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Vietnam Power Sector: Generation Options

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Abbreviations and acronyms

ACT	Avoided cost tariff
ASTAE	Asia Sustainable and Alternative Energy Programme (World Bank)
BNE	Best New Entrant
BOT	build-operate-transfer
bp	Basis point (see glossary)
CCCT	combined cycle combustion turbine
CBM	Coal bed methane
CDCF	Community Development Carbon Fund
CDM	Clean Development Mechanism
CEB	Ceylon Electricity Board (Sri Lanka)
CER	Certified emission reduction (see glossary)
CFB	circulating fluidised bed
CGM	Competitive generation market
cif	cost insurance freight
CPI	consumer price index
CRESP	China Renewable Energy Scale-up Program
DAF	Development Assistance Fund (of the GoV), now VDB
DFCC	Development Finance Corporation of Ceylon
DSCR	debt service cover ratio
EMA	Energy Market Authority (of Singapore)
EPC	engineering, procurement, construction (contract)
ERAV	Electricity Regulatory Authority of Vietnam
ERR	economic rate of return
ERU	emission reduction units (see glossary)
ESDP	Energy Services Delivery Project (World Bank, Sri Lanka)
ESMAP	Energy Sector Management Assistance Programme (World Bank)
EU	European Union
EVN	Vietnam Electricity
FERC	Federal Energy Regulatory Commission (US)
FFA	Forward freight agreement
FGD	flue gas desulphurisation
FIDIC	International Federation of Consulting Engineers
FIRR	financial internal rate of return
fob	free on board
FOREX	Foreign exchange
FS	feasibility study
GEF	Global Environment Facility
GDP	gross domestic product
GHG	greenhouse gas
GoSL	Government of Sri Lanka
GoV	Government of Vietnam
HFSO	High sulfur fueloil (380cst, 3.5%sulfur)
HH	Household
HHV	Higher heating value
ICB	international competitive bidding
IDA	International Development Association
IDC	interest during construction
IFI	international financial institution
IoE	Institute of Energy
IPP	independent power producer

IRR	internal rate of return
ISO	International Standards Organisation
JCC	Japan Crude Cocktail
JICA	Japan International Cooperation Agency
JSC	Joint Stock Company
LF	load factor
LV	low voltage
LHV	Lower heating value
LIBOR	London Inter-Bank Offer Rate (see glossary)
LNG	liquefied natural gas
LRMC	long run marginal cost
MARD	Ministry of Agriculture and Rural Development
MCM	million cubic meters
MER	Market exchange rates
mmBTU	Million British Thermal Units
MMS	mandated market share (see glossary)
MV	medium voltage
NPT	National Power Transmission Company
MNES	Ministry of Non-conventional Energy Sources (India)
MoF	Ministry of Finance
MoIT	Ministry of Industry and Trade
MoNRE	Ministry of Natural Resources and Environment
MoU	memorandum of understanding
MWL	Minimum water level
O&M	operation and maintenance
OCCT	Open cycle combustion turbine
OECD	Organisation for Economic Cooperation and Development
OPEC	Organisation of Petroleum Exporting Countries
ORB	OPEC Reference Basket (crude oils)
PAD	Project Appraisal Document (of the World Bank)
PCF	Prototype Carbon Fund
PC	pulverised coal
PDP6	6th Power Development Plan
PDP5	5th Power Development Plan
PLN	Perusahaan Listrik Negara (Indonesian State Electric Utility Company)
PPA	power purchase agreement
PPP	purchase power parity
PTC	production tax credit
PURPA	Public Utilities Regulatory Policy Act (of the US, 1978)
PV	photovoltaics
QF	qualifying facility
RARE	Remote Area Rural Electrification
RCEE	Research Centre for Energy and Environment
RE	renewable energy
REAP	Renewable Energy Action Plan
RESPP	Renewable energy small power producer
RoR	run-of-river
SBV	State Bank of Vietnam
SCF	Standard conversion factor (see glossary)
SEIERP	System Efficiency Improvement, Equitization and Renewables Project (World Bank)
SERF	Shadow exchange rate factor (see glossary)

SGD	Singapore dollars
SHP	small hydro project
SLF	system load factor
SPPA	Standardised Power Purchase Agreement
T&D	Transmission and distribution
TA	technical assistance
TGC	tradable green certificate
ToR	terms of reference
UAE	United Arab Emirates
UNFCCC	United Nations Framework Convention on Climate Change
UREA	Uttranchal Renewable Energy Agency (India)
USC	ultra super critical
US	United States (of America)
VAT	value added tax
VDB	Vietnam Development Bank (previously DAF)
VER	Verified emission reduction (see glossary)
VSRE	Vietnam-Sweden Renewable Energy Programme
WACC	weighted average cost of capital
WTI	West Texas Intermediate (crude oil)
WTP	willingness to pay

UNITS and CONVERSION FACTORS

cst	Centistoke (a measure of viscosity)
cumec	cubic meters per second
TCM	thousand cubic metres
m/s	meters/second
GW	Gigawatt = 1000 MW
MW	Megawatt = 1000 kW
KW	Kilowatt
bbl	barrel
kWh	kilowatthour=3412 BTU
BTU	British Thermal Unit
KCal	Kilocalorie
mmBTU	Million British Thermal Units
mtpa	million tons per annum
dwt	Dead weight tons

CURRENCY EQUIVALENTS

VND	Vietnamese Dong
$US	United States Dollars 1$US=17,773 VND

1 INTRODUCTION

Background

1. Economic growth of over 7 percent over the past several years is at the root of many of the issues in Vietnam's energy sector: growing GDP feeds increasing demand, while meeting that demand enables GDP to continue to grow. The electricity sector has met the challenge well. Between 1995 and 2008, household access increased from 50 percent to nearly 94 percent percent; and annual per capita consumption increased from 156 kilowatt hours (kWh) to about 800 kWh. In recent years, a supply shortage has become more visible, though it narrowed in 2008 as demand growth reduced during the economic downturn.

2. Power demand in Vietnam has grown at around 15% per year for the past several years and is forecast to continue to grow at that rate for the next two to three years, before tailing off to about 10% in 2015 or so. The strong demand for power is closely linked to Vietnam's economic growth (GDP is expected to continue to grow at 7.5% per year or more over the same period). Light manufacturing, food processing and other electricity-intensive industries have been and are expected to continue to be major sources of economic growth, hence power is a key input for continued economic growth. Business climate surveys cite electricity quality and availability of one of the top two infrastructure constraints and one of the top four of all constraints to business growth in Vietnam.

3. The main electricity provider is Vietnam Electricity (EVN), which owns about two thirds of all generation in Vietnam. Through its subsidiary National Power Transmission Company (NPT) and Power Companies, EVN owns and operates the transmission and medium voltage (MV) distribution systems, the low voltage (LV) distribution to the main urban areas and LV distribution in some rural areas. EVN's average tariff revenue was about 5.3 cents/kWh in 2008, sufficient to make a profit. Losses (technical and non-technical losses plus electricity for EVN's own consumption) fell to an estimated 11 percent in 2008, down from over 20 percent ten years earlier.

4. Non-EVN actors include two internationally owned and financed power plants under build, operate, transfer (BOT) arrangements at the Phu My complex in southeastern Vietnam. Large Vietnamese energy and

construction companies also own independent power plants (IPPs). Between them, IPPs and BOTs accounted for about one third of generation in 2008. About two-thirds of LV distribution is owned and operated by local distribution utilities (LDUs) which receive their supply from EVN.

5. The Government of Vietnam (GoV) passed a market-oriented Electricity Law in November, 2004, followed by the establishment of the Electricity Regulatory Authority of Vietnam (ERAV) in 2005. The Government is implementing a roadmap for reform, the first step of which is scheduled to be completed in 2009. It will establish a Generation Competitive Market (GCM) and unbundle the sector, with separation of ownership of generation, transmission and distribution.

6. In the 6th Power Development Plan (PDP6), Vietnam has a good planning framework to meet this growth. PDP6 envisages growth of all three major power generation sources – hydropower, gas and coal – as well as a significant contribution from renewable energy, predominantly small hydropower of less than 30MW, and imports, mainly from China and Laos. Transmission and distribution system investments must accompany the increase in generation capacity, and there is substantial scope for demand side management to ensure that the system is optimized for least economic cost. Work has now started on the 7th Power Development Plan.

7. The central task for the power sector in Vietnam is to meet demands for electricity in sufficient quantity and of an acceptable quality, in as commercially and financially efficient a way as possible. Several issues arise if this task is to be accomplished in the short and medium term. They are:

- Optimizing power investments – particularly for generation;
- Financing the investments that must be made;
- Implementing the reforms in the power industry and restructuring EVN;
- Improving access and service quality; and
- Addressing shortcomings in pricing and tariffs.

Study objectives

8. This study discusses the first of these issues. – though inevitably there is some overlap, particularly with respect to pricing (and hence reforms in related sectors such as coal and gas), and with respect to linkages between generation choices and capital mobilisation. (private investment is much more likely in small hydro than in large hydro; and more likely for short gestation gas-fired projects than long gestation coal or nuclear projects).

9. The study has four specific objectives.

i. ***To informdecisions about technology choices***. Whatever the uncertainties, there is little doubt that Vietnam's generation mix will shift to coal, and by 2020 require significant coal imports. While Vietnam's per capita GHG emissions are still low even with the anticipated increases in emissions, the importance of maximizing the efficiency of coal use remains a top priority. While the CGM provides the necessary financial incentives for maximizing efficiency, technical and coal quality issues constrain some of the choices. The options need careful examination, and the necessary policy consequences drawn.

ii. *To inform decisions on energy and power sector policy.* The government is committed to the competitive generation market, and to a range of policy reforms (that the Bank proposes to support under a Development Policy Loan). But many important linkages to related sectors – notably coal and gas - remain unresolved, and great uncertainty remains about the best way to promote renewable energy.

iii. *To inform the power sector planning process.* The Government has started a 7th PDP, and we hope to provide some insights on how the current planning methodology might be improved. PDP7 will be under great pressure to examine low carbon options, and analytical approaches used by the Bank elsewhere could be usefully applied in Vietnam (carbon shadow pricing and life-cycle assessment, multi-attribute trade-off analysis to identify the most cost-effective options for reducing carbon emissions)

iv. *To inform the internal discussion within the Bank on how Vietnam's power sector development can be assisted*. Stated simply, the main question is whether the Bank should support Vietnam's development of thermal generation, and, if so, how.

10. These objectives notwithstanding, it is not our purpose to provide an alternative plan to the 7th PDP, currently under preparation by IoE. All of the scenarios presented here are limited to the purpose of identifying and discussing issues.

Outline of the report

11. Chapter 1 reviews the domestic resource endowment. The main questions relate to the degree to which these resources will constrain generation choices over the longer term. In part because of very high load growth assumptions, PDP6 concluded that resource constraints would force Vietnam into imported coal and nuclear power by 2020-2025.

12. Section 3 reviews the international energy markets with a view to assessing future international energy prices. Relative prices are the issue in the choice of thermal generation: at present, both domestic gas and coal prices for power generation are highly subsidized, but in future it is the relative international fuel prices that will govern fuel choices.

13. Section 4 assesses technology choices: we evaluate the extent to which technology choices may be constrained by the unique characteristics of the domestic resources, and to what extent international advances in clean coal technology may benefit Vietnam.

14. Section 5 examines load forecasts. The past decade has highlighted the difficulties of load forecasting: those of PDP5 were too low, those of PDP6 were too high. The relevance of load forecasts to generation planning is largely its influence on *timing* of capacity additions: since the lead times for different technologies vary from 2-3 years for gas projects to 5-7 years for nuclear and hydro, how to deal with load forecast uncertainties is one of the main challenges for power system planners.

15. Section 6 reviews the most likely future path of the power system as seen by the Vietnam's foremost power system planning entity, the Institute of Energy. In the short term, this is largely shaped by the investment commitments made over the past few years as anticipated by PDP6. Over the longer term it is shaped by the current views regarding the load forecast, and the timing of when the constraints on domestic resources begin to require imported thermal fuels.

16. Section 7 review carbon accounting issues – of increasing concern given the urgency of dealing with climate change. These issues affect not just greenhouse gas emissions from thermal projects, but also the potential for emissions from hydro reservoirs, and the need to include emissions not just from combustion, but from the entire life-cycle. Emissions from gas combustion are significantly lower than from coal combustion, but life cycle emissions from gas (particularly where gas fields have high CO2 contents, or when converted to LNG) may considerably narrow the difference in emissions against mine-mouth coal generation.

17. Section 8 examines alternatives to the business as usual reference case of Section 6. We assess these alternatives in terms of economic production costs and in terms of their greenhouse gas emissions, with a view to identifying win-win options, and, where trade-offs are required, with a view to identifying cost-effective ways of achieving low carbon growth. Technology plays some role in this (such as the choice of supercritical v. subcritical coal combustion), but the broader policy context – such as reforms in the coal and gas sectors to reduce fuel subsidies – prove to be equally important.

18. Section 9 discusses the specific problem of how best to deal with risk and uncertainty. Much concern has been expressed about energy security, and the extent to which, and how, countries need to hedge against the volatility of international fuel prices and the uncertainty of load forecasts.

19. Section 10 concludes the study with a summary of recommendations. These fall into the four categories related to the main objectives of the study: recommendations on technology choices; recommendations for policy reform; recommendations for improving the planning methodology; and recommendations about the role of the World Bank in assisting the continued development of the power sector.

2 DOMESTIC RESOURCES

20. In this section we examine the availability of domestic resources for power generation. Vietnam's gas resources are in the South, and there appear to be few prospects for significant natural gas finds in the North. Whether domestic gas supplies will be adequate to meet the longer-term gas requirement for power generation in the South is unclear. The question of gas sector development to meet such potential demands is taken up in a separate report.[1]

21. For coal, there is a widespread view that domestic coal resources cannot meet demand over the medium to long term, forcing coal imports, and a gradual phasing out of coal exports.

22. In the case of hydro, there is a similar perception that the bulk of the available conventional economic hydro has been developed, and that over the longer term, hydro imports and pumped storage will need to provide the peaking power capacity of the North. However, in the absence of a supply curve, such generalisations lack a rational basis in economic analysis: whether higher cost hydro resources should be developed will depend upon the cost of the natural gas alternative, (which in turn will depend upon the level of oil prices over the long term)[2]

Gas

23. There are wide variations in forecasts of gas use for power generation. According to the Gas and Petroleum Masterplan (GPMP) total annual gas supply including natural and associated gas will increase from the current 5 billion cubic meter currently to about 11.1 billion cubic meter in 2010; 14.6 billion cubic meters in 2015 and 14 - 15.6 billion cubic meters in 2020.[3] The estimates in the PDP6 plan itself, however, are slightly lower,[4]

[1] *Gas Sector Development Framework*, Draft Report to the World Bank, 25 May 2009.

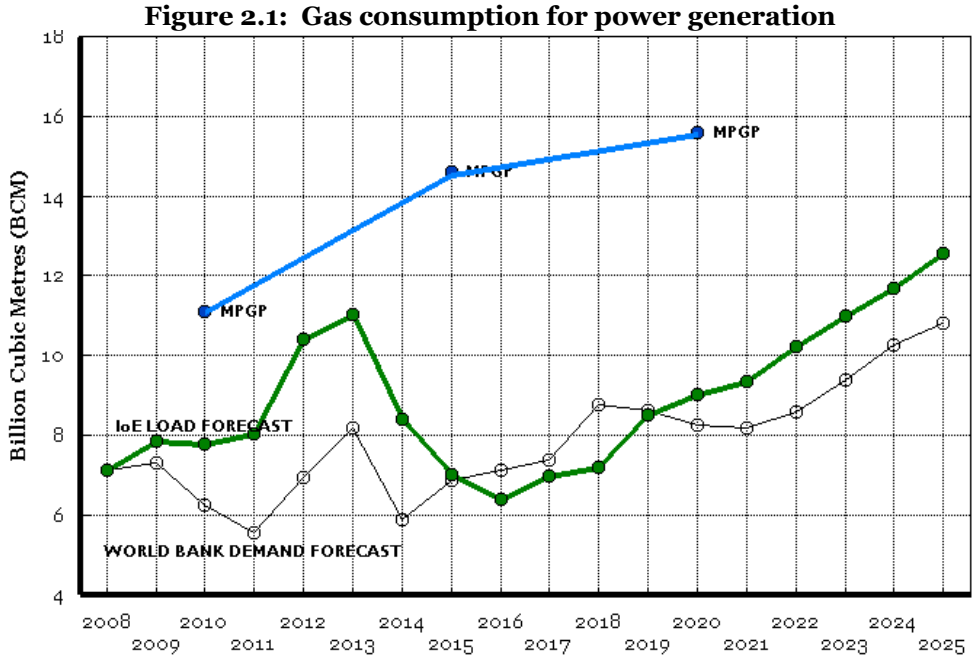
[2] As argued in the next section.

[3] Annual gas demand for other sectors such as fertilizer industry (Phu My, Ca Mau plants), steel, ceramic, cement, etc is forecasted to increase from 0.5 billion cubic meter at present to 1.75 billion cubic meter in 2010 and up to 1.8 - 2.0 billion cubic meter in following years.

rising to 7.6 BCM by 2010, 11.7BCM by 2015, 14.7 BCF by 2020 and 16.8BCM by 2025.

24. Such large increases are a consequence of the very high electricity demand forecasts in the PDP6, but in the last few years, electricity growth has been less than expected by PDP6. This is illustrated in Figure 2.1, which compares the gas consumption for power generation as estimated by IoE in July 2009 for the IoE and World Bank load forecasts[5] with earlier forecasts, namely that of the Masterplan for Gas and Petroleum,[6] and the PDP6 estimates.

Figure 2.1: Gas consumption for power generation



25. Gas demand for power generation as predicted in the IoE models shows a peak around 2013, and then declines to about present levels, before gradually increasing again in the latter part of the planning horizon. The decline in consumption is a consequence of the impact of significant new hydro capacity in the next few years, including Son La and Lai Chai.

26. Whether such variations could be accommodated under the current take-or-pay arrangements is unclear. Gas fired power plants have annual take-or-pay volume. At the end of the year, if take or pay volume has not been fully consumed, generator must pay the difference (unused gas), but the

[4] PDP6, Chapter 7, Generation development (see Table 7.7)

[5] These are discussed further in Section X.

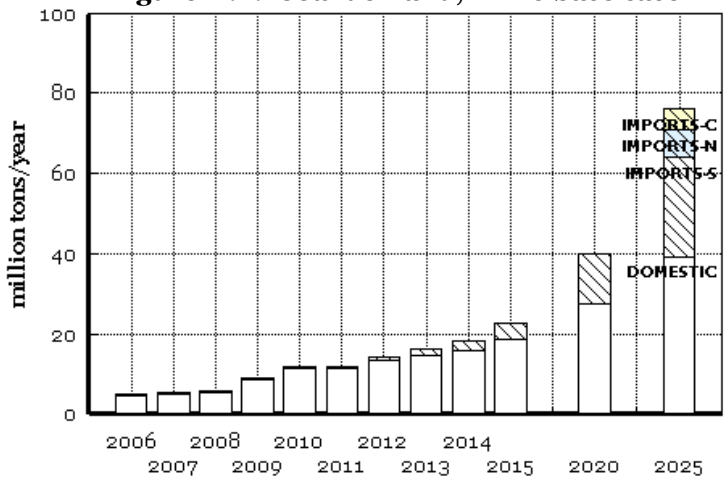
[6] Master Plan for Gas and Petroleum Development of Vietnam to 2015 with view to 2025

not consumed volume is carried over and can still be used by the power plant during the next year i.e., take or pay obliges to pay by the end of the year the gas volume, but actual gas volume can be used over a 2 year period.

Coal

27. PDP6 anticipates a very large increase in domestic coal use,[7] rising in the base case from 5 million tons per year (mtpy) to 18.6 mtpy in 2015 and 27.7 mtpy by 2020. Similarly imported coal rises from less than the present 1 mtpy to 12 mtpy by 2020 and 37 mtpy by 2025 (Figure 3.2).

Figure 2.2: Coal demand, PDP6 base case



	Domestic	imported coal			total
		north	centre	south	
2006	4.8			0.3	5.1
2007	5.1			0.4	5.5
2008	5.3			0.4	5.6
2009	8.6			0.4	8.9
2010	11.4			0.4	11.7
2011	11.5			0.4	11.9
2012	13.6			0.6	14.2
2013	14.6			1.6	16.2
2014	15.7			2.5	18.2
2015	18.6			4.0	22.6
2020	27.7			12.4	40.0
2025	39.4	7.2	5.2	24.5	76.2

[7] As of January 2008, Vietnam's total coal reserves were estimated at 40.93 billion tons[7], but the recoverable reserves are 3.39 billion tons. Nearly all these reserves are anthracite in Northern Vietnam. There are reserves of sub-bituminous coal in the Red River Delta and peat in the Mekong River Delta, but they are not easily recoverable.

28. The 2005 estimates for the domestic coal demand for power generation in the Coal Masterplan[8] are quite similar, as shown in table 3.1, with 2025 demand projected at around 42 mtpy.

Table 3.1. Forecasted coal supply for power generation, 1000 tons

Year	Basic case	High case
2008	6,585	7,535
2009	9,255	13,655
2010	16,305	21,935
2011	23,385	23,985
2012	27,455	27,785
2013	27,785	27,975
2014	27,785	28,545
2015	27,380	29,380
2020	32,693	40,430
2025	41,790	42,830

Source: IoE

29. The extent to which coal supply could be expanded as quickly as these forecasts require is unclear, and there has been much talk about the need to limit coal exports to ensure an adequate supply for domestic needs.

30. In any event, a comparison of these forecasts with the latest IoE model results is again instructive. The domestic supply constraint is binding, and any increase in demand (for the high IoE load forecast) is taken up by imported coal, plus some additional domestic gas (which at 14.2BCF in 2025 is still below the Gas Masterplan estimate for 2020 of 14-15 BCF).

Table 3.2: IoE modelling results for 2025: coal consumption

		World Bank load forecast	IoE load forecast
load forecast	TWh		
domestic coal	mtpy	40.5	40.6
imported coal	mtpy	41.4	66.7
gas	BCF	12.2	14.2

31. The forecasts of large amounts of imported coal being needed starting in 2015 raises the obvious question of whether imports in such quantities would actually be available to Vietnam (were they required). That subject is taken up in the next section (on international coal prices) – for it is generally true that for a freely traded international commodity, there is never a shortage at the prevailing spot market price (Indeed fact, there is much more likely to be a shortage of coal in the *domestic* market, where prices are set by Government).

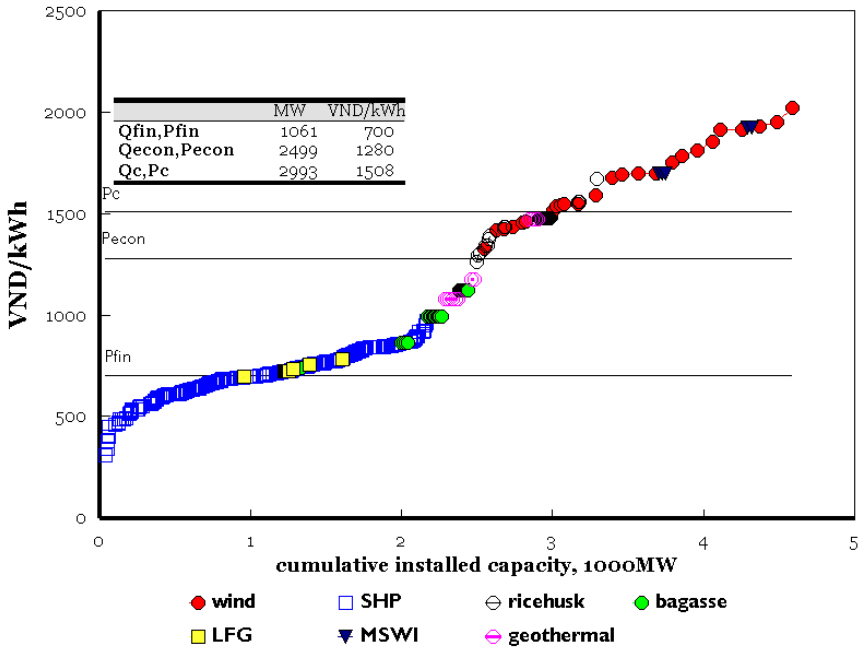
[8] Vietnam Coal and Mineral Industries Group, *Vietnam's coal industry development Master Plan for the period 2006-2015 with a vision to 2025*, Hanoi, 2008

Renewable energy resources

32. Over the past few months a lively debate over the contribution of renewable energy resources has arisen in Vietnam, fueled in part by increasing pressure from developers and some bilateral assistance agencies to promote wind power. PDP6 included some ambitious targets for small hydro, and recent reforms to introduce a standardised power purchase agreement (SPPA) and a published avoided cost tariff (ACT) will provide clearer signals to developers about the type of renewable energy facility that is of most value to the system.

33. The Renewable Energy Master Plan has derived the supply curves for renewable energy: as shown in Figure 2.4 for cumulative installed capacity. Under the ACT first issued in December 2008, the average tariff yield (denoted P_{fin} in Figure 2.4) is around 700VND/kWh. This is expected to enable around 1,060 MW of renewable energy, mainly small hydro.

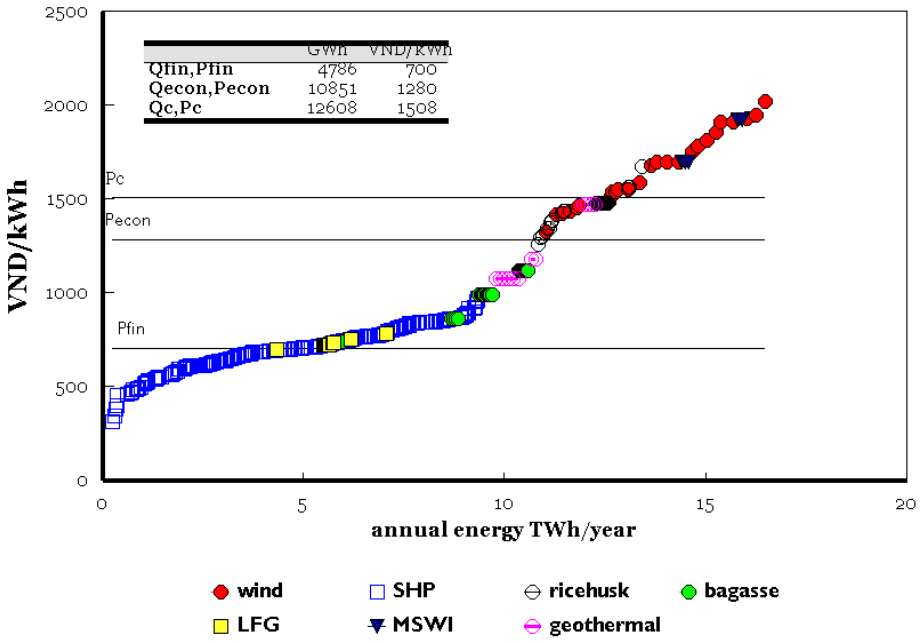
Figure 2.4: Supply curve for renewable energy, MW



*LFG=**landfill gas;** SHP=**small hydro;** MSWI =**municipal solid waste incineration***
P_{fin}=average tariff yield at the avoid cost tariff
P_{econ}=average avoided social cost of thermal energy
$P_c=P_{econ}$+CERrevenue at 15$/ton$CO_2$

34. The corresponding supply curve for energy is shown in Figure 2.5. Increasing the tariff to the avoided social cost (P_{econ}), estimated by a recent MoIT report to be around VND1,200/kWh, would enable an additional 6,000 GWh per year of renewable energy, more than doubling the amount enabled at the ACT.

Figure 2.5: Renewable energy supply curve, GWh



*LFG=**landfill gas;** SHP=**small hydro;** MSWI =**municipal solid waste incineration***
P_{fin}=average tariff yield at the avoid cost tariff
P_{econ}=average avoided social cost of thermal energy
$P_c=P_{econ}$+CERrevenue

35. While the extent of Vietnam's small hydro resource is well documented., that of the wind resource is still controversial: past estimates of physical potential are generally recognized to be speculative, and the amount of high quality wind data in the public domain remains limited. Nevertheless, based on the best data available that was used by REMP to create the supply curve, the cost of wind power is significantly above the avoided social cost of thermal generation – most identified wind projects in Figure 2.5 lie at the upper end of the supply curve. Table 3.3 shows the contribution of different renewable energy technologies expected to be introduced by different levels of the tariff.

Table 3.3: Renewable energy by technology

	Installed capacity, MW				Energy, GWh			
	Pfin	Pecon	Pg	total	Pfin	Pecon	Pg	total
SHP	1,054	976	0	2,030	4,757	8,814	8,814	22,385
rice husk	0	15	139	154	0	66	658	724
bagasse	0	250	0	250	0	896	896	1,791
LFG	7	45	0	52	29	214	214	456
MSWI	0	0	0	0	0	0	0	0
geothermal	0	152	79	231	0	862	1,249	2,110
wind	0	0	276	276	0	0	778	778
total	1,061	1,439	494	2,993	4,786	10,851	12,608	28,244

Source: REMP

3 FUEL PRICES

36. The optimal generation mix is strongly influenced by fossil fuel prices. The balance between hydro and renewables on the one hand, and thermal generation on the other, is set by the *level* of fossil fuel prices. And the balance between oil, coal and gas generation is set by the *relative* prices of these fuels.

37. Forecasts of fossil fuel prices over the long planning horizons necessary for power sector planning are not distinguished by their accuracy, and we make no claims that the price scenarios constructed here benefit from some unique insight. However, it is worth noting that forecasting the world oil price 6 years from now is in many ways easier than forecasting the world oil price 6 *months* from now. Indeed, the price forecasts issued by the World Bank have long taken the view that what matters for investment decisions are estimates of fuel prices over the longer term, which are guided by the long-term marginal costs of increasing global oil supplies, not by short term volatility determined by the happenstance of inventory disruptions, geopolitical uncertainty and speculation.

The World Oil Price

38. The starting point for deriving a consistent set of border prices for an economic analysis is an assumption for the world oil price. Unfortunately forecasts of oil prices, even for as little as one year ahead, are notoriously unreliable. In this study we use $75/bbl as the long term crude oil price, for reasons explained in Box 3.1.

Box 3.1: Crude oil prices

Forecasting oil prices is a difficult business. In December 1998, crude oil prices were at a historic low, briefly touching 10$/bbl. In early 1999 The *Economist* Magazine predicted $5/bbl as the long run crude oil price! Ten years later, at the peak of the oil price bubble of in July 2008 when crude oil traded at 140$/bbl peak, Goldman Sachs confidently forecast that $200/bbl would be reached by 2009 – shortly after which the price collapsed to $35/bbl, at which point the Goldman Sachs forecast was for a further decline to $30/bbl: in fact by mid 2009, oil was trading around $50/bbl, and the price in November 2009 is around $75/bbl. Goldman Sachs may be the world's most profitable Investment Bank, but its profits are certainly not attributable to its published oil price forecasts.

The World Bank report "*Global Economic Prospects 2009: Commodities at the Crossroads*" proposes $75/ bbl as the long term price (at constant 2008 prices), based on the proposition that the long-run marginal cost will be set by the cost of extraction from high cost sources such as Canadian tar sands. But the critical question is whether the pace of addition of new reserves will match the inevitable increase in global oil demand once global economic growth resumes after the present recession - about which authorities differ sharply. The World Bank's stated view is that

> *if the pace at which new oil reserves are discovered declines, the rising price for oil will make alternative sources of energy (including coal, natural gas, nuclear, and renewable alternatives) more competitive and induce increased conservation and technological change. Simulations suggest that if oil production fails to rise between now and 2030, oil prices might double but most of the energy shortfall would be met by increased coal and natural gas consumption, albeit at higher cost.*[9]

IEA's 2009 Global Energy Outlook[10] has a somewhat higher crude oil price forecast, increasing to $100/bbl by 2020, and $115/bbl in 2030 (at constrant2008 prices).

39. Definitions of crude oil price vary, and for Vietnam we recommend use of the so-called OPEC reference basket.[11] The World Bank definition of average crude oil price (as used in its "Pink Sheets" and commodity price forecasts) is the average of West Texas Intermediate (WTI), Brent, and Dubai, typically $1-2/bbl higher than the OPEC Reference basket. The Japan crude cocktail (JCC) is used as a benchmark for LNG pricing, and lags

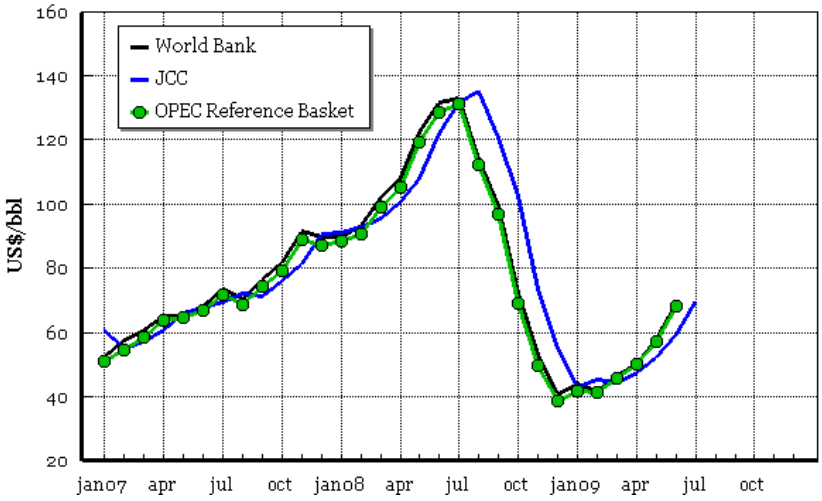
[9] *Global Economic Prospects 2009, op.cit., p.40*

[10] International Energy Agency, *2009 World Energy Outlook*, November 2009.

[11] The new OPEC Reference Basket (ORB), implemented on 10 September 2007, is currently made up of the following crude oils: Saharan Blend (Algeria), Girassol (Angola), Minas (Indonesia), Iran Heavy (Islamic Republic of Iran), Basra Light (Iraq), Kuwait Export (Kuwait), Es Sider (Libya), Bonny Light (Nigeria), Qatar Marine (Qatar), Arab Light (Saudi Arabia), Murban (UAE) and BCF 17 (Venezuela).

the other indicators by about one month (peaking in August rather than July 2008) (Figure 3.1).

Figure 3.1: Monthly average crude oil prices



Source: OPEC; World Bank, Japan Petroleum Association
JCC=Japan Crude Cocktail (average of oil imports to Japan, cif)

Petroleum products

40. In Vietnam, we may take as the border price of fueloil or diesel the Singapore spot market price (as published, for example, by Platt's) plus freight (and insurance) from Singapore to the Vietnamese port. These spot market prices are closely tied to the world crudeoil price at consistent relative prices: the ratio of fueloil to ORB averages 78.5% with little variation over time (Table 3.1).

Table 3.1: Oil prices

	ORB(1)	gasoil	fueloil (2)	fueloil
	$/bbl	$/bbl	$/bbl	ratio to ORB
	[1]	[2]	[3]	[4]=[3]/[1]
1997	18.7	24.2	14.7	0.79
1998	12.3	15.5	9.9	0.80
1999	17.5	19.1	14.8	0.85
2000	27.6	32.5	23.0	0.83
2001	23.1	27.3	19.4	0.84
2002	24.4	28.2	21.8	0.89
2003	28.1	33.4	25.1	0.89
2004	36.1	47.3	26.6	0.74
2005	50.6	68.7	38.4	0.76
2006	61.1	82.1	46.4	0.76
2007	69.1	88.5	55.5	0.80
2008	94.5	122.1	74.9	0.79
avg 2006-2008	74.9			0.785

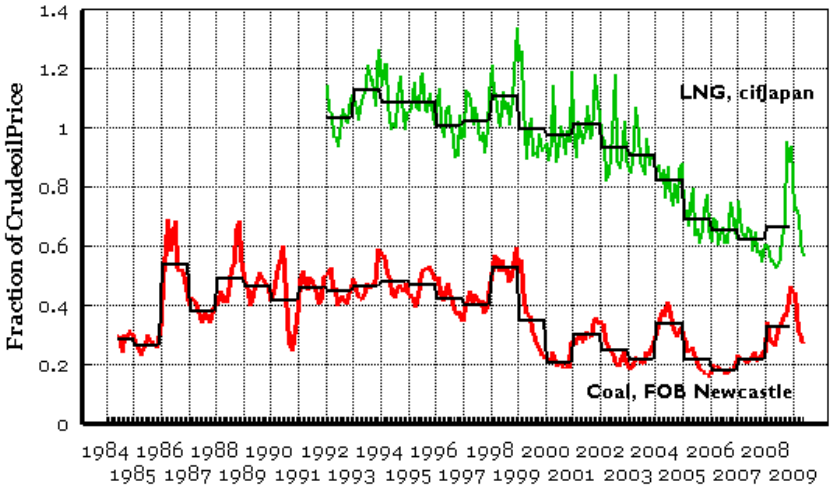
Source: OPEC, Annual Statistical Bulletin
(1) OPEC Reference Basket, as published by OPEC
(2) Singapore spot market price, 380cst, 3.5% sulfur
(3) Singapore spot market price, 0.5% sulfur.

Natural gas

41. Setting the border price of natural gas is more difficult because pipeline gas is not widely traded in Southeast Asia, and the pricing benchmarks are not as transparent (as they are, for example, in the USA, for which the price at Henry Hub is the generally accepted benchmark). Most gas traded in the Asia Pacific region is in the form of LNG, for which there is even less transparency in pricing – the exact pricing formulae are often confidential, and can only be inferred from indirect sources (such as from customs data of the importing countries).

42. The relative price of LNG to crude oil (on a BTU basis) has undergone significant changes over the past 10 years: between 1992 and 2001, the LNG price was at or slightly above crude oil parity; but since 2002, the average price has fallen significantly, and since 2005 has been between 60-70% (Figure 3.2).

Figure 3.2: Prices for LNG and Coal relative to the crudeoil price (as $/mmBTU)



To establish the LNG price we use the ratio given in the 2008 IEA World Energy Outlook, which forecasts the long term LNG price (cif Japan) at 76% of the oil price (on a BTU basis). This gives a price of $10.26/mmBTU delivered to a coastal power plant location in Vietnam (Table 3.2).

Table 3.2: Estimated price of LNG, cif Vietnam

		75$/bbl
Crude oil price	$/mmBTU	12.93
IEA forecast, relative LNG price	[ ]	0.77
cif Japan	$/mmBTU	9.96
less shipping Qatar-Japan	$/mmBTU	1.00
FOB Qatar	$/mmBTU	8.96
Shipping Qatar-Vietnam	$/mmBTU	0.70
CIF Vietnam	$/mmBTU	9.66
Terminal & regasification costs (1)	$/mmBTU	0.60
Delivered price	$/mmBTU	10.26

43. The price paid for natural gas by power plants in Vietnam varies across fields and by project:

- $3.2/mmBTU for gas delivered from Block 6.1 of the Nam Con Son field, escalating at 2% 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%/year, to which is added a transportation cost of about $0.9/mmBTU.
- gas delivered to the Ca Mau project is priced at 45% of the Singapore fuel oil price (on a BTU basis) plus 1.17$/mmBTU (for transportation). If crude oil stands at $75/bbl,[12] the delivered price of gas at Ca Mau will be $5.58/mmBTU.

44. However, even the Ca Mau gas pricing formula gives a price that is significantly below international prices, the relevant benchmark for which is the price paid by Singapore for gas imported from Malaysia – namely 90% of the HFO price (on a BTU basis) as quoted in the Singapore market (for 90 day forward delivery).

45. We thus have a variety of possible benchmarks for the economic price of coal (given a $75/bbl crude oil price):

- The actual Cau Mau price, 45% of Singapore HSFO +1.17 = $5.58/mmBTU.
- The price based on the Singapore import price from Malaysia $8.82 /mmBTU
- The LNG price, based on cif Japan less a transportation differential to Vietnam, $10.26/mmBTU (Table 3.2).

46. In this study, we use the average of the Ca Mau (Vietnam) and Singapore prices, namely $7.20/mmBTU.

47. One of the main questions in the development of additional gas resources is pricing.[13] The gas sector development framework report notes that the present arrangements of case-by-case ad hoc negotiation with the Government is a negative factor for private investors in gas, and the report argues for "value-based" pricing, in effect setting the gas price on the basis of imported coal generation, for which a sample calculation suggests a price of $6.10/mmBTU (when imported coal is priced at $90/ton cif Vietnam). It rejects setting gas prices on the basis of the cost of imported LNG.[14]

48. Gas *pricing* is about the allocation of resource rents, in such a way as to provide sufficient incentive for the mobilisation necessary investment. However in this report the focus is on the economic case for the gas v. coal

[12]Except where otherwise noted, any reference to crude oil price is to the value of the Opec Reference Basket (ORB), as published in OPEC's Monthly Bulletin.

[13] *Gas Sector Development Framework*, Draft Report to the World Bank, 25 May 2009.

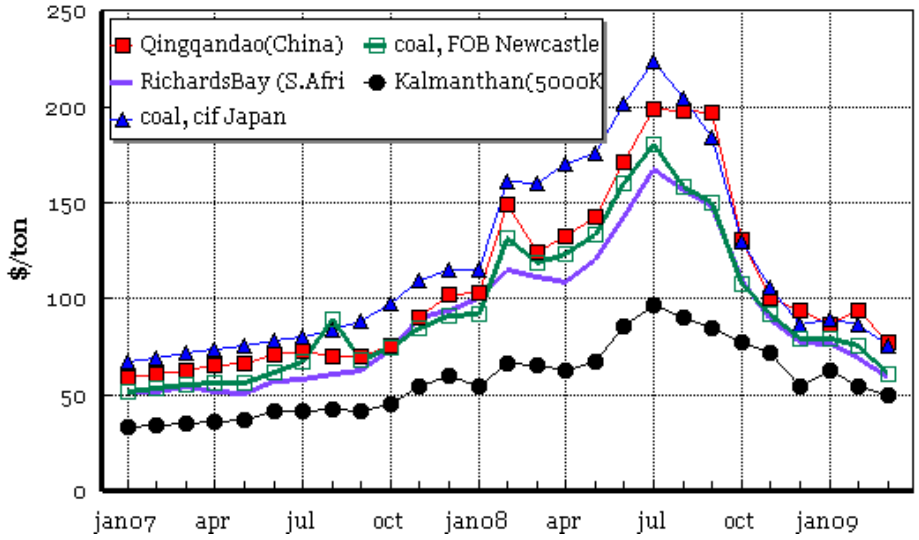
[14] "LNG import opportunity price" (no example has been found where the price of domestically-produced gas is driven by the cost of LNG imports): large volume imports of LNG to Vietnam are unlikely in the near future.

comparison, for which international prices are the relevant benchmark. As noted, internationally traded LNG in Asia is benchmarked against heavy fueloil, not coal.

Coal

49. Internationally traded coal prices were subject in 2008 to a similar price bubble as oil, as shown in Figure 3.3 for coal traded in the Asia Pacific market.

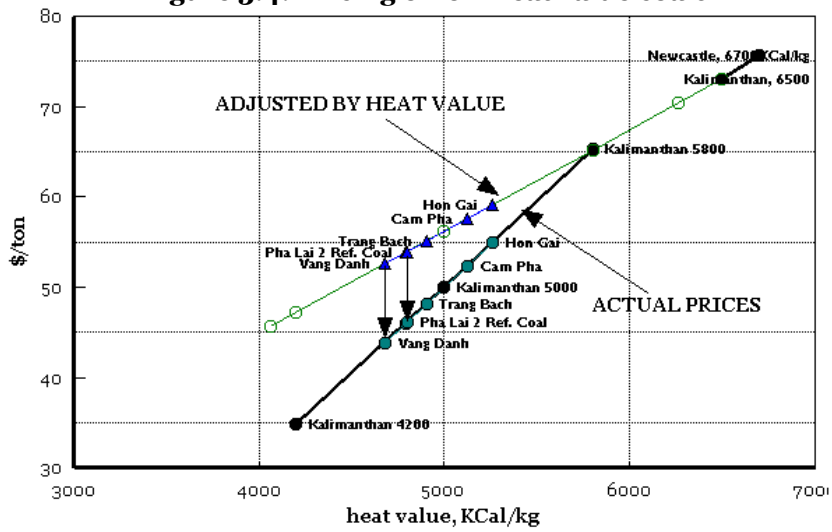
Figure 3.3: Asia Pacific coal prices



50. As in the case of LNG, coal prices relative to crude oil have changed significantly in the last decade (Figure 3.2). For most of the 1990s, the Australian coal export price was between 40-50% of the crude oil price (on a BTU basis). This fell to 20% in 2001, and has since been in the range of 20-35% of the crude oil price, reaching 40% only briefly at the peak of the commodities boom in 2008

51. Coals of lower heat value trade for less than what can be accounted for by heat value, as is illustrated by Indonesian coal: in the first quarter of 2009, so-called "Indonesian performance coal", at 5,900 Kcal/kg, traded at an average of $69.90/ton fob Kalimanthan,[15] whereas the more abundant Indonesian 5000 Kcal/kg grade traded at $55.17/ton (Figure 3.4).[16] If heat value were the dominant determinant, then the 5000 Kcal/kg grade would be priced at $59.15/ton, $4.00/ton more than the actual price.

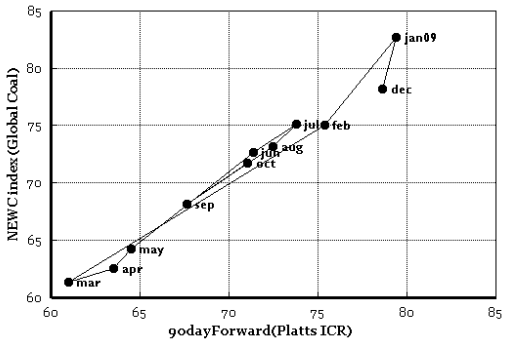
Figure 3.4: Pricing of low heat value coals



52. If the same discounts are applied to Vietnamese coals, then the ex-mine prices as would apply to Vietnamese coals calculate as shown in Table 3.3. Pha Lai 2 reference coal would be priced at 53.90$/ton if adjusted just by heat value; with the additional discount observed in Indonesian low heat

[15] "Performance" coal does not need to be blended, whereas lower grade Indonesian grades would generally be blended with high calorific value Australian coals.

[16] Prices are Platt's benchmark for 90-day forward contracts published in (Platts *International Coal Report*) average of the monthly assessments. For Australian coal fob Newcastle, the Platt's assessments differ little from the widely cited NEWC index, published weekly by the GlobalCoal exchange at http://www.globalcoal.com/.



value coal the price is $46.1/ton (fob export port). The netback to the mine would be less to account for the transportation costs to the export port.

Table 3.3: Economic value of Vietnamese coals

		heat value adjusted	discounted price
	Kcal/kg	$/ton	$/ton
Kalimanthan	6500	73.0	73.0
Cam Pha	5126	57.6	52.3
Hon Gai	5260	59.1	54.9
Mao Khe	4790	53.8	46.0
Trang Bach	4904	55.1	48.1
Vang Danh	4678	52.5	43.8
Pha Lai 2 Ref. Coal	4800	53.9	46.1

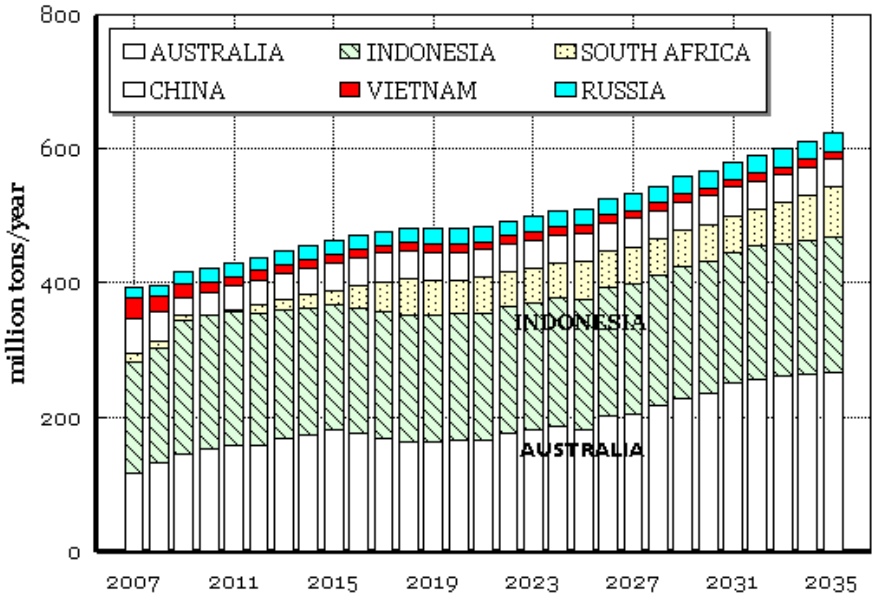
The Asia pacific coal market

53. As noted previously, there is never a shortage of an internationally traded commodity at the prevailing spot price. So the question for power sector planning in Vietnam is not whether there will arise shortages of imported coal, but what price will need to be paid. That in turn depends upon the incremental volumes required compared to the prevailing market conditions: a buyer needing a few million tons a year will have little impact in a market trading 500 million tons a year; but a buyer whose needs increase from less than a million tons a year to over 30 million tons a year in the space of a few years (as anticipated by PDP6) may well have an impact on prices.

54. At present, some 600 million tons of coal is traded in Asia-Pacific markets (including South Africa, which is a major supplier to India): the two dominant exporters are Australia and Indonesia, and by 2025, the total export market is expected to increase to 1 billion tons. However, much of this is metallurgical coal, and the current steam coal market in the Asia pacific region is around 400 mtpy. (Figure 3.5). Most expect this to grow by about 50% over the next 20 years,[17] and most of this export growth is anticipated to come from Australia and South Africa, given Indonesia's determination to use more coal (rather than oil) for domestic power generation, limit its exports to the current levels, and export oil and gas rather than coal.

[17] Australia is the number one exporter when metallurgical coal is included, but Indonesia is the biggest exporter of stem coal in the region.

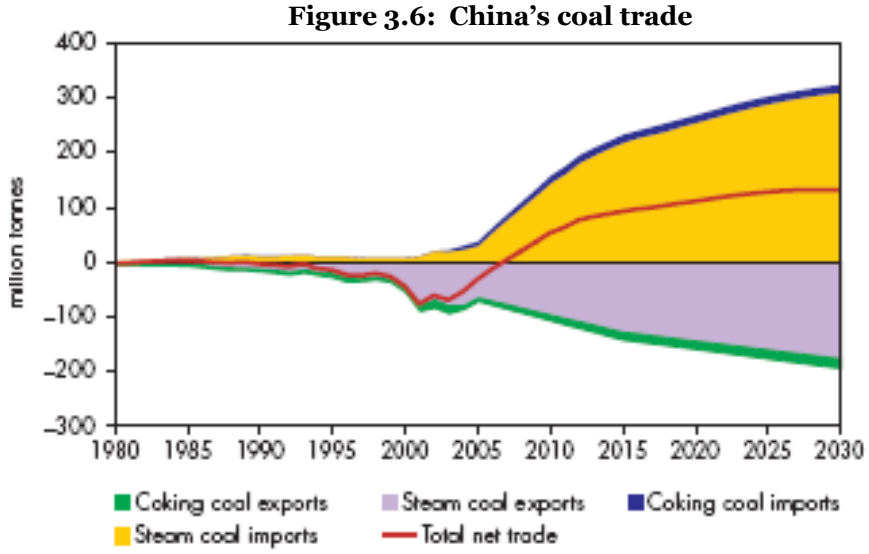
Figure 3.5: International steam coal markets



source: EIA *Annual Energy Outlook 2010*, December 2009

55. Much of that increase in demand is expected to come from China and India: China will turn from net exporter to a net importer, needing some 150 mtpy by 2025 (Table 3.6). India's coal imports are expected by IEA to rise form the present level of around 30 mtpy to over 52 mtpy by 2015 and 139 mtpy by 2020.

Figure 3.6: China's coal trade



Source: IEA, *2007 Global Energy Outlook* (Figure 10.13)

56. Based on the IoE's latest modelling results (see above), Vietnam's likely import coal requirements by 2025 are in the range of 40-66 million tons per year. This would represent roughly 20% of the likely increase in the size of the Asia-Pacific steam coal market by 2025 - and it is just not clear to what extent Vietnam's rapid growth in imports has been factored into most current market forecasts.

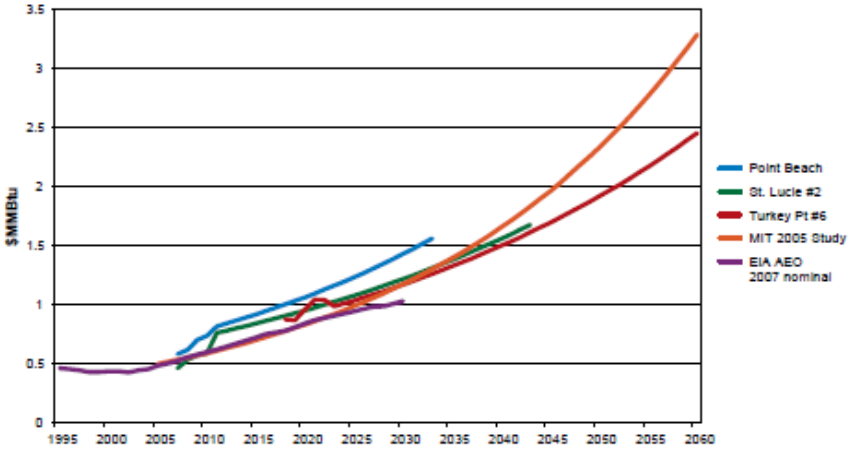
57. There are important policy implications for Vietnam. First is the importance of moving to the most efficient coal technologies – a subject examined in the next section. Second is the importance of a rational pricing framework: if indeed Vietnam's high demand for imported coal increases price pressure in the Asia-pacific markets, to continue the present policy of high subsidies to domestic coal will entail ever growing costs to the Government.

58. However, even if relative prices of coal increase to the levels seen in the 1980s (see Figure 3.4), it remains far cheaper than gas, and certainly so for baseload generation. Whether the implied shadow price of carbon would force a shift to gas (even assuming that additional domestic gas were available) is examined in Section 8.

Nuclear

59. The cost of nuclear fuel plays a relatively small role in the economics of nuclear power. Nevertheless, most forecasts envisage significant increases in nuclear fuel costs (Figure 3.5), particularly if nuclear power sees a resurgence consequent to climate change concerns. This study assumes a constant nuclear fuel price of $0.5/mmBTU delivered to a coastal location in Vietnam.

Figure 3.5: Nuclear fuel costs



Source: E.Kee *Nuclear fuel future*, CRA Corporation,

4 TECHNOLOGY OPTIONS[18]

Coal

60. Table 4.1 provides a summary of the coal-fired technologies suitable for the coals available in Vietnam now and in the future. The periods (2009-2020; 2020-2030; after 2030) are intended to provide approximate timeframes when the new technological options are expected to be commercially available. The percentages shown in parentheses indicate HHVnet efficiencies. Supercritical steam conditions (pressure above 22.1 MPa) are desirable because the resulting plant efficiency is higher (Table 4.1). Ultra-supercritical (USC) is the state of the art technology in terms of steam conditions and has the highest efficiency.

Table 4.1: Available coal technologies

Coal type	Now to 2020	2020-2030	After 2030
Anthracite	Subcritical Arch PC (35-36%) Subcritical CFB (35-36%)	Supercritical PC (38-40%) Supercritical CFB (38-40%)	USC PC (40-44%) USC CFB (40-43%)
Coal Blend	Supercritical PC (38-39%)	USC PC (40-42%)	USC PC (40-44%)
Imported Coal	Supercritical & USC PC (38-41%)	USC PC (40-42%) IGCC (40-43%)	USC PC (40-44%) IGCC (41-45%)

Notes:

PC: Pulverized Coal; 600 MW nominal size

Supercritical PC: 600 MW nominal size

CFB: Circulating Fluidized Bed; 500 MW nominal size

USC: Ultra-Supercritical steam conditions; 600 MW nominal size

IGCC: Integrated Gasification Combined Cycle; 500 MW nominal size

Blend is assumed to be 50% anthracite and 50% imported coal

Efficiencies of actual projects in Vietnam may be affected by site-specific considerations especially coal properties and ambient conditions.

61. Because domestic anthracite is difficult to burn, the state of the art power plant design cannot be utilized and power plant efficiencies are limited below 36%. Technological developments in conventional pulverized coal technology and CFB (mainly increasing steam conditions to

[18] This section was prepared by S. Tavoulareas.

supercritical) are expected to benefit anthracite-firing and increase plant efficiency to the 38-40% range. However, these developments will take 5-10 years to be incorporated in commercially available offerings.

62. In the meantime, the only options to raise the efficiency of new power plants are:

- Design them to burn a blend of anthracite and imported coal (e.g., 50%/50%); this make it possible to utilize supercritical steam conditions which increase the plant efficiency to the 38-40% range. Also, it makes it easier to deal with fuel supply risks.
- Design the plants for 100% imported coal in which case ultra-supercritical (USC) conditions can be used resulting in efficiency above 40%.

63. All power plant designs are expected to improve over time benefitting from increasing steam conditions (to supercritical and ultra-supercritical), as well as new technologies such as IGCC (Integrated Gasification Combined Cycle). However, these options will be available over time and careful consideration is needed regarding the suitability and proven experience of each technology with the specific fuel (e.g., anthracite, imported coal, etc.).

64. While higher efficiency power plants are feasible for Vietnam, utilization of these technologies (supercritical and ultra-supercritical pulverized coal and CFB) would require a comprehensive effort to build the indigenous capacity for planning and implementing such projects, and operate power plants. Each of the options shown in the table are discussed below

Pulverized coal utilizing anthracite

65. Vietnam's anthracite has the following characteristics:

- Moisture: 6-12%
- Ash: 10-30%
- Sulfur: 0.2-0.8%
- Volatile Matter (VM): 2-9%
- Calorific Value (HHV): 3,500 – 5,500 Kcal/Kg

66. Each of these properties affects power plant design and efficiency. The higher the moisture content of the coal, the lower the plant efficiency. Anthracite has low moisture relative to other coals (especially subbituminous). Ash content does not significantly affect the performance of the power plant, but it is inert material which affects the coal handling and ash handling equipment, as well as the boiler design.

67. Sulfur content is important to determine how to design the desulfurization equipment of the plant to satisfy the relevant emission standards. Vietnam's standards require that SO2 emissions are kept below

500 mg/Nm^3. In the technologies described in this section, this is achieved by including Flue Gas Desulfurization (FGD) in the pulverized coal plants and by injecting limestone in the CFB boilers. The calorific value of the coal affects the coal flow rate required to generate the design power output. The higher the calorific value, the lower the amount of coal through the power plant.

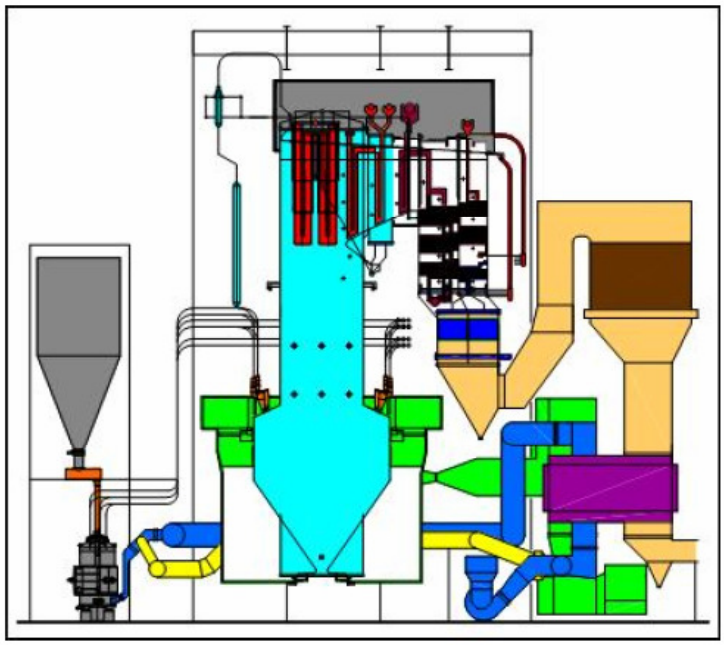
68. Volatile Matter (VM) is a property of the coal indicating how easily it burns. The lower then VM, the more difficult to ignite and burn. Anthracite has the lowest volatile matter (typically less the 10% VM); bituminous coal has 20-36% VM.

69. Because of the low VM of Vietnamese anthracite (less than 10%), presently the only suitable technologies are:

- Arch-fired pulverized coal boiler with W-shape flame (see Figure 3.1)
- Circulating Fluidized Bed (CFB) boiler.

70. The W-shape flame provides the coal particles with more time in the furnace ("residence time") to burn completely. Nevertheless, flame stability continues to be a problem, especially at low loads (below 60%) and during start-up. For this reason, support fuel (usually oil) is provided to ensure stable flame and safe operation.

Figure 4.1. Arch boiler configuration



71. Presently, there is approximately 51 GW of installed capacity worldwide utilizing different grades of anthracite. The majority of these plants are in China, but other countries with substantial experience include

Germany, Russia and Spain. All boilers burning anthracite with less than 10% VM are arch-fired (W-shape flame) and utilize subcritical steam conditions; as of the writing of this report (mid-2009), none of these plants is supercritical.

72. Plants burning a blend of anthracite and hard coal (bituminous or subbituminous) or anthracite with VM above 10% (anthracite which is referred to as "lean coal" in China and has Volatile Matter in the 10-18% range) are typically tangential-fired (T-fired) or wall-fired boilers, similar to conventional boilers burning hard coal. For such plants (mainly due to the geometry of the boiler), it is easier to utilize supercritical steam conditions. In fact, there are a few such supercritical plants:

1. T-fired supercritical power plants burning anthracite with VM>10% in China:
    - Huangdao #5 and #6 (660MWe each), which are in operation since November 2006 and June 2007, respectively.
    - Huaneng Ruijin #1 (350MWe) operating since December 2008.
2. T-fired supercritical power plants burning a blend of anthracite and higher VM coals such as bituminous:
    - Datang Xiangtan #1 and #2 (600MWe each) in China, which started operating in March and November of 2006, respectively.
    - Kashirskaya #3-6 (each 300 MW) operating in Russia since the late 1960s.

73. Vietnam has approximately 1,620 MW of anthracite-fired capacity. The old units (Pha Lai 1, Uong Bi and Ninh Binh) utilize T-fired and wall-fired boilers,[19] but the combustion efficiency is very low. The most recent plant (Pha Lai 2, 2X300 MW) utilizes W-type arch boiler.

74. Summarizing the options for pulverized coal technology burning Vietnam's anthracite:

- Presently, 100% anthracite can only be burned in arch-type boilers, which can not utilize supercritical steam conditions. Hence, plant efficiency is limited to 35-36%
- On-going technological developments (especially in China and Europe) suggest that low VM anthracite would be able to utilize supercritical steam conditions in a few years. Vietnam should monitor such activities (especially in China) and be ready to utilize

[19] However, according to IoE, Pha Lai 1 and Uong Bi are expected to be retired by 2015. The environmental and economic impact of such retirements are discussed in Section 5.

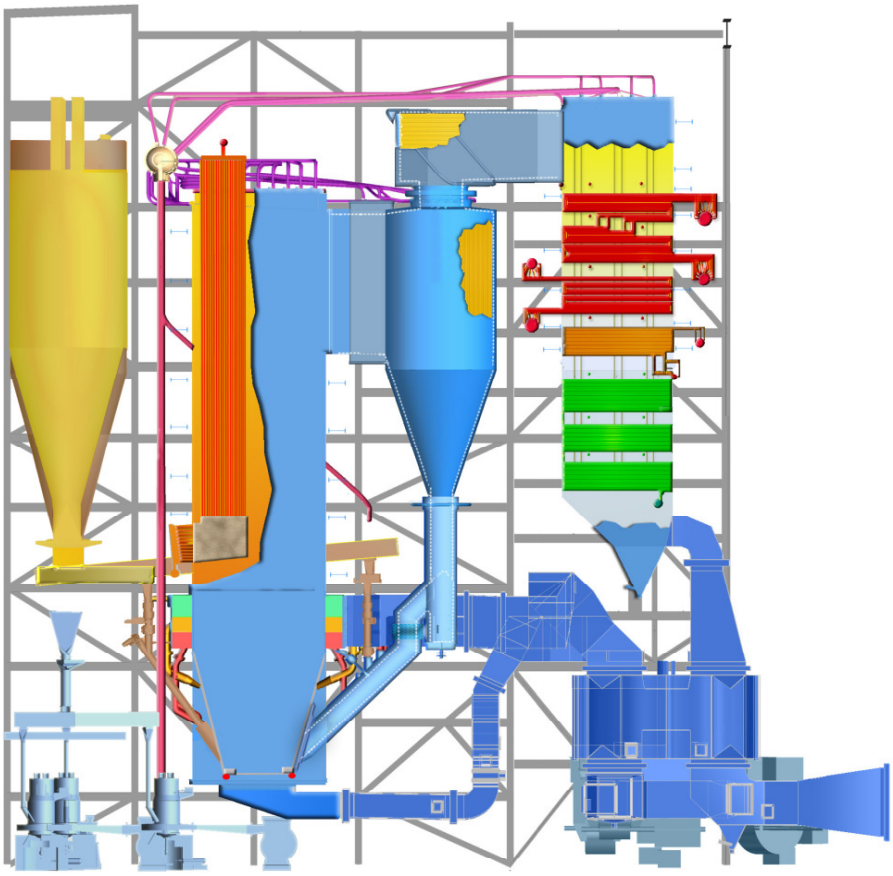
such designs within the next decade without assuming increased technology-related risks.

- As pulverized coal technology continues to develop further, USC steam conditions will become suitable for Vietnamese anthracite, but this is likely to take more than 10 years.

CFB for Anthracite

75. CFB is similar to conventional pulverized coal boilers (see Figure 4.2) except for the limestone which is being injected in the boiler and the cyclone which has downstream to separate and recycle unburned coal particles. CFB is a technology particularly suitable for fuels which are difficult to burn such as low VM anthracite and anthracite wastes. For this reason, CFB is an important technology for Vietnam. Also, CFB reduces acid rain pollutants (SO_2 and NOx) without the need for flue gas desulfurization (FGD) downstream of the boiler.

Figure 4.2. CFB Power Plant



76. There are numerous CFB units in operation worldwide burning anthracite; most of them are in the 50-80 MW range; the largest one is a 300 MW unit at Baima, China, which has been in operation since April 2006.

Also, a 150 MW CFB plant (Itoigawa #1 owned by Taiheiyi Cement Corp.) is operating since 2001 in Japan. A 600 MW plant consisting of four 150 MW units is presently in start-up phase in Vietnam (Cam Pha plant owned by Vinacomin; see Figure 4.3); it is designed to burn anthracite wastes. The first two units are expected to start commercial operation in 2009 and the remaining two in 2010.

Figure 4.3: Cam Pha Thermal Power Plant Under Construction

77. All the above anthracite-fired CFB plants utilize subcritical steam conditions. However, the industry is developing the next generation of CFB plants which will be supercritical. Two noteworthy developments:

- A 460 MW supercritical CFB plant is starting up this year (2009) in Lagisza, Poland. While it is designed for Bituminous coal, it represents an important technological development milestone and is applicable to anthracite applications, too.
- A 600 MW CFB burning low-VM anthracite is planned at Baima, China. Design of this plant has been completed and construction has commenced.

78. In summary:

- Presently, CFB technology utilizing subcritical steam conditions is a suitable option for Vietnam's anthracite. The technology is commercially available in boilers up to 300 MW each, but larger plants can be constructed using multiple CFB boilers (e.g., 2X300 MW or 4X150 MW boilers with one 600 MW or two 300 MW steam

turbines). For fuels similar to Vietnam's anthracite, the maximum size in operation is 150 MW.

- The industry is developing CFB with supercritical steam conditions which are expected to be available and suitable for anthracite too in the next decade.
- While CFB is a commercially available, special attention needs to be paid to training of power operators and engineers, as the technology is different from conventional pulverized coal. CFB is an important technology for Vietnam and it is worthwhile for the country to build the technical capacity to plan and implement CFB projects, as well as operate and maintain CFB plants.

Coal blending

79. Blending anthracite with bituminous or subbituminous coals is a widespread practice. In most case, this is done to eliminate flame stability problems associated with 100% firing of low-VM anthracite. However, blending also provides more flexibility in terms of boiler design, making it feasible to utilize conventional boiler configurations (T-fired and wall-fired) with supercritical steam conditions. As mentioned above, the Datang Xiangtan #1 and #2 (600MWe each) in China and Kashirskaya #3-6 (each 300 MW) in Russia are examples of supercritical plants in operation burning blends of anthracite and hard coal. No USC plant is in operation burning a blend of anthracite and bituminous or subbituminous coal.

80. For Vietnam, blending of anthracite and imported coal may offer a number of advantages:

- Coal blending allows Vietnam to build more efficient power plants earlier than if 100% anthracite is used.
- Supercritical plants can be build immediately without assuming unnecessary technology-related risks; such plants will have higher efficiency (and lower CO_2 emissions) than plants burning 100% anthracite.
- Anthracite-imported coal blend would be able to utilize earlier USC steam conditions than 100% anthracite.
- Considering that Vietnam's long term fuel supply outlook suggests that coal imports are essential, plants capable of burning both the domestic fuel and imported coal would provide flexibility in terms of fuel procurement.

81. Issues which need to be addressed before the power plant design is finalized include:

- What is the optimum fuel blend? Answering this question should be part of a site-specific feasibility study. However, 50% anthracite and

50% imported coal could be used as a basis with +/-20% variation for both fuels.

- Does it make a difference if the imported coal is bituminous or subbituminous? Yes, the boiler design is impacted significantly by coal type and a decision needs to be made if the imported coal is bituminous or subbituminous. It is feasible to design the plant to be able to burn all three types of coals (anthracite, bituminous and subbituminous), but it is likely to be very expensive. Hence, it is desirable to narrow down the design specifications to one type of imported coal (e.g., bituminous).
- While higher efficiency can be achieved when a blend of anthracite-imported coal is used, the trade-off is increased coal supply and procurement risks associated with the imported coal. To minimize the coal supply risks, multiple sources are desirable.
- The infrastructure for receiving and potentially transporting in-land imported coal may need to be developed or strengthened.
- Blending could be used in new power plants as well as existing plants.

Imported coal

82. Coal can be imported in Vietnam from various countries; the most common sources are Australia, Russia and South Africa for bituminous coal and Indonesia for subbituminous. All these coals are well-known and there is plenty of experience utilizing them in state-of-the-art power plants in countries such as Australia, China, Japan and South Korea. For example, imported coals are used in Japan in power plants with USC steam conditions and efficiency above 40%. Similar plants can be built in Vietnam. Aspects which would require particular attention include:

- Systematic training in operation and maintenance of supercritical and USC plants is needed. Also, management training is recommended, as there are no supercritical plants in operation.
- There are a number of aspects of plant operation (such as maintaining water quality) which are more critical for USC plants than for conventional subcritical plants.

83. Issues which need to be addressed before the design is finalized include:

- What are the appropriate steam conditions of the first few supercritical plants in Vietnam? If the plant will be operated by a company with extensive experience in coal-fired supercritical and USC plants, state of the art steam conditions (590^{o}C-605^{o}C) could be used. If the operator is not familiar with such technologies, a more

cautious approach could be taken to build the first few plants with supercritical steam conditions (e.g., 565^{o}C).

- What fuel flexibility should the plant have? While it is feasible to build a plant capable of burning all the fuels available in the region, the wider the fuel range, the higher the plant cost. Hence, it is important to identify the likely available coals and design the plant for these fuels. Bituminous coals are more readily available from multiple sources in the region and are likely to be used as the base fuel. Indonesian subbituminous coal is also traded in the region, but its growth may be limited. Identification of the optimum plant design (considering the available fuel sources) is typically done as part of a detail site-specific feasibility study.

IGCC

84. Integrated gasification combined cycle (IGCC) is commercially available for bituminous and subbituminous coals, but not for anthracite. For Vietnam, IGCC is a technically feasible option for imported coal, but its economics are not attractive to displace conventional pulverized coal technology, at least under present market conditions. For this reason, IGCC is not expected to be used in Vietnam in the near-term. In the long-term, IGCC is a technology which may become more attractive, especially if carbon capture and sequestration (CCS) becomes feasible and is required.

85. Another emerging option is underground coal gasification. This is similar to IGCC, but the coal is gasified underground. The technology is not commercially available, but research and development activities have increased significantly and may be worth monitoring for potential long-term application in Vietnam (e.g., Red River Delta).

Conversion of anthracite plants to burn imported coal

86. The potential for converting an existing power plant to burn imported coal has been raised as an option. Certainly this is technically feasible. However, the design of anthracite-fired plants has substantial difference from bituminous or subbituminous plants and significant modifications would be needed. The following are the key distinguishing features of anthracite plants:

- The coal flow rate of anthracite plants is typically lower than the bituminous and subbituminous plants, because the heating value of anthracite is higher. Hence, converting an anthracite plant to bituminous and/or subbituminous would require modification of the

pulverization and coal feed system. Also, additional coal storage and handling systems would need to be added.

- Bituminous and subbituminous require higher amount of hot air for drying (due to higher moisture content) and higher amount of "transport air" (typically Primary Air/Fuel ratio is 0.5 for anthracite and 2.0 for bituminous and subbituminous). Hence, the existing primary air and coal feed system (including the burners) would need to be modified.
- The furnace of anthracite-fired boilers is small and often lined with refractory; the refractory would need to be removed and some surface modifications may be needed, too.
- Slagging in the furnace and fouling in the backpass may increase requiring more efficient surface cleaning devices. This is likely to be more severe with subbituminous coal.
- Finally, the volume of flue gas through the boiler is less for anthracite-fired boilers. Hence, switching to imported coal is likely to increase the velocity through the convection sections of the boiler; depending on their design tolerances, such increase may or may not be acceptable; in the latter case, modification or replacement of these sections may be necessary.

87. Considering the above, a conversion from anthracite to imported coal requires extensive modifications which are likely to cost above $100/kW. Such conversion should be evaluated against other alternatives such as:

- Blending anthracite and imported coal instead of 100% conversion; such option would have lower investment requirements and more fuel flexibility.
- Build new power plants which are designed for blending instead of investing in conversion of existing ones.

88. The outcome of such evaluations will be affected by site-specific considerations.In Vietnam, conversion of anthracite plants is practically feasible, but it is likely to be unattractive for the following reasons:

- The existing very small-old-inefficient plants are not good candidates for conversion, because of limited remaining life. Also, converting them to imported coal will result in a plant which has low efficiency (since the efficiency can not be increased substantially) and uses an expensive fuel.
- The new anthracite-fired plants could be converted to imported coal, but it may be preferable to design a new plant to fire imported coal, since Vietnam is planning to build so many new coal-fired plants. The new plant

design would be more efficient as it can be optimized for imported fuel.

Biomass Cofiring

89. Cofiring biomass in a coal-fired power plant is becoming a common practice in many countries. As reduction of greenhouse gases becomes more important, cofiring is being used more frequently, because biomass is "CO2-neutral".

90. Biomass may include rice husks, rice straw, switch-grass, sawdust, wood wastes, municipal solid wastes and other waste fuels. In most cases, biomass is limited to a maximum of 15 percent of the total plant input. The boilers could be designed specifically to accommodate biomass combustion or existing boilers could be modified; the industry has experience with both.

91. The technical feasibility of this option is not an issue. Common issues associated with it are:

- Logistics associated with biomass collection and transportation; unless biomass can be obtained from 1-2 sources, it is difficult to arrange collection.
- Availability of biomass may be an issue too depending on the location of the coal-fired power plant.
- Biomass prices may be high or may increase after the co-firing project is implemented.
- Power companies avoid modifying their most efficient new power plants considering that co-firing may increase the probability of reliability problems. The most common concerns are failures of the biomass feed system, slagging and potential corrosion impacts on the boiler.

92. The economics of this option are very site-specific. Adding biomass co-firing capability in a new boiler or retrofitting a cyclone or stoker boiler is estimated to cost up to $50/kW. Retrofitting an existing pulverized coal or CFB boiler may cost $150-300/kW[20].

Gas Turbine-based power plants

93. Gas turbine plants come in two configurations: open cycle gas turbines (OCGT) and combined cycle gas turbines (CCGT). OCGT is used for peaking duty, while CCGT for intermediate and baseload.

[20] Source: National Renewable Energy Laboratory, "*Biomass cofiring: A renewable alternative for utilities*", DOE/GO-1020000-1055, June 2000

94. The most commonly used fuel is natural gas (either from gas pipeline or liquefied natural gas (LNG)). Other fuels could be used too, but with adverse impacts on plant investment, performance, reliability and operating costs. Light (low-sulfur) distillate oil is a fuel which can be used in both OCGT and CCGT plants without major adverse impacts. Heavier grades of oil have been used in many countries (where natural gas is not available), but the impacts could be moderate-to-severe; the presence of sulfur, vanadium, small amount of ash and other substances affect the reliability of the gas turbine resulting in more frequent maintenance requirements. A thorough site-specific assessment is needed to evaluate the advantages (significantly lower fuel prices) and disadvantages (increased maintenance costs and potentially lower reliability)[21].

95. Gas turbine-based systems may also utilize coal bed methane (CBM). There is no comprehensive assessment of the CBM resource in Vietnam. For example, the Quang Yen Basin, which has an estimated 5 billion tones of anthracite, should have substantial amount of CBM; however, there is no assessment carried out so far. The only estimate available is for the Red River Delta area which is expected to have at least 6-10 TCF of CBM.

Nuclear

96. The 6th PDP envisaged the first nuclear power units by 2021. However, despite press reports about imminent agreements with Chinese and Russian partners, it seems quite unlikely that such a timing is feasible. Vietnam may decide to pursue the nuclear option as a hedge against future uncertainties, but certainly for the next 10-15 years, commercial nuclear power plants are hardly practical and they are certainly very much more expensive than other options available to Vietnam in the medium term.

97. Nuclear power is subject to significant scale economies, and for units presently commercially available the minimum unit size is around 1,000MW.[22] If by 2020 the demand were indeed as suggested by the 6th PDP, units of this size would be feasible from a system reliability point of view. There is much discussion about the development of a new generation

[21] A heavy fuel based CCCT has been operating satisfactorily in Sri Lanka for some 9 months now (at Kerawalapitiya). The cost advantage over diesel is high, and more than offsets the higher maintenance costs. Each turbine is taken off line one day every two weeks, and there is some derating for fueloil as well. Nevertheless, even with the additional maintenance time and derating, the kWh cost is 20% less than auto-diesel costs. These are GE Frame 7 machines, and carry full GE warranties for HFO operation

[22] In a recent review of nuclear power costs (World Nuclear Association, *The Economics of Nuclear Power*, November 2008), all the units for which cost estimates are reported involve units in the range of 1,080MW to 1,350MW: the typical project currently under consideration is 2 x 1,100MW.

of small (250-500 MW) units, which are under development in many countries based on a wide variety of new design concepts.[23] However, the costs of such small units – not yet commercially available, are subject to large uncertainties.[24] Indeed, the track record of capital cost overruns the nuclear industry is very poor, in part because of lengthy construction delays (notably in the US).[25]

98. As of mid 2009, according to the MIT study on nuclear power[26] there are 44 plants under construction around the world in 12 countries, principally China, India, Korea, and Russia.[27] However, reliable cost information is hard to come by, and estimates in the recent literature vary from $2,000/kW to $10,000/kW. At least some of the variation is explained by financial costs: with a 5-6 year construction time, IDC substantially increases overnight costs. For example, the MIT study estimates overnight costs at $4,000/kW, but when IDC is added, the cost increases to $5,400.[28] Late 2008 cost estimates for US utilities are 4,924$/kW (Duke Energy, overnight) to TVA Bellafonte (7,833$/kW, including financial costs).[29] Reported costs for Chinese nuclear plants are much lower, in the range of $1,400-1,800/kW for overnight costs for the nuclear EPC (i.e. without site costs, cooling system etc).[30]

99. Whether a country has nuclear fuel resources (uranium or thorium) has little bearing on its nuclear fuel costs: absent fuel processing capability, even a country with good resources is exposed to the international market for power plant grade nuclear fuel. However, if indeed Vietnam had exploitable

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[23] For a complete description of these new design concepts, including those based on thorium cycles and advanced breeder reactors, see e.g. www.world-nuclear.org/info/inf08.html.

[24] There are few estimates of costs for this new generation of small nuclear units. However, given the lack of scale economies, even with advanced materials and design it is quite unlikely that their cost would be much lower than the large units on a $/kW basis.

[25] Finland's effort to build the world's first new generation nuclear reactor at Olkiluoto is now over 2 years behind schedule after beginning in 2005, and construction cost estimates have already overrun by at least one billion euro.

[26] MIT, *2009 Update of the 2003 Report Future of Nuclear Power*, Cambridge, Mass., 2009

[27] According to the 2009 MIT report, the forty four plants under construction are: China (11), Russia (8), India (6), Korea (5), Bulgaria (2), Taiwan (2), Ukraine (2), Japan (2), Argentina (1), Finland (1), France (1), Iran (1), Pakistan (1), and the United States (refurbishment, 1).

[28] Assuming six-year construction period with six equal mid-year disbursements, and a weighted cost of capital of 10%.

[29] World Nuclear Association, *The Economics of Nuclear Power*, November 2008.

[30] Ibid., p.12.

nuclear ores, then whether their development for export is economic is an entirely separate question to whether nuclear power plants should be built.

5 LOAD FORECASTS

100. A regional comparison of per capita electricity consumption is shown in Table 5.1 (2005 figures are the latest available for all comparable countries, 2002 for electrification rates). Consumption of electricity per capita can be expected to rise to the levels seen in China and Thailand and other middle income countries (which worldwide averaged 1,492 kWh per capita per year in 2005). Although Indonesia and the Philippines have comparable levels of per capita consumption, the electrification rate is substantially lower, and much of the supply is from mini-grids on remote islands, which do not run 24 hours a day. It is therefore reasonable to conclude that the trend for Vietnam will be towards the middle-income countries average or the regional average, suggesting continued high demand growth rates over the coming years. Between 1995 and 2008, household access increased from 50 percent to nearly 94 percent; and annual per capita consumption increased from 156 kilowatt hours (kWh) to about 800 kWh.

Table 5.1: Per capita electricity consumption (2005)

	kWh/capita[1]	PPP $GDP/capita[2]	Electrification Rate (2002)[3]
China	1783	4100	99.0
Indonesia	509	3040	52.5
Philippines	578	3200	71[3]
Thailand	1988	6730	91.1
Vietnam	**598**	**2100**	**79.6**
East Asia	1928	-	88.8
Middle Income	1492	-	n/a

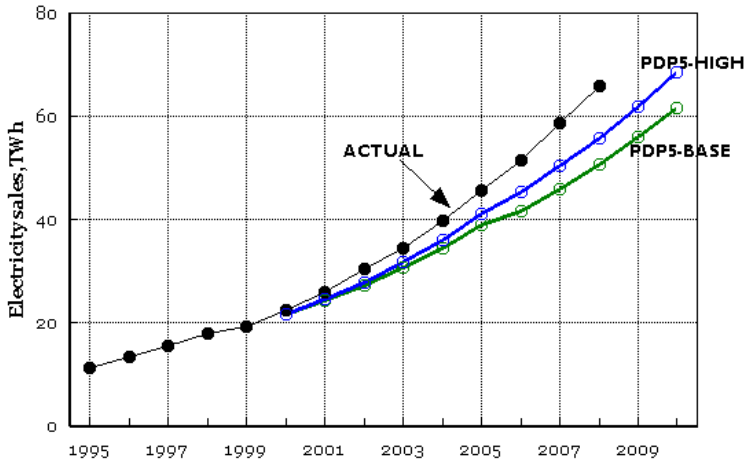
Sources: 1: World Bank World Development Indicators Database; 2: IEA World Energy Outlook; 3: Authors' estimate. n/a: not available

101. Between 2003 and 2008, installed capacity increased from about 9,300MW to over 15,800MW, implying a demand elasticity of about two: for every one percentage point of GDP growth, the demand for electricity grows by two percent.

102. From the point of view of methodology, given the difficulties of long-term growth and income elasticity forecasts, alternative forecasts should capture a reasonable range of outcomes. This was clearly not the case in PDP5, as shown in Figure 5.1, where we compare actual historical electricity

sales with the PDP5 base and high forecasts. The actuals have been significantly higher than the PDP5 forecast.[31]

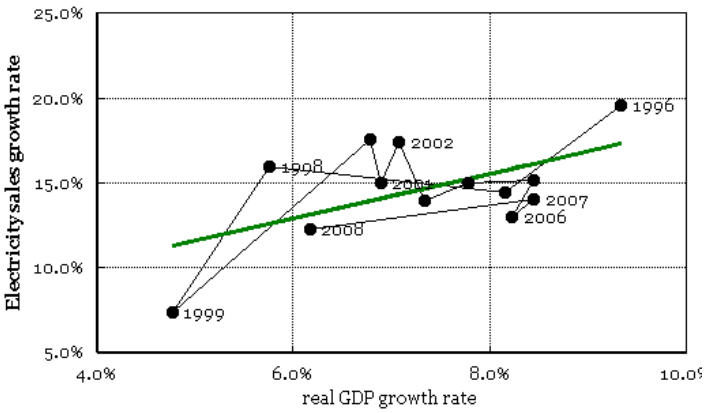
Figure 5.1: Electricity sales and the PDP5 baseline forecast



103. The PDP6 load forecasts were prepared in 2004-2005, with after several years of high growth (Table 5.2), and shortages were relatively widespread. In the expected 6-9% range of real annual GDP growth, demand growth had varied little. Moreover, the judgement of planners was understandably influenced by the fact that PDP5 had significantly underestimated demand: the result was the PDP6 forecast very high demand growth rates.

Table 5.2: Historical demand growth

	GDP growth	sales	sales growth
	[%]	[GWh]	[%]
1995	9.5%	11185	
1996	9.3%	13374	19.6%
1997	8.2%	15303	14.4%
1998	5.8%	17739	15.9%
1999	4.8%	19049	7.4%
2000	6.8%	22398	17.6%
2001	6.9%	25752	15.0%
2002	7.1%	30228	17.4%
2003	7.3%	34446	14.0%
2004	7.8%	39597	15.0%
2005	8.4%	45603	15.2%
2006	8.2%	51514	13.0%
2007	8.5%	58726	14.0%
2008	6.2%	65927	12.3%



[31] This point was noted already in the Bank's 2006 Power Sector Strategy document, which noted *"Assessment of power demand is particularly hard during periods of fast economic growth. Demand scenario should be quite different from each other – the purpose is not only to foecast the nmost probable scenario, but also to understand how the schedule of investment would change under faster or slower growth"*

104. Yet the rate of demand growth dropped almost as soon as the PDP6 was approved. The actual 2007 consumption was 68.5 TWh as against the PDP6 forecast of 71.8TWh, and 2008 consumption grew just 11% to 75.8 TWh, rather than the 22% demand growth forecast in PDP6.

105. In early 2009 IoE issued a revised forecast (column [5] and [6] of Table 5.3), which, although much lower than the PDP6 forecast (190 TWh by 2015 rather than the 332 TWh of PDP6), still reflects very high growth rates in 2009 and 2010, which for reasons of the global recession and lower GDP growth have little chance of realisation: (the first eight months of 2009 shows an annualized growth rate of about 10 percent).

Table 5.3: Comparison of Load Forecasts

	Peak load, MW		Annual energy, TWh					
	World Bank	IoE	World Bank	(%)	IoE	(%)	PMDP-6	(%)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
2007			**68.500**		**68.500**		71.875	
2008							87.571	22%
2008	**13.027**	**13.027**	**75.830**	**11%**	**75.830**			
2009	14.049	16.744	82.776	9%	98.642	30%	108.006	23%
2010	15.381	19.031	91.053	10%	112.658	14%	133.642	24%
2011	16.990	21.253	101.069	11%	126.418	12%	164.017	23%
2012	18.938	23.556	113.197	12%	140.790	11%	199.004	21%
2013	21.111	25.982	126.782	12%	156.024	11%	238.673	20%
2014	23.323	28.568	140.727	11%	172.366	10%	283.151	19%
2015	25.768	31.352	156.207	11%	190.047	10%	332.242	18%
2016	28.239	34.218	171.828	10%	208.201	10%	385.444	16%
2017	30.801	37.198	188.152	10%	227.224	9%	442.163	15%
2018	33.448	40.457	205.087	9%	248.052	9%	502.374	14%
2019	36.156	43.916	222.519	8%	270.263	9%	565.268	13%
2020	39.009	47.727	240.321	8%	294.012	9%	632.087	12%
2021	41.974	51.495	259.546	8%	318.400	8%	702.860	11%
2022	45.166	55.508	280.310	8%	344.481	8%	778.753	11%
2023	48.598	59.820	302.735	8%	372.634	8%	861.289	11%
2024	52.290	64.224	326.953	8%	401.555	8%	949.996	10%
2025	56.244	68.758	353.110	8%	431.664	7%	1,045.947	10%

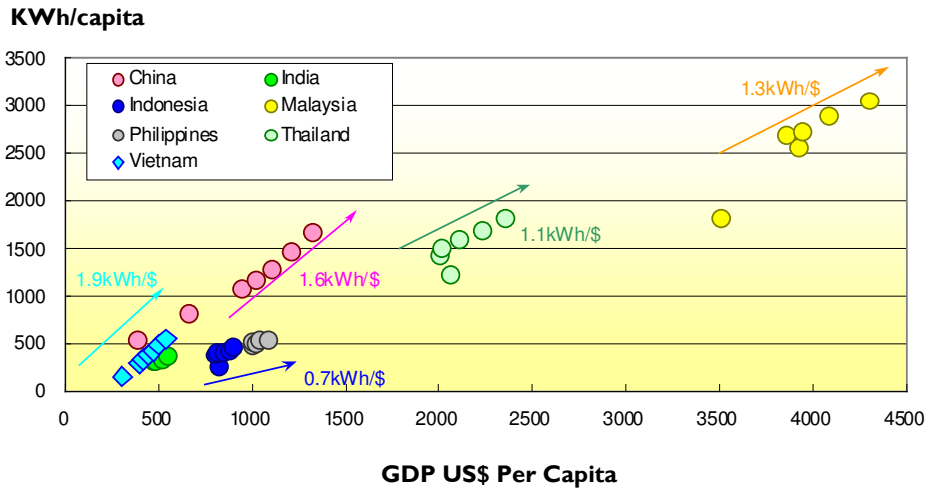
106. The IoE methodology for load forecasting in PDP6 contains an important inconsistency. It appears that the forecast includes a *prior* estimate of "generation self-use", which rises from 2.7% in 2005 to 4.2% by 2025. The own-use rates applied are the same for all three regions. This would not be problematic if all generating plants had the same rate of own-use. But this is clearly *not* the case: own-use ranges from 0.5% for hydro plants to 10% for some coal plants, and, in effect, 156% for pumped storage plants. With the total own-use very much a function of the plant mix – which is likely to vary greatly by region - the justification for including own use in the load forecast is unclear.

107. It is more logical that the load forecast be seen as the busbar generation requirement, i.e. the *net* output that must be dispatched to meet the demand. The contribution of each potential generation project is then its

net send-out. We recommend that IoE change its methodology in order to conform to international best practice.[32]

Box 5.1: Income elasticity

Over the last few years, the income elasticity has been at a fairly high value of around 2 – i.e. a 1% increase in GDP results in a 2% increase in electricity demand: as shown in the figure below, this is much higher than in Vietnam's neighbors (China is 1.6; Thailand 1.1).



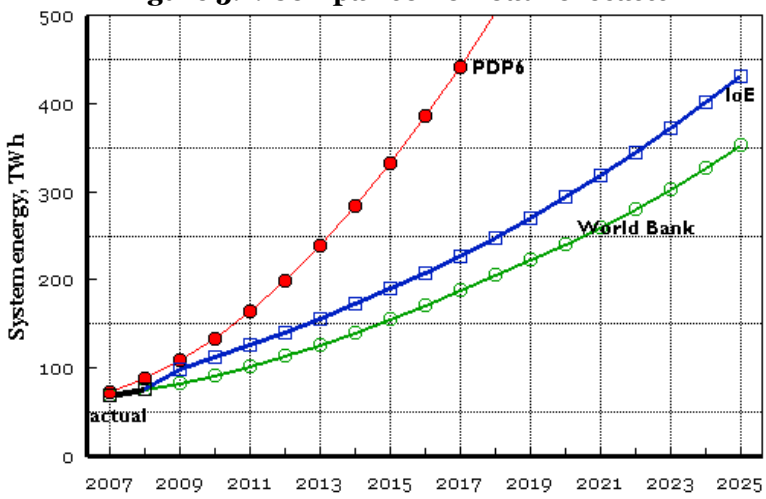
Source: JICA, *Vietnam: A Study on National Energy Masterplan*. November 2007

Although it is reasonable to suppose that energy intensity will decline in the future, its timing is highly uncertain. As noted, the alternative World Bank forecast assumes a somewhat faster reduction in income elasticity, with a 2015 energy requirement some 34TWh lower than the IoE forecast (Table 5.2).

108. At the time the World Bank appraised the Trung Son hydro project in 2009, a new forecast was prepared by the Bank, which makes more modest assumptions about short-term demand growth (9% in 2009 and 10% in 2010, see Figure 5.1). Demand growth is assumed to peak at 12% in 2012 following the presumed global recovery, declining to 8% by 2019, as the expected energy intensity of the Vietnamese economy falls (see Box 1).

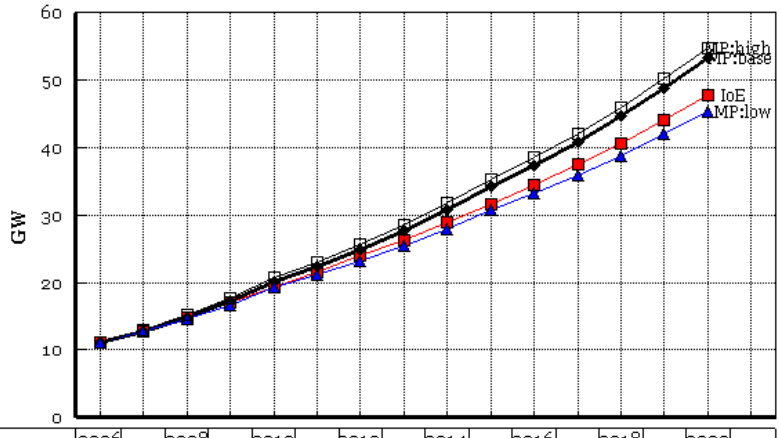
[32] In mitigation it may be noted that Vietnam is not alone in this practice

Figure 5.1: Comparison of load forecasts



109. Again we see that the various PDP6 load forecasts spanned only a very limited range (and this time on the high side, than on the low side, as in PDP5). In Figure 5.2 we show the range of load forecasts in PDP6, which for 2008 showed a range of 14.6 to 15.1 GW (the actual being 13 GW): the range for 2015 (ten years from the date of forecast) is between 30.7 and 35.3 GW – a range of 4.6GW. This may be compared to the range of forecasts in Table 2.1 for ten years hence which are in range of 36.1 to 43.1 GW (a range of 7GW). The point is simply that few insights about the impact of load forecast uncertainty can be derived if the forecast range is too narrow. This is taken up in more detail in Section 10 of the report.

Figure 5.2: Range of forecasts in the PDP6



	2006		2008		2010		2012		2014		2016		2018		2020	
■ IoE	11.0	12.8	14.8	17.0	19.3	21.6	23.9	26.2	28.8	31.6	34.5	37.5	40.6	44.0	47.8	
◆ MP:base	11.0	12.8	14.9	17.3	20.1	22.4	24.9	27.7	30.8	34.2	37.4	40.9	44.7	48.9	53.4	
▲ MP:low	11.0	12.7	14.6	16.7	19.2	21.1	23.2	25.5	28.0	30.7	33.2	35.9	38.8	41.9	45.3	
⊟ MP:high	11.0	12.9	15.1	17.7	20.8	23.1	25.7	28.6	31.7	35.3	38.6	42.1	46.0	50.2	54.8	

110. What is clear that the reserve margins in the past decade have been uncomfortably low, and that even in the absence of strong load growth, additional capacity is required to bring these margins to acceptable levels: In

2008 the power system was unable to meet peak demand of over 13,000MW[33] with 15,800 MW of installed capacity. This is unsurprising as reserve margins have been eroded in recent years, and are well below the 25-30 percent levels normally considered prudent for a modern power system

111. For a 2015 load forecast of 25.8 GW, a 25% reserve margin implies reserve capacity of GW. In 2008, the reserve margin was GW. So just to achieve a satisfactory reserve margin requires capacity additions of GW over the 7 year period in question.

Price elasticity of demand

112. It is generally held that in countries at Vietnam's stage of economic development, demand is largely driven by income growth, and that the price elasticity of demand is low. This is an important issue for some of the policy reforms under consideration, notably the reduction of cross-subsidies (between industrial and commercial consumers on the one hand, and domestic consumers on the other), and on the elimination of fossil fuel subsidies. If the subsidies on fossil fuels for power generation were eliminated, electricity prices would increase, with potential implications on demand.

113. The literature on the price elasticity of electricity demand in Vietnam is scanty. The JICA National Energy Planning study makes arbitrary adjustments to GDP growth rates in its "high energy price" case (reducing GDP growth from 8.5% to 8% for 2010-2020).[34] The Institute of Energy PDP6 load forecasts are also based largely on assumptions for income elasticity, and while price elasticity is mentioned as a potential factor in the load forecasting chapter of PDP6, the spreadsheets actually used show no evidence of explicit assumptions about price elasticity of demand. And such academic literature as exists on the subject for Vietnam reveals no rigorous econometric study of the subject (and generally confines itself to largely undocumented assertions that price elasticity of electricity demand is "low", and likely to be around –0.1).[35]

[33] Due to system outages and the difference between name-plate installed capacity and actual capacity of each plant which is affected by ambient conditions, age, fuel quality and other factors.

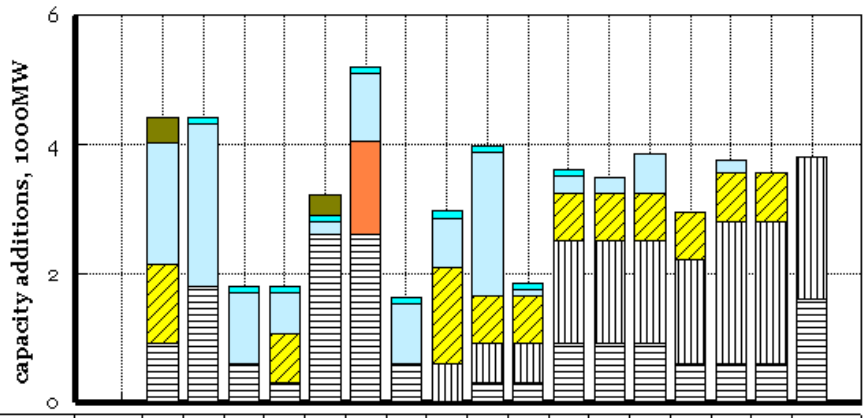
[34] Institute of Energy Economics& Tokyo Power Company, *A Study on National Energy Masterplan*, Report to JICA and MoIT, January 2008.

[35] see, e.g., B.Leemeechokchai and D. Hieu, *IRP with Carbon Tax: Effects on Power Generation Expansion Planning in Vietnam*, Int.J.Science&Technology,8(2),p55-64 (2003)

6 THE BASELINE

114. Because the official load forecasts prepared for PDP6 have now been overtaken by events, the corresponding capacity expansion plan prepared for PDP6 is equally unrealistic, and need not be discussed further. Consequently we take as our business as usual baseline the capacity expansion plan derived by IoE for the World Bank's load forecast described in the previous section (Figure 6.1).

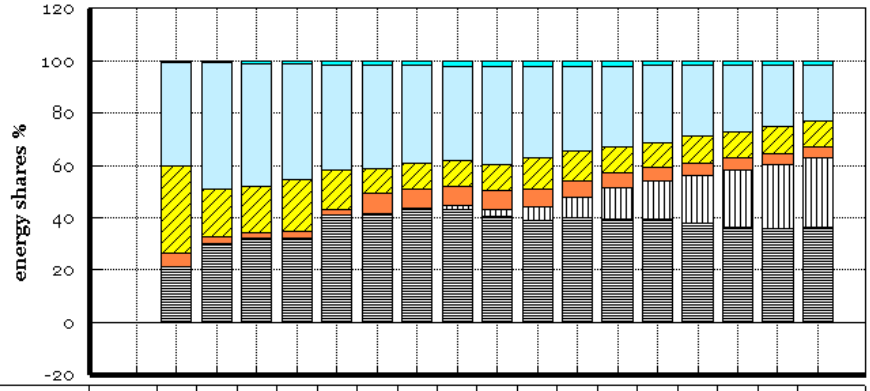
Figure 6.1: Baseline expansion plan



		2009		2011		2013		2015		2017		2019		2021		2023		2025
coalSteam		0.9	1.8	0.6	0.3	2.6	2.6	0.6	0.0	0.3	0.3	0.9	0.9	0.9	0.6	0.6	0.6	1.6
coalSteamI		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.6	1.6	1.6	1.6	1.6	2.2	2.2	2.2
CFB		0.0	0.0	0.0	0.0	0.0	1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CCGT		1.2	0.0	0.0	0.8	0.0	0.0	0.0	1.5	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.0
hydro		1.9	2.5	1.1	0.6	0.2	1.1	0.9	0.8	2.2	0.1	0.2	0.2	0.6	0.0	0.2	0.0	0.0
hydroPS		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SHP/RE		0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
CCCT_LNG		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
imports		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
oil,CT, other		0.4	0.0	0.0	0.0	0.3	0.0	-0.3	-0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

115. Figure 6.2 shows the corresponding energy generation mix. Note the gradually declining share of hydro, and the growth of imported coal projects (that are in the South).

Figure 6.2: Energy generation mix



	2009		2011		2013		2015		2017		2019		2021		2023		2025
coalSteam	21	30	32	32	41	42	43	43	40	39	40	39	39	38	36	36	36
coalSteamI	0	0	0	0	0	0	0	2	3	5	8	12	15	18	22	25	27
CFB	5	3	2	3	2	8	7	8	7	7	6	6	5	5	5	4	4
CCGT	34	18	18	20	15	10	10	10	10	12	11	10	9	10	10	10	10
hydro	40	49	47	44	40	39	37	36	38	35	32	31	29	27	25	23	22
hydroPS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SHP/RE	0	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	1
CCCT_LNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
imports	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
oil,CT, other	1	0	0	-0	0	0	-0	0	0	0	0	0	0	-0	0	0	0

116. Although the above figures show the results for the entire national system, the two main load centres of Hanoi and HCMC are separated by a distance of 1500 km. The power system is really three separate systems weakly connected by a single 500kV transmission corridor and a few 220kV links. The carrying capacity of the 500kV is quite small in comparison to the loads and generation at its two ends (Table 6.1).

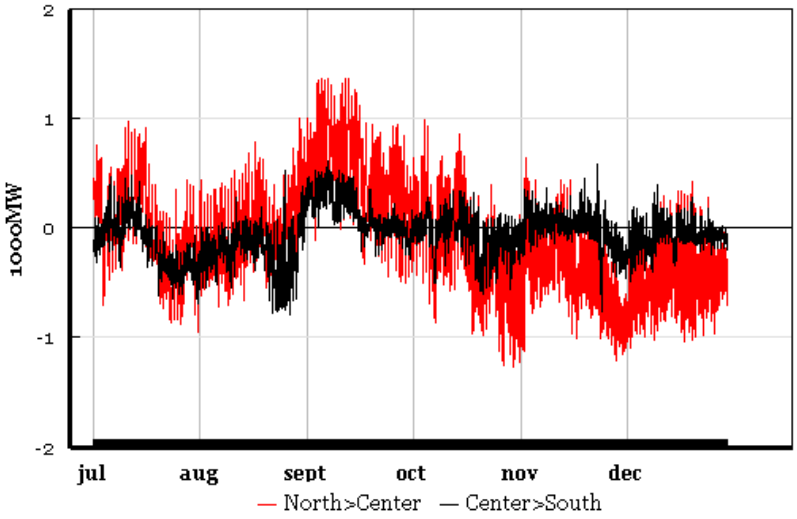
Table 6.1: Interregional transmission constraints, maximum MW transfers

	2010	2015	2020	2025
North-central	1,800	2,400	2,400	2,400
Central-South	1,800	2,400	3,200	3,200

117. Figure 6.3 shows the 500kV system flows from North to Centre, and Centre to South in 2007-2008. Transfers rarely exceed 1000MW: for most of the dry season (January-May), the North and Centre are in deficit, so flows are from the CCGTs in the South to the Centre and North. During the North's wet season, it exports to the centre (and a lesser amount to the South), a flow reversed in November and December, when the Centre's hydro peak.

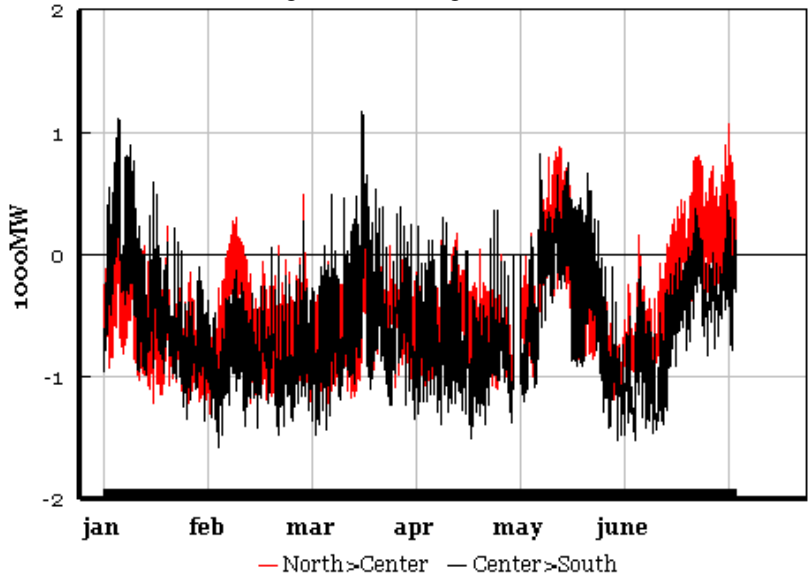
Figure 6.3: Flows in the 500kV system

A. **July 1 2007 –Dec 31 2007**



Negative values indicate flows in the reverse direction (Centre>North, South > Center)

B. Jan 1 2008 – June 30 2008

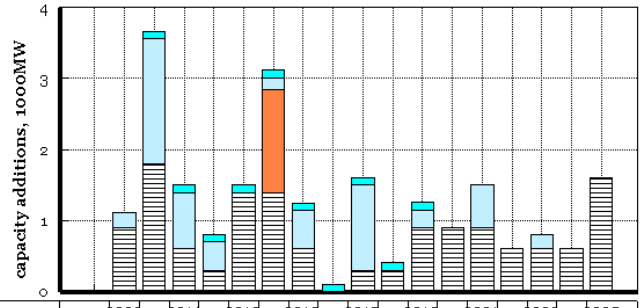


Source: EVN daily operations reports, 2008

118. The expansion plans for the North and the South are quite very different, as determined by the distribution of fossil fuel resources: domestic coal and hydro in the North, hydro in the centre, and gas, imported coal, and a lesser contribution of hydro in the South.

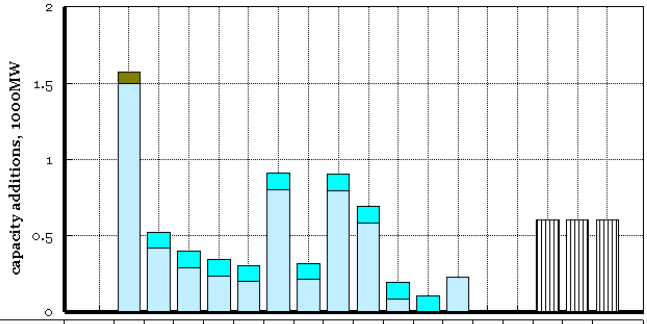
Figure 6.4: Expansion plans by region

NORTH



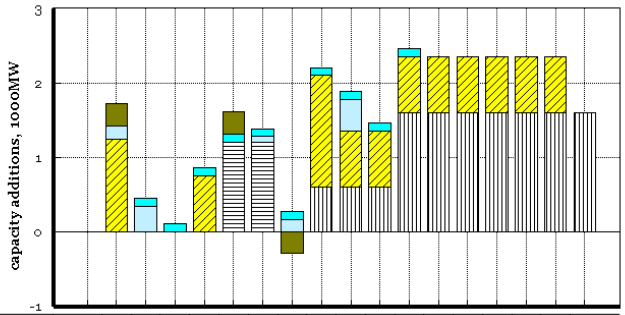
	2009	2011	2013	2015	2017	2019	2021	2023	2025
coalSteam	0.9 1.8	0.6	0.3	1.4	1.4	0.6	0.0	0.3	0.3	0.9	0.9	0.9	0.6	0.6	0.6	1.6
coalSteamI	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CFB	0.0	0.0	0.0	0.0	0.0	1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CCGT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
hydro	0.2	1.8	0.8	0.4	0.0	0.2	0.5	-0.0	1.2	0.0	0.2	0.0	0.6	0.0	0.2	0.0	0.0
hydroPS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SHP/RE	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
CCCT_LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
oil,CT, other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

CENTRE



	2009	2011	2013	2015	2017	2019	2021	2023	2025
coalSteam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
coalSteamI	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.6
CFB	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CCGT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
hydro	1.5	0.4	0.3	0.2	0.2	0.8	0.2	0.8	0.6	0.1	0.0	0.2	0.0	0.0	0.0	0.0	0.0
hydroPS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SHP/RE	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
CCCT_LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
oil,CT, other	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trung Son hydro																	

SOUTH



	2009	2011	2013	2015	2017	2019	2021	2023	2025
coalSteam	0.0	0.0	0.0	0.0	1.2	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
coalSteamI	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.6	1.6	1.6	1.6	1.6	1.6	1.6
CFB	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CCGT	1.2	0.0	0.0	0.8	0.0	0.0	0.0	1.5	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.0
hydro	0.2	0.3	0.0	0.0	0.0	0.1	0.2	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
hydroPS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SHP/RE	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
CCCT_LNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
oil,CT, other	0.3	0.0	0.0	0.0	0.3	0.0	-0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trung Son hydro																

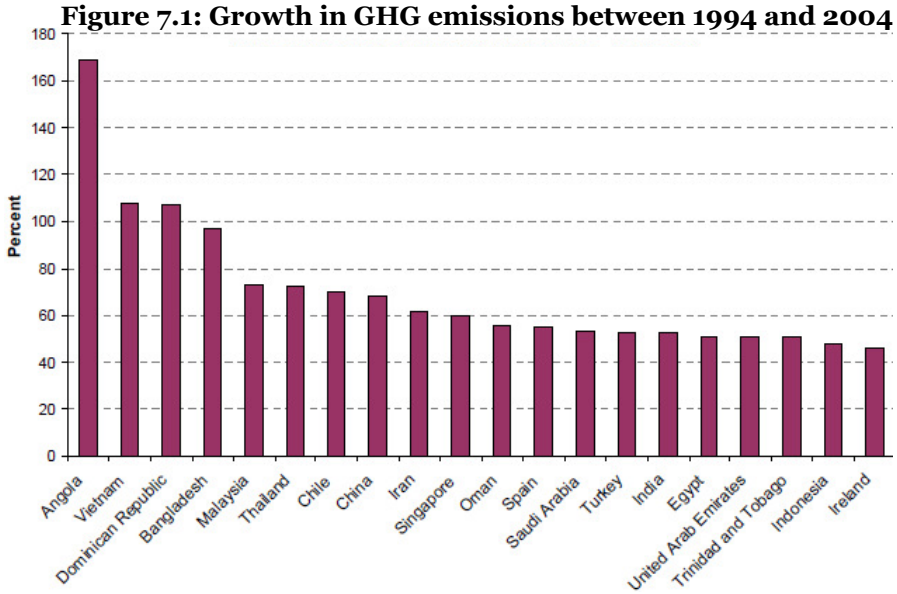
7 CARBON ACCOUNTING

119. With the increasing concern over GHG emissions, carbon accounting issues are important, especially where significant increases in coal-fired generation are planned.

GHG emissions

120. In the past decade, Vietnam's GHG emissions have risen sharply, and a recent World Bank comparative study shows Vietnam to have the second highest GHG emission growth rate among countries in the decade 1994-2004 (Figure 7.1) – albeit from a very low base.

Figure 7.1: Growth in GHG emissions between 1994 and 2004



Source: R. Bacon and S. Bhattacharya, *Growth and CO2 emissions: how do different countries fare?*, World Bank Environmental Department Papers, 113, November 2007.

121. The growth rate may be high, but in absolute terms emissions are still low: Vietnam's emissions, and emissions per capita, are the lowest among its main regional neighbours, as is its per capita GDP (Table 7.1). Only in

terms of emissions per unit of GDP is it comparable to Malaysia, Thailand and Indonesia.

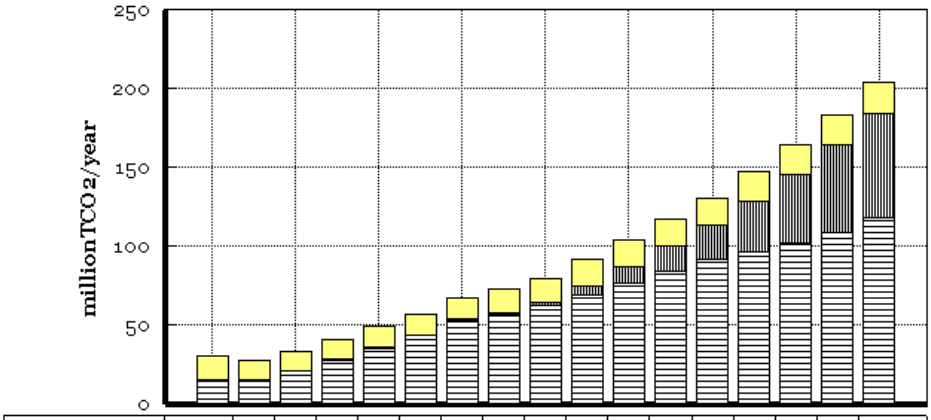
Table 7.1: Comparative indicators for Vietnam's GHG emissions

	2004 emissions, million metric tons	2004 Per capita GDP at market exchange rate	Tons/ $million GDP at market exchange rate	%CO2 from fossil fuel combustion	Emissions per capita (tons/ person)
Vietnam	**57**	**496**	**1,394**	**52**	**0.69**
China	4,707	1311	2,745	59.5	3.60
Philippines	75	1,094	836	30.4	0.92
Indonesia	308	894	1,564	9.3	1.4
Malaysia	154	4,296	1,437	12.5	6.17
Thailand	219	2,356	1,457	48.8	3.43
USA	5,912	36,234	552	86.8	20.01

Source: Bacon & Bhattacharya, *op.cit.*

122. Power sector GHG emissions will rise rapidly over the next decade, as shown in Figure 7.2 for the reference case – from around 30million tons CO_2 to 200 million tons by 2025.

Figure 7.2: Power sector GHG emissions



	2009		2011		2013		2015		2017		2019		2021		2023		2025
domestic coal	15	16	21	28	35	44	53	57	62	69	76	84	91	96	102	108	118
imported coal	1	0	0	1	0	0	0	1	1	6	11	16	22	32	43	56	66
gas	14	12	12	13	14	13	13	16	15	16	17	17	17	18	19	19	20
oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Combustion emission factors

123. Table 7.2 shows the IPCC default emission factors for the main fossil fuels. Vietnam's domestic coal is largely anthracite, which has higher CO_2 emissions than imported bituminous coal.

Table 7.2: CO2 emission factors from combustion

	Kg CO2/TJ	Kg/mmBTU
Anthracite	98300	93.21
Bituminous	94600	89.70
sub-bituminous	96100	91.12
Lignite	101000	95.77
Diesel	74100	70.26
Fueloil	77400	73.39
Gas	56100	53.20

Source: IPCC, default values

124. More importantly, the GHG emissions per kWh across the various existing projects varies considerably, from just 0.37 Kg/kWh at Phu My2.2 to 1.44 at Pha Lai 1. In the case of coal, large modern units as are now under construction will have significantly better heat rates and emission factors (and even based just on cost considerations, Pha Lai 1 and the old units at Uong Bi are prime candidates for retirement, as discussed in the next Section).

Table 7.3: GHG emissions from thermal generation projects

		Heat Rate	CO2 emissions	
	fuel	GJ/MWh	tonsCO2 /TJ	kg/kWh
PhuMy22	NCS Gas	6.6	56.10	0.37
CaMau1	Cai Nuoc Gas	7.2	56.10	0.40
CaMau2	Cai Nuoc Gas	7.2	56.10	0.40
PhuMy3	NCS Gas	7.3	56.10	0.41
PhuMy1	NCS Gas	7.5	56.10	0.42
PhuMy4	NCS Gas	7.8	56.10	0.44
PhuMy21	NCS Gas	8.0	56.10	0.45
BaRia Total	CL Gas	8.0	56.10	0.45
NhonTrachGT	NCS Gas	8.0	56.10	0.45
VeDan	NCS Gas	8.0	56.10	0.45
HiepPhuoc	HSFO	11.7	77.40	0.91
Cai Lan	HSFO	12.0	77.40	0.93
Uong Bi S7, 8	Coal	9.5	98.30	0.93
CanThoS4	HSFO	12.8	77.40	0.99
ThuDucS2-3	HSFO	12.8	77.40	0.99
Formosa	iCoal	10.9	94.60	1.03
Na Duong	Coal	10.7	98.30	1.05
Cao Ngan	Coal	10.7	98.30	1.05
Pha Lai 2	Coal	10.8	98.30	1.06
Uong Bi S5-6	Coal	11.1	98.30	1.09
CanThoGT1-4	Distillate	14.8	74.10	1.10
ThuDucGT	Distillate	14.8	74.10	1.10
Ninh Binh	Coal	13.4	98.30	1.32
Pha Lai 1	Coal	14.6	98.30	1.44

source: heat rates from PB New Zealand, *Analysis And Implementation Of Water Valuation In Vietnam*, Report to World Bank, August 2009. CO_2 emissions factors form IPCC defaults (Table 7.2).

GHG emissions from reservoirs

125. GHG emissions from hydro dams remains a controversial topic, and in 2000 the World Commission on Dams noted three points that are still valid:[36]

- Hydropower cannot, a priori, be automatically assumed to emit less greenhouse gas than the thermal alternatives. Net emissions should be established on a case by case basis.
- The flooded biomass alone does not explain the observed gas emissions. Carbon is flowing into the reservoir from the entire basin upstream, and other development and resource management activities in the basin can increase or decrease future carbon inputs to the reservoir.
- As natural habitats also emit greenhouse gases it is the net change due to impoundment that should be used for assessment, and not the gross emissions from the reservoir.

Power density

126. The so-called power density, measured as watts/m^2 of reservoir area has come into increasing us as a proxy for the GHG efficiency of a hydro project. UNFCCC has issued a draft guideline for the CDM eligibility of hydro projects that uses this measure to classify the eligibility of hydro projects:[37]

- Projects with power densities (installed power generation capacity divided by the flooded surface area) less than or equal to 4 W/m^2 are excluded;
- Projects with power densities greater than 4 W/m^2 but less than or equal to 10 W/m^2 can be eligible, but with an emission penalty of 90 g CO_2eq/kWh;
- Projects with power densities greater than 10 W/m^2 are be eligible, without penalty.

127. UNFCCC notes that in a database of 245 hydro plants in operation in the world today with at least 30 MW of installed capacity, it finds the average power density is 2.95W/m^2. Table 7.3 shows power densities for hydro projects in Vietnam, including power densities for the small hydro projects to be financed under the World Bank's renewable Energy Development Project (REDP): all have much better power densities than the global average.

[36] World Commission in Dams, *Final report on Dams and Development A New Framework for Decision-making to the Framework Convention on Climate Change*, November 2000.

[37] UNFCCC CDM Methodology Panel, Nineteenth Meeting Report, Annex 10, *Draft Thresholds and Criteria for the Eligibility of Hydroelectric Reservoirs as CDM Projects*.

Table 7.4: Power Densities of representative Projects

Project	Installed Capacity	Reservoir area	Power density
	MW	Km2	W/m2
Medium Hydro			
Trung Son	260	13.13	19.8
Song Bung 4	156	15.8	9.9
Small Hydro			
Sung Vui	18	3.2 ha	563
Nam Tang	6.5	0.3 ha	2167
Dak Me	4	2.1 ha	190
Can Ho	4.2	0.7 ha	600
Ha Tay	9	64ha	14

128. These power densities also compare favourably with the range of power densities for Brazilian projects for which detailed methane and CO_2 flux survey data is available (and which represent the basis for the thresholds proposed by UNFCCC) (Table 7.5).

Table 7.5: Power densities for Brazilian hydro projects

Project	Province	Installed capacity	Reservoir area	Power density
		MW	Km2	W/m2
Xingo	Caatinge	3000	60	50
Trung Son	**Vietnam**	**260**	**13.13**	**19.8**
Segredo	Mata Atlantica	1260	82	15.47
Song Bung 4	**Vietnam**	**156**	**15.8**	**9.9**
Itaipu	Mata Atlantica	12000	1549	8.13
Miranda	Cerrado	390	50.6	7,72
Tucuri	Amazonica	4240	2430	1.74
Serra da Mesa	Cerrado	1275	1784	0.71
Barra Bonita	Mata Atlantica	141	312	0.45
Samuel	Amazonica	216	559	0.39
Tres Marias	Cerrado	396	1040	0.38

Source: Marco Aurélio dos Santos *et al*., *Variability of Greenhouse Gas Fluxes from Hydropower Reservoirs in Brazil*, UNESCO Workshop on Freshwater reservoirs and GHG emissions, Paris, November 2006.

Life cycle emissions

129. Finally, there is the question of whether one need only consider emissions from combustion, or whether one should attempt the quantification of life cycle emissions. The increasing attention to life cycle emissions is largely the consequence of criticism about claims regarding the GHG benefits of nuclear and hydro generation, and the recognition that all technologies, including renewable generation such as wind, have an impact on GHG emissions by virtue of the energy required for the manufacture of equipment, as well as in fuel extraction, transport and decommissioning.

130. There is little doubt that the bulk of GHG emissions associated with thermal generation technologies derive from actual fuel combustion. The

necessary calculations are relatively straightforward and uncontroversial, and subject to relatively modest uncertainties.

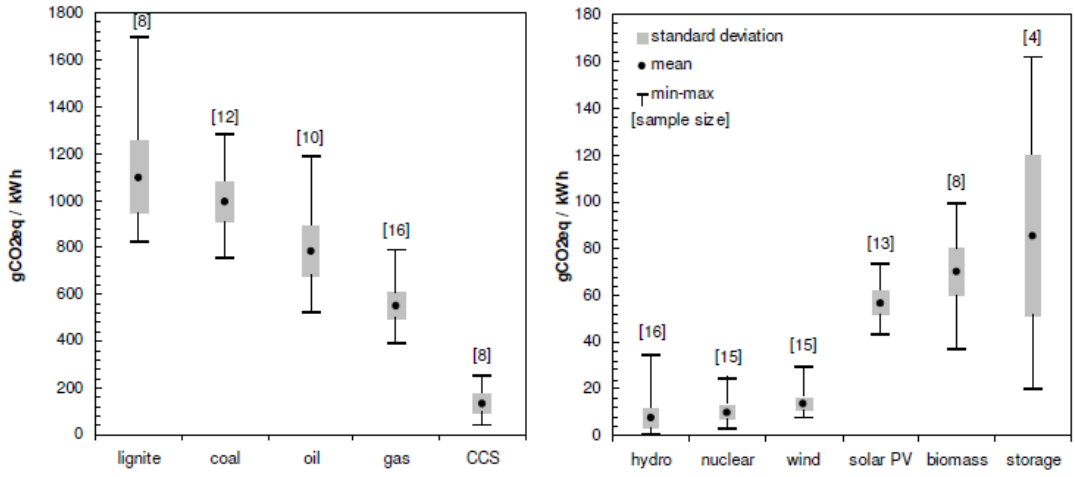
131. Whether one should account for these indirect impacts as well as the direct impacts of combustion depend upon the answers two further questions:

- how large are these impacts compared to combustion?
- can reliable calculations of indirect impacts be made, and, if so, under what circumstances is the burden of calculation reasonable?

Magnitude of life-cycle emissions

132. Leaving aside the more extreme claims, the consensus of the technical literature appears to be that, *in general*, the life cycle emissions associated with mining, transport, materials inputs, construction and decommissioning represent 5-10% of lifecycle emissions for most fossil fuel technologies. The results of a recent literature review are shown in Figure 7.3, which summarises life-cycle emissions estimates of some 50 studies: hydro, nuclear and wind all have emissions in the range of 10-40gCO_2 /kWh, compared to 800-1300gCO_2 for coal.

Figure 7.3: Summary of Life-cycle GHG emissions



Source: D. Weisser, *A Guide to Life-cycle GHG emissions from electric supply technologies*, Energy (32) 2007, pp. 1543-1559.

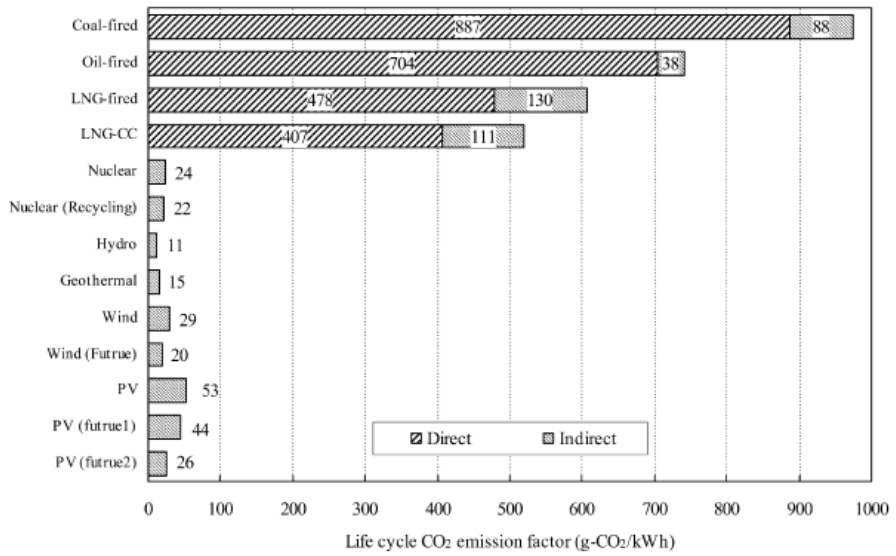
133. Figure 7.4 summarises the results of a typical country-specific study- in this case for Japan,[38] the most interesting finding of which is the high value for non-combustion impacts of LNG. The indirect emission factors for an LNG CCGT (111 gms CO_2/kWh) and 130 gms/kWh for a steam cycle LNG fueled project are the largest for any technology, and significantly higher than for coal projects (88gms CO_2/kWh). Liquefaction is an energy

[38] *Source*: H. Hondo, *Life cycle GHG emission analysis of power generation systems: The Japanese case*, Energy,30 (2005) 2042-2056.

intensive process, but more important is the high CO_2 content of the extracted gas, which is released during processing – 20-30% in the case of Indonesia.[39]

134. For gas fueled plants there is the further issue of leakage, which, given a global warming potential of 21, has a disproportionate impact on aggregate GHG emissions: in the Japan study, methane leakage in LNG production was estimated at 9 g/kWh, with a further 19.4 g/kWh in LNG transportation.

Figure 7.4: Lifecycle GHG emission factors



Source: H. Hondo, *Life cycle GHG emission analysis of power generation systems: The Japanese Case*, Energy,30 (2005) 2042-2056.

135. In the case of coal plants, much depends on the technology and its efficiency, with ultra-supercritical plants having significantly lower emissions than present sub-critical projects (Table 7.6) – though this is mainly a consequence of different efficiency, not of different life cycle impacts.

[39] Similarly in Vietnam, the gas field supplying the O Mon power complex (Chevron Block B) is reported to contain 23% CO_2

Table 7.6: GHG emissions for coal technologies

	Steam temperature (^{O}C)	Steam pressure (Mpa)	Thermal efficiency	Life cycle emissions g CO_2 /kWh
Sub-critical	540	16.6	37.6%	941
Supercritical	560	25	43%	788
Ultra-supercritical	630	30	45.3%	716

Source: University of Sydney, *Life Cycle Energy Balance and GHG Emissions of Nuclear Energy in Australia*, Report to the Australian Government, 3 November 2006, Table 6.13

Table 7.7 compares the life cycle emissions for coal and hydro in an Australian study: again the hydro estimates do not include any reservoir impacts (but they do include dam *construction*). The results are similar to the Japanese results of Figure 7.5 for hydro (14.9 g/kWh as compared to 11g/kWh in Japan). But for coal, the Japanese results are significantly higher, because they include the transportation over long distances the distant mines (in Australia). For domestic anthracite in Vietnam, distances are also relatively short, though for imported coal the transportation impacts will be much higher.

Table 7.7: GHG emissions for coal and hydro

	Super-critical coal mine-mouth		Hydro (run-of-river)	
	gCO2/KWh	% of total	gCO2/KWh	% of total
Mining	33.0	3.2%		
Transport	0.4	0.0%	0.2	1.6%
Construction	6.9	0.7%	3.3	22.2%
Materials			11.4	76.2%
Combustion	995.5	96.1%		
Decommissioning	0.3	0.0%		
Total	1036.1	100.0%	14.9	100%

Source: University of Sydney, *Life Cycle Energy Balance and GHG Emissions of Nuclear Energy in Australia*, Report to the Australian Government, 3 November 2006, Table 6.13

The reliability of life cycle calculations

136. Life cycle emissions calculations encounter a range of problems:

- Emissions may depend upon highly variable site specific circumstances. For example, in a study of life cycle GHG emissions for wind projects in Brazil and Germany,[40] it was found that the emissions related to steel manufacture depend critically on the proportion of scrap used (high in Germany, low in Brazil), and on the generation mix of electricity used in manufacturing industry (low emissions in hydropower dominated Brazil, high emissions in Brown coal dominated Germany): in some cases – as in this comparative study of Brazil and Germany, these may cancel out, but in others not, leading to large differences in values.

[40] M. Lenzen & U Wachsman, *Wind Energy Converters in Brazil and Germany: An example of Geographic Variability*, Applied Energy, 2004 (77) 119-130.

- Process analysis, a bottom-up approach to life cycle calculations, for which the energy requirements of the main production processes and suppliers of inputs are assessed in detail, suffers from what has been described as "unavoidable truncation of the system boundary".[41]
- In Input-output analysis, which avoids this problem, and which can account for the energy requirements from upstream inputs and supply chains of infinite order, suffers from its own shortcomings of allocation and aggregation, and requires much more complex models.[42]

Conclusions

137. The following conclusions can be drawn

- The life cycle emissions associated with materials and construction of hydro plants are small, and will be taken as 15gCO_2/kWh.
- The calculations of emissions from coal and natural gas combustion can use the IPCC default values for the fuel concerned (Table 4.2), but adjusted for actual efficiency of the assumed marginal plants (rather than the averages as in the CDM calculations for Song Muc) for the calculation of economic returns including net GHG benefits.
- The life cycle emissions for mine mouth coal plants will be taken as 40g/kWh for domestic anthracite (based on the Australian study), and 80g/kWh for imported coal (based on the Japan study).
- For natural gas plants, the life-cycle emissions will be taken as 70 g/kWh but 130 g/kWh for LNG (to account for the significant energy inputs into liquefaction, as well as the high CO_2 content of Indonesian natural gas. the most probable source for Vietnamese LNG imports).

[41] University of Sydney, *Life Cycle Energy Balance and GHG Emissions of Nuclear Energy in Australia*, report to the Australian Government, 3 November 2006.

[42] Input-output models which describe the transactions among production sectors are rarely designed with the requirements of energy-environmental analysis in mind. For example in the case of nuclear projects, enriched uranium or heavy water may not be well represented by the closest sector available (such as "chemicals").

8 ALTERNATIVES

Alternatives To Supply Side Expansion

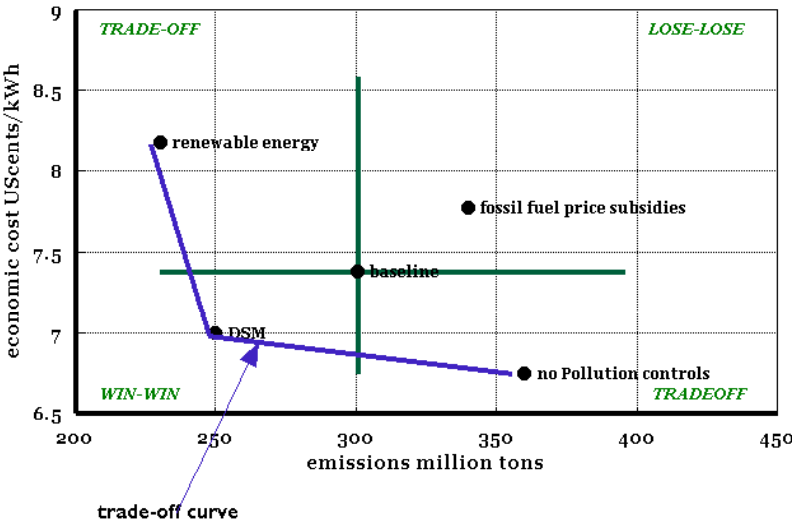
138. Any assessment of generation options needs to begin by addressing the concerns of those who argue that supply side expansions – or at least a significant fraction of proposed new projects - could be avoided by demand side alternatives and improved efficiency. These are valid concerns, particularly given that many such demand side interventions and efficiency improvements are warranted on the basis of cost as well as environmental concerns.

139. In many South Asian countries, T&D losses were unacceptably high, and much of the assistance to the power sector from IFIs over the past 20 years was directed at improving T&D efficiency. But with 2008 losses of around 11%, Vietnam's T&D efficiency is already better than in most Asian countries, and without the high commercial losses of South Asia. That this has been achieved notwithstanding an aggressive program of rural electrification where losses are intrinsically higher than in urban areas testifies to EVN's success in establishing an efficient T&D system. Significant investments are planned to bring T&D losses down further to around 9%, and the load forecasts already incorporate these targets.

140. However, a range of other alternatives to supply side expansion are worth more detailed examination, and the Section starts with a review of opportunities for DSM and other policy reforms, notably the reduction of subsidies. This is then followed by a discussion of alternative supply side interventions.

Box 8.1: Trade-off curves

Trade-off curves are simply XY plots of attributes, two at a time. Typically one shows quadrants relative to some baseline refernce scenario, into which fall the options as may be defined as perturbations of that baseline. The figure shows such an (illustrative) plot.



- Quadrant I contains solutions best described as "*lose-lose*" –containing options that have higher emissions and higher costs. Typical options in this quadrant would be option involving fossil fuel price subsidies (assuming the baseline is at economic prices), or ***not*** sub-critical coal units (if the baseline includes supercritical units).
- Quadrant II contains solutions involving tradeoffs – costs decrease, but emissions increase. No FGD, or pumped storage would be options that typically occupy this quadrant.
- Quadrant III contains solutions that are "win-win", of which DSM, or reduction in T&D losses, are typical examples. Here both attributes improve – lower emissions *and* lower economic costs.
- Quadrant IV again contain options that require a trade-off – emission decrease but only at increased cost. Renewable energy options, and substitution of coal by LNG, are typical options to be found here.

The figure 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 the figure, 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 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 tradeoff 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 very much greater emissions than DSM, but only a very small cost advantage – so a decision maker would have to give enormous weight to cost, and almost no weight at all to emissions, to chose this option. Similarly, "renewable energy" (as drawn here) has only slightly lower emissions, but very much higher cost than DSM - so again, to prefer renewable energy over DSM would require huge weight be given to emissions, and very small weight 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.

DSM

141. Measures to improve demand side efficiency have three main consequences for the power system, which can be illustrated by a CFL. First, a CFL reduces consumer *consumption* (since the energy consumed by a CFL is 20% that of an incandescent bulb providing similar lumen output). Second, by reducing peak hour demand, it improves the system load factor, and may defer the construction of peaking capacity. And third, since transmission losses are proportional to the square of the load, reducing the peak hour load results in a disproportional decrease in total T&D energy losses. Since the marginal plant is always a thermal project, all three effects, in whatever combination associated with a particular DSM intervention, reduce emissions.

142. The result of EVN's so-called Phase 2 DSM program, which included CFLs, time-of-use tariffs, direct load control and efficient fluorescent tube lamps has been generally encouraging (Table 8.1)

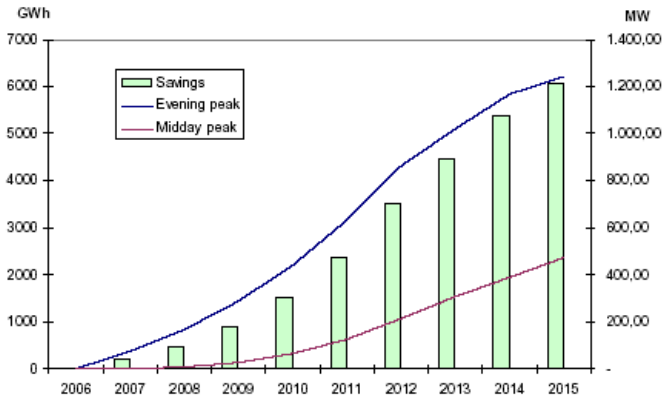
Table 8.1: DSM impacts, Phase 2

	Goal	Results
Time-of-use tariffs	69.7 MW	45 MW
CFLs	33.4 MW, 303 GWh	30.1 MW, 243 GWh, indirect market transformation impact estimated at 280MW peak saving
direct load control	3.1 MW	program cancelled
efficient fluorescent lamps	14.4 MW, 196 GWh	savings not estimated

Source: Danish Energy Management, *Technical Assistance for EVN's Phase 2 DSM programme*, Final Report, August 2008

143. The remaining DSM potential is substantial, and has been estimated by Danish Energy Management[43] at 1,200MW of evening peak reduction and 6,000 GWh of energy savings (Figure 8.1)

Figure 8.1: Estimated savings and peak load reductions



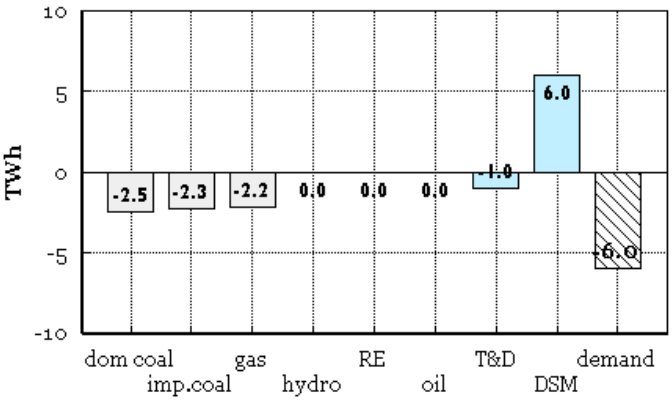
Source: Danish Energy Management, *Technical Assistance for EVN's Phase 2 DSM programme*, Final Report, August 2008, Figure 9.1.

[43] *Source*: Danish Energy Management, *Technical Assistance for EVN's Phase 2 DSM program,* Final Report, August 2008.

144. When this potential is superimposed on the baseline scenario, there are significant changes to energy generation, as shown in Table 8.2. Thermal generation decreases across all fuels.

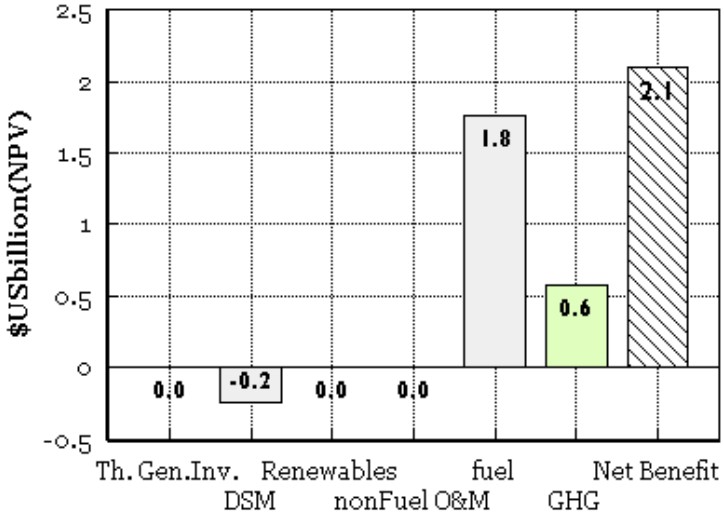
Table 8.2: DSM scenario: energy generation changes 2020

TWh	*baseline*	Impact	*DSM scenario*
domestic coal	87.6	-2.5	85.1
imported coal	18.7	-2.3	16.4
CFB	11.5	0.0	11.5
CCGT	33.6	-2.2	31.4
hydro	70.9	0.0	70.9
hydroPS	0.0	0.0	0.0
SHP/RE	4.8	0.0	4.8
CCCT_LNG	0.0	0.0	0.0
imports	0.0	0.0	0.0
oil,CT, other	4.6	0.0	4.6
total	231.7	-7.0	224.7
T&D loss	20.6	-1.0	19.6
demand	211.1	-6.0	205.1
DSM	0.0	6.0	6.0



145. The corresponding impacts on the cost structure are shown in Figure 8.2. The benefit cost ratio is high: an investment of $240million (as NPV) results in lifetime fuel savings of $2.1 billion.[44] Any capacity benefit would increase the net benefits further.

Figure 8.2: DSM impacts on cost structure



Note: positive numbers indicate (net) benefits, negative numbers (below the line) indicate costs. The net economic benefit is simply the sum of the individual impacts, and includes avoided GHG emissions valued at $15ton CO_2

[44] By way of comparison, the Danish DSM study reports a benefit cost ratio to EVN of 99 (ratio of EVN's avoided fuel costs to EVN's DSM program costs).

146. The lifetime GHG emission savings are also significant, saving 138 million tons CO_2 (Table 8.3). DSM is win-win, so the carbon shadow price is not defined.

Table 8.3: Impact of DSM on GHG emissions

		baseline	impact	*[%]*	*DSM scenario*
2020 GHG emissions	[million tons/year]	117.1	-4.90	-4.2%	112.2
LifetimeUndiscountedEmissions	[million tons]	4251	-138	-3.2%	4113
PV(GHGemissions)	[million tons]	916.9	-38.3	-4.2%	878.6
PV(damage cost) @ 15$/ton CO_2	[$USbillion]	13.8	-0.58	-4.2%	13.2
PV(system cost)	[$USbillion]	82.5	-1.52	-1.8%	81.0
carbon shadow price	[$/ton CO_2]	not applicable, win-win			

Fuel subsidies

147. The distortions created by subsidies on fossil fuels are well understood (Box 8.1), and several studies have documented the global environmental benefits that would accrue were these eliminated.[45] In Vietnam, both natural gas and domestic coal presently enjoy significant subsidies, with coal and gas deliveries to thermal power plants at prices much below their border prices.

148. Eliminating these subsidies can be expected to have the following consequences in the power sector:

- generation prices in the CGM will increase, and hence under the proposed retail tariff methodology (that treats wholesale power purchase costs as pass-throughs), consumer prices will also increase; therefore, all other things equal, consumption will decrease – as will GHG emissions.
- In general, the relative price of coal and gas will change, that in principle might affect the merit order and, over the long run, the mix of coal and gas capacity. However, in the specific case of Vietnam, because of the transmission capacity constraint between North and

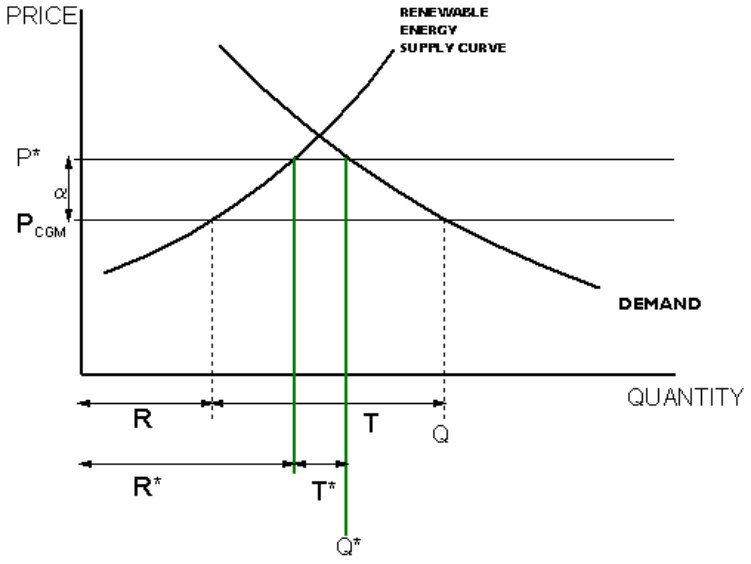
[45] The 1999 IEA World Energy Outlook (International Energy Agency: 1999 Insights, *World Energy Outlook: Looking at Energy Subsidies: Getting the Price Right)* analysed energy subsidies in 8 non-OECD countries (including among China, India, Indonesia, and Kazakhstan), for which on average end-use prices are 20% below their opportunity cost or market based reference levels. The studies found that removal of these subsidies would reduce primary energy consumption by 13%, lower GHG emissions by 16%, and increase GDP though higher efficiency by almost 1%. A 2007 UNFCCC report (T. Morgan, *Energy Subsidies: Their magnitude, how they Affect Energy Investment and Greenhouse Gas Emissions, and Prospects for Reform*, UNFCCC Secretariat, Financial and technical Support Programme) estimates that annual energy subsidies are between 250-300 billion net of taxes, and account for 0.6 to 0.7% of world GDP. This compares to support for low carbon sources of $33billion, of which only $10billion is for renewables, $6billion for biofuels, and $16 billion for existing nuclear power plants.

South, and the fact that domestic coal is in the North, while gas is in the South, the substitution between these two sources will be limited.

- The avoided cost tariff (ACT) that applies to renewable energy generation will increase, enabling a larger share of renewable energy. This is based on EVN's avoided financial costs, so as the financial costs increase to international price levels, the ACT increases.

Box 8.1: Impact of removing coal price subsidies

The impact of fuel subsidies is readily illustrated. Consider the figure below, which shows the demand for electricity, the renewable energy 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 σ. The quantity consumed at this price, Q, is given by the intersection of the demand curve with P_{CGM}. The amount of renewables will be R (namely that quantity whose production cost is less than P_{CGM}), and the balance will be fossil generation, T ($T=Q - R$).



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 the lower level of consumption Q^*. More renewable energy will be economic at the higher price P^*, and the quantity of fossil energy reduces to T^* ($R^*+T^*=Q^*$). Thus there are three important consequences of reducing the subsidy on coal: (i) less electricity is consumed (ii) the amount of fossil energy, and hence GHG emissions, is reduced, and (iii) the amount of renewable energy is increased. It is easily shown that both social and global welfare increases as a result of the elimination of the subsidy: the reduction in fossil fuel subsidies is win-win

149. In the case of renewables, whether the ACT rises to the economic tariff because the subsidies on fuel are reduced, or whether a subsidy is provided to renewable energy producers to cover the difference between the avoided cost of thermal generation and the yield from the avoided cost tariff,

makes no difference: the additional renewable energy that is induced is the same provided that in both cases the incremental costs are passed to consumers (and in both cases, total consumption declines to the extent of the price elasticity effect). If the subsidies are eliminated, then the higher costs will be passed to buyers in the CGM, and thence passed to consumers since these are treated as pass-throughs. Similarly if additional renewable energy is enabled by subsidy from the renewable energy development fund (REDF), as proposed by the renewable energy Masterplan, and that subsidy collected directly from consumers through a kWh levy, the impact on the consumer tariff should be roughly the same (and differ only by the transaction costs of the REDF).

Supply side options

Nuclear Power

150. Assuming an overnight cost of $4,500, and a six-year construction period with a 10% cost of capital, the completed cost is $6,084/kW.[46] Together with a fuel cost of $0.5/mmBTU, and a net heat rate of 10,450 BTU/kWh,[47] nuclear costs per kWh are as shown in the screening curve of Figure 3.4: over the entire range of load factors the cost of nuclear is substantially above that of coal. It is therefore very unlikely that nuclear power will be economic in Vietnam, and indeed is not chosen by IoE's capacity expansion planning model..

151. Nevertheless, there may be arguments to consider nuclear power, including the avoidance of GHG emissions (as noted in Section 7, even when life-cycle emissions are taken into account, nuclear power projects have negligible GHG emissions compared to coal and gas), and the improvement of electricity supply diversity (particularly as a hedge against extreme disruptions to imported fossil fuels). But unlike Japan, that has no domestic fuel resources and imports significant quantities of fuel for power generation from the Middle East (LNG and crude-oil), the need for such a hedge in Vietnam's case is less apparent.

Retirement and rehabilitation of old coal projects

152. Strict merit order dispatching will affect the load factors of the existing coal projects, which will in turn affect the economics of rehabilitation. A study (funded by USAID) evaluated Pha Lai 1, Ninh Binh

[46] Assuming six equal mid-year disbursements over the construction period.

[47] The average heat rate reported by EIA for nuclear projects in the US is 10,488 BTU/kWh. The 2003 MIT study assumes 10,400BTU/kWh

and Uong Bi and proposed rehabilitation of Pha Lai 1.[48] These plants have very poor heat rates, even compared to the more modern Pha Lai 2 project, as shown in Table 8.4.

Table 8.4: Heat rates at the existing coal-fired units in Northern Vietnam

	2003	2004	2005	2006	Average heat rate, Kcal/kWh	efficiency
Pha Lai 1	2578	2202	2458	2937	3146.6	27.3%
Pha Lai 2	3202	3529	4300	4315	2351.6	36.6%
Uong Bi	730	641	670	756	3747.5	22.9%
Ninh Binh	680	633	690	793	4155.3	20.7%
average						26.9%

Source: IoE. Heat rates are gross.

153. Rehabilitation cannot restore efficiency to the original value, much less to that of a modern plant. In fact, rehabilitation of the old coal plants will not change the relative merit order, so a rehabilitated plant will be dispatched no more than an un-rehabilitated project. The other alternative is their retirement (as suggested by some of the IoE modelling studies).

154. Table 8.5 compares the existing emissions from Pha Lai 1 with those achievable after renovation, and with those of the modern Muong Dong 1 project. Rehabilitation reduces the variable cost per kWh from 1.69 to 1.56 UScents/kWh, but the modern coal plant has an even lower variable cost (1.31 UScents/kWh). Even when taking the coal price at its economic rather than financial value, these differentials remain.[49]

[48] Energy Technology Enterprises Corp, *Energy Efficiency Audits in Existing Thermal Power Plants in Vietnam*, Report to USAID, Sept.2008.

[49] Discussed further in Section 4

Table 8.5: Rehabilitation of Pha Lai 1.

		design	actual 2007	rehabilitated	New Plant, Muong Dong
		[1]	[2]	[3]	[4]
MW(gross)	MW	110	98	105	
MW(net)	MW	101.2	86.51	96.075	
Auxiliary consumption	%	8.0%	9.7%	8.5%	9.5%
Efficiency	%, net	31.0%	25.6%	28.5%	35%
Heat rate, net	BTU/kWh	11018.4	13304	11972	9668
	KCal/kWh	2776.8	3352.8	3017.1	2436.5
Coal calorific value	KCal/kg	5035	4946	4846	4654
	kg/kWh	0.552	0.678	0.623	0.524
	kgCO2/kWh	1.138	1.399	1.285	1.081
annual plant factor			0.76	0.76	
GWh/year			575	640	
tons CO_2 /year			805	822	
tonsCO_2/year (for equivalent kWh)				739	
CO_2 saving				8.2%	
Coal cost,	$/ton	26.0	25.0	25.0	24.0
cost/kWh	UScents/kWh	1.43	1.69	1.56	1.26

Source: columns 1-3, Energy Technology Enterprises Corp, *Energy Efficiency Audits in Existing Thermal Power Plants in Vietnam*, report to USAID, Sept.2008; Data for Muong Dong I from the EIA and Annex 5 of the Renewable Energy Masterplan. The coal cost has been adjusted for heat value (though it is not clear that VINACOMIN's domestic coal pricing has comparable rationality).

155. The USAID report provides no rigorous economic or financial analysis, and acknowledges that "the investment requirement cannot be assessed with the available data" However, whatever the costs of rehabilitation and life extension, even if efficiency is restored to the original design values, its variable cost would still be significantly above that of all of the new projects.

156. Under the strict merit order dispatch in the CGM, it is therefore very unlikely that any of the three old plants (Phai Lai 1, Uong Bi and Ninh Binh) would be dispatched except during the dry seasons of very dry years, and long term average load factors will therefore fall from the present range of 65-75% to less than 30%. Therefore the CGM will force the retirement of these projects rather than their rehabilitation.

157. The benefit of the retirement of these three old coal projects is significant, and is shown in Table 8.6. The lifetime CO_2 savings amount to some 82 million tons CO_2 [50]

[50] The ability to make a full assessment of the capacity consequences of retirement in our model is limited by the lack of data on hydro conditions: in very dry years the old coal and oil plants would still have an important role. To make an assessment of this issue would require the hydro generation for all five hydro conditions used by IoE in the WASP-STRATEGIST model. This data is considered confidential by IoE and was not made available to us.

Table 8.6: GHG emission consequences of retirement of old coal projects

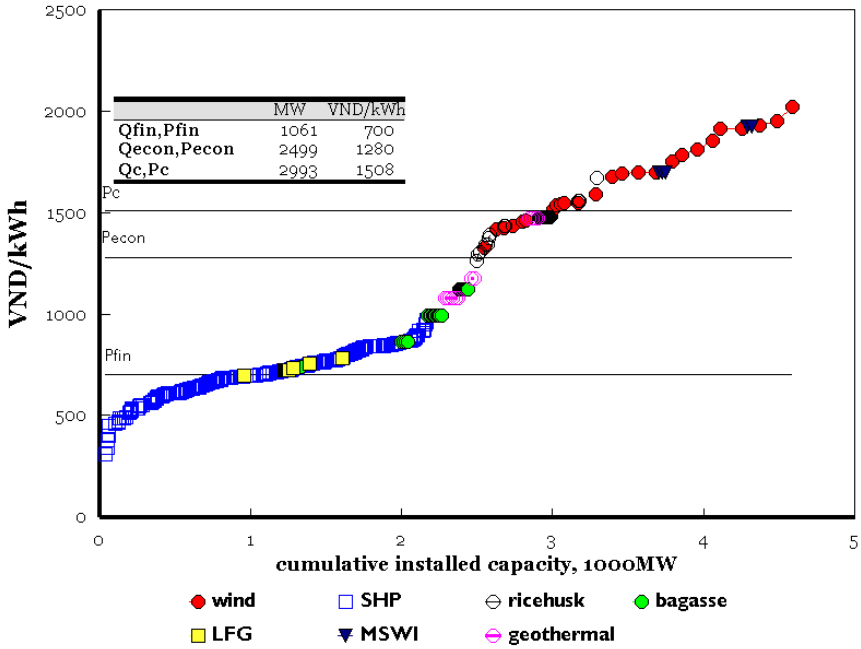
		baseline	impact	*retire old coal projects*
2020 GHG emissions	[million tons/year]	122.4	*-3.6*	118.8
LifetimeUndiscountedEmissions	[million tons]	4374.0	*-82.4*	4291.7
PV(GHGemissions)	[million tons]	952.8	*-17.8*	935.0
PV(damage cost)	[$USbillion]	14.29	*-0.27*	14.02

[Peter: I assume that you know that I wrote the USAID report. Nevertheless, I agree with your arguments and conclusions. The conclusion of my assessment was that clearly Uong Bi and Ninh Binh should NOT be rehabilitated, but for political reasons we tried to sugarcoat the conclusion to say that more detailed assessment is needed. For Pha Lai 1, we do recommend a more detail assessment and believe that a low-budget rehabilitation program may make sense]

Renewables

158. The Renewable Energy Master Plan has derived the supply curves for renewable energy, shown in Figure 8.3. Under the avoided cost tariff first issued in December 2008, the average tariff yield (denoted P_{fin} in Figure 8.3) is around 700VND/kWh. This is expected to enable around 1,060 MW of renewable energy, mainly small hydro.

Figure 8.3: Supply curve for renewable energy, MW

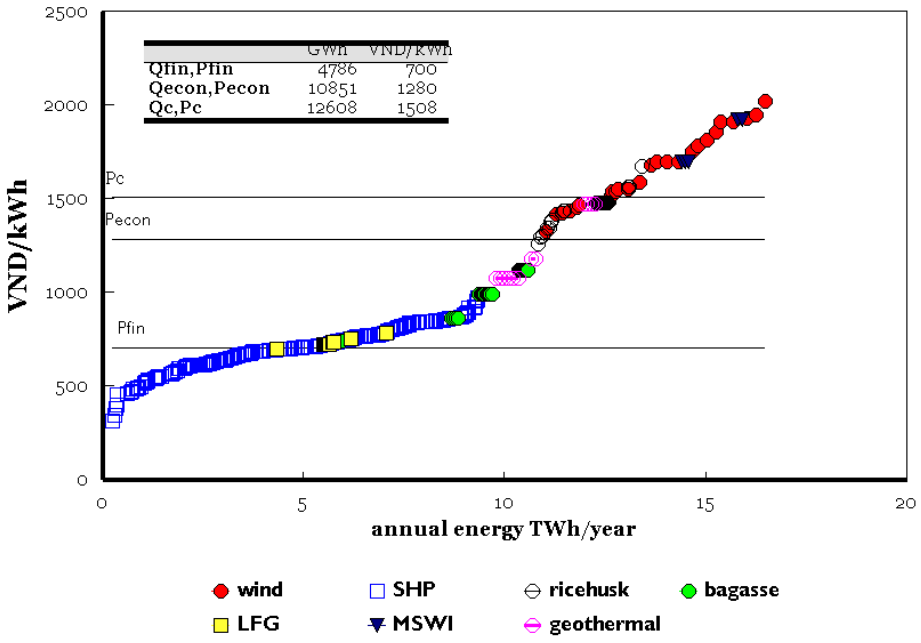


*LFG=**landfill gas;** SHP=**small hydro;** MSWI =**municipal solid waste incineration***
P_{fin}=average tariff yield at the avoid cost tariff
P_{econ}=average avoided social cost of thermal energy
$P_c=P_{econ}$+CERrevenue at 15$/ton$CO_2$

159. The extent of support payments is substantial. A recent report to MoIT estimates the avoided social cost of thermal energy at VND1,280/kWh,[51] including the avoided cost of CCCT capacity (based on a recent benchmark study for the Singapore regulator). At this price, denoted P_{econ} in Figure 8.4, an additional 1,500 MW of renewable energy would be enabled, including additional small hydro, bagasse, geothermal and rice husk gasifiers. Another 500MW of would be enabled by CER revenue under the Clean Development Mechanism (CDM). However, most wind projects would require a tariff significantly above the avoided social cost of thermal generation (discussed below).

160. The corresponding supply curve for energy is shown in Figure 8.4. Increasing the tariff to the avoided social cost would enable an additional 6,000 GWh per year of renewable energy, more than doubling the amount enabled at the ACT.

Figure 8.4: Renewable energy supply curve, GWh



*LFG=**landfill gas**; SHP=**small hydro**; MSWI =**municipal solid waste incineration***
P_{fin}=average tariff yield at the avoid cost tariff
P_{econ}=average avoided social cost of thermal energy
$P_c=P_{econ}$+CERrevenue

[51] P. Meier, *Social Cost of Thermal Power Generation*, Report to MoIT, September 2009.

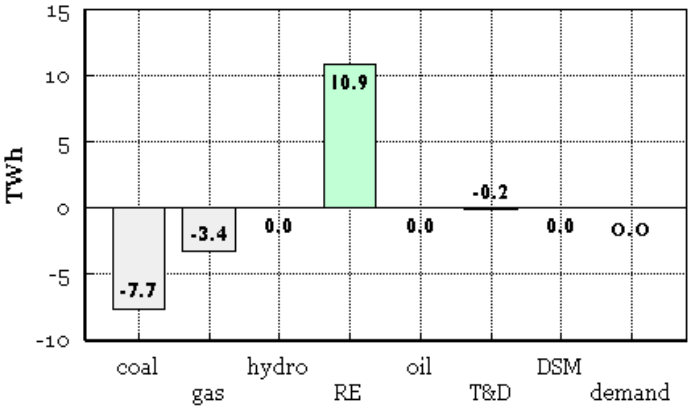
Table 8.7: Totals by technology

	Installed capacity, MW				Energy, GWh			
	Pfin	Pecon	Pg	total	Pfin	Pecon	Pg	total
SHP	1,054	976	0	2,030	4,757	8,814	8,814	22,385
rice husk	0	15	139	154	0	66	658	724
bagasse	0	250	0	250	0	896	896	1,791
LFG	7	45	0	52	29	214	214	456
MSWI	0	0	0	0	0	0	0	0
geothermal	0	152	79	231	0	862	1,249	2,110
wind	0	0	276	276	0	0	778	778
total	1,061	1,439	494	2,993	4,786	10,851	12,608	28,244

161. Table 8.8 shows the changes to the 2020 energy balance, the additional 10.9 TWh of renewable energy induced by the elimination of fossil fuel subsidies is offset by lower gas and coal generation (the latter as a result of a 300MW northern coal unit that is displaced by the RE portfolio). Because the additional renewable energy is assumed connected at 35kV, some transmission losses are also avoided.

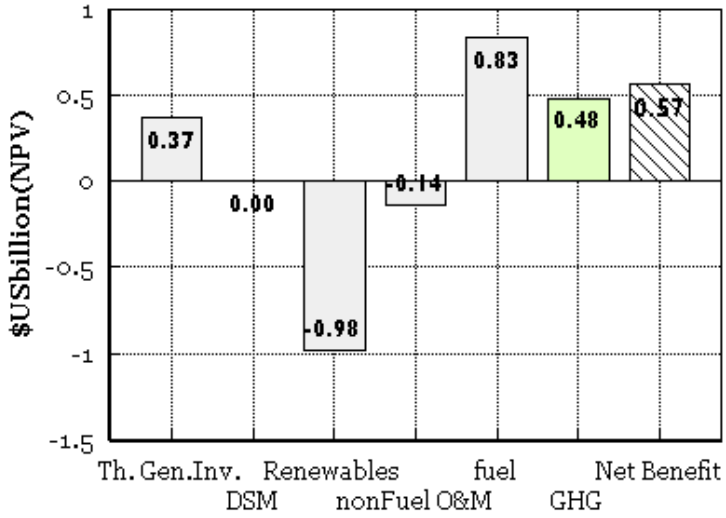
Table 8.8: 2020 energy balance changes,TWh

	baseline	impact	*renew to Pecon*
domestic coal	92.4	-6.4	85.9
imported coal	26.5	-0.3	26.2
CFB	13.7	-1.0	12.7
CCGT	23.4	-3.4	20.0
hydro	70.9	0.0	70.9
hydroPS	0.0	0.0	0.0
SHP/RE	4.8	10.9	15.6
CCCT_LNG	0.0	0.0	0.0
imports	0.0	0.0	0.0
oil,CT, other	0.0	-0.0	-0.0
total	231.7	-0.2	231.5
T&D loss	20.6	-0.2	20.4
demand	211.1	0.0	211.1
DSM	0.0	0.0	0.0



162. The corresponding changes in cost structure are shown in Figure 8.11. The net economic benefit is some $1.67 billion, including the benefit of a 600MW capacity credit; when the avoided GHG damage costs are added (valued at $20/ton CO_2), the net benefits increase to $2.32billion.

Figure 8.5: Cost structure changes, renewable energy



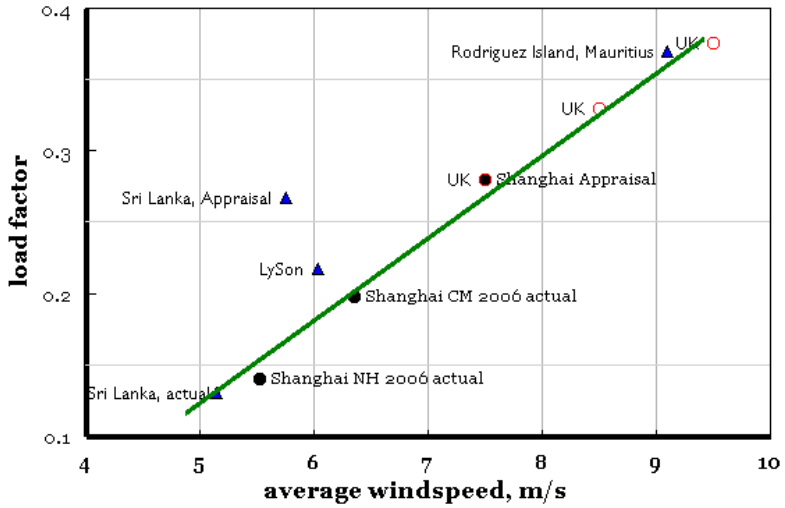
Wind power

163. Given a wind regime that is at best modest, the cost of most wind power will be substantially above the avoided social cost of thermal generation. Leaving aside for the moment the details of the feed-in tariff that would be required to make wind projects *financially* feasible, the economic costs are largely determined by the capital costs and by the achievable annual load factor.

164. Wind data in Vietnam is generally poor, and the only reliable windspeed data we have sighted is the 60m data for Ly Son Island, and the three sites currently under investigation in a World Bank supported study (for which, at the time of writing, nine months of data are available). Much of the other data is not in the public domain. A detailed study of the Ly Son Island data for ADB shows an annual load factor of 22% (if connected to the national grid), and only 13% under the limited ability to absorb wind power in an isolated grid. Anecdotal claims of excellent sites with annual load factors in excess of 30% are widespread, but the World Bank experience suggests such claims require great caution (see Box 8.1). For this assessment of wind power we assume an annual load factor of 27.5%, corresponding to an average annual wind speed of about 7.5m/sec (Box 8.1).

Box 8.2: Average wind speeds and annual average load factors

The empirical evidence suggests that actual average annual load factors are strongly (and linearly) correlated with average annual wind speeds, as shown in the figure below. However, as shown in the figure, estimates of wind speed and load factors at appraisal are almost always greater than what is actually achieved in practice.



Sources:

Shanghai wind farms (CM, NH) from the World Bank Implementation Completion Report for the Bank-supported wind farm development Project.

Sri Lanka from the World Bank Implementation Completion report on the Sri Lanka Energy Services Delivery Project which included a GEF grant for a wind forma demonstration project in Southern Sri Lanka. The estimate at appraisal deviates significantly from the general relationship, a deviation confirmed by the actual performance revealed by the actual operation.

UK data from Garrad Hassan, a leading UK wind consultancy firm. The UK (particularly Scotland) has the best wind regime in Europe.

Ly Son from the ADB economic analysis report on the proposed RERMIC project: the estimate is based on a 250kW Suzlon turbine.

165. According to the annual survey in *Windpower Monthly*,[52] in 2008 the average investment cost was 1300-1700 Euro/kW. The average equipment price is reported as 1100 Euro/kW, so balance of project costs are in the rnage of 200-600 Euro/kW. We assume that Vietnam would be near the low end of this range for site costs. Our baseline assumptions are thus as follows

- Equipment cost: 1,100 Euro/kW ($US1,540/kW)
- Balance of investment cost (site costs, access roads, connection to the national grid) 250 Euro/kW ($US350/kW).
- annual O&M costs 1.5% of initial capital investment

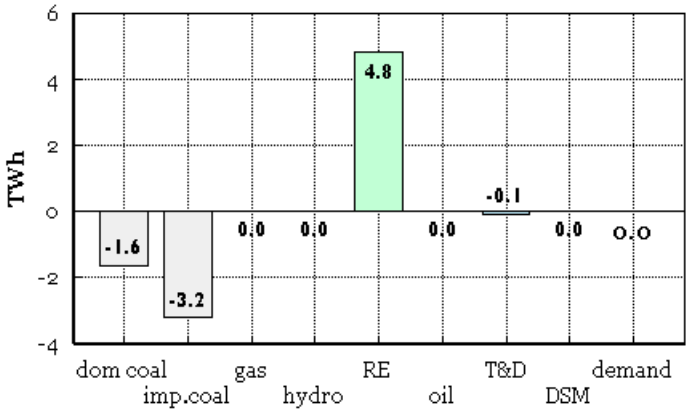
[52] *Windpower Monthly*, January 2009, p51-55

166. To compare the impact of an aggressive wind power development programme against other options for reducing GHG emissions, we hypothesize a programme that would develop 2,000MW over the next ten years. At the indicated load factor of 27.5%, this would provide some 4818 GWh, or 2.3% of the 2020 demand of 240TWh.

167. When this potential is superimposed on the baseline scenario, there are significant changes to energy generation, as shown in Table 8.9. Thermal generation decreases across all fuels.

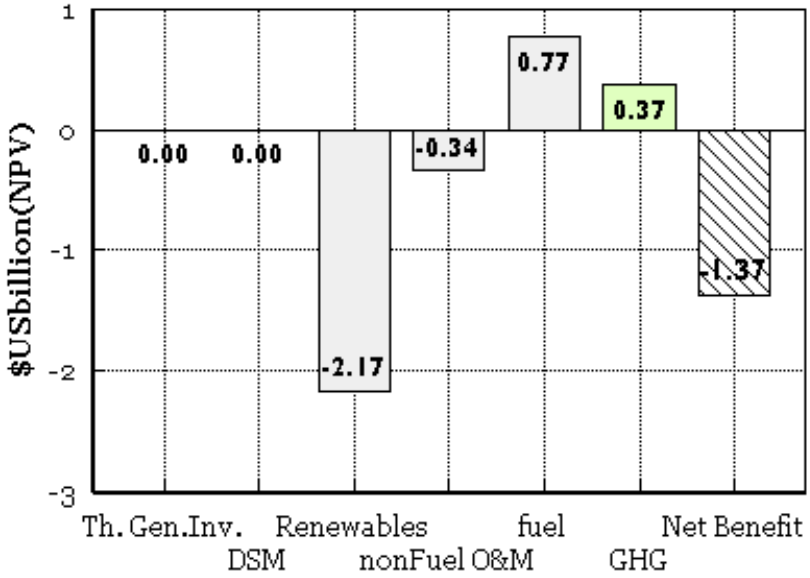
Table 8.9: Wind scenario: 2020 energy generation changes,TWh

	baseline	Impact	*wind scenario*
domestic coal	87.6	-1.6	85.9
imported coal	18.7	-3.2	15.4
CFB	11.5	0.0	11.5
CCGT	33.6	0.0	33.6
hydro	70.9	0.0	70.9
hydroPS	0.0	0.0	0.0
SHP/RE	4.8	4.8	9.6
CCCT_LNG	0.0	0.0	0.0
imports	0.0	0.0	0.0
oil,CT, other	4.6	0.0	4.6
total	231.7	-0.1	231.6
T&D loss	20.6	-0.1	20.5
demand	211.1	0.0	211.1
DSM	0.0	0.0	0.0



168. The corresponding impacts on the cost structure are shown in Figure 8.6.

Figure 8.6: Wind scenario impacts on cost structure



169. The wind power scenario achieves a 2.4% saving of lifetime GHG emissions, but system costs increase by 2.1%, and the carbon shadow price computes to $70/ton.

Table 8.10: Impact of wind development scenario on GHG emissions

		baseline	impact	*[%]*	*wind*
2020 GHG emissions	[million tons/year]	117.1	-4.15	-3.5%	113.0
LifetimeUndiscountedEmissions	[million tons]	4251.4	-102.3	-2.4%	4149.1
PV(GHGemissions)	[million tons]	916.9	-24.73	-2.7%	892.2
PV(damage cost) @ 15$/ton CO_2	[$USbillion]	13.8	-0.37	-2.7%	13.4
PV(system cost)	[$USbillion]	82.5	1.74	2.1%	84.2
carbon shadow price	[$/ton CO_2]				$70

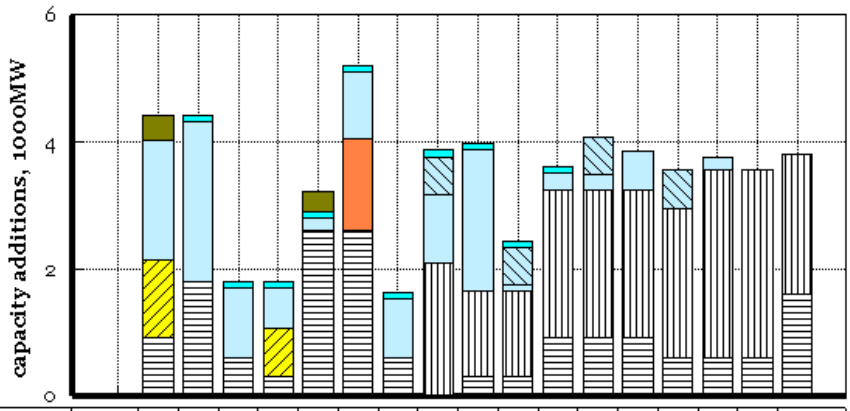
Constrained gas supplies: coal+pumped storage

170. Although the modelling results suggest that under the World Bank load forecast the additional gas required for the least cost expansion plan is well below the gas forecast by the Gas Masterplan to be available for power generation, under higher load growth this constraint may be yet encountered within the planning horizon. In the absence of additional domestic gas, at that point the choice would be between imported coal and LNG.

171. To illustrate the implications of constrained gas supplies, we first assume that all of the additional CCGTs required by the least cost expansion plan 2015 are replaced by imported coal units plus pumped storage.[53] Figure 8.7 shows the resulting capacity expansion plan: the changes are all in the south.

[53] Assumed to run for 4 hours/day at an overall efficiency of 0.7.

Figure 8.7: Capacity expansion plan: Coal+pumped storage replaces CCGTs after 2015

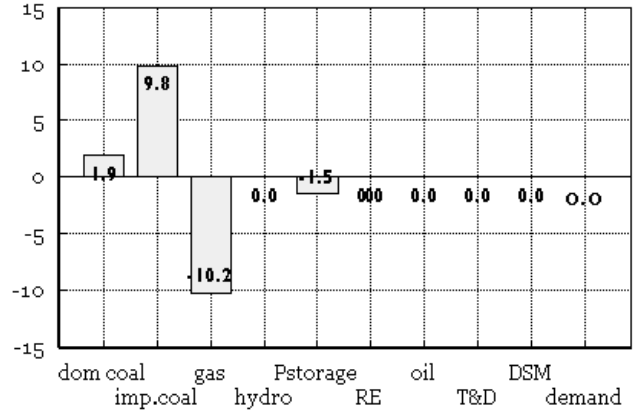


	2009	2011	2013	2015	2017	2019	2021	2023	2025
coalSteam	0.9 1.8	0.6	0.3	2.6	2.6	0.6	0.0	0.3	0.3	0.9	0.9	0.9	0.6	0.6	0.6	1.6
coalSteamI	0.0 0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.1	1.4	1.4	2.4	2.4	2.4	2.3	3.0	3.0	2.2
CFB	0.0 0.0	0.0	0.0	0.0	0.0	1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CCGT	1.2 0.0	0.0	0.0	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
hydro	1.9 2.5	1.1	0.6	0.2	1.1	0.9	1.1	2.2	0.1	0.2	0.2	0.6	0.0	0.2	0.0	0.0
hydroPS	0.0 0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.6	0.0	0.6	0.0	0.6	0.0	0.0	0.0
SHP/RE	0.0 0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
CCCT_LNG	0.0 0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
imports	0.0 0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
oil,CT, other	0.4 0.0	0.0	0.0	0.3	0.0	-0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

172. The resulting changes in the 2020 generation balance are shown in Table 8.11. Pumped storage appears as a negative entry, since the net *energy* impact of a pumped storage project is negative (pumping energy exceeds energy delivered during the peak period). .

Table 8.11: coal+pumped storage scenario: energy generation changes 2020

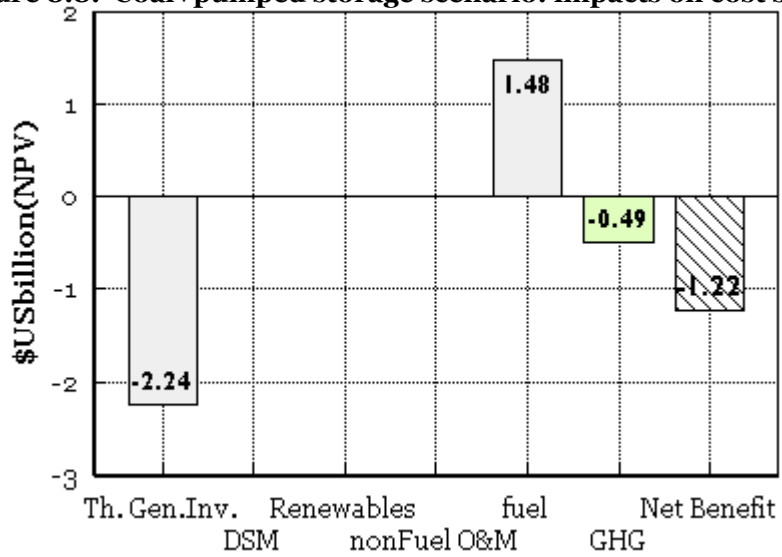
		baseline	Impact	*no Gas*
domestic coal	[GWh]	87.6	1.6	89.2
imported coal	[GWh]	18.7	9.8	28.5
CFB	[GWh]	11.5	0.3	11.8
CCGT	[GWh]	33.6	-10.2	23.4
hydro	[GWh]	70.9	0.0	70.9
hydroPS	[GWh]	0.0	-1.5	-1.5
SHP/RE	[GWh]	4.8	0.0	4.8
CCCT_LNG	[GWh]	0.0	0.0	0.0
imports	[GWh]	0.0	0.0	0.0
oil,CT, other	[GWh]	4.6	0.0	4.6
total	[GWh]	231.7	0.0	231.7
T&D loss	[GWh]	20.6	0.0	20.6
demand	[GWh]	211.1	0.0	211.1
DSM	[GWh]	0.0	0.0	0.0



173. The corresponding impacts on the cost structure are shown in Figure 8.8: the net impact is a loss of $1.22billion. Though there are fuel cost savings (attributable to the shift from high cost gas to lower cost coal), these

are outwighted by the capital cost penalties: the capital costs of coal and pumped storage projects far outweigh the much lower capital cost of gas CCGT.

Figure 8.8: Coal+pumped storage scenario: impacts on cost structure



174. The GHG implications are significant: relative to the reference case, lifetime emissions increase by 5%. Since both GHG emissions and system costs increase, this falls into quadrant I of the trade-off graph ("lose-lose", see Box 8.1), and the carbon shadow price is not applicable.

Table 8.12: Impact of coal+pumped storage development on GHG emissions

		baseline	impact	*[%]*	*coal+PS*
2020 GHG emissions	[million tons/year]	117.1	5.98	5.1%	123.1
LifetimeUndiscountedEmissions	[million tons]	4251.4	174.51	4.1%	4425.9
PV(GHGemissions)	[million tons]	916.9	32.67	3.6%	949.6
PV(damage cost) @ 15$/ton CO_2	[$USbillion]	13.8	0.49	3.6%	14.2
PV(system cost)	[$USbillion]	82.5	0.73	0.9%	83.2
carbon shadow price	[$/ton CO_2]	not applicable, lose-lose			

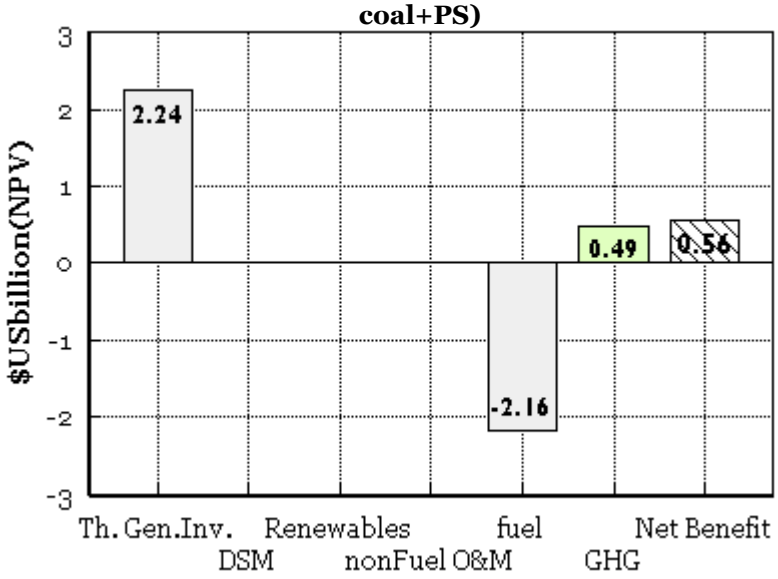
LNG

175. The other option were domestic gas to be constrained is LNG. To illustrate this choice, we simply assume that all of the additional CCGTs added after 2015 would be fueled by imported LNG rather than domestic gas: the expansion plan itself remains otherwise unchanged, and is fuel consumption..

176. Figure 8.9 shows the cost impacts relative to the alternative of coal+pumped storage. There is a benefit of $2.24 billion in reduced capital

costs (CCGT being far less capital intensive than coal and pumped storage), and (obviously) a significant benefit of lower greenhouse gas emissions. On the cost side there is the increase in fuel cost, LNG being more expensive than domestic gas.

Figure 8.9: LNG scenario: impacts on cost structure (relative to coal+PS)



9 CONCLUSIONS

177. There exists no panacea to Vietnam's power sector planning problem. As a poor but rapidly developing country with a still low per capita electricity consumption, there simply is no other alternative to meeting these development needs than a significant increase in electricity supply. This review of generation options sees no alternative to the general strategy proposed by PDP6 – namely that of a diversified expansion strategy that in the first instance emphasises development of the indigenous resource base: conventional hydro, small renewables, gas, and domestic coal.

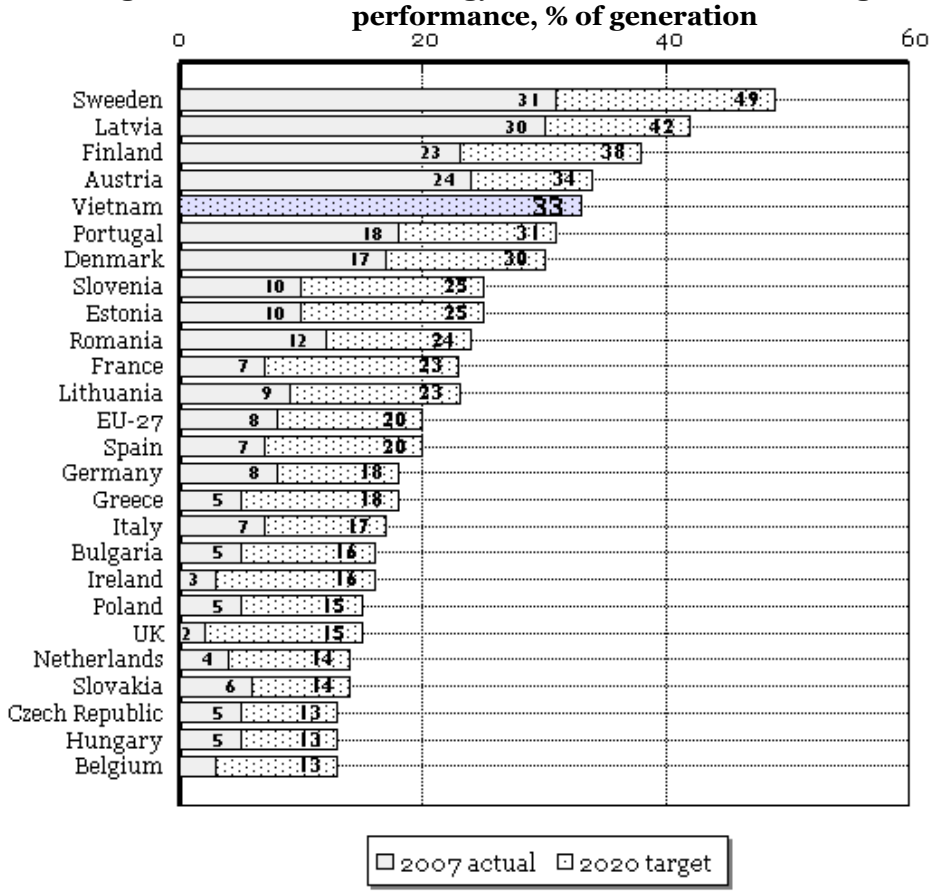
178. Over the longer term, whether additional domestic gas can substitute for some of the base load coal depends on the extent of additional gas discoveries, which in turn will depend upon whether the government can establish a suitable institutional and pricing framework - issues discussed in the Bank's Gas Framework Report. Gas is certainly the thermal fuel of choice from an environmental perspective, but gas prices would have to decline very substantially for gas to be competitive with coal for base load generation. Also, use of gas in other sectors (e.g., industrial and transport) needs to be considered.

179. We doubt that nuclear power will play a significant role for Vietnam in the time frame suggested by PDP6 (i.e. with a first unit by 2020). This is so for several reasons, but most importantly that of capital cost. The shadow carbon price associated with nuclear power remains substantially above other options, and substantially above most recent estimates of the social cost of carbon. Perhaps with a global resurgence of nuclear power, more cost effective designs will become commercially available, but this is at least 15-20 years away. While it is true that the addition of nuclear power would further diversity the supply mix, that diversity could just as well be furthered by much cheaper alternatives, including imported hydropower and LNG.

180. As to the possibilities of increasing the share of renewable energy in the supply mix, several points may be noted. By 2020, the share of generation from renewable energy (conventional hydro, and small renewables) is 33%. That compares favourably with most countries in the EU, as shown Figure 9.1. Of course the 33% share is mainly conventional

hydro, but then the same is true of the EU countries that have high shares of renewables (such as Sweden, Finland and Austria).

Figure 9.1: Renewable energy shares in the EU: 2020 targets v. 2007 performance, % of generation



Source: European data from EU, Eurostat; Vietnam reference case expansion plan (World Bank load forecast)

181. Advocates of wind power argue that it is the only renewable energy form that could be brought on-line in large amounts and quickly. While that is perhaps generally true, the reality is that the wind resource in Vietnam is not particularly good, so wind power would be an exceptionally expensive option for Vietnam. With probable annual load factors (25%) half that of a typical hydro project (50%), and wind capital costs of around $2,000/kW, it follows that hydro would be competitive with wind at $4,000/kW.

Technology recommendations

182. Presently, the following coal-fired power generation options are available for Vietnam:

- Use of CFB technology with local anthracite or other fuels including low quality and fuel blends. Considering the status of the

technology, CFB boilers of maximum 300 MW should be used, but they could be configured in multiple boilers feeding one or more steam turbines to develop plants of larger than 300 MW size (e.g., 600 MW, 900 MW or 1200 MW). A more conservative approach for the first few plants would be to use CFB boilers of maximum 150 MW. Vietnam should monitor progress in CFB technology and update its strategy regarding what size CFB boilers to allow.

- Utilization of high efficiency pulverized coal technology could be achieved by using:
    - supercritical design with a blend of local anthracite and imported coal or
    - supercritical or USC design with 100% imported coal.
- Even the presently available commercial options (mentioned above) require extensive training to build the indigenous capacity to plan, supervise implementation and operate-maintain power plants.
- Even though more detail assessment is needed, conversion of anthracite-fired plants to imported coal does not seem to be attractive, considering that many new plants will be coming on-line which can be designed for imported coal or a blend of local anthracite and imported coal.
- Rehabilitation of existing power plants requires site-specific assessment, but based on a preliminary evaluation it does not seem attractive.
- Biomass co-firing (up to 15-20% of the total haet input) is a desirable and should be pursued both for existing and new power plants.

183. In the future, higher efficiency power plant designs and new technologies will become viable options for Vietnam. More specifically:

- Higher plant efficiency should be sought in supercritical and USC plants. These technologies cover a broad spectrum of design options (mainly steam temperature and pressure) and technological developments are expected to continue. It is expected that Vietnam will start with the proven designs for the specific fuel being considered and as its experience increases and the technologies improve worldwide, higher steam conditions and efficiencies could be achieved by the new power plants.
- Development of supercritical plants burning anthracite are of particular interest for Vietnam. Countries such as China and Russia are developing further these designs and Vietnam should monitor such developments.

- Similarly, CFB technology is expected to develop further especially with regard to utilization of supercritical and USC steam conditions and availability of CFB boilers in larger size (e.g., 600 MW and 800 MW).
- Finally, developments in IGCC and CCS options should be monitored, as they may change the technology choice in the future.

Planning methodology

184. While Vietnam's power sector planning methodology is generally sound, this study points to a number of improvements relevant to the preparation of the 7th Power Development Plan, currently underway at IoE.

Load forecasts

185. The rnage of load forecasts should illustrate a wide range of outcomes. In PDP5 the range of load forecasts were all too low, and in PDP6 the range of load forecasts were all too high, perhaps in response to the under-forecasts of PDP5. The point of a wide range of forecasts is to illustrate the robustness of investment planning decisions to the uncertainties in the determinants of load growth..

Net v. gross

186. The practice of including generating plant own-use into the load forecast does not conform to international best practice.[54] The are substantial differences in own-use across generation types, ranging from less than 1% in the case of hydro to more than 8% in the case of coal units with FGD. The accounting of energy at each generating plant should be on a net basis, which is in any event desirable for a reliable accounting of inter-regional transmission flows.

The role of the World Bank

As a multilateral institution the World Bank could assist Vietnam in a variety of projects. Focusing on the need to reduce the carbon footprint of the country, the World Bank could assist Vietnam with options such as:

- Immediate introduction of high efficiency coal-fired plants such as:
    - supercritical CFB burning anthracite or

[54] The Ceylon Electricity Board in Sri Lanka, which until 2008 also included generating plant own-use in the load forecast, has recently also changed to a net basis for running its generation expansion planning models. To our knowledge, no other country still uses gross data for the energy and load forecast balances.

  - supercritical pulverized coal burning a blend of local anthracite and imported coal or
  - USC burning imported coal.
- Addition of biomass co-firing in existing and new power plants.
- Training and capacity-building to plan, implement and operate power plants which utilize the above power technologies.