	7.8	8.3	8.8	9.3	9.8	10.3	10.8	11.3	11.8
1,300	7.6	8.1	8.6	9.1	9.6	10.1	10.6	11.1	11.5	12.0
1,400	7.8	8.3	8.8	9.3	9.0	10.3	10.8	11.3	11.8	12.3
1,500	8.1	8.5	9.0	9.5	10.0	10.5	11.0	11.5	12.0	12.5
1,600	8.3	8.8	9.3	9.8	10.2	10.8	11.3	11.8	12.3	12.8
1,700	8.5	9.0	9.5	10.0	10.5	11.0	11.5	12.0	12.5	13.0
1,800	8.8	9.3	**9.8**	10.3	10.8	11.3	11.7	12.2	12.7	13.2
1,900	9.0	9.5	10.0	10.5	11.0	11.5	12.0	12.5	13.0	13.5
2,000	9.2	9.7	10.2	10.7	11.2	11.7	12.2	12.7	13.2	13.7
2,100	9.5	10.0	10.5	11.0	11.5	12.0	12.5	13.0	13.5	14.0

Feasible at the same tariff as wind (7.8 USc/kWh)
Feasible at the avoided social cost of thermal generation (10.8 USc/kWh)
Requires tariff higher than the avoided social cost (uneconomic)

Source: ERAV 2012.
Note: kW = kilowatt; kWh = kilowatt-hour; USc = U.S. cents.

This shows, for example, that at $1,800/kW and a $22/ton rice husk price, a tariff of 8.56 cents/kWh is required to achieve the 15 percent FIRR. But the experience of Thailand shows that rice husk price escalation is a major risk once a support tariff is issued: if the real rate of rice husk price escalation is 3 percent, the baseline tariff increases to 9.8 cents/kWh, as shown in table 3.11.

The discussion about biomass targets for electricity generation and the FIT required to enable bankable projects is often ill informed. From the perspective of reducing carbon emissions, it matters little whether it is achieved by electricity generation or by use as a fuel for heat—it is only important that agricultural waste is not burnt or dumped into rivers. A significant proportion of rice husk is used as a fuel for brick-making, at rice mills, and in the rural ceramics industry—in all cases it replaces oil as a fuel. Moreover, if used for power generation, biomass displaces gas; if used for process heat, it displaces oil. Since greenhouse gas (GHG) emissions from oil are much greater than those from gas, diverting biomass from process heat into electricity generation may well result in an *increase* in aggregate GHG emissions, not a decrease.[19]

It is well understood that rice husk prices were bid up in Thailand once rice husk projects received a generous adder. But in Vietnam, rice husk prices have been bid up by the successful development of rice husk pelletizing, with ready markets for pellets in the Republic of Korea and Japan. In the space of the past few years, prices have already reached as much as $35/ton. One may note that from a global GHG perspective, it does not matter whether rice husk displaces oil in Vietnam or oil in Korea and Japan.

The Avoided Social Cost of Thermal Generation

Examination of Vietnam's power generation shows that even during the wet season, when the output of the North's hydro projects peak, CCGTs (in the South) generate power throughout the day. Consequently the avoided cost of thermal generation is given by the CCGT with the highest variable cost (figure 3.12)—which in practice means the Ca Mau project, whose gas price is indexed to the Singapore fuel oil price.[20]

Production cost simulations prepared for the Seventh Power Development Plan (Vietnam) (PDP7) showed that CCGTs would be run 24 hours a day until at least 2025 (figure 3.13). Consequently, one may take the avoided social cost of thermal generation in Vietnam as a CCGT, with gas priced at international levels.

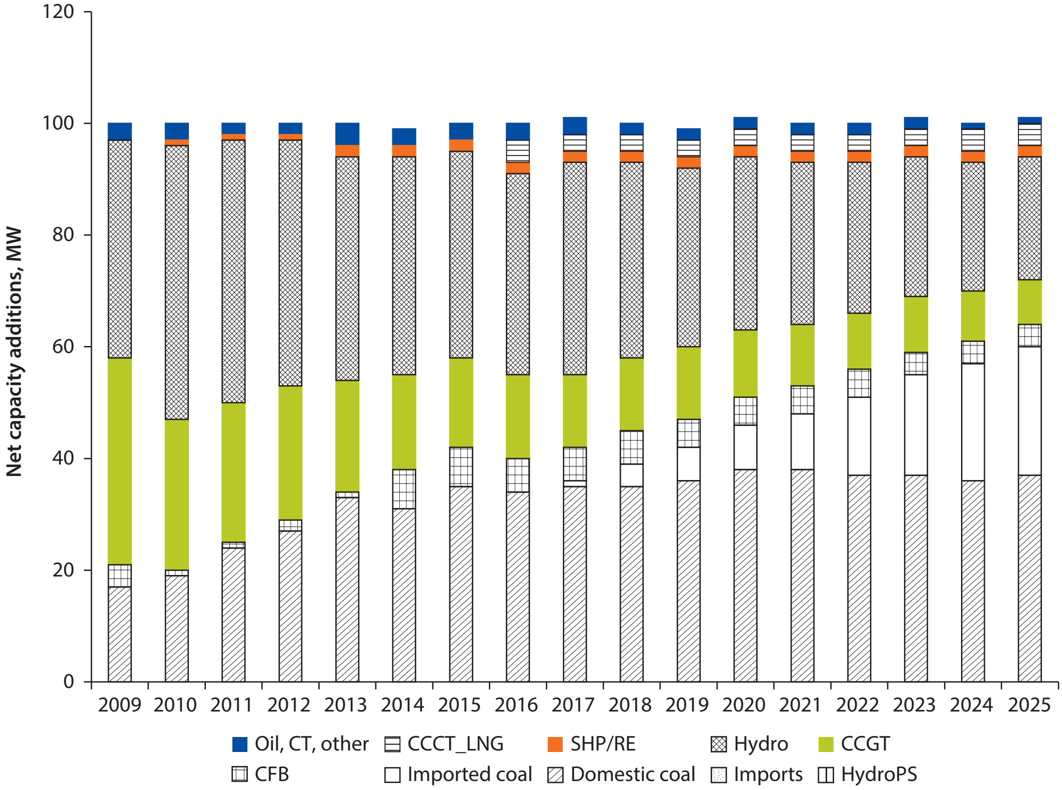
Table 3.12 shows the calculation for Vietnam, based on the Malaysia-Singapore gas power purchase agreement (PPA) as the benchmark for the border price: Malaysia and Vietnam share the Ca Mau gas field. The avoided social cost (P_{ECON}) is 11.7 cents/kWh for a $111/barrel (bbl) OPEC Reference Basket[21] price (average 2012). We note this is higher than the 11 cents/kWh required for wind generation, so in the absence of a capacity penalty wind power is economic.

There are no reliable health damage studies for nitrogen oxide (NO_X) emissions from gas generation in Vietnam, so $P_{ENV} \sim P_{ECON}$. The calculations for the financial price of gas, at the Ca Mau pricing formula of 0.45 of the Singapore border price, show the financial avoided cost at 5.7 cents/kWh ($=P_{FIN}$).[22]

Carbon Accounting and the Clean Development Mechanism (CDM)

Vietnam well illustrates the problems of carbon accounting. After a slow start,[23] by 2012 there were 29 grid-connected RE projects registered with the United Nations Framework Convention on Climate Change (UNFCCC). All of these

Figure 3.12 Vietnam's Expected Generation Mix (2008–25)



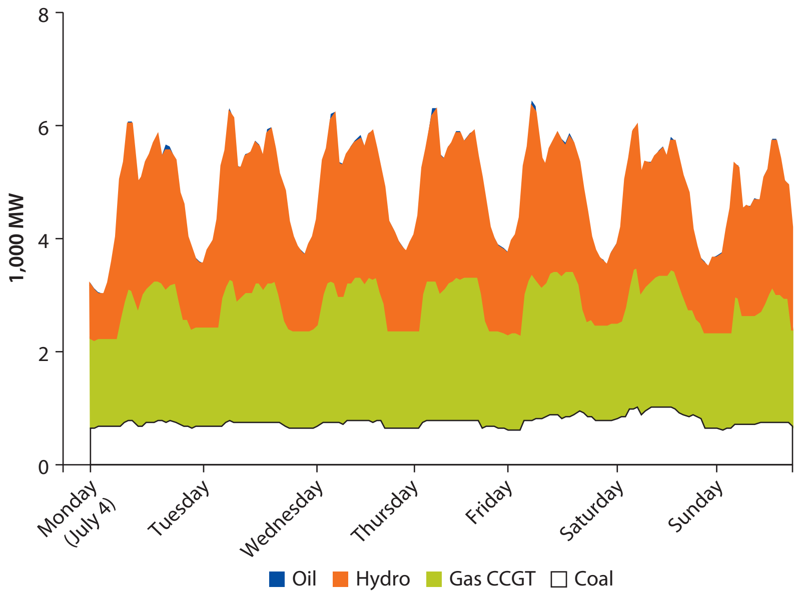
Source: Meier 2011.
Note: CFB = circulating fluidized bed; CCCT = combined-cycle combustion turbine; CT = combustion turbine; MW = megawatt; PS = pumped storage; RE = renewable energy; SHP = small hydro project.

projects used the standard UNFCCC methodology for calculating emission factors to be used, and those under 15 MW used the simplified methodology that calculates the emission factor as the weighted average of the build and operating margins. The most recent official calculation by Vietnam's Designated National Authority (DNA) is 0.54 kg carbon dioxide (CO_2)/kWh, based on the average of the build margin (BM) 0.4722 and the operating margin (OM) 0.6095.

But at the margin, it is the CCGTs that are displaced by additional RE in Vietnam, whose GHG emission factors are much lower than the grid average. In the economic analysis one should use the best estimate of the actual impact, not an accountant's artifact—even though the UNFCCC methodology is to the advantage of the developing country when calculating the magnitude of carbon credits. Consequently in the calculations that follow, we use the CCGT emission factor in economic analysis, but the DNA estimate of emission factors for calculating the financial contribution potentially made by the CDM in buying down the incremental costs.

Table 3.13 illustrates the potential impact CDM revenues may have on the revenue of a daily peaking small hydro with a tariff of 5 cents/kWh. At \$15/ton CO_2,

Figure 3.13 Wet Season Generation, Typical July Week



Source: ERAV 2012.
Note: CCGT = combined-cycle gas turbine; MW = megawatt.

Table 3.12 Avoided Social Cost of Gas Generation

		Units		Basis
1	World oil price	$/bbl	111.5	OPEC Reference Basket
2	Singapore HFO price ratio	Number	0.942	
3	HFO	$/bbl	105	OPEC Reference Basket
4	HFO	mmBTU/bbl	6.29	
5	Singapore HFO price	$/mmBTU	16.71	
6	Singapore gas price ratio	Number	0.9	
7	Singapore border price	$/mmBTU	15.0	
8	Ca Mau price	$/mmBTU	6.8	Ca Mau gas supply agreement, 0.45 of Singapore price
9	Assumed price	$/mmBTU	15.0	Border price
10	Transportation	$/mmBTU	1.1	Ca Mau gas supply agreement
11	Delivered gas price	$/mmBTU	16.1	
12	CCCT heat rate	BTU/kWh	7,250	ERAV
13	Avoided variable cost	$/kWh	0.117	
14	Exchange rate	D/$	20,830	
15	Avoided variable cost	D/kWh	2,436	

Source: ERAV 2012.
Note: bbl = barrel; BTU = British thermal unit; CCCT = combined-cycle combustion turbine; ERAV = Electricity Regulatory Authority of Vietnam; HFO = heavy fuel oil; kWh = kilowatt-hour; mmBTU = million British thermal units; OPEC = Organisation of Petroleum Exporting Countries.

Table 3.13 Potential CDM Revenue

Carbon price	*\$/ton CO_2*	*10*	*15*	*20*	*25*	*30*
Emission factor	kg/kWh	0.54	0.54	0.54	0.54	0.54
Carbon price	D/kg	207	310	414	517	621
Value	D/kWh	112	168	223	279	335
CER fraction	Number	0.75	0.75	0.75	0.75	0.75
Value	D/kWh	83.8	125.7	167.6	209.5	251.4
	Cents/kWh	0.4	0.6	0.8	1.0	1.2
Typical tariff	Cents/kWh	5	5	5	5	5
Impact	%	8	12	16	20	24

Source: MoIT 2011.
Note: Exchange rate for 2012 at \$1 = D20,690. CER = certified emission reduction. CDM = clean development mechanism; kg = kilogram; kWh = kilowatt-hour; tonCO_2 = ton of carbon dioxide.

the incremental revenue—if 75 percent of carbon offsets can be sold—is an additional 16 percent. But with only 26 SHPs registered among the 88 projects (known to ERAV) likely to be eligible, two issues have discouraged developers: the up-front transaction costs, and the increasing difficulty of demonstrating additionality.

Renewable Energy Targets

Although there are no headline targets for RE (as in the case of Sri Lanka or Indonesia), RE targets do appear in a variety of government documents and plans. For new and RE the *National Energy Strategy*, approved in 2007, established a target of 3 percent of commercial primary energy by 2010, increasing to 5 percent by 2020.[24]

The Seventh Power Development Plan (PDP7), approved by the prime minister in July 2011,[25] established the following capacity targets for RE:

- Wind energy: 1,000 MW by 2020; 6,200 MW by 2030.
- Biomass crop residues: 500 MW in 2020; 2,000 MW in 2030.
- Hydropower: from 9,200 MW in 2010 to 17,400 MW by 2020.

The expected 2020 generation mix is 19.6 percent hydro, 46.8 percent coal, 24 percent gas, 4.5 percent RE (small hydro, wind, and biomass), 2.1 percent nuclear, and 3 percent imported power. In addition, to achieve 100 percent household electrification by 2020, it was decided to electrify the remaining 600,000 households not likely to be connected to the grid by RE.

Attached to the PDP7 is an officially approved list of projects. In the case of RE, the total additions from "wind farm and renewable energy" between 2011 and 2020 is 1,660 MW (slightly more than the 1,500 MW listed above). Individual projects are not identified—only the aggregate annual targets. The best-founded targets, based (at least in part) on a supply curve analysis, are those set out in the MoIT's draft REMP, as discussed above.

Neither the PDP7 nor the National Energy Strategy targets have much practical significance, in part because they are unsupported by any detailed analysis and are simply political statements. Also, as noted above, the REMP has yet to be approved by the government, so the REMP targets in any event have no official standing. A draft of a proposed RE Decree currently under consideration by the MoIT, does not mandate numerical values of RE targets, but makes the MoIT responsible for issuing a set of headline targets and empowers the MoIT to adjust preferential tariffs to ensure that such targets are met. But in the absence of agreement on how any incremental costs will be recovered, the prospects for issuing targets in the near future are small. Indeed, this report takes the position that issuing targets in the absence of a process for sustainable incremental cost recovery is pointless.

Design of Incentive Schemes

VEPF Subsidy Scheme

In principle, the Ministry of Finance/Ministry of Natural Resources and Environment (MoNRE) Circular 58 provides a mechanism for providing subsidy to RE projects,[26] under which the VEPF would provide a subsidy equal to the difference between actual production cost plus fair return, and the tariff offered by EVN. But to date, no grid-connected RE project has been enabled by this mechanism. The one application that was made to the VEPF to support a biomass project was unsuccessful. The scheme provides no incentive for developers to seek CDM funding, nor even to design an efficient project—and precisely what constitutes a "fair return" was not defined.

Avoided Cost Tariff

The design of an ACT was entrusted to ERAV, which developed the basic rationale of setting the tariff on the basis of the avoided cost of gas generation. There remain some very high-cost diesel and fuel oil generation projects in the EVN system, but these are either being phased out, or serve mainly for system frequency support at remote parts of the network, and would not therefore be displaced by RE. We have already noted, above, the success of this tariff in enabling SHPs.

One of the design features of the SPPA that proved unnecessary was the cap-and-collar option, under which a developer would be *guaranteed* receipt of a minimum of 90 percent of the tariff prevailing on the date of PPA signature, in exchange for agreeing to a maximum payment of 110 percent of the tariff.[27] Of the 88 SPPAs signed till end 2011, *none* elected for this option—which is really a vote of confidence in the tariff methodology and the announced procedure for annual adjustment.

Wind Feed-In Tariff

The basis for the level of the wind FIT has never been made public. In fact the Institute of Energy (IoE) conducted a detailed study of wind farm production costs (based on Chinese wind turbines) and proposed a tariff of 10–11 cents kWh. This found no favor with the utility EVN and the government. Notwithstanding that wind power cannot substitute for base-load coal generation, it was proposed that the avoided cost of coal generation might be a suitable yardstick, which was estimated at 6.8 cents/kWh (though the calculations of this estimate were never published). The VEPF was enlisted to provide an additional 1 cent/kWh, though as noted, the plausibility of this contribution has been questioned given that the VEPF itself has no sustainable source of revenue.[28] Notwithstanding anecdotal reports that Chinese developers have expressed interest, the plausibility of the level of the tariff may be judged by comparison with the wind FITs in China—which have higher rates of remuneration for much better wind regimes.

Fichtner, the German wind power and adviser to the MoIT, has long advocated the merits of a "stepped" FIT, exactly following the German model (Fichtner 2009). Under this principle, the FIT is adjusted for the load factor—the higher the load factor, the *lower* the FIT. The consultant's report argued that: "A stepped FIT design leads to a homogenous generator profit that is nearly the same across all load factors, and will decrease windfall profits."

Concerns about "windfall profits" are almost always a reflection of poorly designed policies—in this case first-come, first-served access to a preferential technology-specific tariff. The solution is to make access to a guaranteed price and must-run dispatch dependent on a competitive process, rather than build further complexity into an already inefficient mechanism.

Such a design feature has no merit for Vietnam (or indeed for any other developing country where economic efficiency must be the priority). Wind developers should be encouraged to develop the best sites, not poor sites. The rationale for its adoption in Germany was regional equity—an effort to promote wind development in the interior of the country, rather than the Northwest coast, where most of Germany's wind farms are located (and where the wind regime is best). But such motivation is a luxury for rich countries, and has no basis in economic efficiency.

The principle of "degression," wherein FITs are reduced by some fixed rate over time, was also first introduced in Germany, and has been advocated as an incentive to early investment and for reducing technology costs. But the existing Vietnam wind FIT is so low that discussion of degression is academic.

Finally, arguments for technology-dependent FITs or auctions have no merit for relatively poor developing countries. Targets by technology, it is argued, are necessary to encourage *all* forms of RE. But why? What matters is that GHG emissions are reduced, not by what technology (or policy) this is achieved. The marketplace is a much better mechanism to decide what mix of technologies can most cost-effectively meet given levels of RE generation.

It is claimed that in a technology-neutral auction, in Vietnam most of the offered capacity would be hydro; a general lack of wind capacity promises to constrain wind power in the country. But why wind power should be seen as an end in itself remains a mystery. Clearly, large quantities of wind power can be enabled if the FIT is set at high levels, since the certainty of a FIT makes for a more predictable revenue stream, and is therefore favored by both lenders and potential private sector investors. But the question is at what cost, and who pays.

Great caution needs to be exercised when making international comparisons of wind energy prices. While the Decision 37 wind power tariff is certainly the lowest in Asia, prices even *lower* than 7.8 cents/kWh have been reported in Latin America, especially in Brazil, which has pioneered RE auctions (Cunha and others 2012). Support for wind power in Brazil was initially provided through a fixed FIT (the Program for the Promotion of Renewable Energy [PROINFA] scheme), with a tariff of 15.7 cents/kWh (table 3.14). In the first auction, in 2009, some 1,800 MW was offered for an average of 8.5 cents/kWh; in subsequent auctions, prices fell to the 6–7 cents/kWh range. But such low prices are made possible only by an unusually good wind regime: annual load factors of around 50 percent, and average annual wind speeds of 9 m/sec. Such high-capacity factors are extremely unlikely in Vietnam.

Moreover, the gap between developer expectations and actual performance in practice remains wide. In Brazil the National Electricity Operator (ONS) issues a monthly report tracking production of several wind farms. In the Northeast, just two wind farms that have been on line for more than a year were operating above estimated capacity factors over the past 12 months. The largest discrepancies include Praia do Morgado, a 28.8 MW wind farm owned by Energimp/Cemig, which claims an estimated capacity factor of 50 percent but has operated at an average of 31 percent in the 12 months to March; and Praia Formosa, a 104.4 MW project owned by SIIF Énergies, which claims an estimated capacity factor of 39 percent but has been operating at an average of 28.4 percent.[29] Indeed, independent experts cast significant doubts on whether the actual performance of auctioned projects will live up to their claimed capacity factors (see, for example, Barroso 2012). Table 3.15 shows a comparison of capacity factors, by country, for wind farms in operation.

Summary Evaluation

Table 3.16 compares various tariff designs using the criteria noted in chapter 2. Only the ACT can be judged successful.

Table 3.14 Capacity Factors and Wind Auction Prices in Brazil

	Power, MW	Capacity factor (%)	Brazilian real/kWh	Cents/kWh
PROINFA, feed-in tariff	1,288	32.5	308.3	15.72
2009 LER reserve energy auction	1,807	43.3	167.38	8.54
2010 LFA alternative sources auction	1,584	43.9	147.19	8.24
2010 LER reserve auction	528	50.5	134.25	7.52
A-3 2011 auction	1,067	45.4	101.35	6.18
2011 LER reserve auction	861	49.8	101.56	6.20
A-5 2011 auction	976	49.0	105.12	6.41

Source: Gornsztejn 2012.
Note: See chapter 9 for further details on Brazilian RE auctions. kWh = kilowatt-hour; LER = Reserve Energy Auction; LFA = Alternative Source Auction; MW = megawatt; PROINFA = Program for the Promotion of Renewable Energy.

Table 3.15 Wind Capacity Factors in Selected Countries

	End-2009 installed capacity	*2009 capacity factor %*
Ireland	1,270	29.0
United Kingdom	4,058	28.7
Greece	1,087	21.9
Portugal	3,535	27.1
Sweden	1,560	22.0
Denmark	3,480	23.0
Netherlands	2,221	23.6
Spain (incl. Canary Islands)	19,149	23.0
France	4,538	22.3
Germany	25,777	17.4
Italy	4,850	16.2
United States	—	28.8
India	—	12.0
Egypt, Arab Rep.	—	38.6
China	—	20.0
Brazil (auction bids)	—	43.0

Sources: Europe: Renewable UK 2011; India: World Bank; Others: International Renewable Energy Agency (IRENA).
Note: — = not available.

Table 3.16 Design of Existing RE Incentive Schemes in Vietnam

	VEPF subsidy scheme	*Avoided cost tariff*	*2011 Wind feed-in tariff*
Introduced	2008	2009	2011
Achievement to date, MW	0		0
GWh	0		0
Economically efficient	**No** (no incentives for developer to reduce costs or seek CDM)	**Yes, in principle** (though tariffs have yet to reach actual marginal cost)	**No** (level far below avoided social cost)
Market principles	**No** (first come, first served)	**Yes**	**No** (first come, first served)
Sustainable recovery of incremental costs	**No** (no sustainable source of funding)	Not applicable	**No** (unclear that VEPF can cover incremental costs)
Transparency	**Yes**	**Yes** (methodology published)	**No** (rationale unclear)
Adaptability	Not applicable	**Yes** (updated annually, reviewed by regulator)	**Limited** (only adjustment for FOREX to maintain $ denominated price)
Successful?	**No**	**Yes**	**No**

Note: CDM = Clean Development Mechanism; FOREX = foreign exchange; GWh = gigawatt-hours; MW = megawatts; VEPF = Vietnam Environmental Protection Fund.

Incremental Costs and Their Recovery

Wind Power

The incremental financial cost to the buyer (the Central Power Company, CPC) is the difference between the cost of wind energy (at the FIT) and the cost of conventional energy from the generation market operator (that is, the average wholesale price as calculated by ERAV), as shown in table 3.17. It is immediately obvious that the incremental cost to the CPC is higher than the 1 cent/kWh that Decision 37 provides as a subsidy to the buyer from the VEPF.

But D662/kWh is not the *true* incremental cost, because when 1 kWh of additional wind power is purchased by the CPC from a wind farm, the generation market (EVN) responds by reducing dispatch in *its most expensive thermal generator* by 1 kWh, and therefore avoids the *marginal financial* operating cost at that facility, and not the average wholesale price. For Ca Mau—the most expensive CCGT in the EVN system—this marginal fuel cost calculates to D1,296/kWh, so the actual (financial) incremental cost to EVN is D321/kWh (1.55 cents/kWh)[30] (table 3.18).

Small Hydro

In principle, the ACT for RE makes a buyer indifferent to whether a given quantity of RE is purchased from an SHP, or whether the same quantity of thermal energy is purchased from the system market operator (SMO). But distribution companies[31] have noted that in some areas, large concentrations of SHPs impose significant additional network development costs that need to be recovered, and that therefore potentially affect the retail tariff.

In the past, the PCs have also noted that purchases of energy from SHPs are more expensive than purchases at the bulk-supply tariff. Even though this should in principle be equalized across PCs over the long term, in the short run this difference may raise cash-flow issues.

Table 3.17 CPC's Incremental Financial Cost of Wind Energy, 2011

	D/kWh	*Cents/kWh*	
Wind power tariff	1,617	7.8	As stipulated in Decision 37
Wholesale cost	956	4.6	As calculated by ERAV
Incremental financial cost	662	3.2	

Source: ERAV 2012.
Note: CPC = Central Power Company; kWh = kilowatt-hour; ERAV = Electricity Regulatory Authority of Vietnam.

Table 3.18 EVN's Incremental Financial Cost of Wind Energy, 2011

	D/kWh	*Cents/kWh*	
Wind power tariff	1,617	7.80	As stipulated in Decision 37
EVN avoided cost	1,296	6.25	Ca Mau
Incremental financial cost	321	1.55	

Source: ERAV 2012.
Note: kWh = kilowatt-hour; EVN = Electricity of Vietnam.

Table 3.19 Small Hydro Project: Typical Purchase Costs vs. Wholesale Price, 2010–11

	2010		*2011*	
	RoR	*Daily peaking*	*RoR*	*Daily peaking*
Wholesale price	718	718	891	891
SHP	600	740	640	850
Impact of SHP	–118	22	–251	–41

Source: ERAV 2012.
Note: RoR = run-of-the-river; SHP = small hydro project.

In 2010 the wholesale price (before equalization) was D718/kWh, whereas a typical RoR SHP had a tariff of around D600/kWh, so RoR prices (and projects with old PPAs with average tariffs of D625/kWh) were *cheaper* than the wholesale price. But purchases from daily peaking projects under the ACT were D22/kWh more expensive (table 3.19).

But by 2011 even daily peaking power projects under the ACT, at D850/kWh, were D41/kWh cheaper than the wholesale price. Energy from RoR projects is cheaper still. Indeed, for reasons discussed further below, the *actual avoided costs* of SHP are greater than the ACT.

But the problem of high network developments costs associated with SHPs is significant: these costs arise because local loads in some of the rural provinces where there is much SHP development are smaller than the SHP output, especially in the wet season, which must therefore be evacuated to more distant load centers. In practice, often because of the very long distances involved, this means additional 110 kV development costs.

For example, nowhere is this disparity greater than in Muong Te district in Lai Chau province (in Vietnam's Northwest): by 2020 the local loads are unlikely to exceed 10 MW, but 120 MW of small hydro will feed into the Muong Te 110 kV substation. This power needs evacuation to the national grid. But a clear identification of incremental 110 kV development costs, attributable solely to SHPs, is more difficult than it at first appears. Many 110 kV lines in remote areas would be built anyway as part of the national strategy to extend the grid into rural areas: the presence of SHPs simply accelerates the *timing* of these lines. Indeed, a review of provincial transmission and distribution (T&D) development plans reveals that by 2020 almost all district towns, even in the most remote areas, would be served by the grid, even where there is no SHP development.

In 2011 ERAV prepared a detailed examination of these incremental transmission costs in six provinces with large concentrations of small hydro. The detailed transmission plans were examined in these projects, and 110 kV network costs, classified by whether they were needed solely for SHP power evacuation, or would be needed even in the absence of small hydro. The results are shown in table 3.20: for the six provinces, some $67 million in incremental network development costs were identified, equivalent to $51/MW in additional investment costs. These costs are not recovered in the present avoided cost generation tariff.

Table 3.20 Summary of Incremental Network Costs

	To 2015	*2016–20*	*Total*
Incremental costs (D billion)			
Dak Nong	117	84	201
Nghe An	153	0	153
Gia Lai	506	0	506
Lai Chau	236	109	345
Son La	198	0	198
Total	1,210	193	1,403
Dak Nong	63.4	87.5	71.7
Nghe An	48.0	0.0	41.1
Gia Lai	71.1	0.0	65.8
Lai Chau	66.2	28.2	46.5
Son La	33.7		33.7
Total	56.0	32.6	51.0
Total, D billion/MW	1.1	0.7	**1.0**

Source: ERAV 2012.
Note: MW = megawatt.

Table 3.21 Connection Costs at Large Hydro and Thermal Projects

		220 kV	*Installed capacity*	*Cost*		
Project	*Type*	*Circuits x km*	*MW*	*D billion*	*D billion/MW*	*$/MW*
Non Trach 1	CCGT	(2 x 0.7 km) + (4 x 0.7 km)	450	18.3	0.04	2.0
O Mon 1	CCGT		600	66.7	0.11	5.4
Average	CCGT		1,050	85.0	0.08	**3.9**
Nghi Son 1	coal	2 x 6.7 km	600	130.0	0.22	10.6
Son Dong	coal	2 x 18 km	220	73.4	0.33	16.3
Average	coal		820	203.3	0.25	**12.1**
Srepok 4	hydro	2 x 6.7 km	70	30.9	0.44	21.5
A luoi	hydro	2 x 30 km	150	146.0	0.97	47.5
Dong Nai 3	hydro	2 x 30 km	180	81.7	0.45	22.2
Dong Nai 4	hydro	2 x 11.4 km	340	39.9	0.12	5.7
Huoi Quang	hydro	2 x 17.9 km	560	149.6	0.27	13.0
Trung Son	hydro	2 x 63 km	260	452.8	1.74	84.9
Ban Chat	hydro	2 x 27.4 km	220	163.5	0.74	36.3
Average	hydro		1,780	1,064.3	0.60	**29.2**

Source: ERAV 2012.
Note: CCGT = combined-cycle gas turbine; km = kilometer; MW = megawatt.

How do these costs compare to the connection costs of *thermal* generation and of large hydro—which in most cases are at 220 kV and the responsibility of the National Power Transmission Company? As shown in table 3.21, the average connection cost of CCGTs is $3.9/MW, $12.1/MW for coal, and $29.2/MW for large hydro. So even when the avoided thermal connection costs were subtracted from the small hydro requirements, there remains a balance of around $40/MW that is apparently unrecovered.

This unrecovered cost is, however, offset by a deviation from strict marginal cost evaluation in the calculations used to determine the avoided fuel cost. The original intention of the tariff design was to calculate the average fuel costs of a set of the most expensive thermal plants that corresponded to the inventory of renewables in the portfolio. So, if there were 500 MW of small hydro operating, one would calculate the average variable cost of the most expensive 500 MW of thermal capacity. This was already a deviation from a strict marginal cost evaluation, which would simply have applied the variable cost of the single-most expensive project.[32] But this last method would have resulted in a tariff that was unacceptable to the PCs, and therefore the final procedure adopted an averaging interval whose width was determined by the regulator.

To show the impact of this averaging interval, consider Vietnam's most expensive thermal projects, as shown in table 3.22. Ca Mau has the highest variable (fuel) cost at D884/kWh (4.67 cents/kWh), followed by the Formosa imported coal project at D671/kWh (3.77 cents/kWh), and then the other CCGTs listed in order of decreasing cost.

Assume that in the peak hour, all of these plants are operating and are stacked in the order shown in figure 3.14. In the peak hour, if there were an additional 270 MW of SHPs, the most expensive thermal project (Ca Mau) would be backed down, so the avoided cost is D884/kWh. But the ACT calculates the average of thermal costs across a capacity band across all six plants (3,798 MW), which brings the amount to D636/kWh. So the benefit to EVN is the difference between these two values, D248/kWh.

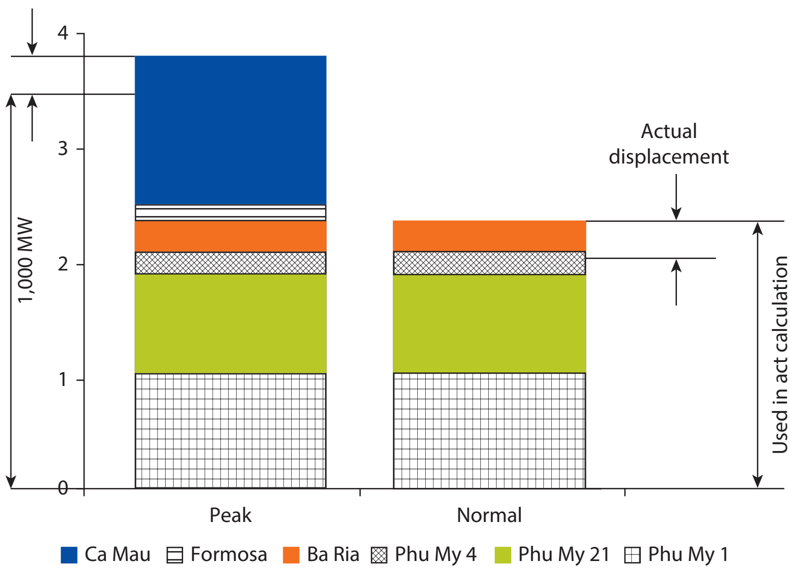
In normal, off-peak hours, neither Formosa nor Ca Mau would be dispatched[33]; 300 MW of SHP would result in 270 MW of Ba Ria (D545/kWh), plus 30 MW of Phu My 4 (D494/kWh) being backed down, for an average of D540/kWh. But the ACT averages costs over all four of the operating plants, namely D499/kWh. In short, the actual avoided costs are higher than the reimbursement (presently) provided to the SHP in the ACT.

Table 3.22 Merit Order Stack, 2010

	Fuel cost		*Capacity*
	D/kWh	*Cents/kWh*	*MW*
Ca Mau	884	4.67	1,286
Formosa	671	3.55	150
Ba Ria	545	2.88	270
Phu My 1	494	2.61	1,021
Phu My 21	494	2.61	858
Phu My 4	494	2.61	213
Total			3,798

Source: National Load Dispatch Centre (Vietnam) (NLDC) avoided cost tariff (ACT) calculations.
Note: Exchange rate at $1 = D18,920. kWh = kilowatt-hour; MW = megawatt.

Figure 3.14 Averaging Intervals in the Avoided Cost Tariff



Source: ERAV 2012.
Note: MW = megawatt.

The conclusion is that even though the incremental transmission cost was not included in the ACT, this is offset by the wide averaging interval used for the calculation of the avoided fuel cost, with the result that the ACT as issued is a good approximation of EVN's avoided cost. But the problem is that the incremental transmission investments have to be provided *up front* by the PCs before the SHPs are operating, which in the present situation of stressed cash flows they find difficult to mobilize.

Cost Recovery

At the time of writing, a sustainable mechanism for incremental cost recovery has yet to be established. As noted, the MoIT is presently drafting a RE Decree that may or may not include a new proposal to establish an RE fund supported by a consumer levy. With the bulk of the RE having been provided by small hydro at costs lower than the EVN's actual avoided cost, there has been no need for a cost-recovery mechanism.

All this would change if a FIT were introduced for wind at around 12 cents/kWh—the level recommended by the many advocates of wind power in Vietnam. The difficulty is that the bulk of the wind resource falls into the service area of the CPC, the distribution company in the central region, with whom the PPA would be signed. Serving mainly the areas with low-load density, the CPC is one of the weakest of Vietnam's distribution companies, whose cash flow and margins are causing problems even in the absence of such additional cash obligations. As the signatory to the PPA, it would be required to meet invoices from the wind farms within 30 days of billing *in cash*. But as shown in table 3.23,

Table 3.23 Impact of a 12 Cents/kWh Feed-In Tariff on CPC Cash Flows

		2011	2012	2015	2020	2022	2023
Without RE purchases							
Sales growth	%		12	12	12	12	12
Total kWh sales	TWh	10	11	16	27	34	39
Retail tariff [table 3.10]	D/kWh	1,242	1,292	1,370	1,370	1,370	1,370
Consumer bill	D billion	12,296	14,322	21,347	37,621	47,191	52,854
Purchased from SO	TWh	11	12	17	30	37	42
Average purchase cost to PC	D/kWh	956	994	1,055	1,055	1,055	1,055
SO purchases	D billion	10,287	11,983	17,860	31,476	39,483	44,221
Distribution margin	D billion	2,008	2,339	3,487	6,145	7,708	8,633
With RE purchases							
Installed capacity	MW	26	26	255	850	1,360	1,785
RE energy purchased	GWh	64	64	637	2,122	3,395	4,456
Average cost of RE	D/kWh	2,520	2,520	2,520	2,520	2,520	2,520
RE purchases	D billion	160	160	1,604	5,348	8,556	11,230
Energy from SO	TWh	11	12	16	28	34	37
SO purchases	D billion	10,227	11,919	17,189	29,237	35,902	39,520
Distribution margin	D billion	2,008	2,339	3,487	6,145	7,708	8,633
Incremental capacity costs	D billion	0	0	170	609	986	1,301
Total cost	D billion	12,395	14,419	22,449	41,340	53,153	60,685
Incremental costs							
Additional cash required	D billion	100	97	1,102	3,719	5,961	7,830
As % of distribution margin	%	5.0%	4.2%	31.6%	60.5%	77.3%	90.7%

Source: ERAV 2012.
Note: CPC = Central Power Company; kWh = kilowatt-hour; PC = pulverized coal; RE = renewable energy; SO = system operator; TWh = terawatt-hour.

the incremental cash costs of meeting the 2020 PDP7 target (1,000 MW, of which 850 MW is assumed to be in the CPC's service area) represent 60.5 percent of the CPC's distribution margin.

This is the main reason for the RE fund. Without the fund, it is very doubtful whether the CPC can meet its current cash obligations for the incremental costs of a significant amount of wind power, and at some point the CPC may simply refuse to sign additional PPAs. There will be difficulties even at the 7.8 cent tariff of Decision 37: at higher tariffs the incremental cash requirements will be impossible to meet. But *with* the guarantee of the fund, which could disburse the incremental costs upon submission of the seller's invoices within weeks, the CPC's cash shortfall is quickly made up.

Impact of Renewable Energy Tariffs on the Consumer

In the case of Vietnam, one can only examine the future impact of RE tariffs on the consumer, either because existing tariffs have no impact (because they are unsuccessful, as in the case of the wind FIT) or because, by definition, the ACT involves no incremental costs. Therefore, we examine the potential impact on

Table 3.24 Impact on Consumers: 1 Percent Additional Wind Power by 2020

		Units		*Source*
1	2020 baseline generation, PDP7	TWh	211	PDP7
2	Target energy to be replaced	[%]	1.0	
3	Target energy to be replaced	GWh	2,118	
4	Load factor of wind	[ ]	0.269	IoE assumption
5	MW of wind required	[MW]	899	
6	Cost of wind power	Cents/kWh	11.3	
7	Wind capacity penalty	Cents/kWh	1.2	
8	Avoided cost of gas-fired CCGT	Cents/kWh	–5.7	
9	Incremental cost	Cents/kWh	6.8	
10	Total incremental cost	[$ million]	145	
11	Impact on consumer			
12	Retail sales	TWh	194	8% growth over 2012
13	Incremental cost per kWh	Cents/kWh	0.07	
14	Incremental cost per kWh	D/kWh	15.5	
15	Baseline tariff	D/kWh	1,450	Expected 2013 tariff
16	Tariff increase	[ ]	1.1%	
18	Avoided GHG emissions			
19	Emission factor	kg/kWh	0.4	Emission factor for natural gas
20	Avoided GHG emissions	Million kg	847	
21	Carbon value	$/ton	171	

Note: CCGT = combined-cycle gas turbine; GHG = greenhouse gases; GWh = gigawatt-hour; IoE = Institute of Energy; kWh = kilowatt-hour; MW = megawatt; PDP7 = Seventh Power Development Plan; TWh = terawatt-hour.

the consumer if the wind FIT were raised to the 12.9 cents estimated as the baseline financial cost (including the capacity penalty).

Table 3.24 shows the calculations, assuming that 1 percent of the 2020 generation (2,118 GWh) would be replaced by wind power, which would require an additional 899 MW of wind power. The total incremental variable cost is $145 million.

When spread over total consumer sales (194 TWh), the incremental cost per retail kilowatt-hour is D15/kWh (0.07 cents/kWh), corresponding to a 1.1 percent consumer tariff increase. While this increase may seem small to some, the Government of Vietnam evidently sees this as unacceptably too high. Indeed, replacing gas generation with wind implies a high carbon price to the consumer, equal to $171/ton CO_2eq.

Another way of assessing the magnitude of this incremental cost is to compare it with the avoided emissions that result from a 5 percent increase in electricity price (the expected increase in the 2013 retail tariff), from a decline in overall energy consumption (as might be the consequence of a small improvement in the income elasticity of electricity demand). A 1 percent demand reduction would again be accommodated by reducing the generation of 2,118 GWh in the most expensive thermal generation, namely, CCGT gas (equivalent to the output of a 280 MW CCGT).

Decreasing the Consumer Cost with International Assistance

Can the high consumer cost of carbon reduction be "bought" down by other interventions? The following seven measures may be considered:

- *Sale of carbon credits*: for which we assume \$15/ton CO_2 in a seven-year Emissions Reduction Purchase Agreement (ERPA), renewed once, with 70 percent of expected CERs sold (this corresponds roughly to the terms of the project development agreement [PDA] currently under consideration).
- *Government-owned development bank financing*: based on a subsidized interest rate of 12 percent (versus 18 percent for normal commercial borrowing), 15 years including a 2-year grace period.
- *Income tax exemption*.
- *Accelerated depreciation*: five years rather than the 20 years in the baseline.
- *International Bank for Reconstruction and Development (IBRD) finance*: 24.5 years, including 9 years' grace, \$ London inter-bank offer rate (LIBOR) swap 2.85 percent + 2 percent spread.
- *Carbon finance*: Clean Technology Fund (CTF), noninterest bearing, 40 years, 10-year grace period, service charge at 0.35 percent.[34]

The results are shown in table 3.25. Almost 100 percent of the incremental cost can be bought down by carbon finance (under typical CTF terms); the IBRD loan brings the remaining incremental cost to Vietnam (for a 30 MW wind farm) to \$50 million. By comparison, the CDM revenue (at \$15/ton CO_2, achievable in the past in some years, but doubtful in the short term) buys down just 6 percent of the incremental cost.

The Cost of Fossil-Fuel Subsidies

There are two major sources of fuel subsidy in Vietnam. The first is for coal, supplied to the EVN's coal-burning power stations by the state-owned monopoly coal company (VINCOMIN). The price to EVN is fixed by the government, and

Table 3.25 Buying Down the Cost

	Tariff required, cents/kWh	*Buy down, \$ million*		*Remaining incremental cost, \$ million*
Baseline	11.3	0.0		41.7
CDM	10.8	2.6	6%	39.2
Income tax exemption	9.7	8.9	21%	32.8
Accelerated depreciation	10.8	2.8	7%	39.0
SBV loan	9.8	8.6	21%	33.1
IBRD	5.7	31.7	80%	10.1
CTF	4.0	41.6	99%	0.2

Note: CDM = clean development mechanism; CTF = clean technology fund; IBRD = International Bank for Reconstruction and Development; kWh = kilowatt-hour; SBV = State Bank of Vietnam.

Table 3.26 Impact of Price Increases to Reduce Subsidy

1	Baseline tariff	D/kWh	1,361
2	New tariff	D/kWh	1,491
3	Increase	[percent]	9.55
4	Inflation	[percent]	6.00
5	Real price increase	[percent]	3.35
6	Price elasticity (–0.2)	[percent]	99.34
7	Demand contraction at consumer	[GWh]	1,277
8	At bus bar	[GWh]	1,379
9	Avoided costs	D billion	2,056
10	Loss of consumer surplus	D billion	90
11	Deadweight loss recaptured	D billion	1,966
12	Deadweight loss recaptured	$ million	94
13	Emission reduction	Million kg	552

Note: kg = kilogram; kWh = kilowatt-hour.

kept at a low level in the interest of keeping down the electricity price. The theory is that profitable export sales can offset losses in domestic sales to EVN. The government also imposes a 20 percent export tax on coal. Promises that domestic coal prices would be raised to at least the production cost, if not the international border price, have been made since 2006, but to date, price increases have been small. The net result is that VINCOMIN is now making large losses, and the present situation is not sustainable. Significant price increases are expected to be passed to the consumer in 2013 and in the coming years.

Gas is also subsidized. As noted, gas from the older onshore fields is priced at production cost, without a depletion premium, while offshore; Ca Mau gas is priced at roughly 45 percent of the border price. But at least one can say that the cost is above the production cost, which is clearly not the case for coal.

In table 3.26 we show the impact of the proposed tariff increase in 2013, from D1,361/kWh to D1,491/kWh, which at 6 percent inflation provides for a real price increase of 3.35 percent. At a price elasticity of –0.2, this results in 1,277 GWh less demand at the consumer level, or 1,379 GWh at the bus bar. This corresponds to avoided costs of D2,056 billion, offset by loss of consumer surplus, for a net economic gain of $94 million (which represents the recapture of the deadweight loss of the subsidy).

Conclusions

We draw the following conclusions from this case study:

- *Resource endowment*. Compared to the wind resource in China (or to the U.S. state of Texas, or Scotland, or the Arab Republic of Egypt), the wind resource in Vietnam is modest. Its most unfavorable characteristic is its high degree of seasonal variation. By contrast, Vietnam's competitive advantage lies with small hydro: at least another 1,000 MW could be exploited at costs below or at the avoided social cost of thermal generation.

- *Targets*. Although RE targets are included in a number of official documents, to date there is no widely publicized headline target. But given the lack of agreement on incremental cost recovery, there is indeed no point in setting targets.

- *Design of incentive schemes*. Paradoxically, Vietnam has both the best and the worst of designs. Both the VEPF and the wind FIT are poorly designed, not transparent, and unsuccessful. On the other hand, Vietnam's ACT, coupled with institutional reforms (such as standardization of the PPA and regulatory devolution to the provinces for small projects) is one of the Asian RE success stories.

- *Recovery of incremental costs.* In large measure because of the success of the small hydro program, creating a mechanism for the recovery of incremental costs for the more expensive renewable technologies (wind and biomass) has been seen as a low priority: the proposal for an RE fund to facilitate disbursement to wind developers languishes. But the cash-flow calculations for the CPC, where most of the wind resource is located, shows clearly that without such a fund, the CPC cannot meets its obligations for timely cash payments to wind farms as required by any bankable PPA. Without such a mechanism, the chances of large-scale wind development in Vietnam are in any event small.

- *Impact on consumers.* The impact on the consumer tariff of an additional 1 percent of RE from wind power by 2020 is estimated at 0.07 cents/kWh, or 1.1 percent of the estimated 2020 tariff. That may seem small, but reflects an incremental cost of $145 million, and an avoided cost of carbon of $171/ton CO_2. It is clear that such increases in tariffs are not politically acceptable for the time being (the best evidence of which is the continued refusal of the government to approve the proposed REMP, which proposes a consumer tariff levy of about this magnitude).

- *Transmission development*. Most of the discussion about the need to develop the transmission infrastructure to enable RE development has been in support of wind power. But Vietnam's experience shows that successful small hydro development is no less dependent on transmission network development. The problem in Vietnam has been not so much the *magnitude* of the incremental investment required (at $51/MW a small increase [3 percent] compared to the capital costs of around $1,500/kW), but that the entities responsible for transmission have weak cash flows and difficulty in meeting even the normal investment requirements. International financial institution (IFI) and bilateral assistance to the sector has been directed primarily to generation (in the case of the Bank's RE Development Project, on lending for developers): future support should also be made available to the PCs for related transmission network development.

- *Regulatory framework*. Although there is a regulator (ERAV), as part of the MoIT it is not sufficiently independent (as is the case, for example, in the Philippines, or the Public Utilities Commission [PUC] in Sri Lanka). Nevertheless, ERAV has high technical competence, and has been at the forefront of innovative RE tariff development, as evidenced by its 2009 introduction of the ACT. Its annual review of the tariff has been transparent and timely.

- *Fossil-fuel subsidies*. The average wholesale cost of electricity is expected to rise considerably over the next few years, as the subsidies to the coal industry have become unsustainable, forcing price rises in the cost of coal to EVN. Coal projects, even when paying full market price, are not at the margin of the merit order so this will have little impact on the ACT or the avoided social cost of thermal generation. But the average price of electricity to the PCs will increase, pushing average prices higher than the current ACT for RE. This will make it easier for the MoIT to raise the ACT, which will be helpful to the development of further SHPs.

- *Off-grid* RE. Notwithstanding the expectations of the 2001 REAP, powering small grids of less than 1 MW in remote areas with small hydro have mostly proven unsuccessful. Costs have trebled over early estimates, and competent construction supervision in remote areas has proven virtually impossible.[35] Vietnam has yet to develop a sustainable institutional model for electrifying these remote areas with RE at reasonable cost—in which it is of course in good company with its Association of Southeast Asian Nations (ASEAN) neighbors.[36]

- *Environmental impact of renewable*. Small hydro development is not without its environmental problems. Often the most damaging impacts arise in road construction necessary for projects in the remote hilly areas subject to torrential rains in the wet season. But there have also been problems related to dam safety. This is largely a consequence of regulatory devolution from the MoIT (which until 1997 had an important technical review function) at the center to the provincial authorities—authorities whose capacity to evaluate and monitor dam safety and environmental issues of even small projects is often weak—for projects less than 30 MW.

- *Buying down incremental costs*. The analysis shows that carbon finance, the IBRD, and concessionary loads can indeed buy down the incremental costs of wind power. But the question of who pays does little to improve the balance sheet or the economic comparisons, and does not change the high avoided cost of carbon, relative to other more cost-effective renewables, notably hydro.

- *The main problem*. In 2011–12 the pace of small hydro development slowed, largely a consequence of a credit squeeze, high interest rates, and increasing civil costs. While the World Bank–supported RE Development Project offers financing support (on-lending though commercial banks) at longer tenors than those available in the commercial banking system, for reasons explained above interest rates are tied to the commercial lending rate, so there have been few takers, and substantial funds remain undisbursed. Calls for making subsidized loans through the Vietnam Development Bank available have been resisted, largely on grounds that social and agricultural development sectors should have priority on the available funds: such funds would indeed buy down the consumer burden. But poverty alleviation and rural development have a much higher priority for the government, thus challenging a rational economic case for extending subsidized loans for grid-connected RE generation.

In short, Vietnam is a success story for RE even though it has refused thus far (and in our view, correctly so) to provide subsidy for wind and biomass. The ACT (and related PPA reforms) has enabled 800 MW of small hydro at no incremental cost to the government or consumers. Provided the government adheres to its announced policy to end coal price subsidies to EVN, and to raise consumer tariffs to better reflect the true cost of supply, the impact on GHG emissions relative to the existing baseline will be much the same as another 800 MW of RE generation. Indeed, reducing subsidies incurs no incremental costs, but rather brings net economic *benefits*, as deadweight losses are recaptured.

Notes

1. The reform program involved a set of measures aimed to gradually move from central planning to market mechanisms and to open up the economy to trade and foreign investment. Key measures included:
   - *Agricultural sector reform*. Agricultural collectives were dismantled, land was distributed among farming households, and peasants were given land-use rights for 20 years. These land-use rights could be renewed, and there was also the option of selling or mortgaging the land.
   - *Price reform*. Controlled prices for most goods and services were abolished.
   - *Macroeconomic reform*. Production and consumption subsidies were eliminated from the budget. Interest rates on loans to state firms were raised above the level of inflation.
   - *Increased integration with the international economy*. The opening of Vietnam's economy to international markets was initiated with the unification of the country's multiple exchange rates and the devaluation of the dong, followed by gradual structural reforms in foreign trade and investment.

2. A 2008 MoIT survey showed the following project pipeline for SHPs:

	Number of projects	*Total installed capacity, MW*	*Average project size, MW*
MoU	178	2,175	12.2
Under construction, no tariff information	21	260	12.4
Under construction, tariff known	67	630	9.4
Under construction, signed power purchase agreement (PPA)	11	101	9.2
In operation	42	278	6.6
Total	319	3,443	10.8

3. The need for such a fund had been identified already in 2001 in the RE Action Plan (REAP), though under the original proposal it was to be funded just by the Government of Vietnam and donors.
4. The classification of hours into peak (4 hours), normal (14 hours), and off-peak (6 hours) follows that of the retail tariff design.
5. This 20 × 1.5 MW wind farm, built by a Joint Stock Company, started operation in 2009, and used German Fuhrlaender Turbines. How the project was financed in the absence of a PPA is unknown. The project operated under an interim agreement with EVN at a reported 4.5 cents/kWh. It is hardly surprising that this project is the first (and only one) to have signed up for the new wind FIT of 7.8 cents/kWh.
6. Decision 37/2011/QD-TTg, June 29, 2011: *On the Mechanism Supporting the Development of Wind Power Projects in Vietnam*.
7. The GTZ-Fichtner Report on wind power in Vietnam estimated the average levelized cost of wind generation as a function of the quality of the wind regime, assuming an after-tax return on equity of 15 percent, Nordex S70 turbines, weighted average cost of capital (WACC) of 11.5 percent, and capital cost of $1,813–$1,842/kW, depending on hub height. Based on these calculations, Fichtner recommends an initial FIT of 10.5 cents/kWh, which would "allow for developing an average site under good conditions."

		Poor	*Fair*	*Good*
Average annual wind speed at 60 meters	m/sec	5.8	6.7	7.22
Full load hours	Hours	1,929	2,712	3,055
Annual load factor	%	22.0%	31%	35%
Average levelized cost (20-year life)	Cents/kWh	16.5	12.0	10.8
	D/kWh	3,399	2,472	2,224

Note: Exchange rate: $1 = D20,600; €1 = D28,000.

8. This problem not restricted to RE; the officially approved list of large thermal and hydro projects in the Seventh Power Development Plan (Vietnam) (PDP7) is also a poor indication of what is likely to be realized: the issue is simply that projects that are *not* included in the official list find subsequent approvals difficult to obtain.
9. Through a mix of s mall hydro (Northwest), PV and wind-diesel hybrids (coastal islands), household PV solar home systems, and some biogas (in the South).
10. By comparison, in the Philippines the capital cost assumption for calculating the FIT is $2,758/kW.
11. Annual foreign exchange (FOREX) depreciation rate = (1 + domestic inflation rate)/(1 + $ inflation rate).

12. According to the 2012 tax code revisions, losses can now be carried forward to a maximum of five years.
13. The reported cost of the 20 × 1.5 MW Tuy Phong wind farm—the only operating wind farm in Vietnam at present—is $80 million ($2,666/kW) (Tuan 2010). This is for the first phase of the project, but may include road and site development costs for its total development, which is planned at 120 MW. Also, the capital cost reported in the Project Design Document submitted to the United Nations Framework Convention on Climate Change (UNFCCC) for Clean Development Mechanism (CDM) registration shows a capital cost of D798 billion (at the 2006 exchange rate of $1 = D16,000, equal to $1,664/kW).
14. Estimates of the capacity credit in a range of U.S. systems was first reviewed by Grubb and Meyer (1992). The capacity credit was found to generally *decrease* as the level of wind in the system *increases*. For example, in the Kansas Gas and Electric system the capacity credit falls from 50 percent at 5 percent wind penetration (wind megawatts as a percentage of system peak) to 30 percent at 20 percent penetration. At low penetration levels (5–10 percent), most estimates of capacity credit are between 20 percent and 50 percent. The flood of more recent studies on the topic vary little in their conclusions, as acknowledged by leading industry groups such as the British Wind Energy Association (BWEA).
15. http://www.ofgem.gov.uk/Networks/Trans/.../8449-19604_BWEA.pdf.
16. Even though such small plants are not in fact under the control of the regional or national load dispatch centers, the project operator has strong incentives to dispatch into the peak period because of the incentive provided by the ACT—namely a capacity payment of D1,805/kWh (see table 3.3) for power delivered during peak dry season hours.
17. In 2008 the ADB proposed a wind-diesel hybrid for Ly Son Island. But the economic analysis showed that even with an off-peak tariff to encourage ice-making during the night (fishermen presently pick up ice from the mainland before heading out to sea), the effective load factor of wind power was just 14 percent. The level of subsidy required for the hybrid was little less than the current level of subsidy to maintain an old diesel unit, and the proposal was abandoned. Now under consideration are small-scale coal units (as in the many Indonesia Islands presently served by old diesel units), but the (Chinese) technology for such units has yet to be successfully demonstrated and its environmental impacts are yet unresolved.
18. There are significant climate differences across the major regions of Vietnam. In the North, the wet season is July–September; in the Central Highlands, it is September–December. The system coincident peak is in November.
19. An excellent example of the law of unexpected consequences.
20. There are a number of older CCGTs in Vietnam whose heat rates are significantly below that of Ca Mau, but whose gas price is subsidized. These are lower (cheaper) in the merit order.
21. Organisation of Petroleum Exporting Countries (OPEC) Reference Basket (crude oils).
22. The financial price from older domestic gas fields is much lower:
    - $3.2/million British thermal units (mmBTU) for gas delivered from Block 6.1 of the Nam Con Son field, escalating at 2 percent per year. The price includes taxes, gas transmission costs, and PetroVietnam's fees.

- $2.2/mmBTU for gas delivered from Block PM3-CAA in the Southwest basin of Ca Mau. The wellhead price also escalates at 2 percent per year, to which is added a transportation cost of about $0.9/mmBTU.

23. Climate Focus 2008. By mid-2008 there were only two registered CDM projects in Vietnam—the Rang Dong Gas Flaring Reduction project and a single SHP (2 MW, Sing Muc). This compared to 54 SHPs approved in China, and 39 in India by mid-2008.
24. Office of the Prime Minister, *Approving Vietnam's National Energy Development Strategy to 2020, with Outlook to 2030*, 1855/QD-TTg, December 27, 2007.
25. Office of the Prime Minister, *On Approval of the National Power Development Plan between 2010 and 2020, with Outlook to 2030*, 1208/DD-TTg, July 21, 2011.
26. Circular 58/2008/TTLT-BTC-BTN&MT, Ministry of Finance and Ministry of Natural Resources and Environment, Financial Mechanisms, Policies of Investment Project under the Clean Development Mechanism.
27. See the Sri Lanka case study, chapter 4, for a similar provision in the Sri Lanka ACT.
28. Its main sources include a 2 percent levy on certified emission reduction (CER) sales, and revenues from environmental permits. Although it has published a subsidy scheme for grid-connected RE projects, the one application for a biomass combustion project was unsuccessful.
29. ABEEólica (the Brazilian wind power association) reports that 12 wind farms across the country performed at an average capacity factor of 32.54 percent in the first three months of 2012, compared with 15.82 percent during the corresponding period in 2011. This documents the large annual variations that may be encountered in operating wind farms, with a variability that is much greater than for small hydro.
30. Note that this is lower than the avoided *social* cost, which is based on the full international border price of gas, not 0.45 as mentioned in the Ca Mau gas supply agreement.
31. The distribution companies, which have been unbundled from EVN were formerly known as power companies (PCs). Some serve urban areas, but the three most affected by RE development are the Northern, Central, and Southern power companies, with generally low load densities and serving large rural areas. To maintain a national uniform tariff, the PCs are cross-subsidized by the urban PCs (such as the Hanoi and HCMC power companies), a process known as equalization.
32. As noted, fuel oil and diesel plants, in fact the most expensive projects in the EVN system, were excluded from the calculations precisely on the grounds that these would not likely be displaced by RE projects given their role in meeting peak-hour system stability at the extremities of the network.
33. In reality, Formosa is a base-load plant, and would not follow the daily load curve.
34. Terms as per the Indonesian IBRD/CTF loan for the Ulubelu and Lahendong Geothermal Projects.
35. This is true of small-scale electrification of systems supported by the JICA, by the Swedish SIDA, as well as the Bank-supported program in Muong Te.
36. For example, the Philippines has struggled to find a sustainable model for PV solar home systems (SHSs): the model currently under consideration in which rural coops provide PV SHSs as a fee-for-service may be sustainable (the so-called "PV mainstreaming" model), but has over twice the cost of providing the same level of service with small diesels.

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CHAPTER 4

Case Study: Sri Lanka

Sector Background

The Sri Lankan economy has seen robust annual growth at 6.4 percent over the last decade, well above its regional peers. Following the end of the civil conflict in May 2009, gross domestic product (GDP) growth rose initially to 8 percent, largely reflecting a "peace dividend" following the end of the civil conflict, and underpinned by strong private consumption and investment. Growth was around 7 percent in 2013, driven by a rebound in the service sector which now accounts for approximately 60 percent of GDP (World Bank 2014).

The Ceylon Electricity Board (CEB) is the main state-owned vertically integrated power utility. It has the monopoly for large hydro and transmission, and for most generation, together with a number of independent power producers (IPPs). Two entities are involved in distribution: the CEB and the Lanka Electricity Company Pvt. Ltd. (LECO).[1] The LECO was established in 1983 to distribute electricity in areas previously served by local authorities (municipal councils and so on), mainly between Galle and Negombo along the Western coastal belt: the LECO purchases its entire supply from the CEB at 33 and 11 kV. In 2011 the CEB had 4.7 million customers, the LECO 490,000 (SLSEA 2011).

Load growth over the past two decades has averaged around 7 percent (table 4.1), though with much lower growth in the years of severe power cuts (that have occurred frequently in dry years, largely for reasons of the failure to build additional base load generation projects).[2]

Even though tariffs have increased over the past few years, in real terms the tariffs have increased little: indeed, as noted below, in real terms the tariffs have barely changed since the mid-1980s.[3] Nevertheless, even if the electricity intensity of the economy has been permanently reduced, with the resumption of robust economic growth, continued electricity demand growth—and the consequent need for additional generation investment—must be expected. But whether the on-going rehabilitation of the war-distributed areas will result in significant additional electricity demand is unclear: the bulk of the consumption in these areas is residential.[4]

Table 4.1 Electricity Sales
GWh

	2000	2005	2009	2010	2011	2012
Domestic	2,061	2,866	3,373	3,651	3,928	4,063
Religious	37	49	51	55	59	63
Industrial	2,203	2,732	2,773	3,148	3,379	3,528
Commercial	1,073	1,465	2,059	2,224	2,490	2,614
Street lighting	68	141	133	130	133	139
Total	5,443	7,253	8,389	9,209	9,989	10,407
Growth rate (%)		5.9	3.7	9.8	8.5	4.2

Source: SLSEA 2012.

Primary Energy Use

The primary energy supply in Sri Lanka is dominated by biomass (43.7 percent in 2011, down from 50.7 percent in 2000), followed by petroleum (43.4 percent), hydro (8.5 percent), and renewable energy (RE) (excluding large hydro 1.5 percent) (SLSEA 2011). A small amount of coal is imported for industry. *Biomass* supplies are largely from home gardens and from the replanting program of the rubber industry, while rice husk and other agricultural waste is also increasingly used for energy requirements. *Petroleum* requirements—crude oil and refined products—are imported. About 40 percent of petroleum product consumption is for power generation (as diesel, fuel oil, and naphtha), with the remainder largely used in transport. *Hydropower* was the main resource for electricity generation until the mid-1990s, after which the growing demand for electricity has been met mainly by oil. *Wind power* generation is limited to a small pilot-scale plant.

Institutional and Regulatory Framework

Sri Lanka's energy industry is managed by two ministries (power and energy, and the petroleum and petroleum resource development). Although all electricity utilities remain under direct or indirect state ownership, there is significant private sector participation in power generation and in petroleum distribution. Biomass remains in the informal market, but an estimated 20 percent of biomass is traded.

The Public Utility Commission of Sri Lanka (PUCSL) was established in 2002 by an Act of Parliament, with the objective of regulating the utility industries. The PUCSL is expected to regulate the electricity, petroleum, and water sectors, and possibly other utilities at a later date. Individual industry acts of parliament must be amended to enable the PUCSL to perform its regulatory functions.

After some delays, the new Electricity Act[5] was declared operational as of April 2009. The PUCSL commenced its functions by issuing temporary licenses. A regulatory manual was published in May 2009,[6] and the Ministry of Power and Energy issued policy guidelines to the PUCSL. As provided by the act, the longer-term licenses have since been issued (in October 2009) to all the key industry players (the CEB, the LECO, and IPPs), while other licenses (small power producers, and so on) are being now being regularized to be in compliance with the act.

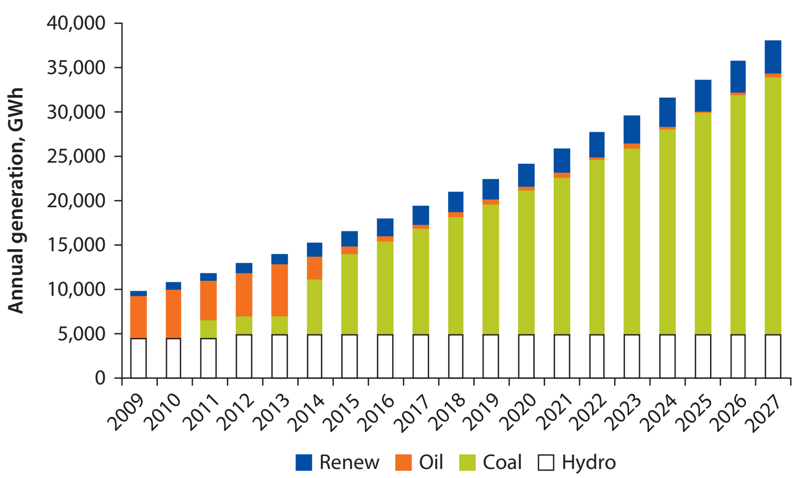
Power Sector Development

Until the mid-1990s, the largest share of electricity generation was from hydropower. With most of the major hydroelectric potential developed by then, nonhydro sources have met most of the additional demand in the past decade. By 2009 only 42 percent of the total electricity demand was provided by the hydroelectric power plants (both large and small), compared with 94 percent in 1995. Sri Lanka's main problem over the past 20 years has been its reliance on oil-based power generation because of a lack of indigenous fossil fuels: only recently has the first coal project been built.

The RE share in electricity generation (that is, mainly large hydro) is expected to decline further as the growing demand is to be met with thermal generation. But the 2006 National Energy Policy declared that Sri Lanka would endeavor to serve 10 percent of electricity generation (in energy terms) with nonconventional and renewable energy (NCRE) sources by 2015,[7] with the planned generation mix as shown in figure 4.1.

The government has announced a new initiative to grow biomass as a commercial fuel, by recognizing grown biomass as the fourth commercial plantation crop.[8] An incentive scheme is already in place to grow biomass as an undercrop in coconut plantations. Recent efforts have explored the large-scale development of biomass plantations, with fast-growing, coppicing varieties. Experiments with *Gliricidia* have met with some success. Initially, one manufacturing industry

Figure 4.1 Generation Mix: The Vision, 2009–27



Source: World Bank 2010.
Note: GWh = gigawatt-hour; NCRE = nonconventional and renewable energy.

commenced purchasing *Gliricidia* sticks from outgrowers for use in a boiler, and this concept and practice has now spread to several industries.

Renewable Energy Development

Off-grid hydro development started more than 100 years ago as a source of power for tea plantations, and many such schemes lasted into the 1950s.[9] Most were abandoned with the extension of the national grid into the Sri Lankan hill country, and with the advent of low-cost diesels.

In the modern era, interest in grid-connected hydro started in the late 1980s, when the CEB Hydro Master Plan identified a number of small projects. But by the mid-1990s just one such project had been developed. In 1995 the government and the World Bank/Global Environment Facility (GEF) established the Energy Services Delivery Project (ESDP), which was designed to support a range of RE projects, including the first 3 megawatts (MW) wind demonstration project, support for solar photovoltaic (PV) for household electrification, a village hydro program for off-grid electrification, and support for private sector development of grid-connected small hydro for plants below 10 MW. Key reforms included the introduction of a standardized power purchase agreement (SPPA) and an avoided cost tariff (ACT) for renewable energy (see below for more details). This was so successful that a successor program followed in 2003–07—the Renewable Energy for Rural Economic Development (RERED) project, which received additional financing for 2008–11.

Prior to the ESDP, there was no interest in the commercial financing of renewables. The ESDP disbursed $24 million through two development banks and three commercial banks; under the RERED follow-up project one development bank, one commercial bank, and two leasing companies were added, as well as two finance companies and a rural development bank providing independent credit financing *outside* the World Bank project. The Sri Lanka ESDP has been successful not only in serving as a catalyst to the establishment of a viable, private sector, small hydro industry, it has also been successful in establishing a broader basis for commercial financing for renewables (box 4.1).

The SPPA offered by the CEB is a standardized, nonnegotiable 15-year contract. The contract specifies the conditions, current prices, and pricing policy on which electricity will be purchased by the CEB. The first SPPA was signed in 1996. Investor confidence in Sri Lanka is so far seen mainly in the development of small hydro; investors have shown some interest in developing biomass and wind power plants, but with little success. The new tariff policy announced in 2007 changed this situation (see below), and applications are reported to be flowing in to the Sri Lanka Sustainable Energy Authority (SLSEA) in large numbers to develop non-hydro projects.

In 2007 the SLSEA was created: energy-efficiency programs previously residing in the Energy Conservation Fund were transferred to the SLSEA, with the additional task of formulating strategies to ensure energy security and RE

Box 4.1 The ESDP On-Lending Program for Renewable Energy Finance

The arrangements under Sri Lanka's World Bank–financed Energy Services Delivery Project (ESDP) were as follows:

- Funds were provided to the Government of Sri Lanka as an International Development Association (IDA) credit under typical terms, for which the government carries the exchange risk.
- The government in turn nominated the Development Finance Corporation of Ceylon (DFCC) to administer the program, which operated a special account set up in the Central Bank of Sri Lanka.
- Developers obtain finance from qualified commercial banks under normal lending terms, with interest at the normal bank rate ("average weighted deposit rate, AWDR" + 5 percent).[10]
- The commercial banks then refinance, at the AWDR, with the administrator of the program (DFCC), some portion (typically 75–80 percent) of this loan.

This was designed to achieve the following objectives:

- Banks that had previously been reluctant to lend to developers for small hydro projects (SHPs) (on grounds of unfamiliar risk, unwillingness to lend at long loan tenors) can offload the risk by refinancing from the DFCC.
- Developers obtain 10-year loans, significantly longer than the 3–7 years normally obtainable.
- Developers deal with normal commercial banks, and establish normal long-term banking relationships that build confidence among all parties over time, so that banks become more familiar with the risks (or lack thereof) entailed in SHPs.

development—effectively implementing these on behalf of the Ministry of Power and Energy. The Sri Lanka Public Utilities Commission (SLPUC) really only became effective in 2010 when the first tariffs (based on a new methodology) were approved. Jurisdiction over RE tariffs, previously calculated (without regulatory oversight) by the CEB, was also transferred to the SLPUC: its first tariff issuance for revisions to the 2009 feed-in tariff (FIT) came into force in mid-2012 (see further discussion below).

Renewable Energy Resource Endowment and the Renewable Energy Supply Curve

Biomass

Sri Lanka has an extensive potential biomass resource for power generation, and for some time so-called dendropower, based on fast-growing species planted in degraded marginal land, has been advocated as a power source. A hectare planted with 5,000 Gliricidia, Acacia, or Cassia trees in the dry zone of Sri Lanka would produce about 25–30 tons (dry) per hectare (ha) per year. At a rate of 5,000/ha, an estimated 0.8–1.6 million ha of suitable land (estimates vary greatly!), 12,000–24,000 gigawatt-hours (GWh) could be produced per year. In 2008–09 there were proposals to use such biomass as a supplementary fuel at the first coal power project in Puttalam, but these were not pursued because of difficulties in establishing a viable supply chain. A detailed resource assessment is under way at the SLSEA. A 10 MW biomass project in the Trincomalee area to produce power for a cement plant was registered for the clean development mechanism (CDM) in 2009.[11]

Of the substantial quantities of agricultural waste, much is already being used as a source of heat. Paddy is the main agricultural crop in Sri Lanka, grown in some 0.76 million ha across the country, and tea, rubber, and coconut—which are major export crops—are grown on another 0.8 million ha. The potential power generation capacity from residue generated from these fields is substantial—but again the main problem is its economic collection.

Wind

As everywhere, generalized assessments of wind resource potential mean little. The 2003 National Renewable Energy Laboratory (NREL) wind energy atlas of Sri Lanka suggests a wind potential of 24,520 MW (Elliot and others 2003) (table 4.2). But according to the SLSEA, due to system absorption limitations, under business-as-usual circumstances its short-term potential is limited to 200 MW.

Sri Lanka's first wind project, a 3 MW pilot supported by the GEF, was commissioned in 1999. This was not a particularly successful project, with production significantly below expectations.[12] But the project served its purpose as a pilot, and production at the first recent project built under the new FIT has met the annual capacity factor expectations of the full scale (at 30 percent) (table 4.3).

Sri Lanka's monsoonal climate results in the characteristic wind-speed pattern shown in figure 4.2: between November and April, average wind speeds are less than 5.0 meters per second (m/sec), but during the monsoon are around 9 m/sec.

Table 4.2 Wind Resources of Sri Lanka

	Wind class	*Wind power at 50 meters, Watts per m²*	*Wind speed at 50 meters, m/sec*	*Land area, km²*	*Lagoon area, km²*	*Total area, km²*	*Percent windy land, %*	*Total installed capacity, MW*
Good	4	400–500	7.0–7.5	2,341	664	3,005	3.6	15,000
Excellent	5	500–600	7.5–8.0	788	41	829	1.2	4,150
Excellent	6	600–800	8.0–8.8	517	0	517	0.8	2,600
Excellent	7	>800	>8.8	501	0	501	0.8	2,500
Total				4,147	795	4,852	6.4	24,250

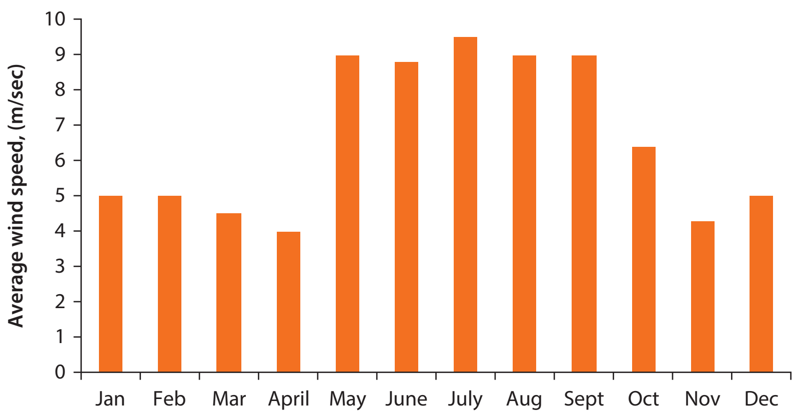
Source: Elliot and others 2003: table 7.1.
Note: km² = kilometers squared; m² = square meters; m/sec = meters per second; MW = megawatt.

Table 4.3 Wind Projects in Sri Lanka

	Installed capacity, MW	*Start-up*	*Owner*	*Configuration*
Hambantota	3	1999	CEB	
Mampuri	10	March 2010	Senok	8 x 1.25 MW Suzlon
Norocholai	9.75	—	—	—
Seguwantivu	14.2	May 2013	—	—
Vidatamunai	9.6	May 2013	—	—

Source: SLSEA.
Note: CEB = Ceylon Electricity Board; MW = megawatt; — = not available.

Figure 4.2 Wind Characteristics in Sri Lanka



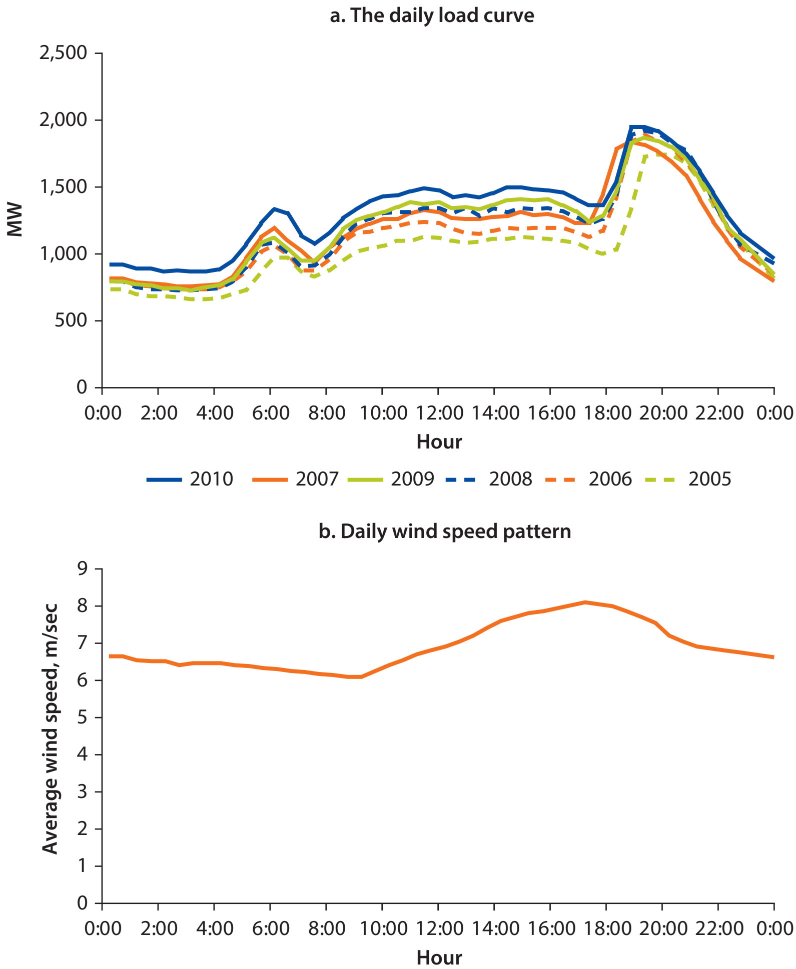
Source: http://www.windpower.lk.
Note: m/sec = meters per second.

In the case of wind, not only seasonal variations but also daily variations determine its value to the grid. Figure 4.3 compares the typical daily pattern of wind speed for sites on the west coast (where the current batch of wind projects is located) that benefit from the daily sea breeze, which, on average, peaks between 16:00 and 18:00 but then declines rapidly—exactly when the load peak increases. But with a difference of just a few hours, the storage in the hydro system should be able to absorb the wind peak production without major impact on the normal pattern of hydro releases.

Small Hydro

Sri Lanka's small hydro program has been a success, and was supported by a series of World Bank/GEF projects that provided both financial assistance (through an on-lending program with Sri Lanka's domestic banks) and technical assistance. As shown in table 4.4, since the first projects were commissioned in 2002, 188 MW of small hydro in 77 projects has been added under these programs. Currently under construction (with the last tranche of lending support) are a further 11 projects (55 MW). The average size of the projects is relatively small, though gradually increasing, reaching just 2.4 MW in 2012.[13]

Figure 4.3 Wind Generation and the Daily Load Curve



Source: Daily load curve from SLSEA (2011) National Energy Balance; daily wind speed pattern from http://www.windpower.lk.
Note: m/sec = meters per second.

Estate Sector Hydro

Significant potential exists for SHPs in the plantation estates: a survey of 276 sites estimated a potential of around 97 MW (table 4.5) (Fernando 1999). Of the 137 sites in old estates, 49 were found to be in operation, 14 not in operation (but relatively easily rehabilitated), and 74 abandoned. The Asian Development Bank (ADB) is currently funding a project to restore some of these old projects.[14]

Village Hydro

The village hydro program was no less successful. By the end of the RERED in 2011, 174 schemes had been successfully completed, serving some 6,100

Table 4.4 Small Hydro Projects in Sri Lanka, 2002–12

	Projects added	*Installed capacity added, MW*	*Average size, MW*	*Cumulative capacity, MW*	*Cumulative number of projects*	*Cumulative average size, MW*
2002	17	30.9	1.8	30.9	17	1.8
2003	2	4.5	2.2	35.3	19	1.9
2004	12	33.7	2.8	69.1	31	2.2
2005	7	13.7	2.0	82.7	38	2.2
2006	12	20.8	1.7	103.5	50	2.1
2007	2	7.5	3.8	111.0	52	2.1
2008	10	19.0	1.9	130.1	62	2.1
2009	5	23.6	4.7	153.7	67	2.3
2010	3	12.5	4.2	166.2	70	2.4
2011	5	13.9	2.8	180.0	75	2.4
2012	2	7.6	3.8	187.7	77	2.4

Source: http://www.energyservices.lk/statistics/esd_rered.htm.
Note: MW = megawatt.

Table 4.5 Potential Small Hydro Projects in the Estate Sector

Site classification	*Number of sites*	*Utilized, MW*	*Potential, MW*	*Largest site, kW*	*Smallest site, kW*
Old estate sites	137	6.1	23.7	1,665	5
New estate sites	71		20.7	1,127	8
Nonestate sites	49		53.0	5,192	44
Total	257		97.4		

Source: Fernando 1999.
Note: kW = kilowatt; MW = megawatt.

rural households in remote areas—with an average size of just under 10 kilowatts (kW), serving an average of 35 households each. The success of the program was dependent not just on a good design concept (generally very high heads, and sized according to the availability of dry-season flows),[15] and the ESDP/RERED financing facility, but on a significant "sweat equity" component involving beneficiary households—which was successful because of the relatively high educational levels in Sri Lanka's rural areas (also reflected in the capability of its village leaders). The availability of good local consulting engineers in Colombo to design and advise these projects was another reason for successful project completion.[16] Such a sustainable model has eluded Vietnam, whose off-grid small hydro program in the modern era has been much less successful.

Supply Curves

Formal RE supply curves, of the type shown in figure 3.6 for Vietnam, do not appear to have been constructed to date. Table 4.6 shows the commissioned capacity as of March 31, 2013, and the projects for which the CEB has signed an SPPA: this can be taken as the current project pipeline potentially realizable in the next few years.

Table 4.6 Status of Grid-Connected RE Projects, March 31, 2013

	Number of projects	*Installed capacity, MW*
Commissioned		
Mini hydropower	111	238.990
Biomass—agricultural and industrial waste power	2	11.000
Biomass—dendro power	1	0.500
Solar power	4	1.378
Wind power	9	73.650
Total—commissioned	128	330.518
SPPA signed		
Mini hydropower	72	167.262
Biomass—agricultural and industrial waste power	4	21.300
Biomass—dendro power	2	4.000
Solar power	10	56.770
Wind power	1	10.000
Total—commissioned	89	259.332

Source: CEB.
Note: RE = renewable energy; MW = megawatt; SPPA = standardized power purchase agreement.

Capital Costs

The first set of SHPs built between 1998 and 2003 had average completed financial capital costs of $1,055/kW—though with considerable variation around the average (figure 4.4).[17]

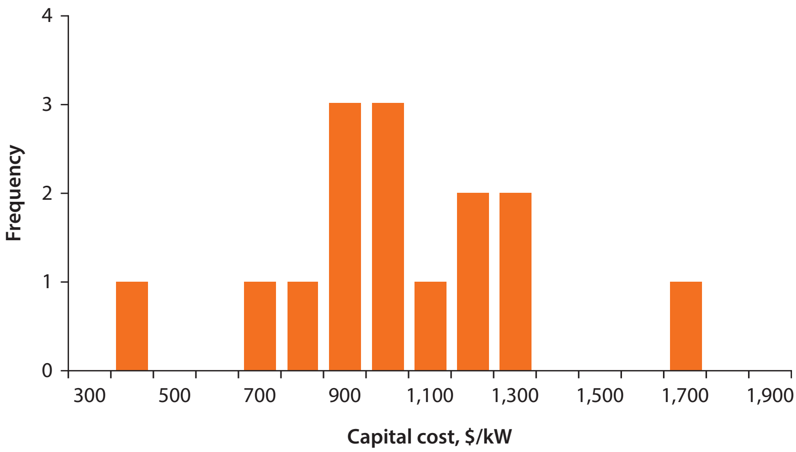
By 2009 the capital cost assumption for small hydro had risen to $1,620/kW (as shown in table 4.7, together with the capital cost assumptions for the other technologies).

The Avoided Social Cost of Thermal Generation

Unlike Vietnam, for which the calculation of the avoided social cost of thermal generation is straightforward because it involves just a single fuel in a single technology (combined-cycle gas turbine, CCGT),[18] the rapidly changing generation mix makes such calculation more difficult in Sri Lanka. With increasing coal generation, whether renewables will displace oil (as at present) or coal will depend on the extent to which the large storage hydro projects can provide the offsetting load following energy and capacity. There is some evidence that this may be the case (Siyambalapitya 2001); if so, there may be no oil generation for some hours, and the portfolio of renewable energy would permit coal units to be backed down for several months in the wet season (when both wind and SHP production is at its peak). But with some future coal units being planned as IPPs, this may be constrained by take-or-pay clauses (which would argue for two-part IPP tariffs to give the CEB more operational flexibility).[19]

While a study of the transmission system implications of larger amounts of renewable energy has been completed,[20] a comparable study of generation

Figure 4.4 Distribution of Capital Costs for Small Hydro Projects



Source: World Bank 2003.
Note: kW = kilowatt.

Table 4.7 2009 Feed-In Tariff Cost Assumptions

	Capital cost		*Annual operating costs as % of capital cost*	*Assumed capacity factor (%)*
	SL Rs million/MW	*$/kW*		
Minihydro	190	1,621	3.00	42
Wind	230	1,962	3.00	32
Biomass	217	1,852	4–5.00	80
Agricultural waste	217	1,852	4–5.00	80
Municipal waste	313	2,671	7.00	80
Waste heat recovery	217	1,852	1.33	67

Note: At the exchange rate of $1 = SL Rs 117.2 (August 31, 2009). kW = kilowatt; MW = megawatt.

dispatch, which would involve a detailed chronological production simulation (assessing merit order dispatch over at least hourly intervals over the next 20 years for several scenarios of RE penetration), is not yet available.

For the purpose of this report, therefore, we rely on an estimated economic value of new and renewable energy to the CEB system, based on the Wien Automatic System Planning (WASP) model, with and without a portfolio of renewables (that must be forced into the solution), which was estimated at 7.12 cents per kilowatt-hour (kWh). The baseline plan without renewables also does not build any of the other alternatives offered for the express purpose of low carbon development, including wind, small hydro, medium hydro (defined as hydro projects in the 10–100 MW size range),[21] liquefied natural gas (LNG), or electricity generated in coal-based supercritical projects in southern India.[22]

Figure 4.5 illustrates the two capacity expansion plans: in the base case (figure 4.5a) the only new hydro project is the Upper Kotmale project, under construction at the time this plan was formulated. Figure 4.5b shows the capacity expansion plan for the NCRE scenario (which continues beyond 2015 to maintain the same 10 percent share), and figure 4.5c shows the differences between the two. Two 300 MW coal units are displaced entirely, and beyond 2022, some larger units are delayed.

Carbon Accounting and CDM

With the expected growth in coal generation, the grid emission factors for CDM will increase (table 4.8). The first coal project was commissioned in 2011, in which year the combined margin increased from 0.53 to 0.73; additional increases are expected in the coming years as the share of coal in the generation mix increases further.

But the prospects for buying down the incremental costs from CDM have become poor: although the grid emission factor in Sri Lanka is increasing, the certified emission reduction (CER) price is decreasing. Table 4.9 shows the early May 2013 forecasts for European Union (EU) Allowance Unit of one ton of CO_2 (EUA) and CER. Because of the oversupply of CERs eligible for Phase III of the European Union Emission Trading Scheme (EU-ETS, 2013–20), the CER price is significantly below the forecast EUA price, and remains below €1/ton throughout the forecast period.[23] The table also shows the current ECX (European Carbon Exchange) futures prices for CER for delivery by end-December of each year.

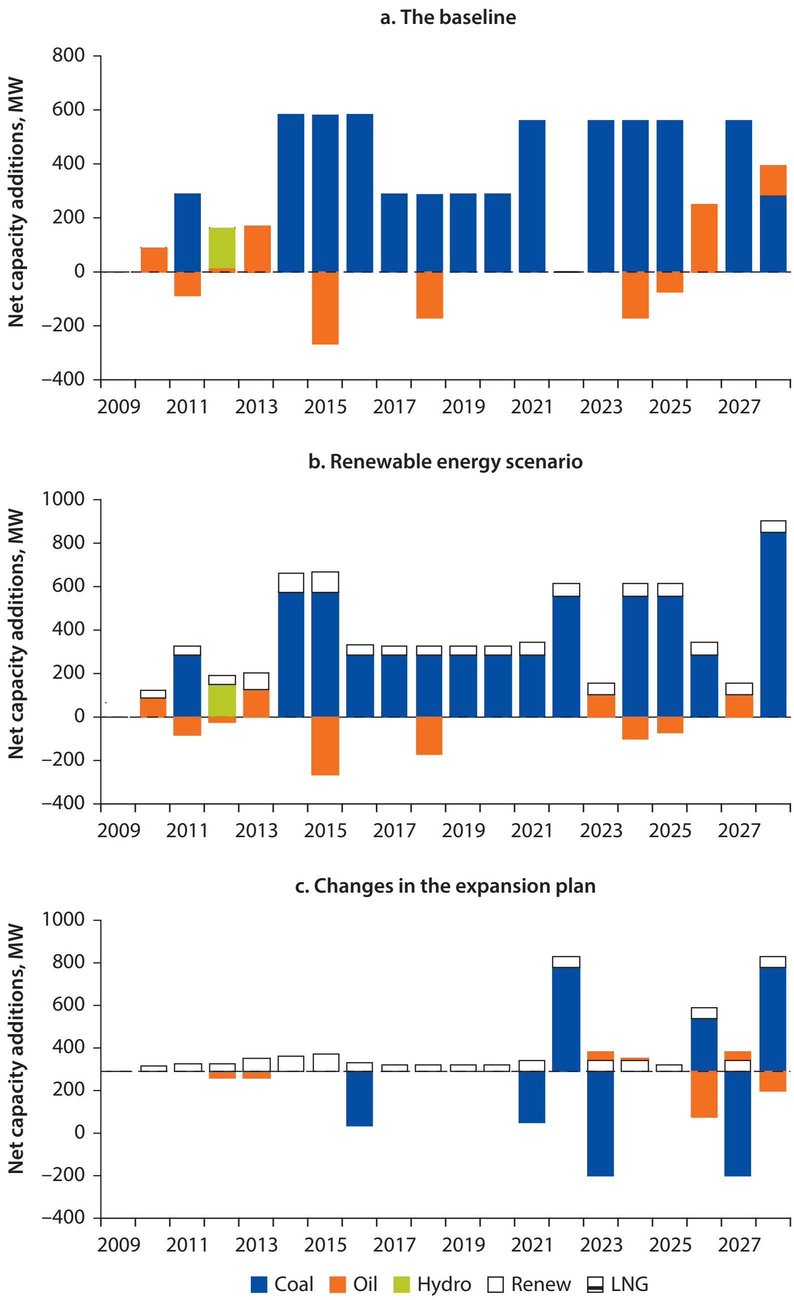
The *Sri Lanka: Environmental Issues in the Power Sector* (EIPS) study (World Bank 2010) allowed calculation of the avoided cost of carbon for the range of low-carbon-emission options—all of which, as noted, needed to be forced into the expansion plan. The options considered were:

- LNG (CCGT to replace those coal units not under construction or under active development).
- Medium hydro: Uma Oya, (150 MW),[24] Broadlands (35 MW), Moragolla (27 MW), and Ging Ganga (49 MW).
- NCRE (wind and small hydro, as listed in table 4.11).
- “Green scenario” (LNG+NCRE).
- Supercritical coal.

The Sri Lankan power system is still too small to be able to accommodate 500–600 MW scale supercritical units. They are indeed more efficient than subcritical, so greenhouse gas (GHG) emissions decline, but being so large, their size exceeds the annual increase in base-load requirement, so there is additional excess capacity, and hence the system PV increases.

Table 4.10 shows the result of this analysis. When life-cycle emissions are also considered, most RE options have somewhat lower avoided costs. But in the case

Figure 4.5 The Least Cost Expansion Plan, 2009–27



Source: World Bank 2010.
Note: LNG = liquefied natural gas; MW = megawatt.

Table 4.8 Grid Emission Factors, 2008–11

Our	*2008*	*2009*	*2010*	*2011*
Build margin	0.5986	0.6081	0.5684	0.7491
Operating margin	0.6990	0.6975	0.6920	0.7047
Combined margin	0.6487	0.6520	0.6302	0.7269

Source: SLSEA.

Table 4.9 Carbon Point Forecasts, 2008–20

	Point carbon price forecasts		*ECX CER futures*	
	EUA, €/ton	*CER, €/ton*	*Price, €/ton*	*Open interest, €/ton*
2008	22.4	17.4		
2009	13.3	11.8		
2010	14.5	12.4		
2011	13.3	9.8		
2012	7.6	2.9		
2013	3.0	0.5	0.42	64,028
2014	4.0	0.6	0.45	36,903
2015	5.0	0.6	0.51	11,241
2016	5.0	0.5	0.56	2,382
2017	6.0	0.4	0.69	4,426
2018	6.0	0.4	0.73	560
2019	8.0	0.3	0.93	697
2020	8.0	0.2	1.04	1,146

Source: ECX.
Note: CER = certified emission reduction; ECX = European Carbon Exchange; EUA = European Union Allowance Unit of one ton of carbon dioxide.

of LNG, the avoided cost increases, a consequence of high methane emissions associated with liquefaction, transportation, and regasification.

These options all lie in quadrant IV of the trade-off between system cost and GHG emissions—that is, higher costs allow lower GHG emissions—and do not include the win-win options. But as shown in figure 4.6, demand-side management (DSM) lies in the win-win quadrant—so an avoided cost is not defined. But the remaining potential for DSM is quite limited, so the quantity of GHG emission reduction is quite small compared to the supply options. Pumped storage lies in the trade-off quadrant II—GHG emissions increase, while system costs decrease—a simple consequence of the fact that the pumping energy is provided by coal. Appendix B provides further information on trade-off curves and the tools of multi-attribute decision analysis.

Renewable Energy Targets

The 10 percent target is an aspirational political statement, not one that is based on economic analysis. The SLSEA expects that this will be met largely by a combination of existing small hydro, new small hydro, wind, and

Table 4.10 Avoided Costs of Carbon

	Combustion impacts only	*Life-cycle emissions*
Composite renewables scenario to meet 10% target (NCRE)	87	80
Medium hydro	37	34
Supercritical coal	7	6
LNG	86	98
Green (LNG+NCRE)	79	81

Source: World Bank 2010.
Note: LNG = liquefied natural gas; NCRE = nonconventional and renewable energy.

biomass: table 4.11 shows the implementation scenario that would meet such a target, with relative shares of different technologies based on current expectations of what might be feasible. At present the bulk of the energy is still small hydro (70 percent in 2012), but the SLSEA expects that wind and biomass will take up increasing shares, with wind accounting for 37 percent of NCRE by 2025.

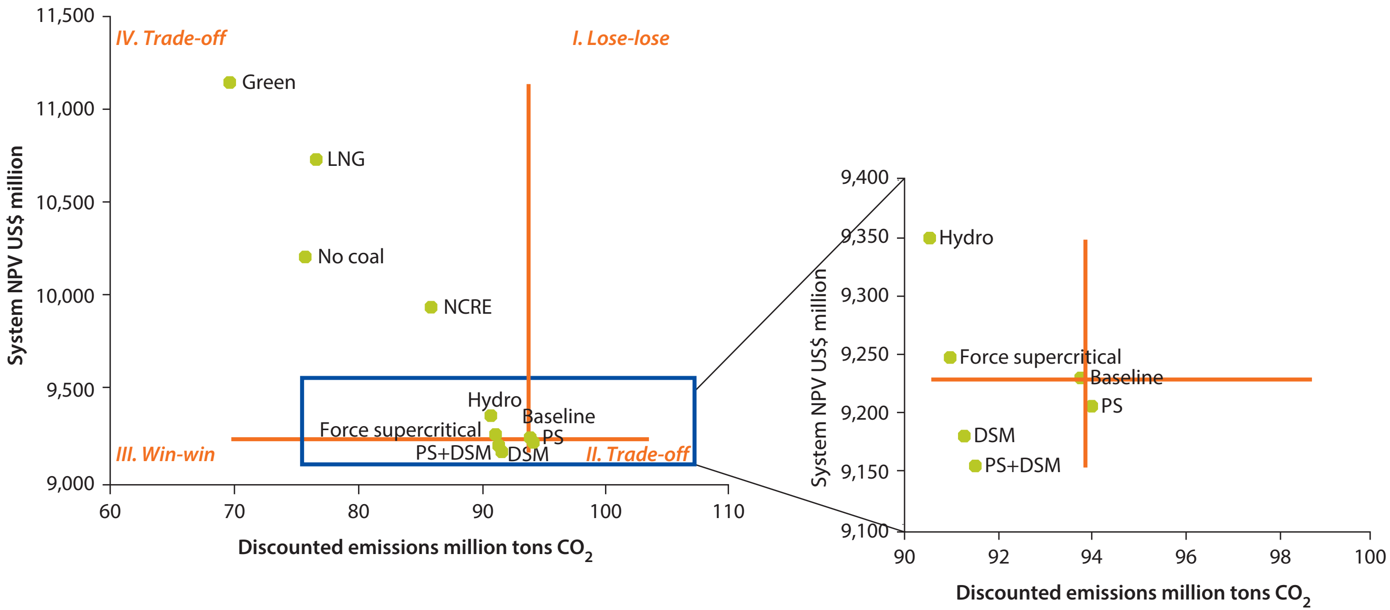
This forecast calls for 100 MW of wind by 2013, but what is achieved is just 40 MW. To meet the target in 2015 requires 220 MW of wind capacity, but this is unlikely to be attained.

Design of Incentive Schemes

A range of policy incentives are in place to encourage grid-connected RE projects, including:

- There is no solicitation process; all projects are on a first-come, first-served basis, provided only that they meet the CEB's technical standards for connection.
- The power purchase agreement (PPA) is standardized and nonnegotiable (thus avoiding lengthy negotiations).
- The support tariff is published and uniformly applied to all small power producers (SPPs) (until 2006–07 it was based on avoided costs, and then subsequently replaced by a technology-specific FIT).
- Projects qualify for Board of Investment (BoI) concessions if they meet the standard criteria laid out by the board. In general, projects with an investment exceeding SL Rs 50 million qualify for BoI incentives, which offer duty-free import of investment equipment and material, and a tax holiday between five and eight years, and a concessionary tax rate thereafter.
- Financing support (through competitive interest rates and the ESDP/RERED projects).
- A "net" metering facility is available to all LECO customers (also to be extended to the CEB in due course). Consumers are free to use any qualified RE[25] source, based on availability and affordability. The capacity limit is the

Figure 4.6 Greenhouse Gas Emissions vs. System Cost Trade-Offs



Source: World Bank 2010.
Note: CO_2 = carbon dioxide; DSM = demand-side management; LNG = liquefied natural gas; NCRE = nonconventional and renewable energy; NPV = net present value; PS = pumped storage.

Table 4.11 Implementation Scenario for NCRE: 2010 Projection

		2009	*2010*	*2011*	*2012*	*2013*	*2014*	*2015*	*2020*	*2025*
Capacity										
Small hydro	MW	170	190	200	210	250	270	280	340	390
Wind	MW	0	10	40	70	100	160	220	320	470
Biomass	MW	12	13	14	14	15	15	36	61	121
Other	MW	0	2	4	6	8	10	12	27	52
Total	MW	182	215	258	300	373	455	548	748	1,033
Energy										
Small hydro	GWh	469	566	596	625	745	804	809	983	1,093
Wind	GWh	0	25	102	184	272	449	597	869	1,235
Biomass	GWh	42	44	47	63	66	72	188	346	740
Other	GWh	0	9	18	26	35	44	53	130	273
Total	GWh	511	643	762	899	1,117	1,369	1,647	2,328	3,342
Energy shares										
Small hydro	[%]	92	88	78	70	67	59	49	42	33
Wind	[%]	0	4	13	20	24	33	36	37	37
Biomass	[%]	8	7	6	7	6	5	11	15	22
Other	[%]	0	1	2	3	3	3	3	6	8

Source: World Bank 2010.
Note: GWh = gigawatt-hour; MW = megawatt; NCRE = nonconventional and renewable energy.

contract demand, subject to a maximum of 42 kVA.[26] In any given month, the customer will be billed for the net purchase from the grid. Any surplus exports are credited to the bill, to be used at any time, in any month in the future. Credits can be carried through until the end of the net metering contract (10 years).

Avoided Cost Tariff

Sri Lanka introduced a standardized PPA for SHPs in 1997 at the start of the World Bank–financed ESDP, based on a published avoided cost based tariff (ACT). The CEB's actual avoided energy costs (that is, without any capacity credit) are updated annually: table 4.12 shows the tariff for the 16 years of the operation of the system.

The ACT system was introduced a number of years before the establishment of an independent regulator. The CEB's calculation of avoided costs was at times controversial, and the disputes were not resolved by the investigation and report of an independent expert (Siyambalapitya 2001), resulting in several developers instigating arbitration and court actions against the CEB on grounds of alleged inconsistencies and mistakes in the tariff calculation. Nevertheless, despite the pleadings of the developers, the success of the program speaks for itself.

Only short-run avoided variable costs were considered in the calculation. Small hydro plants connect to the 33 kV system, so costs were adjusted for

Table 4.12 Avoided Cost Tariff, 1996–2011

	Dry season (SL Rs/kWh)	*Wet season (SL Rs/kWh)*	*Exchange rate (SL Rs:$)*	*Dry season (cents/kWh)*	*Wet season (cents/kWh)*
1996	2.9	2.9	55.2	5.3	5.3
1997	3.4	2.9	58.9	5.7	4.9
1998	3.5	3.1	64.7	5.4	4.9
1999	3.2	2.7	70.6	4.6	3.9
2000	3.1	2.8	76.6	4.1	3.6
2001	4.2	4.0	89.2	4.7	4.5
2002	5.1	4.9	95.4	5.4	5.1
2003	6.1	5.9	96.3	6.3	6.1
2004	5.7	5.0	101.0	5.6	4.9
2005	6.1	5.3	100.4	6.0	5.3
2006	6.7	5.8	103.6	6.5	5.6
2007	7.6	6.9	110.2	6.9	6.3
2008	9.7	8.9	108.1	8.9	8.3
2009	11.2	10.6	114.7	9.7	9.2
2010	11.9	11.1	112.8	10.6	9.8
2011	11.2	10.2	110.3	10.1	9.3

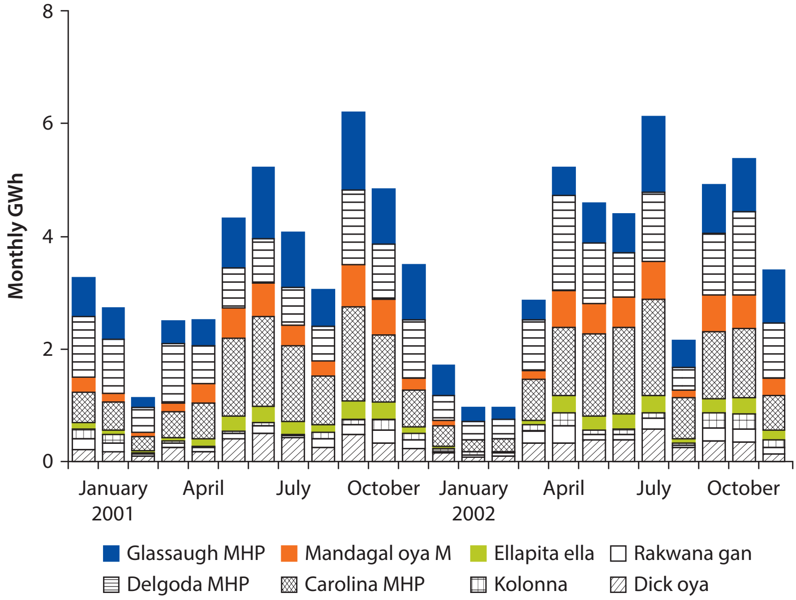
Note: kWh = kilowatt-hour.

average losses to the 33 kV level. The avoided cost was computed separately for the dry season (February to April) and the wet season (May to December and January). The seasonal tariff that was announced by the CEB every year is a three-year moving average of the past three years' avoided energy costs. If the announced tariff for a particular year fell below 90 percent of the tariff during the year in which the SPPA was signed for a given small power producer (SPP), the tariff applicable would be the tariff of the previous year.

A number of methodological issues arise in the Sri Lanka approach, most notably the absence of a capacity credit. While a single 3 MW run-of-river (RoR) hydro may have little impact on capacity deferrals, a portfolio of 100 MW of small hydro, when taken as a whole, is very unlikely to have zero capacity credit. Even in the driest months, the output from the portfolio is not zero (figure 4.7). It should be noted that the original recommendation for the ACT (Vernstrom 1995) did argue for a capacity credit (table 4.13).

In any event, the calculation of avoided variable costs in the CEB's thermal plants tells only part of the story in a system with significant amounts of conventional annual storage hydro. A report prepared by an independent consultant in 2001 (commissioned to help mediate disputes between some developers and the CEB), showed a significant benefit to end-year reservoir storage (equivalent to some 23 GWh, equal to 10 percent of the total SHP contribution of 294 GWh in 2001); in addition, the SPP contributed to a reduction of unserved energy demand of another 11 GWh (Siyambalapitya 2001). These benefits were not included in the CEB's estimates of avoided costs.

Figure 4.7 Monthly Production from Small Hydro Projects, 2000–02



Source: World Bank 2003.
Note: GWh = gigawatt-hour; SHP = small hydro project.

Table 4.13 Original Recommendation for the Small Power Purchase Tariff

	Tariff component	*Time of day*	*Dry season (SL Rs/kWh)*	*Wet season (SL Rs/kWh)*	*Dry season (cents/kWh)*	*Wet season (cents/kWh)*
HV	Energy	Peak	4.37	4.11	8.21	7.73
		Off-peak	3.43	2.68	6.45	5.04
	Capacity	Peak	1.67	0.18	3.14	0.34
		Off-peak	1.67	0.18	3.14	0.34
MV	Energy	Peak	4.7	4.48	8.83	8.42
		Off-peak	3.64	2.85	6.84	5.36
	Capacity	Peak	3.48	1.79	6.54	3.36
		Off-peak	1.83	0.2	3.44	0.38

Source: Vernstrom1995, exhibit S-2.
Note: (1) at the 1995 exchange rate: $1 = SL Rs 53.2; HV = high voltage; kWh = kilowatt-hour; MV = medium voltage.

Revisions to the Sri Lankan Tariff Support System

Notwithstanding its unique success, in 2007 Sri Lanka changed its ACT system in favor of a production-cost-based FIT. The argument for the change was as follows:

- Avoided costs were expected to decline after 2011 (in real terms) once the first coal projects finally came into operation. While existing developers would be protected by the 90 percent floor (thus preserving 90 percent of the expected revenue at the time of the PPA signature, regardless of the actual future ACT), this would be of no value to new projects entering at the lower tariff.

- To ensure that the benefits of renewable energy flow into society (to whom the natural resources belong) in the longer term, after the developers have been given adequate returns on their investments (*in other words, in the plain speak of economics, to capture the producer's surplus*).
- To encourage renewables other than small hydro (wind, biomass) to come on line, which are not viable on the basis of avoided costs. Only small hydro was considered viable at the present tariff. Low heads, smaller projects (<500 kW), biomass, and wind all require more than avoided costs to be viable. The government had just declared a 10 percent target of grid energy by nonconventional renewable energy by 2015, and the view was that small hydro alone could not achieve this target.
- Predictable tariffs would bolster the bankability of projects.
- The best SHP sites had been developed, and additional projects would require higher tariffs.

None of the stated reasons are valid objections to an ACT; rather, they reflect the shortcomings of the way in which the tariff was *implemented*:

- Argument (1) correctly anticipates that average avoided costs may fall when the coal plants come on line—though it is hard to see how auto-diesel-fueled combined-cycle combustion turbines (CCCTs) would not be at the margin even when coal plants are in the system. A better response to this problem would have been to introduce a capacity credit (as originally recommended by Vernstrom (1995).
- Argument (2) is the classic preoccupation of government committees that worry about "windfall profits" to developers. It may well be true that the tariff would increase in the next few years, subsequently to decrease again after the coal plants come on stream. But there are better ways to deal with this problem than to introduce FITs, for example, by making risk-sharing *symmetrical*: if a developer benefits from the 90 percent floor price, the buyer should also have benefited from a corresponding cap.[27] Moreover, if there is a concern about developers of good SHP sites capturing site rents (though objection [5] states that no low-cost SHP sites remain), the best way to deal with that problem is through bidding, as introduced in Zhejiang.
- Argument (3) correctly notes that wind and biomass are presently uneconomic, and would not be developed at the present ACT.
- Argument (4) is true. But there was no evidence that the variations in the ACT discouraged bankable projects: the number of projects attested to the bankability of the tariff.

In reality, the change in policy resulted from the alignment of interests of the established developers (whose industry association has become increasingly vocal as the small hydro industry developed) and of the government, which wished to demonstrate concrete steps had been taken to achieve the 10 percent target.

The 2007 Feed-In Tariff

The new system provided a technology-specific tariff offered for the main RE technologies considered to be promising: wind, small hydro, biomass (in two categories, agricultural wastes and biomass plantation crops ["dendro-thermal"]), and municipal solid waste. The Sri Lankan FIT embodied a number of unique and important features:

- Recognizing the reality of short loan tenors in the commercial banking system, developers' costs are frontloaded during the first years of debt service. Therefore, to achieve an acceptable debt service cover ratio (DSCR), the tariff needs to be higher in the early years. A tiered system was therefore introduced, under which the tariff was highest in years 1–6, then lower in years 7–15, and lower still in years 16–18.
- A bank guarantee was required to ensure that the SPP operates in years 7–12 of the second tier, in return for the high tariffs paid in the first tier. The guarantee was to be provided to the buyer in years 1–6, and returned from year 7 onwards.
- The target financial internal rate of return (FIRR) was set at a high 22 percent return on equity.
- In addition to the tiered tariff, a flat-rate tariff was offered that required no bank guarantees (table 4.14). The methodology is to calculate the liveliest tariff using a discount rate equal to the weighted average cost of capital (WACC) (that is, 40 percent equity at 22 percent, 60 percent debt at 19.22 percent = 20.33 percent).
- In 2009 the SLPUC published a spreadsheet that was used as a basis for the updated tariff (see box 4.2). Few FITs in the world are published with this degree of transparency (although the Philippines regulator publishes a list of proposed assumptions).

The hazards of setting production-cost-based FITs are well illustrated by the latest tariff issuance, issued by the PUCSL in October 2012, just following a sharp depreciation in the exchange rate. The commission used an exchange rate of $1 = SL Rs 132.86, but no sooner had the tariff been issued than the Sri Lankan rupee started to appreciate against the dollar: in April 2013, the average exchange rate was $1 = SL Rs 128.9 (table 4.14).

Summary Evaluation

Table 4.15 summarizes our evaluation of the tariff incentive systems in place in Sri Lanka.

Incremental Costs and Their Recovery

The 2006 Energy Strategy called for the establishment of a fund, to be funded by a tax. A mechanism to recover the incremental costs is obviously required if another goal of the strategy—namely that the "NCRE shall not cause any additional burden on end use customer tariffs"[28]—is to be met.

Box 4.2 Sri Lanka's Feed-In Tariff, 2009

Option 1: Three-tier Tariff

The tariffs for the first tier (that is, years 1–6) are as follows (for SPPAs signed in 2007, in SLR/kWh):

	Year of operation	*1*	*2*	*3*	*4*	*5*	*6*
Mini Hydro	Nonescalable	7.99	7.99	7.99	7.99	7.99	7.99
	escalated O&M	0.48	0.52	0.56	0.60	0.64	0.69
	Total	8.47	8.51	8.54	8.59	8.63	8.68
Wind	Nonescalable	13.88	13.88	13.88	13.88	13.88	13.88
	escalated O&M	1.67	1.80	1.93	2.08	2.23	2.40
	Total	15.55	15.68	15.81	15.95	16.11	16.27
Biomass	Nonescalable	5.22	5.22	5.22	5.22	5.22	5.22
	escalated fuel	5.00	5.25	5.51	5.78	6.07	6.37
	escalated O&M	0.84	0.90	0.97	1.04	1.12	1.20
	Total	11.06	11.37	11.70	12.04	12.41	12.79

The tariffs for the second tier (years 7–15) are substantially lower:

	Year of operation	*7*	*8*	*9*	*10*	*11*	*12*	*13*	*14*	*15*
Mini Hydro	Nonescalable	2.79	2.79	2.79	2.79	2.79	2.79	2.79	2.79	2.79
	escalated O&M	1.48	1.59	1.71	1.84	1.97	2.12	2.28	2.45	2.63
	Total	4.28	4.29	4.50	4.63	4.77	4.91	5.07	5.24	5.42
Wind	Nonescalable	4.85	4.85	4.85	4.85	4.85	4.85	4.85	4.85	4.85
	escalated O&M	2.57	2.76	2.97	3.19	3.43	3.68	3.96	4.25	4.57
	Total	7.43	7.62	7.82	8.04	8.28	8.54	8.81	9.10	9.42
Biomass	Nonescalable	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82
	escalated fuel	6.68	7.01	7.36	7.73	8.11	8.51	8.98	9.37	9.84
	escalated O&M	1.29	1.39	1.49	1.60	1.72	1.85	1.98	2.13	2.29
	Total	9.80	10.22	10.67	11.15	11.65	12.18	12.74	13.33	13.95

And for the third tier (years 16–18) are lower still, as follows:

	Year of operation	*16*	*17*	*18*	*19*	*20*
Mini Hydro	Nonescalable	2.06	2.17	2.27	2.39	2.51
	escalated O&M	2.82	3.03	3.26	3.5	3.76
	Total	4.89	5.2	5.53	5.89	6.27

box continues next page

Box 4.2 Sri Lanka's Feed-In Tariff, 2009 *(continued)*

	Year of operation	*16*	*17*	*18*	*19*	*20*
Wind	Nonescalable	2.06	2.17	2.27	2.39	2.51
	escalated O&M	4.9	5.27	5.66	6.08	6.53
	Total	6.97	7.44	7.94	8.47	9.04
Biomass	Nonescalable	2.06	2.17	2.27	2.39	2.51
	escalated fuel	10.32	10.84	11.37	11.94	12.53
	escalated O&M	2.46	2.64	2.84	3.05	3.27
	Total	14.85	15.64	16.48	17.37	18.31

Option 2: Flat Tariff

Technology	*All inclusive rate*	*(SL Rs/kWh) for years 1–20*
Mini-hydro	7.10	(1,070 SL Rs/kWh)
Wind	12.83	(1,934 SL Rs/kWh)
Biomass	11.87	(1,789 SL Rs/kWh)

Source: SLSEA.

Note: O&M = operation and maintenance; SPPA = standardized power purchase agreement.

Table 4.14 Flat-Rate Feed-In Tariffs

	Issued flat rate tariff rate	*At assumed SLPUC exchange rate (132.86)*	*At actual April 2013 exchange rate*
	SL Rs	*Cents/kWh*	*Cents/kWh*
Mini-hydro	16.7	12.6	13.3
Mini-hydro, local	17.15	12.9	13.6
Wind	20.62	15.5	16.4
Wind, local	21.22	16.0	16.9
Biomass (dendro)	25.09	18.9	19.9
Biomass (agricultural and industrial waste)	17.71	13.3	14.1
Municipal solid waste	26.1	19.6	20.7
Waste heat	9.19	6.9	7.3

Source: SLPUC.
Note: kWh = kilowatt-hour; SLPUC = Sri Lanka Public Utilities Commission.

The Sustainable Energy Authority Act established three funds. The first is the Fund of the Authority (which covers the authority's expenses); second, the Sri Lanka Sustainable Energy Fund (with the main source of revenue tax on imports of fossil-fuel products, and from which subsidies to RE producers were to be funded); and third, the Sustainable Energy Guarantee Fund (which provides loan guarantees for energy-efficiency projects).

Table 4.15 Summary Evaluation of Tariff Designs

	Avoided cost tariff	*Feed-in tariff small hydro*	*Feed-in tariff wind*
Introduced	1997	2007	2007
Achievement to date, MW	187	[?]	40
Economically efficient	Yes	No	No
Market principles	Yes	No (first come, first served)	No (first come, first served)
Sustainable Recovery of incremental costs	Yes (by definition)	No (though not the fault of the tariff design itself)	No (though not the fault of the tariff design itself)
Transparency	Yes	Yes	Yes
Adaptability	Yes (updated annually)	Yes (in principle) (but with long delays in issuance of updated tariff)	Yes (in principle) (but with long delays in issuance of updated tariff)
Successful?	Yes	Yes (extensive project pipeline)	To be seen

Note: MW = megawatt; [?] = not available yet.

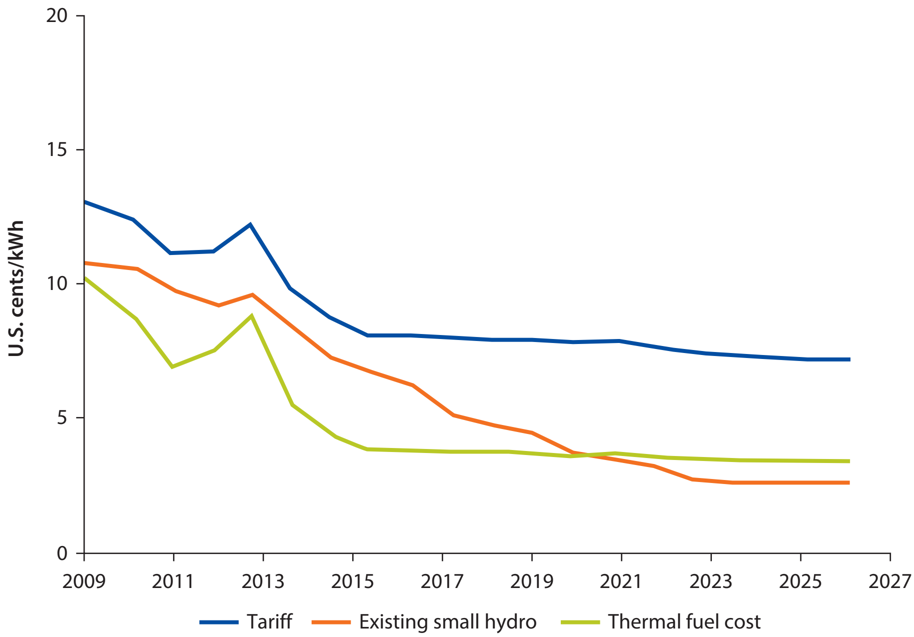
In the first few years of the scheme, the Fund was unable to pay the CEB's invoices for incremental costs. The original expectation was that as more and more of the PPAs of existing SHPs expired, and compensation would fall to the low "tier 3" level (and below the CEB's avoided cost), then even with much higher tariffs for wind and new small hydro, the average tariff of the entire NCRE portfolio would be close to the avoided cost (thereby meeting the requirement that NCRE not increase consumer tariffs). But for whatever reason, these forecasts proved optimistic. Subsequently, the SLPUC allowed these costs as part of the CEB's general revenue requirements, but it is unclear whether this is to be a permanent feature of the tariff methodology.[29]

Impact of Renewable Energy Tariffs on the Consumer

Figure 4.8 shows the tariff expectations of the baseline. In the absence of the additional NCRE, only the existing SHPs are assumed, whose tariff declines because, as the old PPAs expire, average compensation will be limited to the "tier 3" level of around 3 cents/kWh by 2025 (when the last 15-year PPA under the old tariff system expires). The CEA's overall tariff also declines from the pre-coal era of 13 cents/kWh to around 10 cents/kWh by 2016, and to around 8 cents/kWh by 2025.

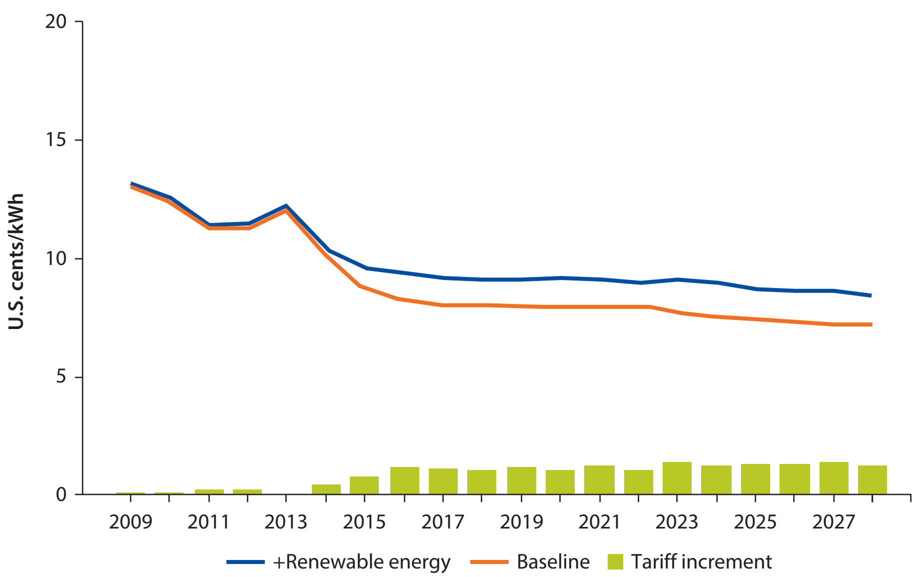
Figure 4.9 shows the impact of the 10 percent RE target on the consumer tariff. These results are based on a financial model of the CEB that forecasts the CEB's revenue requirements (and which include a return on equity). By 2020 the impact is about 1 cent/kWh (sold). The tariff increase is 8 percent in 2015, 12.5 percent in 2020, and 17.5 percent by 2025. This obviously conflicts with the above-noted stipulation that NCRE should not increase tariffs!

Figure 4.8 Tariff Expectations: Baseline, 2009–27



Source: World Bank 2010.

Figure 4.9 Tariff Impact of the 10 Percent RE Target: 2009 Forecast



Source: World Bank 2010.

Nevertheless, it is not an unreasonable question to ask why, with a generally declining tariff that comes with the substitution of coal for oil, is an increasing penetration of more expensive renewable energy such a problem for the CEB: since the tariff is projected to decrease, the additional cost of NCRE simply means the tariff *decline* is somewhat smaller than it would otherwise have been. But at least in the short term, the main reason for the CEB's objections is that its overall financial situation remains poor, and until such time as the CEB is in sustainable financial health, ***any*** incremental expenditure (and above all any claim on its cash flow) will be opposed. Only once the principle that incremental expenditures for renewable energy are treated no differently than purchases of energy from other IPPs in the retail tariff methodology, and its additional cost of working capital is allowed, will the CEB become indifferent to renewable energy—always assuming that a 10 percent share of non-dispatchable and intermittent energy poses no problems for network operation and stability.

Table 4.16 shows the calculation of our comparative consumer tariff indicator that estimates the impact on the consumer tariff of a 1 percent increase in the quantity of RE generation. These estimates use the revised FITs of 2012, which particularly in the case of wind have somewhat lower rates than in 2009. According to the baseline demand forecast for 2020, generation is 23,950 GWh, sales are 20,870 GWh, and the average 2020 tariff (for the least-cost baseline) is 8.04 cents/kWh.[30] The incremental energy required is 204 GWh, supplied by the mix of renewable energy as shown in the NCRE scenario of table 4.10.

Table 4.16 Impact of a 1 Percent Increase in Renewable Energy

		Units				
1	2020 Baseline generation	GWh	23,952			
2	Target energy to be replaced	%	1.0%			
3	Target energy to be replaced	GWh	240			
4	Target energy to be replaced		Hydro	Wind	biomass	other
5	Share		0.42	0.37	0.15	0.06
6	Generation	GWh	101	89	36	14
7	Financial cost	SL Rs/kWh	16.70	20.62	21.00	15.31
8	Financial cost	Cents/kWh	14.5	17.9	18.3	13.3
9	Financial cost	Cents/kWh	7.1	7.1	7.1	7.1
10	Incremental cost	Cents/kWh	7.4	10.8	11.2	6.2
11	Total	$ million	7.5	9.6	4.0	0.9
12	Total incremental cost	$ million	22.0			
13	Impact on consumer					
14	Retail sales	GWh	20,869			
15	Average consumer tariff	Cents/kWh	8.04			
16	Total cost [RR]	$ million	1,678			
17	Tariff increase	%	1.3			
18	Tariff increase	Cents/kWh	0.105			

Note: GWh = gigawatt-hour; kWh = kilowatt-hour.

The incremental cost is $22 million, which results in a tariff increase of 1.3 percent (or 0.105 cents/kWh).

Table 4.17 explains why renewable energy is seen by the CEB as costly. While incremental purchases from IPPs (RE producers) amount to $314 million, fossil-fuel savings are only $68 million. As noted earlier, some coal units would be displaced and deferred by NCRE, but the incremental decline in revenue requirements for debt service, and the CEB's equity return on new projects, amounts to only another $33 million, for a net increase in revenue requirements of $216 million.[31]

Sri Lanka is perhaps an outlier, insofar as the fuel displaced by renewable energy may well be coal (since the storage in the many large hydro projects serves as the matching mechanism to the load curve)—but since coal is the cheapest of all of the fossil fuels, the incremental costs of renewable energy are correspondingly high.

The Cost of Fossil-Fuel Subsidies

Unlike many other case study countries (for example, Indonesia, the Arab Republic of Egypt, and Vietnam), Sri Lanka lacks its own fossil resources,[32] and must import all its thermal fuels for power generation. Most of the fuel used in the power sector is auto diesel, of which a substantial fraction is imported, since the refinery at Sapugaskanda, operated by the government-owned Ceylon Petroleum Corporation (CPC), cannot meet the entire domestic demand; this diesel does not benefit from subsidy.

Table 4.17 Impact of RE on CEB Revenue Requirements

	US$ million
Fossil fuel costs	–68
Fixed O&M	0
Debt service, principal	–1
Debt service, interest	–24
IPP capacity payments	0
Purchases from RE IPPs	314
Past debt service	0
T&D investment	0
Other expenses	0.2
LNG terminal costs	0
CEB equity return, new projects	–8
Total revenue requirement	216

Source: World Bank 2010.
Note: CEB = Ceylon Electricity Board; IPP = independent power producers; LNG = liquefied natural gas; O&M = operation and maintenance; RE = renewable energy; T&D = transmission and distribution.

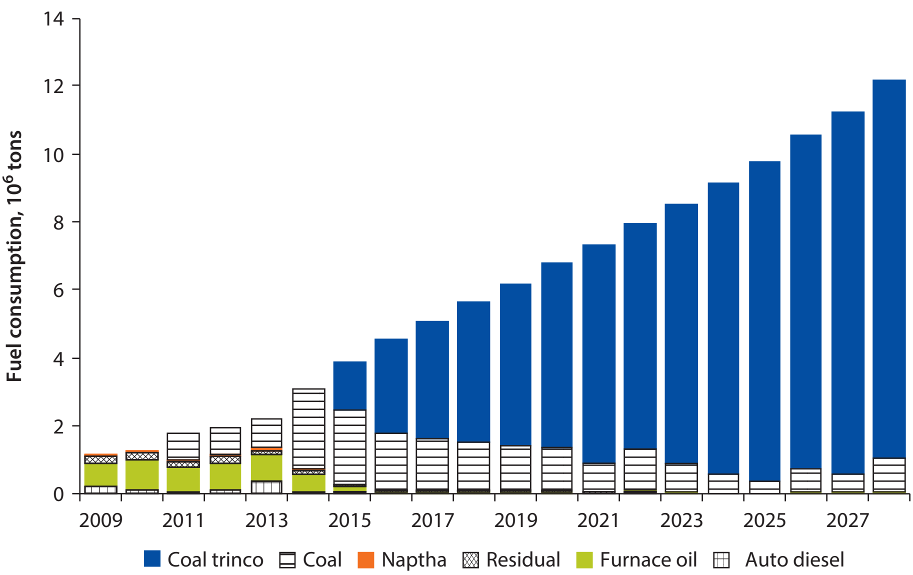
The question of whether the CEB benefits from subsidies relates mainly to heavy fuel and naphtha (as a fuel for some CCGTs). Residual fuel is delivered directly to the CEB's heavy diesels, and is so viscous it must be heated for transportation. With both the CEB and CPC making large losses,[33] it is not surprising that it is alleged (by the CPC) that the CEB benefits from subsidized heavy fuel. The problem is not that significant subsidies on this fuel are in place by explicit government design, but that during the years when international oil prices were rising—such as in 2010–11—the price adjustment mechanism was insufficiently flexible. Since domestic prices are fixed by the government, if these are not adjusted regularly and frequently, then the CPC incurs large losses because it buys at the increasing international price but has to sell at the still-to-be-adjusted domestic price. In this situation it is not surprising that the CPC has made losses in 2010 and 2011.

But from the perspective of the RE policy, this is largely moot. The use of heavy furnace oil is expected to be phased out in the next few years (figure 4.10); residual oil will be used for somewhat longer (since there is no other use for it, and it cannot be exported).[34]

Financing New and Renewable Energy

In the case of small hydro, with the ESDP and RERED support, the local banking sector seems comfortable with lending: the track record of the industry has been good to date, so capital mobilization for SHPs should not be a major problem

Figure 4.10 Forecast of CEB Fuel Use, 2009–27



Source: World Bank 2010.
Note: CEB = Ceylon Electricity Board. "Coal" is that used in the Puttalam (west coast) coal projects; "Coal Trinco" is the coal consumed at the projected projects in Trincomalee (on the east coast).[35]

given the end of the ESDP and RERED financing facilities—also shown by the large number of pending projects (see table 4.4). The present level of the small hydro FIT will allow projects to be built at much higher capital costs than the first set of SHPs.

In the case of wind projects, note that two of the three wind projects recently completed are 100 percent equity, and the third is 50/50 equity/debt—made possible by the small size of the projects (less than 20 MW). The extent to which this reflects the skepticism of lenders about the economics of wind projects is not known, but such levels of equity do not provide a sustainable model for achieving the NCRE wind energy targets.

Conclusions

The conclusions of Sri Lanka's experience with renewable energy can be summarized as follows:

- *Targets*. The 10 percent target for renewable energy was a political statement issued at a time of power shortages, and was not supported by a credible analysis of its economic impact. By end 2013, only 40 MW of wind power was in place, making the required 220 MW of wind that would be necessary to meet the 2015 target most unlikely. A new target of 20 percent by 2020 has now been proposed.
- *Design of incentive schemes*. Sri Lanka's ACT must be judged a great success, having enabled some 188 MW of grid-connected small hydro schemes in 77 projects. This was replaced by a FIT, which was the result of the alignment of interests of the government (which wanted to demonstrate practical measures in support of achieving its 10 percent 2015 RE target) and of the Small Hydro Developers Association (who faced a declining ACT with the increased penetration of coal, and wanted an increase rather than a decrease in tariff!).
- *Recovery of incremental costs.* While the ACT was in operation, recovery of incremental costs was not an issue. But with the higher levels of support under the FIT, recovery of incremental costs in the first few years of the tariff have been problematic, because the expectations of offsetting tariff declines in the *existing* SHPs have not materialized. This has created difficulties in timely payment of the CEB's invoices for its incremental costs, leading in turn to a halt of further issuance of Letters of Intent (LoIs). Although tariffs are expected to decline significantly in the face of the move from oil to coal, the CEB is still making large financial losses, and therefore will continue to oppose having to absorb the incremental costs of renewable energy until such time as it is in better financial health, and the tariff methodology explicitly recognizes that these incremental costs are part of the CEB's legitimate revenue requirements.
- *Impact on consumers.* The impact on the consumer tariff of an additional 1 percent of renewable energy in 2020 is estimated at 0.15 cents/kWh, or an

increase in the average consumer tariff of 1.3 percent (corresponding to an incremental cost at 2012 price levels of $22 million). Since the tariff is projected to fall from the present 13 cents/kWh to around 8 cents/kWh (as a result of coal projects replacing expensive auto-diesel generation), this may be seen as an acceptable increase. But meeting the NCRE target of 10 percent implies a 13 percent tariff increase, which is unlikely to be acceptable.

- *Regulatory framework*. The SLPUC has been slow to assume its tariff responsibilities, and there was much delay in the revision of the 2009 tariffs—the new tariff was only issued in mid-2012.
- *Fossil-fuel subsidies*. The extent to which subsidies on the CEB's purchases of heavy fuel have risen during the past few years of oil price increases is a function not of an explicit intent to subsidize the CEB, but is a consequence of the slow oil price adjustment system. In any event, with the expected transition from oil to coal, this issue is moot—unless difficulties with implementing the Trincomalee coal projects again push Sri Lanka into oil generation.
- *Off-grid renewable energy*. Unlike Vietnam, Sri Lanka's village hydro program has been successful. It has developed an institutional model that is closely aligned to the capacities of its rural beneficiaries, and that can be replicated on a large scale. Rehabilitation of the estate sector SHPs is also promising.

Notes

1. Although still owned by the government, it is mandated to run on commercial lines, and has made major progress in rehabilitating the distribution system: its losses were greater than 50 percent when it took over its new franchise area; its losses today are 8 percent.
2. Finally resolved in March 2011, when the new coal project at Norocholai, North of Colombo, started operation.
3. For a detailed assessment of the influence of tariffs on demand growth and the demand forecast, see *Sri Lanka: Environmental Issues in the Power Sector* (World Bank 2010) (hereafter cited simply as EIPS).
4. The CEB continued to serve the eastern province throughout the conflict period that ended in 2008, but new investment on grid extensions and service quality improvements were not implemented. Network losses (both technical and commercial) are high in the Eastern Province owing to lack of investment and poor supervision. In the Northern Province the CEB redeveloped the Jaffna distribution network after 1995, operated it as a mini-grid served by diesel-engine generators on short-term contracts, and continued to do so even after the end of the conflict until the transmission link was reestablished. Several other towns in the North were provided with a limited power supply by the CEB using diesel engines, intermittently throughout the duration of the conflict.
5. Sri Lanka Electricity Act No 20 of 2009: http://www.pucsl.gov.lk/download/Electricity /electricity20act202009.pdf.
6. http://www.pucsl.gov.lk/download/pucsl/regulatory20manual.pdf.

7. NCRE is defined as small hydro (less than 10 megawatts, MW), wind, biomass, and other sources such as energy from agricultural waste, landfill gas, and municipal waste.
8. The others being rice, tea, and rubber.
9. Colonial planters were the first to tap hydropower in small streams to generate electricity and motive power for their plantation industries. It is estimated that around 500 such micro-hydro plants had been in operation in the early part of the twentieth century.
10. But these sub-loan maturities are limited to 10 years including a maximum 2-year grace, and no more than $3 million to any individual project.
11. This would use 75 percent paddy husk and 25 percent fuel wood to produce 72 GWh/year, using a moving grate boiler. A survey around Trincomalee indicated that 240,000 million tons (MT) of paddy husk are available as unmanaged agricultural waste, which would otherwise be left to decay or be burned in the open air. The annual requirement of rice husk for the 10 MW power plant is 81,000 MT, which would account for 34 percent of the available rice husk in the area. To produce annual requirements of fuelwood (27,000 MT), an effective land area of 1,000 ha is required; Gliricidia is proposed as the fuelwood species.
12. At appraisal, the annual load factor was estimated at 27.5 percent. When the wind turbines went to tender, the turbine manufacturers asserted that the wind regime would provide just 22 percent. In the first few years of the project, the actual load factor was around 15 percent. The main problem was the location; because of various factors (including the air force, and the interest of a nearby bird sanctuary) the project had been moved to a less-favorable location.
13. This is much smaller than in Vietnam, where the average size of small hydro projects is 11 MW.
14. The Estate Micro Hydro Rehabilitation and Re-Powering Project (EMRRP), which is funded by the ADB Sustainable Power Sector Support project.
15. This is possible where heads are very high requiring a low volume of water, which means that the design flow is only a small fraction of the average annual flows. Many engineers would describe this as underutilization of the potential—since most of the wet season water remains unused.
16. Some of these villages now receive grid electricity, but they are now eligible to sell into the grid under the SPPA: Athureliya is a 21.8 kW village micro-hydro scheme that was the first to sell electricity.
17. Economic costs were estimated to be slightly lower, at $963/kW.
18. As discussed in chapter 3, throughout the typical short-to-medium term planning horizon, gas CCGT is forecast to run in Vietnam 24 hours/day until at least 2025.
19. In other words, the IPP should recover its capital costs, equity returns, and fixed operating costs in a fixed charge, independent of generation, with a variable charge covering fuel costs.
20. See Siemens Power Technologies UK 2008. This study showed that with a targeted program of network reinforcement, by 2013 some 690 MW of embedded generation from renewable energy could be absorbed, under the assumption that the output of CEB generators would be reduced by this amount.
21. There are four such projects in Sri Lanka: Uma Oya (150 MW), Broadlands (35 MW), Moragolla (27 MW), and Ging Ganga (49 MW)—none of which are in the CEB's least-cost plan at 10 percent. But as noted in section "Renewable Energy

Development," at the lower discount rate of 8.5 percent these hydro projects *are* in the least cost plan.

22. And brought to northern Sri Lanka by a dedicated transmission line (including an underground cable section and back-to-back direct current [DC]).
23. In early 2012 many observers were still optimistic about Phase III of the EU-ETS, with a survey of forecasts showing a consensus expectation of around €8.5/ton. But with the April 2013 vote of the EU parliament on backfilling (which many observers thought would revive the market), and with the continuing economic malaise in the Eurozone, recovery of the CER price to former levels is seen as very unlikely.
24. The Uma Oya hydro project is under construction (for start-up in 2015).
25. Including waste-heat recovery.
26. Corresponds to a three-phase, 60 Ampere supply, which is the highest rating for a retail supply.
27. Precisely this symmetry of risk sharing was introduced in the Vietnam ACT, 10 years later (see section "Design of Incentive Schemes" in chapter 3).
28. This stipulation that there be no impact on end-use tariffs would appear to preclude an RE levy on electricity similar to the universal charge in the Philippines.
29. In Vietnam, as noted in chapter 3, purchases of renewable energy from small power producers are a pass-through in the retail tariff methodology (just as are purchases from the system operator for conventional power).
30. This is considerably lower than the present tariff of SL Rs 13.42/kWh (12.2 cents/kWh).
31. There is no change in IPP capacity payments, since these are fixed in the PPAs and are unaffected by more or less renewable energy.
32. Indonesia has oil, coal, and gas; Vietnam has coal and gas; and Egypt has gas.
33. In 2012 the CPC lost SL Rs 94.5 billion ($859 million), and the CEB lost SL Rs 65 billion ($591 million).
34. Fuel oil has long been exported, because the product mix at the refinery does not match that of the domestic market.
35. Trincomalee was the originally proposed location for the first coal project, as recommended by the original feasibility study in 1986, mainly for it excellent deep-water sheltered harbor, which would allow coal impacts on cape-size vessels. But this area was under the control of the Tamil Tigers, so the site for the coal plant was shifted first to the south, and then to the Puttalam area, north of Colombo (where the first coal project is now operating). But with the end of the conflict, Trincomalee is again the preferred site for coal projects.

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CHAPTER 5

Case Study: Indonesia

Sector Background

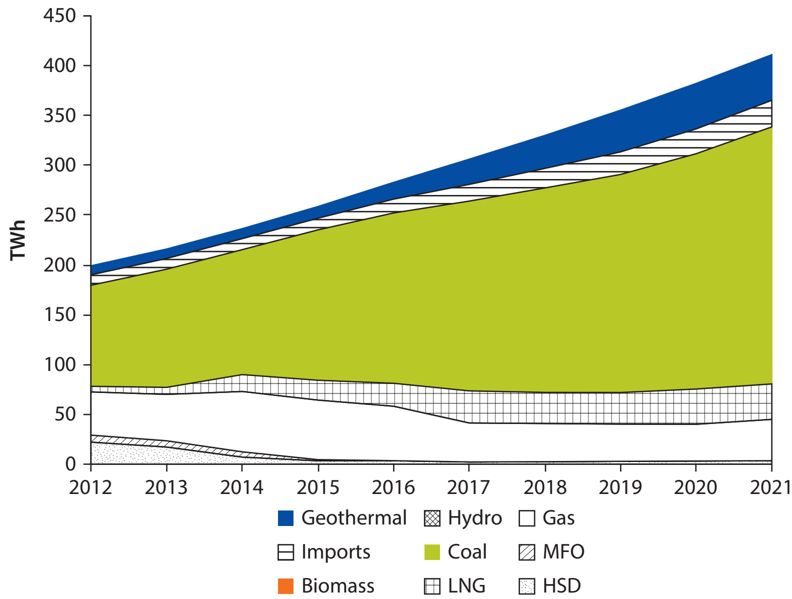
Indonesia's power industry expanded rapidly from the early 1980s to the late 1990s, when the Asian financial crisis seriously disrupted the Indonesian economy. But since then, the power sector has been gradually recovering, especially in the past few years. By June 2012 the total installed generation capacity of the national power system reached 35,167 megawatts (MW),[1] making it one of the largest in Southeast Asia. But given the size of its population, Indonesia's per capita electricity consumption, at 655 kilowatt-hours (kWh) per capita per year, and electrification ratio, at 71 percent,[2] are still low compared to other middle-income countries.

The state-owned national power company, PT Perusahaan Listrik Negara (PLN), has the constitutionally mandated responsibility for Indonesian electricity supply. It is a vertically integrated power company and generates, transmits, and distributes most of the electricity in the country. PLN is solely responsible for Indonesia's transmission systems. But acting as the single authorized buyer at the wholesale level, PLN buys electricity from an increasing number of independent power producers (IPPs) and some large captive power plants. In 2011 PLN sold 160 terawatt-hours (TWh) of electricity to some 45.9 million customers nationwide.[3]

The Geological Agency of Indonesia (2010) estimates that Indonesia holds some 28,500 MW of geothermal resources, a significant proportion of the global potential. As of 2012, however, only some 1,190 MW of geothermal power capacity had been commissioned. Nevertheless, Indonesia ranks third behind the United States (3,093 MW) and the Philippines (1,904 MW) in terms of installed geothermal power generation capacity. The government has announced an ambitious target for the development of this resource (9,500 MW by 2025), the bulk of which is to be achieved by the private sector.

But renewables development must be put into the context of the overall PLN generation plan, which is overwhelmingly coal. According to PLN's current investment plan, the share of coal in the generation fuel mix will increase from around 35 percent in 2012 to roughly 70 percent by 2020 (figure 5.1). A range

Figure 5.1 The Forecasted Generation Mix
GWh



Source: PLN 2012b, figure 5.3.
Note: GWh = gigawatt-hour; HSD= high-speed diesel; LNG = liquefied natural gas; MFO = marine fuel oil; TWh = terawatt-hour.

of major challenges faced by PLN—and that also have a claim to PLN's limited financial resources—make achievement of the geothermal target very difficult.

Large Investment Requirements

Significant investments from both the public and private sectors are required to meet fast-growing energy demand, and to increase access to modern and sustainable energy solutions for all. PLN's financial condition is critical to the financial viability of the power sector as a whole, and the sector's ability to attract the large amounts of capital required to keep up with the growing electricity demand.

The magnitudes involved are formidable: according to PLN's latest investment plan (2012–22), between 2012 and 2021 the total investment requirement is $107 billion, of which $77.2 billion is for generation, $16 billion for transmission, and $13.8 billion for distribution. Although PLN's $2 billion bond issue in 2012 was oversubscribed (PLN 2012a), and there are plans for about one-third of the new generation additions to be provided by the private sector, the challenge for PLN is clear.

Low Rate of Electrification

Electrification levels remain low, especially outside Java-Bali. The current national electrification rate is 71 percent, leaving 78 million people without electricity access, or access to only very unreliable non-grid supply. Most of those without access to electricity live in the remote areas of Java and Bali, or in islands outside the area covered by the Java-Bali system. In 2011 the electrification rate was 76 percent in Java-Bali and 64 percent in the rest of Indonesia. The government has set an electrification target of 92 percent by 2021.[4]

High and Highly Subsidized Tariffs

Electricity tariffs that are significantly below the cost of supply undermine PLN's financial viability and lead to large government subsidies. In 2011, the subsidy of Rp 93 trillion accounted for 45 percent of PLN's total revenue requirements of Rp 206 trillion ($21 billion) a sharp increase from 2005 when the subsidy was just Rp13 trillion (World Bank 2012). Tariffs below cost-recovery levels are the main barrier to improving energy efficiency and achieving greater private sector participation. At the same time, Indonesia's average cost of power generation is very high (15.5 cents/kWh in 2011), which is in large part attributable to the unusually high share of oil in the thermal generation fuel bill.[5]

Gas Supply

Subsidized domestic gas prices and underdeveloped gas infrastructure have caused delays in the expansion of the domestic gas sector and have contributed to a suboptimal generation mix: the consequences of gas shortages in the short run are either that more oil is used to meet intermediate and peak demand, and/or that coal projects are used as load followers (with significant efficiency penalties). In the longer term, as applies to the investment plan, less domestic gas translates into more (expensive) liquefied natural gas (LNG).

Geographical Imbalance

In 2012 the Java-Bali system accounted for 77 percent of total PLN sales; Sumatra, 15 percent; and all the rest of Indonesia, just 8 percent (table 5.1). As discussed below, this creates great difficulties for the implementation of geothermal energy, much of which is in remote provinces far from the institutional center in Jakarta. The island fragmentation also creates significant problems for electricity planning: PLN uses the Wien Automatic System Planning (WASP) IV capacity expansion planning model for seven major grids, plus a further 97 systems with peak demand of more than 1 MW for which a simpler supply-demand balance model is used to forecast generation requirements. Much of the planning work for the Eastern Islands is devolved to PLN's regional offices.

Table 5.1 Regional Imbalances of Electricity Supply

	2012		*2021*		
	TWh		*TWh*		*Expected annual growth rate*
Sumatra	26	*15%*	62	*17%*	10.5%
Java/Bali	132	*77%*	259	*72%*	7.9%
Rest of Indonesia	14	*8%*	37	*10%*	11.4%
Total	172	*100%*	358	*100%*	

Source: PLN 2012b.

Renewable Energy Development and the Resource Endowment

Lack of incentives, a complicated and uncertain regulatory environment combined with the relatively weak institutional capacity of central and local institutions, and the weak and low coverage of transmission networks, has hindered substantial development of renewable energy (RE) resources, especially geothermal, hydropower, and biomass.

Geothermal

Systematic development of geothermal energy began with the enactment of the 2003 Geothermal Law. This opened geothermal development to direct private participation through competitive tendering, and provided an active role for the regional government to conduct these tenders and issue licenses. Prior to this law, geothermal work areas were awarded to developers on a memorandum of understanding (MoU) basis without competition.

But progress since enactment of Law 27/2003 has been slow. The tender process for geothermal working areas (known as Wilayah Kerja Pertambangan Panas Bumi [geothermal work areas as known in Bahasa, Indonesia] WKPs)[6] has revealed various impediments to rapid expansion of geothermal power capacity. The pricing framework for geothermal power has been revised several times, but the cost differential between geothermal power and coal-fired generation has only recently been taken up by the government. A Ministry of Finance (MoF) regulation provides that the incremental cost of geothermal energy be funded under the public service mechanism (PSO).[7]

So-called legacy WKPs are those that were awarded prior to 2003; a number of these are proposed to be expanded in the near future. The current development framework provides for private sector entities to take on the bulk of the exploration risk. Government involvement in geothermal energy is through a Pertamina subsidiary (Pertamina Geothermal Energy, PGE).

Small Hydro

As in Sri Lanka, small-scale hydropower started in the tea plantations. In West Java, one of the main tea regions in Indonesia, the first turbine was installed in 1885. At this time turbines were providing shaft power to tea rollers and other machinery in the tea factory, but not directly driving generators. Later, with advancing turbine and generator technology, hydroelectric power plants were built. In 1910, 40 private tea plantations owned hydropower plants, and by 1925 there were 400 such projects with a total capacity of some 12.5 MW. In the modern era, off-grid hydro has been actively promoted, but comprehensive information about the extent of these projects is not available. Nevertheless, as noted below, the target of several hundred megawatts of off-grid hydro should be within reach. Moreover, because many of these systems are on small islands that will never become accessible to the interconnected national grid, these are much less likely to become abandoned (as, for example, in Vietnam).

Renewable Energy Targets

The National Energy Plan 2006 sets targets for a range of RE technologies (table 5.2), with the share of renewable energy in the primary energy supply to grow from 4.3 percent in 2006 to 17 percent by 2025.

The 9,500 MW target appears to be reasonable in light of the resource estimates published by Indonesia's geological agency. But as with estimates of wind potential in Vietnam, these are quite misleading since they are divorced from economics. A 2007 study estimates the exploitable potential at 9,000 MW, spread across 50 fields, with a maximum potential of 12,000 MW (WestJEC 2007). PLN's latest investment plan (2012–22) anticipates total capacity additions by 2021 of 57,300 MW, so the additional 8,200 MW of geothermal capacity represents 14 percent of the required capacity additions. But with geothermal capacity typically requiring investment at $4,000–5,000 per kilowatt (kW), compared to coal at $1,500/kW, the geothermal proportion of total capital investment is much greater.

In 2010 the Ministry of Energy and Mineral Resources (MEMR) set an additional target of 3,967 MW to be achieved by the end of 2014—a target that is unlikely to be achieved given the current installed capacity of around 1,300 MW. This target lists 43 projects, of which 37 (3,627 MW) are to be developed by the private sector, and 6 (340 MW) by PGE. Most of the larger projects are on Java or Sumatra.

Production Costs

The price per kWh for operating geothermal projects, and for WKPs under development where the price is available, is shown in table 5.3.[8]

There is no evidence of scale economies, except that very small projects below 10 MW have costs above 9.5 cents/kWh (figure 5.2).[9]

Geothermal Development Policy Issues

It is widely asserted that a major reason for the slow pace of geothermal development in Indonesia is that most developers are reluctant to assume exploration risk (Fichtner 2011). It is held that only the largest of companies with access to

Table 5.2 Renewable Energy Targets: The 2006 National Energy Plan

	Installed capacity, MW
Geothermal	9,500
Biomass	810
Grid-connected small hydro	500
Off-grid small hydro	330
Wind	255
Solar	80

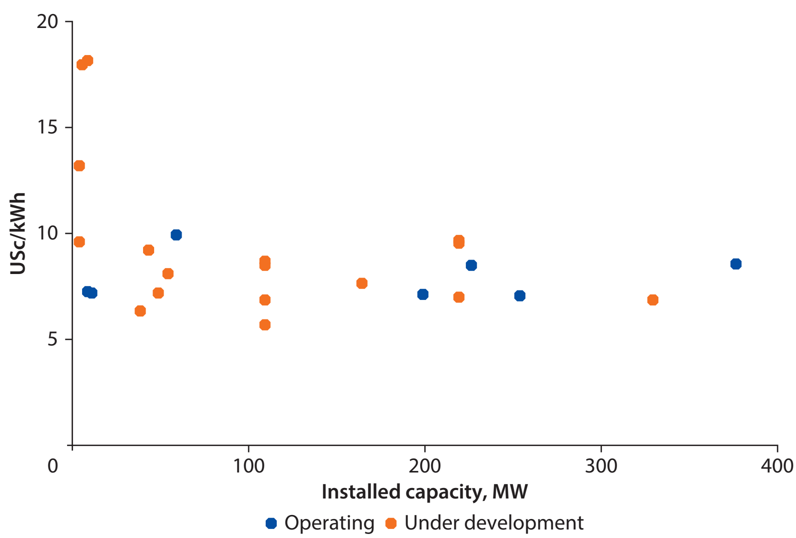
Source: National Energy Plan 2006.
Note: MW = megawatt.

Table 5.3 Prices for Geothermal Projects

Project	*Status*		*MW*	*Cents/kWh*
Tangkuban perahu 1	Under development	Java	110	5.56
Tampomas	Under development	Java	40	6.24
Silangkitang (Sarula 1a and b)	Under development	Sumatra	110	6.79
Namora i langit (Sarula 2)	Under development	Sumatra	330	6.79
Suoh sekincau	Under development	Sumatra	220	6.90
Darajat 1, 2, and 3	Existing	West Java	255	6.95
Kamojang 1–4	Existing	West Java	200	7.03
Cisolok-cisukarame	Under development	Java	50	7.09
Sibayak	Existing	North Sumatra	12	7.10
Bedugul	Existing	Bali	10	7.15
Wilis/ngebel	Under development	Java	165	7.55
Sorik merapi	Under development	Sumatra	55	7.96
Kaldera dano	Under development	Java	110	8.35
Wyang Windu 1 and 2	Existing	West Java	227	8.39
Salak 4, 5, 6	Existing	West Java	377	8.46
Ijen	Under development	Java	110	8.58
Ungaran	Under development	Java	44	9.08
Muaralaboh (liki oinangawan)	Under development	Sumatra	220	9.40
Atadei	Under development	LEMBATA	5	9.50
Rajabasa	Under development	Sumatra	220	9.52
Dieng 1	Existing	West Java	60	9.81
Sokoria	Under development	FLORES	5	13.03
Jaboi	Under development	SABANG	7	17.78
Jailolo	Under development	TERNATE	10	18.01

Source: For projects under development, the prices are as shown in Castlerock Consulting (2010, exhibit 4.2).
Note: kWh = kilowatt-hour.

Figure 5.2 Electricity Price vs. Installed Capacity



Note: kWh = kilowatt-hour; MW = megawatt; USc = U.S. cents.

balance sheet financing (which in Indonesia would include Chevron and PGE) have the necessary equity to adequately fund exploration, and that smaller developers whose projects are ultimately dependent upon nonrecourse project finance simply do not have the necessary equity to carry the exploration risk. Moreover, only the large entities can themselves mitigate this risk by portfolio diversification.[10]

Therefore, the argument is made that to attract more and better entrants, ways must be found to mitigate this risk. The problem arises because under the Indonesian geothermal development model, bidders for WKPs have had to estimate an electricity price *prior* to exploration (albeit subject to renegotiation when the business license is awarded once a decision to proceed is made by the developer). It is not generally possible for a project company to raise debt finance for exploration work, and therefore the question arises whether enough equity can be raised commensurate with the risks and rewards.

But the extent to which smaller companies have *in fact* been discouraged from bidding for WKPs, or have lost tenders to larger competitors for reasons of an uncompetitive electricity price, is unclear. The Castlerock Consulting study (2010, exhibit 4.2) presents a list of WKPs and their status (as of December 2010), and, where tenders are complete, the winning tender and in some cases the "price per kWh"[11]—but provides no information on the number and identity of the unsuccessful bidders, or on the prices offered by unsuccessful bidders. Indeed, there are many other reasons why projects are stalled: while Castlerock identifies 13 WKPs with "commercial problems,"[12] 12 WKPs have permit problems (predominately land and forestry permits). Discussions with developers confirm that permitting issues are a major problem, particularly for land and forestry permits, and these represent one of the main obstacles to timely implementation.[13] But discussions with developers also suggest that a major problem lies in the tendering process: many successful bidders for smaller projects are unable to deliver projects at the excessively low prices bid. Indeed, the $10 million performance bond requirement for winning bidders is not enforced, and the bid bonds are typically far too low to discourage speculators and unqualified entities.

Exploration Risk

For all the general discussion about exploration risks, no rigorous quantification of the exploration risk has been undertaken to date, which would inform us to the extent to which higher tariffs would in fact mobilize the additional equity required.

But a study that assessed Indonesian drilling success performance suggests that geothermal exploration risk in Indonesia is smaller than in most other countries with prospective geothermal resources (Sanyal and others 2011). Average depths per well are smaller than elsewhere, and megawatts per well are higher. The average megawatt per successful well, which was around 6 MW initially, has gradually increased to 9–10 MW, and the overall success rate—with over 200 wells drilled, is now around 60 percent. Similar learning curve effects are observed at individual fields: in the well-developed Kamojang field, the drilling success rate—initially around 40 percent, is now 70 percent. The study concludes that the current well development cost per megawatt is \$300,000–\$400,000, so with a median well size of 9 MW the average cost per well is \$3 million–\$4 million.[14]

The view among developers is less optimistic. Many note that the "low-hanging fruit" has already been picked, and that unit drilling costs are on the increase. Costs for a full-sized development well (seen in recent feasibility studies) are around \$6 million,[15] but some expect costs to be \$8 million and more.

Capacity Reductions

Another yardstick for gauging the extent of risk during the exploration phase is the change in estimated capacity between expectation at the outset and current capacity. If exploration risks are high, one would expect the final project design to have lower capacity than originally expected. But of 52 WKPs listed in the Castlerock status survey, 47 show *no change*. One project has increased its estimated capacity from 205 MW to 220 MW (Chevron project in Suoh Sekincau, Lampung, Sumatra), and five projects show a decrease (table 5.4).

A somewhat higher failure rate is implied by the Castlerock reassessment of overall geothermal potential in the WKPs. That analysis takes into account the probabilistic variations in input parameters, and the revised potentials represent the expected value of commercial potential. Of the 52 WKPs examined, only 10 show no change, 7 show an increase, 20 show a decline, and 14 (or 27 percent) show zero potential. This compares to the current overall drilling failure rate of 38 percent (Sanyal and others 2011).

The Renewable Energy Supply Curve

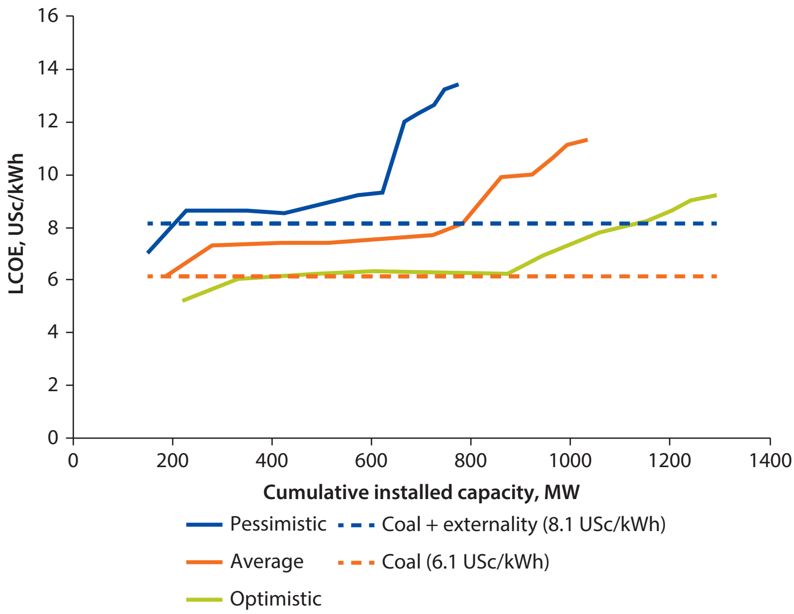
Castlerock prepared supply curves for all major geothermal areas in Indonesia, for which the curves for Java-Bali are shown in figure 5.3. These recognize the wide range of uncertainty in the supply curves, having been derived with a probabilistic model of geothermal exploration and exploitation.[16] These are compared to the avoided costs of coal (6.1 US cents [USc]/kWh) and with the costs of coal plus local and environmental externalities (8.1 USc/kWh)—following exactly the procedure recommended in section "Renewable Energy

Table 5.4 Changes in Capacity

Project	*Location*	*Developer*	*Original MW*	*Revised MW*	*Change MW*
Suoh Sekincau	Sumatra	Chevron	205	220	15
Tampomas	Java	Wika Jabar Power	45	40	–5
Salak	Java	Chevron	40	0	–40
Darajat	Java	Chevron	110	0	–110
Parutra 1, 2, and 3	Java	GDE	180	55	–125
Wayang Windu 3 and 4	Java	Star Energy	240	110	–130

Source: Castlerock Consulting 2012.
Note: MW = megawatt.

Figure 5.3 Supply Curve for Java-Bali



Source: Castlerock Consulting 2010, exhibit 2.6.
Note: kWh = kilowatt-hour; LCOE = levelized cost of energy; MW = megawatt; USc = U.S. cents.

Development and the Resource Endowment," the economic quantities are given at the point where the supply curves intersect the avoided costs of coal. These supply curves need to be updated, because drilling costs have increased significantly since 2009 when these curves were prepared.

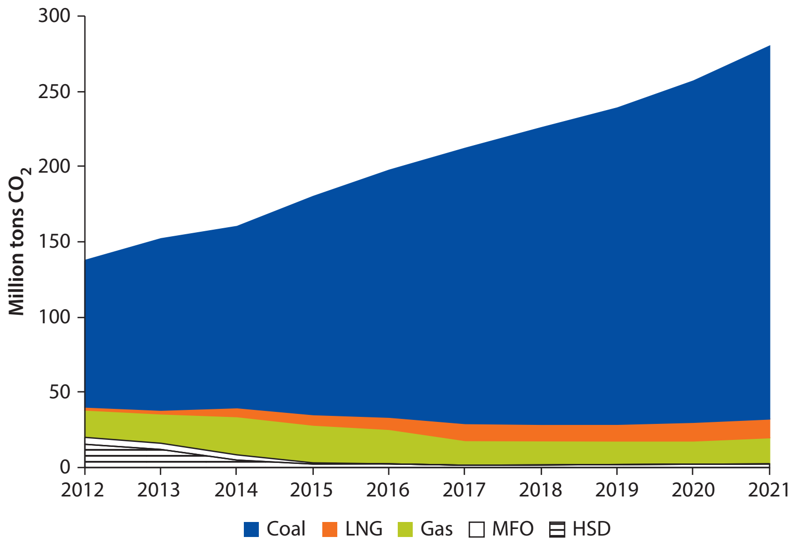
This supply curve (and similar ones for Sumatra and the Eastern islands) reveal rather lower estimates of potential than the government expects—if 10 cents/kWh were set as the feed-in tariff (FIT) (or as the tariff ceiling), then the potential is just another 1,300 MW on Sumatra and 900 MW on Java-Bali (under the average cost and capacity conditions shown in figure 5.3). Expressed differently, to achieve the target of 9,500 MW is wishful thinking not just because of the state of the actual resource, but the incremental cost required to achieve it.

Carbon Accounting and CDM

With the large number of new coal projects, the greenhouse gas (GHG) emissions of Indonesia's power sector are expected to increase from 150 million tons of carbon dioxide (CO_2) per year to 280 million tons by 2021 (figure 5.4). These estimates are based on the Intergovernmental Panel on Climate Change (IPCC) default emission factors.

The 2010 Castlerock report states that sale of certified emission reductions (CERs) could cover a significant portion of the incremental costs of geothermal (up to 38 percent of total incremental cost in 2014, 45 percent in 2016,

Figure 5.4 PLN CO_2 Emissions
Million Tons/Year



Source: PLN 2012b.
Note: CO_2 = carbon dioxide; LNG = liquefied natural gas.

and 31 percent in 2020).[17] Indeed, the economic analysis presented in that report assumes CER revenue at $20/ton CO_2. But as discussed in section "Carbon Accounting and CDM" in chapter 4 (see table 4.9), the prospects for such carbon prices in the next five to seven years are minimal, given the oversupply of registered CERs.

Design of Incentive Schemes

Over the past 15 years, Indonesia has issued a number of incentive schemes for renewable energy:

- The 1995 avoided cost tariff (ACT) for small RE producers.
- The competitive tariff and tendering scheme for geothermal development (in a series of regulations to implement the Geothermal Law of 2003).
- The geothermal fund.
- Feed-in tariff for geothermal of August 2012.

The Avoided Cost Tariff of 1997

Indonesia introduced an ACT in December 1995.[18] Indeed, the ACT and the standardized power purchase agreement (SPPA) were the cornerstones of a World Bank/Global Environment Facility (GEF) RE small power project approved in 1997. The basic principle of the tariff was that it was to be based on 100 percent of PLN's avoided costs, but differentiated by region. The original scheme envisaged nonfirm contracts with a single energy charge, and firm contracts with energy and capacity charges (the latter with complicated escalation provisions to hold constant the rupiah-dollar exchange rate for the first five years, with the objective of protecting foreign debt service obligations). But with the disruptions of the 1997–98 financial crisis, few small hydro projects (SHPs) were completed and the Bank's project—which would have made loans available at longer tenors—was cancelled in late 1998.[19]

Geothermal Law of 2003

In 2003 the Government of Indonesia issued Geothermal Law No. 27/2003, which required all new geothermal concessions to be competitively tendered for development. To be consistent with the country's law on decentralization, the authority to carry out most geothermal tenders rested with the local or provincial governments.

But most sub-national institutions lacked the capacity and experience to carry out multimillion-dollar international tenders, and many public institutions faced capacity constraints in planning and managing geothermal developments. The result was a number of poorly structured geothermal development opportunities being tendered and none achieving financial closure. With a lack of preliminary information regarding the field and the credibility of the information offered being questioned (despite Indonesia having a vast database of mapped geothermal fields and related information), many leading geothermal developers did not participate in the tenders. Those that did participate proceeded to renegotiate the terms after the concession was awarded. Since the tenders did not include a standardized power purchase agreement (PPA) with PLN, the financial prospects of the offer were undermined.

In practice, the electricity price offered by a developer at the WKP stage could be (slightly) renegotiated at the award of the geothermal business license (known as Izin Usaha Panas Bumi (IUP),[20] though in 2010 the government set an upper bound of 9.7 cents/kWh. The renegotiation has been limited to indexation and escalation:[21] the base price itself (i.e., the price set in the first year of commercial operation) is not subject to change.

The Geothermal Fund

In 2012 the government created a $220 million geothermal fund for the purposes of geothermal exploration, funded by the state budget, and administered by a unit of the MoF. In principle, this can fund up to $30 million per WKP for geothermal exploration. But the precise workings of this fund have yet to be sorted out, though there are several proposals for how this might work—including the possibility of a secured loan to a license holder for a new or legacy WKP to conduct exploration. But the problem yet to be solved is what happens if the exploration program does *not* lead to a commercial development: if the developer remains at risk (secured through collateral) then there is little benefit to take out the loan. But with 100 percent collateral demanded as security for a loan, there have been no takers thus far.

The government is now considering a proposal to use the fund to provide up-front de-risking of WKPs prior to tender, as a public good, with resource data from at least three wells. Because the cost of private equity for funding first-stage exploration is very expensive, de-risking provided as a public good can achieve significant tariff reductions (from 1 to 3 cents/kWh), particularly in smaller projects in the Eastern Islands, that attract little interest from the big developers. The smaller the project, the greater is the impact of such up-front de-risking (Meier, Lawless, and Randle 2014a). The proposal is for the costs of up-front exploration to be recovered from the developer only at the time of financial closure, when most of the risk has been taken out of the project, and the costs of recovery in the tariff can be achieved at a weighted average cost of capital (WACC) far below the returns required by early-stage, high-risk private equity.

The 2012 Geothermal Feed-In Tariff

A fixed FIT for grid-connected geothermal projects was introduced on August 16, 2012 (table 5.5).[22] This replaced the earlier system of competitively bid tariffs that was part of the geothermal tender system. These new tariffs are higher than currently paid by plants in operation in Java and Sumatra (6.95–9.81 cents/kWh),[23] and higher than the ceiling price of 9.7 cents/kWh for projects currently under development. The expectation of the government was that the higher tariffs would motivate developers to accelerate geothermal development, given that over the past few years progress in achieving government targets has been slow.

The FIT was based on the recommendation of the tariff study by Castlerock Consulting (2010, 2012), which proposed that the tariff be based on the cost of the alternative fossil generation. Geothermal projects operate at high annual plant factors (85–95%), and unlike most other RE forms, which are non-dispatchable (such as wind), they serve as an excellent substitute for base-load coal, upon which Indonesia is relying for the bulk of its future base-load-generating capacity.

But this tariff has been unsuccessful: not a single PPA has been signed under this tariff, which has been widely criticized (for a counterfactual see the geothermal development in the Philippines and Kenya, summarized in box 5.1). The MEMR has recognized the problems, and is currently considering a new tariff issuance that returns to the previous system of competitively tendered projects subject to a price ceiling based on the *benefits* of geothermal energy.

Table 5.5 The New Geothermal Feed-In Tariff (Established in 2012)

		Tariff (cent/kWh)	
No	*Region*	*High voltage*	*Medium voltage*
1	Sumatra	10	11.5
2	Java, Madura, and Bali	11	12.5
3	South Sulawesi	12	13.5
4	North Sulawesi	13	14.5
5	NTB, NTT, Maluku, and Papua New Guinea	15	16.5
6	Maluku and Papua New Guinea	17	18.5

Source: Ministry of Energy and Mineral Resources.
Note: kWh = kilowatt-hour.

Box 5.1 Counterpoint: Geothermal Development in the Philippines and Kenya

The *Philippines'* build, operate, transfer (BOT) model for geothermal development has been more successful than Indonesia's model. With 1,900 MW of installed capacity, the Philippines is the leading developing country for successful geothermal development (see table B5.1.1). The key difference is that geothermal risk is taken by the government-owned geothermal company.

The first application of the BOT-based geothermal public-private partnership (PPP) in the Philippines is the World Bank–supported Leyte-Cebu Geothermal Power Project—a 200 MW geothermal project to be implemented by a private firm through a BOT contract with PNOC EDC, the publicly owned national geothermal development company. PNOC EDC provides the exploration and development of the geothermal field, while the power plant contractor designs, supplies, installs, and commissions the plant for a predetermined cooperation period of 10 years.

During the cooperation period, PNOC EDC pays for the plant through an energy conversion tariff (essentially a BOT fee), which covers operating costs and provides for capital recovery and return on capital. Plant ownership is transferred and handed over to PNOC EDC at the end of the cooperation period. Finding commercial funding for the private BOT contractors was not a problem because the exploration (geothermal resource) risk and the off-take risk were carried by the state through PNOC EDC and the National Power Corporation (NPC), the national power utility. Furthermore, payments to the BOT contractor were backed by a government undertaking in case of default by PNOC EDC or the NPC.

In *Kenya* the January 2010 FIT included a fixed tariff for geothermal. The stated objectives of the Kenyan FIT system are to facilitate resource mobilization (by providing investment security and market stability for investors) and reduce transaction and administrative costs and delays (by eliminating the conventional bidding processes). The tariff provides a fixed payment of 8.5 cents/kWh delivered at the interconnection point for 20 years, and is subject to an SPPA. It applies only to the first 500 MW (first come, first served), and only to plants not less than 70 MW.

Table B5.1.1 Global Installed Geothermal Capacity, December 2010

	Installed capacity, 2010, MW	*Geothermal generation, GWh*	*Share of geothermal in generation mix, %*
United States	3,093	17,014	0.4
Philippines	1,904	10,723	17.6
Indonesia	1,197	8,297	5.6
Mexico	958	7,056	2.7
Italy	843	5,520	1.7
New Zealand	628	4,200	9.6
Iceland	575	4,038	24.5
Japan	536	2,752	0.3
El Salvador	204	1,519	25.5
Kenya	167	1,180	16.7
Costa Rica	166	1,131	11.9

Sources: ESMAP 2012; Kenya Energy Regulatory Commission 2012.
Note: GWh = gigawatt-hour; MW = megawatt.

Detailed Design of the Geothermal Feed-In Tariff

The FIT introduced in August 2012 has been a failure, and the reasons for that failure are worth reviewing in some detail.

Lack of Transparency

Developers were confused about the basis of the tariff, since normally a "feed-in tariff" is understood to be based on the estimated costs of the producer, not the avoided costs of the buyer.[24] The ministry (MoF) published no information on the basis, methodology, and assumptions of the tariff.

The regulation was silent on the impact of changes in law on the tariff. According to the MoF Regulation 9/2012, there is a 5 percent royalty on steam and 2.5 percent royalty on the gross electricity price. There are also fixed fees payable for exploration $2/hectare (ha), and $4/ha during exploitation. Were these royalties and fees to change in the future, it is a reasonable question for developers to ask whether and how it is intended that the FIT be adjusted.

But these concerns are testimony to the misunderstandings surrounding terminology. There should indeed be some provision for updating, but if the tariff is based on avoided costs, it is the avoided costs of the *buyer*, not the costs of the seller, that need review.

Transmission Costs

The tariff was silent about transmission costs. It was unclear whether the FIT was to include or exclude the costs of connection.

Tendering

Under the existing system, tenders involved price competition, albeit subject to some renegotiation of the PPA at a later time. But the FIT fixed the tariff in advance: for any particular region, all now have access to the same tariff. But if there is to be no price competition, then on what basis are developers to be selected for new WKPs? A new selection methodology would be required.

The MEMR (and Castlerock) have suggested a "quality selection" approach ("beauty contest")[25] but this becomes increasingly difficult if there are several contestants who can all demonstrate financial strength and documented geothermal experience, making a qualitative differentiation subjective. Castlerock argues that such a process is the basis for selecting oil and gas developers in the United Kingdom. But a successful licensing program based purely on qualitative factors requires significant institutional and technical expertise that is at least as good as the companies seeking licenses, likely to be true in the case of the United Kingdom and New Zealand (which has a similar licensing round process) but unlikely to be true for the MEMR, and even less likely to be true of tenders in the hands of regional governments. Indeed, several developers have expressed frustration at some of the prequalification processes conducted in Indonesia, where obviously qualified and experienced developers have not made the shortlist.[26]

Economic Basis for the Tariff

The economic basis for the FIT was provided by Castlerock. The methodology was to calculate the cost of coal (or diesel) generation in six regions of the country, then add premia for fuel volatility, local environmental externalities, and global externalities. In short, the basis is the avoided social cost of thermal generation—which is coal in the large systems, and diesel in most of the outlying small islands—in some of which the PLN investment plan calls for small coal projects where there are no geothermal resources (3 MW or less) because government policy requires that no new diesels be built.[27] The result of these calculations is shown in table 5.6: these are suggested as "minimum values" and are based on levelized costs based on some WACC, and a coal cost of $80/ton.

This analysis raises several issues:

- The basis of the global environmental cost ($10/ton CO_2) is based on a review of the European Union Emission Trading Scheme (EU-ETS) and carbon market conditions. Even if it were appropriate for a global environmental cost to be reflected in an Indonesian tariff, the value to use should be based not on the current state of carbon markets, but on studies of actual damage costs (such as the Stern Report, or the American Inter-agency Working Group on the Social Cost of Carbon).[28]
- The "fuel volatility" adjustment is incomprehensible.
- The estimate of local environmental damage cost is based on arbitrary adjustments (see box 5.2 for details of the damage cost estimates).

Whatever may be these objections, Castlerock emphasized several important aspects of the tariff—none of which, sadly, were incorporated into the tariff as issued by the MEMR in August 2012:

- The need to clarify the responsibility for the costs of transmission.
- The need to regularly update the tariff and to stipulate a mandatory review period based either on time (for example, every two years) or on number of tenders completed (for example, every 5 or 10 tenders).

Table 5.6 Avoided Costs of Thermal Generation
Cents/kWh

				Others		
	Java-Bali	*Sumatra*	*Sulawesi*	*Coal (small islands)*	*Diesel*	*(80% coal/20% diesel)*
Conventional	7.7	8	9.8	13.6	44.2	19.7
Fuel volatility	0.1	0.1	0.2	0.2	0.8	0.3
Local environmental costs	0.5	0.3	0.3	0.3	0.05	0.22
Global environmental cost	0.8	0.9	0.8	0.8	0.8	0.8
Total cost	9.2	9.3	11.1	14.8	45.9	21.1

Source: Castlerock Consulting 2010, exhibit 3.14.
Note: kWh = kilowatt-hour.

Box 5.2 Local Environmental Damage Costs of Thermal Generation in Indonesia

The most recent assessment of the local environmental damage costs from Indonesian thermal generation projects is by Kusumawati, Sugiyono, and Bongaerts (2010), who studied damage costs at the Paiton coal project, the Gresik gas project, and the Muara Karang oil project. These projects have emission factors for the main criteria pollutants as follows:

Emission Factors, Grams/kWh

Project	*SO_2*	*NO_2*	*PM-10*
Paiton coal	4.34	4.56	0.67
Muara Karang oil	11.7	2.32	0.29
Gresik gas	0	1.79	0

Using the SIMPACT model, damage costs per kWh were estimated as follows:

Damage Costs, Cents/kWh (at 2010 Price Levels)

	Gresik	*Muara Karang*	*Paiton*
	Gas	*HFO*	*Coal*
PM-10	0	1.301	0.207
SO_2	0	0.517	0.016
NO_2	0.051	0.063	0.008
Sulfates	0	0.148	0.042
Nitrates	0.036	0.173	0.045
Total	0.087	2.202	0.318

These damage cost estimates differ slightly from those estimated by Liun, Kuncoro, and Sartono (2007), who use the same SIMPACT model as Kusumawati, Sugiyono, and Bongaerts (2010):

Damage Costs, Cents/kWh (at 2010 Price Levels)

	Gresik	*Muara Karang*	*Paiton*	*Suralaya*	*Tanjung Jati*
	Gas	*HFO*	*Coal*	*Coal*	*Coal*
Kusumawati, Sugiyono, and Bongaerts (2010 prices)	0.087	1.301	0.207		
Liun, Kuncoro, and Sartono 2007[29]	0.074			0.097	0.646

Kusumawati, Sugiyono, and Bongaerts (2010) and Liun, Kuncoro, and Sartono (2007) use U.S. damage cost estimates, adjusted by purchasing power parity adjusted per capita gross domestic product (GDP) (though as noted in chapter 2 of this report, since this procedure is clearly invalid across the EU countries, it is not clear why this should be valid for the even greater differences between the Organisation for Economic Co-operation and Development [OECD] and developing countries). None of these estimates can be considered reliable, except for the *order of magnitude* of damage costs.[30]

Source: Kusumawati, Sugiyono, and Bongaerts 2010; Liun, Kuncoro, and Sartono 2007.
Note: HFO = heavy fuel oil; kWh = kilowatt-hour; PM-10 = particulate matter (no greater than 10 microns in diameter); NO_2 = nitrogen dioxide; SO_2 = sulphur dioxide.

Level of the Tariff

The additional incentive provided by the new tariff can be gauged by a comparison with existing tariffs. In principle it appears that the range of FITs is *above* the tariffs negotiated in the past. But under the existing arrangements, the price negotiated at the PPA stage is generally subject to escalation and indexation. Some developers have noted that at least in the case of Sumatra, the FIT of 10 cents/kWh may not constitute an improvement over the present ceiling of 9.7 cents + future escalation. Indeed, the lack of transparency led to a situation where the MoF believed the tariff would lead to *higher* prices, and the developers that it would lead to *lower* prices.

Stakeholder Consultation

In part the confusion about the tariff was a consequence of the complete lack of stakeholder consultation. The MEMR issued a tariff without proper consultation with the two parties most affected: the MoF, who bears the incremental costs, and the developers themselves.

Impact of the Tariff

Arguably the main deficiency was that the MEMR issued a tariff without understanding what would be the impact on incremental costs. Under the present Indonesian tariff system, these are carried by not by PLN, but by the MoF—who is under intense pressure to reduce subsidies.

Conclusions

For developers and their lenders to have confidence in the tariff system, its calculation must be according to a known methodology. It is therefore important for the MEMR to state the rationale for the tariff, and present the calculations involved. The tariff as issued, and the apparent reluctance of the MEMR to issue the necessary clarifications, makes this a textbook example of a poor regulation, which in fact has hindered resolution of the problems of geothermal development rather than being helpful. Table 5.7 shows our summary evaluation of the various stages of the geothermal tariff implementation.

Incremental Costs and Their Recovery

New estimates have recently been made of the probable level of incremental costs, based on the current estimate of PLN's avoided cost for a base load generation of 6.7 cents/kWh. The level of subsidy will depend upon the outcome of tender bids, and on the outcome of the many renegotiations of past PPAs that are currently being sought—outcomes that will be subject to tariff ceilings based on the avoided costs of the buyer plus adjustments for externalities (for example a valuation of avoided GHG emissions based on \$30/ton CO_2) and local regional economic development multipliers. Table 5.8 shows the results of

Table 5.7 Summary Evaluation of Tariff Designs

	Avoided cost tariff	*2003 geothermal law (tendering and negotiation)*	*New feed-in tariff*
Introduced	1997	2003	2012
Achievement to date, MW	0	1,300	0
Economically efficient	Yes	Yes	No
Market principles	Yes	Yes (competitive tendering)	No
Sustainable recovery of incremental costs	Yes (by definition)	No (though not the fault of the tariff design itself)	No (though not the fault of the tariff design itself)
Transparency	No (no published tariff)	Yes	No MEMR published no explanations
Clarity of transmission provisions	Yes	Yes (included in scope of final negotiation)	No (no mention in tariff)
Adaptability	Yes (in principle)	Yes	No (no provision for updating)
Successful?	No (Asian financial crisis)	Yes	No

Note: MEMR = Ministry of Energy and Mineral Resources.

Table 5.8 Impact of Subsidy on Assumptions (Java and Sumatra)

				MoF subsidy if tender prices are at:			
	Ceiling	*Installed capacity*	*Incremental capacity*	*LCOE*	*LCOE with de-risking*	*@tariff ceiling*	*@tariff ceiling adjusted for de-risking*
	[1]	*[2]*	*[3]*	*[4]*	*[5]*	*[6]*	*[7]*
	Cents/kWh	*MW*	*MW*	*$ million*	*$ million*	*$ million*	*$ million*
PLN avoided cost (2014)	6.7	186	186	0	0	0	0
Old ceiling	9.7	1,583	1397	120	104	168	152
Higher ceilings	11.0	1,900	317	197	141	298	242
	11.5	1,900	0	197	141	298	242
Proposed ceiling	12.5	1,949	49	214	149	316	251
	13.5	2,028	79	248	170	345	267
	14.0	2,094	66	277	188	368	279
	15.0	2,156	62	305	206	388	290
	16.0	2,237	82	348	234	413	299
	17.0	2,292	55	381	256	428	303
	18.0	2,332	40	407	274	438	305
	19.0	2,332	0	407	274	438	305
	20.0	2,362	30	430	291	445	306

Source: Meier, Lawless, and Randle 2014a.
Note: kWh = kilowatt-hour; LCOE = levelized cost of energy; MoF = Ministry of Finance; MW = megawatt; PLN = Perusahaan Listrik Negara (Indonesian State Electric Utility Company).

these calculations, as a function of the proposed tariff ceiling, and as a function of tender outcomes[31]:

- Tender prices at or near the levelized cost of energy (LCOE), as based on the Castlerock supply curves (column [4]).
- LCOE adjusted for lower tariffs as are expected from the up-front de-risking using the Geothermal Fund (column [5]).
- Tender prices under the pessimistic assumption that a published tariff ceiling will push up bid prices to the ceilings (column [6]).
- At the tariff ceiling adjusted for up-front de-risking (column [7]).

While the calculated incremental costs for the currently proposed ceiling of 12.5 cents/kWh are modest compared to the overall magnitude of the MoF tariff subsidies to PLN ($149 million–$316 million per year), that is only for a geothermal total of some 2,000 MW. This should be compared to the $10 billion of overall subsidy provided by MoF to PLN in 2013 to cover the shortfall between revenue requirements and the consumer tariff. However, to achieve the much more ambitious target as envisaged by the so-called second fast-track program (FTP2)—an additional 4,925 MW on top of the existing 1,335 MW by 2020—the incremental costs will be much greater, on the order of $800 million–$1.0 billion.

Potential Impact of Incremental Costs on the Consumer

Because of the disconnect between the PLN tariff and the consumer tariff, the impact of the incremental costs of geothermal energy is in the first instance felt as an increase in the PSO (that is, an increase in the subsidy provided by the MoF), rather than as an increase in the consumer tariff. Table 5.9 shows the

Table 5.9 Impact of Incremental Costs

	Units	*2020*
PLN sales	GWh	310,000
1% as geothermal energy	GWh	3,100
Incremental cost	Cents/kWh	0.058
	$ million	179.8
Cost-reflective tariff	Rp/kWh	1351
	Cents/kWh	15.49
Revenue requirement	$ million	48,007
Incremental cost to PLN	%	0.37
Consumer tariff	Rp/kWh	737
	Cents/kWh	8.45
Consumer bill	$ million	26,189
Incremental cost to consumer	%	0.69

Note: GWh = gigawatt-hour; kWh = kilowatt-hour; PLN = Perusahaan Listrik Negara (Indonesian State Electric Utility Company).

impact of 1 percent additional geothermal energy, assuming a worst-case average incremental cost of 5.8 cents/kWh. The impact on the tariff is just 0.17 percent, significantly less than the corresponding impact in Vietnam (1.1 percent) or Sri Lanka (1.3 percent)—a reflection of the relatively small incremental cost of geothermal power compared to wind.

Buying Down the Price of Renewable Energy with International Assistance

Buying down the value of renewable energy is well illustrated by the example of the Ulubelu Geothermal Project, one of two PGE geothermal projects supported by the World Bank. The total (economic) cost for the 110 MW project is $359 million ($3,300/kW). Alternative financing approaches can be assessed as follows:

- The project is funded entirely by PGE equity, for which the relevant cost of capital is the cost of equity (assumed in the Project Appraisal Document [of the World Bank] [PAD][32] at 14 percent).
- The debt is funded by the International Bank for Reconstruction and Development (IBRD) for which typical terms are 30-year London inter-bank offer rate (LIBOR)[33] of 3.87 percent (as of November 2010) + 1.15 percent fixed spread = 5.02 percent, and a term of 24.5 years with a 9-year grace period.
- The debt is funded by highly concessional carbon finance—in this case by the Clean Technology Fund (CTF) for which typical terms are 0.25 percent service charge over 40 years, with a 10-year grace period.
- The actually proposed financing: 44.3 percent PGE equity, 32.2 percent IBRD, and 23 percent CTF.[34]

The distinguishing feature of geothermal financing is the very long period of capital investment—here assumed at eight years (four years for exploration plus four years of construction). This is longer even than a large hydro storage project or nuclear project (assuming no litigation delays), and stands in stark contrast to other RE projects such as wind, for which two years would be a comparable preoperational period for a 110 MW project.

Thus the presumption is that debt finance will start only in year 6 (at the start of construction), and that all the exploration is funded by equity. This stands in sharp contrast to the standard IPP model, in which equity contributions are required *pari passu* with debt (excepting up-front development expenses carried by the developer).

Table 5.10 shows the results of the financial analysis. The financial model calculates the tariff that would be necessary to achieve a 14 percent financial internal rate of return (FIRR) for PGE (which is the assumption of the PAD). As an equity-only project, the required tariff is 10.3 cents/kWh (which is above the 10 cents/kWh FIT for Sumatra).

Table 5.10 Buying Down the Incremental Costs

	PGE FIRR nominal	*Tariff*	*Incremental cost (1)*
	%	*Cents/kWh*	*$ million*
All equity	14	10.3	827.7
IBRD only	14	8.3	320.9
Blended, as proposed	14	7.7	185.9
CTF only	14	7.0	0.0

Note: CTF = Clean Technology Fund; FIRR = financial internal rate of return; kWh = kilowatt-hour; IBRD = International Bank for Reconstruction and Development; PGE = Pertamina Geothermal Energy.

If the debt portion is funded entirely by the IBRD, the required tariff falls to 8.3 cents/kWh, and the incremental costs fall to $321 million; if funded entirely by the CTF, the tariff required is exactly 7 cents/kWh (the assumed cost of coal generation). For the blended IBRD/CTF financing, the incremental costs are bought down to $185 million.

The Environmental Costs of the Electricity Subsidy

There are few countries in the world that provide as large a subsidy to electricity as Indonesia.[35] In 2011 the PLN's costs would have required a tariff of Rp 1,351/kWh (15.5 cents/kWh), but the actual average tariff was just Rp 737/kWh (8.45 cents/kWh). Of course, one of the reasons for the high tariff is Indonesia's unusual dependence on oil for power generation. But while tariff increases will (obviously) reduce the consumer surplus, this is more than offset by a decrease in the PLN's costs, recapturing the 2011 deadweight losses of $790 million/year. Moreover, this comes with a *reduction* of GHG emissions of some 20 million tons/year (assuming the impact is a reduction in coal generation).

In rows [17]–[23] of table 5.11 we show the quantity of geothermal power that would be necessary to achieve the same level of GHG emission reduction: under the optimistic assumption of an average incremental cost of just 3 cents/kWh, 3,021 MW of geothermal would be required, at an incremental *cost* of $675 million/year.

With the expected growth of generation, by 2021, the deadweight losses associated with the subsidy rise to $1.65 billion (column [1]); elimination of the subsidy would reduce GHG emissions by 42 million tons/year. To achieve the same GHG emission reduction by geothermal would require 6,387 MW, at an incremental *cost* of $2.1 billion.

These calculations are obviously a function of the assumed price elasticity (table 5.12), and are notional because elimination of the present level of subsidy would need to be phased in gradually. At lower levels of (long-run) price elasticity, the impact of subsidy elimination will be less. Moreover, the PLN's costs and its tariff requirement should decline over the next few years as oil generation is gradually phased out, so the amount of tariff increase associated with elimination of the subsidy would be smaller.

Table 5.11 Impact of Electricity Subsidies, 2011 and 2021

			2021	*2011*	
		Units	*[1]*	*[2]*	*Areas in box 5.3*
1	Baseline tariff	Rp/kWh	737	737	P1
2		Cents/kWh	8.4	8.4	
3	New tariff	Rp/kWh	1,351	1,351	P2
4		Cents/kWh	15.5	15.5	
5	Real price increase	%	83.31	83.31	
6	Price elasticity		–0.25	–0.25	
7	Price elasticity adjustment	%	–14.1	–14.1	
8	Demand contraction at consumer	GWh	46,815	22,494	Q1–Q2
9	Q1	GWh	333,000	160,000	
10	Q2	GWh	286,185	137,506	
11	PLN avoided costs	Billion Rp	204,462	98,240	+C+D+B
12	Loss of consumer surplus	Rp billion	–190,090	–91,334	B+C
13	Deadweight loss recaptured	Rp Billion	14,372	6,906	D
14		$ million	1,647	792	
15	Emission factor	Kg/kWh	0.90	0.90	
16	Avoided GHG emissions	Million tons/year	42	20	
17	Equivalent geothermal capacity	MW	6,387	3,021	
18	Average load factor	[Proportion]	0.85	0.85	
19	Geothermal generation	GWh	47,558	22,494	
20	Avoided GHG emissions	Million tons/year	43	20	
21	Incremental cost	Cents/kWh	4.5	3	
22		$ million	2,140	675	
23	Avoided cost	$/ton	50.0	33.3	

Note: 2011 exchange rate: $1 = Rp 8,724. GHG = greenhouse gas; kWh = kilowatt-hour; GWh = gigawatt-hour; MW = megawatt; PLN = Perusahaan Listrik Negara (Indonesian State Electric Utility Company).

Table 5.12 Impact of the Price Elasticity Assumption, 2011

Price elasticity	*Demand reduction, %*	*Deadweight loss, $ million*	*GHG emissions, million tons CO_2/year*	*Required geothermal capacity, MW*	*Incremental cost of geothermal capacity, $ million*
–0.05	–3.0	168	4	641	143
–0.10	–5.9	331	8	1,264	282
–0.15	–8.7	489	13	1,867	417
–0.20	–11.4	643	16	2,453	548
–0.25	–14.1	792	20	3,021	675
–0.30	–16.6	936	24	3,572	798
–0.35	–19.1	1,076	28	4,107	917

Note: CO_2 = carbon dioxide; GHG = greenhouse gas; MW = megawatt.

Nevertheless, the conclusion is inescapable: reducing large consumer tariff subsidies is win-win for the environment and the economy; 20 million tons/year GHG emission reduction incurs no incremental cost, but comes together with a macroeconomic benefit of $790 million/year. By 2021 the annual benefit of subsidy elimination increases to $1.6 billion, with 42 million tons of CO_2 avoided.

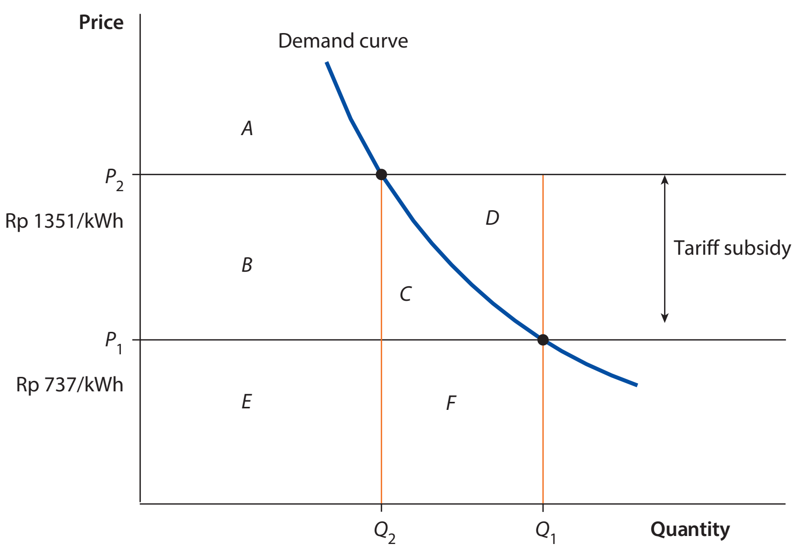
Box 5.3 Deadweight Losses of Electricity Tariff Subsidies

At the subsidized price of P_1, the quantity Q_1 is demanded (160 TWh) in 2011. At the tariff corresponding to PLN's costs, P_2 (Rp 1,351/kWh), the smaller quantity of Q_2 is demanded (286 TWh assuming a price elasticity of −0.25).

At the old price P_1, the consumer surplus is the area $A + B + C$. If the subsidy is removed, then at the higher price P_2 the consumer surplus is only the area A—so there is a loss of consumer surplus of ($B + C$). But at the old price PLN makes a loss $B + C + D$, whereas at P_2, PLN's revenue covers its costs. So there is a gain to PLN of $B + C + D$. Therefore, the net gain is the area D—the so-called deadweight loss associated with the tariff subsidy.

Note that the validity of consumer surplus (CS) to assess changes in welfare consequent to price changes is subject to important qualifications (see figure B5.3.1), notably that income and price elasticities and the magnitude of the price shift should all be small: where these conditions do not hold, then the method of equivalent variation (EV) or compensating variation (CV) should be used (though these typically bracket the CS estimate, as shown in the numerical example provided in Bacon [1995]). The estimates presented here using CS may therefore be subject to an error of +10–20 percent. But at this level of uncertainty, the main message remains unchanged: large subsidies incur significant deadweight losses!

Figure B5.3.1 Impact of Tariff Subsidy



Note: kWh = kilowatt-hour.

Conclusions

Resource Endowment and Targets

There is little question that Indonesia has a substantial geothermal resource endowment. But the magnitude of the target, 9,500 MW, is best described as wishful thinking, announced before an understanding of the incremental costs, and of the consequences for electricity subsidies. Much of the perception that the geothermal program is in trouble is related to apparently little progress in achieving the 9,500 MW target or even the revised 2014 target. But today's 1,100 MW of geothermal capacity, achieved largely at quite modest incremental costs, is no mean achievement: it is modest only when measured by an unreasonable yardstick.

Design of Incentive Schemes

In principle, an ACT can be successful in enabling significant private sector investment in renewable energy—as well illustrated by Vietnam's ACT. But this is merely a necessary condition, not a sufficient condition. To be successful, such a tariff needs to be transparent and—as to methodology—be accompanied by a nonnegotiable SPPA, propose clear arrangements for transmission costs, and be clear about the magnitude of expected incremental costs and how these will be recovered. Unfortunately, the August 2012 FIT meets none of these conditions, and will likely be soon replaced. A tariff that is so misunderstood that some developers believed the published values to be *lower* bounds for negotiation, when in fact these were fixed tariffs, is obviously in trouble.

Tendering

Concession systems for natural resources work best where what is to be auctioned is well defined: the better the information available at the time of bid, the easier it is for bidders to make realistic assessments of the risk-return trade-off. From the perspective of achieving the government geothermal targets, it is the larger projects (most likely on Java and Sumatra, say those larger than 50 MW) where the efficiency gains of a tender system are likely to justify the transaction costs—where there is sufficient demand to absorb the output without difficulty, and where costs of exploration failure to the PLN system are small because even successful projects would represent just a few percent of the grid requirements. These are the projects where the bulk of the financial impact of the FIT on PLN subsidy requirements will be felt, and where efficiency gains are the most important.

Indeed, it seems useful to make a distinction between larger projects whose main rationale is carbon emission reductions, and smaller projects on smaller islands whose principal rationale is a more cost-effective alternative to diesel generation—here geothermal costs are in the 12–20 cents/kWh range, and still provide a cheaper option than diesel generation.

But for the smaller projects on smaller islands, the consequences of exploration failure for PLN are much greater, because of the difficulties of assuring alternative supplies. These prospects will in any event be of less interest to large companies who are in a much better position to assume exploration risks.

Whether "quality selection" works is primarily a function of the capacity of the government entities that make the selection to make informed judgments. That such capacity exists in the United Kingdom (U.K.) Ministry of Energy that regulates the U.K. oil and gas sector (held up by Castlerock as the model) seems reasonable, but whether such capacity exists in Indonesia, particularly in the regions, may well be questioned.

Regulatory Framework and the Geothermal Fund

While in principle the geothermal fund could be used for exploration, there is concern about the consequences of an *unsuccessful* exploration program—not all exploration programs will lead to a commercial prospect (indeed, if they *were* all successful, there would be no risk, and no need for the fund in the first place). But because there are in place severe penalties for misuse of government funds, there is a fear that the individual or entity that makes the final decision will be subject to prosecution for having "wasted" government monies. In the Philippines the exploration risk has been successfully passed to a state company established expressly for this purpose, but in Indonesia the 2003 Geothermal Law appears to require the private sector to assume this risk, and so rational application of the resources in the geothermal fund has been subject to interminable delays.

It is unclear whether the oil and gas sector is the best model for the geothermal sector, because in oil and gas there is a much closer alignment of interests between the oil company and the government: the primary interest of both parties is simply the maximization of physical production (*barrels* of oil), and the negotiation is simply about how that revenue is shared equitably between the two. Except in the highly unlikely case of the discovery of a giant superfield, the *price* of what is extracted is unaffected by the success or failure of the exploration program itself. But in the case of geothermal development, there are additional conflicting public interests: on the one hand, the government wants the *lowest* electricity price possible (PLN, MoF), but also the *maximum* royalty revenue (local/regional government) and the maximum quantity (the MEMR has to meet its geothermal targets).

Tariff Subsidies

Few countries have electricity price subsidies as high as Indonesia: in 2011 the average tariff was just 8.5 cents/kWh compared to PLN's cost of 15.5 cents/kWh. Such subsidies are also badly targeted, with small residential consumers capturing no more than 25 percent of the total subsidy. Although is there is some uncertainty about the price elasticity of demand, it is clear that reducing consumer subsidies is win-win for electricity costs and GHG emissions: to achieve the same reduction of GHG emissions as achieved with the elimination of subsidies, by 2021 some 6,400 MW of geothermal capacity would be needed, with an incremental *cost* of more than $2 billion per year. But reducing the general electricity subsidy is accompanied by a *benefit* of $1.6 billion as the deadweight losses are recaptured.

Buying Down Incremental Costs

Highly concessional carbon finance—as represented by the CTF—is the key to buying down the incremental costs of renewable energy for developing countries. But how much additional carbon finance is actually available to Indonesia remains unclear.

The Main Problem

Few countries in the world have achieved significant development of their geothermal resources without a significant portion of the exploration risk being assumed by the state. Indonesia is the only country that modeled its geothermal development on the oil and gas sector, where it is typical that the private sector assumes the exploration risk—in return for substantial returns when exploration is successful. Most importantly, the price of the output, oil, is set by the international global oil market, whereas for geothermal, the output price is set by the government—and preferably as low as possible. Fortunately, revisions to the Geothermal Law are currently before parliament, which would declassify geothermal development as a "mining" activity, which should make environmental and forestry permits easier to obtain.

But short of the repeal of the 2003 Geothermal Law, Indonesia must find some other path to move forward on geothermal development. The conclusions of this case study are straightforward:

- *Recognize the differences between large projects* in Java and Sumatra, whose main objective is the avoidance of GHG emissions, and whose scale is sufficient to warrant the interest of international developers, and the smaller projects in the outlying islands, where the objective is to avoid the high cost of diesel generation. In these small projects, the transaction costs of tendering are high, and PGE should take the lead on behalf of the state. The geothermal fund should be able to support exploration in these areas, and since the beneficiary of successful exploration would be PGE, the issue surrounding possible waste of public funds to the benefit of the private sector (where exploration is unsuccessful) should not arise. In these areas the criterion for proceeding with development is whether the costs exceed the cost of diesel generation.

- *Clarify the arrangements for transmission*. The responsibility for constructing the transmission line should be passed to the developer, and handed over at the time of commissioning. The costs should be recovered by an adder to the bid tariff (which should be limited to that of the generation project).

- *Update the resource supply curves* developed in 2010 by Castlerock to provide a more reliable basis for estimating future incremental costs. Drilling costs in particular have risen dramatically since most of the cost estimates for Indonesia projects were developed in the 2004–07 time frame.

- *Replace the 2012 FIT with a new tariff* that is based on a consultative process involving the main stakeholders, notably the PLN, the MoF, and the developers. No tariff that is misunderstood by those primarily affected can be successful. The methodology of the tariff must be transparent, and published.

- *To be compliant with the 2003 Geothermal Law, tendering should continue to be price based*, but with a focus on improving the tender process. The priority should be to create a new central entity to conduct tenders on behalf of provincial entities (and indeed also serve this function for other forms of renewable energy such as hydro). Most importantly, by up-front de-risking using geothermal fund resources, the number and quality of bidders is likely to improve. The commercial terms of the PPA should be fixed at the time of tender, and not subject to *ad hoc*, post-tender negotiations.

Notes

1. Total PLN installed capacity as of June 30, 2012, is 35,169 MW. In addition, there were 26 IPPs with a contract capacity of 5,634 MW.
2. PLN Statistics 2011, table 19.
3. PLN Statistics 2011, tables 1 and 4.
4. In Indonesia a household is considered electrified if it has at least a solar lantern. A village is considered electrified if at least 10 percent of its households are connected.
5. The subsidy mechanism is known as PSO (public service mechanism).
6. In Bahasa, Wilayah Kerja Pertambangan Panas Bumi, hence WKP.
7. Ministry of Finance regulation 111/2007.
8. Some of the prices are quoted in rupiah (Rp); these were converted at the exchange rate of Rp 9,590 per $1.
9. The prices shown in table 5.2 are the so-called base prices, applicable to the first year of commercial operation: in many PPAs, some portion of this base price is escalated at the U.S. producer price index.
10. For example, of the 52 WKPs in progress as of December 2011, PGE is the developer for 11 projects (Castlerock Consulting 2010).
11. It is also unclear from the report whether the price refers to that bid at the tender price, or whether the price is the final price negotiated in the power purchase agreement (PPA).
12. These include instances where winning bid prices are higher than the cap of 9.7 cents/kWh imposed by Permen 32/2009; where a price has been agreed, but the PPA has not been signed; and where a developer is unwilling to invest in further exploration absent a binding commitment from PLN to purchase power.
13. This is a problem not just for geothermal development, but for all of PLN's generation projects. Currently there are negotiations under way for a service level agreement between PLN and 11 ministries that stipulate performance obligations among the parties.
14. For reasons that are unclear, the one statistic that is not presented in this report is the per well drilling cost.

15. See, for example, the feasibility study for Ullubelu, which presents costs of $6 million for development wells, and $1 million for reinjection wells.
16. The pessimistic assumptions are based on costs and capacity both one standard deviation lower than the average, the optimistic assumptions one standard deviation above the average.
17. Castlerock Consulting 2010, Exhibit 6.2. The assumption is that CER revenues are available only up to 2020, and that all CERs produced could be sold at that price. But it would be quite unusual for an Emissions Reduction Purchase Agreement (ERPA) to cover 100 percent of total potential CO_2 emissions.
18. Known under the Bahasa Indonesian abbreviation PSKSK.
19. At the time of project appraisal in 1996, the prospects for a successful operation were good since the following conditions were in place: (a) the Indonesian authorities had put in place important policy and regulatory changes, (b) PLN was supportive of the project and willing to purchase power from all eligible private projects, (c) four of the strongest commercial banks in Indonesia had expressed interest in participating in the project, and (d) there was a firm pipeline of projects ready to use funding provided by the Bank and GEF at a reasonably early date. But the value of the rupiah plummeted from Rp 2,341/$1 in September 1996 to Rp 17,000/$1 by January 1998. As a consequence, the capital costs in rupiah terms became too high, and the anticipated investments were no longer viable commercially.
20. Izin Usaha Panas Bumi.
21. In the typical PPA, some part of the base price is indexed to the U.S. producer price index.
22. Decree of the Minister of Energy and Mineral Resources: *Assignment to PT PLN to Purchase Power from Geothermal Plants and Standard Purchasing Price of PT PLN to Geothermal Power Plants*, Number 22, year 2012, August 16, 2012.
23. See table 5.2 for details.
24. This confusion was not helped by Castlerock's own comments. For example, Castlerock states that an FIT should be "dynamic, changing as external conditions change, for instance, if there is a sustained increase in the fossil fuel prices, the FIT should be adjusted accordingly" (Castlerock Consulting 2012, section 3.4, 3–21). This is correct for a FIT based on avoided social cost. But then Castlerock goes on to state that "if the FITs do not yield a level of developer interest (as demonstrated by the number and quality of firms competing for WKP tenders), then the government may consider raising the FIT." But this is inconsistent with the concept of avoided cost—which should be completely *independent* of developer costs or developer interest. If one is going to make arbitrary adjustments to a tariff simply to achieve some target, then there is no point to claiming it is based on the avoided costs of PLN.
25. One hesitates to use this term given its generally negative connotations, but the term has been used by the MEMR, and appears in the Revision Matrix for Regulation 59/2007.
26. In any event, the scale and nature of the U.K. North Sea Oil and Gas licensing program is entirely different from that of the Indonesian geothermal WKP selection. For example, on October 26, 2012, the U.K. Ministry of Energy awarded 167 licenses for exploration rights in the 27th Licensing Round; 224 applications had been received for 330 blocks of the U.K. Continental shelf. This follows the award of 46 licenses in May 2012 for areas off the coast of Scotland. Licenses are indeed selected on the basis

of the U.K. Energy Ministry judgments about the best exploration program rather than by auction; licensees pay a nominal escalating annual rental fee. There are stringent requirements about relinquishing acreage, environmental management, and nonperformance to agreed work programs.

27. There are significant uncertainties about the practicality of a proliferation of small coal units in the small outlying islands, to say nothing of the potential environmental impacts. There is presently just one such project in operation using Chinese equipment, but local manufacture is being planned.
28. See section "The Social Cost of Carbon" in chapter 2.
29. The World Bank Ulubelu and Lahendong Geothermal Project economic analysis used a value of 0.546 cents/kWh as the coal damage cost, as stated as the average of the high and low estimates in the Liun study for Suralaya. We were unable to confirm these estimates in the original paper.
30. Indeed, none of these various studies have been published in the peer-reviewed literature.
31. See Appendix C for details of such calculations.
32. Project Appraisal Document (of the World Bank).
33. London Interbank Offered Rate.
34. For the project as a whole, which also includes the Lahendong Geothermal Project: the equity amounts are $125 million, CTF; $175 million, IBRD; and $243 million, PGE.
35. It is also worth noting that the subsidy is poorly targeted: the principal beneficiaries of the subsidy are large industrial and commercial customers; very small residential customers capture just 24 percent of the total subsidy disbursement (World Bank 2012).

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CHAPTER 6

Case Study: South Africa

Sector Background

South Africa relies heavily on coal, which supplies around 70 percent of its primary energy and more than 90 percent of its electricity. The country also has a highly energy-intensive economy. These combined factors mean that South Africa's carbon emissions, on a per capita and gross domestic product (GDP) basis, are disproportionately high (although, in total, they amount to little over 1 percent of global emissions). South Africa does not face any formal commitments under the United Nations Framework Convention on Climate Change (UNFCCC) to mitigate climate change but, mindful of risks to its future international competitiveness, it has pledged to reduce its carbon emissions below a business-as-usual scenario. It is within this context that South Africa has embarked on an ambitious renewable energy (RE) program to diversify its energy mix.

The country has abundant wind and, especially, solar resources, although exploiting these still comes at a higher cost than its cheap coal (ignoring externalities). After first exploring feed-in tariffs (FITs) for grid-connected RE, a competitive tender system has been implemented that has engendered a great deal of interest from private developers and financiers, and has seen prices fall in subsequent bid rounds. In 2012 South Africa ranked among the top 10 countries globally in terms of RE investments: over $9 billion[1] was invested in 2,460 megawatts (MW) of grid-connected wind, photovoltaic (PV), and concentrated solar power (CSP). The country presents an interesting case of having introduced incentive schemes for RE within an environment of heavy dependence on fossil fuels and a relatively low-cost electricity environment.

South Africa's publicly owned national utility, the Electricity Supply Commission of South Africa (Eskom), generates 96 percent of the country's electricity, which amounts to just over half of the electricity generated in Sub-Saharan Africa. Private generators contribute about 3 percent of national output (mostly for their own consumption) and local municipalities contribute less than 1 percent. Power generation is heavily dependent on coal (92 percent) with nuclear, hydroelectricity, bagasse (from sugarcane), and emergency diesel-fired turbines accounting for the rest.

Eskom owns and controls the national integrated high-voltage transmission grid and distributes about 60 percent of electricity directly to customers. The remaining electricity distribution is undertaken by about 179 local authorities, which buy bulk electricity supplies from Eskom.

Eskom imports power from Mozambique and, in the past, also has imported from the Democratic Republic of Congo and Zambia. It also sells electricity to neighboring countries (Botswana, Lesotho, Mozambique, Namibia, Swaziland, Zambia, and Zimbabwe). Imports and exports constitute about 5 percent of total electricity on the Eskom system. Eskom's power stations are listed in table 6.1.

Direct electricity sales to mines and industrial customers account for more than 40 percent of Eskom's electricity sales. Eskom also operates retail distribution services for 4.65 million customers (4.5 million of these are households) and the municipal distributors service slightly more customers. About 85 percent of South Africans have access to electricity.

Eleven of Eskom's 13 coal-fired power stations are located in Mpumalanga Province in the northeast; the other two are at Lephalale in Limpopo Province

Table 6.1 Eskom's Power Stations

Name	*Location*	*Fuel*	*Available MW*
Arnot	Middelburg	Coal	2,232
Camden	Ermelo	Coal	1,430
Duvha	Witbank	Coal	3,450
Grootvlei	Balfour	Coal	950
Hendrina	Hendrina	Coal	1,865
Kendal	Witbank	Coal	3,840
Komati	Middelburg	Coal	940
Kriel	Bethal	Coal	2,850
Lethabo	Sasolburg	Coal	3,558
Majuba	Volksrust	Coal	3,843
Matimba	Lephalale	Coal	3,690
Matla	Bethal	Coal	3,450
Tutuka	Standerton	Coal	3,510
Acacia	Cape Town	Gas/petroleum	171
Ankerlig	Atlantis	Gas/petroleum	1,327
Gourikwa	Mossel Bay	Gas/petroleum	740
Port Rex	East London	Gas/petroleum	171
Gariep	Orange River	Hydro	360
Vanderkloof	Orange River	Hydro	240
Drakensberg	Bergville	Pumped storage	1,000
Palmiet	Grabouw	Pumped storage	400
Koeberg	Cape Town	Nuclear	1,830
Total			41,847

Source: Eskom Annual Report 2012.
Note: The table excludes four small, nonoperating hydro plants in Transkei. The balance of non-Eskom-generating capacity totals about 1,150 MW and is located mainly at Sasol's synfuels plant (520 MW), Kelvin (128 MW), Rooival (155 MW), Pretoria West (100 MW), Steenbras (180 MW), and mini-hydro (65 MW).
Eskom = Electricity Supply Commission of South Africa; MW = megawatt.

and at Sasolburg. The two major hydro stations are located on the Orange River in the center of the country. Eskom's Koeberg nuclear power station is located 30 kilometers (km) north of Cape Town. The open-cycle (kerosene/diesel) turbines are on the coast and are used for emergency peaking loads. Peak demand is also supplied by pumped storage schemes in the Cape and in the Drakensberg mountains in KwaZulu-Natal. The South African power system is thus characterized by power stations that are concentrated in the interior near the mines and industries of Gauteng and Johannesburg, and long transmission lines down to coastal areas, which depend on power transfers from the northeast.

Eskom embarked on a massive investment program in the 1970s and 1980s. It overestimated demand growth and, in the 1990s, there was significant overcapacity. But after a decade or more of little investment, Eskom is having to play catch-up. It is building two massive new coal-fired plants—Medupi and Kusile—each 4,800 MW, as well as a new pumped storage scheme, Ingula. At the same time, it has commenced procurement of its first RE power: a 100 MW wind farm, Sere, and a 100 MW CSP plant. These last two power projects have been funded mainly by several public lenders: the World Bank and African Development Bank, and the Clean Technology Fund. The engineering, procurement, and construction (EPC) contracts have been competitively bid for, but the final power costs will be blended (nontransparently) into Eskom's average power generation costs.

The government has also accepted that independent power producers (IPPs) should be allowed to enter the market. A rough 70:30 spilt between Eskom and the private sector was accepted by the cabinet after the Energy Policy White Paper was published in 1998. Work commenced on the design of a Nordpool-like power exchange. But with looming power shortages, the prospective competitive wholesale market was abandoned in 2004 in favor of a single-buyer model, with Eskom being the offtaker. For many years, however, the policy and regulatory framework for procuring IPPs was not put in place. As described below, this changed with the initiation of the RE IPP program in 2012.

South Africa has a fairly rigid energy-planning system. By law, an electricity plan (Integrated Resource Plan, IRP) has to be produced by the Department of Energy (DOE) (although in practice this is delegated to the planners within Eskom). Based on this plan, the minister of energy makes periodic "determinations" of what power needs to be built and when. The regulator can only license new capacity within these ministerial determinations.

The most recent IRP is for the period 2010–30 and is shown in table 6.2. For the first time it included RE options. These were "forced" into the plan as they were not least cost but were necessary for South Africa to meet its carbon mitigation pledges, described in the following section.

South Africa's electricity once ranked among the cheapest in the world. Eskom's average electricity sales price in 2007–08 was as low as 2.5 cents per kilowatt-hour (kWh). Effectively it had paid for much of its existing capacity, and prices were close to short-run marginal costs. But with the commencement of a new investment program of more than $50 billion (a large proportion of which

Table 6.2 South African Integrated Resource Plan, 2010–30

	Committed build										
	RTS capacity (coal)	*Medupi (coal)*	*Kusile (coal)*	*Ingula (pumped storage)*	*DOE OCGT IPP (diesel)*	*Cogeneration, own build*	*Wind*	*CSP*	*Landfill, hydro*	*Sere (wind)*	*Decommissioning*
	MW	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*
2010	380	0	0	0	0	260	0	0	0	0	0
2011	679	0	0	0	0	130	0	0	0	0	0
2012	303	0	0	0	0	0	300	0	100	100	0
2013	101	722	0	333	1,020	0	400	0	25	0	0
2014	0	722	0	999	0	0	0	100	0	0	0
2015	0	1,444	0	0	0	0	0	100	0	0	–180
2016	0	722	0	0	0	0	0	0	0	0	–90
2017	0	722	1,446	0	0	0	0	0	0	0	0
2018	0	0	723	0	0	0	0	0	0	0	0
2019	0	0	1,446	0	0	0	0	0	0	0	0
2020	0	0	723	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	–75
2022	0	0	0	0	0	0	0	0	0	0	–1,870
2023	0	0	0	0	0	0	0	0	0	0	–2,280
2024	0	0	0	0	0	0	0	0	0	0	–909
2025	0	0	0	0	0	0	0	0	0	0	–1,520
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	–2,850
2029	0	0	0	0	0	0	0	0	0	0	–1,128
2030	0	0	0	0	0	0	0	0	0	0	0
Total	1,463	4,332	4,338	1,332	1,020	390	700	200	125	100	–10,902

Source: Eskom's Annual Report.
Note: CCGT = combined-cycle gas turbine; CSP = concentrated solar power; DOE = Department of Energy; FBC = fluidized bed combustion; IPP = independent power producer; OCGT = open-cycle gas turbine; MW = megawatt; PF = pulverized fuel; RTS = rotary triboelectrostatic separator; PV = photovoltaic.

was required to finance the two new coal-fired power stations), tariffs had to be increased to sustain Eskom's financial viability (even though the utility successfully accesses private capital markets and has secured a substantial sovereign guarantee). Figure 6.1 shows how electricity prices have risen in nominal and real terms. The regulator has agreed on above-inflation increases for the next five years.

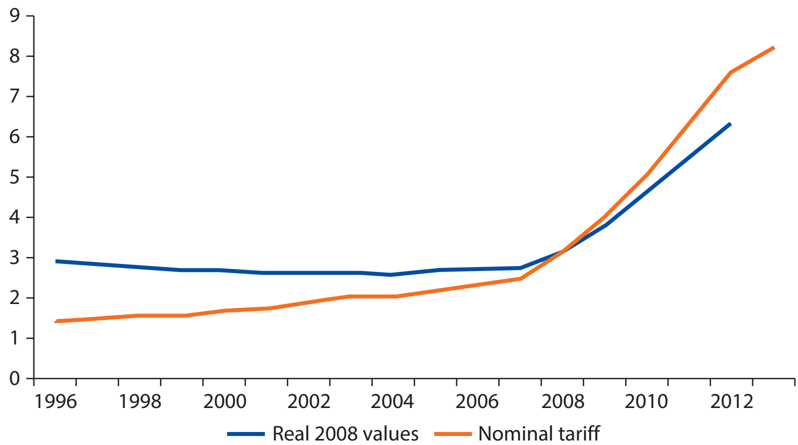
Renewable Energy Development

While the official RE policy has not been very effective in applying practical implementation strategies, policies to mitigate climate change have had a much more profound impact. In many respects this is surprising. As a non–appendix A

New build options									
Coal (PF, FBC, imports)	*Gas CCGT (natural gas)*	*OCGT (diesel)*	*Import hydro*	*Wind*	*Solar PV*	*CSP*	*Nuclear*	*Total new build*	*Total system capacity*
MW	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*
0	0	0	0	0	0	0	0	640	44,535
0	0	0	0	0	0	0	0	809	45,344
0	0	0	0	0	300	0	0	1,103	46,447
0	0	0	0	0	300	0	0	2,901	49,348
500	0	0	0	400	300	0	0	3,021	52,369
500	0	0	0	400	300	0	0	2,564	54,933
0	0	0	0	400	300	100	0	1,432	56,365
0	0	0	0	400	300	100	0	2,968	59,333
0	0	0	0	400	300	100	0	1,523	60,856
250	237	0	0	400	300	100	0	2,496	63,352
250	237	0	0	400	300	100	0	2,010	65,362
250	237	0	0	400	300	100	0	1,212	66,574
250	0	805	1,143	400	300	100	0	1,365	67,939
250	0	805	1,183	400	300	100	1,600	2,358	70,297
250	0	0	283	800	300	100	1,600	2,424	72,721
250	0	805	0	1,600	1000	100	1,600	3,835	76,556
1000	0	0	0	400	500	0	1,600	3,500	80,056
250	0	0	0	1,600	500	0	0	2,350	82,406
1000	474	690	0	0	500	0	1,600	1,414	83,820
250	237	805	0	0	1000	0	1,600	2,764	86,584
1000	948	0	0	0	1000	0	0	2,948	89,532
6,250	2,370	3,910	2,609	8,400	8,400	1,000	9,600	45,637	

country under the Kyoto Protocol, South Africa does not face any commitments to reduce greenhouse gas (GHG) emissions. Nevertheless, research work was commissioned by the Department of Environmental Affairs on long-term mitigation strategies, and these provided the basis for President Zuma to make a pledge at the Copenhagen Conference of Parties (COP) in 2009 that South Africa would reduce its carbon dioxide (CO_2) emissions by 34 percent below a business-as-usual scenario by 2020 and by 42 percent by 2025, provided the international community supported South Africa with financial aid and the transfer of appropriate technology. This peak, plateau, and decline scenario for carbon emissions subsequently informed the development of the IRP 2010–30. The power sector in South Africa contributes roughly half of South Africa's carbon

Figure 6.1 Average Nominal and Real Eskom Electricity Prices
Cents/kWh



Source: NERSA annual reports.
Note: Eskom = Electricity Supply Commission of South Africa; kWh = kilowatt-hour.

emissions and an effective emissions cap was set of around 275 metric tons (Mt)/year CO_2 equivalent. A subsequent National Climate Change Response White Paper, published in 2011, provided a wider band for emission caps but maintained the peak, plateau, and decline trajectory.

South Africa's voluntary Copenhagen pledge to reduce its carbon emissions from a business-as-usual scenario set the stage for new procurement strategies for RE.

Renewable Energy Targets

In 2003 the government published a RE Policy White Paper that set a target of reaching 10,000 gigawatt-hours (GWh) of RE production by 2013. For years, very little was done to achieve this target and there was a great deal of confusion surrounding what this target actually meant: was it a cumulative or annual target? Did it include RE sources other than electricity? The Department of Energy clarified that the target would be met by a combination of biomass, wind, solar, and small hydroelectricity.

Design of Incentive Schemes

FITs have been the most widely applied support mechanism internationally to encourage the growth of grid-connected RE. But have RE feed-in tariffs (REFITs) provided desirable or optimal outcomes in terms of affordable and competitive electricity prices? Could competitive tenders or auctions offer lower prices while still providing adequate incentives for RE suppliers to enter the market? South Africa at first explored the option of FITs but then abandoned them in favor of competitive bids for RE (REBIDs). The initial outcomes have been encouraging: there has been a great deal of market interest and subsequent bidding rounds have seen prices fall. Could there be lessons in this for other countries?

The Birth and Death of REFITs in South Africa

South Africa relies on coal for electricity production. But in the face of climate change concerns, it has embarked on a transition to lower carbon-emitting technologies. The electricity plan (IRP 2010) included, for the first time, ambitious targets for RE, namely 18,800 MW of wind and solar, out of a total projected system capacity of around 90,000 MW by 2030.

In 2009 the National Energy Regulator of South Africa (NERSA) approved a REFIT policy. Tariffs were designed to cover generation costs—plus a real return on equity of 17 percent—and to be fully inflation indexed (NERSA 2009). The first-published FITs (assuming an exchange rate of R8 per $1)—15.6 cents/kWh for wind, 26 cents/kWh for CSP (troughs with 6 hours storage), and 49 cents/kWh for PV—were generally regarded as generous by developers. But considerable uncertainty remained, including the legality of FITs within South Africa's public procurement framework, and delays in finalizing power purchase agreements (PPAs) and interconnection agreements with the national utility, Eskom. In March 2011 the NERSA unexpectedly released a consultation paper with lower FITs, arguing that a number of parameters—such as the cost of debt and exchange rates—had changed. The new wind tariffs were 25 percent lower, CSP was down by 13 percent, and PV down by 41 percent (in nominal rand terms). Furthermore, the capital component of these tariffs could no longer be fully inflation indexed. Importantly, in its revised financial assumptions, the NERSA did not change the required return for equity investors of 17 percent (NERSA 2011).

More policy and regulatory uncertainty was to come. After receiving legal advice that FITs were inconsistent with public finance and procurement laws, the DOE announced that a competitive bidding process for RE would be launched, known as the Renewable Energy Independent Power Producer Procurement (REIPPP) program. Subsequently, the regulator abandoned FITs: not a single megawatt of power had been signed in the two years since the launch of the REFITs (although it is probably fair to admit that a practical procurement process for REFITs was never actually implemented). These developments were met with dismay by many RE project developers that had secured sites and had initiated resource measurements and environmental impact assessments. Subsequently, however, it was these early developers that were ready to benefit from the first round of competitive bids.

The Birth of the REIPPP Program in South Africa

The DOE, with the assistance of the Public Private Participation Unit in the National Treasury, and a phalanx of international transactional advisors, commenced work on bid documents. A Request for Qualification and Proposals was issued in August 2011. A compulsory bidders' conference was held in

September of that year and attracted over a 1,000 participants, many from abroad. A total of 3,625 MW of new power capacity was offered with overall procurement caps for specified technologies—mainly wind and PV but also smaller amounts for concentrated solar, biomass, biogas, landfill gas, and small hydro (see table 6.2).

The tender for different technologies was held simultaneously. Bidders could bid for more than one project and also for different technologies. Projects had to be larger than 1 MW and an upper limit was placed for different technologies: for example, 50 MW for CSP and 140 MW for wind projects. A further 100 MW was reserved for small projects below 5 MW. Price caps were specified for each of these technologies at levels not dissimilar to the NERSA's 2009 REFITs, all of them much higher than the national utility's average generation tariff of around 5 cents/kWh at the time. Standard 20-year, local-currency-denominated power purchase agreement (PPA) contracts were offered for the different technologies with the offtaker being the national utility, Eskom. Up to five discrete bidding rounds were envisaged, at more or less six-month intervals, with the first round of bids due in November 2011.

Qualification Criteria

In the first request for proposals (RfPs) the full 3,625 MW was made available. The evaluation process involved a two-step process. In the first, bidders had to satisfy certain minimum threshold requirements in six areas: environment, land, commercial/legal, economic development, financial, and technical. For example, wind developers were required to provide 12 months of wind data for the designated site and an independently verified generation forecast. Project developers were responsible for identifying appropriate sites and for paying for measurement and early development costs at their own risk. Wind turbines had to be international standard International Electrotechnical Commission (IEC) 61400-1 certified. These economic development requirements, in particular, were complex, incorporating 17 sets of minimum thresholds and targets that needed to be met (table 6.3). For example, for wind projects, at least 12 percent of the shareholding in the project company had to be by black South Africans and a further 3 percent by local communities. At least 1 percent of project revenues had to go to socioeconomic contributions. The minimum threshold for local content was set at 25 percent, while a target of 45 percent was encouraged.

Bid bonds or guarantees had to be posted, equivalent to $12,500/MW of nameplate capacity of the proposed facilities, and the amount was doubled once preferred bidder status had been announced.

Bidders who satisfied the threshold requirements then entered the second step of evaluation where bid prices counted 70 percent with the remaining 30 percent weighting given to composite scores on job creation, local content, preferential procurement, enterprise development, and socioeconomic development. Bidders were asked to provide two prices: one fully indexed by inflation, the other partially indexed with the bidder being able to determine the proportion that would indexed.

Table 6.3 Economic Development Threshold and Target Levels for Wind Energy

Economic development factor	*Subcriteria*	*Threshold*	*Target*
Job creation	South Africa–based employees who are citizens	50%	80%
	South Africa–based employees who are black citizens	30%	50%
	Skilled employees who are skilled black citizens	18%	30%
	South Africa–based employees that are citizens from local communities	12%	20%
Local content	Value of local content spend	Wind 25% PV 35%	Wind 45% PV 50%
Ownership	Shareholding by black people in the project company	12%	30%
	Shareholding by black people in the contractor responsible for construction	8%	20%
	Shareholding by black people in the operations contractor	8%	20%
	Shareholding by local communities in the project company	3%	5%
Management control	Black top management	n.a.	40%
Preferential procurement	BBBEE procurement spend	n.a.	60%
	QSEs and EMEs procurement	n.a.	10%
	Women-owned vendors procurement	n.a.	5.0%
Enterprise development	Enterprise development contributions	n.a.	0.6%
	Adjusted enterprise development contributions	n.a.	0.6%
Socioeconomic development	Socioeconomic development contributions	1.0%	1.5%
	Adjusted socioeconomic development contributions	1.0%	1.5%

Source: South Africa's Department of Energy.
Note: BBBEE = broad-based black economic empowerment; EME = exempt micro enterprise; PV = photovoltaic; QSE = qualifying small enterprise; n.a. = not applicable.

Round One Outcomes

Fifty-three bids were received initially, totaling 2,128 MW. A large legal, technical, financial, and governance evaluation team was assembled in a high-security environment with 24-hour voice and closed-circuit television (CCTV) monitoring. The team included local legal firms Bowman Gilfillan, Edward Nathan Sonnenberg, Ledwaba Mazwai, Webber Wentzel, and BKS, as well as international firms Linklaters for legal, Mott Macdonald for technical, and Ernst & Young and PricewaterhouseCoopers for the financial and governance reviews. The evaluation resulted in 28 qualifying bids, amounting to 1,416 MW of new capacity. For the first round, a deadline of July 2012 was set for financial closure (the date was later extended), and closure of development (COD) had to be reached by the end of 2014.

Although bidders could not know for certain the total capacity that would be bid, they probably assumed that the tight deadlines, and challenging threshold qualification criteria, would result in the total capacity bid being less than the total made available in round one. Accordingly, prices bid were mostly uncompetitive and only marginally below the caps specified in the RfPs. Direct and PPAs were signed in November 2012 between the government, Eskom, and each of the 28 successful bidders, resulting in a total investment of close to $6 billion. Much of the debt component was provided by local South African commercial banks.

Second Round

The design of the second bid round incorporated the above lessons, and less capacity (1,284 MW) was offered to stimulate more competition (table 6.4). The second round closed in March 2012. Seventy-nine bids were received totaling 3,255 MW; 51 of these bids met the qualifying criteria, of which 19 were granted preferred bidder status (next-best bids would have resulted in more than the full window being allocated). Wind and solar PV prices in the second round were much more competitive: on average, 20 percent for wind and 40 percent for solar PV (table 6.5)! The range of prices bid was also wider, with wind prices varying from 10 cents/kWh to 12 cents/kWh and solar PV from 17.5 cents/kWh to 22 cents/kWh. The price of CSP fell by 7 percent, with one preferred bidder taking up the remaining available capacity. There was little competition in small hydro, with only two qualifying bids, both at the capped price.

Table 6.4 Capacity of Renewable Energy Made Available for Bids and Finally Allocated to Preferred Bidders

	Capacity (MW)				
Technology	*Available in round 1*	*Allocated in round 1*	*Available in round 2*	*Allocated in round 2*	*Remaining in round 3*
Wind	1,850	634	650	562.5	563.5
Solar PV	1,450	631.5	450	417.1	401.1
Solar CSP	200	150	50	50.0	0
Small hydro	75	0	75	14.3	60.7
Landfill gas	25	0	25	0	25
Biomass	12.5	0	12.5	0	12.5
Biogas	12.5	0	12.5	0	12.5
Total	3,625	1,415.5	1,275.0	1,043.9	1,165.6

Source: South Africa's Department of Energy.
Note: CSP = concentrated solar power; MW = megawatt; PV = photovoltaic.

Table 6.5 Prices for Renewable Energy: REFITs, REBID Caps, and Average Bids

	Price R/kWh					*Price cents/kWh*
Technology	*REFIT 2009*	*REFIT 2011*	*Bid cap*	*Round 1 average*	*Round 2 average*	*Round 2 average*
Wind	1.25	0.94	1.15	1.14	0.90	11.25
Solar PV	3.94	2.31	2.85	2.76	1.65	20.63
Solar CSP	2.10	1.84	n.a.	2.69	2.51	31.38
Small hydro	0.94	0.67	1.03	n.a.	1.03	12.88
Landfill gas	0.65	0.54	n.a.	n.a.	n.a.	n.a.
Biomass	1.18	1.06	1.07	n.a.	n.a.	n.a.
Biogas	0.96	0.84	n.a.	n.a.	n.a.	n.a.

Source: South Africa's Department of Energy.
Note: Prices assume full inflation indexing over a 20-year contract. CSP = concentrated solar power; kWh = kilowatt-hour; PV = photovoltaic; REBID = renewable energy bid; REFIT = renewable energy feed-in tariff; n.a. = not applicable.

The bidders who preferred the second window also offered superior local content terms, with average local content for solar rising from 28.5 percent to 47.5 percent, wind rising from 21.7 percent to 36.7 percent, and CSP from 21 percent to 36.5 percent. The deadline for financial closure for round two was extended from the end of 2012 to March 2013. The remaining 1,167 MW was made available in the third bid round in May 2013.

While prices have fallen in South Africa, they are not necessarily as attractive as those achieved in other countries. For example, Maurer and Barroso (2011) reports that in Brazil average auction prices for wind power fell from 9.8 cents/kWh in 2009 to 8.5 cents/kWh in 2010 to 6 cents/kWh in 2011. The same source quotes 6.9 cents/kWh for wind and 12 cents/kWh for PV in Peru. South African prices might be higher because of local content and economic development criteria. Interviews also suggest that the initial bidding round involved high transaction costs in terms of advisors and financing. These costs fell in round two (along with equipment prices) and are likely to fall further in subsequent rounds.

Impact of Renewable Energy Tariffs on the Consumer

Renewable power has been contracted at prices higher than the average Eskom generation cost and higher than the marginal cost of new coal-fired power. Eskom has signed 20-year PPAs with RE IPPs. The costs of these contracts are blended in with the costs from its other power stations. In its most recent application to the NERSA, Eskom estimated that power purchase costs from IPPs (mainly renewable IPPs) would add 3 percent to the tariff, on average, over the next five years.

There are no direct fiscal subsidies for grid-connected renewable power. Customers are paying the additional costs of renewable power. At present these additional costs are relatively modest and there has not been much public opposition. But as the proportion of RE increases, and as consumers continue to face above-inflation tariff increases, this could become a more sensitive political issue.

Conclusions

The South African REIPPP program is not only the largest RE program in Africa, it is also the largest IPP program of any African country and probably the most complex public-private procurement ever run on the continent. According to Bloomberg New Energy Finance, South Africa ranked in the top 10 counties investing in clean energy in 2012, ahead of Canada, Brazil, Spain, and France. This is all the more remarkable, given South Africa's previously dismal record in IPPs and the dominance of its national utility. Eskom, on the government's instructions, had attempted to run a number of IPP procurements before, all of which failed. Ultimately, the Department of Energy and National Treasury had to wrest control of the REIPPP from Eskom.

Although projects still have to achieve commercial operation, the South African REIPPP program can be considered a success in terms of attracting a multitude of private project developers and investors. In its second round, the REIPPP has also fostered competition with consequent, and impressive, falls in prices, which would in all likelihood not have happened in a REFIT program. And it has achieved this in record time: bids closed three months after the issuing of the RfP, preferred bidders were announced within a month, and contract signing and financial closure were achieved 10 months later—even though as many as 28 projects, employing different technologies of different sizes at different sites, had to be processed in parallel. The following elements have contributed to this success:

- *The procurement process was well designed*. Recognizing that there was little institutional capacity to run a sophisticated, multiproject, and multibillion dollar international competitive bid process for RE, South Africa's Department of Energy sought the assistance of the Public Private Participation Unit in the National Treasury who, in turn, relied extensively on local and international transaction advisors.
- *High standards were set* and, apart from necessary clarifications, the government stuck to the announced schedule and core bid requirements (although the deadline for financial closure slipped a few months as the government finalized financial security arrangements). Despite a tight time schedule and tough qualification criteria, the REIPPP program attracted 58 bids in round one and 79 in round two. A significant number of these met the minimum qualification thresholds: namely, 28 in round one and 51 in round two. But it should be noted that the announcement of the REFIT two years before the launch of the REIPP contributed to early market interest, and a number of bidders had already identified sites and begun resource measurements. Prior to the issuing of the RfP, the DOE had also issued an earlier Request for Information from prospective project developers, which confirmed significant market readiness.
- *The design of subsequent bid rounds was flexible*, allowing lessons to be incorporated and thus improving the competitiveness of bids and prices. For example, it became apparent that the capacity made available in round one exceeded the capacity of the market to deliver, and tendered capacity was subsequently reduced in round two to induce more competition.
- *The RE sector is potentially highly competitive*, given the diversity of energy sources, the modular nature of most of the technologies, and the number of project developers. When South Africa ran its first competitive tender for IPPs—two large gas turbine peaking plants—it received only two bids, one of which subsequently withdrew. It is, perhaps, no accident that the first successful international competitive tender for power in South Africa has been in RE.
- *Subsequent bid rounds have also incorporated more stringent thresholds*, as well as target criteria for local content objectives.
- *Initial investment was significant*. The total investment in the REIPPP's 3,725 MW of RE will approach $15 billion. The local capital market has

responded positively to this opportunity. Commercial banks have been willing to finance construction and some are on-selling debt to insurance. But local banks will be stretched to further fund the REIPPP's programs (given competing demands in other infrastructure sectors in South Africa); other sources of funding (such as pension funds) will need to be mobilized.

- *Equity returns in round one were close to 17 percent, in real terms (in local currency)*, that was envisaged in determining the original REFIT tariffs. Equity returns dipped slightly in round two for wind, and probably more substantially for PV. Dollar returns in the range of 12–13 percent have been reported.
- *Project bidders are required to incorporate a tax of 1 percent of project revenues* that will go into a government RE Fund to fund subsequent procurement programs.

General Lessons

But in hindsight, some areas could have been better designed and managed:

- The size and readiness of the local RE market was initially overestimated, resulting in less capacity being bid than was made available. There was thus limited competition in round one, and bid prices were close to the price cap. The single price offer (rather than a dynamic reverse auction—as employed, for example, in Brazil) also restricted competition.
- The size and complexity of the REIPPP meant that available legal and financial advisory services were stretched to the limit. Some firms were permitted to offer advisory services to both government and private bidders and funders, provided they created adequate "Chinese walls" within their firms. Some bidders complained that legal and finance firms were offering a "one size fits all" service that was not always appropriate for specific projects.
- The above two points suggest that it may have been more prudent to start smaller, and then gradually ramp up the program, with larger blocks of capacity being offered in subsequent rounds.
- All of the successful bidders in round one have reached financial closure and have commenced construction. It remains to be seen what proportion of preferred bidders in round two will achieve financial closure. The aim of the REIPPP is lower prices, but projects must still be bankable. A successful bidding process should have a low attrition rate of preferred bidders. Bid prices need to be realistic.
- Specifications on what constitutes local content could be improved, including more focus on those parts of the value chain that maximize local employment.
- A balance needs to be struck between the promotion of economic development and prices. Already the economic development thresholds and target

criteria are more stringent than in any other domain (and, indeed, more stringent than previous PPPs in South Africa). The South African RE market is small by international standards, and investment in local manufacturing capability is not necessarily competitive. International benchmarks indicate that South African RE prices are high.

- In some areas, there is inadequate transmission grid capacity and otherwise viable and attractive projects have to compete for access. There have also been complaints about the lack of responsiveness of Eskom transmission planners. Integration of planning, procurement, and contracting functions in an independent transmission, system, and market operator will make it easier to resolve these constraints.

- The transaction costs for the REIPPP were high for both the government and bidders (certainly higher than a REFIT program). The government has had to rely on external transaction advisors. But there is the potential to transfer these skills and experience in future procurement rounds and to build capacity in the proposed independent transmission, system, and market operator.

- The levelized energy costs that were calculated for the initial REFIT tariffs served as the departure for the REIPPP program. It should be noted that some other countries such as Tanzania have used avoided costs as their starting point.

- In October 2012 the minister of energy announced that an additional 3,200 MW of renewable power projects would be bid out, with a target of COD between 2017 and 2020. South Africa's power market continues to be shaped by centrally managed power-planning and procurement processes. But there are growing political and stakeholder concerns around rising electricity prices. Demand growth is also lower than predicted. The sustainability of the REIPPP program is dependent on volumes and predictable procurement processes. But its sustainability will depend also on the rate at which RE prices fall and compete with alternatives.

Note

1. An exchange rate of R8 per $1 has been used throughout this chapter.

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CHAPTER 7

Case Study: Tanzania

Sector Background

Tanzania's energy supply is dominated by biomass-based fuels, providing an estimated 90 percent of the national primary energy requirements. These fuels are mainly used in the informal sector, for household and small industrial use, drawing on the nation's 35.5 million hectares (ha) of forests and home gardens to provide a cheap and accessible source of energy for the population of 45 million people.

The main commercial forms of energy used are petroleum, gas, and electricity. Electricity is mainly produced from hydropower plants, but in recent years, substantial thermal power generation, too, has been required to meet the growing demand and to improve supply security. Petroleum and hydropower account for about 8 percent and 1 percent of the primary energy supply, respectively. Another 1 percent of the primary energy requirement is met with coal, solar, and wind power. The estimated primary energy consumption was 22 million tons of oil equivalent (TOE) in 2003, amounting to a per capita consumption level of about 0.7 TOE.

The main indigenous sources of energy are (a) biomass and agricultural waste, (b) hydropower, (c) natural gas, (d) coal, and (e) other forms of renewable energy (RE) such as wind and solar power. These sources are available in abundance, but so far, large-scale developments have been only in the hydropower and natural gas subsectors. While a large hydroelectric potential remains to be developed, exploration for natural gas and petroleum is ongoing. Coal use for electricity generation is limited to a small power plant, while there is no significant use of other renewables for electricity generation in a commercial scale.

The national energy policy (Ministry of Energy and Minerals 2003) identifies the following challenges: (a) *increased demand for electricity supply and distribution* (with demand tripling over a period of 20 years) will accelerate the need for investment in all elements of the electricity industry including private sector participation; (b) *development of the petroleum sector* to sustain gas production and increase gas and oil exploration will save foreign currency spent on the import of petroleum products; (c) *improved regional and international interconnection* will support growth and improve reliability of electricity supply for mutual benefit; (d) *greater rural electrification* will make electricity available for economic activities in rural areas, townships, and commercial centers and balance socioeconomic growth; and (e) *the reaching of more rural households*, providing energy supply to replace kerosene used for lighting and improve the efficiency of wood-fuel use will better the household environment and reverse deforestation.

With regard to the supply of electricity, the relevant policy statements declare that (a) competition, as a principle to attain efficiency, will be applied to the electricity market, (b) generation of electric power will be fully open to both private and public investors, (c) there will be open access to the grid, (d) regional cooperation and integration will be given priority to ensure reliability and to exploit low-cost power, (e) priority shall be given to developing domestic power generation capacity, (f) strategic partnerships with technically suitable and financially strong partners will help develop a competitive market in generation and distribution, (g) Tanzania will conduct research and participate in international research on commercially viable large-scale technologies for renewable sources of electricity generation, (h) support will be given to ownership contracts to ensure competition and a high level of investment, and (i) a new governance system shall be established, differentiating the roles of policy making, regulatory functions, and operational functions.

Tanzania is continuing with the exploration of liquid petroleum but has not had any positive results so far. Therefore, all liquid petroleum products are imported. The total annual demand for petroleum products exceeded 1.5 million tons/year, and cost over $300 million in 2005. Petroleum products are used in transport (45 percent), manufacturing (25 percent), agriculture (10 percent), households (10 percent), and commerce (5 percent). Petroleum fuels are used for power generation as well. Since 2003 a 100 megawatt (MW) fuel-oil-burning power plant has been in operation, and was used heavily to address the power crisis of 2006. A few small diesel-burning power plants are used in the main grid as well as the mini-grids. The petroleum supply industry is fully liberalized and several players are in the market.

The proven natural gas reserves are located offshore near the Songo Songo island in the Indian Ocean. The important gas discoveries have been in Songo Songo (30 billion cubic meters, bcm) and Mnazi Bay (15 bcm). Discovered reserves are limited and used for electricity generation, industrial applications, and petrochemical industries. A gas-fired power plant (Songas) has been in operation for several years, and presently has a total capacity of 190 MW. To address the ongoing generating system crises that started in 2006, gas-fired generation was increased in the system on a short-term basis. More gas-fired generating plants are also under construction. As of 2013 gas-fired power plants generating a total of 244 MW are in operation. A pipeline has already been built to deliver gas to Dar es Salaam for use in power generation.

Coal reserves are found in Mchuchuma, in southwestern Tanzania near the northern end of Lake Nyasa. Some studies indicate that the Mchuchuma coal deposits can provide fuel for 400 MW generation capacity for up to 35–40 years.

A small coal mine at Songwe-Kiwira started production in 1988. A small coal-fired power plant with an effective capacity of 1.5 MW is in operation at Kiwira and sells electricity to the Tanzania Electric Supply Company (TANESCO). Coal reserves in Tanzania are being used for industrial applications, but this major resource is yet to be exploited at its full potential. A small amount of electricity is being produced but there are plans to build larger power plants to use coal.

Hydropower is the main form of RE used in Tanzania for the supply of commercial energy, that is, electricity. The country presently has an installed capacity of 561 MW of hydropower across six power plants. A few off-grid small hydroelectric power plants are in operation. Tanzania's total technical hydroelectric energy potential is reported to be in excess of 4,700 MW of installed capacity or about 3,200 MW of firm capacity. Of this potential installed capacity, only about 12 percent has actually been developed. The economic potential—when the costs of developing hydroelectric capacity are compared with gas and coal-fired thermal power generation—is yet to be established (table 7.1). Research and measurements are being conducted on wind energy potential in various parts of the country.

Tanzania has large reserves of indigenous energy resources, including enough natural gas, coal, and hydroelectric potential to meet the demand of the power sector for many years. There is also an undetermined potential of geothermal energy. Tanzania is likely to heavily use natural gas for electricity production in the foreseeable future, owing to the limited access to other sources of energy for electricity generation. Other uses of natural gas (such as for petrochemical industries) would also emerge, establishing competing uses of gas. Liquid petroleum products might need to be imported in the foreseeable future, or until the ongoing exploration yields any positive results. The prospects of using coal are promising, in the face of increasing prices of petroleum products and competing uses for natural gas, particularly in a scenario where Tanzanian coal is most suitable for use within Tanzania owing to the relatively lower heat content when compared with internationally traded coal. The potential for further developments in

Table 7.1 Hydro Candidates

Plant/site	*Installation, MW*	*Average energy, GWh*	*Firm energy, GWh*	*River*
Kakono	53	404	335	Kagera
Upper Kihansi with addition at Lower Kihansi	120	69	99	Rufiji
Mpanga	144	955	646	Rufiji
Masigira	118	664	492	Ruhuhu
Ruhudji	358	1,928	1,333	Ruhudji
Rumakali	222	1,475	908	Rumakali
Rusumo	62 (21 Tanzania)	463	425	Kagera
Songwe	340	1,669	1,045	Songwe
Steiglers Gorge to Phase 3	1,200	5,259	3,227	Rufiji

Source: Based on Power System Masterplan Study, TANESCO, 2008.
Note: GWh = gigawatt-hour; MW = megawatt.

hydropower, in both large and small projects, is high. Other renewable sources for commercial energy supply (particularly wind energy and biomass) also remain high, and more research and feasibility studies are required to establish their potential and economic justification.

Sector Institutions

The electricity supply industry in Tanzania is structured as follows: (a) TANESCO—a vertically integrated utility owned by the government—is in the business of generation, transmission, distribution, and supply of electricity through the main national grid, operating at 220 kilovolt (kV), 132 kV, 66 kV, 33 kV, 11kV, and 400 V; (b) there are 12 mini-grids, owned and operated by TANESCO, served with diesel power plants; and (c) there are distribution companies in Zanzibar, Resolute (mining area), and Kahama (mining area), which purchase from TANESCO and distribute in their own areas. TANESCO owns and operates the national grid. Generation into the grid is predominantly hydroelectric, but recurrent droughts in the past eight years have caused the thermal generation share to be significant.

Demand Forecasts

The forecast growth in demand for electricity is significant. Table 7.2 provides the forecast used in the most recent master plan study.

The total national installed capacity on the grid is 1,438 MW (January 2013). Efforts are being made to increase power generation from local resources (namely natural gas, coal) and RE sources (namely geothermal, solar, wind, and biomass). With about 900,000 TANESCO customers, electricity is available to an estimated 18 percent of the population. A target of reaching an access level of 30 percent by year 2015 has been stated by TANESCO.

Renewable Energy Development

Prior to 2008 there are no reported incentives for generation of electricity using RE. It has been reported that some prospective investors in RE-based power plants have been negotiating with TANESCO for several years, on tariffs and power purchase agreements (PPAs).

Table 7.2 National Demand Forecast

	2006 Actual	*2006 Unconstrained*	*Increase (%)*	*2016*	*Growth (%)*	*2031*	*Growth (%)*
National sales (GWh)	2,784	3,400	22	8,600	9.7	23,100	6.8
National losses (GWh)	806	1,100	36	2,100	6.7	4,000	4.4
National generation (GWh)	3,590	4,600	28	10,700	9.0	27,100	6.4
National sum of peak demands (MW)		800		1,700	7.8	4,800	7.2

Source: *Power System Masterplan Study*, TANESCO 2008.
Note: GWh = gigawatt-hour; MW = megawatt.

In 2008 Tanzania formalized the incentives for RE-based electricity generation by announcing (a) a procedure for the development of RE for electricity generation, (b) a standardized power purchase agreement (SPPA) and a standardized tariff (a feed-in tariff, FIT), and (c) initiating a series of incentives for development of off- and on-grid RE power plants, and associated mini-grids. Of these, establishment of (a) and (b) was supported by the World Bank through technical support, with the expectation that the small power producer (SPP) program would operate independently, with the FIT being the key instrument. Incentives for project development, such as matching grants for feasibility studies and matching grants for project implementation, continue to be supported by the World Bank's project and are financed by a number of agencies.

The Small Power Producer Program

SPPs eligible to sign a standardized power purchase agreement (PPA) are defined as those whose: (a) primary source of energy is either an RE source or waste heat, (b) net export is less than or equal to 10 MW, and (c) agreements and FITs are standardized and nonnegotiable. SPPs are accepted both for main grids and mini-grids (either existing or new). But the FIT is only applicable to TANESCO-owned mini-grids. SPPs on the main grid are nondispatchable, must run for the SPP, and are a must-take for TANESCO. This means that for the main grid, TANESCO cannot refuse to purchase power at any time (irrespective of the generation economics at this time), except in a case where TANESCO is constrained from purchasing power (such as when the transmission line to the SPP is interrupted).

Three SPPs were the first additions under the SPPA introduced in 2008. Three power plants that existed at the time of the introduction of the SPP program have since been grid connected under the SPPA: TPC (9 MW), operating on bagasse (waste sugarcane); TANWAT (1.5 MW), operating on wood waste from the leather tanning industry; and the Mwenga (4 MW) hydropower plant. Many new, small power plants are being developed by the private sector.

Renewable Energy Targets

Tanzania has not published a quantity target for RE-based electricity, as have most of the other case study countries. As such, Tanzania is free to allow the most economically optimal (mix of) sources of RE to be developed for electricity production.

Design of Incentive Schemes

FITs for SPPs serving the main grid and mini-grids are based on two formulae that use the calculated avoided cost of the respective grids. The SPP tariffs for the main grid were first calculated for 2007 and 2008. From 2009 onwards, tariffs were calculated for both the main grid and existing isolated mini-grids. Tariffs are revised every year, based on an Energy and Water Utilities Regulatory Authority (EWURA)–approved methodology, which considers a number of parameters including the projected long-run marginal costs of the TANESCO grid and forecast costs of thermal power generation (both from TANESCO and from non-TANESCO sources in the subsequent year for main-grid-connected SPPs, and the cost of a generic diesel-fired off-grid generating facility for SPPs connected to an isolated mini-grid).

Grid-Connected Tariffs

The system for setting SPP FITs followed by EWURA is based on avoided costs to TANESCO, and the tariffs are technology neutral. This means that (a) TANESCO pays SPPs a price that reflects what it costs to produce or procure electricity from other sources, and (b) there is no special preference or price incentive given to any specific technology. If the resource is renewable or from cogeneration and the SPP intends to export the electricity produced from 10 MW or less of export capacity, then electricity generated from that power plant qualifies to pay the FIT announced for each year. With varying conditions of hydropower available in TANESCO's main power plants, oil and gas prices forecast the hydro-thermal mix in the ensuing year. The SPP FITs announced by EWURA for the main grid, based on estimates of TANESCO's long- and short-run marginal costs in Tanzania, are listed in table 7.3.

Mini-Grid Tariffs

The system for setting up SPP FITs for supply to mini-grids is similar: (c) the average of the avoided costs to the mini-grid is calculated by the average cost of generation from a diesel power plant and the avoided cost of the main grid, and (b) the tariffs are technology neutral. This means that (a) TANESCO pays SPPs a price that reflects what it costs to produce or procure electricity from typical diesel power plants serving the mini-grids, with the objective that it will someday be connected to the main grid;[1] and (b) there is no special preference or price incentive given to any specific technology. If the resource is renewable or if it is

Table 7.3 SPP Tariffs for the Main Grid, 2008–12

Season	*Price offered*	*Year*			
		2008	*2009*	*2011*	*2012*
Dry season	T Sh/kWh	120.5	115.33	145.36	183.05
	In equivalent cents/kWh[a]	9.36	9.66	10.74	12.06
Wet season	T Sh/kWh	90.4	86.5	109.02	137.29
	In equivalent cents/kWh[a]	7.02	7.25	8.06	9.05
Weighted average	T Sh/kWh	100.43	96.11	121.13	152.54
	In equivalent cents/kWh[a]	7.80	8.05	8.95	10.05
		1287.50	1193.55	1352.92	1,517.65

Source: For 2008, Ministry of Energy and Minerals (MEM) reports; from 2009 onwards, EWURA (2010, 2011a, 2011b, 2012a, 2012b). In year 2011 no FIT was announced, and the 2009 FIT is presumed to be operational in 2010 as well.
Note: The dry season is August to November, the wet season is from January to July, and December. kWh = kilowatt-hour; SPP = small power producer.
a. Exchange rate used in the tariff calculations of each respective year.

Table 7.4 Mini-Grid Feed-In Tariffs, 2009–12

	2009	*2011*	*2012*
Min-grid FIT	334.8	380.22	480.50
T Sh/$	1,193.55	1,352.92	1,517.65
Cents/kWh	28.05	28.10	31.66

Source: EWURA (2010, 2011a, 2011b, 2012a, 2012b).
Note: No FIT was announced in 2010, and the 2009 FIT is presumed to be operational in 2010 as well.
FIT = feed-in tariff; kWh = kilowatt-hour.

from cogeneration and the SPP intends to export the electricity produced from 10 MW or less of export capacity, then electricity generated from that power plant qualifies to pay the FIT announced for each year for mini-grids. Unlike for the main-grid FIT, the tariff is not seasonal. Mini-grid FITs announced in the recent past are summarized in table 7.4.

The rationale for offering a high FIT for TANESCO mini-grids is that they are served by diesel generators that cost around 40 cents/kilowatt-hour (kWh) to produce, and that any SPP producing below this production cost would offset or completely eliminate expensive diesel generation. Mini-grids are gradually absorbed into the national grid, and when that happens, the mini-grid SPP automatically converts into a main grid FIT. There would be a significant reduction in the FIT but possible improved dispatch of the SPPs' output, which now would not be limited by the customer load profile in the mini-grid. In an SPP operating in a mini-grid, TANESCO can purchase only what it can dispatch to customers.

Transparency

The SPP process in Tanzania was established in year 2007 through a series of stakeholder consultations, involving policy makers (at the ministry level), the utility (TANESCO), prospective investors, prospective lenders, the regulatory authority (EWURA), and academics. The guidelines for project development, optional methods to calculate FITs, and the conditions of the SPPA were widely discussed (at not less than five workshops held over 2007–08) before EWURA first announced a public consultation on the first FIT proposed for the year 2008. The publication of EWURA consisted of (and continues to include in subsequent revisions) (a) the standardized tariff methodology document including data sources and (b) detailed tariff calculations including actual data used from various sources. Separate publications address grid-connected and mini-grid SPPs. After a comments period of three weeks, the EWURA board makes a determination and issues the tariff order.

This procedure for review and opening for public comments and subsequent decisions was followed in the years 2008, 2009, 2011, and 2012. But there was no tariff announced for 2010. Furthermore, at the time of writing (May 2013), the FIT for 2013 had not been announced by EWURA. Therefore, while the incentive scheme is transparent (by way of a standardized procedure and tariffs), there are delays in announcing the FIT each year.

Other documents associated with the SPP process and useful for developers have been published by EWURA, too, such as (a) guidelines for developers, (b) guidelines for grid interconnection (in three parts), and (c) the SPPA. These are available on the EWURA Web site as approved/recommended documents. Accordingly, information about the incentives provided through the SPP procedure is easily available to any developer or stakeholder. The information appears to be reasonably up to date.

But there are limitations to the information available, especially regarding the actual procedure to be followed in project development. A procedural document has been developed, but is not available in the public domain as yet. As such, a developer does not have easy access to project development guidelines. Additionally, the procedure to secure a letter of intent from TANESCO is somewhat long, although documented.

Implementation Issues

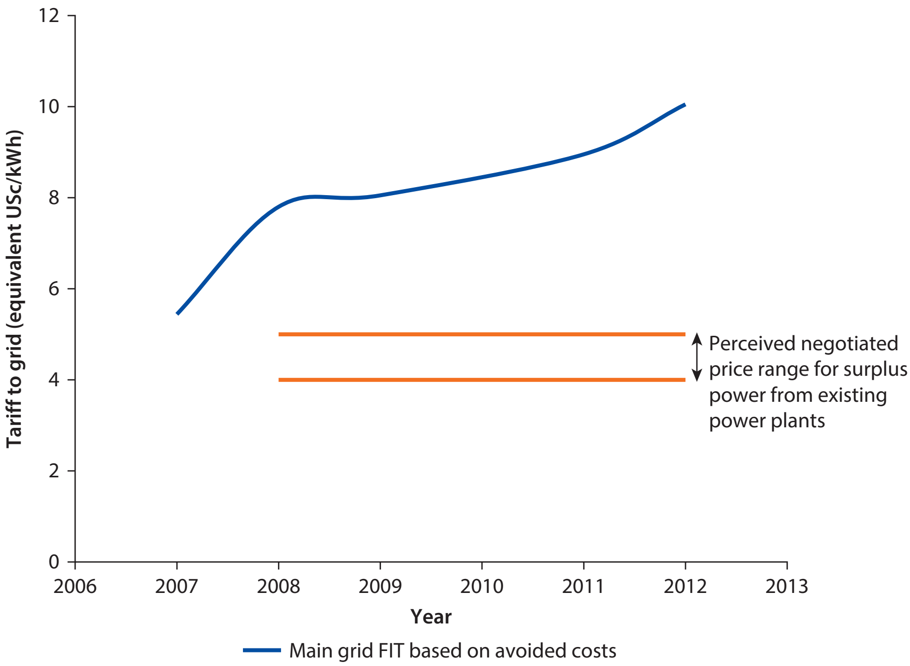
Tanzania's government decided, at an early stage of policy formulation, that the SPP program would establish a tariff on the basis of avoided costs to the grid and to mini-grids. Therefore, in principle, there is no additional financial burden to the offtaker (TANESCO) owing to purchases from SPPs. But several constraints were observed that may have caused apparent losses to TANESCO and prospective investors. The two key issues raised are as follows:

- Of the first three power plants to be grid connected, two had been in negotiations with TANESCO for several years to sell their surplus to the grid at prices in the range of 5 cents/kWh, whereas the SPP process and the FIT commenced at 7.8 cents/kWh in 2008 and is currently at 10.05 cents/kWh. Thus, TANESCO views the first three SPPs as reaping undue profits, as electricity would otherwise have been purchased at lower prices and benefits passed on to customers (or used to cushion the losses of TANESCO).

- Developers of greenfield (that is, new) hydroelectric power plants see the FIT as inadequate to meet their cash-flow requirements and achieve a reasonable return on equity (ROE), while prospective developers of power plants who use other RE sources (such as wind and biomass) see no prospects at all of developing power plants at the FIT offered.

The apparent additional purchase price (the FIT, which in turn is higher than a possible negotiated price) has since been effectively passed on to customers or added to TANESCO's losses.[2] But TANESCO has had to sign up for emergency power plants operating on diesel to boost the supply to the grid, which was suffering from lower hydropower inputs from TANESCO's own power plants as a result of recurring droughts in the period 2008–12. Thus, one may argue that the inputs from the three initial SPPs would have otherwise been produced using diesel at costs much higher than the FIT, although the SPPs are viewed to be reaping windfall profits (see figure 7.1). But the numbers of such preexisting

Figure 7.1 Announced FIT and Surplus Power from Existing Power Plants, 2007–12



Source: EWURA 2010, 2011a, 2011b, 2012a, 2012b.
Note: FIT = feed-in tariff; kWh = kilowatt-hour; USc = U.S. cents.

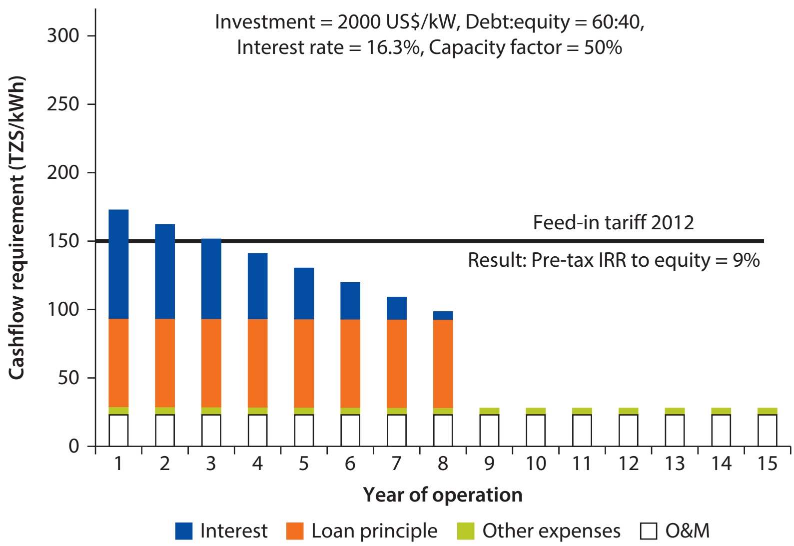
power plants using RE, and qualifying for the SPP program, are not many. Thus, this issue will be resolved, accepted a necessary concession and the unavoidable reality of standardization. On the positive side, these three projects—all of which involved lengthy negotiations—were quickly grid connected and now deliver power. Meanwhile, TANESCO has delayed payment to these SPPs, an issue that will be dealt with later.

Developer Cash Flows

The issue of lower returns on equity and negative cash flows in the initial year (previously highlighted) remains a barrier to the development of mini-hydro SPPs, the only type of SPP that is possibly viable at the range of the avoided-cost-based FIT (7.8–10.1 cents/kWh) announced in recent years. Figure 7.2 illustrates the typical situation of such an SPP hydropower developer. Given that the lending rates in Tanzania are about 16 percent (16.3 percent calculated in this example, on the basis of Bank of Tanzania assessments), an internal rate of return (IRR) of 7 percent pretax is not adequate if a mini-hydro SPP costs $2,000 per kilowatt (kW) to build, in spite of the fact that this example assumes a good site with a capacity factor of 50 percent.

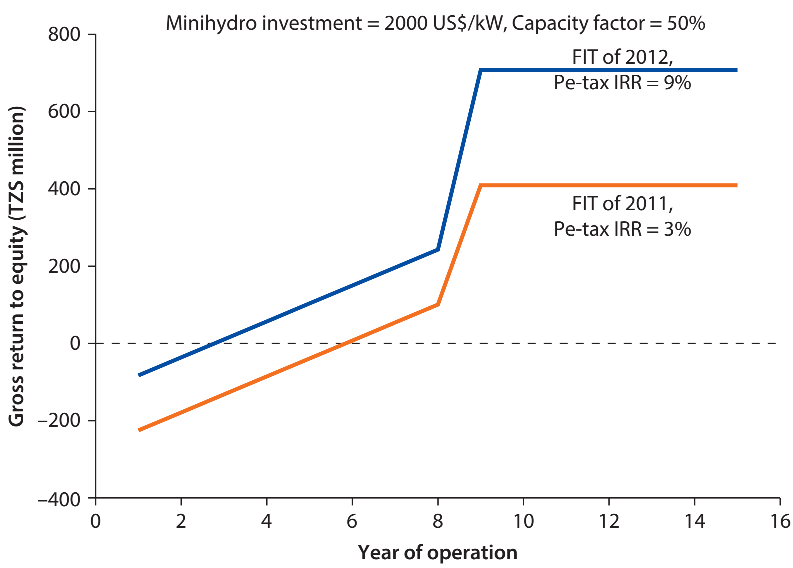
In the initial years, the cash flow is negative for the example considered, an inherent problem with any SPP program incentives based on avoided costs (see figure 7.3). It is assumed that the guaranteed price for all future purchases will

Figure 7.2 A Hypothetical Case, Illustrating Negative Returns in the Initial Years



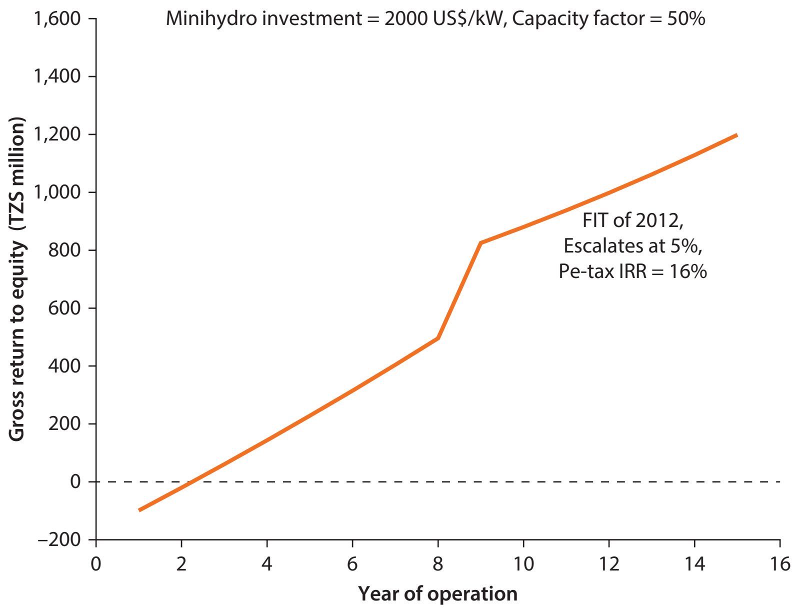
Note: This figure does not represent any particular small power producer, but illustrates a typical situation. IRR = internal rate of return; kW = kilowatt; O&M = operation and maintenance.

Figure 7.3 Cash Flow Profiles for a Mini-Hydro SPP



Note: SPP = small power producer; FIT = feed-in tariff; IRR = internal rate of return; kW = kilowatt.

Figure 7.4 Cash Flow Profiles for a Mini-Hydro SPP with a 5 Percent Growth in FIT



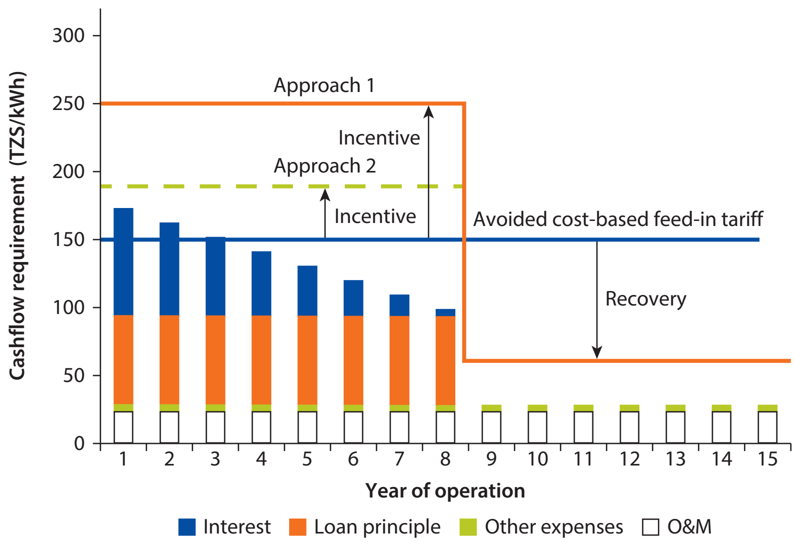
Note: SPP = small power producer; FIT = feed-in tariff; IRR = internal rate of return; kW = kilowatt.

be the floor price, which in the Tanzania SPP program is the FIT of the first year. But as seen in the five-year period since 2008, the FIT has increased at a compound average growth rate of 10 percent per year. Consideration of a moderate 5 percent increase in dollar terms yields a significantly improved ROE of 14 percent, which is not adequate (as seen in figure 7.4). Therefore, mini-hydro SPPs that cost significantly lower than $2,000/kW (say $1,500/kW) and with a capacity factor of 50 percent, are more likely to be viable under the FIT regime presently operational in Tanzania.

Additionally, the perception of SPP developers that the FIT is low (7.8–10.1 cents/kWh) compared with the costs of incremental generation from short-term emergency power contracts (about 30 cents/kWh) is also a negative factor. While it is granted that SPP developers under the 15-year SPPA enjoy a purchase guarantee on a nondispatchable basis over a relatively long period, and that short-term emergency generation has to be operational on demand, this has not been considered an adequate explanation for the large gap between the FIT and the price of emergency purchases.

A possible means of addressing the lower or negative cash flow to equity in the initial years is to offer a tiered tariff, by which the first six to eight years of operation are awarded a higher FIT (possibly a certain percentage higher than the calculated announced avoided costs), in return for a FIT that is lower than the avoided costs in the second half of the SPPA. In Tanzania such a policy and

Figure 7.5 Optional Approaches to Improve the Cash Flow of Mini-Hydro SPPs



Note: SPP = small power producer; FIT = feed-in tariff; kWh = kilowatt-hour; O&M = operation and maintenance.

options have been discussed but not yet implemented. Figure 7.5 shows two possible approaches by which over the period of perceived debt repayment by the SPP (a) an incentive is paid that is recovered in the later years or (b) a non-recoverable incentive is paid.

A common misconception is that a site has only one capacity (MW) rating, one capacity factor, and nothing else. This position is incorrect. If a site is found to be financially unviable at the FIT offered, a cautious developer with competent professional advice would examine whether it can develop the same site at a lower installed capacity (hence lower investment), which will yield a higher capacity factor (hence an improved utilization of the asset) using lower-cost equipment (hence lower investment). Developers and other analysts often speak of a site as an *x* MW site. Once optimized to the offered tariff, the site may be rated lower or higher than *x*. After all the options to optimize the site have been investigated and found to be uneconomical, then it should not be developed.

There will be other sites proposed by other developers that can meet their own profitability criteria, and such sites should be developed first. Sites that cannot be made viable at the offered FIT, in principle, should wait until avoided costs (and hence the FIT) increase further (for example, if fossil-fuel prices increase in the future). Until then, developers have to wait. This is a common situation in many countries with an SPP or similar program. In the same manner, if the FIT is inadequate to ensure the commercial viability of other technologies, such as wind and solar, these, too, should be postponed until avoided costs (and hence the FIT) increase to higher levels.

Tariff Requirement for Project Viability

A more reasonable assessment would be to examine the required FIT to make a generic SPP project viable so it achieves an equity IRR of (say) 22 percent—the minimum IRR expected by a Tanzanian investor. When the increase in dollar terms is assumed to remain at 5 percent per year, table 7.5 shows the break-even points at which the project becomes viable to the investor, when the year 1 FIT is changed. Results indicate that small hydro SPPs would be viable at the 2012 FIT, provided they (a) can be built at a cost not exceeding \$1,600/kW of capacity, (b) the site has a good flow uniformity so that a capacity factor of 50 percent is optimal, and (c) the FIT is increasing by 5 percent per year in real terms. But in Tanzania, developers claim that owing to long transport distances for project equipment and construction material, and difficult access to sites from main roads, the project capital costs are not in the range of \$1,500/kW, but higher.

The FIT offered is adequate for the project to be profitable if developers respond to the incentive by initially developing the potentially better sites (those with a lower specific investment and a higher capacity factor) or sites for which the parameters are such that an optimized design to achieve an equity IRR of 22 percent would yield a viable project.

Conclusions

Since its first introduction in 2008, three existing power plants quickly went through the SPP process and connected as main-grid SPPs: TPC (an existing thermal 9 MW power plant, which previously served only the sugar company's mini-grid), TANWAT (which previously served the tanning company's mini-grid and was closed down for about one year because the main grid had reached the factory, but then was restarted to feed 1.5 MW to the grid), and Mwenga (an existing small hydropower plant that is grid connected and serving 4 MW to the grid). Actual energy delivered to the grid has not been published as yet; any significant inputs are likely to be from year 2012 onwards.

The payment record of TANESCO and its adherence to contractual conditions have not been encouraging. There are reports that payments to the three operational SPPs do not come on time, or even several months later. A dispute

Table 7.5 Required Additional Incentives to FIT for Project Viability

Investment (\$ per kW)	*1,500*	*1,600*	*1,700*	*1,800*	*1,900*	*2,000*
Capacity factor (%)	45	45	45	45	45	45
Base year FIT (T Sh/kWh)	153	153	153	153	153	153
Escalation of FIT in real terms (%)	5	5	5	5	5	5
Incentive above FIT (%)	0	0	0	0	0	0
Equity IRR (%)	24	22	20	19	17	16
Incentive above FIT (%)	0	0	7	12	19	24
Equity IRR (%)	24	22	22	22	22	22

Note: FIT = feed-in tariff; IRR = internal rate of return; kW = kilowatt; kWh = kilowatt-hour.

with a thermal independent power producer (IPP), ongoing for several years, has not improved investor confidence in the SPP process or the SPPA. While there are reasons for TANESCO to be short of cash, a constrained cash flow has caused a loss of confidence among prospective SPP developers, in addition to the anxiety caused by lower FITs.

A significant development was the biomass power plant on Mafia island (offshore), where a TANESCO mini-grid is operational. The power plant project was developed and made operational. Being on a mini-grid displacing diesel, the project is offered the higher mini-grid tariff, with no risk to the investor of the mini-grid being absorbed into the main grid, which may cause tariffs to drop.

As there is no centralized clearinghouse for applications for SPPs, it is difficult to know the number of projects being developed by investors, and their viability (or its lack) under the FIT. Indicative estimates can be obtained on the basis of the letter of intent issued by TANESCO and the environmental licensing authority.

By providing the concession of offering an SPPA and a FIT, Tanzania is fulfilling the country's policy objective of encouraging the private sector to invest and operate power plants to contribute to grids and mini-grids. By limiting such concessions to SPPs (RE), the desire to develop RE is also being fulfilled. The SPP program had been running for five years (2008–12) at the time of this writing. Initial delays in making the SPP process and the SPPA acceptable to the government, TANESCO, prospective lenders, and the developer community probably constrained the number of power plants built and made operational in five years.

Notes

1. TANESCO plans to gradually connect its mini-grids on the mainland of Tanzania to the main grid by 2017.
2. TANESCO has been reporting losses for several years, owing to an increase in production costs and an inability to raise tariffs to reflect such costs.

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CHAPTER 8

Case Study: The Arab Republic of Egypt

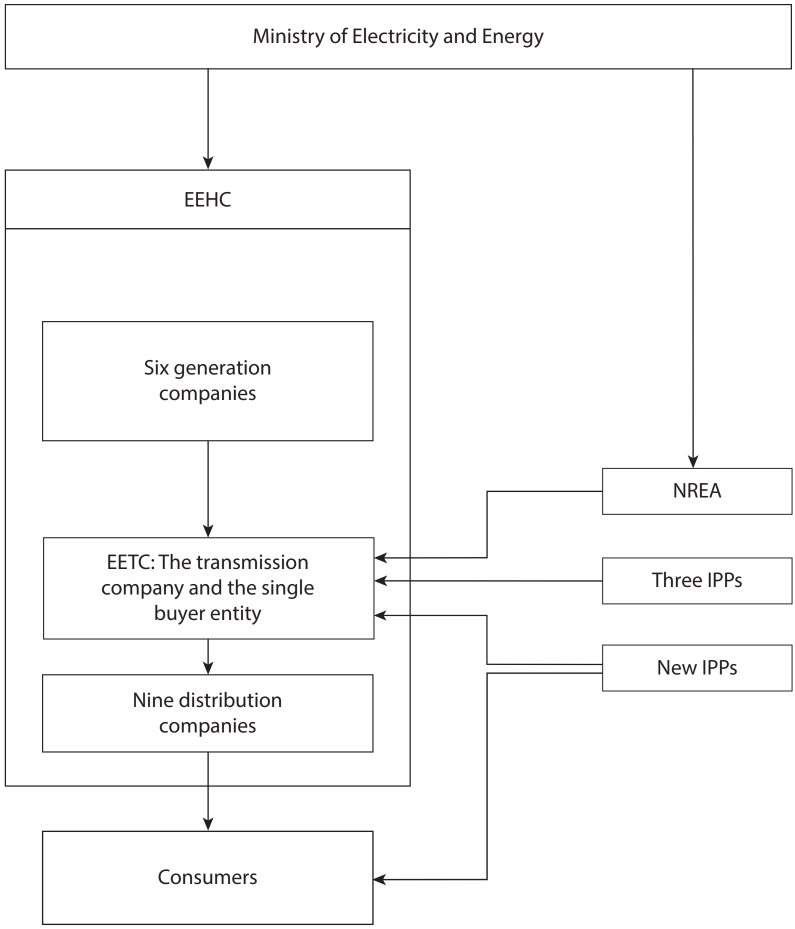
Sector Background

Egypt's power sector reforms have involved both the unbundling and rebundling of its state-owned power entities, combined with the shuffling of responsibilities for policy and regulatory oversight and corporate governance. A major institutional reform was undertaken in 2000 through Law 164, which formed the Egyptian joint stock (holding) company under the name Egyptian Electricity Holding Company (EEHC). In July 2001 more restructuring took place through the unbundling of generation, transmission, and distribution activities into 13 companies (5 generation, 1 transmission, and 7 distribution). An internal wholesale power pool was also created in 2002 under Law 164 to replace the previous dispatch processes. Under the pool provisions, the generators provide bids for dispatch, and their generating units are scheduled for dispatch on the basis of these bids. The bids are based on costs, however, and so the pool has never operated as a genuine market-clearing exchange. Moreover, the EEHC has retroactively adjusted the cost-based prices in the pool to maintain substantial cross-subsidies among the pool members, which has further blunted any competitive pressure to improve efficiency.

Further unbundling took place in 2002 with the division of one of the distribution companies into two companies, and again in 2004 with the division of another of the distribution companies into two companies. Currently, as illustrated in figure 8.1, the Egyptian electricity market is composed of government-owned utilities (6 generation, 1 transmission, and 9 distribution) under the direct management of the EEHC; three independent power producer (IPP)–owned projects; one wind-generating company, New and Renewable Energy Authority (NREA) within the Ministry of Electricity and Energy (MOEE); and about 12 small isolated and/or semiconnected independent service providers in either generation or distribution.

All of these reforms took place without an independent regulator. The regulatory agency was established in May 2001 and started operations in early 2002.

Figure 8.1 Structure of the Egyptian Power Sector



Source: Vagliasindi and Besant-Jones 2013.
Note: EEHC = Egyptian Electricity Holding Company; EETC = Egyptian Electric Transmission Company; IPPs = independent power producers; NREA = New and Renewable Energy Authority.

In addition to ensuring an adequate supply of electricity to meet demand at equitable prices, the NERA's mandate covers for competition in the power market. The NERA's powers fall short of a truly independent regulatory agency, however, because it does not have tariff-setting power. Moreover, its rulings are under government influence: its board is chaired by the minister of electricity and energy. Between 1992 and 2004 there were no changes to the tariffs in nominal terms, even though a substantial decline in real terms resulted. Then in October 2004 the cabinet of ministers approved nominal tariff increases of approximately 5 percent per year for the next five years, with the aim of covering costs by 2009. In August 2007 the government announced a three-year plan to remove subsidies from natural gas and electricity tariffs for energy-intensive industries. In June 2008 the tariff increases under this plan were accelerated and implemented immediately.

Egypt has embarked on a program of targeted energy pricing and fuel subsidy reforms to achieve cost-recovery and to replace untargeted subsidies with targeted social safety net programs, which were off limits in the past. This is a significant first step toward achieving fiscal sustainability in the sector. It should be noted that this program was launched during the postrevolutionary period, which was marked by greater political and economic instability and when reforms were typically difficult to implement. An overall 15 percent electricity tariff increase for households and commercial consumers was implemented in two steps in November 2012 and January 2013, together with a tariff increase of up to 50 percent for energy-intensive users implemented in January and July 2012. These reforms of tariffs (mainly those for commercial and energy-intensive users) are expected to increase economic efficiency for the targeted sectors, improve the financial sustainability of the EEHC, and send a price signal to save energy.

The EEHC organized the first tender for private power generation in 1996 and awarded a contract under a power purchase agreement (PPA) in 1998. The PPA provided for power to be supplied from a gas-fired steam generator of 682.5 megawatt (MW) capacity for a period of 20 years under build, own, operate, transfer (BOOT) arrangements with project financing. Subsequently, the EEHC quickly concluded two more BOOT projects for generating plants under similar contract terms and the same set of conditions extended by the government. Between 1996 and 2003 the private sector added 2 gigawatts (GW) in new power capacity in the form of three gas-fired, steam-generating plants of equal rated capacity of 682.5 MW, accounting at that time for about 10 percent of the country's installed capacity. Debt financing was provided by local and foreign banks as well as by institutional investors and multilateral agencies.

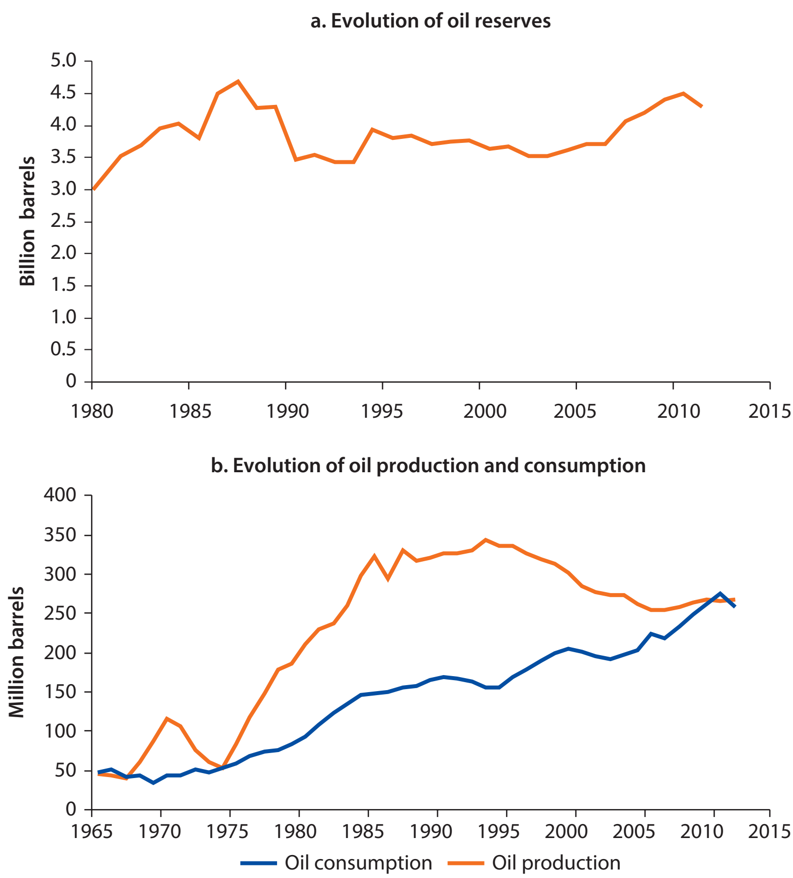
The EEHC has continued to work on five-year development plans—particularly for generating capacity. The EEHC concluded its first fast-track power generation program for adding 4,500 MW of gas-fired, combined-cycle generating capacity during its fifth five-year plan for 2002–07. The EEHC then implemented a second fast-track power generation program during its sixth five-year plan for 2007–12, which consisted of 7,240 MW of new generating capacity (6,500 MW gas-fired plant and 600 MW of wind-power capacity). The EEHC is planning to add about 15,000 MW of new capacity during its seventh five-year plan for 2012–17. Nevertheless, the EEHC's generation reserve margin is expected to remain tight for some time because of the expected growth in power demand.

In conclusion, the government's strategy for meeting Egypt's demand for electricity has managed to expand the power supply impressively, helped by the discovery of large reserves of natural gas that provide low-cost power generation while expanding access to electricity to nearly the whole population. The government has kept electricity prices down to help low-income households afford it, and energy-intensive industries remain competitive. These achievements have, however, come at a cost. The subsidies imposed substantial burdens on the government's fiscal resources and weakened the financial structure of the state-owned enterprises involved in supplying electricity and energy and in financing the energy sector. This outcome has impeded the government's intentions to privatize power supply entities and attract private investment to the sector.

Egypt faces challenges in terms of security of supply. As figure 8.2 illustrates, since 2009 Egypt has become a net oil importer, after reaching a peak in oil production in 1993. In terms of oil reserves, figure 8.2 shows a stable reserve of around 4 billion barrels for the past three decades, indicating that no more large oilfields are expected to be discovered in the future. Alongside a growing population, oil consumption is expected to increase, and with decreasing oil production and flat oil reserves, Egypt will become more dependent on oil imports and more vulnerable to fluctuations in international oil prices. This in turn means more burdens on the already cash-strapped national budget.

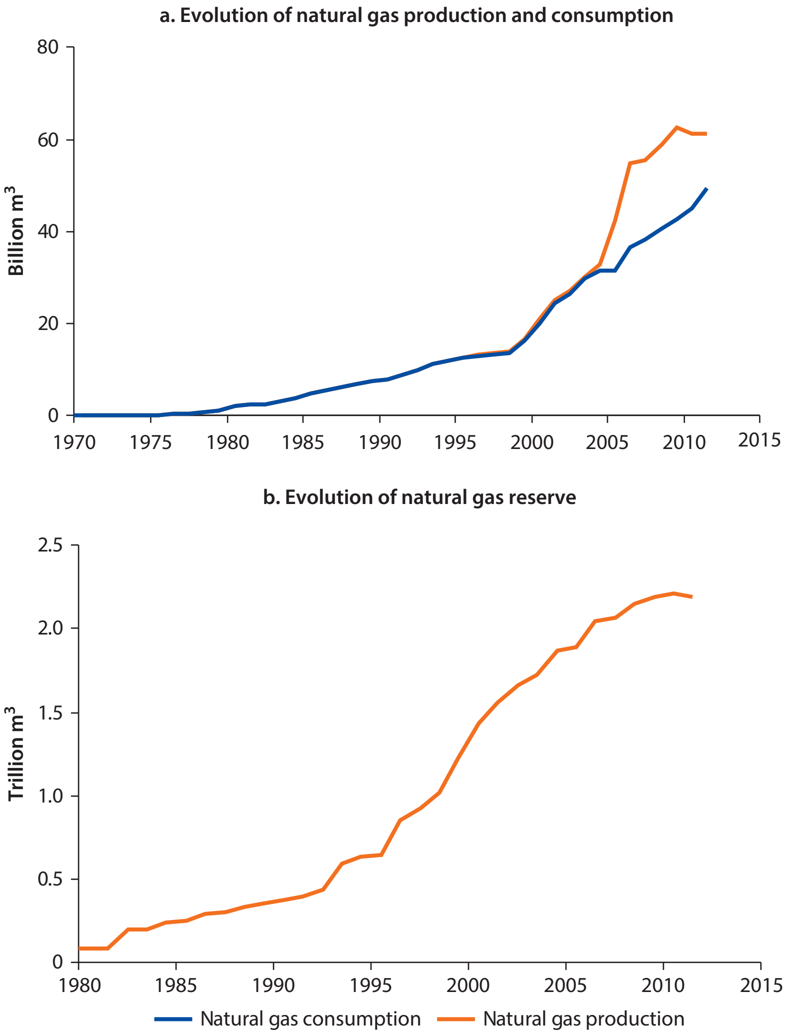
The situation is less dramatic in the case of natural gas, where production is still greater than consumption, as shown in figure 8.3. Whereas consumption is

Figure 8.2 Evolution of Oil Production and Consumption and Reserves



Source: NREA.

Figure 8.3 Evolution of Natural Gas Production and Consumption and Reserves



Source: NREA.
Note: m^3 = cubic meters.

monotonically increasing, production came to a halt in 2009. If both production and consumption keep up their 2012 rate of growth, consumption will surpass production in just four years. Natural gas reserves' rate of increase has been decreasing since the beginning of the millennium, and the reserve value almost peaked in 2010 (as shown in figure 8.3). The Egyptian government has opened areas for international exploring companies in the deep water of the Mediterranean Sea, where there are great hopes of finding large natural gas reserves, as has been done for neighboring countries.

It is worth mentioning (regardless of the fact that production is greater than consumption) that about 85 percent of fossil fuel supplied to power plants is from natural gas, and that since 2010 power plants have experienced production disruption, especially during summer months, because of frequent fluctuation in the pressure of natural gas pipes. The frequent power outages of the past three years are a new experience for Egyptians, and the Ministry of Energy (MoE) has been mitigating the effect by rotating blackouts.

The installed capacity of thermal power plants—which rely primarily on natural gas, not heavy oil—constitutes the major part of the total installed capacity in Egypt, followed by hydropower and a very minor contribution from wind power and one solar thermal power plant. In terms of percentages, figure 8.4 shows how this installed capacity is distributed among the different primary energy resources. This figure also illustrates that dependence on thermal power plants has grown over the past decade.

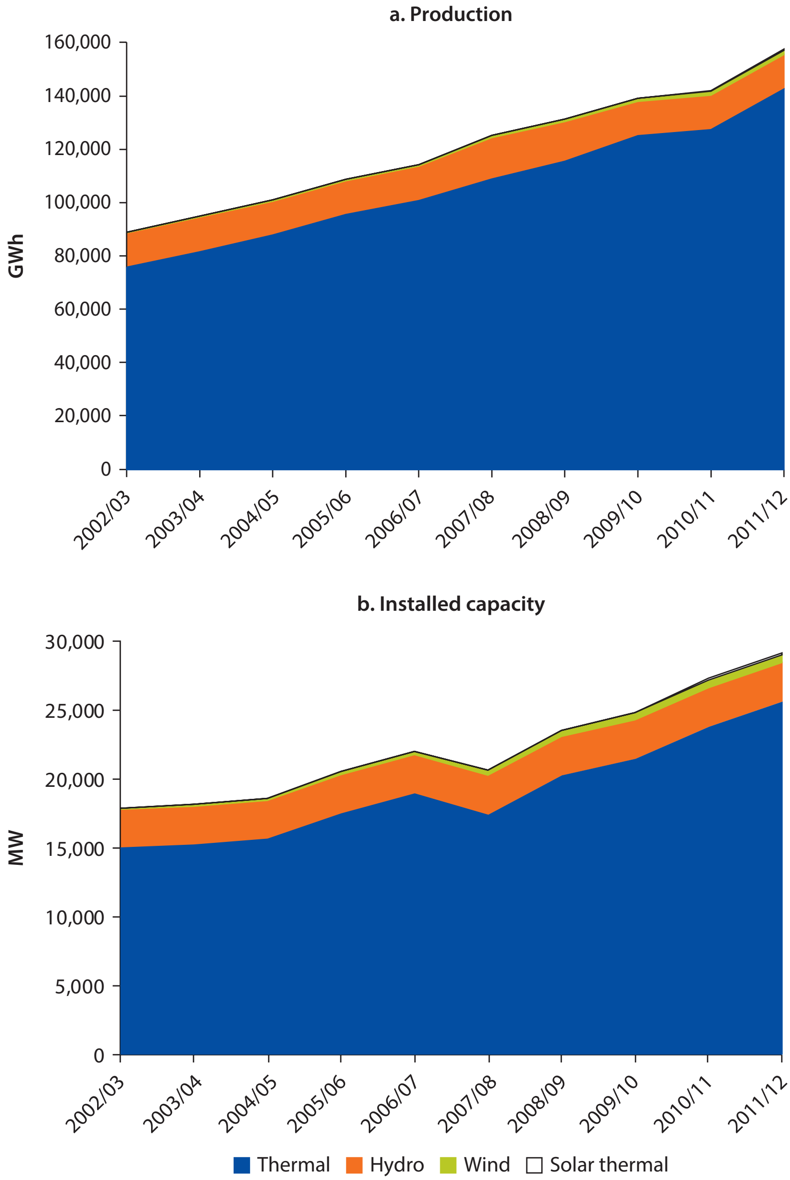
Similarly, as shown in figure 8.4, the total electrical energy production has increased during the past decade by 76 percent—from around 89,000 gigawatt-hours (GWh) to 157,000 GWh, most of it obviously coming from the thermal power plant. The consumption evolution of different primary energy types used for electricity production (in percentages) involves an increasing share of thermal power at the expense of a decreasing share of hydropower (figure 8.4). Taking two snapshots at 2002–03 and 2011–12 shows the percentage of electricity production by different types of primary energy. Regardless of the increasing wind and solar projects developed in the past decade, Egypt is becoming more dependent on fossil fuel now than before.

Rapidly growing demand is a key feature of the power sector in Egypt. This demand is driven by population growth, development of energy-intensive industries, and increasing use of electrical appliances, especially air-conditioners in residential sectors. The residential and industrial sectors are by far the largest consumers, and together account for 70–75 percent of total electricity consumption. Peak electricity demand increased from 15,678 MW in 2005 to 21,330 MW in 2009, and to 24,400 MW in 2011—a 14 percent increase in just two years. The growth in demand has outstripped growth in the supply capacity, leading to some disconnections during the peak summer seasons in recent years and raised public concerns about energy security. Although the annual demand growth slowed to approximately 5 percent during the political crisis, the EEHC forecasts demand growth to rebound to previous levels (6.4 percent) in the foreseeable future.

Renewable Energy Development

Among the six known renewable energy (RE) resources, Egypt enjoys hydropower through the Nile River, wind energy in some specific locations where it is economically feasible, solar energy almost all over the country, and a very minor amount of geothermal energy in the Sinai Peninsula. Although currently there is a national program to exploit biomass resources in the Ministry of Environment, it is not targeting electricity generation but rather biogas and natural fertilizer production for rural development. In this section, we will explore the efforts made in the hydro, wind, and solar energy sectors, as they are the major contributors to the national RE targets and plans.

Figure 8.4 Evolution of Fuel Mix Production and Installed Capacity, FY2002/03 to FY2011/12



Source: NREA.
Note: GWh = gigawatt-hour; MW = megawatt.

Hydro

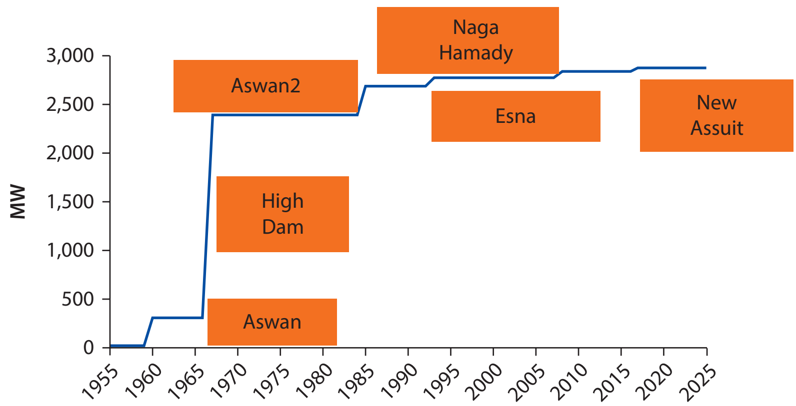
Hydropower was, historically, the first RE resource to be exploited in Egypt. Its generation started with the building of the Aswan Dam 1 (322 MW) in 1960, followed by the High Dam (2,100 MW) in 1967. Table 8.1 and figure 8.5 illustrate the historical evolution of the installed capacity of hydropower plants

Table 8.1 Major Dams on the Nile River

Name	*Installed capacity (MW)*	*Year*
Aswan 1 Dam	322	1960
High Dam	2,100	1967
Aswan 2 Dam	270	1985
Esna Dam	87	1993
Naga Hamady Dam	64	2008
New Assuit barrage	32	2017

Source: NREA.
Note: MW = megawatt.

Figure 8.5 Evolution of Hydropower in the Arab Republic of Egypt, 1955–2025



Source: NREA.
Note: MW = megawatt.

in Egypt, while figure 8.6 shows the amount of generated electricity from each dam in the past five years. Egypt's hydro resources are almost entirely developed, and not available for further development.

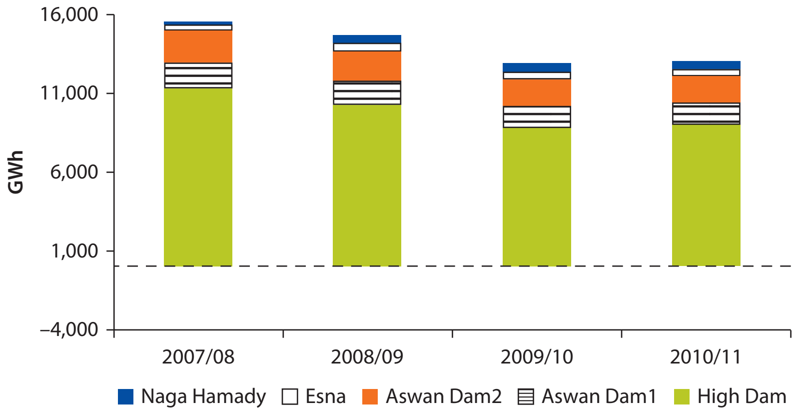
Finally, in the hydro sector there are two micro dams (0.68 MW and a 0.8 MW), located in the Fayoum governorate, that were commissioned in 1991 and 2003, respectively. The latest reports of the Ministry of Electricity do not show further plans for new micro dams in Egypt.

Wind

In 2005, and in a joint venture between the Danish RISO laboratories and the Egyptian Meteorological Authority, a national wind atlas was issued showing that Egypt enjoys some excellent wind regimes in both onshore and offshore regions. Onshore, the wind speed in the Suez Gulf region reaches 10.5 meters per second (m/s), making it one of the best places in Egypt, followed by large regions to the east and west of the Nile River, where the speed ranges from 7 m/s to 8 m/s.

The first wind farm (5 MW) erected in Egypt was in Hurghada in 1993. This was followed by a series of wind farm projects in Zafarana (northern of Hurghada) that extended from 2002 till 2010. Table 8.2 shows the eight wind

Figure 8.6 Evolution of Hydropower in the Arab Republic of Egypt, FY2007/08 to FY2010/11



Source: NREA.
Note: GWh = gigawatt-hour.

Table 8.2 Wind Projects

Project name	*Electric capacity (MW)*	*Number of turbines*	*Turbine power (MW)*	*Provider company (type)*	*Financing country*
Zafarana-1	30	50	0.6	Nordex (N43)	Netherlands
Zafarana-2	33	55	0.6	Nordex (N43)	Germany
Zafarana-3	30	46	0.66	Vestas (V47)	Netherlands
Zafarana-4	47	71	0.66	Vestas (V47)	Germany
Zafarana-5	85	100	0.85	Gamesa (G52)	Spain
Zafarana-6	80	94	0.85	Gamesa (G52)	Germany
Zafarana-7	120	142	0.85	Gamesa (G52)	Japan
Zafarana-8	120	142	0.85	Gamesa (G52)	Netherlands
Total	545	700			

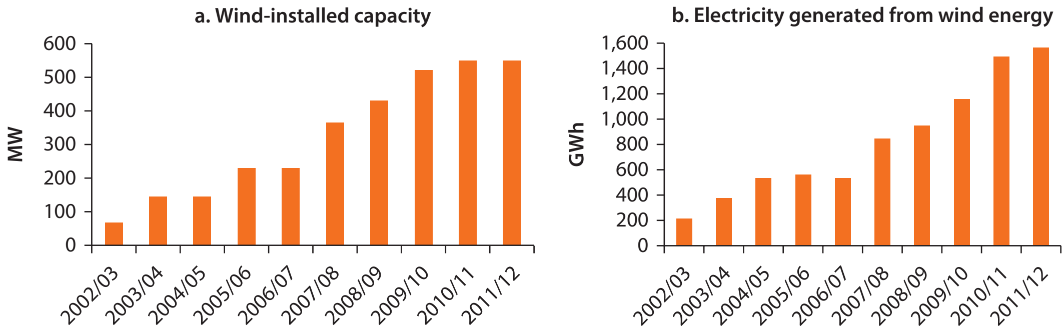
Source: NREA.
Note: MW = megawatt.

farm projects that were implemented in Zafarana along with the installed capacity of each project, the number of turbines, and the power of each turbine. Collectively, the total installed capacity in Zafarana is 545 MW with a total of 700 turbines installed, making it the largest wind farm in the Middle East and North Africa (MENA) region and on the African continent. Figures 8.7 and 8.8 illustrate the historical development from 2002 till 2012 of the wind-installed capacity, electricity generated, fuel saving, and emissions reduction during the construction of the different projects at Zafarana.

Concentrated Solar Power

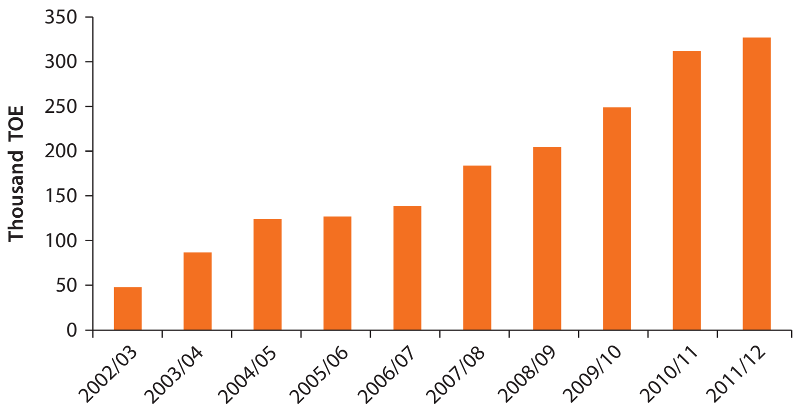
Egypt is one of the sunniest countries in the world, with a large potential of solar energy. Egypt issued its solar atlas in 1991 indicating that the average direct normal solar radiation ranges between 2,000 (north) and 3,200 (south) kilowatt-hour per square meters per year (kWh/m^2/yr), with very few cloudy days and an average sunshine duration of between 9 (winter) and 11 (summer) hours/day.

Figure 8.7 Wind-Installed Capacity and Production, FY2002/03 to FY2011/12



Source: NREA.
Note: GWh = gigawatt-hour; MW = megawatt.

Figure 8.8 Fuel Savings Due to the Implementation of Wind Energy Projects, FY2002/03 to FY2011/12



Source: NREA.
Note: TOE = tons of oil equivalent.

Egypt started to exploit its vast solar energy resource with the Integrated Solar Combined Cycle (ISCC) power plant in Kuraymat, which is one of three similar projects in the world (the other two are in Morocco and Algeria). The plant started its operation in July 2011 and its total installed capacity is 140 MW—20 MW is from the concentrated solar power (CSP) solar field and the remaining 120 MW from a combined cycle gas and steam turbine. Table 8.3 lists technical information about the project, while figure 8.9 shows a schematic diagram of the ISCC power plant.

Renewable Energy Targets

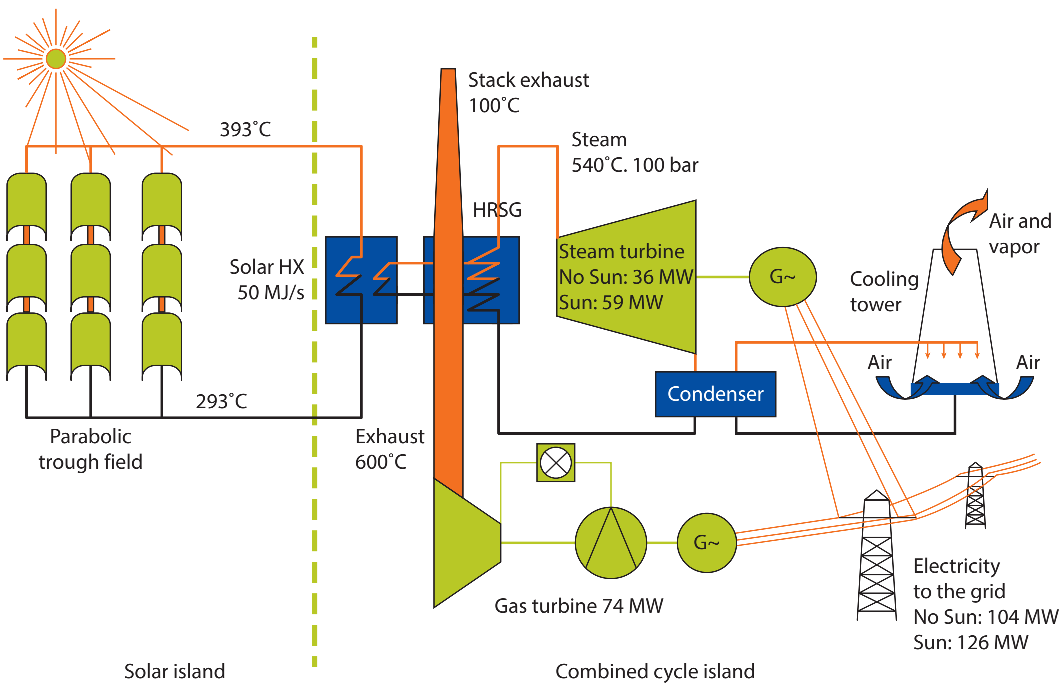
As the cost of electricity production from wind energy is the closest to conventional resources among the different RE technologies, wind energy has the highest priority right now in Egypt's national plans and targets (figure 8.10).

Table 8.3 Technical Specifications of the Kuraymat Solar Field

Site	
Longitude	31.25° E
Latitude	29.27° N
Altitude	60 m
Annual direct normal solar radiation	2,441 kWh/m^2
Field dimensions	678 m (N–S) 921 m (E–W)
Performance	
Annual insolation on solar field	317,975 MWh
Optical efficiency	79.74%
Thermal efficiency	65.6% (peak) 64.4% (annual)

Source: NREA.
Note: E–W = east to west; kWh/m^2 = kilowatt-hours per square meter; m = meter; MWh = megawatt-hour; N–S = north to south.

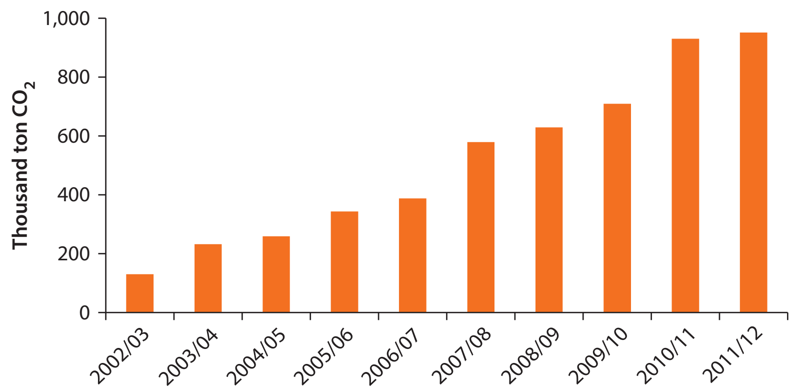
Figure 8.9 Integrated Gas-Steam-Solar Combined Cycle



Source: NREA.
Note: HRSG = heat recovery steam generator; HX = heat exchanger; MJ = megajoules; MW = megawatt.

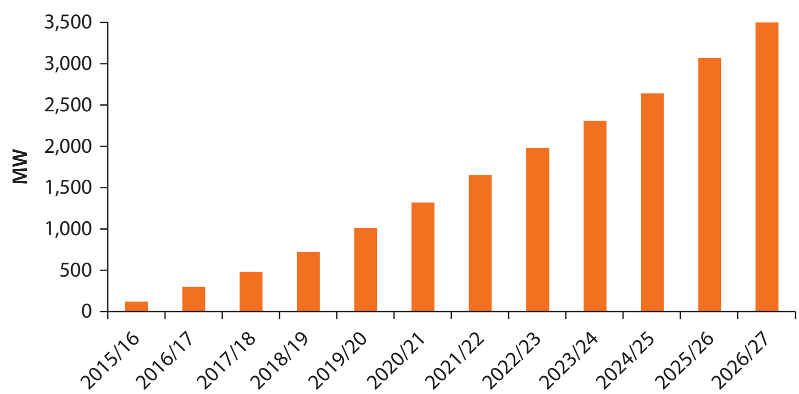
A national strategy for renewable energy that was approved in February 2008 (and that aims to cover 20 percent of the electricity generated by renewable energy in the year 2020) sets a specific target of 12 percent of the electricity generated to come from wind energy in the target year. This target is translated to a total installed capacity of 7,200 MW of grid-connected wind energy in 2020.

Figure 8.10 CO_2 Emissions Reduction Due to the Implementation of Wind Energy Projects, FY2002/03 to FY2011/12



Source: NREA.
Note: CO_2 = carbon dioxide.

Figure 8.11 The Egyptian Solar Plan Approved by the Cabinet in July 2012



Source: NREA.
Note: MW = megawatt.

In a move to put solar energy on the national plan of the energy mix, the ministerial cabinet approved the Egyptian Solar Plan in July 2012. The plan, which starts in 2015, targets installing 3,500 MW of solar energy by 2027 (figure 8.11). The target amount is divided into 2,800 MW of CSP and 700 MW of photovoltaic (PV). The plan also addresses the enhancement of the relevant local industries that can feed into the targeted technologies. It is worth mentioning that the plan relies on a 67 percent share of private investment to implement the required solar projects, revealing a large opportunity for national and international investors to play an essential role in the future of Egypt's solar projects.

One of the first projects under the Solar Plan is a 100 MW CSP power plant, with four hours' storage, proposed for Kom Ombo in Upper Egypt. The proposed financing arrangements for this project, and the extent to which the high

Table 8.4 Future PV Projects

Location	*Installed capacity* *MW*	*Funding agencies*	*Expected year of operation*	*Status*
Hurghada	20	Japan International Cooperation Agency	2016	A feasibility study was completed by the end of 2012.
Kom Ombo	20	French Development Agency	2017	A grant was signed with the French Development Agency in May 2012; €800,000 will fund a feasibility study of the project. A land plot of 15 square kilometers (km^2) was designated for the project in November 2012. A consultant contract was expected to be signed in 2014.

Source: NREA.
Note: MW = megawatt; PV = photovoltaic.

incremental costs can be bought down by concessional financing, is discussed below in some detail.

Finally, the NREA is planning the first two large PV projects in Hurghada and Kom Ombo (of 20 MW each), which are expected to start operations in 2016 and 2017, respectively (table 8.4 provides more detail on each project).

Production Costs

Table 8.5 shows the levelized economic production costs of the generation alternatives in Egypt (as considered in the EEHC master plan).

The costs for CSP are taken from the recent feasibility study (FS) for the proposed Kom Ombo CSP project (Fraunhofer and Lahmeyer International 2012). The resulting levelized costs of around 22 cents/kWh imply an incremental cost of 18–19 cents/kWh, when measured against the alternative of natural gas at $3 per million British thermal units (mmBTU).[1] The incremental cost of wind power is much lower, at around 5.6 cents/kWh.

The economic value of gas is certainly quite low, but was derived in a detailed 2007 study of Egypt's gas resources, and is based on the long-run marginal costs of production, plus a depletion premium (Economic Consulting Associates 2007), which is consistent with the valuation of gas in two recent gas projects financed by the World Bank (Helwan and Giza North). But more recently Egypt has been able to export natural gas to Jordan at a price of $6/mmBTU. At this higher price of gas, the levelized economic production cost increases from 3.8 cents/kWh to 5.7 cents/kWh, with a corresponding decrease in the incremental costs of renewable energy.

Defining a plausible thermal generation counterfactual is not straightforward. Although the indicated thermal alternative is a gas combined-cycle gas turbine (CCGT), Egypt suffers from a periodic natural gas shortage associated with supply infrastructure and transportation bottlenecks. CCGTs are therefore designed to run with diesel oil as a supplementary fuel, while steam cycle gas projects

Table 8.5 Production Costs: Generation Alternatives

		CCGT	OCCT	Steam plant	Steam plant	Wind	CSP	CSP
Fuel		Natural gas	Natural gas	Natural gas	HFO		Wet	Dry
Installed capacity	MW	750	250	650	650	80	100	100
Operating life	Years	25	20	30	30	25	25	25
Overnight construction cost	$/kW	800	500	1,076	1,076	2,000	7,233	7,355
Construction period	Years	3	2	4	4	2	2	2
Construction period adjustment factor	$/kW	1.202	1.144	1.308	1.308	1.144	1.144	1.144
SCF	ratio						0.946	0.946
Local portion	percentage						19.2	19.1
	$/kW						1,588.8	1,607.0
SCF adjustment	$/kW						85.8	86.8
Capacity credit	ratio					0.6		
Capacity cost	$/kW					−244.8		
Economic cost	$/kW	961.6	572	1,407	1,407	2,533	8,189	8,327
Capital recovery factor	ratio	0.110	0.117	0.106	0.106	0.110	0.110	0.110
Annualized capital cost	$/kW/yr	105.9	67.2	149.3	149.3	279.0	902.2	917.4
Fixed O&M	$/kW/yr	16.0	9.0	3.0	4.0	76.0	30.5	29.2
Total fixed cost	$/kW/yr	121.9	76.2	152.3	153.3	355.0	932.7	946.6
Variable cost								
Efficiency	percentage	54.0	34.0	40.3	39.8			
Heat rate	BTU/kWh	6,319	10,035	8,475	8,575			
Fuel cost	$/mmBTU	3	3	3	14.5			
	$/kWh	0.019	0.030	0.025	0.124			
Nonfuel variable O&M	$/kWh	0.0002	0.003	0.0004	0.0004		0.007	0.007
Total variable cost	$/kWh	0.019	0.033	0.026	0.125	0.000	0.007	0.007
Total cost								
Capacity factor	ratio	0.75	0.20	0.85	0.85	0.43	0.51	0.50
Annual generation	kWh	6,570	1,752	7,446	7,446	3,758	4,504	4,369
Total cost/kWh	$/kWh	0.038	0.077	0.046	0.145	0.094	0.214	0.223
Incremental cost over CCGT	$/kWh		0.04	0.01	0.11	0.06	0.18	0.19

Source: World Bank 2013.
Note: CCGT = combined-cycle gas turbine; CSP = concentrated solar power; kW = kilowatt; kWh = kilowatt-hour; mmBTU = million British thermal units; O&M = operation and maintenance; OCCT = open-cycle combustion turbine; SCF = statement of cash flow; HFO = heavy fuel oil.

(like Helwan) are designed to use heavy fuel oil (HFO) as the supplementary fuel (Mazout). But if, in fact, gas shortages were to occur, then the gas that *is* available would be used at the most efficient projects (at CCGTs) and curtailed at gas-*steam* plants. Therefore the counterfactual is a combination of 20 percent HFO (at steam cycle projects) plus 80 percent natural gas (at CCGTs).

There are great hopes that the high capital costs of CSP can be significantly reduced over present levels. But as shown in table 8.6, even if costs were just half of what they are today, and taking into account the avoided local environmental health damages of gas (and HFO) generation, there remains an *economic* incremental cost of $127 million.

Table 8.6 Impact of Capital Cost Reductions

Capital cost reduction	*CSP capital cost*	*ERR*	*ERR + local damage cost*	*Incremental cost (economic) (1)*	*ERR + local + GHG damage cost ($30/ton)*
[%]	*$/kW*	*[%]*	*[%]*	*$ million*	*[%]*
0	7,233	–3.3	–1.4	–412	0.1
10	6,510	–2.6	–0.7	–355	0.9
20	5,787	–1.8	0.2	–298	1.9
30	5,063	–0.8	1.2	–241	3.0
40	4,340	0.3	2.4	–184	4.3
50	3,617	1.8	3.9	–127	6.1

Source: World Bank 2013.
Note: (1) Incremental cost *to* the Arab Republic of Egypt includes avoided local environmental damages. CSP = concentrated solar power; ERR = economic rate of return; GHG = greenhouse gas; kW = kilowatt.

Table 8.7 Incentive Mechanisms

Item	*NREA*	*Competitive bidding*	*Feed-in tariff*
Program size	2,200 MW	2,500 MW	2,500 MW
Single wind farm size	Large (100–400 MW)	Large ten modules (each of 250 MW)	Medium and Small below 50 MW
Developer	NREA	Private (most probably international)	Private (focus on local)
Finances	Governmental and soft financing from international development agencies	Commercial finance	Commercial finance
Tariff setting	Proposed by EgyptERA and approved by the Cabinet of Ministers	According to the bid outcome	Proposed by EgyptERA and approved by the Cabinet of Ministers
Contracting period	20 years	Long-term PPA mostly for 20 years	20/15 (under study) years
Off taker	Grid	Grid	Grid or distribution system
O/M	NREA	Developer	Developer
Construction responsibility	NREA through EPC	Developer	Developer

Source: NREA.
Note: EPC = engineering, procurement, and construction; EgyptERA = Egyptian Electric Utility and Consumer Protection Regulatory Agency; IPPs = independent power producers; NREA = New and Renewable Energy Authority; MW = megawatt; PPA = power purchase agreement.

Design of Incentive Schemes

The governmental wind projects are developed, owned, and operated by the NREA. These projects are financed by multilateral and bilateral financing agencies as well as national government concessional financing and grants, and are open to public bidding. The commercial wind program consists of two components: a competitively bid large-scale IPP commercial wind program and a commercial wind program for small-scale IPPs benefiting from a feed-in tariff (FIT). The key difference between the three schemes is described in table 8.7.

The competitively bid commercial wind program for large-scale IPPs (which is currently approved and in the planning phase) plans to select experienced IPPs through competitive bidding to build, own, and operate (BOO) wind power plants for a term of 20–25 years on predetermined sites (on the shores of the Gulf of Suez and the east and west of the Nile River). The Egyptian Electricity Transmission Company (EETC) will purchase the energy generated from the wind power plant throughout the duration of the agreement, according to the terms and conditions of the PPA. These particular IPP projects benefit from newly approved government incentives.

The commercial wind program for small-scale IPPs (benefiting from a FIT) is currently planned but not yet in effect, pending the passing of legislation. It will be applied to wind farms of up to 50 MW to be executed either on predetermined sites allocated by the Egyptian government or on private sites owned by the developers. The EETC/distribution companies are obliged to purchase all the generated energy from the RE power plant through a declared tariff, which allows the investor to achieve a predefined return on equity. This tariff is divided into blocks: the first is constant for all projects under the FIT, and the second depends on the sites' capacity factors to achieve the predefined return on equity.

A third-party scheme is also included. It is similar to the self-supply approach that served as a catalyst for wind financing and uptake in Mexico. The scheme includes a bilateral agreement between the IPP wind power project and its direct customers, while the EETC provides third-party access to transfer power from the power plant to its customers. Additionally, the EETC will purchase any excess wind power and provide supplemental energy to customers during low wind production time (NREA 2010). The first of these projects is to be undertaken by Italgen, the energy generation arm of Italian cement giant Italcementi. Italgen plans to invest €140 million for a 120 MW facility to be constructed along the shores of the Red Sea in the Gulf El Zeit area and supply energy to the group's Suez Cement Plant. The success of future self-supply in Egypt will depend upon pending legislation, as well as the ability to access government-controlled land where high wind speeds make wind power development feasible.

Wind capacity installed to date has been provided by NREA-led government projects. With the first government phase of wind development under way, Egypt is now focusing on its first phase of commercial IPP business models as it continues to build RE capacity (tables 8.8–8.10). These power projects benefit from the following government incentives approved by the Supreme Council of Energy:

- All permits for land allocation already obtained by the NREA.
- Land-use agreements signed with the investor against payment equivalent to 2 percent of the annual energy generated from the project.
- Environmental impact assessments (including bird migration studies) prepared by the NREA in cooperation with international consultants and financed by the German Development Bank (KfW).

Table 8.8 Wind Projects Currently under Development by the Egyptian Government

Location	*Installed capacity (MW)*	*Funding agencies*	*Expected year of operation*	*Status*
Gabal El Zayt	200	KfW, EIB, European Commission	April 2014	• All construction contracts were signed and the project is under construction.
Gabal El Zayt	220	Japan	n.a.	• A soft loan agreement was signed with Japan in March 2010. • An Environmental Impact Assessment study has been finalized. • Bidders submitted their proposals on January 28, 2013.
	120	Spain	End of 2016	• A €120 million loan was signed in February 2008 with the Spanish government. • The project is exclusive to the Spanish market. • The feasibility and environmental impact assessment study has been finalized. • In November 2012 the Spanish government appointed a consultant to assist in preparing tender documents. • The tender will be issued in the first half of 2013.
Gabal El Zayt	200	KfW, EIB, French Development Agency, European Union	End 2015	• A grant of €10 million from the Neighborhood Investment Facility is secured. • The German government has agreed to provide €140 million. • The feasibility study is expected to be finalized by September 2013.
Gabal El Zayt	200	Masder		• The project will be financed by Masder and the NREA, $220 million each. • A fund of $1 million from the CTF was signed in February 2012 to finance a feasibility study. • The feasibility study is expected to be finalized by September 2015.
Gabal El Zayt	200	French Development Agency, KfW	2016	• n.a.
West of Nile	200	Japan	2017	• A 4,242 m^2 lot west of the Nile River is designated for the project. • In August 2010 a Japanese consultant was appointed to carry out a feasibility and environmental impact assessment. • Ten measuring stations at 80 meters height were installed in the area for wind speed measurement and the study will be finalized in July 2013.

Source: NREA.
Note: CTF = Clean Technology Fund; EIB = European Investment Bank; KfW = German Development Bank; m^2 = square meters; MW = megawatt; NREA = New and Renewable Energy Authority.
n.a. = not applicable.

Table 8.9 Wind Projects That Will Be Built and Operated by the Private Sector on a BOO Basis to Supply the National Electricity Network

Location	*Installed capacity (MW)*	*Expected year of operation*	*Status*
Gulf of Suez	250	Mid-2015	• Ten developers were shortlisted in December 2009. • Measurement studies will be completed by mid-2013.
Gulf of Suez	500	n.a.	• Prequalification document for the second competitive bidding were to be announced in the second half of 2013.

Source: NREA.
Note: BOO = build, own, operate; MW = megawatt.
n.a. = not applicable.

Table 8.10 Wind Projects to Be Built and Operated by the Private Sector for Self-Consumption or to Directly Sell to Consumers

Location	*Installed capacity (MW)*	*Owner*	*Expected year of operation*	*Status*
Gulf of Suez	120	Italgen	2014	• Agreement is signed to build a wind farm to feed the Suez Cement Company. • Environmental study was finalized in April 2010. • In June 2012 the land usufruct agreement was signed.
Gulf of Suez	600	Not determined yet		• The NREA announced the availability of 6 × 15 km^2 pieces of land to establish 100 MW wind farm projects in each on an auction basis.

Source: NREA.
Note: km^2 = square kilometers; MW = megawatt; NREA = New and Renewable Energy Authority.

- All RE equipment and spare parts exempted from customs duties and sales taxes.
- Long-term PPAs of 20–25 years, signed.
- The Central Bank of Egypt to guarantee all financial obligations of the EETC under the PPA.
- The project to benefit from carbon credits.
- The project company to receive licenses for power generation from the Egyptian Electric Utility and Consumer Protection Regulatory Agency (EgyptERA).

Despite the social and political revolution of early 2011 and a lack of final legislation, Egypt moved forward in launching its first 250 MW BOO IPP project and part of the first tranche of a 2,500 MW procurement competitive bidding scheme. This is the first private sector power producer venture in renewable energy in Egypt, and the first in which project developers benefit from ministry-approved government incentives.

A unit to be established within the EETC will be responsible for the sale of the certified emission reduction (CER) credits of the IPP projects. Given that the environmental attributes of the IPP projects remain the property of the Government of Egypt, the proceeds of the CER credits sale remain within the government treasury and do not contribute to the overall IPP financing package.

As part of the RE strategy legislation, and to encourage investors to establish RE power plants, the fund might cover:

- Full or partial deficit between the RE cost and market prices.
- Exchange rate risk, in case the cost is transferred—whether fully or partially—to consumers.
- Guarantee of the transmission company payments.
- Financial support to pilot projects.
- Research and development for renewable energy.

The main sources of the fund include:

- Subsidies currently given to fossil fuels used in power generation.
- The state budget.
- Donations.
- Investment of the fund money.

The current selling price of the electricity produced from wind energy is 17.6 piaster/kWh (including 2 piaster/kWh from fuel saving), while the average production cost is 38 piaster/kWh—hence, the need to fund the substantial incremental cost.

Carbon Accounting

As noted above, the avoided costs of carbon are critically dependent on the thermal alternative under consideration. Table 8.11 shows the avoided cost of carbon for the Kom Ombo CSP, assessed against a thermal alternative consisting of a mix of gas and HFO at varying gas prices. At $6/mmBTU (that is, the current export price of Egyptian gas to Jordan) at a 20 percent HFO share, the avoided cost of carbon is $267/ton.

This may be contrasted to the avoided cost of wind in Egypt, shown in table 8.12. For the same thermal alternative, wind is a win-win! There is a net economic benefit to wind against a set of thermal generation assumptions (indicated by negative [shaded] values in the table).

Table 8.11 Avoided Cost of Carbon: Concentrated Solar Power

	Gas price, $/mmBTU							
HFO share (%)	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*
0	448	429	411	393	374	356	338	319
10	363	349	335	321	307	293	279	264
20	300	289	278	267	256	245	235	224
30	251	243	234	226	218	209	201	192
40	213	206	200	193	187	180	174	168
50	181	177	172	167	162	157	152	147

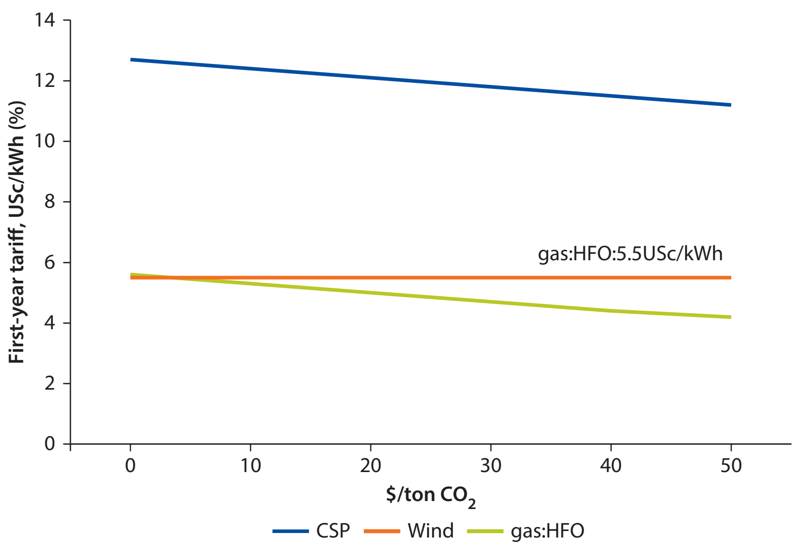
Source: World Bank 2013.
Note: HFO = heavy fuel oil; mmBTU = million British thermal units.

Table 8.12 Avoided Cost of Carbon: Wind

	Gas Price, $/mmBTU							
HFO share (%)	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*
0	76	57	39	21	3	−16	−34	−52
10	46	32	18	4	−10	−24	−38	−52
20	24	14	3	−8	−19	−30	−41	−52
30	8	−1	−9	−18	−26	−34	−43	−51
40	6	−12	−19	−25	−32	−38	−45	−51
50	−17	−22	−26	−31	−36	−41	−46	−51

Source: World Bank 2013.
Note: HFO = heavy fuel oil; mmBTU = million British thermal units.

Figure 8.12 Impact of CDM on Incremental Costs of Wind and CSP



Source: World Bank 2013.
Note: CDM = clean development mechanism; CO_2 = carbon dioxide; CSP = concentrated solar power; HFO = heavy fuel oil; kWh = kilowatt-hour; USc = U.S. cents.

Figure 8.12 shows the impact of potential clean development mechanism (CDM) revenues on the financial internal rate of return (FIRR) and incremental costs. In the case of CSP, under an optimistic case of an Emissions Reduction Purchase Agreement (ERPA) covering 70 percent of carbon dioxide (CO_2) reductions for 14 years, and CER revenue at $20/ton CO_2, the tariff decreases from 12.7 cents/kWh to 12.1 cents/kWh; but in the case of wind under the same assumptions, the tariff falls below that of the gas or HFO alternative. Without carbon revenue the wind tariff is slightly above that of the thermal alternative, so CDM additionality could likely be demonstrated.

But for the more expensive CSP, CDM revenues (if they were available) would do little to buy down the incremental costs. While Egypt derives a financial

Table 8.13 Incremental Financial Cost to the Arab Republic of Egypt, $ million (as NPV)

CER price, \$/ton CO_2	*CSP, \$ million*	*Wind,\$ million*
0	−194	5.8
10	−185	14.8
20	−176	23.8
30	−167	32.8
40	−158	41.8
50	−149	50.8

Source: World Bank 2013.
Note: CER = certified emission reduction; CO_2 = carbon dioxide; CSP = concentrated solar power; NPV = net present value.

surplus of \$5.8 million for wind even without the CER revenues (under the same concessionary financing package as provided to the CSP), for CSP the financial balance is significantly negative. At \$30/ton CER revenue, Egypt would still incur \$167 million in incremental costs—to be carried either by the government or the consumers. The ability to buy down the incremental costs by concessionary financing is discussed in more detail below (table 8.13).

Incremental Costs and Their Recovery

Problems in Traditional Financial Analysis

The conventional financial analysis encountered in project appraisals of RE projects is generally unsatisfactory. Most often one finds a calculation of the project financial return more or less following the format of the economic analysis—adding back in taxes and duties, and then comparing this to some calculation of the weighted average cost of capital (WACC). If the resulting FIRR exceeds the WACC, the project is declared financially feasible. Only rarely does one find an assessment of the annual incremental financial cash flows that must be covered either by tariff increases or by governments through the state budget.

The problem with a WACC calculation is that it looks only at interest rates and not the tenor of loans. But the tenor of loans is rarely coincident with the presumed financial life—and in the case of project financing the WACC tells us nothing about the impact of short loan tenors in typical commercial financings. Worse, the tenors of concessionary loans (and notably carbon finance) may be as much as 40 years, which significantly affects the actual cost of capital. A WACC calculation for a large utility (like Perusahaan Listrik Negara [Indonesian State Electric Utility Company] [PLN] in Indonesia), with a complex mix of debt financing and bond issuances, may be meaningful, but for a project-financed IPP (or subsidiary project company that is supposed to run along commercial lines) one needs to look at the actual proposed financial structure to make informed judgments about financial costs. Comparisons of average levelized costs can be similarly deceptive since they are very sensitive to the discount rate used.

Thus to make a realistic assessment of the financial implications of an RE project, the best approach is to compare the actual financial flows of the proposed RE project against the *actual* financial flows of the thermal alternative.[2] So in the case of the Kom Ombo project, we compare the cash flows of the CSP under the proposed financing scheme with the cash flows of the thermal generation alternative (in this case a gas combined-cycle combustion turbine [CCCT]) under a plausible financing scheme for that alternative (in this case financed by the International Bank for Reconstruction and Development [IBRD]—a plausible counterfactual since the World Bank has indeed recently financed a gas CCGT in Egypt). Such a financial model calculates the tariff necessary to achieve a given equity return, and reveals a first-year tariff requirement of 4.12 cents/kWh. The year-by-year revenue requirements for the fossil-fuel project then provide the yardstick against which the year-by-year tariff requirements for the RE project can be measured.

Who Pays?

Who pays for the incremental cost of renewable energy is conveniently displayed in table 8.14, in which the financial costs and benefits are reconciled among the stakeholders. The columns represent the various stakeholders and the rows, individual transactions—here under the assumption of domestic financing of the Kom Ombo CSP. The net impact on the stakeholders is listed in the bottom row of the table. In the case of the CSP company (whoever that may be), it is assumed that the financial surplus (return) is passed back to the government as dividends, so the net impact on the CSP is always shown as zero. All entries are in million dollars, expressed as lifetime present values at a 10 percent discount rate. In column [12] we also show the environmental benefits, namely the sum of the local avoided environmental damage costs and the avoided GHG emissions (valued at $30/ton CO_2).

The cost to the consumer (at the current assumed retail tariff of 3.5 cents/kWh) is shown in row [2]—$95 million. The consumer, however, derives a benefit of $170 million (which is what he or she would pay for the equivalent amount of electricity in the absence of the subsidy): the difference of $75 million is the consumer surplus.[3]

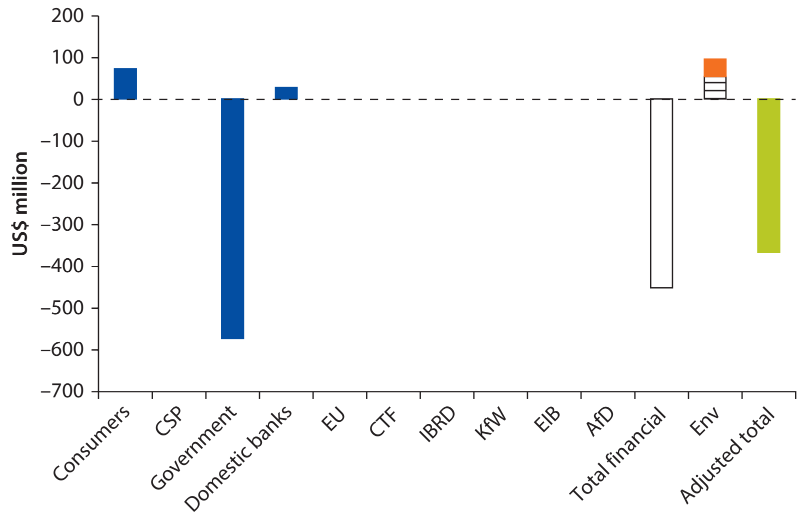
This underscores the impossibility of Egypt investing in a CSP (or any other expensive RE project) without the assistance of the international community. There is a small gain to the domestic banks (because the assumed interest rate of 12 percent exceeds the discount rate). The government gains from income taxes; but even if there were an income tax exemption, there is no change in the net result for Egypt: the total net financial impact on Egypt is $464 million (figure 8.13). Of course, when the environmental benefits are added back in, the net result is less negative (minus $373 million), but the inclusion of global social environmental costs is unlikely to impress ministries of finance. CDM revenue would be real cash, and is relevant to actual financial flows (but as we have seen in section "Carbon Accounting," the prospects of significant CDM revenue in the next few years are poor and dwindling, and therefore not considered here). The required CSP tariff in the absence of international financial institution (IFI) and concessionary finance is 25.1 cent/kWh.

Table 8.14 Reconciliation of Economic and Financial Flows, $ Million, as NPV at 10 Percent Discount Rate (Domestic Finance Only)

	Consumers	*CSP*	*Government*	*Domestic banks*	*EU*	*CTF*	*IBRD*	*KfW*	*EIB*	*AfDB*	*Total finance*	*Env*	*Adjusted total*
	[1]	*[2]*	*[3]*	*[4]*	*[5]*	*[6]*	*[7]*	*[8]*	*[9]*	*[10]*	*[11]*	*[12]*	*[13]*
1. Benefits (cost of CCGT)	170	0	0	0	0	0	0	0	0	0	170	0	170
2. Consumer cost of electricity	–95	0	95	0	0	0	0	0	0	0	0	0	0
3. Tariff revenue, CSP	0	781	–781	0	0	0	0	0	0	0	0	0	0
4. Grants	0	0	0	0	0	0	0	0	0	0	0	0	0
5. Loan disbursements	0	456	0	–456	0	0	0	0	0	0	0	0	0
6. Principal repayments	0	–373	0	373	0	0	0	0	0	0	0	0	0
7. Interest repayments	0	–120	0	120	0	0	0	0	0	0	0	0	0
8. OPEX	0	–63	0	0	0	0	0	0	0	0	–63	0	–63
9. Equity	0	114	–114	0	0	0	0	0	0	0	0	0	0
10. Construction costs	0	–571	0	0	0	0	0	0	0	0	–571	0	–571
11. Income tax	0	–104	104	0	0	0	0	0	0	0	0	0	0
12. Dividends	0	–121	121	0	0	0	0	0	0	0	0	0	0
13. Local environmental benefits	0	0	0	0	0	0	0	0	0	0	0	40	40
14. GHG benefits	0	0	0	0	0	0	0	0	0	0	0	51	51
15. Total	75	0	–576	37	0	0	0	0	0	0	–464	91	–373

Source: World Bank 2013.
Note: AfDB = African Development Bank; CCGT = combined-cycle gas turbine; CSP = concentrated solar power; CTF = Clean Technology Fund; EIB = European Investment Bank; EU = European Union; Env = environmental benefits (GHG+local); IBRD = International Bank for Reconstruction and Development; KfW = German Development Bank; NPV = net present value; OPEX = operating expenses.

Figure 8.13 Stakeholder Impacts, No Foreign Assistance



Source: World Bank 2013.
Note: AfD = French Development Assistance; CCGT = combined-cycle gas turbine; CSP = concentrated solar power; CTF = Clean Technology Fund; EIB = European Investment Bank; EU = European Union; Env = environmental benefits (GHG + local); IBRD = International Bank for Reconstruction and Development; KfW = German Development Bank; NPV = net present value; USc = U.S. cents.

Salient indicators

Indicator	*Value*
Tariff, USc/kWh	25.1
Actual avoided cost of carbon, $/ton	267
Financial package	Private finance only
Share of incremental costs	
Egypt, Arab Rep. (Govt + consumers + domestic banks)	100% ($464 million)
International community	0%

Buying Down the Incremental Costs with Concessionary Finance

From this starting point we can now assess the degree to which the incremental costs can be bought down by the international community. Table 8.15, taken from the CSP feasibility study, shows the likely sources of IFI assistance for Kom Ombo.

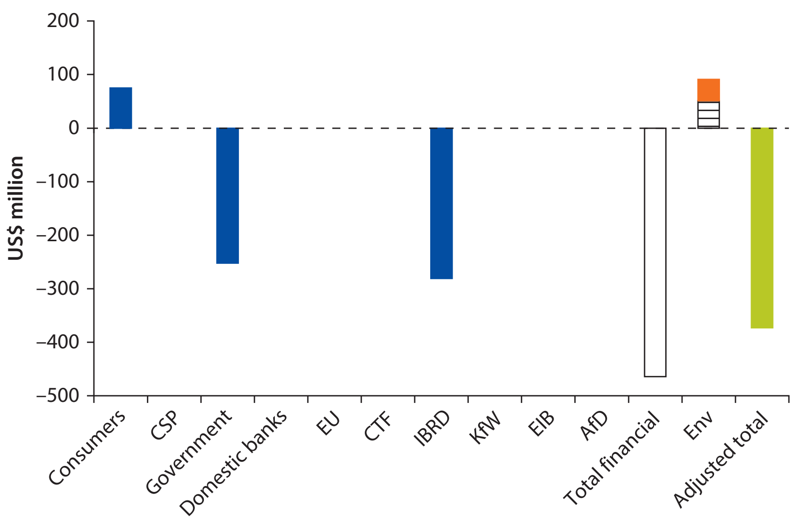
For example, if the entire debt ($579 million) were taken up by the IBRD, the CSP tariff (to achieve 5 percent FIRR) falls dramatically to 12.2 cents/kWh, and the impact on Egypt falls to $183 million (figure 8.14).[4] Note that in this scenario, the CCGT is also assumed to be financed by the IBRD. Of course this leaves open the question of why the IBRD would make this magnitude of resources available for a GHG benefit worth $51 million (at $30/ton CO_2). The IBRD can thus be said to potentially buy down the incremental financial cost by half!

Table 8.15 Financing Options

	Interest rate, %	*Grace, years*	*Repayment period, years*	*Currency*	*Availability*
CTF	0.25	10	30	$	100
IBRD	2.75	6	21.5	$	170
AfDB	2.75	6	20	$	170
KfW	3.00	4	15	Euro	174
EIB	3.15	3	20	Euro	100
AfD	3.70	4	20	Euro	50
NIF(1)	grant			Euro	25

Source: CSP-FS, tables 8.2 and 8.3. IBRD and CTF terms as in the World Bank Egypt Wind Development Project.
Note: AfDB = African Development Bank; AfD = French Development Assistance; CTF = Clean Technology Fund; EIB = European Investment Bank; IBRD = International Bank for Reconstruction and Development; KfW = German Development Bank; NIF = EU Neighbourhood Investment Facility.

Figure 8.14 Impact of IBRD Financing



Source: World Bank 2013.
Note: AfD = French Development Assistance; CCGT = combined-cycle gas turbine; CSP = concentrated solar power; CTF = Clean Technology Fund; EIB = European Investment Bank; EU = European Union; Env = environmental benefits (GHG + local); GHG = greenhouse gas; IBRD = International Bank for Reconstruction and Development; KfW = German Development Bank; NPV = net present value; USc = U.S. cents.

Salient indicators

Indicator	*Value*
Tariff, USc/kWh	12.2
Financial package	Private finance only
Share of incremental costs	
Egypt, Arab Rep (Government + consumers + domestic banks)	39% ($183 million)
International community	61% ($281 million)

Table 8.16 shows the application of funds proposed in the CSP-FS—which includes a €25 million grant from the European Union (EU) Neighbourhood Investment Facility (NIF). The table also shows the more recent proposal of the World Bank, which increases the carbon finance funding (Clean Technology Fund, CTF) by $43 million, to $123 million (with a corresponding decrease in the IBRD financing).

Table 8.17 shows the impact of all the various financing options, assuming (for sake of comparison) that the entire debt (80 percent of the total investment cost) is assumed by each IFI. With financing by domestic banks, Egypt bears 100 percent of the incremental cost ($464 million, as net present value [NPV]). Carbon finance is the most effective in buying down the cost: if 100 percent of the debt were of the CTF, the CSP tariff would fall to 7.4 cents/kWh, and the

Table 8.16 Proposed Application of Funds

	As per FS		*Revised CTF*	
	%	*$ million*	*%*	*$ million*
Equity	*19.8*	143.2	*19.8*	143.2
Domestic debt	*0.0*	0.0	*0.0*	0.0
CTF	*10.6*	76.7	*17.0*	123.0
IBRD/AfDB	*28.2*	204.0	*21.8*	157.7
KfW	*20.2*	146.1	*20.2*	146.1
EIB	*10.6*	76.7	*10.6*	76.7
AfD	*6.2*	44.8	*6.2*	44.8
Grants	*4.4*	31.8	*4.4*	31.8
Total		723		723.0

Source: CSP-FS (Fraunhofer and Lahmeyer International 2012), table 8.3.
Note: AfDB = African Development Bank; AfD = French Development Assistance; CTF = Clean Technology Fund; EIB = European Investment Bank; FS = feasibility study; IBRD = International Bank for Reconstruction and Development; KfW = German Development Bank.

Table 8.17 Comparison of Effectiveness in Buying Down the Incremental Costs

	CSP tariff	*Egypt, Arab Rep.*		*Others*	*Total*
	Cents/kWh	*$ million*	*%*	*$ million*	*$ million*
Domestic debt	25.1	464	100	0	464
CTF	7.4	60	13	404	464
IBRD/AfDB	12.2	183	39	281	464
KfW	17.1	291	63	172	464
EIB	16.5	277	60	186	464
AfD	16.8	286	62	178	464
Proposed	13.2	204	44	260	464
Revised	12.7	194	42	270	464

Source: World Bank 2013.
Note: AfDB = African Development Bank; AfD = French Development Assistance; CTF = Clean Technology Fund; EIB = European Investment Bank; IBRD = International Bank for Reconstruction and Development; KfW = German Development Bank; kWh = kilowatt-hour.

share of the incremental cost carried by Egypt (by some combination of consumers and government) is just 13 percent, or $60 million. As noted, if the IBRD accounted for all the debt, it would be the second-most effective in bringing down the CSP tariff to 12.2 cents/kWh (as noted above).

Impact of the Proposed Financing CSP Packages

The financing package proposed in the FS brings is little different to 100 percent IBRD finance—the low cost of CTF is offset by higher finance costs from KfW, EIB and AfD. The required first-year CSP tariff is slightly higher at 12.7 cents/kWh. Table 8.18 and figure 8.15 show the resulting distribution of costs and benefits.

While the above reconciliation of financial flows shows the impact as lifetime NPVs (and therefore subject to the problems of choosing discount rates, as discussed in chapter 2), from the Government of Egypt's perspective what matters are the actual incremental financial flows required each year to cover the difference between purchasing CSP power and purchasing gas power. These are summarized in table 8.19: the 10-year cost is $348 million, starting in 2017 with an additional subsidy requirement of $32.5 million.

It is clear that subsidies of this magnitude are unlikely to be acceptable to the government, and that a much higher proportion of grant is required. But even with a grant of 50 percent of the total (higher than the presently proposed $31.8 million–$362 million, with the balance financed just by the IBRD and CTF), Egypt's incremental cost is still $46 million in NPV terms, with a ten-year (undiscounted total of $263 million). The annual subsidy requirement is $6.9 million in 2017, increasing to $7.9 million by 2026 (table 8.20). At this level of concessionary aid and grants, the burden of incremental costs to Egypt falls to a more reasonable level—but the likelihood of grants and CTF of this magnitude are close to zero.

Conclusions

Avoided Cost of Carbon

We have already noted in chapter 2 (table 2.8) that the carbon valuation for CSP is so much higher in Egypt ($267/ton), than in South Africa ($115–$155/ton CO_2, depending on the technology configuration and storage provided): it is a simple consequence of what fossil fuel is displaced: in Egypt natural gas, in South Africa coal. The GHG emissions factor for coal is three times higher per kilowatt-hour than for a CCGT. In short, whether CSP has a reasonable (and affordable) avoided cost of carbon depends on the technology against which it competes, and on the economic cost of fossil fuel.

Concessionary Finance

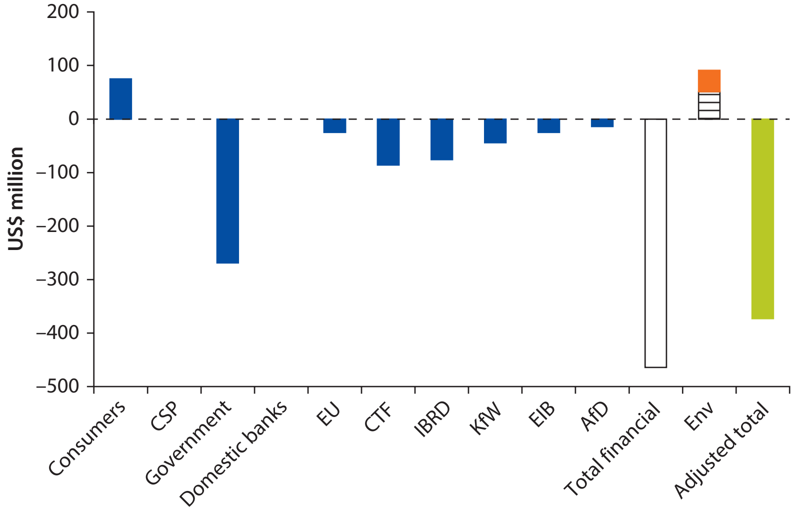
Without concessionary finance, expensive RE technologies impose significant incremental costs on the host country—and it is very hard to argue that given Egypt's current political and economic situation, it should bear a significant share of the incremental costs of CSP. It is even more difficult to explain why Egypt

Table 8.18 Reconciliation of Economic and Financial Flows ($ Million, as NPV at 10 Percent Discount Rate): Revised Finance Package

	Consumers	*CSP*	*Government*	*Domestic banks*	*EU*	*CTF*	*IBRD*	*KfW*	*EIB*	*AfD*	*Total finance*	*Env*	*Adjusted total*
1. Benefits (cost of CCGT)	170	0	0	0	0	0	0	0	0	0	170	0	170
2. Consumer cost of electricity	−95	0	95	0	0	0	0	0	0	0	0	0	0
3. Tariff revenue, SP	0	395	−395	0	0	0	0	0	0	0	0	0	0
4. Grants	0	25	0	0	−25	0	0	0	0	0	0	0	0
5. Loan disbursements	0	433	0	0	0	−97	−124	−115	−61	−35	0	0	0
6. Principal repayments	0	−128	0	0	0	9	23	55	26	14	0	0	0
7. Interest repayments	0	−61	0	0	0	2	25	17	10	7	0	0	0
8. OPEX	0	−63	0	0	0	0	0	0	0	0	−63	0	−63
9. Equity	0	113	−113	0	0	0	0	0	0	0	0	0	0
10. Construction costs	0	−571	0	0	0	0	0	0	0	0	−571	0	−571
11. Income tax	0	−29	29	0	0	0	0	0	0	0	0	0	0
12. Dividends	0	−115	115	0	0	0	0	0	0	0	0	0	0
13. Local environmental benefit	0	0	0	0	0	0	0	0	0	0	0	40	40
14. GHG benefit	0	0	0	0	0	0	0	0	0	0	0	51	51
15. Total	75	0	−269	0	−25	−86	−76	−44	−25	−14	−464	91	−373

Source: World Bank 2013.
Note: AfDB = African Development Bank; CCGT = combined-cycle gas turbine; CSP = concentrated solar power; CTF = Clean Technology Fund; EIB = European Investment Bank; EU = European Union; Env = environmental benefits (GHG+local); GHG = greenhouse gas; IBRD = International Bank for Reconstruction and Development; KfW = German Development Bank; NPV = net present value; OPEX = operating expenses.

Figure 8.15 Revised Finance Package



Source: World Bank 2013.
Note: AfD = French Development Assistance; CCGT = combined-cycle gas turbine; CSP = concentrated solar power; CTF = Clean Technology Fund; EIB = European Investment Bank; EU = European Union; GHG = greenhouse gas; IBRD = International Bank for Reconstruction and Development; KfW = German Development Bank; NPV = net present value; USc = U.S. cents.

Salient indicators

Indicator	*Value*
Tariff, USc/kWh	12.7
Financial package	Proposed package
Share of incremental costs	
Egypt, Arab Rep. (Government + consumers + domestic banks)	42% ($194 million)
International community	58% ($270 million)

Table 8.19 Incremental Financial Flows for Tariff Support, Revised Financial Package

		Total	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*
Energy sold	GWh		449	447	445	443	440	438	436	434	432	430
	Cents/kWh		**12.7**	**13.0**	**13.2**	**13.5**	**13.7**	**14.0**	**14.3**	**14.6**	**14.9**	**15.2**
	$ million	610	57	58	59	60	61	61	62	63	64	65
Gas: HFO tariff	Cents/kWh		**5.5**	**5.6**	**5.7**	**5.8**	**5.9**	**6.0**	**6.2**	**6.3**	**6.4**	**6.5**
	$ million	263	24.5	24.9	25.3	25.7	26.0	26.4	26.8	27.2	27.6	28.0
Net cost to government	$ million	348	32.5	33.0	33.5	34.0	34.5	35.0	35.5	36.1	36.6	37.1

Source: World Bank 2013.
Note: GWh = gigawatt-hour; HFO = heavy fuel oil; kWh = kilowatt-hour. The total is not discounted.

Table 8.20 Tariff Support, 50 Percent Grant

		Total	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*
Energy sold	GWh		449	447	445	443	440	438	436	434	432	430
CSP tariff	Cents/kWh		**7.0**	**7.1**	**7.3**	**7.4**	**7.6**	**7.7**	**7.9**	**8.0**	**8.2**	**8.4**
	$ million	337	31	32	32	33	33	34	34	35	35	36
Gas: HFO tariff	Cents/kWh		**5.5**	**5.6**	**5.7**	**5.8**	**5.9**	**6.0**	**6.2**	**6.3**	**6.4**	**6.5**
	$ million	263	24.5	24.9	25.3	25.7	26.0	26.4	26.8	27.2	27.6	28.0
Net cost to government	$ million	74	6.9	7.0	7.2	7.3	7.4	7.5	7.6	7.7	7.8	7.9

Source: World Bank 2013.
Note: GWh = gigawatt-hour; CSP = concentrated solar power; HFO = heavy fuel oil. The total is not discounted; kWh = kilowatt-hour.

should pay for CSP when the same quantity of GHG emission reductions can be achieved at a third of the incremental cost by wind—and indeed Egypt has some of the best wind resources anywhere in the world, with annual plant factors in excess of 40 percent.

Of course, it is true that the presently high cost of CSP can only be brought down by a global commitment to the technology, but it is hardly an argument that Egypt's (poor) consumers should carry the costs of this technology development.

Notes

1. Million British thermal units.
2. One often hears the argument that a presentation of the *project* financial return is better because it is independent of the financial package that may be developed for the project, the precise details have yet to be negotiated, or (where the project is proposed by a state-owned utility) the returns on equity have no meaning. These are all feeble rejoinders, and particularly so in the case of an RE project with high incremental costs: the specifics of the financing package are central to project feasibility.
3. Of course, if the subsidy on electricity were eliminated, the consumer surplus would decrease. But this is more than offset by a reduction in production costs, the difference being the deadweight loss (see box 5.3 for explanation). But subsidies on fossil fuels should be reduced whether or not a CSP is implemented.
4. Needless to say, higher FIRR have significant impacts on the tariff. For the same scenario with 10 percent equity return, the required IPP tariff increases from 12.2 Cents/kWh to 13.8 cents/kWh.

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CHAPTER 9

Case Study: Brazil

Sector Background

Brazil offers a special case for renewable energy (RE) because of its innovations to make its renewable market competitive based on the predominance of hydroelectricity. Brazil relies on hydroelectricity for most of its power supply, but the proportion of total supply from hydropower has declined steadily from over 90 percent in 1998 to 80 percent in 2012.

Before 1995 the power sector was predominantly government controlled with vertically integrated companies. The federal company Eletrobrás and several state companies owned and operated most of the generation, transmission, and distribution in the country. The reforms of the electric power sector in Brazil were set in motion by the ratification of the Electricity Concession Law No. 9074 early in 1995. Eletrobrás retained the ownership of the transmission grid, the Brazilian part of the binational Itaipu Dam and hydroelectric power station, the nuclear power plants, and the Centro de Pesquisas de Energia Elétrica's (CEPEL's) research and development activities.

The law provided for the unbundling of the sector—principally the functions of the dominant power generator and transmitter, Eletrobrás. Between 1995 and 1998 key institutions were created, including the Brazilian Electricity Regulatory Agency (ANEEL) as an independent regulatory entity, the National Energy Policy Council (CNPE) to propose national energy policies, and the system operator (ONS) to control power generation and transmission activities in the interconnected power system through a tight pool dispatch system, the Wholesale Electric Energy Market (MAE), which was created to promote the accounting of agents' transactions in the multilateral short-term market under market rules.

During 2001–02 Brazil suffered one of its worst droughts, which forced the government to implement a strict rationing program for nine months to reduce the load in 80 percent of the country by 20 percent. Special authority was given to an emergency committee in charge of the program. The country went from a situation of power supply scarcity to one of surplus, helped by some emergency generation capacity installed during the drought. In 2004 the government implemented a second wave of power market reforms, known as the new model, to address some of the problems associated with incentives for installing new generation capacity, improving competitive conditions, and strengthening the institutional framework. The main characteristics of this new model included an emphasis on the forward contract market to induce additions of new generation capacity, the strengthening of the regulatory agencies, and the requirement of mandatory energy auctions for distribution companies to cover 100 percent of all loads. The last requirement meant that distributors could acquire energy only through auctions for contracts of three to five years, which reduced risks for generation investors and promoted competition. Benchmark prices were used for passing through wholesale power costs to consumers procured under the new energy auctions, as the supply costs reflected the average price of all contracts.

The two models differed in significant ways. The original reform model (implemented in 1995) was characterized by the opening up of the power market (with emphasis on the privatization of all the companies) and system expansion (to be achieved through short-term price signals and contracting obligations). In the new model (implemented in 2004) the emphasis was on coexistence between state-controlled and private companies, with the subsidiaries under Eletrobrás holding 69 percent of total transmission lines and about 68 percent of Brazilian distribution assets controlled by private sector companies (Vagliasindi and Besant-Jones 2013).

Renewable Energy Development

Brazil has the second-largest proven oil reserves in South America (12.9 trillion cubic feet of proven natural reserves), but remains a net energy importer. Brazil's RE power capacity, including large-scale hydropower, is the fourth largest in the world. Its biomass power capacity is the second largest. The 4.8 gigawatts (GW) of biomass cogeneration plants at sugar mills generated more than 14 terawatt-hours (TWh) of electricity in 2009, nearly 6 TWh of which was excess fed into the grid. Also, 606 megawatts (MW) of wind farm capacity was installed, with another 450 MW under construction. Other than for small hydro (for which a detailed master plan is available [PECC1 2001]) and agricultural waste (biomass, which can be reliably inferred from official data on agricultural production), other RE resources suitable for grid-connected projects are either largely unknown (if not quite speculative, as in the case of geothermal), too small to make any significant contribution (such as landfill gas), or vastly overestimated in light of existing evidence (as in the case of wind, where estimates of "physical potential" have little practical meaning).

The hydropower sector is highly developed in Brazil. This (including small-scale hydro) is the RE sector that requires the least amount of financing. The 10-year Energy Research Corporation (EPE) plan predicts that installed capacity from hydroelectric plants will rise from just less than 85 GW at present to more than 115 GW. The principal contributor to the increase in hydropower will come from the extra capacity generated by the proposed Belo Monte dam, to be built on the River Xingu through a public-private partnership (PPP), which will commence power generation in January 2015. Belo Monte will be the world's third-biggest hydropower plant. Brazil has an estimated 140 GW of total hydropower potential, with an estimated 40 percent remaining untapped, making it a valuable resource for future electricity generation.

Recent measurements carried out in 2008 and 2009 from the Brazilian wind atlas indicate that the real potential for wind power in Brazil is 350 GW. This is more than double the initial predictions from 2001 of 143 GW, positioning Brazil as one of the future global wind energy leaders. The Brazilian wind market has expanded tremendously since its commencement and now boasts several key market players. Latin America, led by Brazil, is expected to develop 46 GW of total installed wind capacity by 2025; the Brazilian market is expected to represent 69 percent of the total installed capacity in Latin America by then.

Brazil is the third-largest producer of biomass electricity behind the United States and Germany, thanks to large amounts of sugarcane waste that cover most of its needs for solid biomass electricity production.

Because of the country's location, levels of solar radiation (particularly in northern Brazil) are among the highest recorded in the world. The Amazon is the sunniest region in Brazil, with an average radiation level of 6,000 kilowatt-hours per square meter (kWh/m^2). Solar energy potential is estimated at 114 GW. According to the Global Energy Network Institute, total installed capacity of solar photovoltaic (PV) energy is estimated at 12–15 MW and is primarily used to supply telecommunications and rural installations. In 2009 Brazil had approximately 5 million m^2 of solar panels installed; the government plans to triple the area by 2015. Solar hot water technologies are becoming widespread and contribute significantly to hot water production. Brazil led the market for newly installed capacity worldwide during 2009, when its capacity increased 14 percent, bringing total existing capacity to nearly 3.7 GW thermal (5.2 million m^2).

Geothermal remains the least-tapped energy sector in Brazil, with only 1.84 GWh produced in 2005. Despite there being a potential for exploiting geothermal energy, particularly in southern Brazil, investment is currently not being pursued.

Renewable Energy Targets

The Government of Brazil established formal targets for RE in the Program for the Promotion of Renewable Energy (PROINFA), introduced in 2002. The targets, which were to be reached by 2006, are given in table 9.1.

Although no new formal or national targets for RE have been established since the PROINFA, the government produces a 10-year indicative generation expansion plan periodically that provides key guidelines for system expansion without imposing a commitment on developing projects or technologies. The 10-year expansion plan released in 2010—covering the period 2010–19—prioritizes the development of RE with the special objective of complementing the

Table 9.1 Targets under the PROINFA

Technology	*Target to 2006 (MW)*
Wind	1,100
Small hydro	1,100
Bioelectricity	1,100

Source: ANEEL.
Note: MW = megawatt; PROINFA = Program for the Promotion of Renewable Energy.

development of large hydroelectric capacity. But the expansion plan provides only a reference and does not establish any official targets for RE penetration in the country. The reference milestones are summarized below:

- Wind energy: Brazil hit the 1 GW milestone in May 2011, but plans to have to 11.5 GW by 2020.
- Small hydro: An increase from 3.8 GW in 2010 to 6.4 GW in 2020.
- Biomass: An increase from 4.5 GW in 2010 to 9.2 GW in 2020.

In total, wind, small hydro, and biomass are expected to reach 27 GW by 2020, compared to 9 GW in 2010. Investment plans to reach such reference points are as follows:

- R$70 billion ($44.5 billion) for RE sources excluding large hydro.
- R$96 billion ($60.7 billion) for large hydro plants.
- R$25 billion ($15.8 billion) for fossil-fuel projects.

In late 2010 Brazil enacted a decree targeting its carbon dioxide (CO_2) emissions. The decree requires a 1.3 billion ton reduction in emissions by 2020 (UNEP, BNEF, and FS 2012). Brazil aims to maintain or increase the existing share of RE in total energy (44 percent in 2010) and in electricity generation (85 percent in 2010) through 2030, and this policy goal is broken down into a number of technology-specific goals. For wind the government has set a goal of achieving 11.5 GW of production capacity by 2020.

Design of Incentive Schemes

The Experience with Feed-In Tariffs

The Brazilian government uses several tools to promote RE. In 2002 the government launched the PROINFA to encourage the use of RE sources such as wind power, biomass, and small hydropower. The program was intended to be implemented in two stages. By 2008 the PROINFA 1 was to add 3,300 MW of electricity capacity stemming from RE sources (divided equally among wind, biomass, and small hydropower) to the interconnected system and establish a minimum national business participation rate of 60 percent (that is, equipment and services of national origin). In the second phase—which was never implemented—the program called for a 90 percent national business participation rate and established a target for RE supply at 15 percent of total annual electricity consumption. The chosen subsidy instruments were technology-specific feed-in tariffs (FITs) with a cap on the number of supported MW. The program was operated by Electrobrás, which bought energy at preset preferential prices (different for each of the three sources) and marketed the electricity. The cost of subsidies and incentives was covered by the Energy Development Account, funded by end-use consumers through an increase in energy bills. Low-income sectors were exempt from this increase. The PROINFA was expected to generate 150,000 jobs and leverage private investments of around $2.6 billion. The PROINFA 1 was completed in 2008 with 3.3 GW installed. Wind farm capacity increased from 22 MW in 2003 to 606 MW in 2009, as part of 36 private projects; another 10 projects with a capacity of 256 MW were under construction, while 45 additional projects with a capacity of 2,140 MW were approved by ANEEL. The capacities (MW) of the supported biomass projects were far below the original target: the FIT for biomass projects was too low, making it more favorable for new biomass plants to sell directly to the wholesale market.

The incentives in the PROINFA included a technology-specific FIT and a purchase obligation on final consumers. The FIT level was established by the Ministry of Mines and Energy (MME) and designed as an adjustable 20-year tariff, indexed to inflation. The FIT was designed as a function of the plant's capacity factor (CF) with the aim of: (a) promoting the development of wind-based generation in different geographic locations and avoiding possible transmission capacity bottlenecks and (b) avoiding an overcompensation of electricity generation at good wind locations (that is, minimizing the producer surplus for plants with high CFs). The incentive was limited to 220 MW per state, also with the intention of avoiding geographic concentration and bottlenecks in the electrical grid (for example, the best wind conditions can be found in the northeast of Brazil, where the transmission network is less developed). Wind farms with lower CFs received a higher compensation per energy unit than wind farms with higher CFs. The design therefore included a FIT that increased linearly as the CF lowered (that is, from R$180.18/MWh for a CF of 41.93 percent to R$204.35/MWh for a CF of 32.40 percent).

The minimum and maximum CFs were fixed by the MME. The CFs of different plants were verified periodically to adjust the compensation level in the 20-year power purchase agreement (PPA). The average price paid to each technology (2010 prices) is provided in table 9.2.

The PROINFA was indeed the first step toward scaling up RE in Brazil, but it has been criticized for the lack of economic rationale behind project allocation procedures and for the imposition of rules that have created various bottlenecks to RE development. The first criticism is that the allocation of the targeted amount of 3,300 MW in equal shares of 1,100 MW to each source did not promote the least-cost expansion of RE capacity in the system. Project selection—within the technology-specific quotas—was also not based on a least-cost approach.

Table 9.2 Average FIT Levels under the PROINFA

Technology	*PROINFA FIT ($/MWh)*
Wind	154
Small hydro	96
Bioelectricity[a]	77

Source: ANEEL (2010 values).
Note: Exchange rate: $1 = R$1.85. FIT = feed-in tariff; MWh = megawatt-hour; PROINFA = Program for the Promotion of Renewable Energy.
a. Price includes taxes.

Projects were selected based on the dates relevant to environmental permits being issued. The older the permit, the closer the project was in the merit order for contracting. This ended up creating a "black market" for environmental licenses. In fact, the issue of permitting and licensing became a bottleneck to the introduction of new capacity in general, creating serious economic distortions and high transaction costs, leading to lengthy court cases. In addition, the minimum national business participation rate of 60 percent required by the PROINFA became a bottleneck to wind generation development, given that Brazil had just one local wind manufacturer at the time. As a result, not all technologies could reach their quotas, and some volumes of capacity were transferred from one technology to the other to achieve the total target of 3,300 MW. The PROINFA was also very much criticized for its management of the clean development mechanism (CDM) revenues. Under the program, Eletrobrás was responsible for managing the CDM revenues to reduce program costs, which were supposed to be passed on to consumers. But Eletrobrás was unable to prepare and submit the CDM projects as required by formal international procedures, and therefore could not collect the corresponding carbon revenues. The PROINFA target was reached four years later, in 2010, and with the introduction of the auction-based approach, the program was closed without entering into a second phase.

From Feed-In Tariffs to Auctions

Under the regulatory structure introduced in Brazil in 2004, most new power projects participated in auctions for long-term PPAs with energy distributors who were required to enter into long-term contracts for all of their electricity demand via a reverse auction system. The energy auctions were carried out by ANEEL through a delegation from the MME. There were specific auctions for both existing energy sources and for new energy sources. Existing plants were offered short- to medium-term contracts (from a few months to eight years), while new energy initiatives were offered long-term contracts (15–30 years). The clearing price of existing plants was lower than the clearing price of new energy. Auctions for RE plants targeted specific energy sources and large hydropower-project-specific sites. The tenders fixed maximum price caps and had penalties built in for developers who signed contracts they could not uphold.[1]

The procurement of new generation projects is carried out regularly through two public auctions every year (see table 9.3): one for electricity delivery three years ahead and another one for electricity delivery five years ahead (usually referred to as A-3 and A-5 auctions). Each auction offers long-term energy contracts (15-year-duration contracts for thermal plants and 30-year-duration contracts for hydro plants). The auction contract can be of two types: (a) standard financial forward contracts, where generators bid an energy price and (b) energy call options, where generators bid an option premium ($/MW) and an energy strike price ($/MWh). In the call option proposal, the consumer "leases" the plant from the investor, paying a monthly fixed amount (to allow recovery of investment and fixed costs) for its availability and reimbursing the plant's owner on its declared variable operating costs whenever the plant runs. In this case, the consumer is responsible for the cost of trading on a spot basis. Since spot prices tend to be low most of time, the option contract is very attractive. The contract auctions are organized by the government as a centralized process, carried out jointly to meet the total load increase. The objective of the joint auction is to allow smaller distributing companies to benefit from economies of scale in the new energy contracting. But the government does not interfere on the demand

Table 9.3 Renewable Auctions

Date	*Name*	*Technology*
18/06/2007	1º Leilão de Energia de Fontes Alternativas	Biomass, wind
26/07/2007	4º Leilão de Energia Nova	Hydro
16/10/2007	5º Leilão de Energia Nova	Hydro
10/12/2007	Leilão da Usina de Santo Antônio	Hydro
19/05/2008	Leilão da Usina de Jirau	Hydro
14/08/2008	1º Leilão de Reserva	Biomass
17/09/2008	6º Leilão de Energia Nova	Hydro, natural gas
30/09/2008	7º Leilão de Energia Nova	Hydro, biomass
27/08/2009	8º Leilão de Energia Nova	Biomass
14/12/2009	2º Leilão de Energia de Reserva (eolic)	Wind
20/04/2010	Leilão da Usina de Belo Monte	Hydro
30/07/2010	10º Leilão de Energia Nova A-5	Hydro
25/08/2010	3º Leilão de Energia de Reserva (Fase 1)	Biomass
25/08/2010	3º Leilão de Energia de Reserva (Fase 2)	Biomass
25/08/2010	3º Leilão de Energia de Reserva (Fase 3)	PCH, biomass, wind
26/08/2010	2º Leilão de Fontes Alternativas	Eolic, biomass
10/12/2010	9º Leilão de Energia Existente (A-1)	Hydro, biomass
17/12/2010	11º Leilão de Energia Nova (Hídrica A-5)	Hydro
17/08/2011	12º Leilão de Energia Nova	Hydro, wind, biomass
18/08/2011	4º Leilão de Energia de Reserva	Biomass, wind
30/11/2011	10º Leilão de Energia Existente (A-1)	Hydro
20/12/2011	13º Leilão de Energia Nova (A-5)	Wind, biomass, hydro
14/12/2012	14º Leilão de Energia Nova (A-5)	Wind, hydro

Source: ANEEL.
Note: PCH = pequeñas centrales hidroeléctricas (small hydro).

forecast (which is directly declared by the distribution companies) or the energy contracts (each winning generating company signs separate—private—bilateral contracts with each of the distribution companies, in proportion to their forecasted loads). The auction mechanism follows a hybrid design, combining an iterative descending clock auction with a final pay-as-bid round. Finally, in the regular new energy auctions, all technologies compete jointly. Candidate generators require either a concession (in the case of medium and large hydropower facilities) or an authorization (for all other plants). Authorizations and concessions are granted by the MME. Concessions are also granted through auctions, after the EPE studies a relevant site and the MME approves the project.

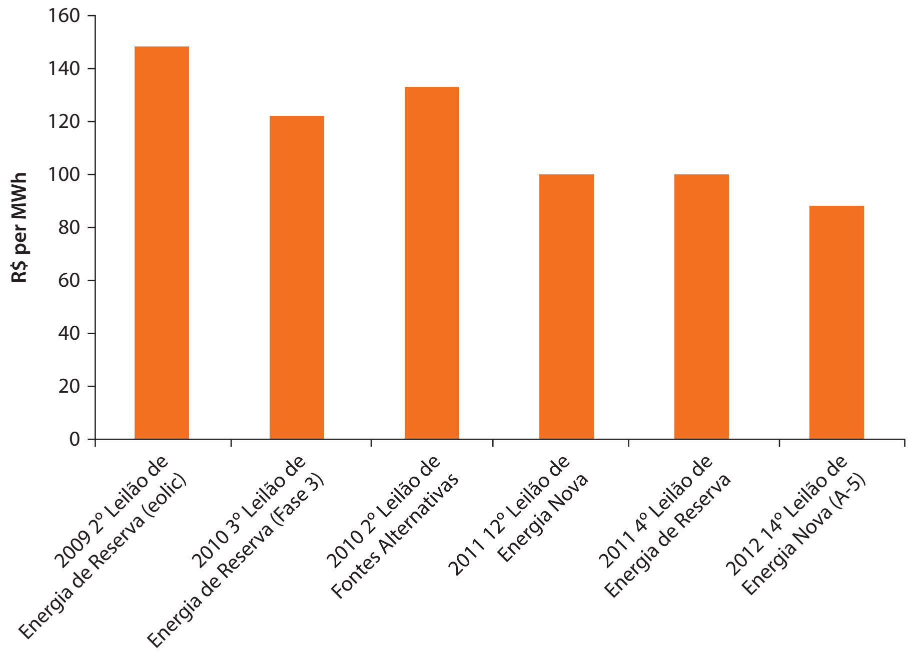
ANEEL held the first biomass-only reverse energy auction in 2008, contracting 2,379 MW produced by 31 thermoelectric plants (using sugarcane and napier grass) with supply beginning in 2009 and 2010, and contracts extending for a 15-year period. The final average price was $32/MWh. With a baseline of 554 MW, ANEEL contracted an additional 191 MW in 2010 and 60 MW in 2011.

The first wind energy auction was carried out in December 2009, resulting in 1.8 GW being contracted from 71 wind power plants scheduled to start operations by July 2012. In August 2010, 89 projects—representing 2.9 GW of installed capacity and involving R$26.9 billion ($15.2 billion) in investments—were contracted from biomass and wind farm developers. Biomass projects with a capacity of 713 MW were contracted at an average price of R$144/MWh, or $83.50/MWh, while the 2.1 GW generated from wind power were contracted at an average price of $74.4/MWh. In December 2012, 12 wind and hydro projects of 574 MW were contracted for an average price of R$91.25. As shown in figures 9.1–9.3 the use of auctions resulted in significant savings over time due to a sharp decline in prices, particularly in the case of wind.

Discounts on Transmission and Distribution Tariffs

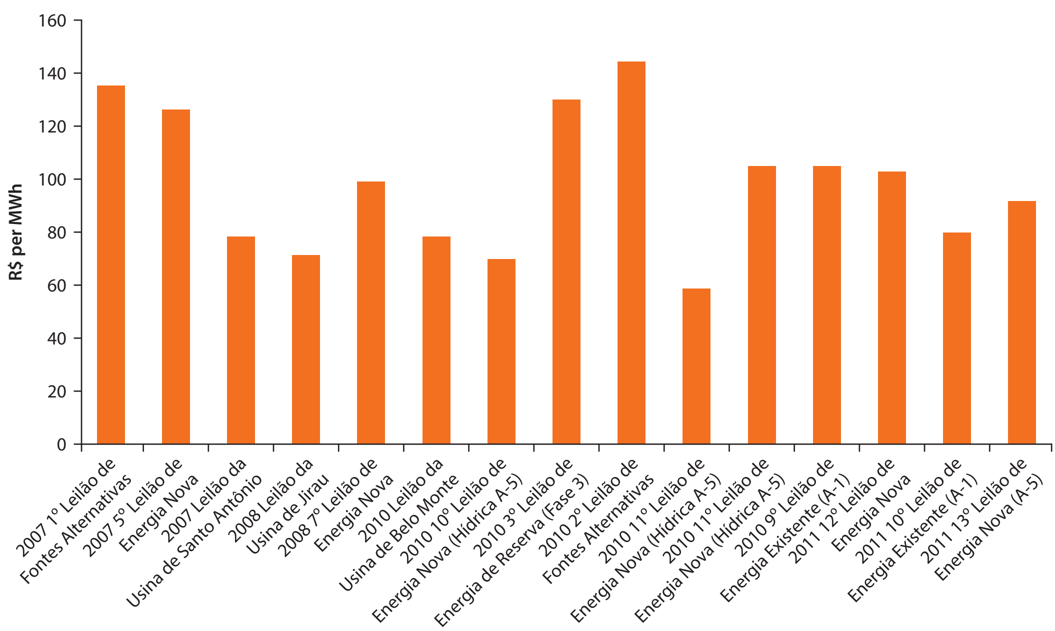
Law 9427/96 sets specific incentives for the sale of RE through contracts in the free market. These incentives take the form of discounts on transmission and distribution (T&D) tariffs for consumers who purchase energy through contracts signed with nonconventional RE developments of up to 30 MW. Although it was introduced in 1996, the incentive was confirmed in ANEEL's Resolution No. 247 of 2006, which established the regulations on the commercialization of RE-based generation (small hydropower, wind, biomass, and solar initiatives with capacities below 30 MW). This resolution also extends the incentive to regulated consumers with loads greater than 500 kilowatts (kW) for whom the wire tariffs are high: as the price reflects distribution costs at lower voltages, an RE contract produces substantial savings. Also, for some types of RE-based generation, this option is economically more attractive than are energy auctions. At present, Brazil has about 50 trading companies, and the number is rapidly growing. Although it is difficult to estimate the amount of RE-based capacity that has been attracted by the incentive, given the small scale and distribution of initiatives, it is estimated that more than 500 MW of both small hydro projects (SHPs) and bioelectricity have been installed under the scheme.

Figure 9.1 Price Evolution through Wind Auctions, 2009–12



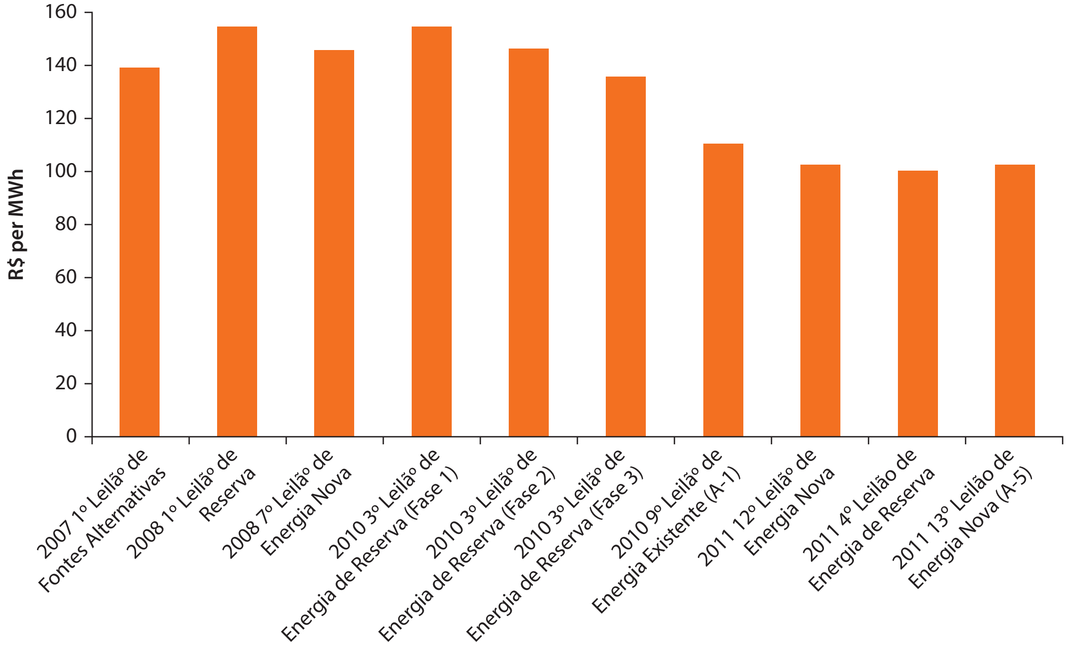
Source: ANEEL.
Note: MWh = megawatt-hour.

Figure 9.2 Price Evolution through Hydroelectric Auctions, 2007–11



Source: ANEEL.
Note: MWh = megawatt-hour.

Figure 9.3 Price Evolution through Biomass Auctions, 2007–11



Source: ANEEL.
Note: MWh = megawatt-hour.

Another strength of Brazil's RE development strategy is that it emphasizes the employment and regional development potential of the RE sector. The Brazilian Development Bank (BNDES) plays a central role in RE finance countrywide. Its funds are often passed to regional banks, which help build the capacity of the more local financing institutions. BNDES is the favored channel for funding for international donors and finance partners, such as the German Development Bank (KfW), which provides a credit line to BNDES for SHPs, supports pilot projects in biogas, and works on grid-connected PV pilot projects. BNDES's overall RE lending amounted to $6.4 billion in 2009.

Moreover, the government uses a number of instruments to ensure that RE investments support the creation and growth of national businesses. To benefit from subsidies and from BNDES financing, projects must fulfill national content requirements. Law 10762 mandates a minimum nationalization of 60 percent in total construction costs, as well as regionalization criteria, where each state has maximum limits of 20 percent of total capacity for wind and biomass and 15 percent for small hydro. Foreign manufacturers of RE and energy-efficiency technology, moreover, face a 14 percent tax surcharge on imports. The 60 percent national content requirement has led to significant installed production in Brazil. Major industry companies (such as Siemens, GE, Vestas, Suzlon, and Führlander) have now started production in Brazil or are actively seeking local presence there. Regional banks, such as Banco de Nord Este, are also active in RE finance, but generally work with BNDES's funds that are passed on to the regional level.

The conditions offered by BNDES to potential projects under the PROINFA were adjusted in 2005 (table 9.4) to support the actual deployment of RE-based capacity, as the combination of incentives (FIT offered by the PROINFA and soft loans offered by BNDES) was not sufficient to trigger investments in RE.

BNDES was therefore the main investment development bank for renewables in Brazil under the PROINFA. In general, the support of BNDES is aligned with the federal government's programs and still plays an important role in the financing of RE capacity. For instance, in 2008 BNDES approved loans for 11 biomass cogeneration projects, 2 wind-based power plants, and a landfill gas initiative with a combined capacity of 532 MW (BNDES 2013). Today, special financing conditions are given by BNDES to different types of generation capacity. These are released directly by the bank through its own programs and regulations. Table 9.5 illustrates the financing conditions applied today, considering the risk spread is upper bound.

The rural electrification program "Light for All" has a strong RE component. It assumes that (a) the use of approximately 130,000 PV systems is the most economically efficient electrification option for about 17,500 localities with small populations in the Amazon territory; and (b) a further 2,300 villages with about 110,000 buildings could be equipped with a mini-grid based on PV or biomass sources, 680 additional medium-sized communities could be supplied

Table 9.4 Financing Conditions Offered by BNDES under the PROINFA

Financial conditions	*2002*	*Adjustment in 2005*
Debt share (depending on nationalization quota)	Up to 70 percent	Up to 80 percent
Amortization period	10 years	12 years
Interest rates	TJLP plus BNDES charges	About 13.25% (TJLP plus BNDES charges)

Source: ANEEL.
Note: BNDES = Brazilian Development Bank; PROINFA = Program for the Promotion of Renewable Energy; TJLP = long-term interest rate.

Table 9.5 BNDES Financing Conditions Offered to Generation Projects

	Equity (%)	*Amortization*	*Interest rates*
Small hydro	30	14 years	100% TJLP* + 2.8% spread
Biomass[a]	20	14 years	100% TJLP + 2.8% spread
Wind	30	14 years	100% TJLP + 2.8% spread
Thermal[b]	30	14 years	50% TJLP + 50% currency basket + 2.8% spread

Source: BNDES 2013.
Note: BNDES = Brazilian Development Bank.
a. It is considered that biomass can finance the whole project, resulting in 20% of equity.
b. For liquefied natural gas (LNG) power plants.
*TJLP: Brazilian long-term interest rate; as of June 2010, its value was 6%.

on the basis of hybrid systems, and 10 larger communities could be provided with power based on conventional diesel generators or hybrid systems.

Brazil is a successful promoter of CDM projects, accounting for 40 percent of all CDM projects in South America and for 44 percent of contracted certified emission reduction (CER) credits up to 2012. Brazil's National Fund on Climate Change is an example of a holistic fund concept with a strong RE component. It aims to mitigate the environmental impact of oil production by allocating a portion of the state's revenue from oil to support projects, studies, and enterprises relating to climate change mitigation and adaptation. The law establishing the fund was adopted in December 2009. At that time, the government pledged $113 million, part of which would come from oil industry revenues. The fund has already started supporting mitigation and adaptation programs and projects involving a wide range of activities. These activities include capacity building, climate science, adaptation and mitigation projects, projects aimed at reducing carbon emissions from deforestation and forest degradation (particularly in vulnerable areas), development and dissemination of technologies, research and development (R&D), development of products and services that contribute to mitigation and adaptation, payment for environmental services, establishment of agro-forestry systems that contribute to reducing deforestation and carbon sinks, and the rehabilitation of degraded areas.

In August 2012 ANEEL announced two new pieces of regulation to support the solar industry: (a) a net metering for micro generation up to 1 MW, and (b) a tax break of 80 percent for installations up to 30 MW. ANEEL also announced that it would launch an auction for solar projects between 1 MW and 3 MW, but no details are available yet.

Financing of Incremental Costs

Eletrobrás was in charge of administering the PROINFA and of transferring the expenditures to consumers in proportion to their consumption (with the exception of the residential low-income subclass, or those with consumption levels below 80 kWh/month). Thus a specific "levy" was applied to recover the incremental costs associated with RE.

For new projects, the PROINFA system has been replaced by ANEEL's energy auctions, which also changed the way the incremental cost of RE is financed. Acquired power is fed into the power pool at the contracted price, raising the averaging pool price. The increase is subject to a politically fixed maximum: the average price of energy for end consumers can increase up to a cap of 0.5 percent annually and 5 percent over 20 years.

Wind became one of the cheapest sources of power in Brazil as a strong currency and slowing global demand for turbines drove down costs. Developers agreed to deliver electricity generated by new wind farms at an average price of R$99.54/MWh ($55.99/MWh) in a government-organized auction in August 2011. This was cheaper than two natural-gas thermal-electric plants and a hydroelectric plant expansion that participated in an energy auction a day earlier, and 33 percent cheaper than contracts awarded in the country's first auction for wind power in December 2009. The average price in the A-5 2012 auction on December 14 was R$87.94/MWh ($42.16/MWh). This was 9 percent below the lowest price contracted in the 2011 auctions, 12 percent below the average prices in 2011, and 21.5 percent below the R$112/MWh "reference price" set by the Brazilian Government Energy Agency, EPE, which manages Brazil's energy auctions. Taking into account the fall in the value of the Brazilian real against other currencies since the 2011 auctions, the low prices are even more concerning. If inflation and exchange rates are taken into account, the prices should in fact have been around R$122/MWh. Just 281.9 MW of wind energy was contracted in 10 projects scheduled for completion by 2017. This stands in sharp contrast to the August 2011 auctions, which saw 1.9 GW of wind power contracted for completion by 2016.

Prices for wind energy in Brazil, currently the lowest in the world, may rise at least 15 percent due to government policies designed to make the nation's power grid more reliable. Developers must install as much as 15 percent more generating capacity at new wind farms to compensate for the variable output from turbines. They also face new restrictions on where they can build. The second policy requires developers to build their own power lines to connect wind farms to the grid or install turbines near existing cables, sites that may not have the most wind. Under previous policies, the government auctioned the right to build power cables that linked wind farms to the grid. The two measures were scheduled to apply to wind projects that participated in an August 2013 government-organized auction to sell power (and perhaps in another auction that same year). The rules were expected drive up the cost of power from wind farms that require more than 150 km of power lines. There are about 600 MW of wind turbines installed in Brazil's northeast (where the breezes are the best) that aren't connected to the grid because the power distributor responsible for building the transmission lines is behind schedule.

Conclusions

The Brazilian experience with FITs and in recent energy auctions is revealing. Auctions have proved to be an interesting way to support the implementation of RE at a minimum cost, for a given portfolio of technologies and renewable quotas defined as part of the energy policy agenda. An auction is perhaps an indirect way to achieve a FIT price discovery. As with FITs, long-term contracting reduces risk aversion and facilitates project financing. In principle, auctions maintain the advantages of FITs (income certainty) while also minimizing costs to consumers, thanks to the exercise of a competitive process.

The technology-targeted energy auctions have catalyzed the RE market and provided:

- A reliable policy framework for investors.
- Involvement from public and private investors.
- Development of a local RE industry.

Brazil provides an excellent example of the implementation of creative policy measures, which, in combination with financial and risk mitigation support, have been able to increase the national RE capacity.

Table 9.6 shows a comparison of the PROINFA with RE-specific auctions in terms of their respective resulting prices, volumes, and costs. The main observation is that although the annual costs of both mechanisms are practically the same (around $1 billion), the energy auction scheme is expected to deliver 20 percent more total capacity, with an average energy cost, and an expected tariff 60 percent lower in the case of wind. In the case of bioelectricity, plants acquired through the auction scheme exhibited higher efficiencies.

The RE-specific auctions being implemented in Brazil can facilitate the introduction of specific projects while avoiding speculative behavior in auction participation.

But the low prices achieved in the wind auctions have raised the fear that projects will not be implemented due to foreseen financial insolvency. On the other hand, if all projects were implemented, the low prices obtained in the wind auctions might have paved the way to a direct competition between wind and other sources. This could avoid the organization of specific auctions for this technology, and wind power could start competing in the regular contract auctions organized by the distribution companies, in which all technologies participate on a level playing field without discrimination.

Indeed, policies seeking to promote the introduction of RE in an economically efficient way must take into consideration the costs of RE generation (in relation to the avoided social cost of generation), resource availability in relation to seasonality, as well as the technical conditions of the system (for example, capacity of T&D lines to absorb specific volumes of RE). An assessment of policy efficiency in this context requires complex modeling coupled with the use of other

Table 9.6 A Comparison of the PROINFA and RE-Specific Auctions

	PROINFA			*Technology-specific auction ("reserve energy" auction)*		
	MW	*GWh/year*	*$/MWh*	*MW*	*GWh/year*	*$/MWh*
Wind	1,423	3,740	154	1,800	6,596	80
Small hydro	1,191	6,260	96	—	—	
Bioelectricity	779	2,661	77	2,379	4,800	84
Small hydro						
Impact on costs						
Total capacity (MW)[a]		3,393			4,179	
Total energy (GWh/year)		12,661			11,397	
Average cost ($/MWh)		109			80	

Sources: Eletrobrás, EPE, Aneel, ONS, and PSR.
Note: Exchange rate: $1 = R$.1.85. Values as of April 2010; prices with taxes. Gross cost is total (fixed) cost paid by the consumers. For the auction case, the net cost includes estimates of yearly spot revenues collected by consumers.
GWh = gigawatt-hour; MW = megawatt; MWh = megawatt-hour. PROINFA = Program for the Promotion of Renewable Energy; RE = renewable energy. — = not available.
a. Installed capacity includes self-consumption. In the auction case, energy values correspond to the excess energy sold to the grid at the auction. More excess energy from the new plants is available to be sold to the free market or at future auctions.

tools to help analyze the adequacy of the institutional structure in place and governance issues.

Nevertheless, and despite the stepped-up tariff, the design of the PROINFA did not explicitly promote the least-cost introduction of RE, since it established equal targets for different types of technologies (a limit of 220 MW of RE per state) and introduced restrictions in the form of a "minimum national participation rate," which became a bottleneck to the development of wind-based capacity.

The PROINFA also did not provide any signal for technology improvement; for instance, the extra energy or surplus produced due to technology upgrades or efficiency improvements was not considered under the program (for example, degression factors in FIT design based on empirically derived progress ratios). Signals for economic efficiency—in terms of least-cost expansion of RE—were poor due to the administrative setting of different prices for different technologies. But beyond the design features of the PROINFA, the management of the program also hindered the introduction of best-performing sites, as projects were selected based on the dates environmental permits were issued. The PROINFA also centralized the management of CDM revenues under very inefficient oversight.

On the other hand, the auctions—as competitive mechanisms—seek to stimulate the introduction of least-cost generation. But the first "reserve energy auction" for wind, carried out in 2009, concluded in very low—perhaps artificial—prices and raised concerns about the risk of delays in construction or of no wind plants being constructed at all. It is also interesting to note that the 2009 auction did not result in a clear correlation between CFs and prices. It is of course too early to assess the merits of the auction scheme in deploying RE with economic efficiency.

In terms of economic efficiency, the reserve energy auctions meant to speed the introduction of RE may have other caveats: (a) they are not technology neutral, and (b) the type of technology and contract volume is discretionary (that is, the government has the prerogative to call an auction to contract a given volume of energy even if it is not contemplated in the demand forecasts prepared by the distribution companies).

Note

1. For more details of the auction system, see Maurer, Barroso, and Chang (2011).

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CHAPTER 10

Case Study: Turkey

Sector Background

Turkey is moderately endowed with primary energy resources, mainly hydropower and lignite with some natural gas, and therefore relies on imports for about 70 percent of its energy needs. But it lies at major international crossroads of energy trade between the gas- and oil-rich regions of the Middle East and Central Asia and the major European demand centers, which enables Turkey to diversify its sources of imported energy and to profit from extensive transit trade in energy products. The country has abundant wind and solar resources that promise to decrease its dependency on imported fossil fuels while reducing greenhouse gas (GHG) emissions.

In 1993 the Turkish Electricity Authority (TEK) was split into two separate public utilities, which were corporatized: (a) the Turkish Electricity Generating and Transmission Corporation (TEAS), responsible for both generation and transmission activities, and (b) the Turkish Electricity Distribution Company (TEDAS), responsible for distribution and retail sale activities (Vagliasindi and Besant-Jones, 2013).

In 2001 the Electricity Market Law (EML) No. 4628 was passed; its aim, among others, was to ease the burden of the power sector on the public budget. The provisions of the EML were designed to be in line with the European Union's (EU's) Energy Acquis, as part of Turkey's ambition to join the European Union (EU). The law overhauled electricity legislation and set the foundation for a radically different framework in both the design and regulation of the Turkish electricity market. The law provided for the unbundling of state-owned electricity assets, opened the market above a certain level of electricity consumption, and allowed third-party access to the grid. The EML required the creation of a bilateral contracting market, complemented by a residual balancing mechanism. All generation capacity was to be sold to wholesalers, retailers, and consumers either directly or via a spot market. In response, the TEAS was unbundled into three separate state-owned entities:

- *The Electricity Generation Company of Turkey (EUAS) for generation*. The EUAS directly owns most hydropower units and acts as the holding company for six

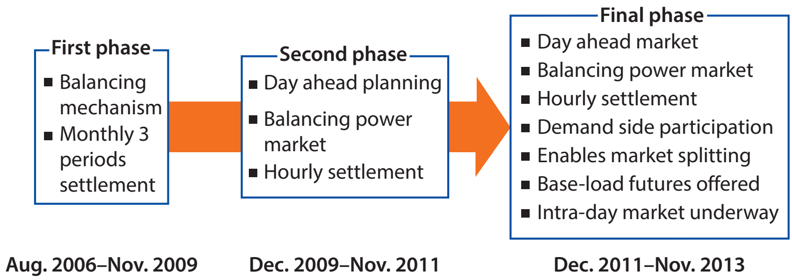
portfolio generation companies with thermal power units and some hydropower units. In addition, several private sector generating units established under build, operate, transfer (BOT), build, operate (BO), and transfer of operating rights (TOOR) contracts supply power to the grid on the basis of power purchase agreements (PPAs) guaranteed by the government.[1] There are also a few privately owned independent power producers (IPPs). Industries with captive generating units (autoproducers) and privately owned renewable energy (RE) units also supply to the grid.
- *The Turkish Electricity Transmission Company (TEIAS) for transmission and dispatch*. The TEIAS also operates the balancing market, which complements the bilateral free market, and acts as a settlement agency.
- *The Turkish Electricity Trading and Contracting Company (TETAS)* acts as the single buyer of electricity sold under the PPAs for BOT, BO, and TOOR units, and on-sells this electricity to the distribution companies.

Although corporatized with separate accounts, these entities remain subject to government decision making and have little managerial autonomy. Distribution is handled by 21 regional distribution companies, 20 of which are the holders of operating rights for their franchise areas from the TEDAS. The remaining one (Kayseri) is a privately owned distribution company. The EML also established the Energy Market Regulatory Authority (EMRA) as an independent and financially autonomous regulator of power, gas, petroleum, and liquefied petroleum gas, to be supervised by the Energy Market Regulatory Board.

In 2004 the strategy paper "Road Map of the Market Reform and Transition" was approved by the Higher Planning Council. It outlined the steps for further liberalization of the electricity sector. It covered procedures for privatizing distribution and generation assets with the introduction of transitory vesting contracts through which generation—either from existing contracts (via the TETAS) or from public companies—would be allocated to distribution companies based on their weighted share in total demand (to compensate for the demand of captive consumers). The strategy paper also provided the basis for determining the revenue requirements of the regional distribution companies ex ante. Any possible differences between the ex ante revenue requirements of the distribution companies and the real incomes collected via the tariff in force were expected to be reimbursed by means of a price equalization mechanism. The paper also envisaged the implementation of a national tariff.

As set out in the strategy paper, the TEDAS, with its 20 regional distribution companies, was transferred to the Privatization Administration (PA) on April 1, 2005. A competitive wholesale electricity market went into operation in 2006. A balancing and settlement system was developed and started operating as a branch of the TEIAS. By 2010 approximately 400 private companies—dispatching about 30 percent of total electricity supply, on average—were trading power in this market. The EMRA issued new balancing and settlement regulations to improve the functioning of the wholesale electricity market in April 2009. In December 2009 the market moved from monthly settlement to hourly settlement (figure 10.1).

Figure 10.1 Evolution of the Power Market in Turkey: Key Phases



Source: Vagliasindi and Besant-Jones 2013.

Renewable Energy Resource Endowment

According to the Wind Energy Potential Map of Turkey (REPA), the high-efficiency wind energy potential in Turkey is nearly 19,000 megawatts (MW); high-potential fields are located in Aegean, Marmara, and the coastal part of the Eastern Mediterranean regions. On the other hand, the REPA study showed that the technically feasible installed capacity potential in regions having a wind speed between 7.5 to 8 meters per second (m/sec) is 29,259 MW, while the potential in more than 9 m/sec wind-speed regions is only 196 MW. That is, Turkey has a 48,000 MW mid-high-efficiency wind energy generation potential and an annual average wind speed of 7.5 m/sec and higher.

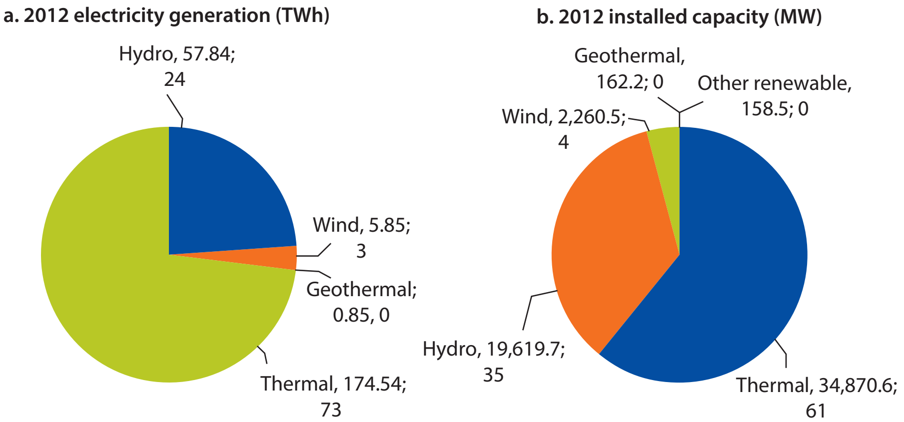
Renewable Energy Development

Turkey's installed power generation capacity in 2012 consisted of 10,100 MW of lignite- and coal-fired plants, 17,600 MW of gas- and oil-fired plants, and 13,900 MW of hydroelectric plants, with 600 MW of geothermal and other types of capacity (see figure 10.2). Annual generation of electricity was 198.6 terawatt-hours (TWh) in 2008, of which about 66 percent was from thermal power generation and 33 percent from hydroelectric generation (the remaining 1 percent was from geothermal and wind power). This amount of power was supplied to 29.52 million consumers. The country is nearly entirely electrified, mostly from these power networks.

Renewable Energy Targets

The Electricity Market and Supply Security Strategy Paper, issued by the High Planning Council in 2009, set the following targets: (a) wind electricity generation capacity to be increased to 20,000 MW by 2023, (b) the known geothermal capacity of 600 MW suitable for electricity generation and all technically possible hydroelectric capacity to be fully utilized by 2023, and (c) the share of electricity generated using renewable sources to be increased to at least

Figure 10.2 Evolution of the Power Market in Turkey: Generation and Installed Capacity
Percent



Source: TEIAS.
Note: MW = megawatt; TWh = terawatt-hour.

30 percent of the total electricity generation. Turkey's first wind power plant was set up in 1998 at Cesme-Alacati with an installed capacity of 1.5 MW, according to the BOT model.

Design of Incentive Schemes

Following the enactment of the EML in March 2001, the process for the installation of RE plants was tailored according to the law, and the process gained pace by the enactment of the Renewable Energy Law (REL). The REL (No. 5346) enacted on May 18, 2005, introduced certain advantages with respect to floor price and priority dispatch. The law included wind, solar, geothermal, biomass, biogas, wave, stream, and tidal energy resources; canal and river-type hydroelectric-generating facilities; and hydroelectric generation facilities with a reservoir area of fewer than 15 square kilometers (km^2).

A Renewable Energy Resource Certificate (RER certificate) was introduced so investors could benefit from these advantages. But this law did not get the desired results, as the declared floor price was found very low by the investors and/or the lenders. Therefore, initially the Turkish Average Wholesale Electricity Price was used to promote all types of RE, and then a floor price of 5€ cents/kilowatt-hour (kWh) and a cap price of 5.5€ cents/kWh were also applied.

The REL has been amended at various times; the most recent comprehensive amendment became effective on January 8, 2011. According to the REL and related regulations, a "renewable pool" was introduced. Renewable generation facilities are supported by distributing the total cost of the electricity supplied to the pool among all the suppliers selling energy to final consumers (rather than only to the direct purchaser of the energy generated by each facility).

The tariff is applied for a period of 10 years from the first operation date (if the commissioning date is between May 18, 2005, and December 31, 2015).

Other critical provisions of legislation are summarized as follows:

- The support scheme is valid for the facilities commissioned until the end of 2015.
- For the later period, beyond the commissioning dates, the feed-in tariffs (FITs) will be determined by a Council of Ministers decree, which in any case will not be higher than the FIT for the first period.
- The facilities that prefer using the FIT cannot sell energy to the market for the current year.
- The total support amount is distributed among the suppliers who sell energy to consumers directly.
- For solar and wind license applications, site measurements are required.
- Solar and wind license applications can be submitted only on the dates determined by the EMRA Board.

The promotion of RE sources in the electricity market was assigned to the EMRA by the EML. Specifically, the Electricity Market Licensing Regulation (LR) assigned the EMRA with the responsibility to encourage the utilization of renewable and domestic energy resources, and to initiate actions with relevant agencies for the provision and implementation of incentives in this field. In the LR, generation facilities based on RE resources are defined as those power plants that utilize wind, solar, geothermal resources, waves, tidal movements, biomass, biogas, and hydrogen; river or canal-type hydroelectric generation facilities; and hydroelectric generation facilities with a reservoir area smaller than 15 km^2 or with pumped-storage hydropower plants.

The EML and LR specified that in case of more than one application for the same region and/or the same transmission substation (in case substation connection capacity is limited), the licensed entity shall be qualified through an auctioning process executed by the TEIAS with respect to the maximum contribution fee per kilowatt-hour.

To promote generation from renewable sources, electricity generation from power plants less than 500 kilowatts (kW) based on renewable sources is exempted from license obligation and, unlike other market activities, the owners of such plants do not have to establish a company. The WPP projects licensed by the EMRA between September 3, 2002 (when the market was opened), and June 4, 2004 (when the license applications for wind power plants were suspended), were mainly the old BOT projects that had been developed earlier. Some of those projects' owners resigned their existing contracts and became license holders. The connection capacity of these projects had already been allocated by the TEIAS; therefore, there was no problem getting connections.

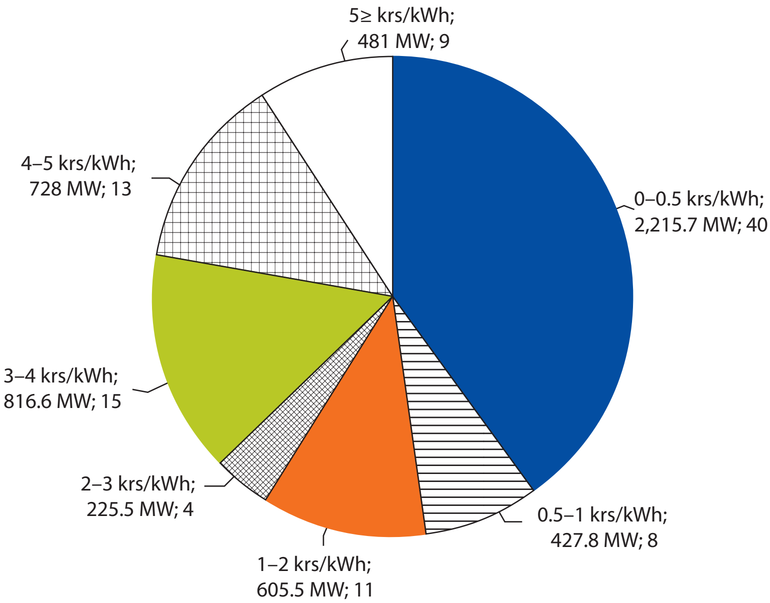
In addition to these old BOT projects, there were several license applications submitted to the EMRA for new wind projects. There were no predetermined wind project sites marked by the public authorities and no published information about the regional or substation-based transmission system connection capacities. Therefore, companies were determining project sites according to their own evaluations and were proposing connection points. But those applications could not be concluded by TEIAS with respect to connection and use of the system. Also, there were criticisms regarding possible problems due to the intermittent behavior of wind energy and its possible effects on system operation, and the limited connection capacity. Furthermore, the regulations did not make provisions for how to select one among several applicants for the same project site. Accordingly, on June 4, 2004, the EMRA board decided to suspend all license applications for WPPs and to stop review, evaluation, and granting processes for six months until the TEIAS issued the maximum annual WPP capacity to be connected to the grid. But the TEIAS was unable to issue these projections, and the EMRA upheld the suspension for more than three years. Due to public pressure, however, the EMRA decided to reopen the applications on November 1, 2007; 751 applications were received by the EMRA for a corresponding 78,000 MW capacity. Most of the applications were made for the same project sites. But as expected the EMRA was not able to take a decision on the applications without inputs from the TEIAS. This lack of necessary information on the evaluation and selection of the applications was followed by another prolonged period of inactivity.

To address this problem the EML was amended on July 9, 2008, to introduce an auctioning process for cases in which more than party applies for the same plant site, or total requested capacity exceeds substation capacity. Meanwhile, new regulations were issued about a pre-elimination of the projects by the Electrical Power Resources Survey and Development Administration (EIE) and the auctioning process by the TEIAS. The TEIAS also decided, in February 2010, that the total capacity to be connected to the grid would be 8,450 MW comprising a total of 142 substations. Accordingly, the EMRA informed the license applicants about the TEIAS's decision and asked for the installed capacities to be revised downwards. The applicants who did not reduce their original installed capacity figures within 10 days' time were disqualified by the EMRA without further notice.

The remaining applications were reviewed and evaluated in technical terms by the EIE, and the applied capacity of nearly 78,000 MW was finally reduced to 31,268 MW. Of this capacity, 1,378 MW were single applications, and the owners were granted licenses, while the remaining (having more than one applicant) were subjected to the auctioning process by the TEIAS.

The TEIAS auctioning process (according to the maximum contribution fee) was started in 2010 for 13 different groups of applicants and concluded in July 2011. A total of 149 projects were qualified through those auctions with a total installed capacity of about 5,500 MW. The weighted average of the contribution fees per kilowatt-hour was realized as TL 1.91, and the highest fees of TL 6.52, TL 5.60, and TL 5.25 were offered to the Antakya, Can-Canakkale (Dardanel), and Izmir substations, respectively. The results of the auctions according to the classification of contribution fees are given in figure 10.3.

Figure 10.3 The First TEIAS Wind Capacity Auction: Capacity Allocations
Percent



Source: TEIAS.
Note: krs= kurus (1/100 of Turkish Lira); kWh = kilowatt-hour; MW = megawatt.

This period lasted more than three years, and the installation of wind power plants also took a considerable amount of time. The allocated capacity and general status of wind projects as of end March 2013 are given in table 10.1.

At the moment, no new license application is being accepted by the EMRA. The EMRA will be issuing a new date for applications, and these will be processed according to the procedures and rules discussed in subsequent sections. The development of installed wind capacity is given in figure 10.4, which shows that the development of wind energy gained pace after the electricity reform and the REL was enacted in 2005.

It is interesting to note that, although the auctioning process was concluded in 2011, nearly 50 percent of the eligible projects have either not been licensed yet or, even if licensed, the project companies have not signed connection agreements with the TEIAS. The main reason for this slow realization appears to be the high and unrealistic bid prices during the auctioning. Considering the FIT level or the market prices, it is very difficult to find financing for projects whose auction prices are as high as 3–5 cents/kWh.

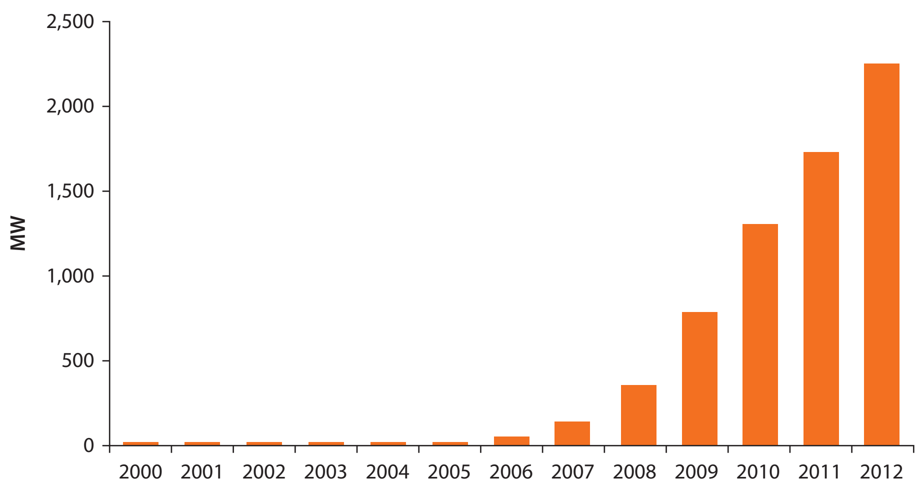
One can expect that high bids for the contribution fee indicates the operator's or project's efficiency—that is, bid prices would normally be based on the bidder's feasibility studies. More efficient projects can achieve greater revenues, and hence these will be bid for at higher prices. In the previous tenders, though the bid prices for some projects were as high as 4–5 cents/kWh, neither the support price of 7.3 cents or the market price of 9–10 cents would suffice to make these projects

Table 10.1 The Results of the First TEIAS Wind Capacity Auction

By type	*MW*
Before November 2007	3,761
For single applications	2,027
For coinciding applications	5,371
For R&D	6
Capacity increases in 2013	752
Total allocated capacity	11,917
In operation	2,337
Positive connection opinion[a]	2,371
Without connection agreement[b]	4,737
With connection agreement	2,472
Total allocated capacity	11,917

Source: Dilli 2013.
Note: MW = megawatt; R&D = research and development.
a. To be licensed.
b. Connection agreement with the TEIAS is pending.

Figure 10.4 Development of Installed Wind Capacity, 2000–12



Source: TEIAS.
Note: MW = megawatt.

feasible. If bidders are careful, then the bidding price will indicate the merits of the project. But unfortunately, past experience shows that it is not always so. Delays in project realization are mainly due to project trading in the Turkish market, and the creation of a secondhand market where projects are bought and sold.

There were about 37,000 MW project capacities in the Ministry of Energy and Natural Resource (MENR) at different stages of project development when the new regime was started in 2001 under the EML. It soon became that, under current economic conditions, even 10 percent of this capacity could not be realized with take-or-pay provisions and treasury guarantees. As such, many artificial project capacities were disqualified in time. The main path followed by affected project developers was to apply to the MENR for the same project when a new project application was announced, or to develop a project similar to that planned by related public institutions.

The new EML introduces a new challenge for those project developers who have a provisional license. In the provisional license period, license holders are not allowed to sell the companies. It was thought that this would be useful for stopping the project trade, or that at least only those projects that fulfilled their provisional license obligations could be transferred to other parties.

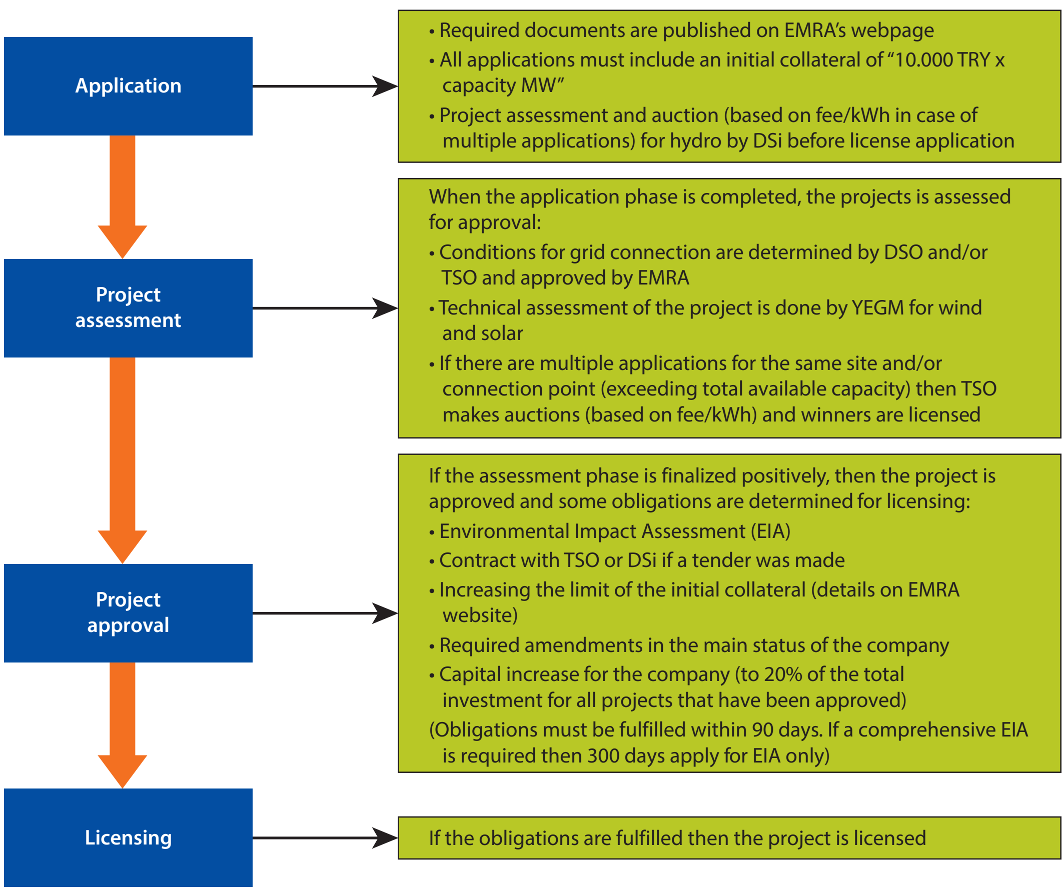
RE generators have two distinct ways to sell their electricity[2]:

- *Through bilateral contracts or in the day-ahead market*. In this case the companies can benefit from incentives except the FIT, and the price will depend on the wholesale market price or bilateral contract price. They are treated as any other generator and would bear the risk of generation imbalances, which might be quite high for wind generation. Since the wholesale market price level is higher than the FIT, most of the companies prefer this and try to hedge their risks by establishing generation portfolios with some thermal and hydro generation. With the introduction of an intraday market (currently in a trial phase), the imbalance risk could be better managed.

- *In the "renewable pool."* Previously, retail sellers were required to purchase an amount of energy equal to a certain percentage of the electricity that they had sold in the previous year from entities holding an RER certificate. Accordingly, they were required to sign bilateral agreements with the RER certificate holders. But the REL set forth a new method for the performance of suppliers, as opposed to that of retail sellers only. According to the REL, instead of executing separate bilateral agreements for each sale transaction between a supplier and an RER certificate holder, the said obligation was to be performed through a program in which all suppliers were obliged to share the cost of energy generated by all willing RER certificate holders in the renewable pool. The regulation for RE resources was issued through a provision of the REL—the RER Support Mechanism (YEKDEM). According to the provision, RER certificate holders are entitled to participate in the YEKDEM on a yearly basis for the first 10 years of operation, provided their power plants are commissioned on or before December 31, 2015. Once they participate, the RER certificate holders cannot terminate their participation during that year, and the option to participate is available only at the beginning of each calendar year. Those who do not wish to participate in the YEKDEM may sell electricity in the free market and may sign bilateral agreements. In such cases, however, they would not be entitled to benefit from the purchase and price guarantee incentives of the REL. The wind capacities of producers that participated in the YEKDEM in 2011, 2012, and 2013 were 469 MW, 688 MW, and 76 MW, respectively.

The licensing process is represented in figure 10.5. To receive an opinion on the connections, the EMRA sends the applications to the TEIAS. If there is no capacity constraint and the connection proposal of the company is deemed appropriate by the TEIAS, the TEIAS shall approve the project. In case the capacity of the application exceeds the substation capacity, the TEIAS notifies the EMRA, and the EMRA sends a notification to the applicant to decrease a portion of the installed capacity. If there is more than one applicant for the same connection capacity or for the same connection region, the TEIAS will organize an auction to determine the qualified applicant(s) to be connected. In the auctioning process, the bidders who offer the highest price per megawatt (that is, contribution fee) will become eligible to connect to the grid until the available capacity is reached. The offered amount will be paid in the first three years of operation.

Figure 10.5 Licensing Process



Source: EMRA.
Note: DSI = Directorate of State Hydraulic Works; EIA = Environmental Impact Assessment; EMRA = Energy Market Regulatory Authority; TSO = transmission system operator; TRY = Turkish Lira; YEGM = Yenilenebilir Enerji Genel Müdürlüğü (General Directorate of Renewable Energy).

An Environmental Impact Assessment (EIA) is required before the granting of the license. In this respect, projects with installed capacities of more than or equal to 75 MW, are obliged to obtain a positive EIA. Projects having an installed capacity of more than or equal to 10 MW are to be checked to decide whether an EIA study is required for them or not. Before the granting of the license the applicants should submit the positive EIA or the decision stating that an EIA is not necessary to the EMRA (although there is no obligation for a positive EIA decision for projects less than 75 MW, investors generally prefer to have it due to lenders' requirements).

Unlike for hydro projects, wind power projects tend to receive public approval. Although some projects have experienced minor problems (particularly for transmission line construction), no major problems have been reported so far.

The new EML limits the provisional license period to 24 months. The legal entity fulfilling the requirements indicated in the LR will be granted a provisional license by an EMRA Board decision. After the granting of the license, the following obligations should be met by the licensee during the provisional license period: establishing of land-usage rights; signing of the Connection and Use of System Agreement; and acquiring of public works permits (from local authorities), road permits, and technical interaction permits (from the Turkish General Staff and National Intelligence Agency). The critical provision in the new EML is that share transfers during the provisional license period are prohibited.

After the above-listed procedures and obligations are completed, the provisional license is granted to the owner. The project company then has to submit project design documents to the MENR. After approval of these technical documents, construction work can start. On completion of construction, the project company applies to the MENR for a Project Compliance Approval. A team formed by the MENR will evaluate the plant site to see if all necessary controls are in place, check whether all permits are obtained, and whether the project is in line with the project technical documentation. After commissioning tests by the team, the plant is officially commissioned and registered.

The EMRA issued a Communiqué on Wind and Solar Measurements on October 11, 2002, to open licensing applications for wind projects. Although the requirements are not detailed, for the licensing application to be accepted by the EMRA, measurement results for one year should accompany the application. The communiqué alone could not increase the number of wind projects' licensing applications without a long-term support scheme for these projects. That support scheme was introduced with the enactment of the REL. Meanwhile, the EIE issued the REPA showing the country's wind potential at different heights, and investors are able to purchase detailed data of specific locations. Following these developments, and also due to pressure from investors, the EMRA removed the measurement requirement by cancelling the communiqué on January 19, 2006.

But after a chaotic experience with wind license applications in November 2007, the EMRA had to issue a Communiqué on Measurement Standards for Wind and Solar Energy License Applications on February 2012. Following this, the Directorate of Turkish State Meteorological Service (SMS) also issued the

Communiqué on Implementation of Wind and Solar Measurements to be performed for Wind and Solar Energy License Applications on July 10, 2012, to regulate principles and procedures of measurement and evaluation of data. According to the new EML for unlicensed wind projects of up to 1 MW capacity, measurement is not required.

The first version of the REL provided the same FIT for every source of renewable electricity generation. After the amendments, the FITs were differentiated according to sources (wind, hydro, solar, and so on), as is reported in table 10.2.

In addition to the basic FIT, a bonus is provided in case the electromechanical equipment is manufactured in Turkey (a local content premium), as reported in table 10.3.

Other incentives include:

- Exemption from the compulsory 1 percent turnover payment for operating businesses on immovable assets of the treasury.
- A 99 percent exemption from the licensing fee and annual license fees for the first eight years of operation.
- Priority in system connection.
- Value added tax (VAT) exemption for domestic equipment for Investment Support Certificate holders.
- VAT, customs tax, and Resource Support Utilization Fund payment exemptions on imports for Investment Support Certificate holders.
- Research and development (R&D) deduction (that is, deduction of R&D expenditures from the corporate tax base at a rate of 100 percent).
- Income tax exemption (of 80 percent of salary income for eligible R&D and support personnel).
- Social security premium support for five years.
- Stamp tax exemption.

All RE generators can benefit from these incentives whether they are participating in the YEKDEM or not.

Table 10.2 Feed-In Tariff

Plant type[a]	*Schedule I*[b]	*Schedule II*[c]
1.Hydro	7.3	2.3
2. Wind	7.3	3.7
3. Geothermal	10.5	5.8
4. Biomass	13.3	2.7
5. Solar (PV)	13.3	6.7
6. Solar (CSP)	13.3	9.2

Source: EMRA.
Note: CSP = concentrated solar power; PV = photovoltaic.
a. Before Law No: 6094, feed-in tariff was € cents 5–5.5 per kilowatt-hour for all of the renewables (Law No: 5346).
b. 10 years for plants to be commissioned until December 31, 2015.
c. Incentive for local content—5 years for plants to be commissioned until December 31, 2015.

Table 10.3 Proposed Premium for Use of Equipment Manufactured Locally
€ cents/kWh

Hydropower	
1. Turbine	1.0
2. Generator and power electronics	0.8
Generation facility based on wind power	
1. Blade	0.6
2. Generator and power electronics	0.8
3. Turbine tower	0.5
4. All of the mechanical equipment in the rotor and nacelle groups (excluding payments made for the blade group and generator and power electronics)	1.0
Photovoltaic (PV) solar power	
1. PV panel integration and solar structural mechanics manufacturing	0.6
2. PV modules	1.0
3. Cells forming the PV module	3.0
4. Inverter	0.5
5. Material focusing solar rays on the PV module	0.4
Concentrated solar power (CSP)	
1. Radiation collection tube	2.0
2. Reflective surface plate	0.5
3. Solar tracking system	0.5
4. Mechanical equipment of heat energy collection system	1.0
5. Mechanical equipment of the system collecting solar rays on the tower and producing steam	2.0
6. Stirling engine	1.0
7. Panel integration and solar structural mechanics manufacturing	0.5
Biomass	
1. Fluidized bed steam boiler	0.6
2. Fluid or gas-fired steam boiler	0.3
3. Gasification and gas cleaning group	0.5
4. Steam or gas turbine	1.5
5. Internal combustion engine or Stirling engine	0.7
6. Generator and power electronics	0.4
7. Cogeneration system	0.3
Geothermal	
1. Steam or gas turbine	1.0
2. Generator and power electronics	0.5
3. Steam injector or vacuum compressor	0.5

Source: EMRA.
Note: kWh = kilowatt-hour.

Green or Concessional Funds

In 2004 the government disbursed a $202.03 million loan from the International Bank for Reconstruction and Development (IBRD) and the World Bank, and opened a special purpose debt facility (SPDF) to finance privately owned RE generation facilities. The SPDF—a term-lending facility—was operated by two financial intermediaries: the Turkish Industrial Development Bank (TSKB, privately owned) and the Turkish Development Bank (TKB, government owned). The SPDF was designed to leverage equity investment from local private RE developers, export credit financing, or other means for the construction and operation of qualified RE projects. The SPDF operated in the period 2004–08. Under the special loan structure, the financial intermediaries required a minimum equity of 25 percent, and were able to offer maximum maturities of 12 years including a 4-year grace period. In 2009 the government disbursed a new $500 million IBRD loan, complemented by a $100 Million Clean Technology Fund (CTF) concessional loan to replenish the facility.

The design of the SPDF required modifications during the implementation period, including the following (as described in the World Bank's Implementation Completion Report of March 2010): (a) the capacity limit on hydro power plants was increased from 50 MW to 100 MW, (b) the maximum loan size allowed for each subproject was increased from $20 million to $40 million, and (c) the international competitive bidding (ICB) threshold for civil works was raised from $8 million to $15 million, and a maximum of $15 million was allowed to finance civil works carried out by a sponsor-related construction firm (that is, in the original procurement guidelines, the financing of construction by a firm or subsidiary affiliated with the RE project's sponsor was not allowed).

With the ratification of the Kyoto Protocol, Turkish power plant operators will now have the right to engage in the trade of various emissions-related financial products after 2012. Before this, Turkish activities were limited to the voluntary carbon markets.

Conclusions

The experience of Turkey offers remarkable lessons. The first notable observation is that around only 5 percent of the total technically feasible potential has been utilized in the past few decades. To reach the 20,000 MW target in 2023, roughly 1,700 MW should be commissioned each year till 2023 (excluding the period 2005–08, the existing added capacity was roughly 500 MW/year). As an approximation, excluding the required transmission investments, a total of $28 billion is needed in the upcoming 10 years for the realization of the wind-based capacity target.

These disappointing results can be mostly attributed to the lack of consensus between different stakeholders. The Turkish government renewed its commitment to RE in 2002, but the selected support scheme was only enacted in 2005 and did not meet expectations. The REL and other support mechanisms, the electricity market reform, the new trading mechanisms (which were implemented in this reform process), and the high electricity prices in the market increase the attractiveness of RE generation. But market prices alone were not sufficient for RE investment decisions and financing. A support mechanism is required to provide long-term certainty and decrease the risk of investment by providing a certain revenue stream for the project. Provided that relevant risks (including the imbalance risks) can be hedged, market reform and competition can also play a role in wind development (new trading mechanisms such as the day-ahead and balancing market provide risk-hedging possibilities, and higher market prices for electricity increase its attractiveness). Implementation of the intraday market (which is currently in the trial phase) also might decrease the imbalance risk of wind power plants.

Although the FIT level set by the last amendment of the REL was not found attractive, it is unlikely that this level will be increased. As mentioned before, projects with a high contribution fee will probably be cancelled and those capacities will be reissued to the market. Projects are mostly being financed by Export Credit Agency (ECA) credits, international financial institution (IFI) lending (such as from the World Bank and the European Bank for Reconstruction and Development [EBRD] through local banks), and some contribution via voluntary carbon-trading mechanisms. Still, the most important bottleneck is financing.

The TEIAS is working to strengthen regional connection capacities for new projects. The intention is to determine new capacity to be utilized each year, starting from 2014. The unused capacities allocated by previous auctions are being determined and included in a new capacity list.

The chaotic experiences of the past have provided valuable lessons for the administration as well as investors. Companies are now much more careful when selecting projects. Under current regulations progress will be slower, but will encompass the realization of feasible projects by more sophisticated investors. Significant problems reported by investors relate to the power of incentive mechanisms to cover risks (such as the currency risk, the uncertainties of local equipment support, the lack of purchasing guarantees, and the imbalance risk in the free market), legal uncertainties (related to the reactive power control obligations and contribution to grid investments), inexperienced investors (improper wind measurements and evaluation, improper project planning, lack of turn-key contracts, incorrect turbine selection, misleading financial analyses), deficiencies in infrastructure (power limitations, financial and administrative weaknesses of the transmission company, low reimbursement value for grid investments realized by licensees, lack of long-term grid investment planning), licensing issues (high contribution fees, lack of an annual license application program, weak coordination among public institutions and lengthy permit procedures, priority of mining fields in licensed sites), and financial issues (lack of an insurance mechanism for local equipment, small number of local banks that can extend IFI loans).

More specific lessons are reported below:

- *The private sector and the government authorities should be well informed about the challenges of wind power projects.* A sustainable and an applicable support scheme should be defined at the outset of the process. It will be useful if the related public organization performs measurements and provides measurement results to the market for constructing wind power plants in suitable sites. The grid company should make necessary studies for calculation of required grid capacities for connections. The specifications of these sites, together with the available connection capacities, should be announced.

- *In the case of more than one application, an auctioning process should be performed to select the successful applicant;* but tendering should be done among equals. The limited connection capacity should not be allocated to an inefficient or unfeasible project owner just because it proposes the highest contribution fee. Implementation of a preselection method, which is based on technical merits and financial capability, would be useful.

- *To integrate wind power to the system without causing system reliability problems, the system operator should be equipped with wind-forecasting tools and control mechanisms*. Projects should be developed according to international technical and financial requirements. The capacity of the transmission system operator, the TEIAS, to integrate increasing volumes of wind and other intermittent renewable sources more effectively into the Turkish power system needs to be built up. More transmission investments and control/dispatch tools (supervisory control and data acquisition, or SCADA) are required for reliable system operation.

Notes

1. BOT, BO, and TOOR refer, respectively, to build, operate, and transfer; build and operate; and transfer of operating rights.
2. For details see Dilli (2013), "Wind Based Energy Development in Turkey," from which this chapter draws.

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CHAPTER 11

Summary and Conclusions

For policy makers seeking to design renewable energy (RE) support mechanisms suited to the needs of developing countries, the main lessons are clear and inescapable. Successful RE policies:

- Will only be effective once the state-owned utilities that are the buyers of grid-connected RE are themselves in good financial health (in all of the case study countries, the power utilities were under financial duress).
- Need to be grounded in economic analysis and the application of market principles to ensure economic efficiency.
- Require a sustainable, equitable, and transparent recovery of incremental costs.

The Financial Health of Power Utilities

The first and arguably most important lesson relevant to sustainable incentives for RE is that the power utilities involved need to be in good financial health. In most of the countries represented in this study, the utilities are in poor financial health, resulting in cash-flow problems. Such problems affect the rural distribution companies that are the typical buyers of RE. This is the case in Indonesia, where the consumer tariff is just 50 percent of PT Perusahaan Listrik Negara's (PLN's) cost, in Sri Lanka because of the unfortunate historical dependence on oil for power generation, and in Vietnam due to the reluctance of the government to raise consumer tariffs.

The effects of the power utilities' financial status are most clearly illustrated in the case of Sri Lanka: with coal displacing oil, the Ceylon Electricity Board's (CEB's) revenue requirement per kilowatt-hour has already begun to decline, offering the opportunity for consumer tariff reductions. But the CEB is still not in good financial health, and consequently still opposes having to absorb the incremental costs of RE.

Until such time as a nation's utilities are in good financial health, and operate under a transparent regulatory system that sets electricity tariffs on a sustainable basis—and that allows for the incremental costs of RE to be passed to the consumer—utilities will continue to oppose what they see as unnecessary costs that worsen their already poor financial situation. The idea that the incremental costs for RE can be recovered on a sustainable basis when utilities are in financial distress is unrealistic.

Power purchase agreements (PPAs) with RE producers require payment in cash within 30 days, which means that cash-flow management is the first priority of utilities that may have a significant number of RE generators. Such utilities are often concentrated in relatively small geographic areas—so it is the rural distribution companies, not those in large urban areas, that feel the most pain. This is well illustrated in the case of Vietnam, where the additional costs of building up the 115 kilovolt (kV) transmission network for power evacuation to the main 220/500kV grid fell on the distribution companies, and where assurances that the tariff methodology would eventually reimburse them for these incremental costs were greeted with great skepticism by entities faced with short-term cash-flow problems.

Widespread Consumer and Political Support

In countries in the Organisation for Economic Co-operation and Development (OECD), governments have been able to impose RE policies not only because of widespread consumer and political support (as in Germany), but because power companies are mainly in private hands and in good financial health (indeed, critics claim they are in *too* good a financial condition, at the expense of consumers), and tariff regulation is most often decided by independent regulators, reasonably free of direct government interference. If it in fact so chooses, an OECD government may make the case that a greater share of RE is in citizens' long-term interests, and then adapt to the challenges it is bound to face (see box 11.1).

Box 11.1 Lessons from Germany: Coping with Higher Shares of Renewables

An increasing share of RE generation does not react to market price signals. How then can we ensure efficiency of the market for plant dispatch? The benefits of a feed-in premium (see figure B11.1.1 for the case of Germany) in addition to feed-in tariffs (FITs) are that: (a) price signals reach RE generators, so they have incentives to adjust to market prices; (b) it helps in efficient market integration; (c) incentives improve diagnosis and balancing; (d) it makes available more players for developing innovative solutions for pooling or demand-side management; and (e) it opens new markets for RE (balancing). Possible drawbacks of a feed-in premium vis-à-vis a FIT are that: (a) wind and photovoltaic (PV) have limited abilities to react to market signals and (b) higher risks also imply higher costs.

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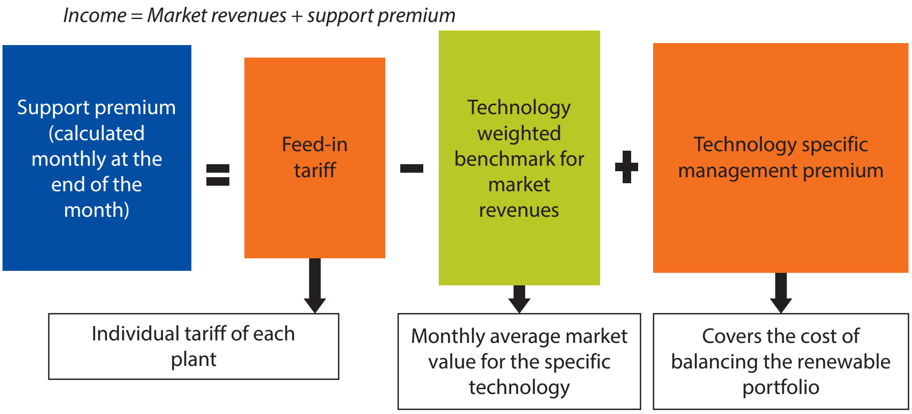
Box 11.1 Lessons from Germany: Coping with Higher Shares of Renewables *(continued)*

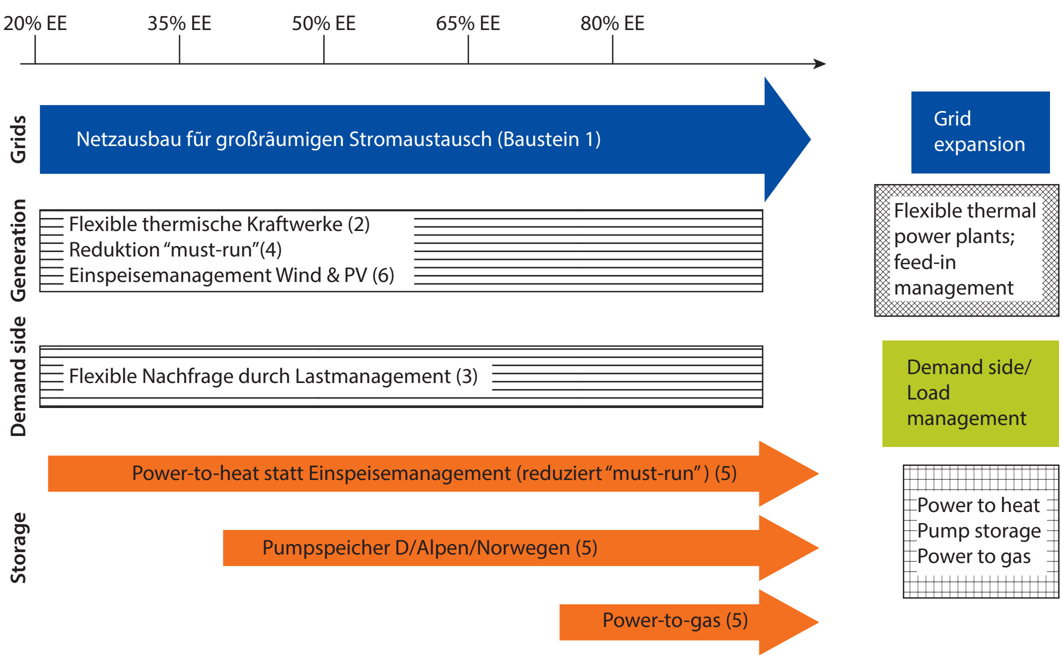
Figure B11.1.1 The German Feed-In Premium



The costs of a FIT can be lowered by:

- Introducing an annual degression right from the beginning.
- Installing a cap when growth becomes too fast too soon.
- Keeping tariff adjustment away from long parliamentary processes.
- Enhancing flexibility of the system and market integration of RE, by enhancing grid expansion, demand-side management, and storage (see figure B11.1.2).

Figure B11.1.2 Enhancing System Flexibility in Germany



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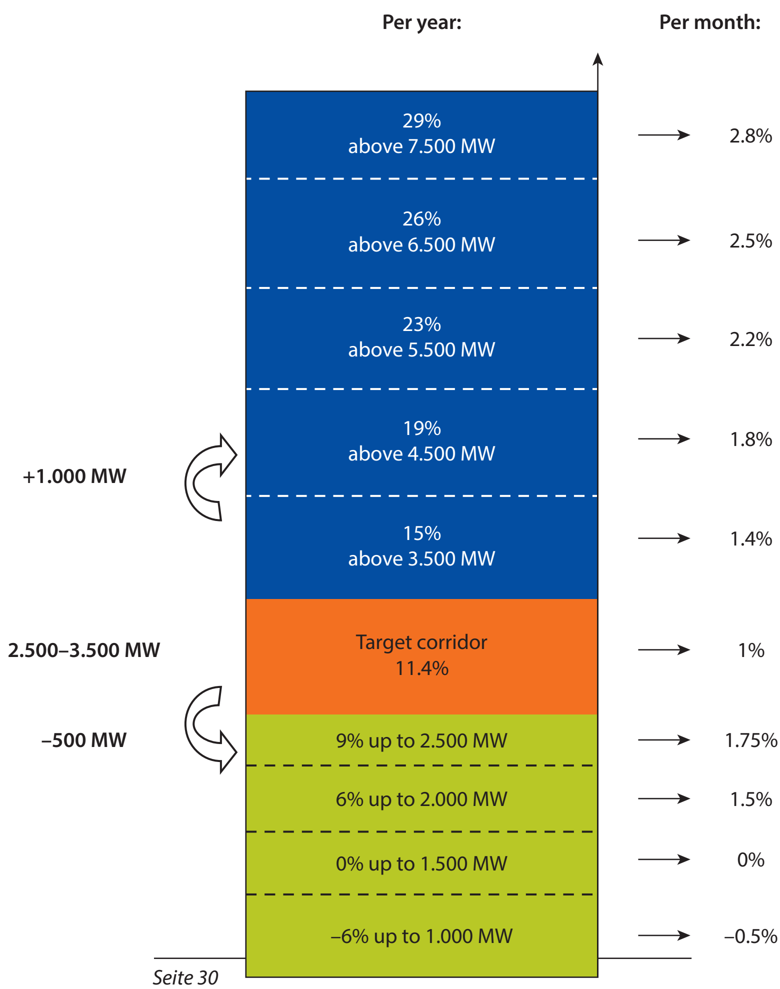
Box 11.1 Lessons from Germany: Coping with Higher Shares of Renewables *(continued)*

In the case of Germany an automatic degression was linked to the newly installed capacity of PV without a cost-assessment study and without undergoing political pressure. The key elements of the system are illustrated in figure B11.1.3.

- The basic annual degression: 11.4 percent until 3.5 gigawatts (GW) was newly installed + 4 percent automatic degression for each gigawatt installed on top of the 3.5 GW.
- Degressions come into effect monthly; to avoid seasonal sales they are based on growth in the last 12 months.
- There is an overall cap of 52 GW solar PV.
- Expiration of the Renewable Energy Sources Act (Erneuerbare-Energien-Gesetz, EEG) PV support, but continuation of priority feed-in.

Figure B11.1.3 Another View of System Flexibility in Germany



Source: Lauber 2013.
Note: MW = megawatt.

By contrast, developing-country governments have a fundamental conflict of interest: they not only set RE policy but they themselves own their (often technically insolvent) power companies—which require extensive government subsidies. In the battle between advocates of RE (typically in ministries of environment, or of energy) on the one hand, and the Ministry of Finance (MoF)—which foots the bill for the electricity subsidy—on the other, it is generally the MoF that wins, on grounds that subsidies are already unsustainable. According to this view, such subsidies should not be made worse by any additions attributable to RE—this lacks a clear economic rationale. In Vietnam the prime minister's office did not support the concept of a renewable fund dependent on even a low consumer levy. In Sri Lanka the National Energy Policy expressly states that the achievement of RE targets shall have no impact on consumer tariffs. And in Indonesia the MoF points out that the new geothermal feed-in tariff (FIT) violates legislation that geothermal prices must be subject to competition, and that the massive subsidies presently paid to support low consumer tariffs are already unsustainable and cannot carry yet further increases.

Setting Renewable Energy Targets

To set an economically rational target for a given year, decision makers need to estimate (a) the RE supply curve for that year, and (b) the expected avoided social cost of thermal generation. Where these two variables intersect defines the target.

Such an exercise is subject to several uncertainties: the cost of RE technologies may change, the world price of fossil energy may change, and new estimates of environmental damage costs may become available. But as shown in the case of the Croatia RE study (Appendix A), a simple analytical framework can deal with these uncertainties (by comparing the losses of setting targets too low against the losses of setting them too high).

Although these economic principles for setting RE targets have been advocated by numerous World Bank studies,[1] few countries have in fact set targets on this basis. Among our case study countries, most RE targets are simply political statements: Sri Lanka's target of 10 percent of total energy by 2015 was unsupported by any economic analysis (table 11.1). In Vietnam the targets for RE electricity generation in power development plans have no analytical basis: the plans for additional RE installed capacity are, quite simply, arbitrary, and the incremental costs were not even costed. The only exception is Brazil (where there are no official targets but indicative benchmarks derived by a 10-year expansion plan).

The lack of intellectual rigor in setting RE targets lies at the heart of the slow uptake of RE generation in most of the case study countries. Targets that bear no relationship to the economic realities of the incremental costs of RE are rarely achieved; even worse are those targets (and associated support tariffs) issued in the complete absence of knowledge about the magnitude of incremental costs

Table 11.1 Renewable Energy Targets in the Case Study Countries

Country	*Target*	*Rationale*
Vietnam	1,600 MW by 2020, set in the 7th Power Development Plan.	Unsupported by any detailed economic analysis.
Indonesia	9,500 MW geothermal by 2025; 3,967 MW by 2014.	Unsupported by economic analysis, or understanding of the incremental costs. Mainly a reflection of wishing thinking.
Sri Lanka	10% renewable energy by 2015.	Political statement, unsupported by economic analysis or incremental costs.
South Africa	10,000 GWh.	
Tanzania	n.a.	
Egypt, Arab Rep.	20% of the electricity generated by renewable energy by 2020, with a specific target of 12% coming from wind. This target translates to a total installed capacity of 7,200 MW of grid-connected wind energy in 2020.	
Brazil	Wind, small hydro, and biomass are expected to reach 27 GW by 2020.	Supported by a generation expansion plan.
Turkey	20,000 MW in 2023 (of which 600 MW geothermal) with 30% share of electricity from renewable energy.	

Note: GWh = gigawatt-hour; MW = megawatt.
n.a. = not applicable.

implied (the most notable recent example of which is the Indonesian geothermal tariff).

The rationale for targets for *biomass*-based, grid-connected power generation needs to be substantiated. From the perspective of reducing greenhouse gas (GHG) emissions, it does not matter whether rice husk is burnt for grid-connected generation, or whether it provides process heat at rice mills (as is the case in much of Vietnam): it is only important that it is not burnt or left to rot in fields (again, as in Vietnam) or discarded into waterways.

The Difficulty of Predicting Unexpected Consequences

The inability to anticipate unexpected consequences is a major problem. Consider the example of biomass in Vietnam: A major technical assistance program supported by a bilateral donor seeks to promote biomass use (and rice husk in particular) for power generation—for which no precise rationale has ever been provided except the presumably self-evident presumption that biomass power generation must surely be desirable. Presently rice husk is used as a fuel in rice mills, in ceramics kilns, and even brick making—where it replaces oil. Rice husk used for power generation will displace the most expensive fossil fuel, which is combined-cycle gas turbine (CCGT) (at projects where gas prices are linked to international fuel oil prices). So rice husk used for power generation will not *reduce* GHG emissions, it will *increase* GHG emissions.

In any event, the marketplace and technology innovations are overtaking the attempts of governments to intervene. Developments in pelletizing technology have now led to an emerging export trade in rice husk pellets to Japan and the Republic of Korea—with the result that rice husk prices have already increased to as much as $30/ton, making rice husk power generation in Vietnam even more expensive.

When this was pointed out at a recent consultation workshop, the reply was that it was a good thing for gas to be conserved, since it is in "short supply." It is true that much domestic gas is sold to Electricity of Vietnam (EVN) at not much more than its production cost (around $3.5 per million British thermal units [mmBTU]), and that there is concern about future gas shortages if no new fields are found soon. But the way to fix that problem is not to provide yet another subsidy to biomass electricity producers, but to reform gas pricing (in this case by adjusting the gas price for an appropriate depletion premium). To correct one subsidy by advocating another is poor economic policy.

Risk and Reward

The fundamental problem with administered pricing for RE—and production-cost-based FITs in particular—is the lack of recognition given to the relationship between risk and reward. All projects of a given RE technology are assumed to be of equal risk, and subject to a single estimate of what is a "fair" or "reasonable" return on equity. But as seen most clearly in the case of the Indonesian geothermal tariff, the risk at the tendering stage is very unevenly distributed across various areas according to the amount of information about the field being bid—with the result that the final electricity price may have to be renegotiated once the resource has been more precisely identified. And herein lies the benefit of an avoided cost tariff (ACT): the marketplace will determine which projects are economic and which are not at the issued tariff, without governments having to guess what rate of return is necessary; the same is true of auctions (whether by price, or by amount of subsidy required for access to a fixed price).

Institutional Barriers

While policies to provide stable price support are obviously necessary to induce private investment in renewables, other institutional and regulatory barriers may be just as critical.

The importance of standardized power purchase agreements (SPPAs) is no better illustrated than in the contrast between Vietnam and the Lao People's Democratic Republic. In Vietnam, largely as a result of a published tariff and a standardized power purchase agreement (SPPA), there is 750 MW of small hydro in place or under construction. In Lao PDR, where proposals to introduce a published tariff and an SPPA have been rejected by vested interests (there is a lively trade in memorandums of understanding, MOUs), the existing small hydro capacity is not much more than 30 MW.

The introduction of the Indonesian geothermal FIT is another example of a false premise, and lack of attention to institutional barriers. It was assumed by the government that an inadequate price was the main barrier to achieving geothermal targets. But in reality, the main barriers to bringing geothermal projects to financial closure are interminable delays in environmental permitting, the lack of an SPPA and contractual documents (though there is some hope that this is now resolved), and uncertainty about guarantees. Moreover, since the announced FIT was not clearly interpreted its introduction made the problem worse, not better.

The Avoided Cost of Carbon

The avoided cost of carbon is a useful indicator for the development of low-carbon emission options. Table 11.2 shows a comparison of such values, taken from the case studies in this report and other recent World Bank reports.

There are several reasons for the variation in estimates:

- As noted in chapter 2, such calculations depend on the dominant fuel in the least-cost case. For example, where concentrated solar power (CSP) competes against CCGTs, as in the Arab Republic of Egypt (which has low emissions per net kilowatt-hour), the avoided cost is much higher than where it competes against coal (whose emissions per net kilowatt-hour are three times that of gas), as in South Africa.
- The quality of the RE resource matters greatly. Wind in Egypt has annual plant capacity factors in excess of 40 percent, compared to Vietnam, where the planning assumption is 27 percent—and so the avoided cost in Egypt ($24 ton) is much lower than in Vietnam ($124/ton).

Table 11.2 Avoided Cost of Carbon

	Sri Lanka	*Vietnam*	*Indonesia*	*Egypt, Arab Rep.*[c]	*South Africa*[d]
Alternative	CEB Least-Cost Plan	—	—	Gas CCGT	Medupi coal
Hydro[a]	37	—	—	—	7[e]
Supercritical coal	7	—	—	—	—
LNG	86	—	—	—	105
Wind	—	—	—	24	124
NCRE[b]	87	—	—	—	—
CSP	—	—	—	300	115–55[f]
Nuclear	—	—	—	—	67
Underground coal gasification	—	—	—	—	223
CCGT (gas oil)	—	—	—	—	275
Geothermal	—	—	20–30	—	—

Note: CCGT = combined-cycle gas turbine; CEB = Ceylon Electricity Board; CSP = concentrated solar power; LNG = liquefied natural gas; NCRE = nonconventional and renewable energy; — = not available.

a. Hydro candidates are not in the least-cost plan but have been proposed in the past, and may be economic at given carbon prices.

b. Sri Lanka's composite renewables scenario to meet the 10 percent target.

c. World Bank 2013. This assumes CSP replaces 80 percent gas and 20 percent heavy fuel oil.

d. World Bank 2010.

e. South Africa's share (2,350 MW) of the 4,360 M Inge-III project in the Democratic Republic of Congo, including the cost of the 3,000-kilometer transmission line to South Africa.

f. Depending on the amount of storage provided.

There is widespread confusion about what value to use to reflect global environmental externalities. This is partly because of the uncertainty about future damage costs (and the discount rate to be used in the analysis of the global social avoided cost of carbon). The result is that every analyst uses whatever value seems appropriate.

Definitions of Renewable Energy

The question of what constitutes an RE technology is uncontroversial except for hydro, for which many countries establish size thresholds when stating RE targets. The rationale for setting this threshold, and the value of the threshold, show large variations (table 11.3).

Arbitrary thresholds between "good" renewables (small hydro) and "not good" (or even "bad") renewables (large hydro) are not rational. There are many examples of poorly executed small hydro projects with significant environmental

Table 11.3 Size Thresholds for "Small Hydro" Projects

	MW threshold	*Comments*
Brazil (PROINFA)	1–30	
Utah (United States)	1	
Nepal	5	
Sri Lanka	10	Set at the maximum level the CEB was willing to permit private developers, with the aim to break their earlier monopoly on power generation.
Thailand (VSPP)	10	The new VSPP is based on net metering.
Oregon (United States)	10	
UNFCCC	15	Simplified CDM rules apply below this threshold.
India	15	India defines projects up to 100 kW as "micro," 101 kW–2 MW as "mini," and 2–15 MW as "small."
European Union	20	Threshold for imports of project-based credits into the ETS.[a]
Vietnam	**30**	Set at the level for mandatory participation in the new competitive generation market (projects less than 30 MW being exempt).
Indonesia PSKSK, 1995	30 (Java Bali) 15 (Other)	
China	50	
Thailand (SPP)	90	The threshold was set at a high level so as to include many large gas-fired (and even coal-fired) cogeneration plants.

Note: Bold: Case study countries. CEB = Ceylon Electricity Board; CDM = clean development mechanism; kW = kilowatt; MW = megawatt; PROINFA = the Brazilian Program for the Promotion of Renewable Energy; PSKSK = the Indonesian avoided cost tariff; SPP = small power producer; UNFCCC = United Nations Framework Convention on Climate Change; VSPP = very small power producer.

a. The European "Linking Directive" that allows for the import of project-based credits into the European Union Emission Trading Scheme (EU-ETS) establishes special conditions for hydropower projects above 20 MW that involve the construction of a dam and reservoir: "In the case of hydroelectric power production project activities with a generating capacity exceeding 20 MW, Member States shall, when approving such project activities, ensure that relevant international criteria and guidelines, including those contained in the Report of the World Commission on Dams will be respected during the development of such project activities."

problems attributable to road construction and poor construction practices, just as there are good large hydro projects that meet all safeguard policies and have excellent environmental and social management plans. Indeed, even the EU includes large hydro in its RE targets (for electricity generation), so there is no rational reason for exclusion of large hydro in the RE targets of developing countries.

Indeed, it is quite rare for such thresholds to be set on the basis of specific environmental reasons. The 10 MW threshold in Sri Lanka was set not with any specific environmental concern, but due to the CEB's monopoly on hydro generation: 10 MW was the maximum it would allow any private sector developer entering the market. Indeed, a better definition might be power density (watts/square meters [m^2] of reservoir area), which although also controversial (as are all thresholds) at least has some explicit link to efficiency.

It is by no means clear how 30 small hydro projects of 10 MW each have environmental impacts that are smaller than a single 300 MW project, especially if the latter falls under internationally recognized safeguards procedures (as in the case of the World Bank Safeguards Policies, or the "Equator" principles).

The Transparency of Tariffs

There are wide differences in practice, in part dictated by very different legal traditions among countries and in part by the presence or absence of an *independent* regulator. The range of practices can be summarized as follows, in order of increasing transparency:

- Publish nothing except the tariff itself (Vietnam wind FIT, Indonesian geothermal tariff).
- Publish the methodology (Vietnam and Sri Lanka ACTs).
- Publish the data assumptions (the Philippines) (table 11.4).
- Publish the spreadsheet used for calculations (Sri Lankan 2009 FITs).

The Philippines provides a particularly interesting example insofar as it highlights the impact of alternative assumptions, and illustrates the conceptual problems of government administrators having to make judgments in the face of wide information asymmetries. Of course it is true that developers will always complain that administered tariffs are too low, and governments will always worry about "windfall profits" if the tariffs are too high: which is why the best way to set RE tariffs uses the social avoided cost of thermal energy.

Transparency is important; private developers and their lenders need to foresee the evolution of the tariff in the future, and need to understand the methodology of its derivation so that they can themselves make an assessment of future cash flows. For example, in the case of Vietnam, the government issued a regulation that described in detail the rationale and methodology, and how the tariff would be calculated each year.

Table 11.4 Tariff Assumptions in the Philippines (for Biomass)

		Proposed by developers	*DoE estimate*	*NREB estimate*
Representative size	MW	8.3	8.3	8.3
Project cost	$/kW	3,191	2,600	3,076
EPC cost	$/kW	1,982	2,324	2,366
Net capacity factors	%	72	72	72
O&M cost	$1,000/unit/year	1,645	987	987
Fuel cost	PhP/ton	1,297	1,464	1,297
	$/ton	31.6	35.7	31.6
Fee rate	kWh/ton	576	800	730
Equity IRR	%	22	16	16
After-tax WACC	%	12	10.2	10.2
Tariff	PhP/ton	8.22	6.09	6.55
	Cents/kWh	20.0	14.9	16.0

Source: Philippines NREB.
Note: Exchange rate $1 = PhP 41. DoE = Department of Energy; EPC = engineering, procurement, and construction; IRR = internal rate of return; kW = kilowatt; kWh = kilowatt-hour; MW = megawatt; NREB = National Renewable Energy Board; O&M = operation and maintenance; WACC = weighted average cost of capital.

We cannot conclude that transparency in setting and adjusting a support tariff will *necessarily* support its acceptance. But we *can* say that the issuance of an opaque tariff makes it very unlikely that it will be successful. The recent wind FIT in Vietnam and geothermal tariff in Indonesia were both issued without any indication of how the tariff was derived, and in the case of Indonesia, without any commentary about how (or even if) it might be adjusted in the future. Neither has been successful. In short, transparency is a necessary—though not a sufficient—precondition for a successful RE support tariff.

Auctions

The examples of Brazil, Turkey, and South Africa provide several important lessons for the design of incentive systems:

- Competitive bids are a viable alternative to FIT programs for RE, and potentially offer better price outcomes with fewer risks of excessive rents being appropriated by RE suppliers.

- The core rationale for introducing FITs in developed industrialized countries was to create market certainty and simplify and lower transaction costs to stimulate production and innovation in climate-change-mitigating RE technologies and markets, thus bringing down prices over time. But this rationale does not apply in many developing countries, especially in Africa, where the market for RE technologies is much smaller. Indeed, for small developing countries with low carbon footprints, the argument for greater use of more expensive RE technologies needs to be balanced against other development priorities.

- While FITs are potentially an attractive alternative to competitive biddings, transaction costs are high and many small developing countries may not have the resources or capacity to run such complex and expensive procurement processes. Competitive bid programs are generally simpler, although the requirements for good design and evaluation should not be underestimated. Development assistance programs, including those from development finance institutions, should consider carefully the costs and benefits of competitive bids versus FIT regimes. Ultimately, it will be more cost-effective to fund the higher initial transaction costs if lower power prices are likely.

The above lessons apply, in the main, to auctions for RE power. Competitive bids generally incorporate a weighting of price and nonprice factors while auctions are awarded solely on the basis of lowest price (sometimes after a number of rounds) among qualified bidders. Running effective auctions might require even more time, expenditure, transaction costs, expertise, and capabilities than tenders. Auctions may also encourage underbidding, with the risk of subsequent contract failures.

Meanwhile, the experience of dynamic reverse auctions—such as for wind energy in Brazil—has been positive: competition has driven prices down dramatically. But the low prices achieved in the wind auction have raised the fear that projects will not be implemented due to foreseen financial insolvency. On the other hand, if all projects were implemented, the low prices obtained in the wind auction might have paved the way to a direct competition between wind and other sources. This would make specific auctions for this technology unnecessary, and wind power could start competing in the regular contract auctions organized by the distribution companies, where all technologies participate on a level playing field without discrimination. Indeed, policies seeking to promote the introduction of RE economically must take into consideration the costs of RE generation (in relation to the avoided social cost of generation), resource availability relative to seasonality, and the technical conditions of the system (for example, the capacity of transmission and distribution lines to absorb specific volumes of RE). An assessment of policy efficiency in this context requires complex modeling coupled with the use of other tools that can help analyze the adequacy of the institutional structure in place as well as governance issues. The poor experience with wind concessions in China (unrealistic prices, projects not delivered) prompted a switch to FITs.

Note

1. As, for example, in the RE studies for Croatia, Serbia, Vietnam, South Africa, and China.

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APPENDIX A

Dealing with Uncertainty in Setting Renewable Energy Targets: Croatia

This report argues for a supply curve analysis as a rational basis for setting renewable energy (RE) targets: where the supply curve intersects with the avoided social cost of thermal generation is the optimal quantity of RE.

But neither this RE supply curve, nor the avoided social cost of thermal energy, is known with any certainty; both are subject to a range of assumptions, many of which are entirely beyond the control of national decision makers.

This appendix provides a practical example of how to deal with such uncertainties, based on a World Bank study of RE options for Croatia (Frontier Economics 2003).

Table A.1 shows the results of such an analysis of RE targets under three sets of input assumptions:

- *Unfavorable assumptions (for renewables)*. Higher than expected capital costs for wind turbines, lower valuations of local damage costs, and avoided social costs based on combined-cycle gas turbines (CCGTs) (that have the lowest emissions of local air pollutants per kilowatt-hour generated).
- *Expected assumptions*. Those that are seen by the government as the most likely.
- *Favorable assumptions (for renewables)*. Low capital costs for wind turbines, high valuations of local environmental damage costs, and avoided social costs based on coal.

The result is a wide range of potential targets, ranging from 37 megawatts (MW) to 1,337 MW! The range is so large because of the high uncertainty in many of the input assumptions, such as the damage cost of thermal generation (which varies by a factor of 4.5). Given such wide ranges in the value of the target, how should one proceed?

Such ranges in uncertainty exist in many planning problems, and one approach to making a decision is to ask about the *robustness* of the decision. Suppose we choose the 317 MW target based on an assessment of what is most likely and make investments to reach that target: renewables replace a

Table A.1 Economically Optimal Quantity of Renewables

		Unfavorable assumptions (for renewables)	*Expected (most likely assumptions)*	*Favorable assumptions (for renewables)*
Local externality value	€ cents/kWh	0.35	1	1.6
Wind turbine capital costs	€/kW	675	600	525
Technology replaced		Gas CCCT	*Gas CCCT* + coal	Coal
Net benefits, 2010	€ million	4.5	13.5	63
2010 target	GWh	175	1,070	3,340
2010 target	MW	37	317	1,335

Source: Frontier Economics 2003.
Note: CCCT = combined-cycle combustion turbine; GWh = gigawatt-hour; kW = kilowatt; kWh = kilowatt-hour; MW = megawatt.

mix of gas combined-cycle combustion turbine (CCCT) and coal, and wind turbine capital costs fall to €600/kW, which brings about estimated annual economic benefits of €13.5 million.

But suppose that having settled on and built the 317 MW target, the future brings *unfavorable* conditions—wind replaces only gas CCCT, and capital costs fall to only €675/kW. What then are the net benefits? And what are the net benefits of the more *favorable* assumptions? Indeed, for the three scenarios portrayed above, there are nine combinations of assumptions and futures.

The various outcomes of this analysis, with three choices and three actual outcomes, can be displayed in a 3 x 3 matrix, as shown in table A.2. The entries in columns 1, 2, and 3 represent the net benefits that correspond to each choice (represented by the rows). For example, if we choose the 317 MW target, but the actual outcome is unfavorable, then there is a net loss of €4.1 million, or if we choose the 1,334 MW target, and the actual outcome is favorable, there is a net benefit of €63.1 million, and so on.

How one makes a decision on the basis of these estimates of costs and benefits then depends upon the:

- Judgments about the probability of different outcomes.
- The decision maker's risk aversion.

Suppose all three outcomes were thought to be equally likely (that is, with a probability of 33.3 percent, as in table A.2). Then we may compute the expected value of the three alternative decisions, as shown in column 4. For example, the expected value, *E*, for the 317 MW target is:

E{expected assumptions} = $-4.1 \times 0.333 + 13.5 \times 0.333 + 29.9 - 0.333 =$ €13.1 million.

Similar calculations are shown for the unfavorable and favorable assumptions. These expected values—shown in Column [4], would be the basis for making a choice for a risk-neutral decision maker: in which case the target selected should be 317 MW, because it has the highest expected value (€22.9 million).

On the other hand, if the government is risk averse, then an alternative criterion is the *Mini-Max* decision rule, which calls for choosing the option that has

Table A.2 Payoff Matrix (Net Benefits in 2010, in € Million)

		Actual outcome			*Decision criterion*	
		Unfavorable	*Expected*	*Favorable*	*Risk neutral [expected value]*	*Risk averse [mini-max]*
		[1]	*[2]*	*[3]*	*[4]*	*[5]*
Probability of outcome		33.3%	33.3%	33.3%		
Target (MW)	*Assumption*					
37	Unfavorable	4.5	6.7	10	7	4.5
317	Expected	–4.1	13.5	29.9	13.1	–4
1,334	Favorable	–7.4	13.1	63.1	22.9	–7.4

Source: Frontier Economics 2003.
Note: MW = megawatt.

Table A.3 Revised Payoff Matrix: Future Coal Plant Unlikely
€ million

		Actual outcome			*Decision criterion*	
		Unfavorable	*Expected*	*Favorable*	*Risk neutral [expected value]*	*Risk averse [mini-max]*
Probability of outcome		30%	65%	5%		
Target (MW)	*Assumption*					
37	Unfavorable	4.5	6.7	10	6.2	4.5
317	Expected	–4.1	13.5	29.9	9.0	–4.1
1,334	Favorable	–7.4	13.1	63.1	9.5	–7.4

Source: Frontier Economics 2003.
Note: MW = megawatt.

the best *worst* outcome. Column 5 of table A.2 shows the worst outcome for each target; based on this criterion the 37 MW target is optimal, since it has the *best* worst outcome of €4.5 million.

The assumptions favorable to RE are based on coal being the fossil fuel being displaced, but given the government's policy not to build a new coal plant, a lower probability may be assigned to this scenario. For example, if the favorable scenario (with coal as the avoided cost) is given only a 5 percent chance of occurring, then the payoff matrix will appear as shown in table A.3.

Now the gain in expected value by choosing the optimistic scenario over the mid-level scenario (from €9.0 to €9.5 million) is quite small, particularly when faced with a possible €7.4 million loss if the unfavorable future occurs.

Such analysis may well require many additional assumptions, but it has the advantage that it forces decision makers to be explicit about their risk preferences, and makes the connection between assumptions and the robustness of decisions more transparent.

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APPENDIX B

Multi-Attribute Decision Analysis and Trade-Off Plots

Multi-attribute decision analysis (MADA) is a set of techniques designed to go beyond the single objective cost-benefit analysis as a basis for making decisions.[1] These offer some practical help in coming to better decisions in the face of multiple objectives where not all variables of interest can be monetized—by providing better insights into the problems, by forcing clarity about goals and risks, by facilitating understanding (if not agreement) among diverse stakeholders, and by assisting decision makers in making trade-offs (Hobbs and Meier 2000). In the assessment of renewable energy (RE) technologies, greenhouse gas (GHG) emissions are often treated as a separate attribute precisely because they are so difficult to value, and invite a distracting debate about discount rates. Undiscounted lifetime GHG emissions are thus an oft-encountered attribute.

The World Bank Study of Sri Lanka (Economic Consulting Associates 2010)—presented in chapter 4—used the following non-monetized attributes to complement the usual economic efficiency variable of total system cost (as generated by the Wien Automatic System Planning [WASP] model):

- *Local air pollution impacts*. Population and stack-height-weighted sulphur dioxide (SO_2) emissions.
- *Energy security (diversity)*. The Herfindahl Index of generation mix (an index used in economics to measure the concentration of firms in an industry)[2]:

$$H = \sum_{n} s_i^2$$

  where s_i is the share of generation from the *i*-th supply source (the lower the value of *H*, the greater is the diversity of supply).
- *Consumer impact*. Levelized average consumer tariff, Rs/kilowatt-hour (kWh).
- *Undiscounted lifetime GHG emissions*.

When framing such attributes, the first priority is to make sure that the attribute is a meaningful indicator of the underlying goal. For example, the simplest proxy for local air emissions is tons emitted per year—now a routine output of most power systems planning models that supposedly provide information about environmental impacts. But as noted, in fact *tons* of emissions say very little about actual impacts on human health, or about the costs—fiscal, social, and other—of health care. In the case of GHG emissions, it matters not where in the world the emission takes place, but in the case of local pollutants such as particulate matter, where and at what height the emission takes place is of crucial importance. One kg of PM_{10}[3] emitted at ground level by a diesel bus in the center of Colombo has an impact on human health several orders of magnitude greater than a kg of PM_{10} emitted from a tall utility stack in a remote and sparsely populated area[4] (and where most emissions are in any event blown out to sea). The difference between gross emissions, and population-weighted SO_2 emissions as a more meaningful proxy for actual damage costs, is illustrated in figure B.1. When location is taken into account, even though gross emissions increase (with the addition of many new coal projects), damage costs may decrease as the location shifts to less densely populated areas.

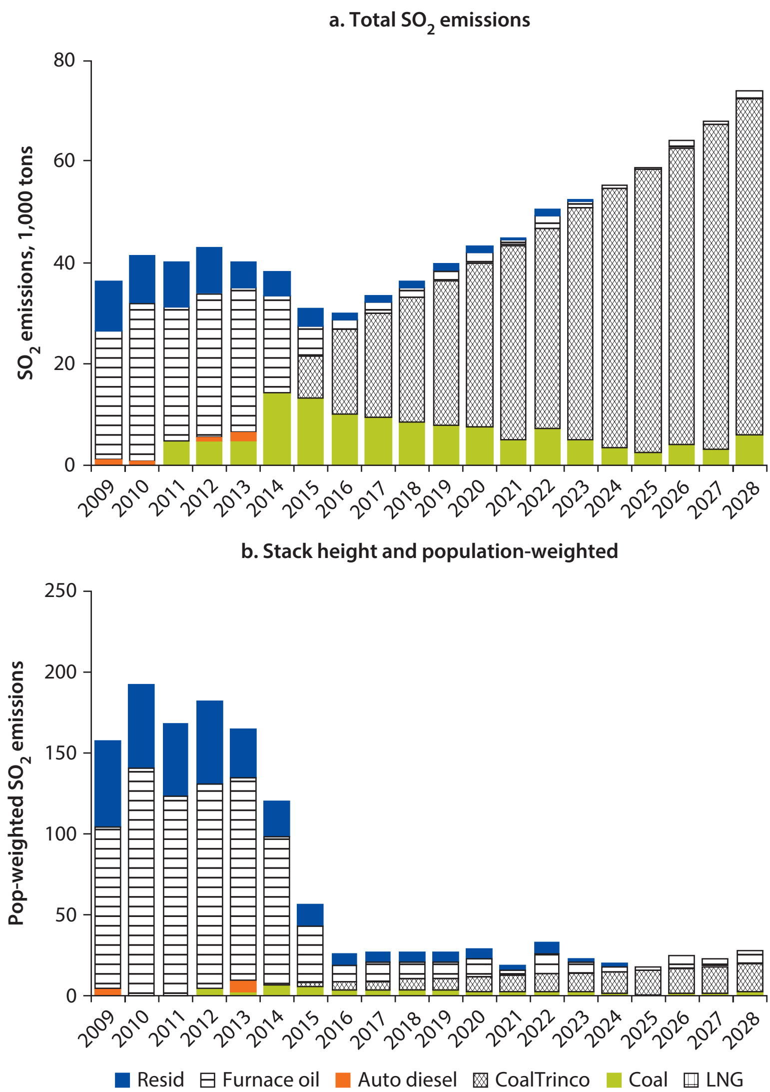
Trade-off curves are simply *XY* plots of attributes, two at a time. Typically one shows quadrants relative to the baseline, into which fall the options that may be defined as perturbations of that baseline. Figure B.2 shows such an (illustrative) plot.

Each quadrant contains different types of projects:

- *Quadrant I* contains solutions best described as "lose-lose"—options that have higher emissions and higher costs. Typical options in this quadrant would be those involving fossil-fuel price subsidies (assuming the baseline is at economic prices), or *not* subcritical coal units (if the baseline includes supercritical units).
- *Quadrant II* contains solutions involving trade-offs—costs decrease, but emissions increase. No flue gas desulphurization (FGD) or pumped storage (PS) are two options that typically occupy this quadrant.
- *Quadrant III* contains solutions that are "win-win," of which demand-side management (DSM) and reduction in transmission and distribution (T&D) losses are typical examples. Here both attributes improve—that is, there are lower emissions *and* lower economic costs.
- *Quadrant IV* again contains options that require a trade-off—emissions decrease but only at an increased cost. RE options and the substitution of coal by liquefied natural gas (LNG) are typical options to be found here.

Figure B.2 also shows the "trade-off curve." This is defined as the set of non-dominated options. Option B is said to be dominated by option A, if option A is better than B in both attributes. Thus, in figure B.2, DSM dominates the baseline—and because it is better in both attributes, a rational decision maker would never prefer the baseline over DSM. Intuitively, one may say that options

Figure B.1 Emissions vs. Stack Height and Population Weighted Index, Sri Lanka

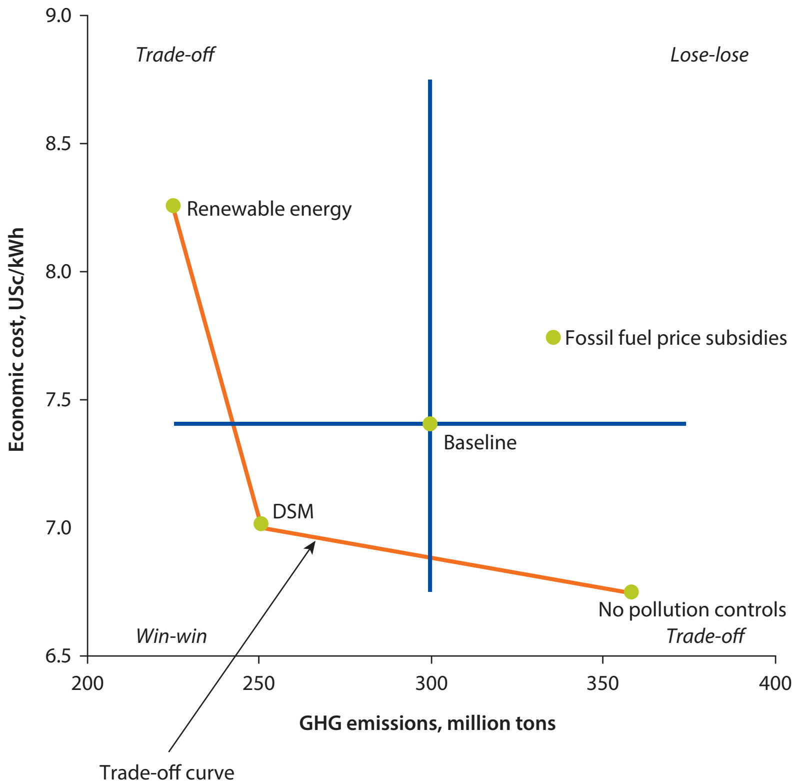


Source: World Bank 2010.
Note: resid = residual oil-fired projects (with no sulfur controls, typically burning high sulfur oil); coalTrinco = coal-fired projects with flue gas desulphurization (FGD) on Trincomalee Bay on the eastern coast, sparely populated; coal = coal projects with FGD sited north of Colombo on the west coast; LNG = liquefied natural gas; SO_2 = sulphur dioxide.

that lie on this trade-off curve are "closest" to the origin, but they all require trade-offs.

If, as in this illustrative example, there is a sharp corner in the trade-off curve (the so-called "knee set"), the option that occupies that corner (or one that may be close to it) would receive special attention. In this example, "no pollution controls" has greater emissions than DSM, but only a very small cost

Figure B.2 Illustrative Trade-Off Plot



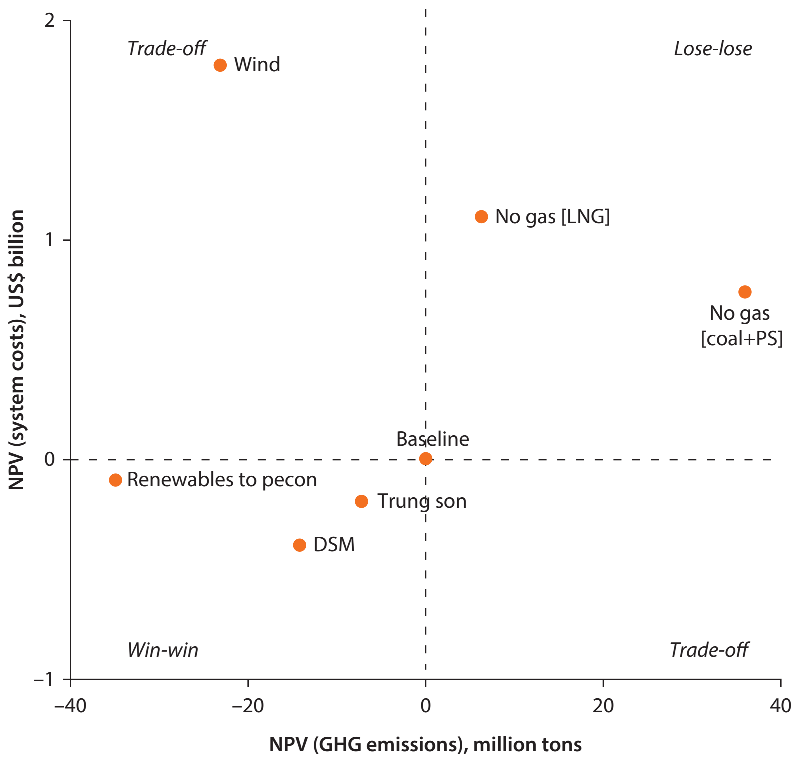
Note: GHG = greenhouse gas; kWh = kilowatt-hour; USc = U.S. cents.

advantage—so a decision maker would have to give enormous weight to cost and almost no weight at all to emissions to choose this option. Similarly, "RE" (as drawn here) has only slightly lower emissions, but a much higher cost than DSM—so again, to prefer RE over DSM would require that huge weight be given to emissions, and not much to cost. Not all trade-off plots have such knee sets, or even any win-win options, in which case decisions are more difficult to make.

Figure B.3 shows a trade-off plot for Vietnam. Trung Son is a World Bank–financed 260 megawatt (MW) hydro project (World Bank 2011). The baseline in this case, which defines the quadrants, is the least-cost capacity expansion plan *without* Trung Son. The system cost and GHG emissions are plotted relative to the baseline: negative amounts indicate improvements to the objectives (cost reductions, GHG emission reductions).

In the lose-lose quadrant are scenarios in which the assumed availability of domestic gas in the baseline is not fulfilled, and must therefore be replaced either by imported LNG or coal plus PS to meet the intermediate and peaking demand of the system. In the trade-off quadrant IV is wind—which in Vietnam is very

Figure B.3 Power Sector Options in Vietnam



Source: World Bank 2011.
Note: DSM = demand-side management; GHG = greenhouse gas; LNG = liquefied natural gas; NPV = net present value; PS = pumped storage.

expensive (because the wind regime is at best modest), though it does of course reduce GHG emissions.

Trung Son is in the win-win quadrant by virtue of lower lifetime power production costs, *and* lower GHG emissions since it displaces gas-fired combined-cycle plants. Also in the win-win quadrant is non-wind renewables. "Renewables to P_{econ}" refers to the point at which the avoided social cost of thermal generation intersects the RE supply curve, which defines the optimal level of RE. DSM (demand-side management and efficiency improvement) is also in this quadrant. Both DSM and renewables (mainly small hydro) are also being financed by the World Bank.[5]

Notes

1. At the World Bank, the use of MADA was first elaborated in an Environment Department Research study of Sri Lanka (Meier and Munasinghe 1995) and subsequently adopted in 1998 for a major World Bank study on environmental issues in the Indian power sector (World Bank 1999), which included detailed state-level

assessments for the states of Rajasthan and Karnataka (World Bank 2004a, 2004b). This followed the introduction of such techniques in the 1990s into the Integrated Resource Plan procedures adopted by many utility regulatory commissions in North America, and the pioneering work of Ralph Keeney and Howard Raiffa (1993). The most recent applications in the Bank include a 2009 study of alternatives to coal-based power generation in Sri Lanka (whose results are described in chapter 4), and an economic analysis of the controversial Medupi coal-fired project in South Africa. The academic literature on MADA applications has grown rapidly since 2000: Wallenius and others (2008) found 267 MADA studies in the energy and water resources literature.

2. The quantification of energy security is one of the more difficult issues. In the case of the United States, increasing energy security is arguably a matter of *reducing* imports. On the other hand, for Nepal, which is dependent entirely on hydro resources, increasing security (and reducing exposure to hydrology risk) is a matter of *increasing* imports of electricity and fossil fuels for power generation. In the case of Sri Lanka, where for the past 20 years major additions to power generation have only been based on imported auto-diesel, importing coal diversifies supply sources and also improves energy security.
3. Particulate matter (no greater than 10 microns in diameter).
4. In a study of damage costs in six large cities in the developing world, the average damage cost in $/ton per 1,000,000 population per $1,000 of per capita income was estimated at $42/ton for particulate matter (no greater than 10 microns in diameter) emitted from high-stack power plants, compared to $3,114/ton from low-level stacks (standby diesel units, diesel buses). See Lvovsky and others (2000).
5. In other words, DSM is not, strictly speaking, a mutually exclusive option (in the sense of the old OP10.04 guidelines for economic analysis): rather, it is a *complement* to supply-side options, and is part of any portfolio of win-win options.

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APPENDIX C

Estimating Incremental Costs from Renewable Energy Supply Curves

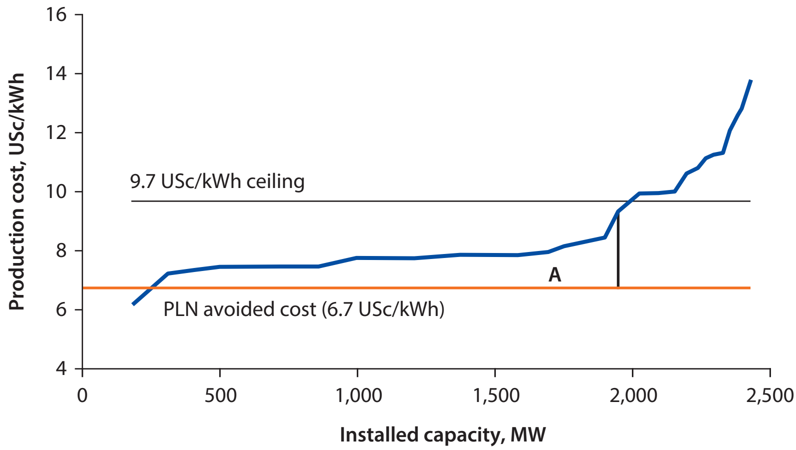
As discussed in chapter 5, increasing the old geothermal tariff ceiling of 9.7 cents/kilowatt-hour (kWh) to 12.5 cents/kWh raised the question of the potential impact of the new ceiling on an additional subsidy payable by the Ministry of Finance (MoF). The incremental costs can be visualized by looking at the intersection of the supply curve with the old and new ceiling prices, and calculating the areas in the relevant segments of the curve. This visualization methodology was first used in the China Renewable Energy Scale-up Program (CRESP) in 2003 (Spencer, Meier, and Berrah 2007).[1]

The supply curve for geothermal projects in Java and Sumatra is shown in figure C.1, which enumerates a total capacity 2,432 megawatts (MW) of geothermal projects. Also shown in this figure are the estimated Perusahaan Listrik Negara (Indonesian State Electric Utility Company, PLN) avoided costs (6.7 cents/kWh),[2] and the former 9.7 cents/kWh ceiling price.

If only the projects whose costs are below the 9.7 cents/kWh ceiling were built, then 1,949 MW would be built. The other 483 MW of geothermal projects in the supply curve exceed the ceiling and would not be built. The incremental costs associated with this level of geothermal development are represented by the (roughly triangular-shaped) area **A** under the curve. This area represents the incremental costs, i.e., the subsidy that must be paid to PLN by the MoF. For the costs as shown here, this comes to $120 million per year once all 1,949 MW that have ceiling prices below 9.7 cents/kWh have been built—assuming the bid tender prices (or negotiated prices for the old, legacy Wilayah Kerja Pertambangan Panas Bumi [geothermal work areas as known in Bahasa, Indonesia] [WKP])[3] were at the levelized cost of energy as reflected in the supply curve.

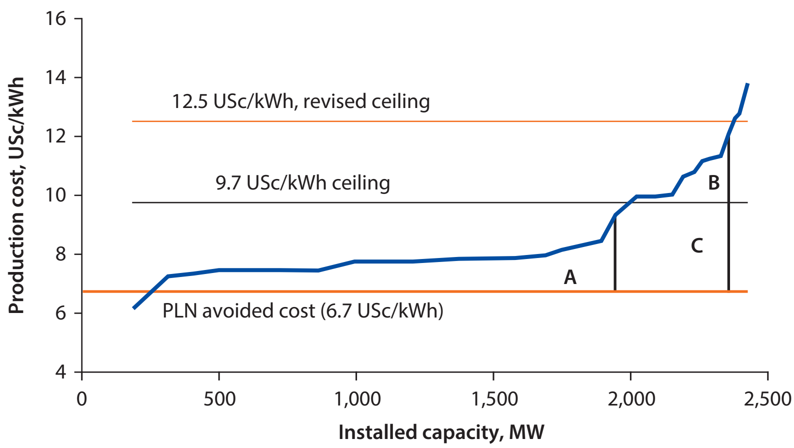
Figure C.2 shows the potential impact of raising the ceiling to 12.5 cents/kWh—which intersects the supply curve at 2,362 MW. Now the incremental costs increase by the additional amount represented by the areas C+B ($104 million), for a *total* subsidy of $214 million per year once all 2,362 MW have been built.

Figure C.1 Castlerock Supply Curve, Java and Sumatra (with the Old Ceiling Price)



Source: Meier, Lawless, and Randle 2014.
Note: kWh = kilowatt-hour; MW = megawatt; PLN = Perusahaan Listrik Negara (Indonesian State Electric Utility Company); USc = U.S. cents.

Figure C.2 Impact of a 12.5 Cents/kWh Ceiling Price



Source: Meier, Lawless, and Randle 2014.
Note: kWh = kilowatt-hour; MW = megawatt; PLN = Perusahaan Listrik Negara (Indonesian State Electric Utility Company); USc = U.S. cents.

Such visualizations have proven useful in communicating the concept of supply curves and incremental costs of renewable energy to stakeholder consultation groups. They are easily calculated in simple spreadsheets, and easily presented for different implementation scenarios of bidding behavior (see table 5.8).[4]

Notes

1. Recall figure 2.4 (in chapter 2).
2. PLN now pays the international price for coal.
3. Wilayah Kerja Pertambangan Panas Bumi (geothermal work areas in Bahasa, Indonesia).
4. The amounts calculated here correspond to column [4] of table 5.8 (i.e., tender bids at the levelized cost of energy [LCOE]).

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green press INITIATIVE

Joining a debate often dominated by widespread misconceptions, this book introduces a rigorous and objective economic perspective on current renewable energy support mechanisms and an empirical analysis of their strengths and weaknesses. It complements the analysis with operational advice on how the regulatory design may need to be modified to minimize the impact on the budget and be affordable to the poor, as well as how to identify and fill the financing gap.

The proposed analytical framework illustrates tradeoffs between thermal electricity generation and renewable energy supply with local, regional, and national impacts in the short and in the long run; studies distributional impacts; captures externalities; and compares alternative projects based on equivalent output and cost. Unsurprisingly, the book stresses the need to get the economic, financial, and institutional basics right for the deployment of renewable energy. The study also integrates renewable energy subsidies with fossil subsidies, bringing important questions to the fore, such as the following: to reduce carbon intensity in developing-country economies, is it more efficient to deploy renewable energy or implement alternative options, such as eliminating subsidies on fossil fuels?

A representative sample of countries based on energy endowments (coal, natural gas, and hydro-based systems) and policy incentives (from feed-in tariffs to auctions) are examined in the book: Brazil, the Arab Republic of Egypt, Indonesia, South Africa, Sri Lanka, Tanzania, Turkey, and Vietnam. These case studies compare the incremental cost of renewable energy with the average cost of generation and determine the impact that alternative support has on the government budget and residential consumers.

The main lessons emerging from *The Design and Sustainability of Renewable Energy Incentives* are that, to be successful, such incentives

- will be effective only once the state-owned utilities who are the buyers of grid-connected renewable energy are themselves in good financial health,
- need to be grounded in economic analysis and accompanied by the application of market principles to ensure economic efficiency, and
- require a sustainable, equitable, and transparent recovery of incremental costs.

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