Volume 2:
Guidelines for Economic Analysis of Power Sector Projects

TECHNICAL NOTES

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BEST PRACTICE RECOMMENDATIONS

ABBREVIATIONS

ADB	Asian Development Bank
BTU	British Thermal Unit
CAPEX	Capital investment expenditure
CBA	Cost/benefit analysis
CCGT	Combined cycle gas turbine
CCS	carbon capture and storage
CEB	Ceylon Electricity Board (Sri Lanka)
CGE	computable general equilibrium (model)
CRESP	China Renewable Energy Scale-up Program
CSP	Concentrated solar power
CTF	Clean Technology Fund
CV	Compensating variation
DMU	Decision-making under uncertainty
DPC	Development Policy Credit
DPL	Development Policy Loan
DSCR	Debt service cover ratio
DSM	Demand side management
EMP	Environmental Management Plan
EOCK	economic opportunity cost of capital
EPRI	Electric Power Research Institute (US)
ERAV	Electricity Regulatory Authority of Vietnam
ERR	Economic rate of return
EU	European Union
EU ETS	European Union Emissions Trading System
FGD	Flue gas desulphurisation
FIRR	Financial internal rate of return
FIT	feed-in tariff
FS	feasibility study
GDP	gross domestic product
GHG	Greenhouse gas
GWh	gigawatt-hour
HHV	Higher heating value (see Glossary)
HSD	high speed diesel
HVDC	High voltage direct current (transmission)
IEA	International Energy Agency
IEG	Independent Evaluation Group (of the World Bank)
IFI	International Financial Institution
IPP	Independent power producer
ISO	International Standards Organisation
IWGSCC	Interagency Working Group on the Social Cost of Carbon (US)
LCA	Life cycle assessment
LCOE	Levelised cost of electricity
LHV	Lower heating value (see Glossary)
LNG	Liquefied natural gas
MAC	Marginal abatement cost
MADA	Multi-attribute decision analysis
MASEN	Moroccan Agency for Solar Energy
MATA	Multi-attribute trade-off analysis
mbd	million barrels per day
MENA	Middle East and North Africa (Region), World Bank
MFO	marine fuel oil
MIT	Massachusetts Institute of Technology
mmBTU	million British Thermal Units
mtpy	million tons per year
MUV	Manufacture Unit Value (index)
NEA	Nepal Electricity Authority
NPV	Net present value
NREL	National Renewable Energy Laboratory (US)
OCC	Opportunity cost of capital
ONE	Morocco State Power Company
OPEX	Operating cost expenditure
OPSPQ	Operations Policy and Quality Department (World Bank)
PAD	Project Appraisal Document (World Bank)
PAF	Project affected person
PCN	Project Concept Note
PLN	Indonesian Electricity Company
PMU	Project Management Unit
PPA	Power purchase agreement
PPP	Public-Private-Partnership
PSIA	Poverty and Social Impact Assessment
PV	Photovoltaic
RDM	Robust decision-making
RE	Renewable energy
SCF	Standard correction factor
SER	Shadow exchange rate
SMP	social mitigation plan
SPR	Strategic Petroleum Reserve (of the US)
SPV	special purpose vehicle
SVC	Social value of carbon
SRTP	Social rate of time preference (see Glossary)
T&D	transmission and distribution
TTL	Task Team Leader (World Bank)
UAHP	Upper Arun Hydro Project (Nepal)
US	United States
USAID	United States Agency for International Development
USEIA	United States Energy Information Administration
VND	Vietnamese Dong
VOLL	Value of lost load
VRE	variable renewable energy
VSL	Value of statistical life
WDI	World Development Indicators (World Bank database)
WACC	weighted average cost of capital
WEO	World Energy Outlook (IEA)
WTP	willingness-to-pay

Part I: Basic Concepts

C1 COSTS

1. All power sector project appraisal economic analyses require as the most fundamental inputs:

- Estimates of the investment and O&M costs of the projects being proposed (and of the costs of alternatives stipulated in the counter-factuals).
- Estimates of the future costs of fossil fuels. True even for renewable energy projects since for these projects, the avoided costs of fossil fuels constitute one of the main benefits. Transmission and distribution projects need estimates of fossil fuel costs to calculate the economic cost of losses. Off-grid renewables and rural electrification require cost estimates of fuels used for lighting (kerosene) and self-generation (diesel).

The reliability of these estimates will determine the reliability of the CBA.

INTERNATIONAL FUEL PRICE FORECASTS

2. In the absence of an official client government forecast, either the latest IEA World Energy Outlook (WEO) forecasts or the Bank's commodity price forecast may be used as the starting point for assumptions about future fossil fuel prices. Those in the latest 2014 WEO are shown in Table C1.1. For the past few years the three forecasts illustrated in Table C1.1 have been provided. For example, the "new policy" forecast could be used as a baseline, with "current policies" and "450 scenario" as alternatives in the sensitivity analysis and risk assessment.

Table C1.1: The 2014 IEA fuel price forecasts

		New policies scenario					Current policies scenario				450 scenario			
	Unit	2012	2020	2025	2030	2035	2020	2025	2030	2035	2020	2025	2030	2035
Real terms (2012 prices)														
IEA crude oil imports	$/bbl	109	113	116	121	128	120	127	136	145	110	107	104	100
Natural gas														
United States	$/mmBTU	2.7	5.1	5.6	6	6.8	5.2	5.8	6.2	6.9	4.8	5.4	5.7	5.9
Europe imports	$/mmBTU	11.7	11.9	12	12.3	12.7	12.4	12.9	13.4	14	11.5	11	10.2	9.5
Japan imports	$/mmBTU	16.9	14.2	14.2	14.4	14.9	14.7	15.2	15.9	16.7	13.4	12.8	12.2	11.7
OECD steam coal imports	$/ton	99	106	109	110	110	112	116	118	120	101	95	86	75
Nominal terms														
IEA crude oil imports	$/bbl	109	136	156	183	216	144	171	205	245	132	144	157	169
Natural gas														
United States	$/mmBTU	2.7	6.1	7.5	9.1	11.6	6.2	7.7	9.3	11.7	5.8	7.2	8.6	10
Europe imports	$/mmBTU	11.7	14.2	16.1	18.5	21.5	14.9	17.3	20.2	23.6	13.8	14.7	15.4	16
Japan imports	$/mmBTU	16.9	17.1	19.1	21.7	25.1	17.7	20.4	24	28.2	16.1	17.2	18.4	19.7
OECD steam coal imports	$/ton	99	127	146	165	186	134	155	178	202	121	128	129	127

Source: IEA, *World Energy Outlook*, 2014.

3. Comparison of this latest IEA WEO forecast with that issued in 2008 (Table C1.2) is instructive. The 2014 current policies forecast for OECD coal imports in 2020 is $134/ton; that issued for the same year in 2008 was $157/ton. For oil imports, the 2014 estimate for 2020 is $120/bbl, that issued in 2008 was $148/bbl – in other words, IEA has revised *downwards* its long term price forecasts.

Table C1.2: The 2008 IEA fuel price forecasts, 2008

	Unit	2000	2007	2010	2015	2020	2025	2030
Nominal terms								
IEA crude oil imports	$/barrel	28	69.3	107.3	120.3	148.2	175.1	206.4
Natural gas								
US imports	$/mmBTU	3.87	6.75	13.72	15.88	19.64	23.18	27.28
European imports	$/mmBTU	2.82	7.03	11.97	13.83	17.13	20.31	24
Japan LNG	$/mmBTU	4.73	7.8	13.63	15.83	19.56	23.08	27.16
OECD steam coal imports	$/tonne	33.7	72.8	128.8	144.3	157.2	171.1	186.1

Source IEA, *World Energy Outlook*, 2008.

4. The latest World Bank commodity price forecasts are shown in Table C1.3. Even that of November 2014 is substantially lower than the IEA forecast: that issued in July

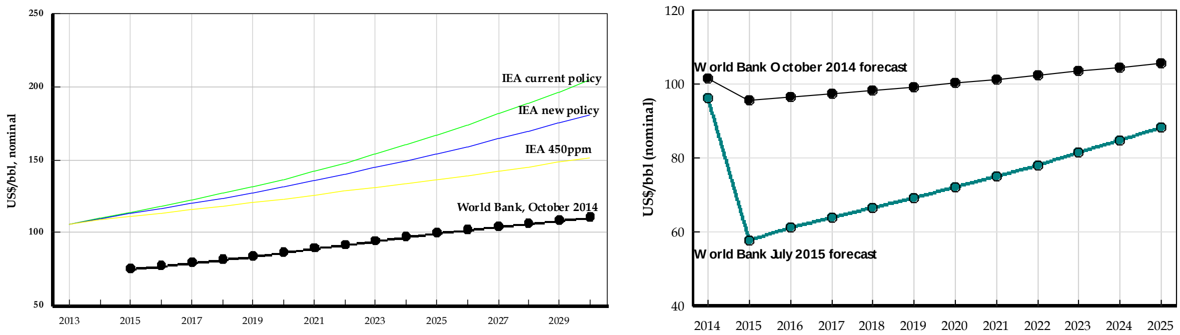
1025 is lower still. . The IEA 2020 forecast suggests a range of $132-144/bbl (nominal, Table C1.1), the World Bank forecast for the same year is $102/bbl (Table C1.3).

Table C1.3: Latest (October 2014) World Bank price forecasts (nominal)

	Unit	2014	2015	2016	2017	2018	2020	2025
November 2014								
Crude oil(1)	$/barrel	101.5	95.7	96.6	97.4	98.3	100.2	105.7
Natural gas								
US	$/mmBTU	4.4	4.7	4.9	5.1	5.3	5.7	7.0
European	$/mmBTU	10.3	10.2	10.1	9.9	9.8	9.6	9.0
Japan LNG	$/mmBTU	16.5	16.8	15.4	15.1	14.7	14.1	12.5
Coal, Australia	$/tonne	71.0	75.0	77.2	79.4	81.8	86.6	100.0
July 2015								
Crude oil(1)	$/barrel	70.1	58.0	59.5	61.1	62.6	66.0	75.0
Natural gas								
US	$/mmBTU	4.37	2.8	3.0	3.26	3.52	4.10	6.0
European	$/mmBTU	10.05	7.60	7.73	7.86	8.00	8.27	9.0
Japan LNG	$/mmBTU	16.04	10.50	10.64	10.78	10.93	11.22	12.00
Coal, Australia	$/tonne	70.1	58.0	59.5	61.1	62.6	66.0	75.0

Source: World Bank Commodity Price Forecast, October 2014, and July 2015.
(1) Average of Brent, WTI and Dubai spot prices

Figure C1.1: Comparison of IBRD and IEA world oil price forecasts (nominal)



VALUATION OF DOMESTICALLY PRODUCED FOSSIL FUELS

5. In countries that produce their own fossil fuels, many governments have long kept domestic prices at prices much below international prices, justified on a variety of arguments (shield domestic consumers from "unreasonable" or "volatile" international prices, share the country's resource endowment with consumers, why should domestic consumers pay more than the cost of *local* production, etc.) One of the main consequences of keeping domestic prices low is that they provide inadequate incentive to invest in new supply – particularly in the case of gas, many countries are in difficulty because low prices have discouraged investment in exploration and resource development (such as Egypt, Vietnam, Indonesia).

6. Indeed, Indonesia is a good illustration of problematic domestic fuel pricing policy, though in recent years some significant improvements have been made (in 2012, the price of coal for power generation was raised to international price levels). Table C1.4 shows the wide range of prices that PLN pays for gas on Java - ranging from $2.84/mmBTU to $11.26/ mmBTU. PLN's LNG price is set by the international price (at around $16/mmBTU in mid-2014, prior to the more recent price collapse). Among many other problems, the economic valuation of domestic gas is an issue for calculating the economic benefits of the Government's proposed renewable tariffs.

Table C1.4: Gas prices for power generation in Indonesia

Plant		2016	2020	2024
Muaratawar	$/mmBTU	5.74	6.09	6.09
Priok	$/mmBTU	6.69	6.97	6.97
CLGON	$/mmBTU	10.61	11.26	11.26
MkarangGU	$/mmBTU	8.61	8.61	8.61
CKRNG	$/mmBTU	6.42	6.42	6.42
Muarakarang	$/mmBTU	9.14	9.41	9.41
Tambaklo	$/mmBTU	2.67	2.84	2.84
Grati2	$/mmBTU	6.30	6.69	6.69
Gresik34	$/mmBTU	10.30	10.30	10.30
Mkrng	$/mmBTU	7.95	7.95	7.95
Gresik23	$/mmBTU	7.84	7.84	7.84
Gresik 1	$/mmBTU	7.84	7.84	7.84
Grati	$/mmBTU	7.84	7.84	7.84

Source: PLN

7. These prices are claimed to reflect the economic costs of production. However, most of these fields are at various stages of approaching depletion, and the Government is now in the process of establishing a national gas pricing policy to encourage the development of additional supplies. At the very least, for evaluating the benefits of renewable energy in this context, the very low financial prices should be adjusted by a depletion premium to reflect the scarcity of the gas resource.

The Depletion Premium

8. The depletion premium is the amount equivalent to the opportunity cost of extracting the resource at some time in the future, above its economic price today, and should be added to the economic cost of production today. It is defined as follows[1]:

$$DP_t = \frac{(PS_T - CS_t)(1+r)^t}{(1+r)^T}$$

where

t	=	year
T	=	year to complete exhaustion
PS_T	=	price of the substitute (internationally traded coal) at the time of complete exhaustion.
CS_t	=	price of the domestic resource in year t
R	=	discount rate

9. The main problem in calculating the value of the premium is the uncertainty about when the resource is exhausted—because the economically exploitable size of a resource is a function of its market value and the cost (and technology) of its extraction. Assessment of reserves can change very rapidly—as illustrated by the dramatic recent developments in gas and oil extraction technology in the US (fracking).

10. Table C1.5 sets out the necessary assumptions for a sample calculation for a gas field with a remaining time of 15 years to exhaustion, and for which the substitute fuel is taken as LNG.

1 See, e.g., ADB *Guidelines for Economic Analysis of Projects*, Economics and Development Resource Center, 1997, Annex 6, *Depletion Premium*.

Table C1.5: Assumptions for depletion premium calculation

	units	Value
Remaining resource	BCF	11,250
Extraction rate	BCF/year	750
time to exhaustion	years	15.0
Present extraction cost	$/mmBTU	4
Substitute fuel		LNG
Substitute price at exhaustion	$/mmBTU	16
Discount rate	[ ]	0.12
Base year		2015
Depletion year [last year of production]		2029

11. Applying the above formula results in the economic valuation shown in Table C1.6. The economic value increases as the time to exhaustion approaches, ultimately reaching the value of the substitute fuel (LNG). The depletion premium calculation is easily adjusted where the substitute fuel is assumed to increase (or decrease) over time (as in the case of the IEA forecasts for LNG shown in Table C1.1).

Table C1.6: Depletion premium and the economic value of gas

	Depletion premium	Economic value
	$/mmBTU	$/mmBTU
2015	2.19	6.2
2016	2.46	6.5
2017	2.75	6.8
2018	3.08	7.1
2019	3.45	7.4
2020	3.86	7.9
2021	4.33	8.3
2022	4.85	8.8
2023	5.43	9.4
2024	6.08	10.1
2025	6.81	10.8
2026	7.63	11.6
2027	8.54	12.5
2028	9.57	13.6
2029	10.71	14.7
2030	12.00	16.0

Import parity price

12. For domestically produced fuels that are also traded, calculations of the economic value of a domestic thermal resource where financial prices for domestic fuels are subsidized require an estimate of the so-called import parity price. This is calculated from the identify

Price of imported coal + freight from port to domestic consumer
= *price of domestic coal (at import parity) + freight from mine to domestic consumer + incremental quality adjustment*

13. When these prices are expressed in currency per ton, freight costs must be adjusted for any difference in calorific value (often domestic coal is of lesser quality than imported coal). This is sometimes taken simply as the ratio of calorific values.[2] In

[2] However, this relationship is not necessarily linear, and is true only of high calorific value coals. Low calorific value coal trades on international markets at a value that is lower than mere adjustment by calorific value would suggest: this is because low value coal may require blending with high value coals, increasing fuel stock management costs.

addition, where there are large differences in ash or sulfur contents, domestic coal may incur additional ash and waste handling costs. Thus the import parity price calculates as

$$IP = P*E*(G_2/G_1) + SCF[(G_2/G_1)*(F_1 - F_2)] - SCF*A$$

Where:

IP	=	Import parity price of coal at mine gate in local currency/ton
E	=	Exchange rate
F_1	=	Freight/Ton (financial prices) from port to consumer (market) in local currency
F_2	=	Freight/Ton (financial prices) from mine to consumer in local currency
SCF	=	Standard correction factor (which adjusts for the tax component of domestic costs)
P	=	Cif import price, in $US
A	=	Coal quality penalty
G_1	=	Gross calorific value of imported coal (kcal/kg)
G_2	=	Gross calorific value of domestic coal (kcal/kg)

Freight costs

14. When building up a border price forecast for a particular location, freight costs can be important particularly for coal.[3] These can be as volatile as the coal price itself, but are generally correlated with the underlying coal price: when the coal prices are declining (as in Spring 2015), freight costs will be low; when coal prices is are increasing, freight costs will (generally) be high (though there are some circumstances when this does not apply). Table C1.7 shows selected freight rates in October 2014 compared with those of February 2015.

Table C1.7: Coal freight, $/metric tone

		October 2014	February 2015
Australia NSW, fob	$/ton (2)	63.9	
South Africa, Richards Bay, fob	$/ton (2)	65.7	
Australia-China	Capesize (1)	11.5	4.65
	Panamax (1)		6.90
Richards Bay-Rotterdam	Capesize	10.50	4.60
	Panamax		7.25
Queensland-Rotterdam	Capesize	17.20	6.95
	Panamax		10.35
Queensland-Japan	Capesize	10.45	4.55
	Panamax		10.35
Bolivar-Rotterdam	Capesize	11.75	6.35
	Panamax		8.25

Source: Coal Trader International (McGraw-Hill) [Available at the World Bank Library]
(1) see glossary.
(2) World Bank "Pink Sheets" (available on line).

CAPITAL INVESTMENT

15. In a CBA, often the biggest problem in estimating capital costs is not for the project being appraised (for which a detailed feasibility study prepared by engineering consultants is often available), but for specifying the capital costs for the counter-factual - which is just as important in assuring the reliability of the CBA calculations as those of the project itself.

[3] Because coal has a much lower value per unit of weight and volume than LNG or oil, freight can make up a much larger fraction of the price delivered at the point of import.

16. Several problems are encountered in establishing the costs for a CBA:

- How to find reliable data on technology costs and performance.
- How to adjust past capital cost estimates to the price level of the CBA.
- How to adjust technology costs for local conditions.
- How to deal with volatile exchange rates.

Reliable data on costs and technology performance

17. In North America, the gold standard for a database on power technology cost and performance was the *Technical Assessment Guide* maintained by the Electric Power Research Institute (EPRI). Unfortunately, despite having access to a large numbers of power projects all over the world, World Bank has not managed to maintain something comparable. There is not even a simple database of capital costs of all World Bank energy sector projects (as estimated in PADs, and as may have been adjusted in Implementation Completion Reports). From time to time the Bank has commissioned useful studies from experienced international consultants (see Table C1.7), but these have not proven to be very useful for estimating costs in typical World Bank client countries.

Table C1.7 Data sources

Source	Description	Comments
	All technologies	
NREL	Black&Veatch, 2012. *Cost and Performance Data for Power Generation Technologies*, Report to NREL	Covers a wide range of fossil and renewable energy technologies.
World Bank, ESMAP	Paucschert, D. *Study of equipment prices in the power sector*, ESMAP, Technical Paper 122/2009.	Analyses costs in great detail, but for just three countries (USA, India and Romania).
World Energy Council	*Cost of Energy Technologies*, 2013	Includes estimates for all technologies, including renewables. For some technologies, highlights the large differences between OECD counties and China (e.g. coal CAPEX: China $660/kW, Australia,UK,USA $2,510-3,100/kW)!
World Bank	Chubu Electric Power Company & ECA, 2012. *Model for Electricity Technology Assessments*	
US Energy Information Administration	*Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants*, April 2013	Authoritative source, useful for thermal generating projects. (See Table C1.8)
	Renewable energy	
RETSCREEN	Suite of financial models to evaluate renewable energy projects.	Sample spreadsheets are protected, so cannot easily be used as a basis for more detailed model. No distinction between economic and financial costs (the model is for financial analysis).
HOMER	Model for operation of mini grids suitable for evaluating wind/PV-diesel hybrids	Widely used for the design of small systems, especially diesel-wind and diesel-PV hybrids.
IRENA	Various reports,e.g.: *Renewable Power generation Costs in 2012: An Overview;* and *Concentrated Solar Power*	A visit to the IRENA website should be one of the first sources to consult for a renewable energy project (www.irena.org).
NREL	**www.nrel.gov**	The NREL website should also be one of the first sources to consult for technology cost and performance data and the latest studies on renewable energy economics & planning.

Table C1.8: US construction costs, thermal generation

	Plant Characteristics		Plant Costs (2012$)		
	Nominal Capacity (MW)	Heat Rate (Btu/kWh)	Overnight Capital Cost ($/kW)	Fixed O&M Cost ($/kW-yr)	Variable O&M Cost ($/MWh)
Coal					
Single Unit Advanced PC	650	8,800	$3,246	$37.80	$4.47
Dual Unit Advanced PC	1,300	8,800	$2,934	$31.18	$4.47
Single Unit Advanced PC with CCS	650	12,000	$5,227	$80.53	$9.51
Dual Unit Advanced PC with CCS	1,300	12,000	$4,724	$66.43	$9.51
Single Unit IGCC	600	8,700	$4,400	$62.25	$7.22
Dual Unit IGCC	1,200	8,700	$3,784	$51.39	$7.22
Single Unit IGCC with CCS	520	10,700	$6,599	$72.83	$8.45
Natural Gas					
Conventional CC	620	7,050	$917	$13.17	$3.60
Advanced CC	400	6,430	$1,023	$15.37	$3.27
Advanced CC with CCS	340	7,525	$2,095	$31.79	$6.78
Conventional CT	85	10,850	$973	$7.34	$15.45
Advanced CT	210	9,750	$676	$7.04	$10.37
Fuel Cells	10	9,500	$7,108	$0.00	$43.00
Uranium					
Dual Unit Nuclear	2,234	N/A	$5,530	$93.28	$2.14

Source: US Energy Information Administration *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants*, April 2013

Adjusting past capital cost estimates

18. Ideally, a detailed feasibility study would be available as a basis for estimating construction costs of major energy projects, at price levels corresponding to the year of appraisal. But that ideal is not always available. , If earlier costs estimates are just a year or two old, the default for bringing these to the cost level used in project appraisal would be application of the Manufactured Unit Index (MUV), published in the Bank's website (Table C1.9).[4]

Table C1.9: MUV Index forecast

	Manufactures Unit Value (MUV) Index			
	expressed in U.S. dollar terms		**Release date: July 7, 2014**	
	History 1960-2013; projections 2014-2025			
	email: gcm@worldbank.org			
	MUV Index		**U.S. GDP deflator**	
	Index 2010=100	ch%	Index 2010=100	
2000	79.56		80.91	
2001	76.58	-3.7	82.76	
2002	75.68	-1.2	84.03	2.3
2003	79.62	5.2	85.71	1.5
2004	85.03	6.8	88.06	2.0
2005	87.70	3.1	90.88	2.7
2006	89.93	2.5	93.68	3.2
2007	95.43	6.1	96.17	3.1
2008	102.83	7.8	98.02	2.7
2009	96.46	-6.2	98.80	1.9
2010	100.00	3.7	100.00	0.8
2011	108.94	8.9	101.96	1.2
2012	107.59	-1.2	103.75	2.0
2013	106.06	-1.4	105.21	1.7
2014	106.34	0.3	106.87	2.1
2015	106.65	0.3	108.85	1.6
2016	108.20	1.5	111.05	1.9
2017	109.73	1.4	113.30	2.0
2018	111.34	1.5	115.58	2.0
2019	113.02	1.5	117.92	2.0
2020	114.77	1.5	120.30	2.0
2021	116.58	1.6	122.73	2.0
2022	118.44	1.6	125.21	2.0
2023	120.35	1.6	127.74	2.0
2024	122.32	1.6	130.32	2.0
2025	124.32	1.6	132.96	2.0

Source: EXCEL file downloaded from the World Bank website

4 The MUV-index is the weighted average of export prices of manufactured goods for the G-5 economies (the United States, Japan, Germany, France, and the United Kingdom), with local currency based prices converted into current U.S. dollars using market exchange rates.

Adjusting technology costs for local conditions

19. The net output of a new CCCT is generally quoted under so called ISO conditions (International Standards Organisation), meaning at an ambient temperature of 15^{o}C, and at sea level. At the higher ambient temperatures encountered in tropical countries, output reduces considerably: as shown in Table C1.10, a nominal 800 MW at ISO project will have a net output of only 718.8 MW under actual ambient conditions – making for a 10% reduction in output.

Table C1.10: Derivation of net CCCT output (for Vietnam)

	deduction	MW
100% at generator, ISO conditions		800
Step-up transformer	-0.3%	797.6
Other auxiliary equipment	-0.05%	797.2
Ambient temperature adjustment	-8.2%	733.4
Cooling water temperature	-0.20%	718.8
Net, MW[5]		718.8

Source:. KEMA, LRMC of CCGT Generation in Singapore for Technical Parameters used for Setting the Vesting Price for the Period 1 January 2009 to 31 December 2010, Report to the Singapore Energy Market Authority, 22 June 2009.

20. Local variations in cost estimates can also be considerable, as illustrated in Table C1.11 for the case of Vietnam. The overnight costs (ISO) range from $646 to 911/kW - at 2010 prices. But when converted to net $/kW (including IDC), costs are much higher. Moreover, the difficulty for a project economist working in Vietnam is that the World Bank's ESMAP META database shows an overnight capital cost for an 800 MW CCGT at $552/kW – when *actual* costs – even gross at ISO – are in the range of 848-948$/kW.

Table C1.11: CCGT cost estimates for Vietnam.

					overnight	including IDC	
	MW (ISO)	VND billion	VND /$US	$US million	$/kW (ISO, gross)	$/kW (ISO, gross)	$/kW (net)
PB consultants, Vietnam estimate	720	19,122	16,970	1,126.8		1,565	1,741
PB consultants, Vietnam estimate	400	7,494	16,970	441.6		1,104	1,228
KEMA, Singapore	**800**			**729.0**	**911**	**1,066**	**1,186**
Non Trach I (2)					848	992	1,104
Non Trach II (2)					948	1,109	1,234
World Bank, India						1,140	1,268
EVN 6th PDP(1)					646	756	842

Source: Electricity Regulatory Authority of Vietnam (ERAV), *Review of the Avoided Cost Tariff for Small Grid-connected Renewable Energy Generation Projects*, Hanoi, September 2011

Notes:

(1) PDP=Power Development Plan

(2) Actual costs

Exchange rates and market conditions

21. A critical issue is exchange rates. Much renewable energy equipment is manufactured in Europe, and hence costs are quoted in Euros: for a US$ denominated economic analysis, foreign exchange rate volatility can therefore cause problems. For example, suppose a detailed cost analysis by a German research institute in mid-2012 provided CSP costs at 3,000 Euro/kW. At the time the exchange rate was $1.26 per Euro, so $3,780/kW. In early 2015 the exchange rate is $1.13 per Euro, or 3,390$/kW. The relevant point is that exchange rate volatility is an important component of capital cost

[5] This is for new plant. As documented in the KEMA report, even with regular maintenance and plant overhauls, a further 3-4% deterioration for ageing will generally arise.

uncertainty, which needs to be reflected in the sensitivity analysis. Moreover, for many components of capital goods, market conditions can easily result in variations of ±20%.[6]

22. A 1996 study examined the construction costs and schedules of 125 thermal and hydropower projects financed by the World Bank between 1965 and 1994. Construction costs were underestimated by an average of 17% (standard deviation 34%), construction schedules by 29% (standard deviation 29%).[7] Whether a similar study of renewable energy projects undertaken today would find better a better or worse track record of *ex ante* cost estimates is an interesting question. These issues all make for increasing importance of the risk assessment (Technical Note **C5**).

Chinese equipment

23. Finally to the question of Chinese equipment, whose quality variations are much greater than those of European vendors. For small renewable energy IPPs, Chinese small hydro equipment can be 35% cheaper than European equipment, but the trade-offs between cost, efficiency, and reliability of Chinese equipment are generally poorly understood. The main financial consequence of equipment failures (and delays in getting spares) is often not the cost of the spare itself, but the loss of generation and consequent revenue shortfall: what matters is life cycle cost, not first cost. Box C1.1 summarises the results of a study of the impact of technology choice for small hydro equipment in Vietnam. This was one of the main issues in the implementation of the Bank's renewable energy development program: such questions need to be understood in the design of such Portfolio projects, where the project economist typically plays an important role. Whether or not the predicted economic returns can be realised in practice depends upon the quality of equipment actually purchased, not what is assumed at appraisal. The lesson here is simple: high quality Chinese equipment from reputable manufacturers (whose cost may be considerably higher than the cheapest offers, but still lower than European equipment) is often the best strategy, and which should be reflected in the CBA at appraisal.

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6 The mid term review of the Indonesian geothermal projects financed by the World Bank makes for interesting reading. The power plant capital cost estimate was made at a time of a sellers' market, but by the time of the competitive bidding, it had became a buyers' market, with prices 20% lower. However, over the same time period, the cost of drilling soared, so coupled with long delays to raise additional equity for drilling, the net impact was still a substantial cost increase.

7 Bacon, R., J. Besant-Jones & J. Heidarian. *Estimating Construction Costs and Schedules: Experience with Power Generation Projects in Developing Countries*. World Bank Technical Paper No. 325 August 1996.

Box C1.1: Impact of low-cost Chinese small hydro equipment

The question of the life cycle cost-effectiveness of low-cost Chinese equipment was studied for the case of small hydro in Vietnam, where substantial numbers of projects procured Chinese turbine-generators. European equipment is likely to be 50% more expensive than good Chinese equipment: and that cost premium will result in better efficiency (average 87% rather than the 85% of the Chinese equipment), and slightly lower routine O&M costs (1.5% of first cost rather than 2% assumed for Chinese equipment). It will also have longer intervals between major maintenance events (T_1 in the table below).

On the other hand, the cheapest Chinese equipment may be available at as much as a 40% discount over good equipment – but at the cost of lower average efficiency (83% rather than 85%), higher routine O&M costs (3% rather than 2% of first cost), and a significantly lower interval between major maintenance events (every three years rather than every 5 years). T_2 in the table below denotes the intervals between complete replacement of equipment.

Assumptions

	Relative capital cost	$/kW	average efficiency	T_1 years	T_2 years	O&M
cheap (poor quality) Chinese equipment	0.6	240	0.83	3	9	3.00%
good Chinese equipment	**1**	**400**	**0.85**	**5**	**20**	**2.00%**
European equipment	1.5	600	0.87	10	20	1.50%

The study then examined financial returns as a function of the equipment choice. The table below shows that indeed good Chinese equipment is the rational choice for SHP developers, and that neither buying very cheap Chinese equipment, nor more expensive European equipment, represent economically rational alternatives. However, reliability and availability of spare parts are more important than O&M and efficiency differences, and failure to include these factors in comparisons at the procurement stage has led many developers into trouble.

Impact of equipment choice

		poor Chinese equipment		**good Chinese equipment**	European equipment	
total equity	VNDb	107	*-12.5%*	**122**	147	*20.2%*
total loan	VNDb	346	*-12.5%*	**396**	475	*20.2%*
total capital cost	VNDb	453	*-12.5%*	**518**	622	*20.2%*
	$/kW	1030	*-10.4%*	**1150**	1350	*17.4%*
average generation	GWh	76.3	*-9.3%*	**84.1**	87.6	*4.1%*
DSCR, first year	[ ]	1.7	*8.2%*	**1.6**	1.3	*-13.9%*
FIRR, nominal	[ ]	14.6%	*-37.3%*	**23.3%**	20.3%	*-13.0%*
FIRR, real	[ ]	8.1%	*-50.3%*	**16.3%**	13.5%	*-17.5%*

Note: percentages indicate deviation form good Chinese equipment

Good Chinese equipment has resulted the best outcomes for developers. Of course the initial outlay of cheap (poor) equipment is 12.5% lower, with a corresponding reduction in both developer's equity and the required size of bank-loan. But generation is also 9.3% lower, and the FIRR is only half that of good Chinese equipment.

European equipment, while better than good Chinese equipment, still has a 3% lower FIRR. Moreover, developer's equity and loan size increase, and the first-year debt service cover ratio – always of interest to the banks – is 1.3, as against 1.6 in the case of good Chinese Equipment.

Vietnamese small hydro producers lucky to have ended up with reliable Chinese equipment have prospered, but those less fortunate have incurred losses as a consequence of poor suppliers, some of whom vanished when major spares were needed.[8]

Source: A. Arter, *Life Cycle Cost Estimation of Small Hydro Projects*, Report to the World Bank, Hanoi, 2010

8 The 5.4 MW *So Lo* small hydro project is an example of an unsatisfactory outcome. The project was set up as 2 x 0.806 MW + 2.12 MW +1.706 MW. The developer stated that this unusual configuration was a result of a "special deal" on machines available from the vendor's inventory. Whether four turbines for such a small project is optimal can be debated, but if multiple units are to be used, they should be of identical design so that just a single inventory of spares can be used. When the plant was visited, two units had been down for several months awaiting delivery of spares.

PRESENTATION OF CAPITAL COSTS

Working capital

24. Only inventories (stocks and spares) that constitute real claims on the nation's resources should be included in economic costs. Other items of working capital reflect loan receipts and repayment flows, and should not be included as an economic cost.

Contingencies

25. It is Bank practice to distinguish between physical and price contingencies. *Physical* contingencies reflect the value of additional real resources that may be required beyond the estimated baseline cost to complete the project, and should be included in the economic cost. However, since economic returns are generally measured at constant prices, *price* contingencies – which reflect increases in nominal costs due to inflation. - should be excluded from the economic cost.

Reconciliation of economic and financial costs

26. Energy sector projects in the Bank have traditionally followed a standard format for the presentation of project costs, with clear breakdown of what costs are incurred in foreign exchange and what in domestic currency; what are the tax and import duty components of each expenditure line item; and what are the price and physical contingencies (and how they are derived). Where construction costs were based on feasibility studies that were one or two years old, the standard format provided transparency in how costs were adjusted for inflation and exchange rate changes. This provides a credible basis for the reconciliation of economic and financial costs, that is the basis for the distributional analysis (see Technical Note **C6**).

27. These various conventions are followed in Table C1.12, which illustrates the general format for presentation of investment costs, with clear presentation of what are local and what are foreign costs, what are taxes and duties, and what are price contingencies and interest during construction that are excluded from the economic cost. For an explanation of row [10] (SCF, Standard correction factor), see Technical Note **M1**.

Table C1.12: Tarbela T4 Hydro extension project, economic and financial costs, $USmillion

		base cost	physical contin-gency	total base cost	price contin-gency	Total, before taxes& duties	explicit taxes& duties	Total (financial) cost	implicit tax content of base cost	economic cost
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
[1]	power house and tunnel works	250	25	275	20	295	15	**310**	19.3	256
[2]	turbine, generator	342	34	376	27	403	28	**432**	26.3	350
[3]	construction supervision	21	1	22	2	24		**24**	1.6	21
[4]	Consultants	2		2		2		**2**	0.2	2
[5]	EMP, SAP	29		29		29		**29**	2.0	27
[6]	project manage-ment, TA, training	34		34		34		**34**	2.4	32
[7]	Total	679	**61**	740	**49**	787.5	43	**831**	51.7	**687**
[8]	Fees&IDC							**84**		
[9]	Total financial cost							**915**		
[10]	SCF adjustment									-10
[11]	Total economic cost									**677**

Source: World Bank, *Project Appraisal Document, Tarbela T4 Hydro Extension Project*, 2012.

Levelised cost of energy calculations

28. Comparisons of levelised cost of energy (LCOE) are widely presented. Many purport to show that some forms of renewable energy are now competitive with their fossil equivalents. Unfortunately for the reasons to be explained below, comparisons of LCOE can be misleading, and may to lead to erroneous conclusions.[9]

29. Consider the comparison of LCOE for a 100 MW wind project compared to a gas combined cycle presented in Table C1.13. With a variable cost of 11.0 USc/kWh (corresponding to a gas CCGT with fuel costs of $14/mmBTU), the LCOE of a gas project is 12.9USc/kWh (row [16]). At $2,300/kW and a 30% capacity factor, the wind LCOE is 12.3 USc/kWh. The wind project appears less costly.

Table C1.13: LCOE for gas and wind

			Wind	gas
[1]	installed capacity	[MW]	100	100
[2]	capacity factor	[ ]	0.3	0.7
[3]	Energy	GWh/year	262.8	613.2
[4]	equiv hours	[hours]	2628	6132
[5]	cost/kW	[$/kW]	2300	900
[6]	capital cost	[$USm]	230.0	90.0
[7]	Life	Years	25	25
[8]	discount rate	[ ]	0.1	0.1
[9]	Capital recovery factor	[ ]	0.11	0.11
[10]	Annual capacity cost	$USm	25.3	9.9
[11]	Fixed O&M	[ ]	0.03	0.02
[12]		$USm	6.9	1.8
[13]	total fixed cost	$USm	32.2	11.7
[14]	Fixed cost/kWh	[USc/kWh]	12.3	1.9
[15]	Variable cost/kWh	[USc/kWh]	0.0	11.0
[16]	LCOE	[USc/kWh]	12.3	12.9

30. OPSPQ indeed allows projects to be selected on the basis of a cost-effectiveness analysis, but the important proviso is that the options considered deliver the same basket of benefits. But the benefits of wind and CCGT are *not* the same. The highest value of the output is that which is delivered during peak and intermediate hours. Most of the output CCGT will be dispatched into these blocks, with little generation during off peak, base load. However, the output of the wind project is not dispatchable into the same blocks, but likely to be random throughout the year around each monthly average.[10] With a 30% capacity factor, the chance it will generate during the peak hours is 30%, not 100%.[11]

31. Suppose the daily load curve is defined as 4 peak hours per day, 8 intermediate hours per day, and 12 base-load (off-peak) hours per day (as might typically be structure of an electricity tariff definition). Let the benefit of peak hour generation be 25 USc/kWh (corresponding to the avoided cost of diesel self generation), of intermediate

9 For a full discussion of the problems of using LCOE for comparisons of generation costs, see, e.g., Joskow, P. 2011. *Comparing the Costs of Intermittent and Dispatchable Electricity Generating Technologies.*

10 As discussed further in Technical Note **T1**, in tropical countries the seasonal variations are much higher than in Northwest Europe and the USA, so unless the seasonal maximum coincides with the time of the annual system peak, the firm capacity contribution of even a project with a good 35% capacity factor may be negligible.

11 That is not necessarily the case – at some coastal locations, the timing of regular evening sea breezes may correspond well to peak residential demands.

generation the cost of gas CCGT (12.9 USc/kWh, from Table C1.13), and the cost of base load generation 6USc/kWh (corresponding to coal). Then in Table C1.14 we note that since wind is non-dispatchable, and assuming that the probability of the wind project operating in any given hour is random (with probability equal to its annual capacity factor), then the wind project will contribute to each segment of the load curve as shown in column [3]. Thus with a capacity factor of 30%, during the total yearly peak hours of 1,460 (row[1] of Table C1.14), the wind project will run (on average) in only 0.3 x 1460 = 438 hours.

Table C1.14: Benefits of wind energy

		hours/day	hrs/year	Hours Available	GWh/ year	value USc/kWh	total value $USm
		[1]	[2]	[3]	[4]	[5]	[6]
[1]	Peak	4	1,460	438	43.8	25.0	11.0
[2]	Intermediate	8	2,920	876	87.6	12.9	11.3
[3]	Base	12	4,380	1,314	131.4	6.0	7.9
[4]	*total value*				262.8		30.1
[5]	USc/kWh						11.5

32. Repeating this calculation for the other load tranches, then multiplying hours dispatched by the economic value (column[5]) gives the total value in column [6], resulting in an average benefit (avoided cost) of 11.5 USc/kWh.

33. In Table C1.15 the benefits of the gas project calculate to 13.8 USc/kWh: this is because the CCGT is dispatchable, so generating during all peak and intermediate hours, and generating a much smaller number of GWh during the low value base-load hours.

Table C1.15: Benefits of gas CCGT

		hours/day	Hrs/year	Hours Available	GWh/ year	Value USc/kWh	total value $USm
		[1]	[2]	[3]	[4]	[5]	[6]
[1]	Peak	4	1,460	1,460	146.0	25.0	36.5
[2]	Intermediate	8	2,920	2,920	292.0	12.9	37.7
[3]	Base	12	4,380	4,380	175.2	6.0	10.5
[4]	*total value*				613.2		84.7
[5]	USc/kWh						13.8

34. In other words, when the value of the output at different times of day are taken into account (i.e. the benefit), the *net* benefit of the wind project is 11.5 – 12.3 =*minus* 0.80 USc/kWh, whereas the net benefit of the gas CCGT is 13.8-12.9=*positive* 0.90 USc/kWh. Of course, it may be that the avoided cost of GHG emissions may make up for this difference, but from the perspective of the *buyer* of energy, these are the incremental financial costs that will be incurred. In effect, the LCOE calculation of Table C1.13 ignores the lack of capacity benefit of the variable renewable energy (VRE).

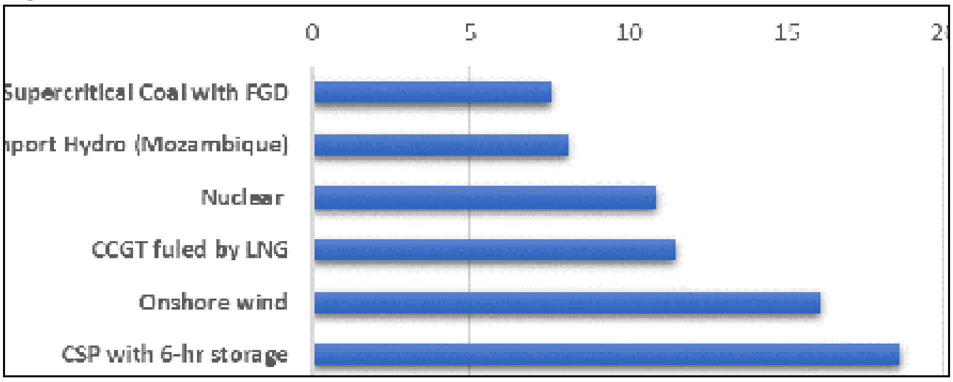
35. We therefore urge caution in the use of tools (including tools issued by the ESMAP/World Bank, such as META) that present comparative results expressed as LCOE. Box C1.2 shows an analysis of LCOE that properly adjusts for capacity penalties of variable renewables.

Box C1.2: South Africa levelised cost comparisons of generation costs including carbon pricing.

This study assesses the cost of power generation alternatives under different assumptions for carbon pricing - namely without carbon pricing, and under the three scenarios for carbon pricing of the World Bank's July 2014 Guidelines for the Social Value of Carbon (see Table M5.1 in the Technical Note on Carbon Accounting). Carbon emissions are based on life cycle emission factors from the US Department of Energy's Harmonisation Project (see Table M5.7). For South Africa, cost and technology data were taken from the Medupi Coal Project PAD.[12] For wind, a capacity penalty was added: based on a report prepared by the German GIZ, the capacity credit was assessed at 30%,[13] so the capacity penalty was calculated as 70% of the capital cost of open cycle gas turbine, which was added to the capital cost of wind.

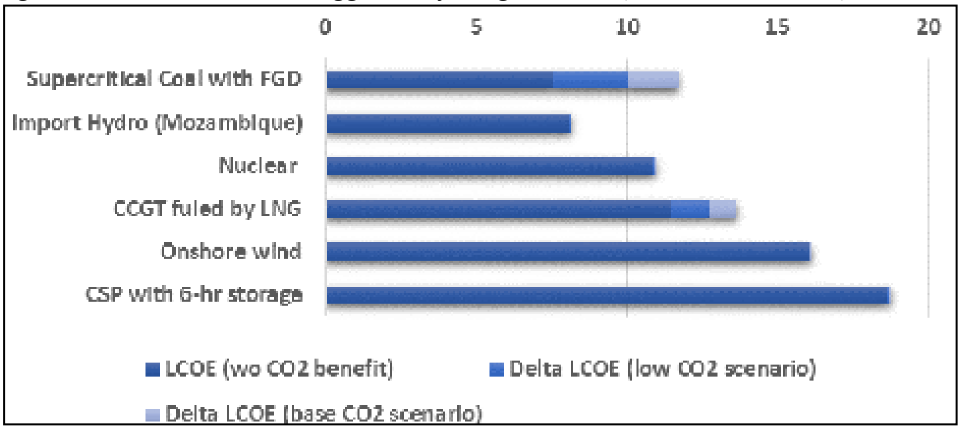
Levelised costs of energy for the generation technology options considered in South Africa, without carbon pricing, are shown in Figure A. Coal is the cheapest option, followed by hydro: onshore wind is more than twice the cost, and CSP 2.5 times the cost of coal.

Figure A: No carbon price



When carbon is valued at the baseline costs as suggested in the Guidelines ($30/ton CO_2 in 2015) – as shown in Figure B - the cost of coal generation increases to 12 USc/kWh, and is now more expensive than nuclear (and hydro) –but still remains below the cost of the renewable options

Figure B: baseline carbon as suggested by the guidelines ($30/ton CO_2 in 2015)



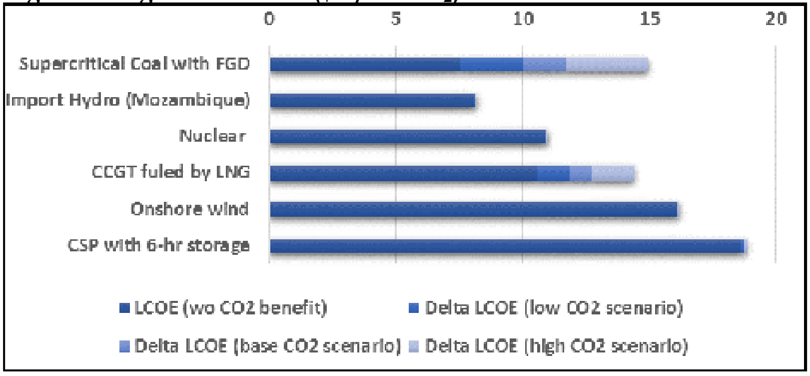
This remains true even at the high carbon price scenario ($45/ton CO_2 in 2014). As shown in Figure C: Onshore wind is still slightly more expensive than coal and CSP, but CCGT based on imported LNG is slightly less expensive.

12 World Bank, 2010. *Project Appraisal Document, ESKOM Investment Support Project*, Report ZA-53425

13 GIZ, *Capacity Credit for Wind Generation in South Africa*, Report to ESKOM, February 2011.

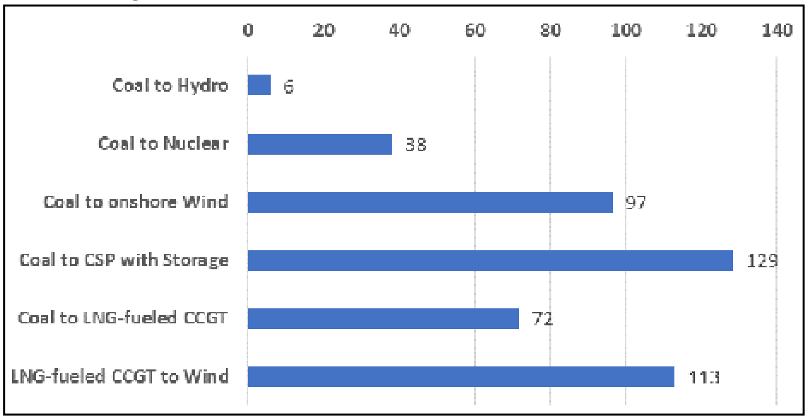
These results would change somewhat under lower discount rates than the 10% used here. Moreover, they are sensitive to the particular fuel costs assumed: lower discount rates and lower LNG prices will make renewable energy more competitive.

Figure C: High carbon costs ($45/ton CO_2)



A different way of expressing the impact of carbon price on technology cost comparisons is to calculate the switching values: what would need to be the value of carbon for the cost of two options to be equal? These are shown in Figure D for South Africa. We note that switching from coal to wind power or CSP with storage would require a carbon price much higher than that of the high carbon price scenario.

D. Switching values, $/ton CO2: South Africa



Based on these analyses, the study concluded that

- In the BAU scenario, coal-fired power plant represents the least-cost generation option among all 6 generation technologies in South Africa, due to large reserves of low-cost coal.
- In the Base CO_2 price scenario, nuclear power becomes more economic than coal-fired power generation, in addition to hydropower.
- In the high CO_2 Price Scenario, coal-fired power plant further becomes less economically desirable than CCGT fuelled by LNG.
- Switching from coal to wind power and CSP with storage would require a carbon price much higher than that under the High Carbon Price Scenario.

Source: World Bank, 2015. *Assessing Impacts of Carbon Pricing Scenarios on the Economics of Power Generation Technologies: Case Studies in South Africa and Bangladesh*. May 13.

Suggested reading

KEMA, *LRMC of CCGT Generation in Singapore for Technical Parameters used for Setting the Vesting Price for the Period 1 January 2009 to 31 December 2010,* Report to the Singapore Energy Market Authority, 22 June 2009. Good example of a careful evaluation of the true cost of CCGT power generation.

US Energy Information Administration (USEIA), 2013. *Updated Capital Cost estimates for Utility Scale Electricity Generating Plants*. The USEIA website is always worth a visit when researching recent trends in technology costs and performance.

Examples in World Bank Economic Analysis

Pakistan: (World Bank, *Project Appraisal Document, Tarbela T4 Hydro Extension Project*, 2012): a good example of setting up transparent reconciliation of economic and financial costs for capital investment.

Best practice recommendations 1: Costs

(1) Valuation of domestically produced fossil fuel prices should be based on import parity prices. This will generally be more reliable estimate than estimates of the LRMC of supply plus a depletion premium. Reliable LRMC estimates require considerable effort to prepare, which may not be available for most projects.

(2) LCOE calculations should be viewed with caution, especially when comparing LCOE of different energy technologies. These should always be accompanied by a comparison of benefits, before any particular option is declared "economic" based on LCOE. Box C1.2 shows how LCOE calculations can be corrected for renewable energy variability.

(3) Although cost and performance data may be available from some of the sources listed in Table C1.7, they need to be used with care. Many do not reflect market conditions in Asia, where less expensive equipment may be available from China, and local site conditions vary greatly. Costs in small post-conflict and fragile countries may be much higher than average costs elsewhere.

(4) Even if variable renewable energy projects have good capacity factors, because of the high seasonal variations in monsoonal countries it cannot always be assumed that the capacity credit would follow the rules of thumb about capacity credits derived from US and European experience (see also Technical Note T1).

C2 BENEFITS

OVERVIEW

36. Different kinds of power sector investment project have different kinds of benefits, some of which may be difficult to quantify. Table C2.1 lists the main issues, and the technical notes that provide more detailed discussion. Additional technical notes are planned to be included in the next FY for projects other than renewable energy.

Table C2.1 The Benefits Energy Sector Projects

Project	Main economic benefits	Main Issues in quantifying benefits
Grid connected renewable energy	• Avoided cost of grid connected thermal generation	In addition to the main benefit of avoided thermal generation, various additional benefits are proposed for high-cost projects, such as Energy Security (Technical Note **C7**) Learning curve (Technical Note **T3**) and macroeconomic benefits that derive from local manufacture of component (Technical Note **C8**). In the case of variable renewable energy (wind, sun of river small hydro) the question of capacity benefit is controversial (Technical Note **T1**)
Off grid projects & rural electrification	• Avoided costs of kerosene and other electricity substitutes (batteries,	Estimating consumer surplus benefits using demand curves derived form household energy survey data is difficult; requires many assumptions, and surveys are expensive. There are also conceptual problems related to the use of consumer surplus unadjusted for income effects (i.e. Marshalian v. Hicksian formulations). See Technical Note **M2**.
T&D rehabilitation, distribution projects	• Lower technical losses (leading to lower generation costs) • Improved electricity quality (fewer outages, better voltage control)	
Generation rehabilitation projects	• Lower O&M costs • Higher generation	The main difficulty is specifying the counter-factual – i.e. for how long can a dilapidated plant keep going (under current trends of increasingly poor performance) before it would abandoned.
Commercial loss reduction	• Avoided deadweight losses[14]	The economic benefit derives from the fact that for a significant proportion of pilferers, their economic benefit (area under demand curve) is lower than the economic cost of supplying them. Their loss of consumer surplus once faced with payment is a small proportion of the gain

[14] It is often assumed that commercial loss reduction is merely a measure to improve financial health of the distribution entities. But there are economic benefits as well (to be discussed in the planned FY16 Technical Note **T6** on Commercial Loss Reduction).

		to the power company (and the country) of the cost of supplying him.
Energy Efficiency projects	• Avoided costs of electricity generation[15] • Avoided costs of fuels used for steam generation and process heat • Avoided costs of other inputs (chemicals, labour) • Lower O&M costs	
Transmission projects (connecting new generation)	• Enables power evacuation for the projects being connected	Such a transmission line should be seen as part of the capital cost of the generation project(s) whose power is being brought to the existing grid. It has no *economic* benefit in the absence of the generation project in question, and claims that the benefit of such a line has a separable ERR are unreliable.
Transmission projects for general network development	• Avoided capacity costs associated with interconnecting load centres • Improved reliability • Lower losses (and hence avoided generation in peak hours which is generally high-cost fossil generation)	Difficult to demonstrate the benefit of a single major substation, or of a particular transmission line. Benefits of substations estimated on the basis of LRMC valuations at different voltage levels are often unreliable.

Benefit sharing

37. There is often confusion about the treatment of benefit-sharing – typically money that is provided to local communities affected by a major investment project that go beyond the usual outlays for any R&R under safeguards policies.

38. Even though these may represent financial costs to the developer as may have been agreed (for example as part of a concession agreement), they should be *excluded* from the economic analysis – though obviously *included* as a transfer payment in the distributional analysis.

15 While the financial benefits to the investor of an energy efficiency project are straight forward (given tariff forecasts), there will often be negative financial impacts on the utility.

C3 EXTERNALITIES

39. The World Bank's 1998 *Handbook on Economic Analysis* defines externalities as

> *The difference between the benefits (costs) that accrue to society and the benefits (costs) that accrue to the project entity.*

But in practice, project boundaries are often much wider than the "project entity." For example, flood control benefits in a multi-purpose water resource project may occur at some distance downstream, and would not normally included in the accounts of the "project entity" – but these have long been included in the benefit stream of a hydro project economic analysis without being called an "externality". Thus a better definition is with reference to the project boundary, the establishment of which is one of the first tasks in the analysis.

40. In other words, externalities can be

- *local* – such as the health damage cost incurred from NOx, SO_2 and particulate matter
- *regional* – such as the impact of a hydro project on fisheries many miles downstream and perhaps even in a different country (such as a Mekong River hydro project in Laos affecting Cambodia and Vietnam fisheries in the Mekong Delta).[16]
- *global* – such as the damage cost from thermal power generation whose impacts are felt by the entire world.

41. A rigorous definition of externality in the economics literature is more nuanced, requiring not merely that a third party is affected, but also that these effects are not conveyed through market price signals.[17]

42. Table C3.1 provides a checklist for the main externalities that arise in renewable energy projects. Where these are significant, one would expect to see a corresponding line item in the calculation spreadsheet of economic flows. The definition of positive or negative is from the perspective of the impact on a renewable energy project (so avoided GHG emissions are a benefit for a renewable energy project, but would be a cost for a thermal generation project).

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16 The old OP10.04 defined "cross-border" externalities as those occurring in neighbouring countries (such as "effects produced by a dam on a river").

17 W. Baumol and W. Oates, 1988. The *Theory of Environmental Policy*. The classic distinction is given by the example of a labor intensive factory using coal for power, setting up next to a laundry. Soot that is deposited on clean washing imposes incremental costs on the laundry, and constitutes an externality. But if the price of unskilled labor in the area increases because the factory offers high wages, the impact of higher labor costs on the laundry is *not* an externality, because it is conveyed by a market price signal.

Table C3.1 : Checklist of externalities (and examples of their analysis)

	Impact in economic flows	Quantification & valuation
All projects		
Local air pollution emissions	Positive (mostly small, except for coal)	The methodology in Technical Note **M4** is now generally accepted. Always need assessment if generation at coal projects changes.
GHG emissions	Positive (significant)	Quantification straightforward. Valuations are now provided by Bank guidance document (2). See Box C3.2 for an example of a study of the impact of incorporating GHG externality costs in generation planning.
Road construction	Requires study	Many energy projects are in remote areas, which may require major road construction through environmentally sensitive areas (geothermal, small hydro). The direct costs are routinely included in the investment cost, and arguments are often presented (though rarely monetised) that better (or new) roads in remote areas may improve agricultural productivity and promote local economic activity. However, experience (especially in small hydro projects) shows that environmental mitigation measures are difficult to enforce in remote areas. The costs of such measures are often ignored in the economic analysis.
Hydro projects		
Flood control benefits	Requires study	The question for economic analysis is whether the constraints on operating rules (that require drawdown to allow for possible flood control measures), and/or the costs of increased storage, are justified by the downstream flood control benefits. The latter are often assessed as the avoided cost of dykes and other downstream interventions, but their credibility always demand scrutiny. See World Bank, *Project Appraisal Document, Trung Son Hydroelectric Project*, 2012.
Downstream fisheries impacts	negative	Often related to sediment control regimes. Difficult to value, with large range of uncertainty, and inevitably controversial. See, e.g., R. Constanza *et al.*, *Planning Approaches for Water Resource Development in the Lower Mekong Basin* , July 2011.
Forestry impacts	negative	When a reservoir inundates forest, a range of forest values may be lost, including timber and non-timber forest products, and environmental services. See Box C3.1 for an example from Vietnam where the information was available in a Strategic Environmental Assessment conducted for all major remaining large hydro projects. (Stockholm Environmental Institute: *Strategic Environmental Assessment, Vietnam Hydro Master Plan*, 2000). Such studies are not always available.
Downstream flow regulation	Positive	The regulation provided by a storage hydro project will in principle benefit downstream hydro projects as well, which should be estimated and added to the benefits of the upstream project. This benefit is rarely acknowledged where the downstream project is in a different jurisdiction: downstream riparians often oppose storage projects upstream for fear that the storage will be used for a consumptive use, especially irrigation The classic example is the interstate water dispute between Andhra Pradesh and Karnataka over the Upper Krishna power project located in Karnataka. The dam is operated at a level lower than that for which it was

	Impact in economic flows	Quantification & valuation
		designed and built (to the detriment of power generation at the dam) because Andhra Pradesh argued that the higher operating height would enable additional water withdrawals for irrigation in alleged contravention of the Dispute Tribunal award. The Supreme Court of India ruled in Andhra Pradesh's favour.
Downstream sediment control	positive	The trapping of sediments by a new upstream project may provide important life extension benefits to a downstream project. A good example is the World Bank financed 4300 MW Dasu project on the Indus river, which will provide life extension benefits to the downstream multi-purpose Tarbela project where high sediment loads are encroaching on the active storage.

Notes
(1) from the perspective of a renewable energy project appraisal
(2) see Bank Guidelines for valuation of GHG emissions

Box C3.1: Lost Forest Value: Hydro projects in Vietnam

The economic analysis of the Bank financed Trung Son project included as a cost the lost forest value. This had been estimated in a Strategic Environmental Assessment (SEA) for the National Hydropower Master Plan, which included all of Vietnam's remaining major hydro projects.

The economic loss of forest value should be itemized and included a project's economic costs. These losses were estimated by the Strategic Environmental Assessment as shown below: the estimates refer to the forest impacted in the Zone of Influence which is larger than the project (and reservoir inundated) area itself. The Trung Son project has the 6th highest value of timber losses among the 16 projects for which data are available. The entries are all as lifetime present values.

Forest value lost at Vietnam's remaining hydro projects

	Timber from natural forest	Timber from plantation forest	Non-timber forest products	Environ. ment services	Total		
	VND mill	VND mill	VND mill	VND mill	VND mill	$USm	$/kW
Bac Me	0	687	0	2,544	3,231	0.2	1
Huoi Quang	13,020	298	260	12,126	25,704	1.5	3
Lai Chau	34,654	0	692	29,341	64,687	3.8	3
Upper Kon Tum	36,597	0	400	17,400	54,397	3.2	12
Dak Mi 4	26,350	0	288	12,528	39,166	2.3	13
Srepok 4	4,209	3,461	46	11,745	19,461	1.1	16
Dak Mi 1	59,104	0	646	28,101	87,851	5.2	24
Song Bung 2	28,912	0	316	13,746	42,974	2.5	25
Hoi Xuan	21,704	0	452	21,108	43,265	2.5	27
Song Bung 5	21,409	0	234	10,179	31,822	1.9	31
Trung Son	64,056	5,248	1,334	78,269	148,907	8.8	34
Khe Bo	29,195	0	608	28,394	58,197	3.4	36
Song Bung 4	75,573	0	826	35,931	112,330	6.6	42
Ban Chat	90,141	2,289	1,800	84,800	179,031	10.5	48
Dong Nai 2	42,087	4,945	460	33,930	81,422	4.8	53
Hua Na	35,437	23,967	738	107,410	167,553	9.9	55

The value of forest lost to the Trung Son zone of influence is VND 148 billion ($US8.8million), or $34/kW. However, when included in the economic analysis, the economic rate of return decreased only by about 0.5%.

Source: World Bank, *Project Appraisal Document, Economic Analysis, Trung Son Hydro Project*, 2011.

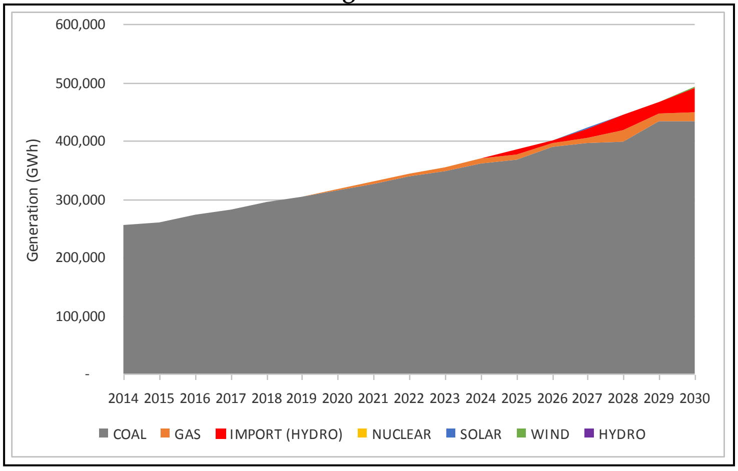
Box C3.2: Impact of carbon externalities on generation planning: South Africa.

Box C1.2 shows how the social cost of carbon can be included in cost comparisons of LCOE. However, to provide additional insights as to how these results would affect the capacity expansion plan over time, and how the cumulative impacts evolve, one needs to simulate the entire system in the context of increasing power demands. Using a linear programming model, the capacity expansion plans for South Africa and Bangladesh were simulated, first with no carbon price, followed by the three carbon price valuation scenarios of the World Bank Guidelines ($15, 30 and 50/ton CO_2 in 2015).

Including the costs of externalities in capacity expansion planning and dispatch models, and of GHG emissions and local air pollutants in particular, was first introduced in the US in the 1990s as part of Integrated Resource Planning (IRP) procedures demanded by State Regulators.[18] There is an extensive literature on such "environmental dispatch" models: [19] a term that captures damage costs (or externalities in general) is easily incorporated into the objective function of optimisation models.[20]

Figure A shows the baseline expansion plan for South Africa: it is dominated by coal, with only small amounts of imported hydro and gas, starting in 2020. Coal generation increases from the current level of 254 TWh to 433 TWh by 2030 (with corresponding increases in GHG emissions).

A. Generation mix: GHG damage costs not included



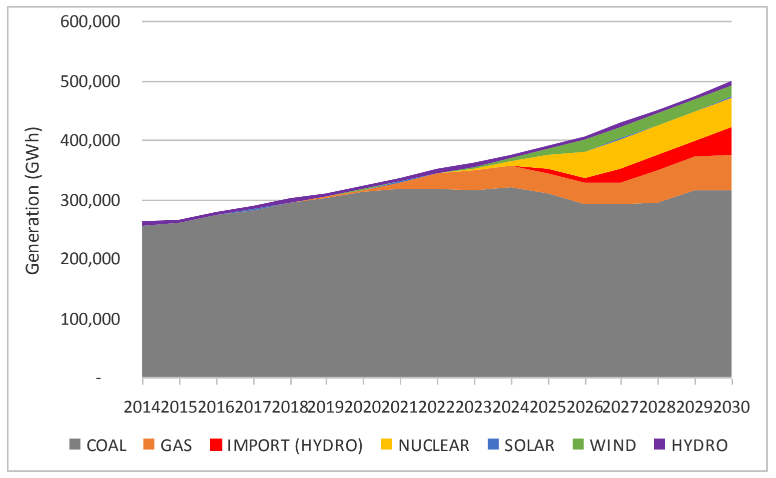
With a baseline CO_2 price of 30$/ton, coal generation starts to decline by 2020, with 2030 generation falling from the present 433 TWh to 314 GWh (Figure B).

18 For example WASP, EGEAS and STRATEGIST, used by the utilities of Pakistan & Indonesia, India (used by the Central Electricity Authority) and Vietnam (EVN), respectively, all have this capability.

19 Linear programming has a number of shortcomings for capacity expansion optimization, which leads to mixed-integer and dynamic programming formulations as the basis of most capacity expansion models used by utilities. However, the objective of this study was to demonstrate the principles involved, rather than provide a definitive study: application of more complex models would unlikely lead to significantly different results or much difference in the main conclusions.

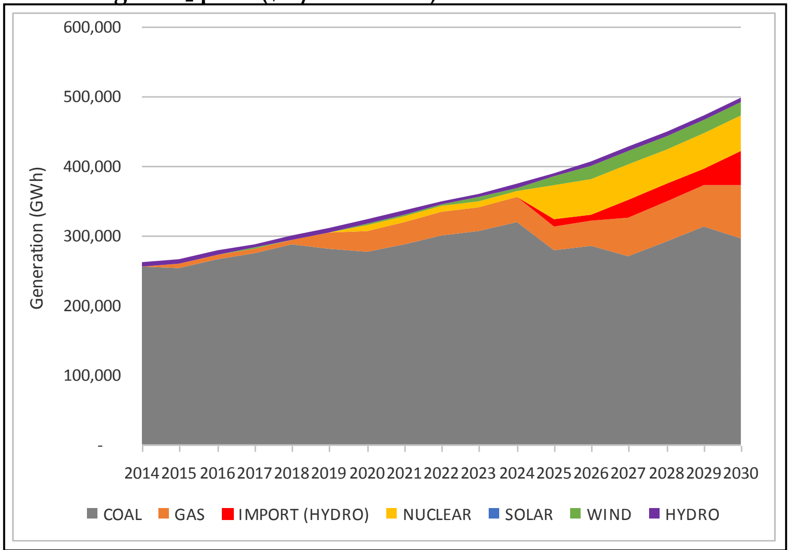
20 see, e.g., Hoog, D. T., and B. F. Hobbs. 1993. *A Nonlinear Programming Integrated Resource Planning Modeling Including Emissions, Value, and Regional Economic Effects*. Energy 18:1153-1160.

B. Generation mixwith baseline CO_2 price ($30/ton in 2015)



At the high carbon price ($50/ton CO_2 in 2015), gas comes into the generation mix already in the short term, and retired coal plants are replaced by gas and the other alternatives, rather than replaced with more coal projects – with coal generation by 2030 declining further to 290 TWh.

C. with high CO_2 price ($50/ton in 2015)



The conclusions of these system simulations were as follows:

- A business-as-usual (BAU) least-cost scenario without any carbon price would see coal as the dominant and growing base load option that will increase power sector CO_2 emissions by 70% in 2030 from the 2014 level.
- A low carbon price stabilizes coal generation with hydro and some gas, reducing cumulative (2014-2030) CO_2 emissions from 5.1 billion tons in the BAU scenario to less than 4.8 billion tons.
- Base and high carbon prices would lead to a reduction in the share of coal generation by 2030, bringing forward the entry of nuclear and gas/LNG.
- Increase in average system costs is significant compared to BAU for all carbon price scenarios, and more than doubles from $42/MWh to over $90/MWh in the high CO_2 price scenario.
- Abundance of cheap coal requires a starting CO_2 price of ~$50/t (high price scenario) for the generation mix to switch at a significant scale, bringing cumulative CO_2 emissions further down to around 4.4 billion tons.

Source: World Bank, 2015. *Assessing Impacts of Carbon Pricing Scenarios on the Economics of Power Generation Technologies: Case Studies in South Africa and Bangladesh*, May 13.

C4 DECISION-MAKING APPROACHES

BEYOND CBA

43. The traditional approach to power systems modelling (and to the related preparation of so-called "Master Plans"), and to the conventional approach to CBA, fall under a decision-making paradigm often described as "predict then act". The presumption is that given some set of assumptions about the future (load forecasts, international energy prices) one can identify an optimal investment plan to meet the stated objective, where optimality is defined as least economic cost (or in the case of a project appraisal, choose that alternative with the highest NPV >0). In a deterministic world, or one where assumptions about the future were not subject to large uncertainties, this approach performed well.

44. As levels of uncertainty increased, the results of a CBA were subjected to more detailed sensitivity analysis, whose purpose is to examine the relationship between a given assumption and the estimate of economic returns. The switching value identifies by how much a given input assumption can increase/decrease for the hurdle rate to be achieved. That provides satisfactory answers if there is agreement on the hurdle rate (in an economic analysis the discount rate), and for uncertainties that can be credibly identified. The main problem is that this looks just at one variable at a time.

45. In the late 1990s a new approach began to be used in CBA with the introduction of so-called Monte Carlo simulation, first used by the World Bank for a power sector project in the 1998 appraisal of the India Coal Mining Rehabilitation Project.[21] This approach argues that because many input variables are stochastic, the calculated value of ERR (NPV) is also stochastic: by repeating the CBA calculation many times (typically 1,000 to 10,000 times), drawing different values for input assumptions at each iteration, one generates a probability distribution for ERR. So now the decision criterion is not whether the best estimate of ERR is above the hurdle rate, but what is the probability of not meeting the hurdle rate (i.e. how much of the probability density function for ERR lies to the left of the hurdle rate). Technical Note **M7** sets out the issues in structuring such a Monte Carlo risk assessment:

- which variables should be treated as stochastic, and how to formulate plausible probability distributions for input variables.
- which variables are likely to be independent (for example, hydrology or wind speed variation, at least in the short- to medium term, are likely to be independent to variables linked to construction delays), and which variables are likely to be correlated (such as construction delays and construction costs).
- Software options.

46. Monte Carlo simulation can often provide useful additional information, but still suffers from several problems

- While the technique works well with variables that allow credible probability distributions to be formulated, it is unclear on what basis one assigns probabilities of future oil prices, or of the timing and magnitude of climate change impacts (say on the inflow hydrology of a hydro project).
- On what basis does one set the threshold of unacceptable probability – is a 30% or even a 50% chance of not meeting the hurdle rate still acceptable? Under the Bank's classical prescription of risk neutrality, the remaining variance (once risk mitigation measures are in place) is not considered, so if the expected value of ERR is above the

21 World Bank, *Staff Appraisal Report, Coal Sector Rehabilitation Project*, July 1997. Report 16473-IN

hurdle rate it would be acceptable even though the probability of returns falling below the hurdle rate is 49.9%.

- The technique also works well where all the variables are independent. But specifying covariances of correlated variables is often difficult.

ROBUST DECISION MAKING[22]

47. The "predict-then-act" paradigm that underpins traditional CBA becomes increasingly problematic as the degree of uncertainty increases. This is particularly the case for so-called "deep" uncertainty, characterised not just by disagreements over the likelihood of alternative futures, but also about how actions are related to consequences (different models yield different results, characteristic for example of the climate change debate), and by disagreements about objectives. The presumption in CBA is that all the stakeholders agree that decisions be made on the basis of NPV (i.e. benefits > costs) – yet even among those prepared to accept maximising NPV as the main objective, there may yet remain disagreement about the discount rate.

Figure C4.1: Traditional CBA: "predict then act"

48. The difficulties with this approach – say for power sector investment decisions in a fragile country like Afghanistan is obvious: for example, forecasting what will be the security situation in 5-10 years time is virtually impossible. The so-called *Robust Decision Making* approach turns this around, into an approach based on "agree on decisions" (Figure C4.2). This approach was originally proposed by the RAND corporation to inform policy choices under deep uncertainty and complexity.

Figure C4.2: Agree on decisions

49. In other words, rather than ask – "given a forecast about the future, what is the best investment decision (and tell us how sensitive is that decision to the assumed forecast)", RDM asks – "given a set of decisions (or strategies), which strategy is the most robust to an uncertain future, and what can we do to reduce vulnerability?" Computationally, RDM tests the performance of a set of alternative strategies for a very large number of alternative futures – and then asks which strategies are the most vulnerable, and which are the most robust, and then attempts to adapt the strategy to improve its robustness.

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22 Much of this summary is based on R. Lempert, *Managing Deep Uncertainties in Investment Decisions: Insights from a Maturing Field*. Presentation to the World Bank, April 2015.

Suggested Reading

Stéphane Hallegatte, Ankur Shah,Robert Lempert, Casey Brown and Stuart Gill, 2012. *Investment Decision Making Under Deep Uncertainty:Application to Climate Change*, World Bank Policy Research Working Paper 6193.

L. Bonzanigo and Nidhi Kalra, 2013, *Making Informed Investment Decisions in an Uncertain World: A Short Demonstration*, World Bank Policy Research Working Paper 6765. Compares a conventional benefit cost analysis of power sector options in Turkey with the additional insights provided by RDM.

DECISION-MAKING UNDER UNCERTINATY

50. As noted, the fundamental problem in making decisions under uncertainty is that forecasts of many key assumptions can be highly unreliable – well illustrated by the difficulties of forecasting world oil prices. Yet it is surprising how few investment decisions are taken in full recognition of the costs and benefits of making the *wrong* decision. Real options is one approach to this dilemma by recognising that there is value in flexibility – it may be better to build a project in stages, rather than in a single step, to hedge against the possibility that the second stage may not be required. So-called Decision Analysis is another, in which each option under consideration is "stress tested" against a range of alternative futures and the choice is made on the basis of which is the least vulnerable to the main uncertainties.

51. The basic concept of robustness is best illustrated by example. Suppose there is a choice between a hydro project and a gas project. If future gas prices are high, hydro would be the best choice; if gas prices are low, then gas is the best choice. So there is a cost associated with making the wrong forecast about oil prices: if you build the hydro project, but gas prices fall, you have needlessly invested in the (irreversible) decision to build a dam. Conversely, if you build the gas project and the price of gas soars, then you have needlessly incurred the high price of gas generation (given long lead times for hydro, one cannot quickly build a hydro project if gas prices were to rise). Thus, in the illustrative example of Table C4.1, if the future gas price is high, the indicated (least cost) choice is hydro. If the future gas price is low, gas is the indicated choice. The cost of the hydro project is fixed – whether the actual gas price is high or low, the cost of 100 is fixed.

Table C4.1: gas v. hydro: PV(cost) $USm

	future gas price	
	high	Low
Hydro	**100**	100
Gas	130	**80**

52. The costs of making the wrong decision (the so-called "regret") may considerable – these are defined by the off-diagonal entries in this table: if the gas price proves to be high, and one has invested in the gas project, then one has incurred a penalty of $30 million (because for the high future gas price, the best decision would have been hydro); on the other hand, if the oil price is low, and one invested in hydro, then one incurs a penalty of an extra $20 million.

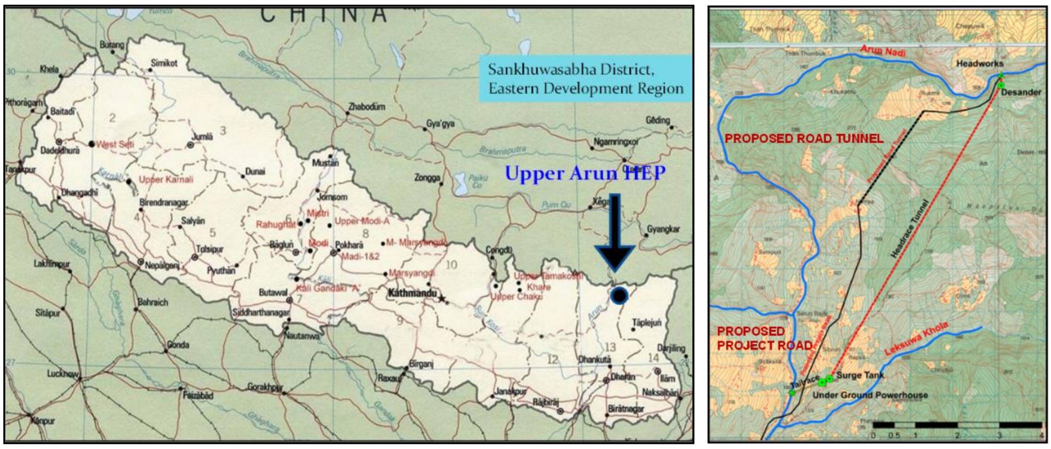
53. The question of which project you build now depends on risk aversion. If you are risk averse, you would build the project with the best *worst* result. The worst result for hydro is $100 million, the worst result for gas being $130 million. Therefore one should build the hydro project – which can be seen as a hedge against high oil prices. On the other hand, if you are risk neutral, you can make a decision based on expected value, but that requires an additional estimate of the prior probability assigned to high

or low gas prices – much more difficult. The following two examples demonstrate how decision-making under uncertainty can be improved.

Assessing climate risks on hydro-projects in Nepal.[23]

54. The Upper Arun Hydroelectric Project (UAHP), which is located on the upper reach of the Arun River, has been identified as one of the most attractive projects in eastern Nepal. The Nepal Electricity Authority (NEA) has given priority for the development of this project to augment the energy generation capability of the integrated Nepal Power System due to its relatively low cost of generation and availability of abundant firm energy. The 1991 feasibility study recommended an installed capacity of the daily peaking UAHP at 335 MW, with expected annual energy generation of 2,050 GWh.

Figure C4.3: The Upper Arun Hydro project[24]



Source: World Bank, *Programmatic Approach to impacts of climate risks on water, hydropower and dams*, May 2015

55. The objective of the analysis was to develop a methodology for assessing climate change risk, and to assess how possible alternative designs perform under different futures whose probability of occurrence, and impacts on inflow hydrology, are difficult to estimate. A methodology for climate risk screening was developed that makes connections between climate scenarios, project scale analyses, choices of decision variables, and economic evaluations of results at progressively more detailed levels, based in the results of a series of screening level analyses. A set of plausible climate scenarios for analysis was proposed, which were then translated into a bounded set hydrologic flow assessments, identifying system performance measures and decision variables for making design adjustments, consideration of other uncertain non-climate inputs, the calculation of impacts and "regrets" in multiple scenarios, and management actions to minimize unacceptable regrets. The decision tree is depicted in Figure C4.1. The modelling technique involves so-called scenario discovery (described in detail in Technical Note **M9**) that identifies patterns in the outcomes of a large number of possible futures.

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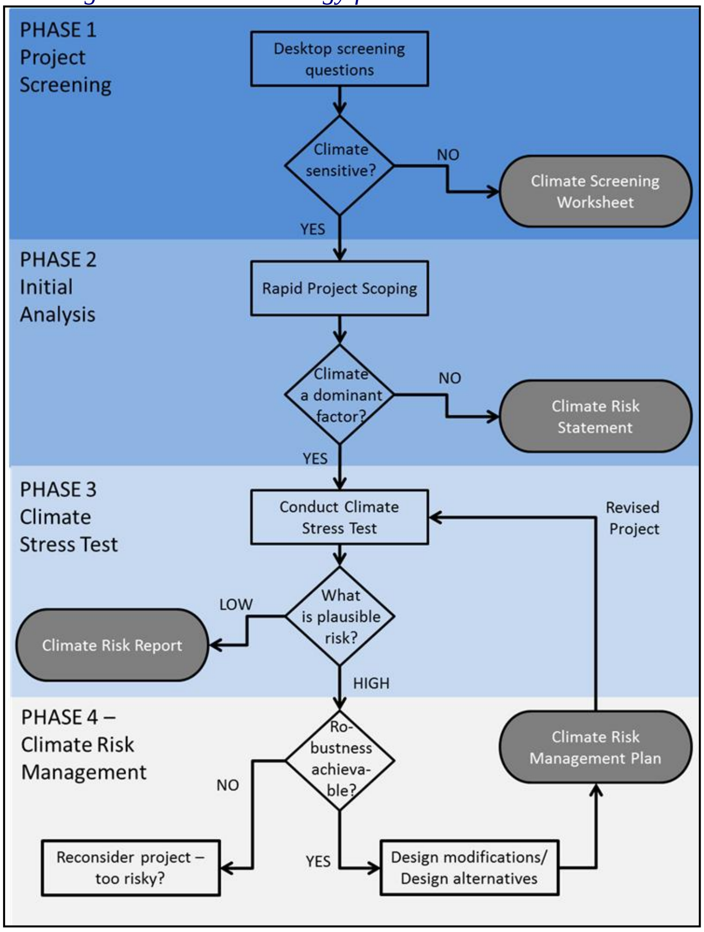
23 World Bank, *Programmatic Approach to Impacts of Climate Risks on Water, Hydropower and Dams*, May 2015

24 The Arun River, one of the main tributaries of the Saptakoshi River, rises at a glacier on the northern slope of Mount Xixabanma in Tibet. The river flows approximately 300 km eastward across the Tibetan Plateau at an elevation of about 4,000 m before crossing the Himalayas and plunging into Nepal where it flows in a narrow 30 to 60 m canyon at a very steep slope –where the proposed project is located. The dam site is located about 15 km downstream of the border with Tibet. The river has a catchment area of nearly 25,700 km^2 (only 400 km^2 of which is within Nepal) and an average run-off approximately 200 m^3/s. Very little development has so far occurred in the catchment area.

Figure C4.4: Methodology for climate risk assessment



Source: World Bank, *Programmatic Approach to impacts of climate risks on water, hydropower and dams*, May 2015

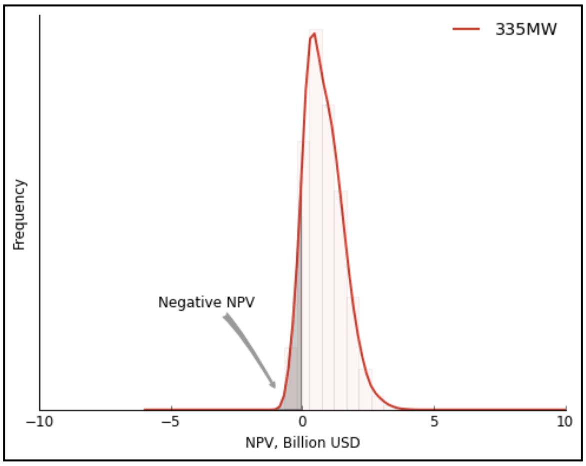
56. The climate change "stress test" then applies the climate change scenarios, hydrologic model, and uncertainty analysis for other non-climate variables to a model which captures the key characteristics of the Upper Arun site. The range of uncertainties evaluated in the stress test included the following:

- **Climate Change**: three scenarios were evaluated spanning a range of temperature changes from 0 to +6^{o}C, and from -40% to +40% precipitation.
- **Wholesale price of electricity**: values for wet season prices (Apr – Oct) of from \$0.045 to \$0.135/kWh were used, and for dry season prices (Nov-Mar) of from \$0.084 to \$0.252/kWh.
- **Discount rate**: 3 percent to 12 percent.
- **Estimated lifetime of plant**: a central value of 30 years was used, with low and high values of 15 and 36 years.
- **Plant load factor**: 0.60 to 0.90.
- **Capital costs (for a 335 MW plan)**: \$446 million to \$1,338 million (at 2013 prices).

57. The stress test was then designed to answer three questions:

- **How does the 335 MW UAHP perform across a wide range of plausible future conditions?** Figure C4.5 shows the performance of the investment options in 6,500 plausible futures, defined by combinations of the above variable inputs. The 335 MW project results in positive NPV in the vast majority of these futures. When only varying climate, the design's performance is positive in all futures. Nonetheless, when we vary all dimensions, there are some futures in which it has a negative NPV (grey shaded area). In general these results may imply that the project is quite robust to both climate and non-climate factors. However, the specific conditions that lead to negative NPVs can be identified and investigated further to better understand whether they are likely and whether they might be mitigated.

Figure C4.5: The NPV (Billion USD) of the 335MW UAHP in 6,500 futures.



Note: The grey shaded areas shows the futures where NPV is negative

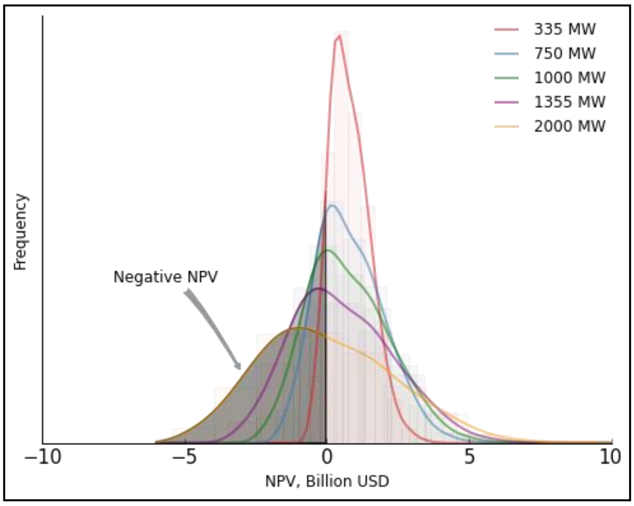
- **Under what conditions does the 335 MW design for the UAHP fail to meet the target of NPV>0?** The results for the 335 MW project revealed that its NPV is negative for a scenario when capital costs increase significantly and this increase in costs is not made up by increases in stream flow or the price of electricity. Specifically the problematic scenario is one where actual capital costs increase by 90% or more, exceeding $850million, **and t**he electricity price in the wet season does not increase by more than 80% (thus it is less than $0.082/kWh) **and p**recipitation does not increase by more than 10%, or decreases. The lifetime of the investment, the discount rate, the actual plant load factor, or changes in average temperature are less important in determining whether the 335 MW UAHP is economically sound. The results imply that increases in capital costs are the primary factor in the future success of the project.
- **Are those conditions sufficiently likely or unacceptable that other options should be considered?** The analysis of the 335 MW design of UAHP has revealed that the project is robust to changes in climate. It has also shown that in some conditions primarily related to increases in capital costs, the project's NPV can be negative. While these conditions do not appear highly likely, they should be carefully considered during project development. In addition, the analysis revealed that there might be potential for realizing additional hydropower generating potential at the UAHP site. Given that the climate risks were very low, and that much greater hydropower potential was available for larger design capacities, the analysis proceeded to Phase 4 to assess alternative designs. While typically Phase 4 (and adaptation generally) is considered a process by which climate risks are managed, instead here an opportunity is investigated.

58. The Phase 4 Risk Management phase analysis added to the Phase 3 "stress test" the following hydropower design capacities for evaluation, in addition to "base case" 335 MW: 750 MW, 1,000 MW, 1,355 MW, and 2,000 MW. The analysis then sought to answer a further three questions:

- **How do the different options perform across a wide range of plausible future conditions? What is the most robust of these investment options?** The climate change analysis showed that each of the designs were robust to the broad range of plausible climate changes, although the largest designs of 1,355 MW and 2,000

MW did show vulnerability to drier conditions. The other designs were clearly robust to climate change. These NPV results are shown in Figure C4.6 below. An additional metric for comparing different projects' performances, especially in terms of realizing opportunities, is the regret metric. In this study, we investigate which project performs better across futures, i.e., which option minimized the maximum regret (the relative lowest NPV) across the 6,500 futures. The option that minimizes the maximum regret across these futures is the 1,000 MW design dam. The results imply that the 1,000 MW design is best able to take advantage of opportunities without suffering too much in other futures. Thus there is a potential trade-off between the design that performs near the best and that which is highly unlikely to have a negative NPV (the 335 MW design). A further step in the analysis is to carefully evaluate the scenarios under which the 1,000 MW design does poorly and consider whether those scenarios are likely and whether then could be mitigated. This scenario is identified below. The result of such an analysis would provide the confidence to conclude that the 1,000 MW design is the best for UAHP.

Figure C4.6: Distribution of NPV ($billion) for UAHP at various project sizes



- **Under what conditions does the 1,000 MW UAHP fail to meet our target of NPV>0?** Using the scenario discovery technique described in Technical Note M9, the common dimensions of the futures where investments do not perform well were identified. The 1,000 MW dam is vulnerable to the following conditions:
  - The electricity price in the wet season is less than $0.092/kWh, **and**
  - Actual capital costs increase by 50% (or more)

  These two conditions need to occur at the same time for the 1,000 MW project to show a negative NPV. Again, the lifetime of the investment, the discount rate, the actual plant load factor, and changes in average temperature and precipitation are less important in determining whether the projects are economically sound. For this investment then, changes in climate are not amongst the main conditions that affect the economic performance of the dam. Thus electricity prices and capital costs again emerge as key considerations for the design of UAHP.

- **Are those conditions sufficiently likely or unacceptable that we should at least consider other options? Or, can the policy makers decide on the preferred investments based on this information?** Before deciding to invest in the 1,000 MW, the Government of Nepal (GoN) should carefully assess whether the two conditions are likely to happen together. The electricity price and an increase the capital costs, although uncertain, to a certain extent fall under the control of the decision makers. In the case of the electricity price, Government and investors may negotiate to make sure the price does not fall below the threshold that influences the vulnerability of the investment. Power purchasing agreements then are crucial for the success of hydropower investments in the Upper Arun. However, the electricity prices required to avoid vulnerability are much higher than the current negotiated tariff for national markets – so it may be difficult to find an agreement on this variable. Nevertheless, the Government could move away from a national focus and negotiate wet season exports to India.

59. In any event, the Government should carefully assess the conditions that lead to implementation delays that are one of the main reasons for capital cost overruns: 90% of hydropower projects in Nepal overshoot their initial cost estimates. NEA and other regional experts should support the Government in a discussion of the plausibility of incurring in 50% higher costs than initially estimated.

60. These risks and their plausibility or acceptability need to be considered by decision makers and they themselves need to make the final choice. The policy-makers themselves will in the end make the call of whether the presented risks are sufficiently acceptable to justify the investment. This is precisely the advantage of DMU approaches: the decision is back in the policy-makers hands, and presented in as a transparent way as possible. These types of analysis can help them make informed choices, even when they cannot have confidence about what the future will bring.

Setting renewable energy targets in Croatia[25]

61. The question posed by the Government of Croatia was how to set a target for renewable energy. While they accepted that the optimal amount of renewable energy is given by the intersection of the supply curve for renewable energy with the avoided social cost of thermal generation, that calculation is subject to a wide range of potential uncertainties about the evolution of capital costs for renewable energy, the level of international energy prices, and what technology would renewable energy displace. In other words, different assumptions would lead to a different decision.

62. Table C4.2 shows the results of such a scenario analysis of RE targets under three sets of input assumptions (each represented by a column in the table):

- *Unfavourable assumptions (for renewables).* Higher than expected capital costs for wind turbines, lower valuations of local damage costs, and avoided social costs based on combined-cycle gas turbines (CCGTs) (that have the lowest emissions of local air pollutants per kilowatt-hour generated, and hence low benefits derived from their avoidance by renewable energy).
- *Expected assumptions*. As presently seen by the government as the most likely.
- *Favourable assumptions (for renewables)*. Low capital costs for wind turbines, high valuations of local environmental damage costs, and avoided social costs based on coal.

63. The result is a wide range of potential targets, ranging from 37 MW to 1,337 MW. The range is so large because of the high uncertainty in many of the input assumptions, such as the damage cost of thermal generation (which varies by a factor of 4.5). Given such wide ranges in the value of the target, how should one proceed?

25 This example is extracted from Meier, P., M. Vagliasindi, and M. Imran, 2015. *Design and Sustainability of Renewable Energy Incentives: An Economic Analysis*, World Bank, Directions in Development; and Frontier Economics. 2003. *Cost-Benefit Analysis for Renewable Energy in Croatia*. Report to World Bank, Washington, DC.

Table C4.2: Economically optimal quantity of renewables

		Unfavourable Assumptions (for Renewables)	**Expected (Most Likely Assumptions)**	Favourable Assumptions (for Renewables)
Local externality value	€ cents/kWh	0.35	**1**	1.6
Wind turbine capital costs	€/kW	675	**600**	525
Technology replaced		Gas CCCT	**Gas CCCT+coal**	Coal
Net benefits, 2010	€ million	4.5	**13.5**	63
2010 target	GWh	175	**1,070**	3,340
2010 target	MW	37	**317**	1,335

Source: Frontier Economics. 2003. *Cost-Benefit Analysis for Renewable Energy in Croatia*. Report to World Bank, Washington, DC
Note: CCCT = combined-cycle combustion turbine.

64. Such ranges in uncertainty exist in many planning problems, and one approach to making a decision is to ask about the *robustness* of the decision. Suppose we choose the 317 MW target based on an assessment of what is most likely, and make investments to reach that target: renewables replace a mix of gas combined-cycle combustion turbine (CCCT) and coal, and wind turbine capital costs fall to €600/kW, which brings about estimated annual economic benefits of €13.5 million.

65. But suppose that having settled on and built the 317 MW target, the future brings *unfavourable* conditions—wind replaces only gas CCCT, and capital costs fall to only €675/kW. What then are the net benefits? And what are the net benefits of the more *favourable* assumptions? Indeed, for the three scenarios portrayed above, there are nine combinations of assumptions and futures.

66. The various outcomes of this analysis, with three choices and three actual outcomes, can be displayed in a 3 x 3 matrix, as shown in Table C4.3. The entries in columns [1], [2], and [3] represent the net benefits that correspond to each choice (represented by the rows). For example, if we choose the 317 MW target, but the actual outcome is unfavourable, then there is a net loss of €4.1 million, or if we choose the 1,334 MW target, and the actual outcome is indeed favourable, there is a net benefit of €63.1 million, and so on.

Table C4.3: Payoff matrix (net benefits in 2010, in € million)

		Actual Outcome			**Decision Criterion**	
		Unfavourable	Expected	Favourable	Risk Neutral [Expected Value]	Risk Averse [Mini-Max]
		[1]	[2]	[3]	[4]	[5]
Probability of outcome>		33.3%	33.3%	33.3%		
Target MW	Assumption					
37	Unfavourable	4.5	6.7	10	7	4.5
317	**Expected**	**-4.1**	**13.5**	**29.9**	**13.1**	**-4**
1,334	Favourable	-7.4	13.1	63.1	22.9	-7.4

Source: Frontier Economics. 2003. *Cost-Benefit Analysis for Renewable Energy in Croatia*. Report to World Bank, Washington, DC

67. How one makes a decision on the basis of these estimates of costs and benefits then depends upon the:

- Judgments about the probability of different outcomes
- The decision maker's risk aversion

68. Suppose all three outcomes were thought to be equally likely (that is, with a probability of 33.3 percent, as in table C4.3). Then we may compute the expected value of each of the three alternative decisions, as shown in column [4]. For example, the expected value, E{ }, for the 317 MW target is:

E{expected assumptions} = *-4.1 x 0.333* + *13.5 x 0.333* + *29.9 x 0.333* = €13.1 million.

69. Similar calculations result in optimistic and pessimistic expected values. If the government is risk neutral, then the target should be the optimistic one of 1,334 MW because it has the highest expected value (€22.9 million).

70. On the other hand, if the government is risk averse, then an alternative criterion is the *Mini-Max* decision rule, which calls for choosing the option that has the best *worst* outcome. Column [5] of table C4.3 shows the worst outcome for each target; based on this criterion the 37 MW target is optimal, since it has the *best* worst outcome of +€4.5 million.

71. The assumptions favourable to renewable energy are based on coal being the fossil fuel being displaced, but given the government's policy not to build a new coal plant, a lower probability may be assigned to this scenario. For example, if the favourable scenario (with coal as the avoided cost) is given only a 5 percent chance of occurring, then the payoff matrix will appear as shown in Table C4.4.

Table C4.4: Revised payoff matrix: future coal plant unlikely (€ million)

		Actual Outcome			**Decision Criterion**	
		Unfavourable	Expected	Favourable	Risk Neutral [Expected Value]	Risk Averse [Mini-Max]
Probability of outcome		30%	65%	5%		
Target (MW)	Assumption					
37	Unfavourable	4.5	6.7	10	6.2	4.5
317	Expected	-4.1	13.5	29.9	9.0	-4.1
1,334	Favourable	-7.4	13.1	63.1	9.5	-7.4

Source: Frontier Economics. 2003. *Cost-Benefit Analysis for Renewable Energy in Croatia*. Report to World Bank, Washington, DC

72. Now the gain in expected value by choosing the 1,337 MW target over the mid-level 317 MW target (from €9.0 to €9.5million) is quite small, particularly when faced with a possible €7.4 million loss if the unfavourable future becomes true.

73. Such analysis may well require many additional assumptions, but it has the advantage that it forces decision makers to be explicit about their risk preferences, and makes the connection between assumptions and the robustness of decisions more transparent.

C5 RISK ASSESSMENT

74. Risks may be classified into three main types:

- Those for which probability density functions can reasonably be defined (such as hydrology variations in the case of hydro projects, or wind variability in the case of wind farms). A number of studies have assessed the probabilities of construction cost overruns and construction cost delays.
- Those for which there exists little or no basis for the assignment of probabilities (such as the timing and occurrence of oil market disruptions of the type that occurred in 1973 or during the Gulf War).
- Ignorance, for which there is no knowledge of the possible outcomes, much less a basis for assigning a probability distribution.

75. The risks in the first category are typically (and usefully) treated in a quantitative risk assessment using so-called Monte Carlo simulation (see Technical Note **M7**). Such a simulation may also include some variables in the second category, though the burden on the economist to construct credible probability distributions is significantly greater (for example in the case of alternative fuel price scenarios, how to assign probabilities to the three forecasts in the IEA World Energy Outlook). Therefore a Monte Carlo simulation is frequently accompanied by a scenario analysis.

THE ASYMMETRY OF RISKS

76. Mathur[26] discusses the importance of distinguishing between *pure risk* and *downside risk.* Pure risk corresponds roughly to the variance of a probability distribution, whose implication is that favourable as well as adverse events may occur. However "downside risk" refers to events for which there is no corresponding "upside" event (which is linked to the popular interpretation of risk as adverse events).

77. Downside risk is an important – though little recognized -- issue for renewable energy generation projects. Notwithstanding that nature's inputs – rainfall, solar insolation, wind – have well-defined probability distributions, offering the prospect of some number of high wind or precipitation years as well as low wind or precipitation years, the moment a physical structure is built to exploit that resource, the ability to profit from favourable events becomes constrained (unless the structure is built to an infinite size). Run-of-river small hydro is the classic example: flows greater than the design flow are simply passed over the weir, while flows lower than the design flow cause immediate reduction in output. Thus the actual (chance) distribution of annual energy generation will be truncated on the upside, but fully exposed on the downside. Large hydro projects with significant annual or monthly carryover storage capture more of the potential upside.

RISK V RETURN

78. The relationship of risk and return is an important issue for energy policy, tariff design, and project appraisal. The relationship is fundamental to private sector involvement in an energy project, because the required rate of return will depend on the investors' perception of risk – which may itself vary across the stages of project development. For example, an investor in a geothermal work area, who may bear the

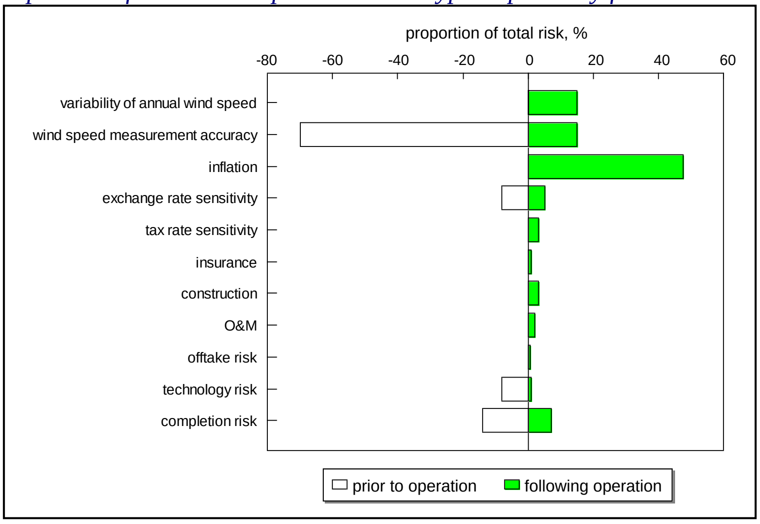
26 Mathur, S. C., 1994. *Risk and Uncertainty: Selection Criteria for Projects Offering Net Positive Domestic Benefits*, Global Environment Coordination Division, Environment Department, World Bank, Washington, DC. This distinction was originally formulated by by J. R. Anderson, and J. C. Quiggin, 1990. *Uncertainty in Project Appraisal*, World Bank Conference on Development Economics, Washington, DC

cost of geothermal exploration drilling entirely from equity (since lenders are reluctant to provide debt at this stage of development), may require returns on that high risk equity typically in the range of 22-25%. Subsequent injections of equity during delineation drilling may demand a lower equity return of 17-20%, while once the steam resource is proven, and just the power plant remains to be developed, any remaining equity requirement might be priced at 14-16%.[27] Box C5.1 provides another illustration of changing risk perceptions as a project progresses.

Box C5.1: Changing risk perceptions in a wind project

The Garrad Hassan study of risk in wind farm financing provides an interesting perspective on the perceptions of lenders about the relative importance of these various risks (in a European project), and how risk change as a project progresses. As shown below, prior to operation, the measurement accuracy of wind speed is perceived as the major risk; following operation, inflation is the biggest concern.

Proportion of total risk as perceived in a typical privately financed wind-farm



Source: Garrad Hassan, 1999. *Understanding the Risks of Financing Wind Farms*. Bristol, UK, p.7.

79. The 2008 global financial crisis highlighted the dangers of reliance on the Gaussian world of portfolio analysis, where risks are symmetrical, "fat tails" ignored, and risk vanishes in diversification.[28] Portfolio risk diversification may have relevance in some Bank renewable energy projects characterised by many small subprojects, but the proposition that the risk profile of a renewable energy project involving major civil works structures (the typical hydropower/flood control/irrigation project), or a large CSP project whose capital costs may exceed a billion dollars, can be diversified away by symmetrical risks in a portfolio of other renewable energy sector projects seems very doubtful. Even if it were argued that the relevant basis for risk diversification is the entire country energy portfolio, there are very large differences in risk exposure and project size between, say, a distribution system rehabilitation project and a CSP project.

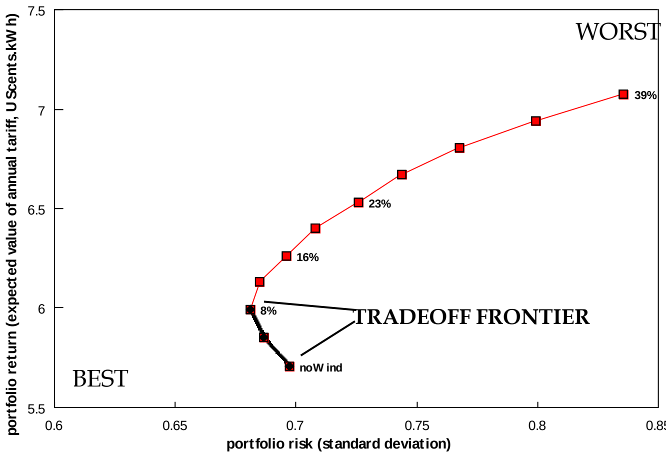
80. One approach is to evaluate the tradeoffs between economic returns and risk using mean-variance portfolio theory (see Technical Note **M8**), which examines the trade-off between expected economic returns (say measured as the levelised cost of energy) against risk (standard deviation of returns). In the example below, the expected value of annual tariff is plotted against portfolio risk for a set of sample portfolio of

[27] World Bank and ADB, 2015. *Unlocking Indonesia's Geothermal Potential*, May 2015.

[28] see, e.g., Taleeb, N. 2007. *The Black Swan: the Impact of the Highly Improbable*, Penguin Books, London and E. Michel-Kerhjan and P. Slovic, Editors, 2010. *The Irrational Economist: Making Decisions in a Dangerous World*, Perseus Books, New York

wind+diesel combinations (Cap Verde) ranging from no wind to 39% of wind. The relevant trade-off frontier is the black line,[29] between no wind (lowest (best) cost, higher risk) and 8% wind as the point of least risk. Only the options (generation mix scenarios) that lie on this part of the curve are of interest – the others (i.e. those with more than 8% of wind) all have both costs (tariffs) that are higher and risk that is higher.

Figure C5.1: Risk v. Return of generation portfolios in Cap Verde



SCENARIO ANALYSIS

81. In the real world it would be very unusual for just a single assumption to prove incorrect: in most instances several of the forecast variables will deviate from the expectations at appraisal. In the most unfavourable future, several variables may all be at values that diminish the expected economic returns. And in a favourable future, several variables may be at values that increase the economic returns.

82. One way of dealing with such uncertainty is to postulate a range of typical scenarios: one that represents a pessimistic case, with several variables at unfavourable value, one that represents the conditions estimated at appraisal to be most likely, and one that represents a favourable future. In the context of a renewable energy planning or investment decision, the pessimistic case might be one where fossil fuel prices fall, and investment costs are higher than expected; the optimistic case would be one where fossil prices increase, and future costs of renewable energy technology falls.

83. Such an analysis highlights provides an assessment of how a project would fare under unfavourable outcomes – along the lines of recent "stress testing" of banks to evaluate how they would perform under unforeseen circumstances. Box C5.2 shows a recent example of such a scenario analysis of the Kali Gandaki hydro rehabilitation project.

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29 The trade-off frontier is the set of so-called *non-dominated* portfolios, i.e. the ones "closest" to the origin (low cost *and* low risk). See Technical Note **M6**.

Box C5.2: Scenario Analysis: Kali Gandaki Hydro Rehabilitation

In a scenario assessment, we define plausible best and worst cases across the range of variables identified in the risk assessment. By plausible worst case we mean a set of unfavourable outcomes as have been experienced at many hydro projects – but excluding catastrophic *force majeure* events (such as earthquakes or war damage). Similarly the plausible best case reflects events – such as higher than expected oil prices and higher efficiency increment - that fall into the range of plausible scenarios. These scenarios are summarised in the table below: the values are based on the discussion of risk factors in the risk assessment.

Scenario definition

	Plausible worst case	Baseline	Plausible best case
Climate change impact	20% decrease in generation by 2035	No change	No change
Efficiency increment	9.15 GWh	18.3 GWh	27.5GWh
Construction delays	1-year delay	None	None
Maintenance outage hours	280	270	250
construction cost over (under) run	15% increase	None	5% decrease
World oil price (1)	Fall in 2020 oil price to $95/bbl .	125 $/bbl by 2020 (IEA forecast)	Increasing to 150$/bbl by 2030
ERR (2)	**13.1%**	**23.2%**	**33.5%**

(1) as per 2011 IEA World Energy Outlook
(2) excluding avoided thermal generation externality benefits

Source: World Bank, 2013: *Kali Gandaki Hydropower Rehabilitation Project*, Project Appraisal Document.

84. However, the approach offers more important insights than merely identifying the impacts of an unfavourable future: it can offer key insights into how the proposed project performs against alternatives – whose performance may also vary as a function of unknown futures. A renewable energy project may be the correct choice against gas CCGT if, as expected, gas prices remain unchanged or if they rise: but if gas prices fall (as has happened in North America), then CCGT would be the better choice. In other words, what is of interest is what are the consequences of making the wrong choice.

85. A robust investment decision is one that is relatively insensitive to uncertain futures. And it may well be the case that the (best) project with the lowest expected value under baseline assumptions proves to be more sensitive to assumptions than a second ranked alternative, which may have lower expected value but which is insensitive to uncertainty – and is more robust.

Box C5.3: Risk v. return in renewable energy tariff-setting

The reality of the risk-reward relationship is rarely confronted in the design of renewable energy feed-in tariffs that are based on estimated production costs. The presumption is that such a FIT should be set at a level that covers costs plus a "reasonable" rate of return: but the presumption that the risks of all projects in a particular technology category are equal is doubtful. Nor is it clear that Governments are in a position to accurately assess what are the relevant production costs – even when extensive public consultations are provided (as in the Philippines), where developers and DoE each proposed their own assumptions for key variables, the final result will rarely please anyone. Worse, in order to avoid the possibility of "windfall" profits, such tariffs are often finely differentiated by size of project, or (as in Germany) by the estimated annual capacity factor. Arbitrary bonuses for characteristics deemed to have special value to Government, and arbitrary rates of "degression" (supposedly to incentivise early investment), further complicate the tariff.

Such tariff structures should not be encouraged by the Bank. If tariffs are finely differentiated by capacity factor, the result is to incentivise projects in areas of poor resource. In Germany they were introduced expressly as a measure to share the burden of wind integration among regions (since most of the capacity was located in the Northwest where wind regimes are the best). But that is a luxury of the rich: in developing countries, where OPSPQ insists that the development outcome has primacy, tariffs should be structured to encourage development of the least cost renewable energy resource.

These problems are of course avoided when feed-in tariffs are set on the basis of benefits - as in the case of the new Indonesia geothermal tariff, the Vietnam renewable energy tariff, or the Sri Lanka renewable energy tariff (1997-2010).

Other suggested reading

World Bank and ADB, 2014. *Unlocking Indonesia's Geothermal Potential*. Provides a detailed discussion of the tariff implications of equity financing of risky geothermal exploration, and the difficulties of setting production-cost based FITs.

Auerbuch, S. 2000. *Getting it Right: the Real Cost Impacts of a Renewables Portfolio Standard,* Public Utilities Fortnightly, February 15. Auerbuch's first paper on the subject of treating risk and uncertainty in power sector generation portfolios in a manner similar to financial portfolios (see also Technical Note **M8**).

Best practice recommendations 2: Risk assessment

(1) In a project appraisal, the first task is to make sure that significant risks as identified in the PAD Risk Matrix have been adequately examined in the economic risk assessment. It is not always possible for these to be *quantified* and their impact on the economic returns evaluated – but in such cases where such quantification is straight forward (as for example in the case of high risk of construction delays), inclusion in the economic risk assessment is mandatory. Indeed, such an analysis will assist in the identification of any residual risks (after mitigation) as may remain.

(2) Whether a formal Monte Carlo assessment, scenario analysis or one of the techniques discussed in Technical Note C4 are required depends on the scale of the project. Certainly where any single investment is greater than $25 million a quantitative risk assessment is desirable, but even for smaller projects (and emergency power projects) at the very least a scenario analysis should examine the consequences of unfavourable futures (as illustrated in the example of the Tarakhil diesel station in Afghanistan).[30]

[30] For details, see Main Guidance Document.

C6 DISTRIBUTIONAL ANALYSIS

86. The purpose of a distributional analysis is to demonstrate how a proposed policy, or a proposed project, affects the various stakeholders, and how the total net economic benefits are shared – which in effect requires a reconciliation of economic and financial flows. In a CBA, transfer payments are netted out, and do not appear in the table of economic flows that is focused on the question of *net* economic benefits to the country. Indeed, whether the net economic benefits can be realised at all may well depend upon the credibility of the recovery of incremental costs – which are the *financial* transactions necessary to realise the economic benefits. The OPSPQ guidelines are quite clear that an assessment of the financial sustainability of projects must be demonstrated.

87. Who pays for these costs is often the central question, and one that our review of recent renewable energy project appraisals shows is rarely clear – in particular what proportion of the incremental costs is bought down by concessional financing, and what remains to be recovered from Government and consumers. The stark reality is that highly concessional funds like CTF are in short supply, and even when blended in with IDA and IBRD, in the case of high cost renewables such as CSP a significant portion of the incremental cost passes to consumers (or Government). When the implicit costs of avoided carbon are calculated, these prove to be not just a multiple of what developed country entities are paying for carbon on global carbon markets, but even a multiple of the valuation now proposed by the World Bank for the global social cost of carbon.

88. How to structure a distributional analysis is best shown by example, of which we here present two. The first example relates to a policy question: should the Government of Indonesia issue a feed-in tariff for rooftop PV in Jakarta, and for wind in Sulawesi. The second example shows how the distributional analysis can easily be incorporated in a standard economic and financial analysis.

THE MATRIX FORMAT FOR DISTRIBUTIONAL ANALYSIS

89. This example illustrates one approach to distributional analysis for a proposed renewable energy policy – namely whether Indonesia should issue a feed-in tariff to support a rooftop solar PV program in Jakarta. The recommended approach to answer such a question rests on two main inputs: what are the costs of a rooftop solar PV program, and what are the benefits. The first question was relatively straight-forward: based on current module prices, assembly process, and other factors that determine the cost of delivering such installations, it was determined that a feed-in tariff based on production costs would need to be around 25USc/kWh.[31]

90. In 2014, Indonesia adopted the principle that feed-in tariffs (and ceiling tariffs where larger projects are competitively tendered) should be based on benefits. In the case of Rooftop PV, the benefits were assessed as shown in Table C6.1.[32] Column [2] multiplies the USc/kWh by the estimated energy contribution in 2024: thus PLN – the Indonesian power utility – would avoid $41.2 million/year in gas costs.

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31 The proposed tariff was graduated according to size of installation, ranging from 20 USc/kWh for the largest 1MW to 30USc/kWh for small household scale systems. A range of other issues was also discussed in the report (such as net or gross metering) these are details that can be viewed in the report.

32 The methodology was developed in 2014: see World Bank and ADB, *Unlocking Indonesia's Geothermal Potential*, May 2015. The example is extracted from the subsequent report on PV and wind: see ADB, 2015. *Development of Wind Power and Solar Rooftop PV Market in Indonesia*. Jakarta, Indonesia.

Table C6.1: Benefits of rooftop PV (in Jakarta)

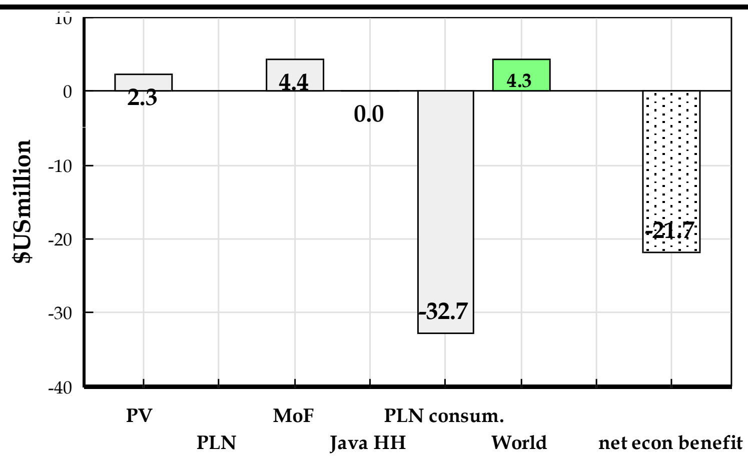
Benefit category	USc/kWh	2024 $USm	
	[1]	[2]	[3]
Avoided fixed cost	0.00	0.00	No capacity benefit claimed
Avoided variable cost	13.45	41.24	On Java, the marginal thermal generation is open cycle combustion turbine. This variable cost of generation is based on a levelised import parity price
GHG emission premium	1.40	4.29	Using IPCC defaults for emission factors and heat rates, and a carbon valuation of $30/ton CO_2
local environmental premium	0.00	0.00	Not considered significant for gas
local economic development	0.00	0.00	None, since by agreement with the Government, this only applies to remote eastern Islands
Energy security premium	0.17	0.52	
System integration costs	0.00	0.00	None, see Table 3.5
Avoided T&D losses	0.90	2.76	This reflects the avoidance of T&D losses (but not CAPEX) involved in bringing thermal energy from the generation site to the Jakarta urban centre
total benefit/ceiling	15.92	48.80	

Source: ADB, 2015. *Development of Wind Power and Solar Rooftop PV Market in Indonesia*. Jakarta, Indonesia.

91. The impact of the proposed FIT on the stakeholders can then be displayed as shown in Table C6.2. The columns in this table represent the stakeholders (PLN, the Ministry of Finance, PLN's consumers, etc.), the rows represent the components of benefits and the producer transactions. The bottom row [15] is simply the sum of the entries in each column and represents the net impact on each stakeholder.

Table C6.2: The matrix format for distributional analysis

		PV	PLN	MoF	Java HH	PLN consum.	World		net econ benefit	FIT USc /kWh
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
[1]	**Benefits**									
[2]	Avoided fixed cost								0.0	
[3]	avoided variable cost		41.2						41.2	*13.45*
[4]	GHG emission premium						4.3		4.3	*1.40*
[5]	local environmental premium				0.0				0.0	*0.00*
[6]	local economic development				0.0				0.0	*0.00*
[7]	energy security premium			0.5					0.5	*0.17*
[8]	Integration costs		0.0						0.0	*0.00*
[9]	avoided transmission losses		2.8						2.8	*0.90*
[10]	**Producer tansactions**								0.0	
[11]	FIT revenue	76.7	-76.7						0.0	
[12]	Production cost	-70.5							-70.5	
[13]	Taxes and duties	-3.8		3.8					0.0	
[14]	incremental cost recovery		32.7			-32.7			0.0	
[15]	Net impact	2.3	0.0	4.4	0.0	-32.7	4.3	0.0	-21.7	15.9



Source: ADB, 2015. *Development of Wind Power and Solar Rooftop PV Market in Indonesia*. Jakarta, Indonesia.

92. Row[14] passes through the incremental financial costs of PLN either to MoF (the situation in the past, under which MoF provided whatever was necessary to cover the gap between revenue requirements and customer revenue), or as shown here to the consumer (under the new cost-reflective tariff, under which purchases of renewable energy are a pass-through), so that the net impact of the FIT on PLN is zero: as a transfer payment, this does not therefore appear in column [8] that represents the net *economic* benefits.

93. Thus, in column [2], PLN benefits from $41.2 in avoided fuel costs (row[3]), and $2.8 million in avoided T&D losses – but the cost of the FIT (at the assumed 25 USc/kWh is $76.7 million – for a net loss of $32.7 million – which here is shown as being passed onto consumers (as a surcharge on the tariff). So despite the GHG benefits ($4.3 million) - assigned to the global community – the net loss economic benefit is -$21.7 million. To the extent that these costs are *not* passed to consumers, but absorbed by MoF under the established subsidy mechanism, then the additional subsidy requirement on MoF is $32.7million.

94. To make a Jakarta Rooftop program economic would require a societal valuation of avoided carbon of 143$/ton CO_2, which is significantly above the generally accepted social cost of carbon of $30/ton CO_2, as also used in the geothermal tariff. From the perspective of the *consumer*, who sees the total financial incremental cost to PLN passed onto the consumer bill, the effective cost is $179/ton CO_2 .

Table C6.3: Avoided cost of carbon

		society	consumer
emission factor	Kg/kWh	0.594	0.594
avoided thermal generation	GWh	306.6	306.6
tons GHG avoided/year	tons	182,120	182,120
incremental cost	$USm	26.0	32.7
avoided cost of carbon	$/ton	143	179

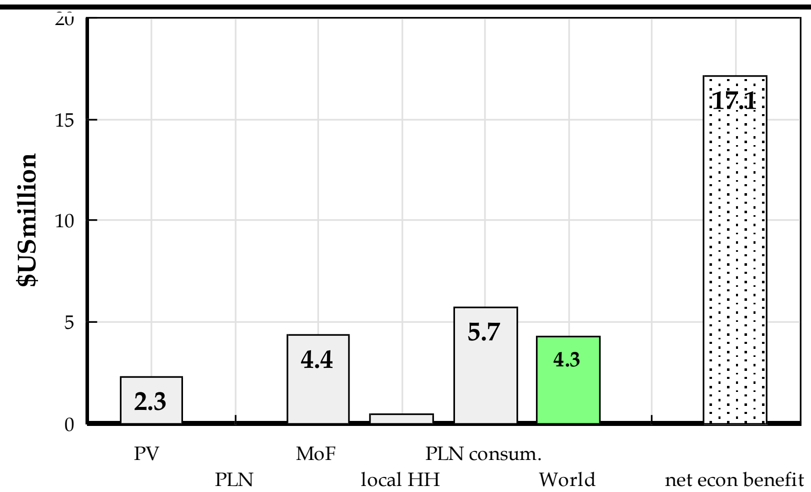
Source: ADB, 2015. *Development of Wind Power and Solar Rooftop PV Market in Indonesia*. Jakarta, Indonesia.

95. However, though PV is uneconomic where it replaces gas, PV is highly economic when it replaces oil. A 25USc/kWh production cost based FIT for PV where the cost of oil-based generation (high speed diesel and marine fuel oil) is 26-30 USc/kWh, results in financial cost *savings* to PLN: as shown in Table C6.4, for such application of PV, there is a net economic benefit of $17.1m per year (in 2024).

96. Indeed, this is the classic "win-win" strategy – as is clear from the diagram, *all* stakeholders experience a net benefit. Here the assumption is that the *savings* to PLN are passed to consumers in the form of *lower* tariffs (which would indeed be the consequence of a cost-reflective tariff). In effect, this is an option under which carbon emissions are achieved at *no cost* to the Indonesian consumer: another example of a win-win result for a renewable energy investment.

Table C6.4: PV on eastern islands where it replaces oil

		PV	PLN	MoF	local HH	PLN consum.	World		net econ benefit	FIT USc /kWh
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
[1]	**Benefits**									
[2]	Avoided fixed cost								0.0	
[3]	avoided variable cost		82.4						82.4	*26.86*
[4]	GHG emission premium						4.3		4.3	*1.40*
[5]	local environmental premium				0.4				0.4	*0.12*
[6]	local economic development				0.1				0.1	*0.03*
[7]	energy security premium			0.5					0.5	*0.17*
[8]	Integration costs		0.0						0.0	*0.00*
[9]	avoided transmission losses		0.0						0.0	*0.00*
[10]	**Producer tansactions**								0.0	
[11]	FIT revenue	76.7	-76.7						0.0	
[12]	Production cost	-70.5							-70.5	
[13]	Taxes and duties	-3.8		3.8					0.0	
[14]	Incremental cost recovery		-5.7			5.7			0.0	
[15]	Net impact	2.3	0.0	4.4	0.5	5.7	4.3	0.0	17.1	28.6



Source: ADB, 2015. *Development of Wind Power and Solar Rooftop PV Market in Indonesia*. Jakarta, Indonesia.

EXAMPLE FROM INDONESIA: DISTRIBUTIONAL IMPACT OF GEOTHERMAL PROJECTS

97. Another example from Indonesia presents a similar analysis for the impact of geothermal energy.[33] Here the allocations of financial & economic costs and benefits, and of externalities, were calculated for the geothermal projects in the Bank's Indonesia Geothermal Investment Project,[34] evaluated against the coal projects that they would replace – a valid comparison since both provide base load power. As shown in Table C6.5, the incremental financial contribution of concessionary CTF financing (NPV $86million) is offset against the global externality of $160 million (valued here at $30/ton CO_2). However, one sees that the financial loss to government ($74million) is offset by a net gain on local health impacts of $45 million, so the net result is that the Government of Indonesia (now the electricity consumers, since tariffs will become fully cost-reflective following the tariff reforms of 2014) is funding $29 million of the GHG benefits that accrue to the global community.[35]

33 Jayawardena, M., M. El-Hifnawi and Y. Li, *Scaling-Up Renewable Geothermal Energy in Indonesia An Integrated Approach to Evaluating a Green Finance Investment*. ESMAP Knowledge Series 015/13.

34 World Bank, 2011, *Geothermal Clean Energy Investment Project*, Project Appraisal Document, 56321-IN

35 i.e., $74 million financial loss, less $45 million in avoided local externality costs.

Table C6.5: Distributional impacts of coal v. geothermal

Geothermal Generation	Financial[1]	Economic Local[1]	Additional Economic "Global"[1,2]	Total Externality	Allocation of Externalities: Government	Local Community	Global Community[2]
Revenue/Benefit	637	527		**(110)**	(110)		
Investment	(454)	(493)		**(39)**	(39)		
Make-Up Wells	(65)	(70)		**(5)**	(5)		
O&M	(87)	(95)		**(8)**	(8)		
Tax	(84)	–		**84**	84		
Health Benefit	–	45		**45**		45	
Reduction of GHG	–		150	**150**			150
CTF Compensation	86	86	(86)	**(86)**			(86)
					(78)	**45**	**64**
Coal-Based Generation	**Financial[1]**	**Economic Local[1]**	**Additional Economic "Global"[1,2]**	**Total Externality**	**Government**	**Local Community**	**Global Community**
Revenue/Benefit	527	527		–			
Investment	(207)	(225)		**(18)**	(18)		
Fuel Cost	(218)	(237)		**(19)**	(19)		
O&M	(56)	(61)		**(5)**	(5)		
Tax	(38)	–		**38**	38		
Health Benefit	–	–		–			
Reduction of GHG	–	–		–			
					(4)	**0**	**0**
NET DISTRIBUTIONAL IMPACT: GEOTHERMAL VS. COAL-BASED GENERATION					**(74)**	**45**	**64**

Notes

[1] Discounted at the economic discount rate (EOCK) of 10%

[2] The global economic benefits accrue to entire global community, including Indonesia

Source: Jayawardena, M., M. El-Hifnawi and Y. Li, 2013. *Scaling-Up Renewable Geothermal Energy in Indonesia An Integrated Approach to Evaluating a Green Finance Investment*. ESMAP Knowledge Series 015/13: Table 4.

Other Suggested reading

P. Gutman, *Distributional Analysis. World Commission on Dams, Thematic Review III.1: Economic, Financial and Distributional Analysis*, 2000

Best practice recommendations 3: Distributional analysis

(1) The OPSPQ guidelines (see Table 1.1) do not *mandate* a distributional analysis – but simply require that the economist assess whether a distributional analysis is "relevant to the careful determination of social cost and benefits". However, it would be very rare for a power sector investment project to have no significant distributional impacts, and best practice would require a minimal distributional analysis for almost all projects.

(2) The minimum presentation is that illustrated above for the Indonesia Geothermal Project. The preparation of such an analysis is straightforward, and cannot be seen as onerous.

C7 ENERGY SECURITY

98. Energy Security is a widely announced objective of public policy. One of the main difficulties is that energy security is difficult to define, and therefore difficult to balance against other policy objectives. Definitions range from broad statements of policy to definitions that equate energy security to freedom from imports (and in particular, as in the example of the US, freedom from oil imports), or to robustness to physical supply disruptions, and, more recently, to robustness against cyber-threats.[36] However, as noted by the eminent MIT economist Paul Joskow, "*There is one thing that has not changed since the early 1970s. If you cannot think of a reasoned rationale for some policy based on standard economic reasoning, then argue that the policy is necessary to promote "energy security.*"[37]

99. The breadth of energy security concerns is reflected in the following sample of Government concerns:

- The **UK Government in 1912**: Arguably the first example of an expressly announced energy security policy, Winston Churchill, famously noted that "*We must become the owners or at any rate the controllers at the source of at least a proportion of the oil which we require*" – a view that led eventually led to the creation of Iraq under British control after the collapse of the Ottoman Empire in 1918.[38]
- **International Energy Agency:** defines energy security as *uninterrupted physical availability at a price which is affordable, while respecting environmental concerns: Energy security has many aspects: long-term energy security mainly deals with timely investments to supply energy in line with economic developments and environmental needs. On the other hand, short-term energy security focuses on the ability of the energy system to react promptly to sudden changes in the supply-demand balance.* [39]
- The **Government of Saudi Arabia in 2012**: the commitment to large scale development of concentrated solar power (CSP) reflects not just its excellent solar regime, and opportunity to become a global leader in a new industry, but the need to hedge the vulnerability of the Saudi oil infrastructure and the vulnerability of its oil exports to blockade of the Straits of Hormuz.[40]
- **The Government of Nepal in the 1990s:** the goal of energy sufficiency was articulated on grounds of its rich hydro resource, and that Nepal's energy policy should build hydro projects and export the hydro surplus to India, rather than rely on electricity imports from India whose Eastern provinces at the time had a surplus of coal-fired capacity, suitable for export as base-load. While electricity self-

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36 There are increasing reports of attacks on control systems of public utilities, and attempts by hackers to break into systems controlling natural gas pipelines (see, e.g., *Financial Times Special Report on Cyber Security*, 6 June 2014). Cyber attacks on industrial control systems reported to the US Department of Homeland Security have increased from 34 in 2010 to 257 in 2013: most remain unreported. On August 15, 2012, the "shamoon" virus cyber-attack deleted data on three quarters of Aramco's corporate computers.

37 Joskow, P., 2009. *The US Energy Sector, Progress and Challenges, 1972-2009*, Journal of the US Association of Energy Economics, 17(2) August.

38 History records the emergence of energy security as a major policy problem for Government in the conversion of the British Royal Navy from coal to oil first proposed in 1882 (by the then Captain, subsequently First Lord of the Admiralty Fisher). The problem was that while Britain had coal, it had no oil, which needed to be secured from the Middle East – a fact that shaped (and held hostage) British foreign policy for the next 50 years.

39 http://www.iea.org/topics/energysecurity/

40 The Saudi Electricity Company 550MW Duba 1 project, an integrated solar combined cycle project, is the first CSP project in a program that has set a target of 41 GW of solar power by 2032 (CSP 25 GW, PV 16 GW).

sufficiency was largely attained, the result of the reluctance to see energy trade as a two-way opportunity resulted in no progress in exporting hydro power, and endemic power shortages, particularly because an almost all-hydro system was exposed to increasing hydrology risk.[41] (This posture changed following the power shortage crisis of 2008: the World Bank is now financing a major 400 kV transmission link between India (Bihar) and Nepal) to accommodate transfers of up to 1,000 MW)[42]

- **The United States in 2011:** The March 2011 speech of President Obama articulated America's energy security problem as freedom from oil imports " *. . .there are no quick fixes. We will keep on being a victim to shifts in the oil market until we get serious about a long-term policy for secure, affordable energy . . . The United States of America cannot afford to bet our long-term prosperity and security on a resource that will eventually run out. . . So today, I'm setting a new goal: one that is reasonable, achievable, and necessary. When I was elected to this office, America imported 11 million barrels of oil a day. By a little more than a decade from now, we will have cut that by one-third".*[43] In fact by 2013 US oil imports had already fallen by *half* - albeit less as a consequence of new Federal Government policies as much as by the private sector-led fracking technology revolution.
- **UK Government in 2011**: Consumers should "have access to the energy services they need (physical security) at prices that avoid excessive volatility (price security), and delivered alongside achievement of our legally binding targets on carbon emissions and renewable energy" [44]
- **Afghanistan in 2015**: At a May 2015 workshop on power sector planning, the main priority was articulated with brevity and focus: "*The people need power*" – a reflection of the need for economic development and the concomitant need for electricity as the main option for improving the long-term prospects to emerge from the current state of internal conflict., If that means that over the short- to medium term the bulk of electricity has to be imported from Uzbekistan and Turkmenistan, then so be it: the geopolitical risks of dependency on just one or two import suppliers are seen as much less important. (see also Box C7.1).

100. The diversity of these energy security issues underscores the fact that there is no one-size-fits-all definition: greater import dependency is seen as desirable by some, highly undesirable by others. More importantly, what can usefully be quantified and monetised will vary greatly form country to country.

101. It is often asserted that a higher share of renewable energy improves energy security,[45] and that this benefit is not captured by conventional cost-benefit analysis. Such arguments are most often heard in connection with high-cost renewable energy projects whose economic returns – even when global carbon externalities are included – still fail to meet the required hurdle rate. If these energy security benefits (together with

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41 See e.g., World Bank, *Nepal Hydropower Exports*, 1999.

42 World Bank, 2011. *Nepal-India Electricity Transmission and Trade Project*, Project Appraisal Document. Report 59893-NP

43 http://www.nationaljournal.com/energy/obama-s-energy-security-speech-there-are-no-quick-fixes-20110330

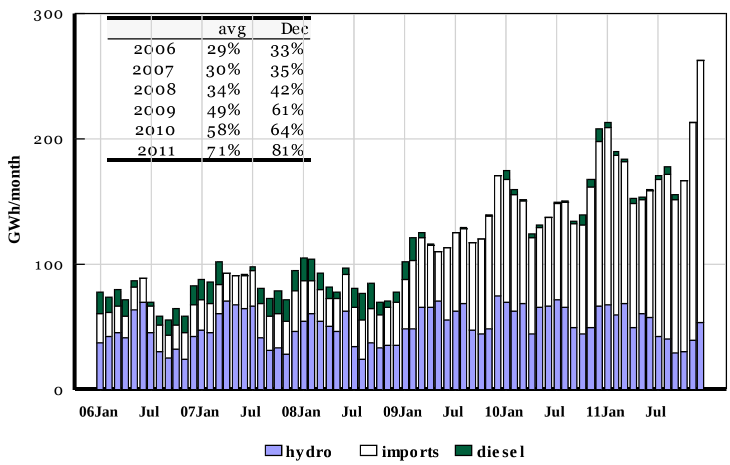
44 UK Secretary of State for Energy and Climate Change, *Energy Security Strategy*, Report to Parliament, November 2012.

45 For example, the PAD for the Concentrated Solar Power (CSP) in Morocco notes that the project will "*improve energy security by diversifying supply and making the country less dependent on imports*" (World Bank, 2014. *Morocco: Noor-Ouarzazate Concentrated Solar Power Project*, Project Appraisal Document, PAD 1007). The Indonesian Geothermal Project PAD states "*Other important benefits to geothermal development that are not quantified include enhancing energy security and guarding against the volatility in fuel prices through Diversification of generation sources*" (World Bank, 2011. *Geothermal Clean Energy Investment Project*. Report 56321-IN.

other benefits derived from learning curve effects and macroeconomic impacts) were properly incorporated into the CBA, then, it is argued (or at least implied), the project would be justified.

Box C7.1: Energy Security and power system diversity in Afghanistan

In Afghanistan, the energy security of the country is demonstrably linked to energy access, and to grid electricity access at affordable prices in particular. Yet in the past five years, electricity supply to Afghanistan has relied on a massive increase in imports from Uzbekistan: imports during the winter peak demand months rose from 33% in 2006 to 81% in 2011.



Evidently the potential risk of supply disruption from the main supplier Uzbekistan has been judged small compared to the (economic) costs of no power at all, or power from diesels also dependent upon imported fuel (and whose cost is 25-30 USc/kWh rather than the 3-6 US¢/kWh for imported electricity).

However, the ability to further increase imports from Uzbekistan is unclear, and given the various geopolitical imperatives of the region, the Government has now created a new Planning Cell in the Ministry of Energy and Water, for whom alternatives to imports has been identified as a pressing policy issue.

THE ISSUES

102. Notwithstanding the difficulties of definition, there is general consensus that energy security is primarily about the resilience of the energy system to risks and uncertainty. Most discussions distinguish between long and short-term threats, and between physical security and price security, a classification depicted in Table C7.1.

103. Note that many of these risk factors are beyond the ability of decision-makers in the Bank's typically relatively small client countries to control. The pace of global climate change will be determined largely by the ability of the world's major GHG emitters to reach agreement on global measures. China's rise – which has had a major impact on rising fossil fuel prices – is an inescapable reality that the world must simply accept. But government decision-makers *can* improve the *resilience* of energy systems to absorb price shocks by

- increasing the diversity of the energy system
- reducing the energy intensity of the economy
- rationalising energy prices

Table C7.1 The risk dimensions of energy security

	Physical security	Price security
Short term	• Technical failures (forced outages at generators)	• Price volatility
	• Natural resource variability (hydrology & wind speed variations)	• Commodity price bubbles
	• Fuel supply disruptions (especially on small remote islands)	
	• Natural force majeure (typhoons, extreme drought)	
	• Political force majeure (strikes, terrorist attacks)	
	• Cyber attacks	
	• Government embargoes	
Long-term	• Resource depletion	• Price fixing by cartels
	• Climate change	• Changing patterns of global demand

Source: Winzer, C., 2012.*Conceptualising Energy Security*, Electricity Policy Research Group, University of Cambridge, Cambridge Working Paper in Economics 1153 and T. Parkinson, 2011. *Valuing Energy Security: Quantifying the Benefits of Operational and Strategic Flexibility*, Lantau Group, October 2011

104. These attributes will largely determine the costs of the risks enumerated in Table C7.1, and of the cost of measures to mitigate them. But these are the principal subject of energy *policy*, rather than characteristics of individual projects.

Energy Security in Policy assessment v. project appraisal

105. In a policy assessment, the energy security question is how to make the energy *system* more resilient to the wide range of risks. So the first task is to select some set of indicators that measures resilience (diversity of supply sources, energy intensity of GDP, discussed further below) (as an example, see Box C7.2 that looks at the reduction in oil intensity (mbd/$GDP), that has dramatically enhanced US energy security). The portfolio of options with which RE must compete is often large - reduce fossil fuel subsidies, electricity tariff reform, energy efficiency, thermal rehab, etc - each of which will have some place in the triangle of major objectives (economic efficiency (indictor NPV), low carbon development (indicator lifetime GHG) and energy security (say diversity index of supply sources). Many may not be mutually exclusive alternatives - the best strategy may well involve several measures.

106. In a CBA, the reality is that energy security, however defined, is *not* likely to be a significant component of the table of economic flows that can be monetised and included in the table of economic flows. The few studies that have attempted this demonstrate very small benefits, typically <0.1 USc/kWh. The only practical approach is scenario analysis, in which the impacts of given assumptions about more or less energy security are explicitly costed.

Box C7.2: Strategic oil reserve v. energy intensity of GDP

There is no better example of the importance of long-term policies to improve system resilience than the US response to the first oil crisis of 1973. One of the policies to reduce exposure to oil price disruptions and oil price volatility was the establishment of a strategic petroleum reserve (SPR)[46] – along the lines suggested by the IEA target for its member countries to provide for at least 90 days of physical storage capacity for imported oil. In practice the SPR has been used only three times with just relatively small sales (in 1991 during the first Gulf War; in September 2005 after the disruption to oil production in the Gulf of Mexico in the wake of Hurricane Katrina, and in June 2011 in connection with the disruptions in Libya). Even if rarely used, the very existence of such a reserve serves as a deterrent, and even limited sales serve to calm markets.

However, the ability to withstand oil embargoes and external price shocks is far more influenced by the oil and gas intensity of the US economy, as shown in the table below: 2005 was the year of peak oil imports, which have fallen significantly in the last 8 years as US production has increased. Actual oil imports today are just 6.2 mbd (million barrels per day). Oil intensity has fallen from 2.7 mbd/trillion$ GDP to just 0.9 mbd/trillion$GDP in 2013. If the oil intensity had remained at the 1975 level, and if domestic oil production were also unchanged, 2013 oil imports would be at 34.4 mbd, almost six times higher! The implications of such a level of oil imports for US foreign policy, for its trade balance, and for global oil prices, would obviously be dramatic.

Impact of oil intensity change on US oil imports

			1975	2005	2013
1	Oil imports	Mbd	5.8	12.5	6.2
2	Domestic production	Mbd	8.3	5.2	7.4
3	Total	Mbd	14.1	17.7	13.6
4	*GDP*	*trillion 2009$*	*5.3*	*14.2*	*15.7*
5	*oil/GDP*	*mdb/t$*	*2.7*	*1.2*	*0.9*
6	Hypothetical demand at 1975 oil intensity	Mbd	14.1	37.8	41.8
7	Domestic production	Mbd	8.3	5.2	7.4
8	Imports	Mbd	5.8	32.6	34.4

Source: US Energy Information Administration (EIA)

That said, the reduction in US energy intensity was also strongly influenced by changes in the sectoral composition of GDP due to a shift of energy intensive manufacturing to other countries, particularly to China.

THE LITERATURE: ENERGY SECURITY AND RISK[47]

107. Some dimensions of risk have long been incorporated into power sector planning: quantification of hydrology risk and reliability of power systems are established features of widely used power system planning models such as WASP and EGEAS. From this follows the easiest quantification of energy *in*security as the expected quantity of unserved energy in a power system. This is straight forward to incorporate into the objective functions of power system planning models by assigning a (high) cost to this unserved energy, and by stipulating some level of reliability (e.g., as loss of load probability). Yet few if any power system planning studies present a clear analysis of the trade-offs between system cost and the reliability criteria and cost of unserved energy exogenously specified by engineers.

[46] This has a capacity of 727 million barrels, the largest such reserve in the world, and sufficient for 72 days of annual imports to the US (at the peak import level of 2007).

[47] More extensive reviews of the literature are provided in Blyth, W., and N. Levebre, 2004. *Energy Security and Climate Change Policy Interactions: An Assessment Framework*, IEA Information Paper. and Winzer, C., 2012. *Conceptualising Energy Security*, Electricity Policy Research Group, University of Cambridge, Cambridge Working Paper in Economics 1153

108. What is conspicuously absent from this literature is the impact of price *volatility* for fossil fuels. Most power systems planning studies do indeed present results for different forecasts of long term trends in international fossil fuel prices (which addresses two of the risks enumerated in Table C7.1: the impact of resource depletion and changes in global supply and demand). But that says nothing about the impact of short term price *volatility*.

109. Translating price volatility impacts into a risk premium that could be built into CBA is difficult, and rarely attempted. A recent study for Latin America by the Inter-American Development Bank[48] suggests the risk premium to be very small, (0.01 USc/kWh), an order of magnitude lower than, say, the damage costs from local air pollution of thermal generation. Another recent study to develop an avoided cost renewable energy tariff for Indonesian geothermal projects[49] estimates the volatility premium at 0.07 USc/kWh (estimated as the cost to Ministry of Finance of short-term financing of unexpected increased subsidy to PLN as a result of volatility induced forecasting errors of coal prices).

110. Another strand of the relevant literature is to cast renewable energy as a hedge against fossil fuel price volatility, as first proposed by Auerbuch.[50] He argued that the role of renewable energy projects in a portfolio of generating projects was akin to the role of essentially risk-free treasuries in a financial portfolio. The application of mean-variance portfolio theory is useful but one must be careful not to overstate the case: wind projects in particular may have high annual variability due to wind speed variations – though because this risk is uncorrelated with the factors that drive fossil fuel price variability, it can still serve as a hedge (for further details of this approach, see Technical Note **M8**)

111. The general theme of renewable energy as a hedge against fossil price uncertainty has been taken up by Bolinger and others at the US Lawrence Berkeley National Laboratory.[51] This work argues that – at least in the US where futures markets for natural gas are well developed – renewable energy can be a cost-effective hedge when compared to futures hedging (a finding that is still valid at the currently low US gas prices).[52] However, sophisticated oil-price hedging strategies for small developing countries are to be recommended only with great caution (Sri Lanka's recent attempts to do so were an unmitigated disaster, with losses in the hundreds of millions of dollars).[53]

THE LITERATURE: ENERGY SECURITY AND RESILIENCE

112. Many definitions of energy resilience are based on simple indicators, ranging from the simple fraction of imports in oil supply (much used in the US) to more sophisticated numerical indicators of diversity of supply (under the presumption that greater diversity implies better energy security). The most common indicator of supply diversity (or generation mix diversity in the case of the power sector) is the Herfindahl

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48 W. Vergara *et al*., *Societal Benefits from Renewable Energy in Latin America and the Caribbean*, IDB Technical Note, January 2014

49 World Bank and ADB, *Unlocking Indonesia's Geothermal Potential*, October 2014

50 Auerbuch, S., 2000. *Getting it Right: the Real Cost Impacts of a Renewables Portfolio Standard*, Public Utilities Fortnightly, February 15

51 Bolinger M., Wiser R., Golove W., 2002. *Quantifying the Value that Wind Power Provides as a Hedge Against Volatile Natural Gas Prices*. LBNL-50484, Berkeley, California.

52 Bolinger, M., 2013. *Revisiting the Long-Term Hedge Value of Wind Power in an Era of Low Natural Gas Prices*, LBL-6103E.

53 Both the ENRON and Ceylon Petroleum Company fiascos are well described at http://www.risk.net/energy-risk/feature/2323248/the-10-biggest-energy-risk-management-disasters-of-the-past-20-years.

Index, a measure used originally to assess the degree of concentration and competition of firms in industrial sectors. The (dimensionless) index ***H*** calculates simply as the sum of squares of the market or generation mix shares s_i for each of the ***n*** shares as follows:

$$H = \sum_{n} s_i^2$$

113. The *lower* the value of ***H*** the *greater* the diversity of fuels. In estimating diversification of supply by this approach, if there were only one fuel the index is 1, if there are ten fuels of the same size the index is 0.1. The shares are best expressed as installed *capacity* shares rather than energy shares. Obviously, introducing new renewable energy forms into a power system will increase such diversity, but whether greater diversity *necessarily* improves energy security is not always true (see Box C7.2). This can also questioned in the case of energy efficiency improvements: all other things equal, T&D loss reduction or energy efficiency will reduce the need for supply, and leave its mix (and hence its H-index) unchanged – but the resilience of the economy (measured per unit of GDP) will surely improve.

114. In the economics literature itself the emphasis of energy security discussions – particularly since the mid 1970s – is on the macroeconomic impacts of oil price shocks. Bohi and others[54] summarise much of the early work (and define energy *insecurity* as the *loss of welfare that may occur as a result of a change in the price or availability of energy*); Tang and others[55] examine the impact of oil price shocks on the Chinese Economy; and Ebrahim and others[56] *et al*. (2014) [57] assess the macroeconomic consequences of oil price volatility - all typical examples of a still-growing literature. Much of this work is focussed on the asymmetries of oil price shocks (the costs of sharp oil price rises – including inflation and recession - are not matched by the benefits of any subsequent price falls): it is the *price* and consequent macroeconomic impacts, rather than curtailments in physical supply, that is the main concern. This is complemented by a substantial World Bank literature that deals with strategies to mitigate the impacts of oil price shocks in developing countries (both importers and exporters).[58]

World Bank Practice

115. Despite the many qualitative assertions of the additional benefits to energy security, no renewable energy project appraisals have successfully quantified such benefits, and included them in the CBA economic flows. Nor has there been any detailed study or research paper on the subject in the Bank's literature. There is one study currently underway that directly confronts the question of how to incorporate energy security questions in energy planning in situations of high uncertainty (typical of post-conflict countries), but its results will be forthcoming only in late 2015.[59]

54 Bohi, D.R., M.A. Toman, and M.A. Walls, 1996. *The Economics of Energy Security*, Boston: Kluwer Academic Publishers.

55 Tang, W, Libo Wu and ZhongXiang Zhang, 2010. *Oil Price Shocks and their Short- and Long-term Effects on the Chinese Economy,* Energy Economics, 2010.

56 Ebrahim, Z., Inderwildi, O., and D. King, 2014. *Macroeconomic Impacts of Oil Price Volatility: Mitigation and Resilience*, Frontiers of Energy.

57 This paper from Oxford University includes an excellent literature review of the various impacts of oil price volatility (industrial production, employment, inflation and monetary policy, unemployment, stagflation).

58 See, e.g., Spatafora and Warner (1996); Bacon and Kojima (2006); Timilsina (2013).

59 World Bank, 2015. *Energy Security Trade-Offs under High Uncertainty – Resolving Afghanistan's Power Sector Development Dilemma,* ESMAP.

116. As noted, the Bank has published several assessments of the vulnerability of oil importing countries, but this focuses on better understanding, and quantification of energy system resilience, rather than quantifying the benefits of specific projects. In short, the Bank does not yet have a satisfactory answer to whether and how energy security concerns should be addressed in the CBA of projects.

Suggested reading

Bohi, D.R., M.A. Toman, and M.A. Walls, 1996. *The Economics of Energy Security*, Boston: Kluwer Academic Publishers.

Feinstein, C., 2002. *Economic Development, Climate Change, and Energy Security –The World Bank's Strategic Perspective*, Energy and Mining Sector Board Discussion Paper Series 3/September 2002.

Joskow, P., 2009. *The US Energy Sector, Progress and Challenges, 1972-2009*, Dialogue, Journal of the US Association of Energy Economics, 17(2) August.

Crousillat, E., and H. Merrill, 1992. *The Trade-off/risk Method: a Strategic Approach to Power Planning*. Industry and Energy Department Working Paper, Energy Series Paper 54, World Bank, Washington, DC.

Crousillat, E., and S. Martzoukos, 1991. *Decision-making under Uncertainty: an Option Valuation Approach to Power Planning*, Industry and Energy Department Working Paper, Energy Series Paper 39, World Bank, Washington, DC.

New York Mercantile Exchange (NYMEX).*A Guide to Energy Hedging*. www.kisfutures.com/GuideEnergyHedging_NYMEX.pdf

Best practice recommendations 4: Energy Security

With so few satisfactory examples of integrating energy security concerns into CBA, it is as yet difficult to define what constitutes best practice.

(1) In the first instance it is important to avoid *false* arguments: avoid an assertion of energy security as an important policy concern for which there exists nothing more than anecdotal evidence. It is claimed, for example, that RE will improve energy security because a country will then be less vulnerable to physical supply disruptions for imported fossil fuels. But can it be shown that the Government has examined other alternatives to address this same concern - that would be proposed even if RE were *not* an option -– for example, by mandating increased physical storage (say an extra 30 days coal supply to be stockpiled at coal projects), or by financial hedging of fuel prices?

(2) One should resist the temptation to double count. It is often (and correctly) stated that Governments are determined to increase renewable energy – even if more expensive - in order to diminish the impact of the macroeconomic shocks of the last run-up in imported oil prices. But the benefit of reducing oil (or gas) imports is *already* captured in the CBA of the renewable energy project: the benefit would be even greater if fossil fuel prices were to increase above the baseline forecast. So why should there be an additional benefit called "energy security"?

(3) Scenario analysis (see example above) appears to be the easiest way to deal with country specific energy security concerns. This requires that the consequence of physical disruptions that are assumed in alternative scenarios be costed out – for example, in case of accidents (powerhouse flooding, transmission substation failure, coal supply disruption) considering not just the cost of repairs, but the value of lost production.

C8 THE DISCOUNT RATE

The World Bank is presently formulating new Bank-wide guidance for the choice of discount rate. A Technical Note on the choice of discount rate for power sector project CBA will be issued in the near future. In the meanwhile, the reader is directed to the following sources for a discussion of the issues:

Belli, Pedro and others, *Handbook on Economic Analysis of Investment Operations*, World Bank, Operational Core Services, Network Learning and Leadership Center, January 26, 1998.

Arrow, A., W. Cline, K Maler, M. Munsinghe, and J. Stiglitz. *Intertemporal Equity, Discounting and Economic Efficiency*; in Global Climate Change: Economic and Policy Issues, World Bank Environment Paper 12, 1995. A comprehensive discussion of the different approaches, and the long-standing differences of views in the economics literature.

Lopez, H., 2008. *The Social Discount rate: Estimates for Nine Latin American Countries*, Policy Research Working Paper 4639, World Bank. – a discussion of the Social Rate of Time Preference (SRTP) approach, noting the difficulties of reliable estimation of the parameters in the Ramsey formula. The results presented are for Brazil, Bolivia, Chile, Honduras, Mexico,Nicaragua, Peru, Colombia, and Argentine.

Lind, R., K. Arrow, P. Das Gupta, A. Sen, J. Stiglitz *et al. Discounting for Time and Risk in Energy Policy*, Resources for the Future, 1982.: although this predates much of the climate change debate, this addresses two important US energy policy issues of the early 1980s: how one should evaluate R&D into new energy technologies where the payback could be quite distant in time, and how to assess technologies (especially nuclear) that may have very long term impacts (such as the inter-generational impacts of radioactive waste disposal)

Zhuang, J., Z. Liang, Tun Lin, and F. De Guzman. *Theory and Practice in the Choice of Social Discount Rate for Cost -benefit Analysis: A Survey*, Asian Development Bank, ERD Working paper 94, 2007.

PART II: TECHNOLOGY RELATED ISSUES

T1 VARIABLE RENEWABLE ENERGY

117. Variable renewable energy (VRE) may bring substantial incremental costs to the buyer beyond the direct cost of power at the point of generation. Three main issues arise:

- The incremental costs of ***transmission*** (discussed in Technical Note **T2**)***:*** renewables are tied to the location of their natural resource, which are often more distant from load centres than the thermal generation they replace: significant additional transmission investments may be required.
- The ***capacity value*** of renewables: simply stated, how much thermal capacity is replaced by an additional MW of variable renewable energy capacity.
- The impacts on the ***operation*** of the system: ranging from heat rate degradation of thermal units that are pushed into part-load operation when backed down to absorb variable renewable generation, to questions of network stability.

118. As noted in the main text, the latter subject is not always easy for non-engineers and economists advising on renewable energy support tariffs, or having to make allowance for integration costs in a CBA: utilities with no experience with renewables will often raise a long list of issues as to why the integration of variable renewables will create both technical difficulties and incremental costs.

119. An important mitigant to the problems of variability is generation portfolio diversification. A single wind turbine may have no capacity value, but a portfolio of wind farms or small hydro projects over a larger region, or a portfolio of different renewable energy projects (say wind and small hydro), can smooth out the aggregate variability.

IMPACT ON OPERATING COSTS

120. The ability of thermal and storage hydro projects to absorb variation from renewable energy projects is subject to a range of economic, technical and environmental constraints. The allowable rate of change of output is termed the *ramping rate*, which varies from technology to technology: Table T1.1 shows typical rates for a CCGT

Table T1.1: Typical operating limits for a CCGT

	Shutdown period	Start-up Period	Simple Cycle mode	Combined Cycle mode
Hot-startup	8 hours	1.5 hours		
Cold startup	77 hours	4 hours		
Allowable rate of load change			8.33% per minute (full range of output)	5.56% per minute (from 50% to100% of output)

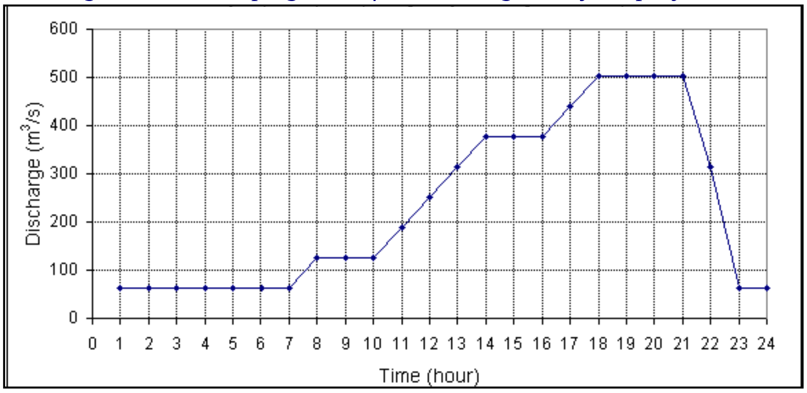
Source: Phu My 2 Phase 2 Power project, Power Purchase Agreement between Electricity of Vietnam (EVN) and Mekong Energy Company Ltd., 715 MW CCGT (Vietnam).

Hydro constraints

121. Very rapid ramp rates are possible technically, but are often constrained by environmental requirements that take the form of maximum rates of change of downstream water levels. Pumped storage projects are generally less constrained in this regard, and are therefore the ideal form of generation to absorb the variations from variable output renewables. But at conventional storage hydro projects, the environmental restrictions can be significant. At the Bank-financed 240 MW Trung Son hydro project in Vietnam, the maximum rate of increase was determined to be 40 cumecs per hour. This implied an 11-12 hour period to increase from the minimum turbine discharge of 63 cumecs to the maximum of 504 cumecs – which limits the proportion of

the total energy available during peak hours. Figure T1.1 shows the ramping curve used in the reservoir simulation runs that provided the input to the economic analysis.

Figure T1.1: Ramping curve for the Trung Son hydro project, Vietnam



Source: World Bank, *Economic Analysis of the Trung Son Hydro Project, 2010.*

122. In this case, the ramping constraint is much more severe than applies to gas fired project: a typical open cycle combustion turbine can ramp up at 8% of its capacity per minute, so just a few minutes, rather than hours, to reach full capacity.

123. The impact of such ramping constraints should be discussed in the economic analysis of hydro projects. In the case of the Trung Son project, the impact of these ramping constraints on ERR is a few percentage points (lower): the economic benefits of simply displacing the *energy* from thermal alternative without any capacity benefit were substantially above the hurdle rate. In short, such ramping constraints on hydro projects should be studied in the CBA, and the impact demonstrated in the sensitivity analysis.

Thermal projects

124. At thermal projects, ramping constraints vary across technologies. Frequent changes in load, or operation at part load, often associated with increased VRE, will affect average heat rates. Load following may be technically possible, but it may affect not just average heat rates, but also result in higher O&M costs, and more frequent intervals for technical overhauls.

125. The operating costs imposed on the buyer of variable energy (notably wind and PV) include the following:[60]

- Increased O&M costs at existing thermal units called upon to ramp output levels over a broader range and more often and with shorter notice.
- The heat rate penalties (and related fuel costs) associated with such increased ramping (different fossil technologies experience different rates of heat rate penalties and incremental O&M costs).
- Regulation costs (that arise from the intra-hour variability of wind resources that requires additional fast response capacity be available).
- Systems operations cost, that arise from less than optimal operation of the system as a consequence of the uncertain nature of wind energy production: the total reserve margin may need to increase by a few percentage points in the presence of highly variable renewables.
- Gas storage costs (that arise from inaccuracies in the amount of gas nominated each day, which may require the need to inject or withdraw gas from storage at short notice)

60 Xcel Energy and EnerNex, *Wind Integration Cost Study for the Public Service Company of Colorado*, August 2011.

- Gas supply take-or-pay penalties: Under certain circumstances, wind incurs not only the cycling costs of the gas turbines when these are ramped down; but if these gas projects then need to increase generation during off-peak hours to meet take-or-pay requirements, then coal projects will be backed down at night to make way for that, incurring a second set of cycling costs - with the result that variable renewable energy in fact displaces coal).[61]

126. The most detailed analysis of power plant cycling costs is a 2012 study by NREL.[62] Table T1.2 compares costs of start-up across technologies: as one might expect, aero-derivative combustion turbines have by far the lowest costs, and coal projects the highest.

Table T1.2: Start-up costs

	Coal			Gas			
Unit Types	small sub-critical	large sub-critical	Super-critical	CCGT	large frame CT	CT Aero-derivative	steam
Typical Hot Start Data							
-O&M cost ($/MW cap.)	58	39	38	31	22	12	26
-FOR Impact (in %)	0.0001	0.0001	0	0	0	0	0
Typical Warm Start Data							
-O&M cost ($/MW cap.)	95	61	56	44	28	12	46
-FOR Impact (in %)	0.0001	0.0001	0	0	0	0	0
Typical Cold Start Data							
-O&M cost ($/MW cap.)	94	89	99	60	38	12	58
-FOR Impact (in %)	0.0001	0.0001	0.0001	0.0001	0	0	0.0001
Startup Time (hours)							
-Typical Warm Start Offline Hours)	4 to 24	12 to 40	12 to 72	5-40	2 to 3	0 to 1	4 to 48

Source: N. Kumar and others, 2012, *Power Plant Cycling Costs*, NREL, April 2012

127. The practical significance of these issues is reflected in PPAs for CCGT IPPs, wherein the deviations from full-load operation are expressly compensated. For example, the PPA for the Phu My 715 MW CCGT requires compensation for the number of hot and cold startups in excess of the contracted annual number,[63] and adjustments to the fuel charge for any time in part-load operation (Table T1.3).

Table T1.3: Heat rate corrections for part load operation, CCGT

Load	primary fuel	secondary fuel
100%	*1*	*1*
95%	*1.0059*	*1.0034*
90%	*1.0122*	*1.0101*
85%	*1.0208*	*1.0192*
80%	*1.0310*	*1.0304*
75%	*1.0442*	*1.0446*
70%	*1.0575*	*1.0581*
65%	*1.0797*	*1.0753*
60%	*1.0927*	*1.0954*

Source: Phu My 2 Phase 2 Power project, Power Purchase Agreement between Electricity of Vietnam (EVN) and Mekong Energy Company Ltd., 715 MW CCGT (Vietnam).

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61 This is the case in Indonesia, where PLN argues that take-or-pay gas supply contracts would force such a result (and since coal costs $4/mmBTU and gas $10-15$/mmBTU, this makes wind quite uneconomic). Such undesirable outcomes may be unlikely for small penetrations of wind that can more easily be accommodated by just a minimum flexibility in gas supply contracts. However, it points to the importance of the necessary breadth of issues when designing a renewable energy policy.

62 N. Kumar, P. Besuner, S. Lefton, D. Agan, and D. Hilleman, *Power Plant Cycling Costs*, NREL, April 2012.

63 The PPA provides compensation of $18,540 for each hot-start and $50,000 for each cold start (and indexed for escalation over the duration of the PPA) when the number of hot and cold startups per year exceed 30. Such clauses are common in thermal PPAs, and reflecting the incremental costs of deviations from optimal dispatch.

SMALL SYSTEMS

128. System integration studies that try to predict the impact of wind on a given grid often suffer from the lack of first-hand data: and a utility with no experience with wind will inevitably be sceptical. Unfortunately there are very few real case studies that have examined several years of operating experience in any detail, in part because there are few places that have extensive and successful experience with small wind-diesel hybrids.

129. Cape Verde is one such system for which good empirical evidence is available about successful operation. As part of a Bank financed wind farm project in the late 1990s, a detailed study of system operation was prepared, which revealed few problems of integration where penetration levels are at the 14-35% level. However, it must be said that the wind regime in Cap Verde is very good, with high capacity factors and a relatively predictable wind regime that allows wind to be dispatched as "firm" on a day-ahead basis. Box T1.4 summarises the results of this study.

Table T1.4: Wind on Cape Verde

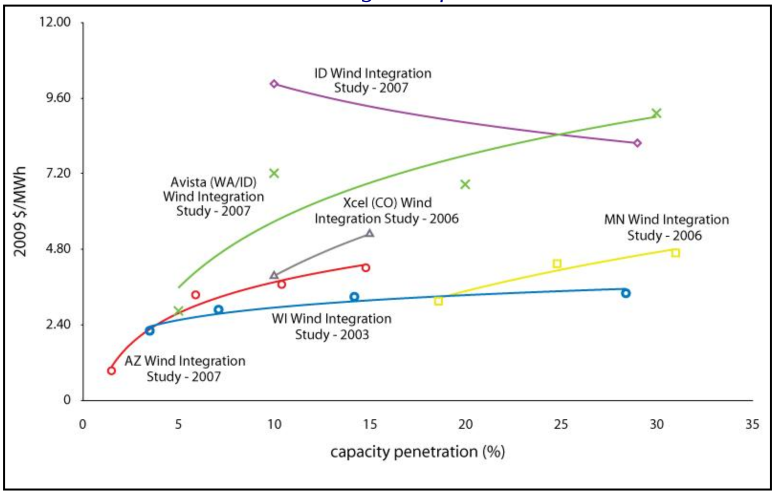
System	Diesel capacity [kW]	Wind capacity [kW]	System maximum demand (1996) [kW]	System energy demand (1996) [MWh]	Wind energy penetration (1996) [% of energy demand]	Highest monthly wind energy penetration [%] (5)	Wind turbine capacity factor (1996) [%]
Praia	10,374	900 (3x300)	6,800	40,912	7.1	14	36.6
São Vicente	13,412	1200 (3x300+10x30)	5,900	33,065	12.7	22	53.2
Sal	3,200	600 (2 x 300)	1,750	10,090	14.3	35	27.3

Source: Garrad Hassan, 1997. *Network Power Quality and Power System Operation with High Wind Energy Penetration*. Report to the World Bank.

AGGREGATE INTEGRATION COSTS

130. Figure T1.2 shows the results of a literature prepared by the US Rocky Mountain Institute. All but one of the studies reviewed show costs increasing with penetration level.

FigureT1.2: Results of studies of wind integration costs versus wind capacity penetration in various regions of the US.[64]



Source: Rocky Mountain Institute, 2014. *Total Wind Integration Costs for Different Capacity Penetrations (http://www.rmi.org/RFGraph-Total_wind_integration_costs_capacity_penetrations)*.

64 http://www.rmi.org/RFGraph-Total_wind_integration_costs_capacity_penetrations

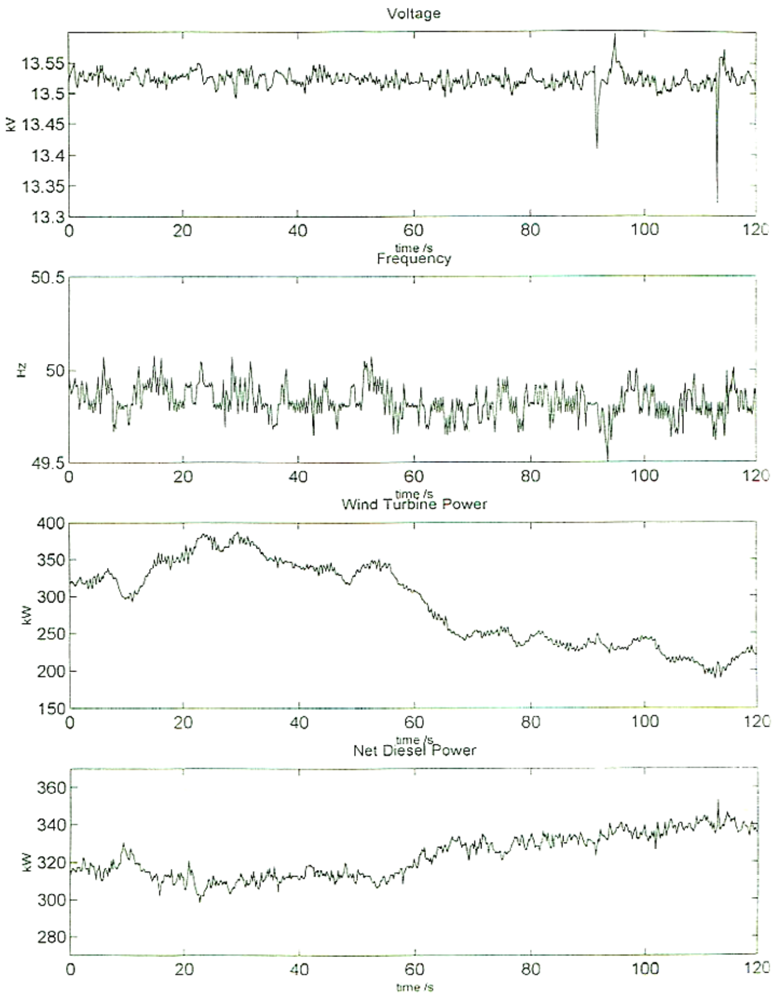
Box T1.1: Small diesel-wind hybrids in Cape Verde

The study examined the operating performance of the wind-diesel hybrids in 1995-1996, including a detailed measurement and recording of total wind power, reactive power, voltage and frequency.

The operating strategy has evolved as experience has grown. In normal circumstances, two diesels are operated to meet the net demand in the most economic way. Provided that the diesels operate at 80-90% (close to peak efficiency), there is sufficient spinning reserve to provide for a sudden drop in wind, a step change in load, or a wind turbine fault. The spinning reserve takes account of the overload capacity of the diesels, which can operate at 110-120% load for short periods. In other words, the wind turbines are treated as "firm" on a day-ahead basis (at least as firm as the diesels): the loss of all wind generation in a short period is not considered credible.

The main conclusions of this study included:

- Even during periods of maximum wind penetration, maximum voltage and frequency variations were well within European limits. Even if the observed voltage and frequency fluctuations could be attributed entirely to wind turbine activity, it would be possible to add additional wind capacity without cause for concern about power quality.
- Complex automated operating strategies in small networks are unlikely to be fully implemented, and simple dispatching rules will be the most effective.
- Such simple operating rules have been able to avoid curtailment of wind turbine output even at periods of very low load and high wind – only one such instance in 1995.



Source: Garrad Hassan, *Network Power Quality and Power System Operation with High Wind Energy Penetration*. 1997: Report to the World Bank.

131. The wind integration costs in Figure T2.1 are those associated with increased reserves in all three timeframes—regulation, load following and unit commitment—that are needed to balance the net variability of wind generation. Modern wind turbines manage intermittency and uncertainty of wind resource with sophisticated plant-level and turbine-level controls that enable stable and well-behaved performance of grids with high levels of wind power penetration.[65]

CAPACITY CREDIT

132. The capacity credit assigned to a variable renewable energy project in a CBA is subject to high uncertainty, and can range from zero (in which case the presence of a renewable energy project would have *no* impact on the capacity expansion plan, and only displaces some part of the energy output of the thermal projects in the system) to some fraction that reflects its contribution to the load on peak system days. The difficulty is often that in monsoonal climates, good production may be limited to a few months of the year, so even with an apparently good annual load factor (say 30-40%), and reliable delivery during the peak hours of the windy period, it may contribute little or nothing during the week or month of the system peak load.

133. In the Bank's literature a few attempts to model the impact of wind and small hydro on capacity expansion plans using capacity expansion optimisation models are noted, but the problem is whether these models can credibly replicate the actual variability of these variable sources. The results for China (Box T1.2) suggest that large amounts of wind and small hydro do indeed have an impact in capacity expansion plans, with apparent capacity credits of between 40-50% (i.e., 1,000 MW of wind displaces 400-500 MW of conventional capacity) – but whether the performance of large wind farms (often modelled as run-of-river hydro projects) is adequately represented in conventional power systems planning models is often contested.

134. The general conclusion of the literature is that as a rule of thumb, the capacity credit of a variable renewable energy project displacing gas in a fairly large system will be roughly the same as its capacity factor. Table T1.5 shows the wind capacity credits revealed in the NREL review of US integrated resource plans. But as we show in the example of a wind project in Vietnam, below, such a rule of thumb is not applicable to projects that are of much greater seasonal variation than wind projects in northern Europe or parts of the USA.

Table T1.5: Wind project capacity credits and capacity factors

	Capacity factor	Capacity credit
PacifiCorp (East)	35%	20%
PacifiCorp (west)	34%	20%
PGE	33%	33%
PSE	32%	20%
Idaho Power	35%	5%
PSCo	29%	10%
Avista	30%	0%

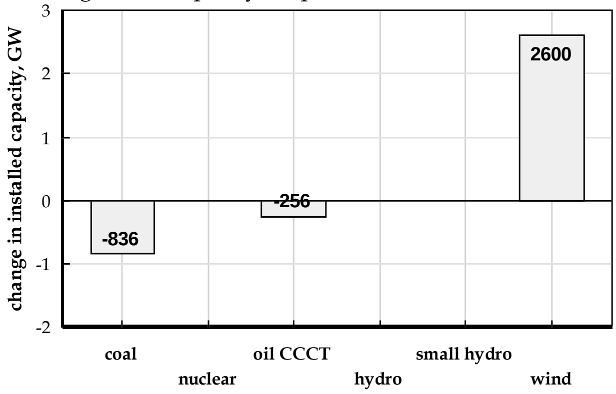
Source: Rocky Mountain Institute, 2014. *Total Wind Integration Costs for Different Capacity Penetrations (http://www.rmi.org/RFGraph-Total_wind_integration_costs_capacity_penetrations).*

65 For details, see, e.g., *N. Miller, GE wind plant advanced controls*, presented at the First International Workshop on Grid Simulator Testing of Wind Turbine Drivetrains, June 2013; (www.nrel.gov/electricity/transmission/pdfs/**turbine**_sim_12_advanced_**wind_plant_controls**.pdf.)

Box T1.2: The Capacity Value of Renewables in China

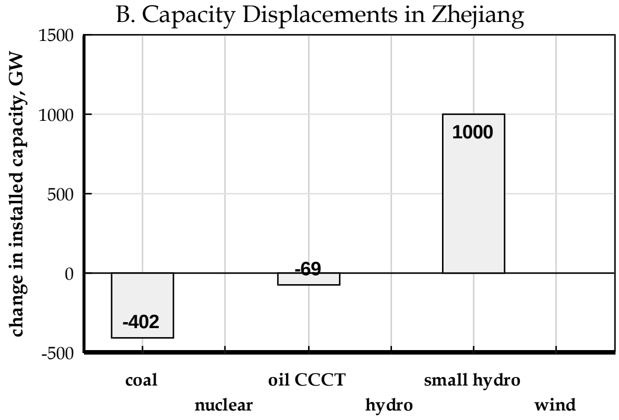
Rules of thumb are all very well, but do they have any basis in reliable studies? One way capacity impacts can be assessed is in a capacity expansion optimization model, in which the least-cost plan is perturbed by forcing in renewable energy, and evaluating how much thermal capacity is actually avoided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

Figure A: Capacity Displacements in the North China Grid



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

B. Capacity Displacements in Zhejiang



Source: World Bank, 2003. *Economic and Financial Analysis of the China Renewable Energy Scaleup Programme (CRESP)*. ESMAP Renewable Energy Toolkit Website.

135. Such rules of thumb apply only to VRE. In contrast, the capacity credit of a geothermal project, that does not have variable output, will be 100% (since these operate at load factors of 90-92%, often greater than the coal plants they displace).

The importance of tariff design

136. Small hydro projects are sometimes dismissed as providing no firm energy, and worthy of no capacity credit. But often this is the consequence of conventional engineering design that could well be influenced by a better tariff structure. The most important feature of a good renewable energy tariff is that it be related to *benefits* - which, unfortunately, is not a commonly encountered feature of fixed feed-in tariffs, most of which are based on estimated *production* costs.

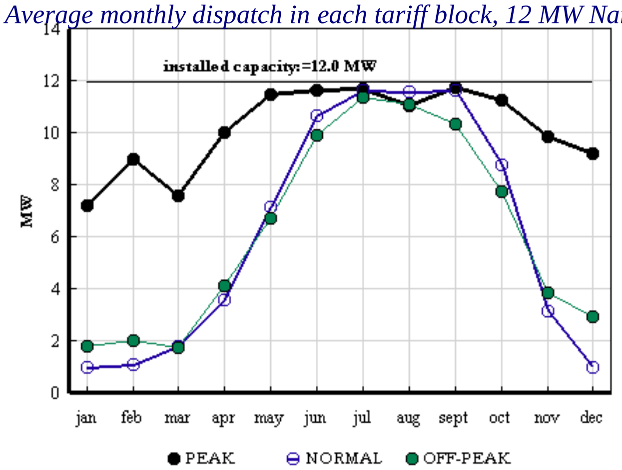
137. In recent years, both Vietnam and Indonesia have given more careful thought to renewable energy tariff design. In Vietnam, the most cost-effective renewable energy

technology is small hydro, and the avoided cost tariff design provided a high premium for dry season energy produced during the peak hours of the day. The Indonesian geothermal tariff ceiling issued in 2014 was also based on the *benefits* of geothermal – whose purpose is to ensure that prices bid in competitive tenders do not exceed the benefits (which includes a premium for avoided GHG emissions valued at $30/ton).

138. The Vietnam avoided cost tariff for small renewable energy projects provides a strong incentive for small hydro projects designed for daily peaking, which in the case of high head projects requires just relatively small volumes of storage. Figure T1.3 shows the result of a dispatch simulation for the 12MW Nam Mu daily peaking small hydro project, showing the average monthly dispatch during each of the three tariff blocks (peak, normal and off-peak). This shows that even during the dry season, the average monthly dispatch during the 4 peak hours is around 8 MW; during the system peak in November it is 10 MW. During the wet months July–August, the plant runs more or less at its full capacity of 12 MW throughout the day. Of course, there is little or no generation in the dry season during off-peak hours—but the economic motivation to build daily peaking capacity rather than pure run-of-the-river is clear.

139. Such capacity benefits in a daily peaking hydro project are simple enough to model in a CBA, particularly for high head projects where the head is relatively constant and the operating rule is straightforward to simulate.[66]

Figure T1.3: Average monthly dispatch in each tariff block, 12 MW Nam Mu small hydro project.



Source: ERAV Electricity Regulatory Authority of Vietnam (ERAV), *Review of the Avoided Cost Tariff for Small Grid-connected Renewable Energy Generation Projects*, Hanoi, September 2011

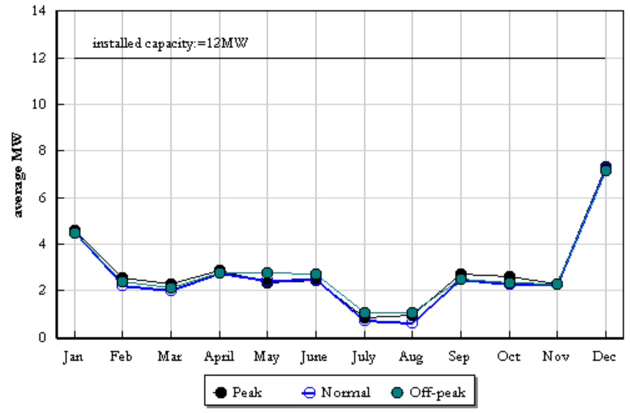
140. By contrast, this may be compared to the analogous evaluation of a wind project proposed for Ly Son Island, (poorly) served by old diesel (Figure T1.4).[67] The output is strongly seasonal - just 2 MW on average for most of the year, 7 MW in the peak month

66 No generation during the night and morning hours until the active storage is full, then part load if any further inflow, and empty the reservoir during the peak hours. Note that if the tariff is properly designed to reward peak hour generation, such projects do not need to be dispatched by a national or regional load dispatch centre – the developers will do that themselves in order to maximise their cash flow. Indeed, in Vietnam, one observes that even older projects, which do not have a PPA under the recently introduced avoided cost tariff, will operate in this manner to secure good relationships with the distribution companies and local dispatchers.

67 In 2008 the ADB proposed a wind-diesel hybrid for Ly Son Island. But the economic analysis showed that even with an off-peak tariff to encourage ice-making during the night (fishermen presently pick up ice from the mainland before heading out to sea), the effective load factor of wind power was just 14 percent. The level of subsidy required for the hybrid was little less than the current level of subsidy to maintain an old diesel, and the proposal was abandoned.

(December), and a little less than 5 MW in January - for an annual average load factor of 22 percent. In short, such a project has very little capacity value, especially when compared to daily peaking hydro.

Figure T1.4 Operation of the Proposed Ly Son Island Wind Project



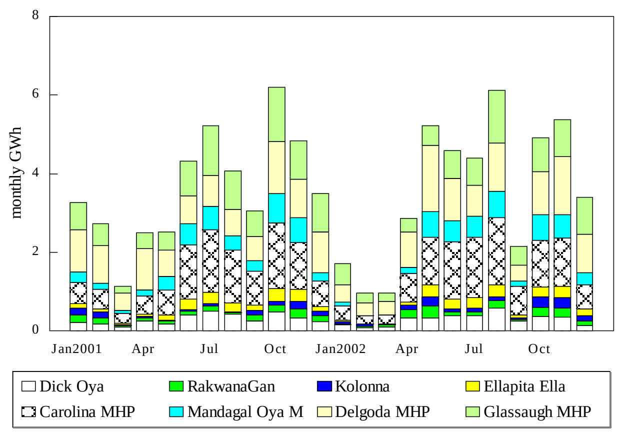
Source: ERAV Electricity Regulatory Authority of Vietnam (ERAV), *Review of the Avoided Cost Tariff for Small Grid-connected Renewable Energy Generation Projects*, Hanoi, September 2011

PORTFOLIO DIVERSIFICATION

141. It is often claimed that undispatchable renewable energy projects – notably run-of-river hydro and wind - have no capacity value, as indeed illustrated by the Ly Son Island example noted above. But that is not always or necessarily true. For example, in Sri Lanka this was the view held by the Ceylon Electricity Board (CEB) in 1998, at the time the avoided cost tariff was under consideration, and so the avoided cost tariff contained no capacity charge. However, from the perspective of the buyer, what really matters is not the impact of a single small project, but the impact of the *portfolio* of projects, whose inevitable diversity ensures that the variations in output are much smaller in the aggregate portfolio than in the single plant (as illustrated in the case of Sri Lanka in Box T1.3).

Box T1.3: Capacity value of SHP in Sri Lanka

The dry season output of the portfolio of small hydro projects shown is rarely zero, as shown here for the monthly production of a portfolio of 8 small hydro projects in Sri Lanka.

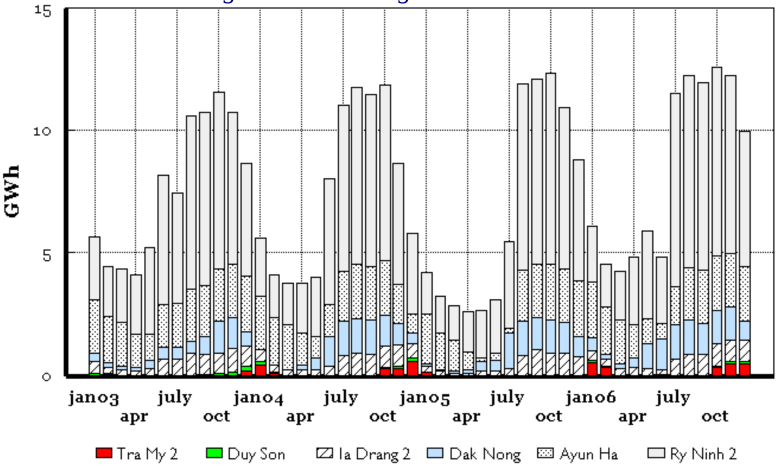


This portfolio benefit can be given quantitative expression by calculation of the coefficient of variation (standard deviation divided by the mean) of monthly outputs. For the set of hydro projects illustrated above, the average of the coefficients for individual plants is 0.56; but the coefficient of variation for the aggregate output of the portfolio, as received by the buyer, is 0.43.

Source: World Bank, 2003. Sri *Lanka, Energy Services Project, Implementation Completion Report.*

142. Figure T1.5 shows the energy production of a set of operating small hydro plants in Vietnam, based on actual generation in 2003-2006. Even in the very dry year of 2005, the aggregate output from the portfolio is clearly not zero: dry season output is roughly 20% of the wet season output (which implies that for 100MW of installed SHP capacity, the capacity credit should be about 20MW).

Figure T1.5: SHP generation in Vietnam

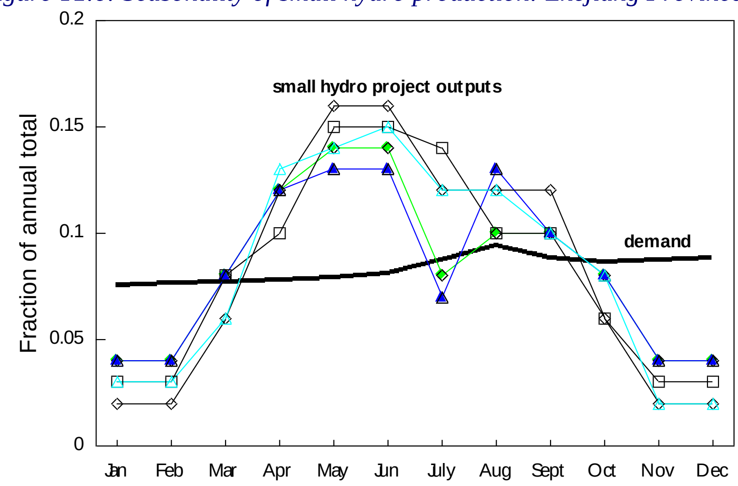


Source: ERAV Electricity Regulatory Authority of Vietnam (ERAV), *Review of the Avoided Cost Tariff for Small Grid-connected Renewable Energy Generation Projects*, Hanoi, September 2011.

143. It is this feature of the portfolio that provides the rationale for a capacity charge in Vietnam's avoided cost tariff, recovered over the peak hours of the dry season. In the wet season, EVN is not capacity constrained, and therefore the rationale for a capacity payment during this season is absent.

144. In some locations, while individual technologies cannot be diversified, combinations of different renewable technologies may provide diversification. Just such a combination may be possible in the Eastern China province of Zhejiang, where small hydro peaks in summer, and wind peaks in winter. Figure T1.6 shows the relative monthly output of five typical small-hydro projects in Zhejiang province compared to the seasonal variation in demand for the Zhejiang grid as a whole. It is evident that the seasonality of output and *grid* demand is poorly matched, even in the case of small hydro projects with substantial storage.

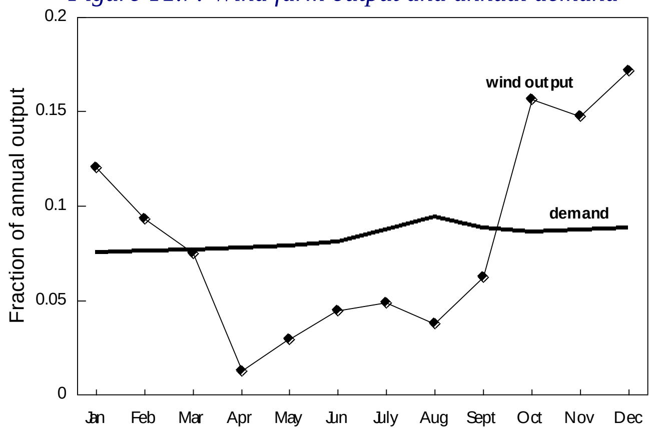
Figure T1.6: Seasonality of small hydro production: Zhejiang Province



Source: World Bank, 2003. *Economic and Financial Analysis of the China Renewable Energy Scale-up Programme (CRESP)*. ESMAP Renewable Energy Toolkit Website.

145. Figure T1.7 shows the corresponding data for the seasonality of wind-farm generation. Again we see a poor match between seasonal output and grid demand.

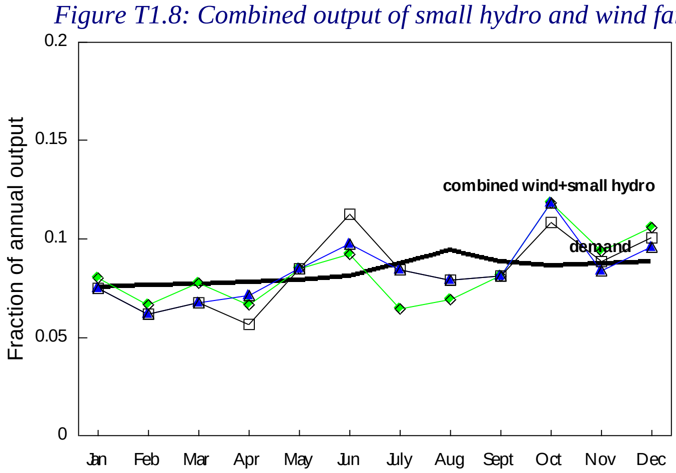
Figure T1.7: Wind farm output and annual demand



Source: World Bank, 2003. *Economic and Financial Analysis of the China Renewable Energy Scaleup Programme (CRESP)*. ESMAP Renewable Energy Toolkit Website.

146. However, when the two are combined, one obtains the result of Figure T1.8, now reasonably matched to the annual demand curve. Moreover, the result shown in this Figure assumes no change in operating rule at those small hydro projects as have some degree of seasonal storage. While changes in operating rule at multi-purpose projects (25% of the total in Zhejiang) may be difficult, and at pure run-of-river projects not possible, at least 35% of small hydro projects in Zhejiang have sufficient daily or weekly storage capacity to permit optimization of the operating rule. Indeed, as shown by the detailed case study, in order for this combination to provide real benefit, the small hydro plants must have at least daily peaking capability, since wind farm output rarely matches the daily load curve.

Figure T1.8: Combined output of small hydro and wind farms



Source: World Bank, 2003. *Economic and Financial Analysis of the China Renewable Energy Scale-up Programme (CRESP)*. ESMAP Renewable Energy Toolkit Website.

147. This complementarity between wind and small hydro points to the even greater complementarity between wind and *large* storage hydro, making wind power much more attractive in systems with good flexibility to absorb the hourly and seasonal variations in wind power output. When a portfolio of renewable resources can be diversified (whether just small hydro alone, or the small-hydro wind combination), the main benefit is that of an increased capacity credit, and the combination may become

economic as a result even though individual plants are not. Thus the capacity credit increase of diversified renewables portfolio reduces overall portfolio costs as well as providing a reduction of portfolio risk. The problem for CBA at appraisal is that the portfolio benefits may become apparent to the utility only *ex post* (as was the case in the ERAV evaluation of the avoided cost tariff for renewable energy in Vietnam). *Ex Ante*, particularly at the outset of a renewable energy support program, utility planners will be very doubtful about the contribution to firm capacity: but these examples may serve as a rebuttal.

Suggested Reading

Garrad Hassan, *Network Power Quality and Power System Operation with High Wind Energy Penetration*. 1997: Report to the World Bank.

Kumar, N., P. Besuner, S. Lefton, D. Agan, and D. Hilleman, *Power Plant Cycling Costs*, NREL, April 2012.

Romero, S., 2013. *Integration of Variable Renewable Technologies (VRE) into Power Systems: Review of Impacts and Solutions for Non-engineers*, ESMAP presentation.

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Madrigal, M. and K. Porter, 2013. *Operating and Planning Electricity Grids with VariableRenewable Generation Review of Emerging* Lessons from Selected Operational Experiences and Desktop Studies. World Bank Study.

Best Practice recommendations 5: Variable renewable energy(VRE)

(1) Even when the proportion of variable renewables is small, and there is no *technical* difficulty in absorbing the variable output, when combustion turbines or CCGTs are used as load followers there will generally be some penalty associated with lower average heat rates. This should be acknowledged. Only where pumped storage or large storage hydro projects serve this purpose (and there are no environmental flow constraints) can the integration costs be deemed negligible.

(2) In practice the options available to the economist charged with preparing the CBA for a wind project are limited. If project preparation resources are available, there is no substitute for a detailed systems study that can identify network stability problems with detailed load flow and hourly dispatch simulations. In the absence of such a study, utilities will frequently object that if only a year or two of detailed wind data is available, even if the project did contribute to the system peak load in that particular year, there is no guarantee that this would be the case every year.

(3) Given that the extent of capacity credit for variable renewables will always be controversial, it is always best for the economic analysis to record capacity and energy benefits separately, and that whatever assumption is made for the capacity credit be included in the variables treated in the sensitivity analysis. LCOE calculations are clearly not appropriate when evaluating variable renewables.

(4) Where any of the costs of intermittency can be itemised, these should be reflected by a corresponding line item in the table of economic flows.

T2 INCREMENTAL TRANSMISSION COSTS FOR RENEWABLES

148. Generalisations about incremental transmission costs are difficult, because much depends on location, the type of renewable energy technology in question, the configuration of the grid, and the extent to which local loads can absorb the incremental generation (rather than dispatched to distant locations). Some RE technologies (such as rooftop PV in urban centres) will avoid T&D energy losses, but not avoid T&D capacity costs.

149. Generation of renewable energy resources is necessarily tied to the location at which they occur. In many countries this entails very long transmission distances, much longer than associated with the thermal equivalent (and sometimes even further distant than large hydro projects). Moreover, thermal peaking projects are preferentially located as near as possible to population centres. Consequently major investments in transmission lines may be required to enable significant amounts of VRE. Indeed the Bank is financing such a $345 million transmission infra-structure scheme in Egypt to bring 3 GW of power from the rich wind resource region in the Gulf of Suez and Gabel El-Zait to the Cairo area (280 km of double circuit 500kV, 50 km of 2 x 220kV and associated substations) effectively costing $115/kW – a substantial incremental cost.[68] Madrigal & Stoft discuss transmission network planning for renewables scale-up. [69]

150. The extent to which renewable energy projects incur incremental transmission network investment costs will vary from country to country, and to the particular applicable locational circumstances. A study for the Electricity Regulatory Agency of Vietnam (ERAV) compared the transmission connection costs (mainly at 115 kV for connections to the 500kV grid) of small hydro with those of thermal and large hydro projects, and found average incremental network investment costs of $51/kW, compared to 29 $/kW for large hydro and 4$/kW for thermal peaking and $12/kW for coal projects (see Box T2.1 for details). On the other hand an ongoing system integration study for Sulawesi (Indonesia) has determined that no additional transmission line reinforcement is required to absorb the output from two proposed 50 MW wind farms (Jeneponto 1 & 2). [70]

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68 World Bank, *Egypt Wind Power Development Project*, Project Appraisal Document, 2010, 54267-EG.

69 M. Madrigal & S. Stoft, 2011. *Transmission Expansion for Renewable Energy Scale-Up Emerging Lessons and Recommendations*, World Bank, Energy and Mining Sector Board Discussion Paper 26.

70 Asian Development Bank, 2015. *Development of Wind Power and Solar Rooftop PV Market in Indonesia*. Jakarta, Indonesia.

Box T2.1: Incremental transmission costs of small hydro in Vietnam

In 2009 Vietnam introduced an avoided cost-based tariff for qualified renewable energy (for projects no greater than 30 MW). This has been very successful in enabling small hydro: in the period 2012-2020, an additional 1,500 MW of such projects is at various stages of implementation. The bulk of this capacity is in five provinces, whose transmission development plans have been accordingly adjusted. These point to significant incremental network development costs, primarily at 115kV, to evacuate this power to the 500kV grid: these are remote provinces whose local demands are much smaller than the planned small hydro capacity. Table A shows the results of a study of these network costs by the Vietnam Electricity Regulator ERAV: on average, the incremental costs were estimated at around $51/kW.

A. Incremental Network costs, small hydro

Province	to 2015	2016-2020	total
incremental MW			
Dak Nong	90	47	137
Nghe An	155	26	182
Gia Lai	347	28	375
Lai Chau	174	188	362
Son La	287	0	287
Total	1,053	289	1,342
$/kW			
Dak Nong	63.4	87.5	71.7
Nghe An	48.0	0.0	41.1
Gia Lai	71.1	0.0	65.8
Lai Chau	66.2	28.2	46.5
Son La	33.7		33.7
Total	56.0	32.6	51.0
total, VNDbillion/MW	1.1	0.7	**1.0**
$/kW			**51.0**

These may be compared to the comparable transmission connection costs (mostly at 220kV) for thermal and large hydro, shown in Table B. The highest average costs are for large hydro projects (at $29/kW): costs for thermal projects (most of which in Vietnam are in the South, close to the Ho Chi Minh City load centre and to the domestic gas fields), are in the range of $4-12/kW.

B. Incremental network costs, thermal and large hydro

		220kV	installed capacity	cost		
project	Type	circuits x km	MW	Đbillion	Đbillion /MW	$/MW
Non Trach 1	CCGT	2x0.7km+4x0.7km	450	18.3	0.04	2.0
O Mon 1	CCGT		600	66.7	0.11	5.4
average	**CCGT**		**1050**	**85.0**	**0.08**	**3.9**
Nghi Son 1	Coal	2 x 6.7km	600	130.0	0.22	10.6
Son Dong	Coal	2 x 18 km	220	73.4	0.33	16.3
average	**Coal**		**820**	**203.3**	**0.25**	**12.1**
Srepok 4	hydro	2 x 6.7km	70	30.9	0.44	21.5
A luoi	hydro	2 x 30km	150	146.0	0.97	47.5
Dong Nai 3	hydro	2 x 30km	180	81.7	0.45	22.2
Dong Nai 4	hydro	2 x 11.4 km	340	39.9	0.12	5.7
Huoi Quang	hydro	2 x 17.9km	560	149.6	0.27	13.0
Trung Son	hydro	2 x 63 km	260	452.8	1.74	84.9
Ban Chat	hydro	2 x 27.4km	220	163.5	0.74	36.3
average	**hydro**		**1780**	**1064.3**	**0.60**	**29.2**

Source: *Source:* Electricity Regulatory Authority of Vietnam (ERAV), *Review of the Avoided Cost Tariff for Small Grid-connected Renewable Energy Generation Projects*, Hanoi, September 2011

Best Practice recommendations 6: Transmission connections for renewables

(1) A major transmission line designed to evacuate large quantities of renewable energy from proposed RE generating stations cannot have its own *economic* return, independent of the generating projects in question (nor indeed can the generating projects be assessed without taking into account the transmission evacuation cost). This is true even if the transmission line is financed and built by completely different entities. The renewable energy project (or projects) and transmission line should be justified together. The Egypt wind power transmission project serves as a good example. Now it may well be that not all wind farms presently expected would be built to the timetable envisaged at the time the transmission line is built. But one deals with that problem by a sensitivity analysis to show how the economic returns are sensitive to the realisation and timing of such future generation project additions.

(2) However, the financial returns to the entity developing he transmission line will of course depend on the transmission pricing regime and the regulatory arrangements governing the transmission system operator (TSO). The details of transmission pricing options will rarely affect the economic flows: the necessary transmission investments (and related O&M) should be separately recorded as lines in the table of economic flows.

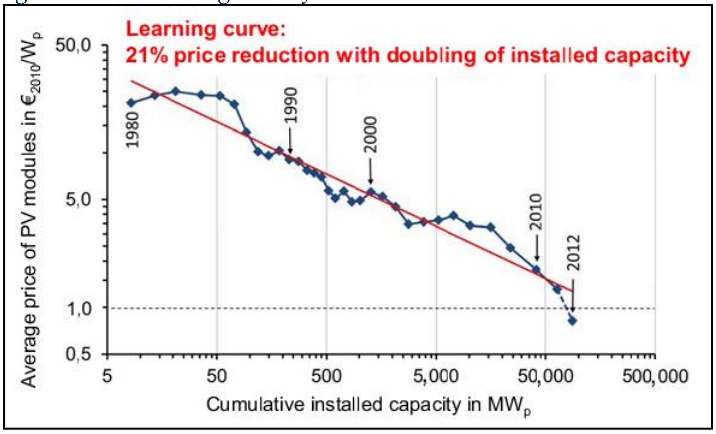
(3) Given the wide range of incremental transmission costs in the literature, there is no substitute for a reasoned project-specific examination – which for a program of small hydro or wind development at the very least requires study of the relevant 115kv/220kv transmission plan for the region in question. As shown in the Vietnam example, even if the connection cost from generating project to the nearest substation is assumed by the developer (as most PPAs require), the aggregate impact of many small hydro projects may still impose significant additional network development costs at 115kV or 220kV on the TSO.

(4) When the incremental transmission costs for renewable energy are potentially significant – which they often are when compared to gas CCGT near the load centres – it is also worth taking a closer look at the gas price to such projects, and examine whether the delivered price properly reflects import parity price (that should include the relevant recovery costs for pipeline transportation from the gas field).

T3 LEARNING CURVE BENEFITS FOR RENEWABLE ENERGY

151. The evidence of learning curve effects for new technologies is irrefutable, best illustrated in the case of photvoltaics. That a similar effect will be observed for new technologies such as CSP is similarly plausible, even if the cost reductions to date have been somewhat lower than for PV modules.

Figure T3.1: Learning curve for PV



Source: Fraunhofer, *Aktuelle Fakten zur Photovoltaik in Deutschland*, 4 April 2014.

152. CSP is considered to be a proven technology that is at the point of exiting the early stage of its cost reduction curve. The learning curve of cost reduction as installed capacity increases is linked to:

- technical improvements, as lessons are learned from installed plants and parallel R&D efforts identify performance improvements;
- scaling to larger installed plant size, that allows for more efficient and more cost effective large components;
- volume production that allows fixed costs of investments in production efficiency to be spread over larger production runs; and
- Improved production process efficiency (e.g., reduced controllable costs, improved assembly lines, outsourcing, etc.).

153. Most assessments of the past learning curve for CSP suggest that thus far, the CSP learning curve rate is no more than 10% - half the rate of 21% shown in Figure T3.1 for PV. However, many of the components and variants of this technology are not yet fully commercial (such as molten salt, tower collectors and Fresnel collectors).

154. We know of two studies in the World Bank literature that have attempted a quantification of learning curve benefits associated with specific bank-financed projects. – for wind power as part of the project preparation for the China Renewable Energy Scale-up Project (CRESP), and for the Morocco Noor II&III CSP projects. In both cases the benefit-cost analysis took the form of enumerating as costs the subsidies required to build projects at (the high) present costs and in the near future, to be balanced against the future benefits that are expressed as the difference between the lower (future) cost of the technology against the fossil fuelled alternative. The Morocco report is still being finalised (to respond to peer review comments on the draft), but even in its first version it strengthened the case for World Bank financing of the Morocco CSP project.

The China CRESP wind power study[71]

155. The question posed was whether subsidies for wind power in the short term, defined as the incremental cost of a feed-in tariff, would be recouped in the future if the capital cost of wind power declined as a result of large scale adoption to the point where it fell below the average grid price, and as capacity factors improved over time, with greater hub heights (increasing from 0.3 in 2004 to 0.36 by 2025).

156. In Table T3.1, the CRESP report hypothesised the wind additions starting in 2004, increasing to 43,000 MW by 2025, with an initial FIT of 0.55 Y/kWh (6.6 USc/kWh at the then prevailing exchange rate), at a time when the average grid price was 0.31 Y/kWh (3.7 USc/kWh). The incremental costs were assumed eliminated by 2010 (i.e., in that year, the FIT would be less than the average grid price), though because of the cost of earlier year tariff support, the annual balance of the total wind portfolio turns positive only in 2015 – it is these annual net balances (column 10) that constitute the basis for the ERR and NPV calculations.

Table T3.1: Benefit cost analysis of feed-in tariff support

year	Additions, MW	total MW	capacity factor	total wind energy, GWh	wind FIT, Y/kWh	grid price, Y/kWh	Feedlaw differential, Y/kWh	Impact of yearly addition, Ymillion	total cost Ymillion
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
2004	160	160	0.3	420	0.550	0.310	0.24	-101	-101
2005	280	440	0.303	743	0.501	0.312	0.19	-140	-241
2006	400	840	0.306	1072	0.455	0.314	0.14	-152	-393
2007	575	1,415	0.309	1556	0.414	0.316	0.10	-153	-546
2008	725	2,140	0.312	1982	0.377	0.318	0.06	-117	-663
2009	860	3,000	0.315	2373	0.343	0.320	0.02	-55	-718
2010	1,000	4,000	0.318	2786	0.312	0.322	-0.01	27	-691
2011	1,200	5,200	0.321	3374	0.300	0.324	-0.02	81	-610
2012	1,400	6,600	0.324	3974	0.298	0.326	-0.03	111	-499
2013	1,600	8,200	0.327	4583	0.296	0.328	-0.03	147	-352
2014	1,800	10,000	0.33	5203	0.294	0.330	-0.04	187	-165
2015	2,000	12,000	0.333	5834	0.292	0.332	-0.04	233	68
2016	2,200	14,200	0.336	6475	0.290	0.334	-0.04	285	353
2017	2,400	16,600	0.339	7127	0.288	0.336	-0.05	342	695
2018	2,600	19,200	0.342	7789	0.286	0.338	-0.05	405	1100
2019	2,800	22,000	0.345	8462	0.284	0.340	-0.06	474	1574
2020	3,000	25,000	0.348	9145	0.282	0.342	-0.06	549	2123
2021	3,200	28,200	0.351	9839	0.280	0.344	-0.06	630	2753
2022	3,400	31,600	0.354	10544	0.278	0.346	-0.07	717	3470
2023	3,600	35,200	0.357	11258	0.276	0.348	-0.07	811	4280
2024	3,800	39,000	0.36	11984	0.274	0.350	-0.08	911	5191
2025	4,000	43,000	0.363	12720	0.272	0.352	-0.08	1018	6209

Source: World Bank. 2003. *Economic Analysis for the China Renewable Energy Scale-up Programme (CRESP)*. Washington, DC: World Bank

157. Under these assumptions scenario, the ERR of the time-slice of investment in up-front FIT subsidy in years 2004-2009 earns an 18.6% return derived from future cost reductions that follow from the learning curve. [72]

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[71] World Bank. 2003. *Economic Analysis for the China Renewable Energy Scale-up Programme (CRESP)*. Washington, DC: World Bank.

[72] The NPV calculations extend to 2050 (so the benefits of the projects built in 2025 extend for 20 years), but with no further wind projects built after 2025.

158. However, there are many uncertainties in this illustrative calculation, and with the benefits of hindsight (at the time of writing a decade later in 2015) we note the following:

- FIT prices are now in the range of 0.51-0.61Y/kWh, (8.3-9.8 USc/kWh), still substantially above the general coal grid price of around 6USc/kWh, but below that of gas at around 11 USc/kWh.
- The 25,000 MW assumed reached in the original calculation by 2020 was reached in 2014: however, average capacity factors are significantly below those projected in 2003, in large measure because of lack of transmission infrastructure. In 2014, the average national capacity factor was just 21% (though that of Fujian province was 28.8%).
- China's National Energy Administration is now reported to be considering a first decrease in the current FIT rates (0.51-0.61 Y/kWh) to 0.47-0.51 Y/kWh (7.6 – 8.3 USc/kWh).
- These calculations did not consider either the avoided local or global externality damage costs, but also did not consider the capacity benefit of wind (see Box T1.3)

The Morocco CSP study[73]

159. Although the economic returns for the Noor II&III CSP projects are negative (or economic only under very high valuations of avoided carbon) the project specific economic assessment does not recognize its contribution to the global public good. If the global community makes a commitment to cover the subsidies necessary to build CSP projects in the short run, the learning curve effects will lower the costs of CSP to the point where it will provide lower cost electricity in the future (an experience clearly documented by PV and wind, and generally expected for CSP as well).

160. The recent changes in the Spanish regulation have had a direct impact in the cost learning curves for CSP. Before 2012, the old feed-in tariff structure in Spain dis-incentivized cost reduction and held the cost of CSP plants at a very high level over several years. However the currently prevailing tender process for CSP projects offers more incentives for cost reductions and innovation. For this reason, a two-phase learning curve approach for CSP was proposed: phase from 2006-2013 with PR = 81.4%; and phase from 2014 on with PR = 80.5%. The progress ratio (PR) is a parameter that expresses the rate at which costs decline for every doubling of cumulative installation. For example, a progress ratio of 80% equals a learning rate (LR) of 20%: in other words, a 20% cost decrease for each doubling of the cumulative capacity. Both terms are used in the literature.

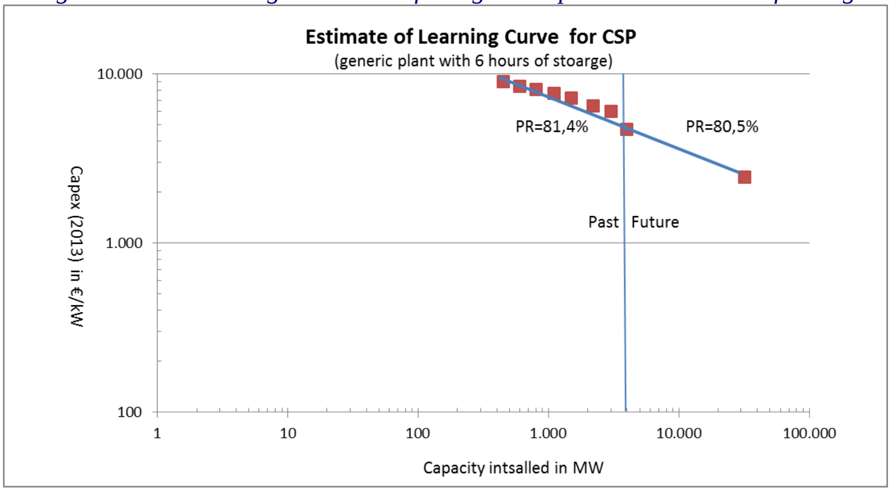
161. The learning cost curve estimate above would indicate that the Noor Complex can be expected to reduce the global cost curve for CSP by 3 percent, while the 2,000 MW Morocco Solar Plan, if it relied solely on CSP, would be capable of reducing global CSP costs by 13 percent.

162. Once the total installed global capacity of CSP reaches some 32,000MW, the capital cost should decline from the present Euro 5,000/kW ($6,800/kW) to Euro 3,000/kW (4,110/kW) that is assumed to be reached by 2030. As shown in Figure T3.3, while CSP today is more expensive than CCGT, requiring a levelised subsidy of 2.1 USc/kWh (when evaluated at the assumed 5% opportunity cost of capital) by 2030, the cost of CSP will be 3.4 USc/kWh cheaper than gas. This is based on the trajectory of the social cost of carbon as estimated by the US Interagency Working Group on the Social

73 Extracted from World Bank, 2014. *Morocco: Noor-Ouarzazate Concentrated Solar Power Project*, Project Appraisal Document, PAD 1007, and P.Meier and R. Weisenberg, *Global Learning Curve Benefits of Concentrated Solar Power.* Background Report for the Morocco CSP Project, April 2014.

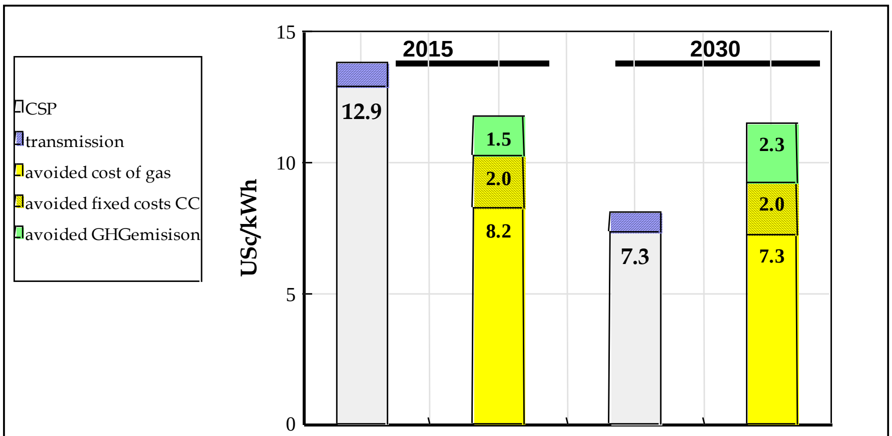
Cost of Carbon (IWGSCC) at the 3% discount rate (from the 2015 estimate of \$38/ton to \$57/ton by 2030).[74]

Figure T3.2: Learning Cost Curve for a generic plant with 6 hours of storage



Source: World Bank, 2014. *Morocco: Noor-Ouarzazate Concentrated Solar Power Project*, Project Appraisal Document, PAD 1007

Figure T3.3: CSP v CCGT



As USc/kWh	CSP	CCGT	CSP	CCGT
CSP	12.9		7.3	
transmission	0.9		0.8	
avoided cost of gas		8.2		7.3
avoided fixed costs CCGT		2.0		2.0
avoided GHGemisisons		1.5		2.3
total	13.8	11.8	8.1	11.5
net subsidy required	2.1			
net benefit			3.4	

Source: World Bank, 2014. *Morocco: Noor-Ouarzazate Concentrated Solar Power Project*, Project Appraisal Document, PAD 1007

163. These 2030 costs, and the benefits that go with them can only be achieved if the world builds 32 GW of CSP which would be necessary to bring down the costs as shown. Considering the ambitious CSP targets announced by some countries (e.g., Saudi Arabia's 25 GW CSP target by 2032, and the IEA's forecast of 70 GW of global CSP

74 These estimates were prepared prior to the new Bank Guidelines on the valuation of carbon (See Table M5.1). However, application of these new values (\$30/ton CO_2 in 2015, increasing to \$50/ton CO_2) would not significantly change the findings of Figure T3.3

capacity by 2035), this estimate of global capacity additions is not unreasonable. Indeed, by 2030, the IEA 450ppm scenario anticipates 15 GW of CSP just in Europe.

164. Detailed calculations show that the global investment into CSP in the short term – to cover the incremental costs and subsidies required for the projects built today, such as Noor II&III – bring a long run (real) rate of economic return of around 7%. This is just like a standard economic analysis, in which the costs are the subsidy requirements in the early years, and the benefit stream is the cost advantage in future years (as shown in Figure T3.3). Table T3.2 summarises the calculations for three scenarios based on the assumption that by 2030, 32 GW of CSP would supply either the European market (and therefore includes the cost of HVDC transmission – for example, from Libya to Milan, and Jordan to Ankara). European gas prices are taken from the 2013 IEA World Energy Outlook. For example in the pessimistic scenario, CSP capital costs only reach 3,800 $/kW by 2030, and carbon prices decline rather than increase.

Table T3.2: CSP learning curve scenarios

		pessimistic	baseline	optimistic
2030 CSP CAPEX	$/kW	3,800	3,350	3,000
2030 carbon price	$/ton CO_2	40	57	80
gas price	$/mmBTU	10.2	10.2	12.2
CCGT efficiency	[ ]	50.0%	48.0%	48.0%
CSP capacity factor	[ ]	37.5%	40.4%	41.0%
HVDC transmission loss	[ ]	12.0%	11.0%	10.0%
ERR	[ ]	3%	6.9%	11.6%

165. The *Noor* CSP project reaps only a very small share of these benefits for itself, for Noor pushes us only a very small distance toward the global learning curve target of 32 GW: none of these benefits were applied to the *Noor* economic flows. This analysis simply illustrates what may be the benefits of the global learning curve, and what are the likely returns if the *global international community* should invest in CSP. There is also the additional question of whether the World Bank should be leading the effort for CSP, given the Bank's own opportunity cost of capital (EOCK). While the 6.9% baseline return is arguably above the (real) OECD opportunity cost of capital, the 10% rate reflects better the real rates of economic return obtainable in other developing country projects and other sectors supported by the World Bank. The analysis suggests that only under very optimistic assumptions would the economic return of a global investment in CSP meet normal EOCK expectations.

Best practice recommendation 7: Learning curve benefits for renewables

(1) As noted in the main text, rigorous quantification of learning curve benefits requires further research, and the only recommendation we can make for this first edition of the guidance document is to avoid generalised textual assertions that a specific renewable energy project has "learning curve benefits". By definition such global benefits accrue to other projects in the future, and therefore serve only to justify support from the global community (and the IFIs) in the short term. No matter how great the learning curve benefit to *future* CSP projects, the incremental costs of the Morocco CSP projects still have to be recovered today, either by Morocco or through grants and concessional finance from the global community.

(2) That said, even if learning curve benefits do not change the project ERR, such studies of learning curve benefits inform the second & third of the three main questions demanded by OPSPQ of a project economic analysis, namely to justify World Bank financing and support in project design.

T4 RENEWABLE ENERGY COUNTERFACTUALS

166. The gold standard of counter-factuals is one prepared with detailed power system planning models. Among the Bank's recent renewable energy projects, such models were available for the Morocco CSP, Indonesian geothermal, and Vietnam hydro projects. In each case the models were maintained by the power system planning departments of national utilities, and were run with and without the proposed renewable energy project. Where the Bank has good established relationships with the utility planning departments, obtaining their cooperation in making sure that the data inputs were appropriate for *economic* analysis (i.e. using border prices rather than the financial prices) is often straightforward (provided the caveats noted in Technical Note T1 concerning the use of economic prices and capacity credit are observed).

Simple counter-factuals

167. The difficulties arise where such models are *not* available, in which case the counter-factual (or "baseline" as it is termed in the carbon accounting guidelines) must be constructed by the project economist. The problem is not so much choosing the type of thermal generation that would be displaced by the RE project (which in some cases is also straightforward), but how the avoided costs are booked in the table of economic flows. Above all this is problematic in the case of variable renewables.

168. What one often sees in such "simple" counterfactuals is that the benefits are simply booked as the levelised cost of thermal energy. Even when this is correctly calculated using the border price or import parity price for the energy, the benefits will be overstated. The correct approach is to separate energy and capacity benefits.

169. Table T4.1 shows such a calculation (using the same basic cost assumptions as in Table C1.13). Row [9] shows that if a 100% capacity credit is taken (i.e. the cost of CCGT capacity necessary to produce the same output as the wind project), then the ERR is 11.2%, or 12.8% when the benefits of avoided GHG emissions are also included.

Table T4.1: Economic flows for a 100MW wind project, 100% capacity credit

				LCOE	NPV	-1	0	1	2	3	4	5	10	15	20
[1]	***costs***														
[2]	Capital cost		[$USm]	*9.6*	*190*		230.0								
[3]	O*M cost		[$USm]	*2.6*	*52*			6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9
[4]	total cost		[$USm]	*12.3*	*242*	0.0	230.0	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9
[5]															
[6]	generation		[GWh]		*1971*			262.8	262.8	262.8	262.8	262.8	262.8	262.8	262.8
[7]															
[8]	***Avoided costs=benefits***														
[9]	Capital cost	**100%**	[$USm]	*1.7*	*33*	19.3	19.3								
[10]	fixed O*M cost		[$USm]	*0.3*	*6*			0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
[11]	fuel cost	0.11	[$USm]	*11.0*	*217*			28.9	28.9	28.9	28.9	28.9	28.9	28.9	28.9
[12]	total cost		[$USm]	*13.0*	*256*	19.3	19.3	29.7	29.7	29.7	29.7	29.7	29.7	29.7	29.7
[13]															
[14]	Net benefits		[$USm]		*14*	19.3	-210.7	22.8	22.8	22.8	22.8	22.8	22.8	22.8	22.8
[15]	*ERR*		[$USm]		11.2%										
[16]	emission factor	0.35	Kg/kWh												
[17]	value	30	$/ton												
[18]	avoided GHG emissions		1000 tons					92	92	92	92	92	92	92	92
[19]			[$USm]	18.6				2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
[20]	adjusted net benefits		[$USm]	30.0		19.3	-210.7	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5
[21]	ERR		[ ]		*12.8%*										

170. But if the capacity credit is zero, then as shown in Table T4.2, the ERR falls to 8.2%, or 9.6% with avoided GHG emissions taken into account: the hurdle rate of 10% is not achieved.

Table T4.2: zero capacity credit

				LCOE	NPV	-1	0	1	2	3	4	5	10	15	20
[1]	***costs***														
[2]	Capital cost		[$USm]	*9.6*	*190*		230.0								
[3]	O*M cost		[$USm]	*2.6*	*52*			6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9
[4]	total cost		[$USm]	*12.3*	*242*	0.0	230.0	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9
[5]															
[6]	generation		[GWh]		*1971*			262.8	262.8	262.8	262.8	262.8	262.8	262.8	262.8
[7]															
[8]	***Avoided costs=benefits***														
[9]	Capital cost	**0%**	[$USm]	*0.0*	*0*	0.0	0.0								
[10]	fixed O*M cost		[$USm]	*0.0*	*0*			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
[11]	fuel cost	0.11	[$USm]	*11.0*	*217*			28.9	28.9	28.9	28.9	28.9	28.9	28.9	28.9
[12]	total cost		[$USm]	*11.0*	*217*	0.0	0.0	28.9	28.9	28.9	28.9	28.9	28.9	28.9	28.9
[13]															
[14]	Net benefits		[$USm]		*-25*	0.0	-230.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
[15]	*ERR*		[$USm]		8.2%										
[16]	emission factor	0.35	Kg/kWh												
[17]	value	30	$/ton												
[18]	avoided GHG emissions		1000 tons					92	92	92	92	92	92	92	92
[19]			[$USm]	18.6				2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
[20]	adjusted net benefits		[$USm]	-5.6		0.0	-230.0	24.8	24.8	24.8	24.8	24.8	24.8	24.8	24.8
[21]	ERR		[ ]		*9.6%*										

171. Setting up the calculations in this way makes it easy to include the capacity credit in the sensitivity analysis: using backsolve,[75] it is easy to show that (in this example), the switching value for capacity credit is 65% (Table T4.3). This is significantly greater than the capacity credits shown in Table T1.5, so in this instance one would conclude that the wind project is not economic from the perspective of the client country.

Table T4.3: Switching value of capacity credit

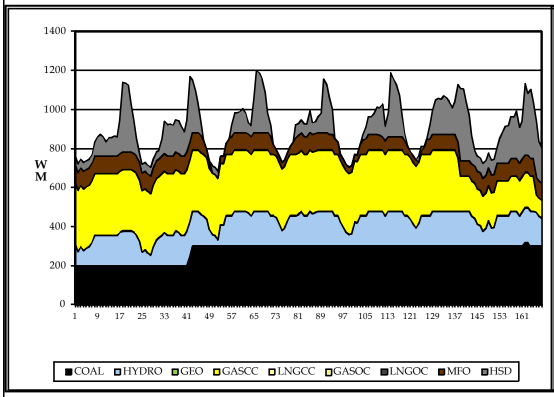
				LCOE	NPV	-1	0	1	2	3	4	5	10	15	20
[1]	***costs***														
[2]	Capital cost		[$USm]	*9.6*	*190*		230.0								
[3]	O*M cost		[$USm]	*2.6*	*52*			6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9
[4]	total cost		[$USm]	*12.3*	*242*	0.0	230.0	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9
[5]															
[6]	generation		[GWh]		*1971*			262.8	262.8	262.8	262.8	262.8	262.8	262.8	262.8
[7]															
[8]	***Avoided costs=benefits***														
[9]	Capital cost	**65%**	[$USm]	*1.1*	*22*	12.5	12.5								
[10]	fixed O*M cost		[$USm]	*0.2*	*4*			0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
[11]	fuel cost	0.11	[$USm]	*11.0*	*217*			28.9	28.9	28.9	28.9	28.9	28.9	28.9	28.9
[12]	total cost		[$USm]	*12.3*	*242*	12.5	12.5	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4
[13]															
[14]	Net benefits		[$USm]		*1*	12.5	-217.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5	22.5
[15]	*ERR*		[$USm]		10.0%										
[16]	emission factor	0.35	Kg/kWh												
[17]	value	30	$/ton												
[18]	avoided GHG emissions		1000 tons					92	92	92	92	92	92	92	92
[19]			[$USm]	18.6				2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
[20]	adjusted net benefits		[$USm]	17.5		12.5	-217.5	25.3	25.3	25.3	25.3	25.3	25.3	25.3	25.3
[21]	ERR		[ ]		*11.5%*										

75 In EXCEL using the "goal seeking" function.

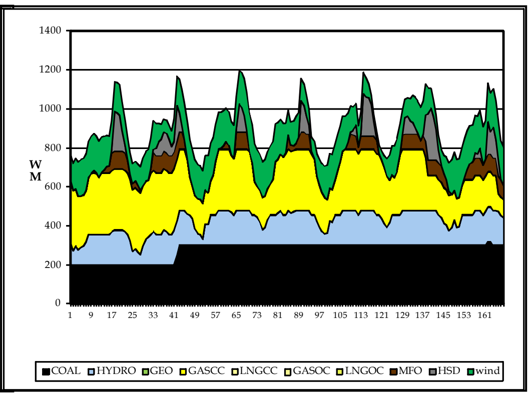
Box T4.1: Counter-factual for Indonesian wind energy using the ProSym Model

A recent study to develop a tariff ceiling based on the benefits of wind energy (rather than on production costs) for Indonesia benefitted from the ability to run detailed dispatch simulations using the ***ProSym*** model used by PLN, the Indonesian utility. This was done both for the large Java-Bali and Sulawesi grids, for which capacity expansion plans had recently been established. Under the assumption that the wind projects would provide no capacity benefit, the optimal hourly dispatch in the absence of wind was perturbed by the hourly output of a wind project (i.e. wind treated as a negative load). These simulations took into account the different ramp rates of thermal projects.

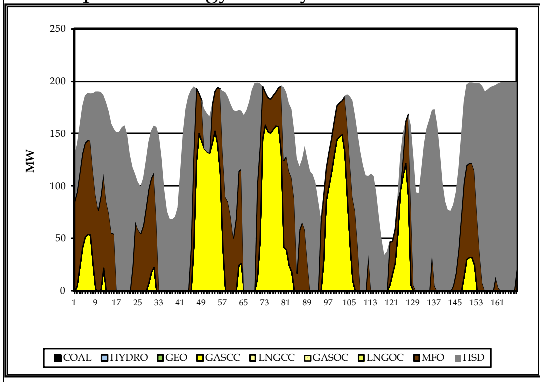
A. Dispatch in the absence of wind



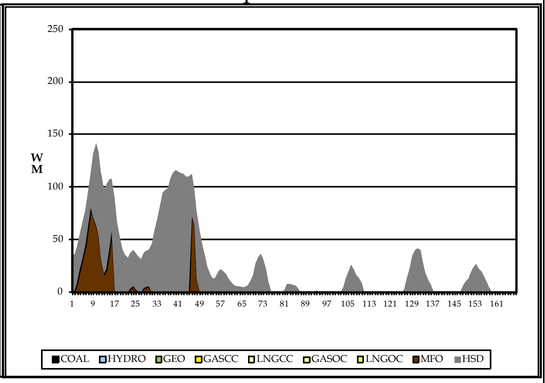
B. With wind



C. Displaced energy: windy week



D. wind-poor week



With these results in hand, the mix of thermal generation displaced in each year was readily established, and could then be valued at import parity price to derive the average avoided energy benefit. In 2016, shown above, wind displaces auto diesel (HSD) and marine fuel oil (MFO); by 2020 these will have been retired and replaced by CCGT.

Source: Asian Development Bank, 2015. *Development of Wind Power and Solar Rooftop PV Market in Indonesia. Jakarta, Indonesia.*

THE COUNTERFACTUAL AND DISCOUNT RATES

172. The discount rate is a critical assumption in any comparison of a renewable energy option against its counterfactual. As an illustration, consider the problem now faced by Afghanistan: should the country continue to rely mainly on imported electricity from its CAR neighbours,[76] or should it build its own generation project based on

76 For details of Afghanistan's electricity imports, see Box C7.1.

domestic (Sheberghan) gas, or develop its own smaller scale renewable energy projects.[77] The comparison is made on the basis of a 300 MW of additional load imported at an annual load factor of 0.7. Comparing like with like means that to produce the same amount of energy as the gas and import options, at a 35% annual capacity factor one must build 600 MW of wind.[78]

173. The NPV calculations at the traditional 10% discount rate are shown in Table T4.4: the results show that the NPV of the cost of imports is $998 million, as against $1,013 million for gas and $1,235 million for renewable energy. Imports are least cost (though not by much).

Table T4.4: NPV calculations, 10% discount rate

				NPV	2015	2016	2017	2018	2019	2020	2021
[1]	**A. Imports**										
[2]	# of 50MW units	6									
[3]		300	MW								
[4]	capacity factor	0.7	[ ]								
[5]	GWh in Kabul		[GWh]				1840	1840	1840	1840	1840
[6]	import price		[$/kWh]				0.08	0.08	0.08	0.08	0.08
[7]	import cost		[$USm]	***998***			147.2	147.2	147.2	147.2	147.2
[8]	levelised cost		[USc/kWh]	***8.0***							
[9]	**B. Gas**										
[10]	# of 50MW units	6									
[11]	total installed capacity	300									
[12]	energy		[GWh]	*12469*			1840	1840	1840	1840	1840
[13]	Capital cost	850	[$/kW]								
[14]	Afganistan premium	1.5	[ ]								
[15]	Investment cost		[$USm]		191.3	191.3					
[16]	Gas cost		[$/mmBTU]				8.0	8.0	8.0	8.0	8.0
[17]	Heat rate	6828	BTU/kWh								
[18]	fuel cost		[$USm]				100.5	100.5	100.5	100.5	100.5
[19]	total cost		[$USm]	***1013***	191.3	191.3	100.5	100.5	100.5	100.5	100.5
[20]	levelised cost		[USc/kWh]	***8.1***							
[21]	**C. Renewable energy**										
[22]	units installed	12									
[23]	total installed capacity	600									
[24]	capacity factor	0.35									
[25]			[GWh]	*12469*			1840	1840	1840	1840	1840
[26]	Capital cost	1500	[$/kW]								
[27]	Afganistan premium	1.25	[ ]								
[28]	Investment cost		[$USm]			1125.0					
[29]	O&M cost	0.04	[$USm]				45.0	45.0	45.0	45.0	45.0
[30]	total cost		[$USm]	***1235***	0.0	1125.0	45.0	45.0	45.0	45.0	45.0
[31]	**levelised cost**		[USc/kWh]	**9.9**							

Note: Calculations assume a 20-year life: for sake of legibility the snapshot shown here is just for the first few years. The calculations are based on costs corresponding to 50 MW-scale increments using gas engines (projects larger than this size will be very difficult to finance for the time being). Gas engines are also easier to operate than CCGT, and are seen as the most appropriate gas generation technology for Afghanistan in the current security environment.

174. But change the discount rate and the conclusions also change. Figure T4.1 shows the NPV for each option as a function of the discount rate. Imports are only the least cost option for discount rates above 9%; from 4 to 9% the indicated choice is gas, and below 4% the indicated choice is renewable energy. In short, lower the discount rate, the more attractive is the renewable energy option.

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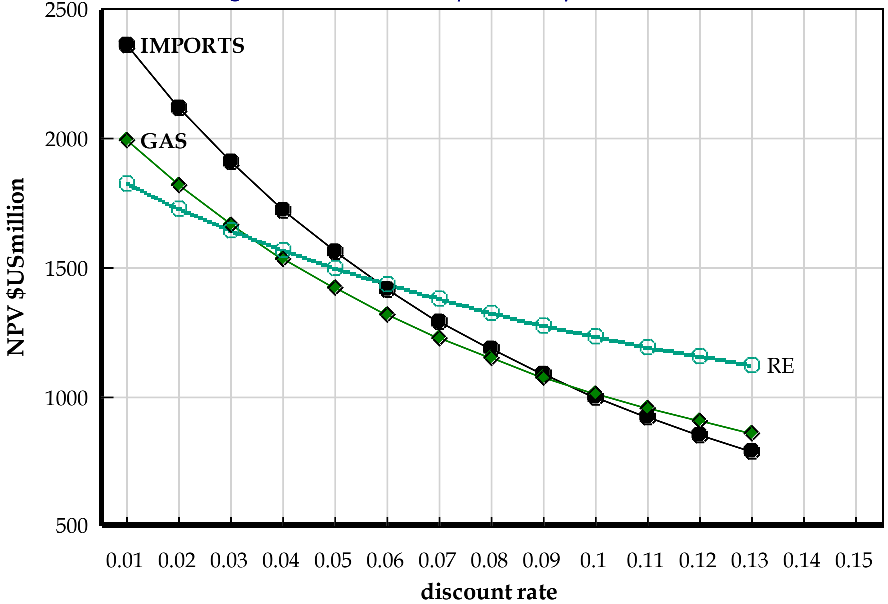
77 This example is extracted from the ESMAP study of Afghanistan: Meier, P., J. Irving, J. and C.Wnuk, *Energy Security Trade-Offs under High Uncertainty: Resolving Afghanistan's Power Sector Development Dilemma*, World Bank, ESMAP, 2015.

78 For the moment, we ignore any capacity penalties associated with VRE

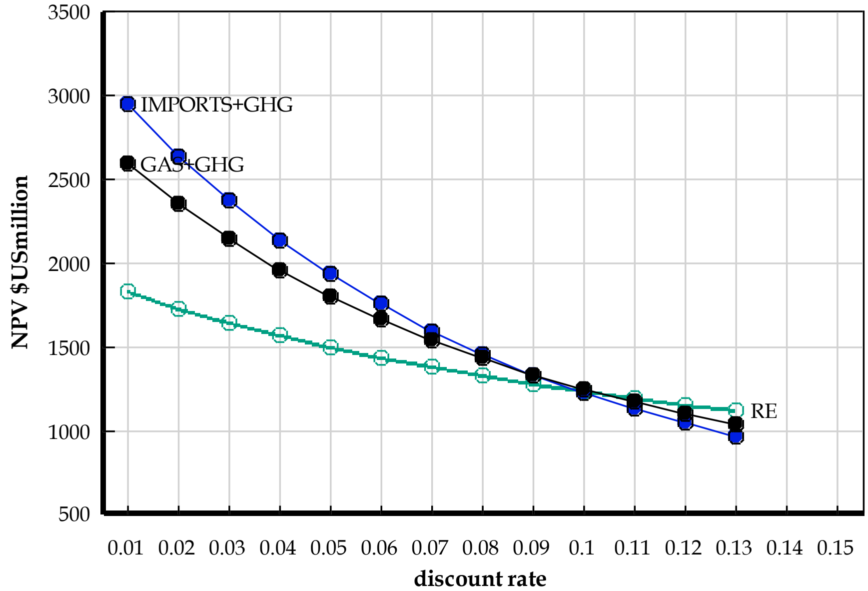
Figure T4.1: NPV as a function of discount rate:



175. However, these comparisons do not take into account the negative externalities of fossil based generation. Imports are based on gas generation in the Central Asian Republics (Uzbekistan and Turkmenistan), and therefore also generate GHG emissions. How do the results change if these externalities are taken into account?

176. In Table T4.5 we include a calculation of the GHG emission damage costs using the values in the World Bank guidance document for the social value of carbon (see table M5.1).[79] Now at the 10% discount rate, the cost of the renewable energy option (NPV=$1,235 million) is only marginally above the import option ($1,126 million), and below the gas option ($1,246 million). Indeed, at all discount rates below 10% renewable energy is least cost when the GHG emission damage costs are taken into account (Figure T4.2).

Figure T4.2: Comparison of NPVs as a function of discount rate when GHG damage costs are included.



79 The values shown in Table T4.5 have been updated to 2015 prices, and interpolated for the annual values shown in row [11].

Table T4.5: NPV calculations including GHG damage costs (10% discount rate)

				NPV	2015	2016	2017	2018	2019	2020	2021
[1]	**A. Imports**										
[2]	50MW units installed	6									
[3]	total installed capacity	300	MW								
[4]	capacity factor	0.7	[ ]								
[5]	GWh in Kabul		[GWh]				1840	1840	1840	1840	1840
[6]	import price		[$/kWh]				0.08	0.08	0.08	0.08	0.08
[7]	import cost		[$USm]	***998***			147.2	147.2	147.2	147.2	147.2
[8]	levelised cost		[$USm]	***8.0***							
[9]	GHGemission factor	0.45	kg/kWh								
[10]	GHG emissions		[1000 t]				828	828	828	828	828
[11]	environmental damage cost		[$/tonCO2]				32.6	33.7	34.7	35.7	37.2
[12]	damage costs		[$USm]				27.0	27.9	28.7	29.6	30.8
[13]	adjusted costs		[$USm]	*1226*			174.2	175.0	175.9	176.7	178.0
[14]	levelised cost		[USc/kWh]	*9.8*							
[15]	**B. Gas**										
[16]	50MW units installed	6									
[17]	total installed capacity	300									
[18]	energy		[GWh]	*12469*			1840	1840	1840	1840	1840
[19]	Capital cost	850	[$/kW]								
[20]	Afganistan premium	1.5	[ ]								
[21]	Investment cost		[$USm]		191.3	191.3					
[22]	Gas cost		[$/mmBTU]				8.0	8.0	8.0	8.0	8.0
[23]	Heat rate	6828	BTU/kWh								
[24]	fuel cost		[$USm]				100.5	100.5	100.5	100.5	100.5
[25]	total cost		[$USm]	***1013***	191.3	191.3	100.5	100.5	100.5	100.5	100.5
[26]	levelised cost		[USc/kWh]	***8.1***							
[27]	GHG emission factor	0.46	kg/kWh				846	846	846	846	846
[28]	damage costs		[$USm]				27.6	28.5	29.3	30.2	31.5
[29]	adjusted costs		[$USm]	***1246***	191.3	191.3	128.1	129.0	129.8	130.7	132.0
[30]	levelised cost			***10.0***							
[31]	**C. Renewable energy**										
[32]	units installed	12									
[33]	total installed capacity	600									
[34]	capacity factor	0.35									
[35]			[GWh]	*12469*			1840	1840	1840	1840	1840
[36]	Capital cost	1500	[$/kW]								
[37]	Afganistan premium	1.25	[ ]								
[38]	Investment cost		[$USm]			1125.0					
[39]	O&M cost	0.04	[$USm]				45.0	45.0	45.0	45.0	45.0
[40]	total cost		[$USm]	***1235***	0.0	1125.0	45.0	45.0	45.0	45.0	45.0
[41]	**levelised cost**		[USc/kWh]	**9.9**							

177. This example illustrates the importance of the choice of discount rate. It also serves as an illustration of how a sensitivity analysis to the discount rate could be presented.

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T5 MACROECONOMIC IMPACTS

178. The general presumption of CBA is that the scale of a single energy sector project is too small to affect important macroeconomic characteristics – labour inputs do not significantly distort national labour markets, no crowding out of investment in other sectors, and the additional power does not significantly change GDP composition. Of course there are some significant exceptions – the Sri Lanka Mahaweli Ganga project (power and irrigation) being one example - a project so large as to have consumed over almost a decade a major share of all national public sector capital expenditure and labor inputs (crowding out investment in other sectors), and changed to such large extent agricultural productivity that significant changes in the structure of the economy were anticipated as a result.[80]

179. Few power sector projects need to run CGE and input/output models to evaluate macro-economic consequences as part of project appraisals. However, as noted earlier, recently CGE modelling has been used in the PSIA of a large power sector reform DPC project (Pakistan) where significant price changes are anticipated as a result of subsidy and efficiency reforms, with potentially significant impacts on poorer households.[81]

180. Potential macroeconomic spillovers have become a major issue in project appraisal of high cost VRE, for which it is has been argued that macroeconomic benefits not captured in a conventional CBA provide additional benefits that offset the incremental costs. Employment creation ("green jobs")[82] and the establishment of new industries related to domestic component manufacture are the most commonly encountered such benefits in this category. A single 50-100 MW wind project will admittedly have negligible macro-economic impact, but a large scale commitment to green energy – in the 1000s of MW (it is argued) would have significant (and presumably) beneficial impact. But at such scale, the incremental capital requirements (even if to some extent covered by concessional green financing) may well crowd out other investments and other job-creating expenditures.[83]

181. Our review of Bank renewable energy projects shows that there is only one such project (the Morocco CSP project) for which macroeconomic impacts have been satisfactorily studied. All of the various studies conducted to date (MENA CSP, various wind programmes) show that the realisation of these macroeconomic benefits are dependent upon the outlook for a significant domestic market - for which government assurances to commitments to further renewable energy projects are critical. Few industrialists will be persuaded on the basis of aspirational renewable energy targets (so many % by RE by 2020 etc) in the absence of sustainable institutional and pricing reforms. In Morocco the Government has backed up its targets with the establishment of a strong agency (MASEN) to implement solar projects, and has assembled a credible

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80 World Bank, 2012. *Sri Lanka, Mahaweli Ganga Development*. Independent Evaluation Group (IEG).

81 World Bank, 2014. *First Power Sector Reform Development Policy Credit, Project* Appraisal Document, Report 86031-PK.

82 See e.g., A. Bowen, *Green Growth, Green Jobs and Labor Markets*, World Bank Policy Research Working Paper 5990, March 2012.

83 Again the South Africa Medupi coal project illustrates the problem. The economic analysis showed that even leaving aside any additional capacity costs to offset the lack of firm capacity of wind projects, to produce by wind power the same energy as at the Medupi coal project would require an additional $20 billion of finance, far in excess of the carbon finance (of around $1 billion) actually available to South Africa. See World Bank, 2010. *ESKOM Investment Support Project*. Project Appraisal Document, Report 53425-ZA.

financial plan, but elsewhere supporting policies are often weak.[84] The practical question for the project economist would be whether project preparation funds are sufficient to include a high quality study of potential macroeconomic benefits for the country in question.

182. In competitively awarded tenders for large projects (as are the Morocco CSP projects), there may well be requirements for specific local sourcing requirements, or bidders may make such commitments for additional consideration. But in a situation where such contracts are also subject to penalty clauses for failure to meet promised commercial operation dates, it remains to be seen whether these targets can in practice be achieved or enforced.

183. All such studies of macroeconomic spill-over effects (including estimates of job creation) suffer from the incremental cost problem – there may well be net job creation from high cost renewable energy, but if the incremental costs are carried by consumers, consumer demand for other goods and services will reduce employment in other sectors (and similarly if Government covers the incremental costs, that crowds out other government investment and its associated job creation potential). Only the application of sophisticated CGE models and properly updated input-output tables will allow credible assessments of these macro-economic effects.

Best Practice recommendations 8: Macroeconomic spillovers

(1) In the absence of a detailed country-specific study of the prospects for domestic manufacture of RE equipment, one should avoid speculative textual claims about macroeconomic spillover effects.

(2) Even where a country-specific study *is* available, with a finding that a general target of, say, 5,000 MW by 2025 would enable cumulative net macroeconomic benefits of $500 million by 2025, the presumption that a 500 MW project today would capture a proportional share of the total would need careful justification. The main difficulty is that today's investment cost may be relatively certain, while the future macroeconomic benefit will be highly *un*certain.[85] In any event, the benefits would not be linearly scalable, because the first project today would unlikely benefit significantly from the gradual introduction of domestic manufacturing capability.

(3) A good country specific study of the macro-economic impacts of a major shift to renewable energy, including employment impacts, will require significant resources, and the application of appropriate input-output and macroeconomic models. Such a study was prepared for the Noor I&II CSP projects in Morocco, which is recommended reading before embarking on any similar effort to support the justification of high-cost renewables in other countries.

EMPLOYMENT IMPACTS

184. Many renewable energy projects make somewhat misleading claims about job creation. In the case of World Bank project appraisal reports, these are often found in the

84 Given the currently difficult economic conditions of the many countries in the MENA region that might otherwise be candidates for additional CSP projects (such as Egypt, Libya, Jordan) an export market for a Moroccan manufacturer of mirrors or parabolic collectors seems doubtful (at least in the short to medium terms). The near-collapse of the solar market in Spain adds further uncertainty (and erodes the hope that CSP energy can be exported to the EU at high prices, at least until such time as carbon prices in the EU ETS have recovered to previous levels).

85 In the PAD economic analysis for Noor II&III, the estimated macroeconomic benefit of 6,000MW of CSP by 2025 was estimated at $900 million.

CTF Annex under the heading of "development impact", where these are presented for "ramp-up" scenarios with high penetration of the RE in question. For example, the Bank's South Africa ESKOM renewable energy project states[86]

> *The analysis indicates that a ramp-up of renewable energy to 15% of the grid connected MW capacity would create new jobs in the region of 35,000-51,000. For the upper limit, 20,000 would be skilled, 22,000 semi-skilled, and 9,000 unskilled.*

quoting the South Africa Renewable Energy Initiative (SARI) as the source.

Issues

185. While it is true these figures are taken from a study prepared by a reputable source, such claims need careful scrutiny by the economic analysis:

- Estimates of gross direct employment creation convey little useful information. Particularly where RE displaces a thermal fuel produced domestically, more renewable energy means less coal/oil/gas – so in the case of South Africa, where coal projects use local domestic coal, less coal means loss of coal mining jobs and in related coal transportation.[87] Only *net* employment creation estimates are meaningful, so it is necessary to also state any relevant job *losses* in the displaced fossil fuel.
- The large employment benefits noted in many studies of European countries are really a consequence of renewable energy technology manufacture (particularly where much equipment is exported, such as in Spain and Denmark in the case of wind), so the question is the extent to which these job gains apply to countries which do not have domestic manufacturing capacity for renewable energy generating equipment or reasonable prospects for doing so (a question to be tested in most small World Bank country clients). The job creation benefit of manufacturing turbines (about 70% of the total cost of a wind farm) generally accrues to turbine producing and exporting countries (China and Europe): local employment during operation of wind farms and small hydro projects is small.
- But even if there were a net employment gain in the energy sector, that does not necessarily mean there is an *economy-wide* gain in employment. For example, where it is electricity consumers who carry the burden of the incremental costs of RE (e.g. in Malaysia, where the incremental costs of the feed-in tariff are passed to consumers by a 1% surcharge on electricity bills of all but the smallest consumers), all other things equal they will accommodate a higher electricity price (at least in part) by spending less of their disposable income on other goods, and therefore employment in those sectors that produce such goods, and in the economy as a whole (when the relevant multiplier effects are included), could potentially fall.
- In project economic analysis, economics treats labour as an input, not an output: the substitution of labour by capital and other factors of production to increase productivity is considered to be one of the driving forces of economic growth.
- If a project has significant domestic labour inputs, consideration should be given to shadow pricing, particularly for unskilled and semi-skilled labour. [88]

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86 World Bank, 2010. *ESKOM Investment Support Project*. Project Appraisal Document, Report 53425-ZA.

87 Some would argue that given often poor working conditions of many coal mining operations in developing countries, reduction of mining jobs is a benefit *per se*, but that is not necessarily how the affected miners, or their Governments, would evaluate such job losses in the mining sector.

88 This is routinely done for ADB energy sector projects, but is relatively rare in recent World Bank renewable energy projects.

- Reliable estimates of net economy-wide employment impacts require use of sophisticated modelling tools that also account for regional employment multiplier effects.

Suggested reading

R. Bacon and M. Kojima, *Issues in Estimating the Employment Generated by Energy Sector Activities*, Sustainable Energy Department, June 2011.

A. Bowen, 2012. *Green Growth, Green Jobs and Labor Markets*, World Bank Policy Research Working Paper 5990, March 2012.

D. Kammen, M Mozafari and D. Prull, 2012. *Sustainable Energy Options Energy for Kosovo: An Analysis of Resource Availability and Cost*. Renewable and Appropriate Energy Laboratory, University of California at Berkeley.

Best Practice recommendations 9: Employment impacts of renewable energy projects

(1) If job creation figures are presented, any direct gross employment estimates associated with the proposed project should be accompanied by employment *loss* figures for the thermal energy that is displaced, and data presented in *net* form. Where such shifts have a regional dimension (for example, most wind and solar projects in Vietnam are in the south, whereas most coal mining is in the north), that should be expressly noted in the distributional analysis.

(2) Even where there is a net employment increase, one should be careful about extrapolating this to the macroeconomic level, particularly for renewable energy projects with high incremental costs.

(3) Where significant labour inputs arise, consideration should be given to shadow pricing labour costs. However, there needs to be some credible source for such adjustments: we recommend against arbitrary values (such as the 0.9 adjustment encountered widely in ADB reports). In any event, there are few renewable energy projects that have large local labour inputs, so the (beneficial) impact of shadow pricing on the economic flows will be small.

PART III: METHODOLOGIES & TECHNIQUES

M1 CBA BEST PRACTICE

186. This note summarises some of the features of a best practice CBA

- The presentation of electricity flows
- The numeraire and adjustments for the opportunity cost of foreign exchange
- Sensitivity analysis

ELECTRICITY BALANCES

187. The importance of a careful electricity flow balance cannot be overemphasised. Table M1.1 illustrates some energy balances for some selected renewable energy projects. Only a careful energy balance can give reliable estimates of the benefits of the avoided cost of renewable energy.

Table M1.1: Energy flow calculation

[1]	renewable energy technology		geothermal	Rooftop PV	wind
[2]	replaced thermal energy		coal	CCGT-LNG	CCGT-gas
[3]	installed capacity	[MW]	100	100	100
[4]	annual (net) capacity factor	[ ]	0.92	0.15	0.32
[5]	Renewable energy output (at meter)	[GWh]	805.9	131.4	280.3
[6]	incremental transmission loss	[ ]	*-2.0%*	*10.0%*	*0.0%*
[7]		[GWh]	-16.1	13.1	0.0
[8]	energy at thermal generation meter	[GWh]	789.8	144.5	280.3
[9]	FGD(1)	[ ]	*2.0%*	*0.0%*	*0.0%*
[10]		[GWh]	17.0	0.0	0.0
[11]		[GWh]	806.8	144.5	280.3
[12]	Dry cooling (1)	[ ]	*0.0%*	*0.0%*	*0.0%*
[13]		[GWh]	0.0	0.0	0.0
[14]		[GWh]	806.8	144.5	280.3
[15]	other own use (1)	[ ]	*5.0%*	*2.0%*	*2.0%*
[16]		[GWh]	42.5	2.9	5.7
[17]	gross generation at generation bus	[GWh]	849.2	147.5	286.0
[18]	gross efficiency LHV	[ ]	*35.0%*	*52.0%*	*52.0%*
[19]	gross heat rate, LHV	[BTU/kWh]	9748.6	6561.5	6561.5
[20]	**Fuel**				
[21]	total heat input	[mmBTU]	8,278,965	967,760	1,876,868
[22]		[mmKJ]=[GJ]	7,847,360	917,308	1779,022
[23]		[mmKCal]	2,086,299	243,876	472,971
[24]	Fuel cost	[$/ton]	78		
[25]	Heat content	[KCal/kg]	5900		
[26]		[$/mmKCal]	13		
[27]		[$/mmBTU]	3.33	15.0	11.0
[28]	Basis		cif	LNG cif	IPP(1)
[29]	annual fuel bill	[$million]	27.6	14.5	20.6
[30]	benefit/kWh of renewable energy	[$/kWh]	0.0342	0.1105	0.0736
[31]	*memo items*				
[32]	net heat rate, LHV	[BTU/kWh]	10482	6695	6695
[33]		[KCal/kWh]	2642	1687	1687
[34]	net efficiency, LHV	[ ]	32.6%	51.0%	51.0%

Notes:
(1) expressed as a percentage of the gross output at the generation bus

188. While the average energy output of the renewable energy project is easily calculated (row[5]), a first question is whether there are any differential transmission losses. In the case of the geothermal project it is assumed (in this illustrative calculation) that the geothermal project is in a remote location relative to its thermal alternative, so the amount of thermal energy replaced is *less* than the geothermal project output. On the other hand, in the case of an urban rooftop PV program, which is in the load centre itself, one avoids the T&D losses associated with supplying the urban load from a thermal project located some distance from the load centre. In this case, the amount of energy

displaced is therefore 10% *greater* than the nominal output of the rooftop PV project (row[6]).

189. In row [18] is entered the gross efficiency on an LHV basis.[89] If FGD or dry cooling is fitted (in the case of the coal project), own use increases. The net efficiency and heat rate – (rows [32]-[34]) are *higher* than the gross rates (because the net heat rate includes the energy required to cover own-use consumption).

190. In rows [20]-[30] one calculates the fuel quantities displaced and the corresponding avoided cost (benefit) of the displaced thermal energy. Coal is generally priced in international markets as $/ton, and LNG and natural gas as $/mmBTU (also the units used in the IEA energy price forecasts and the World Bank commodity price forecasts)

191. Note that these calculations capture only what is replaced by the renewable energy. They do not include the additional penalties imposed on the balance of the thermal generation system. As discussed in Technical Note **T1**, if a 500 MW CCGT is ramped up and down several times a day to absorb the output of a wind project, then the average heat rate of the remaining output is subject to a ramping penalty – which should be calculated and itemised separately under the rubric of integration costs.

192. These calculations should all be built into the table of economic flows, because both the output of the renewable energy project, and the output of the thermal alternative will decline over time (as part of the normal degradation of equipment over time). Moreover, since the Guidance Document for GHG emission valuation now stipulates a value of the social cost of carbon that *increases* over time, the calculations must in any event be done for each year in the project life.

THE NUMERAIRE AND ADJUSTMENTS FOR THE OPPORTUNITY COST OF FOREIGN EXCHANGE

193. Different projects adjust for the opportunity cost of foreign exchange in different ways. If the numeraire is in foreign exchange, domestic costs and benefits are adjusted by the standard correction factor (SCF); if the numeraire is in domestic currency, foreign exchange costs are adjusted by the shadow exchange rate (SER). Without proper adjustment, the economic returns may be over-estimated.

194. In the past, some Country Offices provided an annual guidance document on the SCF (e.g., India in the 1990s). However, this does not appear to be the case today, so if an adjustment is warranted, the calculation has to be done by the project economist on a project by project basis. The data to do this may require some effort (and therefore resources) to collect. Very few RE projects have gone to the trouble of doing this: among the projects reviewed, just two examples were found (the Tarbela T4 Extension, and the Indonesia Geothermal Project).

Issues

195. Many issues arise for energy projects. The avoided health damages of fossil fuel combustion – a benefit of RE projects – is most often calculated in US$ terms through the benefit-transfer method (see *Technical Note M4*). However, because health care costs are non-tradable, they properly require SCF adjustment if the numeraire is in $US (which will *lower* the calculated value of the benefit stream).

196. To illustrate the importance of proper adjustment, consider the calculation of ERR in Table M1.2 (from the Indonesian Geothermal Project), where the numeraire is

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89 See Glossary on the distinction between LHV and HHV definitions.

stated $US. It is assumed that the tariff revenue reflects the economic benefits. The unadjusted ERR calculates to 19.2%.

Table M1.2: Economic returns, unadjusted flows

year		*NPV*	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2025
GWh	GWh						887	887	887	887	887	887	887	887
tariff	$/kWh						0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
revenue	$USm	*685*					106.4	106.4	106.4	106.4	106.4	106.4	106.4	106.4
Investment	$USm	*282*	77.5	110.1	73.1	76.8	21.6							
Make-up wells	$USm	*50*							18.0		18.0		18.0	
O&M costs	$USm	*59*					8.4	8.4	8.4	10.5	9.4	8.4	10.5	8.4
Net flows	$USm	*295*	-77.5	-110.1	-73.1	-76.8	76.5	98.0	80.0	95.9	79.0	98.0	77.9	98.0
ERR	[ ]	19.2%												

197. In Table M1.3 we adjust for the SCF (assumed here at 0.9). *f[dom]* shows the fraction of costs that are non-traded (i.e. domestic): this fraction of the unadjusted value is multiplied by the SCF. For example, electricity revenue (the benefit) is a 100% non-traded good, so the adjusted flow is that of Table M1.2, row[3] namely 106.4 x 0.9 = 95.8. The ERR is 17.6%, *lower* than the unadjusted estimate.

Table M1.3: Economic returns, SCF adjusted flows

year	f[dom]		NPV	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Revenue	1.0	$USm	*617*					95.8	95.8	95.8	95.8	95.8	95.8	95.8
Investment	0.2	$USm	*277*	76.0	107.8	71.6	75.3	21.1	0.0	0.0	0.0	0.0	0.0	0.0
Make-up wells	0.2	$USm	*49*					0.0	0.0	17.6	0.0	17.6	0.0	17.6
O&M costs	0.2	$USm	*58*					8.2	8.2	8.2	10.3	9.2	8.2	10.3
Net cashflow		$USm	234	-76.0	-107.8	-71.6	-75.3	66.4	87.6	69.9	85.5	68.9	87.6	67.9
ERR		[ ]	17.6%											

198. Alternatively, one can adjust the flows by the SER, as shown in Table M1.4. Here *f[FOREX]* shows the fraction of goods that are in foreign exchange, which all need adjustment by the SER (1.111). The resulting economic rate of return is identical to that obtained if the adjustment is for the SCF (17.6%).

Table M1.4: Economic returns, SER adjusted flows

year	f[FOREX]		*NPV*	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Revenue	0	$USm	*685*					106.4	106.4	106.4	106.4	106.4	106.4	106.4
Investment	0.8	$USm	*307*	84.4	119.8	79.5	83.7	23.5	0.0	0.0	0.0	0.0	0.0	0.0
Make-up wells	0.8	$USm	*54*					0.0	0.0	19.6	0.0	19.6	0.0	19.6
O&M costs	0.8	$USm	*64*					9.1	9.1	9.1	11.4	10.2	9.1	11.4
Net cashflow		$USm	260	-84.4	-119.8	-79.5	-83.7	73.8	97.3	77.7	95.0	76.6	97.3	75.4
ERR		[ ]	17.6%											

Best Practice recommendations 10: Numeraire & standard correction factors

(1) Because of the growing importance of GHG accounting and valuation of emissions in $US terms, and the need to include avoided GHG emission benefits in the economic analysis (generally denominated in $US/ton), in most cases the numeraire for the economic analysis should be in $US.

(2) Where the bulk of the investment costs are domestic – generally the case for large countries (and certainly true of most projects in India and China), the numeraire should be in the local currency.

(3 With a $US numeraire, in the tabulation of economic flows of non-traded domestic transactions (such as the domestic component of construction cost, or the electricity output) should be adjusted by the SCF, provided a reliable calculation of SCF is available.

Suggested reading:

W. Ward and B. Deren, *The Economics of Project Analysis: A Practitioner's Guide*, Economic Development Institute of the World Bank, 1991. See especially *Section 6: The Exchange Rate in the Two Numeraires.*

Box M1.1 Calculation of the SCF for the Tarbela T4 extension project

The SCF is defined by the equation:

$$SCF = \frac{\mathrm{I} + \mathrm{E}}{I + NT_{IMPORTS} + E - NT_{EXPORTS}}$$

where:

I	=	Imports
E	=	Exports
NTIMPORTS	=	Net taxes on imports = Import duties + sales tax on imports - subsidies on imports
NTEXPORTS	=	Net taxes on exports = Export duties-export rebates

with values as follows

	2004-2005	2005-2006	2006-2007	2007-2008	2008-2009	average
1. Total Imports (1)	1,223,079	1,711,158	1,851,806	2,512,072	2,723,106	2,004,244
2. Total Exports (1)	854,088	984,841	1,029,312	1,196,638	1,383,852	1,089,746
3. Import Duties (2)	129,297	154,175	142,628	159,923	152,234	147,651
4. Sales Tax on Imports (2)	144,845	171,445	175,909	196,034	203,778	178,402
5. Subsidies on Imports (3)	8,600	8,822	147	69,705	29,600	23,375
6. Export Duties (2)	2,234	2,638	2,410	3,148	3,815	2,849
7 Export Rebates (2)	15,405	11,884	6,333	4585	2,965	8,234

Notes:
(1) Economic survey 2008-2009
(2) CBR Islamabad
(3) Ministry of Finance, Islamabad

Hence

$$SCF = \frac{309990}{2004244 + 147651 + 178402 - 23375 + 1089746 - 2849 + 8234} = 0.90$$

Source: World Bank, 2012. *Tarbela Fourth Extension Hydropower Project (T4HP)* Project Appraisal Document, Report 60963-PK.

CALCULATION FORMAT

199. The universal tabular format for *financial* analysis is that columns represent *years*, rows represent transactions. Every World Bank PAD financial analysis, and all the IFC and ADB projects, adopt this convention.

200. Yet for economic analyses a variety of different conventions are in evidence. Many use a format where columns represent *transactions*, and rows represent years. However, there are several reasons why the analysis and presentation of economic analysis should follow the same convention as the financial analysis in which columns represent years, and rows represent transactions

- Economic and financial analyses share many assumptions, and economic and financial flows are linked. Spreadsheets that have links between some tables in column format and some tables in row format are much more likely to have errors than if all tables follow the same convention.
- Once a time-in-rows format is adopted, there is a tendency to limit the number of columns that can be presented in a single portrait format page, making the calculations less transparent, and even driving a simplification of the analysis itself.

201. Annex **A4** (Sample Economic Analysis), and the various examples in other Technical Notes, illustrate how the economic flows should be presented in the recommended format.

SENSITIVITY ANALYSIS

202. There are wide variations in the quality and scope of sensitivity analysis presented in economic analyses of renewable energy projects:

- No sensitivity analysis at all[90]
- Sensitivity analysis limited to recalculation of ERR by variation of input variables by fixed percentages
- Switching values
- Scenario analysis

203. Sensitivity analysis that is limited to recalculation of ERR by variation of a few input variables by fixed percentages is widespread, but again reflects practice. Table M1.5 illustrates a typical (and unsatisfactory) example.

Table M1.5: Typical sensitivity analysis presentation

Scenario	EIRR%
Base case	5%
Construction cost -15%	7%
O&M cost -15%	6%
Capacity factor increases to 40% from 35%	7%
Economic tariff increases from 7 cents to 9 cents	9%

204. The shortcomings of such an approach to sensitivity analysis were already noted in the 1998 Guidelines: [91]

> *Sensitivity analysis has three major limitations: it does not take into account the probabilities of occurrence of the events; it does not take into account the correlations among the variables; and finally, the practice of varying the values of sensitive variables by standard percentages does not necessarily bear any relation to the observed (or likely) variability of the underlying variables. The switching value presentation is a much better way to give information about sensitivity.*

205. The minimum requirement for an acceptable sensitivity analysis is the calculation of switching values for the main assumptions: this is the value of the assumption that brings the ERR to the hurdle rate (NPV to zero), together with a commentary of the circumstances under which this might occur. The Best Practice recommendations below enumerate the variables that should be considered for inclusion in such an analysis.

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90 The IEG report on Benefit Cost Analysis has also expressed its frustration that many Bank project CBAs present no sensitivity analysis.

91 World Bank, 1998. *Handbook on Economic Analysis of Investment Operations*, by P. Belli, J. Anderson, H, Barnum, J. Dixon and J. Tan, World Bank, Operations Policy Department.

Best Practice recommendations 11: Variables to be included in the switching values analysis

Variables that should always appear in a sensitivity analysis (many of which may be also identified in the project risk matrix) include

All projects

- Construction costs
- Construction cost delay
- The timing and cost of major maintenance events (e.g., runner blade replacement in hydro projects, major refurbishments of CSP equipment, make-up wells in geothermal projects, etc)
- Where benefits are based on WTP and estimates of the demand curve, on the shape of the demand curve (price elasticity)
- For the calculation of returns including avoided externalities, uncertainty in damage costs (which vary by orders of magnitude)
- International fuel prices
- Discount rate

Hydro projects

- sedimentation risk (often higher than expected) – for example modelled by the number of days a plant must be shut down for sediment flushing operations (see Rampur project)
- hydrology risk
- In rehabilitation projects, the achievable efficiency improvements (e.g. changes in operating rules at hydro projects to achieve operation at best efficiency point may be difficult to predict)
- uncertainty associated with environmental flow regimes (sometimes unknown at the time of appraisal)

Off-grid renewables

- Assumptions involved in the estimation of the demand curve and consumer surplus (shape of the demand curve, demand and income elasticities)

Wind (and variable renewables generally)

- wind resource uncertainty (that determines energy production)
- Uncertainty in the value of the capacity credit

Geothermal

- uncertainty in the number of required delineation and makeup wells, and thermal output per well

Rehabilitation projects

- uncertainty in the counter-factual (the assumed rate of dilapidation, or date in which a project would be abandoned in the absence of rehabilitation).

206. A switching values analysis can usefully be presented in tabular form, as shown in the example of Table M1.6. The switching values are those that bring the ERR from the baseline estimate of 37% to the hurdle rate of 10%.

Table M1.6: Switching values analysis

		Baseline assumption	Switching Value	Multiplier	
Capital cost increase	$USm	16.1	58	2.3	A 230% increase in capital cost for a straightforward distribution rehabilitation project is extremely unlikely.
Additional power Evacuation	MW	8	-2	N/A	Difficult to imagine that the rehabilitation of the primary lines would result in a *decrease* in capacity.
WTP	$/kWh	.315	.178	0.56	Switching value is below the average tariff (by definition the lower bound of WTP)
Non-technical loss Reduction	[ ]	5%	None		Even when assumed at zero, ERR is 28%, above the hurdle rate
Collection ratio Improvement	[ ]	10%	None		Even when zero, ERR is 27%, again above the hurdle rate
Implementation lag	[years]	1	None		Even when loss reduction benefits are *never* achieved, ERR=22% (due to additional power evacuation)

Source: World Bank 2012. Sierra Leone Infrastructure Development Fund Project: Economic Analysis of Commercial Loss Reduction, June.

207. Box M1.2 provides other examples of how the results of a good sensitivity analysis can be displayed. An illustration of a sensitivity analysis for the discount rate is shown in Figures T4.1 and T4.2.

208. The main shortcoming of such analysis is that the focus is on one variable at a time: in the real world, it would be very unusual for just a single assumption to be subject to uncertainty and in the future found to have been proven incorrect, while all other values remain unchanged. Two methods to get around this problem can be recommended:

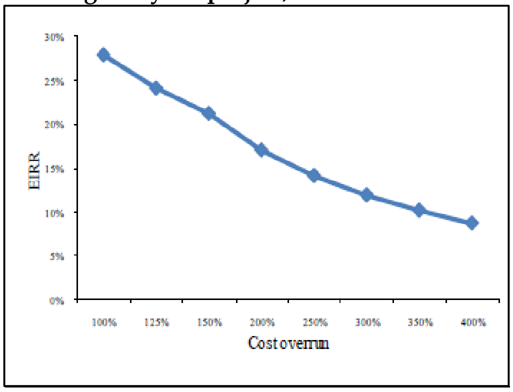
- Monte Carlo simulation for risk assessment, in which all major input assumptions are treated as random variables, with deviations from the expected values for all variables simultaneously examined (see Technical Note **M7**).
- Scenario analysis, in which plausible best and worst cases are constructed, and for which the consequences of making an incorrect assumption are explicitly considered (see Technical Note **C5**)

209. Whether either or both of these techniques should be used to complement the switching values analysis is a matter of judgement: certainly for any major project a Monte Carlo simulation (or an RDM assessment) is now considered to be best practice, and the value of scenario analysis is illustrated by the examples in Technical Note **C4**.

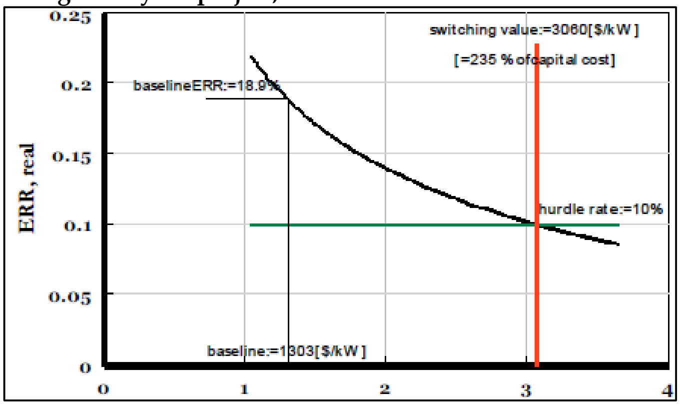
Box M1.2: Sensitivity analysis presentation

Graphical displays to show the sensitivity of economic returns over a range of values are useful to convey the sensitivity of project returns to key assumptions. The examples here, taken from recent PADs, show some useful formats for doing this in the case of construction cost overruns.

Vishnugad Hydro project, India



Trung Son hydro project, Vietnam



If there are just two variables of principal interest, the "staircase chart" can be useful for presentation: in the table shown here, combinations below the staircase do not meet the hurdle rate: the baseline ERR is 14.9%: values below the staircase are below the 12% hurdle rate.

Jiangxi hydro project, China

Variation in cost	Variation in benefits							
	-60%	-50%	-40%	-30%	-20%	-10%	0%	10%
-40%	9.4%	12.4%	14.9%	17.3%	19.4%	21.4%	23.3%	25.1%
-30%	7.5%	10.3%	12.7%	14.9%	17.0%	18.8%	20.6%	22.3%
-20%	5.9%	8.6%	10.9%	13.0%	14.9%	16.7%	18.4%	19.9%
-10%	4.5%	7.2%	9.4%	11.4%	13.3%	14.9%	16.5%	18.0%
0%	3.3%	5.9%	8.1%	10.0%	11.8%	13.4%	**14.9%**	16.4%
10%	2.3%	4.8%	6.9%	8.8%	10.5%	12.1%	13.6%	14.9%
20%	1.3%	3.8%	5.9%	7.7%	9.4%	10.9%	12.4%	13.7%
30%	0.5%	2.9%	5.0%	6.8%	8.4%	9.9%	11.3%	12.6%

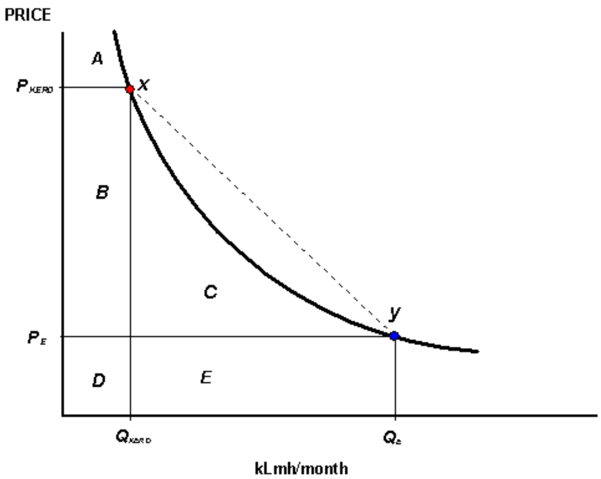
M2 ESTIMATING DEMAND CURVES

DEMAND CURVES AND CONSUMER SURPLUS

210. Estimating the demand curve for household electricity services (lighting, TV viewing) is widely used as the basis for estimating the benefits of rural electrification and off-grid renewable energy projects.

211. Figure M2.1 shows the demand for lighting, in kiloLumenHours/month, as a function of price. Before electrification, a household obtains little light (Q_{KERO}) from expensive kerosene (P_{KERO}) (point *x*). Electrification dramatically reduces the price of lighting, resulting in the consumption of greater quantity of light (Q_E) now supplied by cheap electricity (P_E).

Figure M2.1: Demand curve for lighting



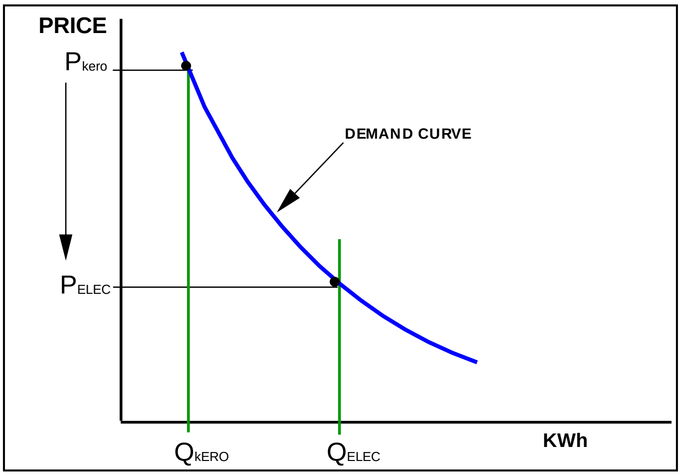
212. The so-called willingness to pay (WTP) is the area under the demand curve. Before electrification the household uses kerosene (at the point x in the figure), so the total WTP = A + B + D. But it pays Q_{KERO} x P_{KERO} = B + D. Therefore the *net* benefit of consuming Q_{KERO} units of lighting is the difference between WTP and cost, namely the area A, a quantity termed the *consumer surplus*.

213. After electrification, WTP is the area under the curve A + B + C + D + E, and the cost D + E= Q_E x P_E , so now the net benefit is the consumer surplus =A + B + C. It follows that the benefit of electrification is the *increase* in consumer surplus, namely (A + B + C) - (A) = B + C.

214. Demand curves for services (such as for lighting in Figure M2.1) are easily converted into demand curves for electricity (Figure M2.2). One sometimes uses the terminology of *non-incremental* and *incremental* demand. Thus, in Figure M2.2,

- substituted demand (non-incremental) $=Q_{KERO}$
- Induced (incremental) demand $=Q_{ELEC}-Q_{KERO}$

Figure M2.2 : Demand curve for electricity



215. Different devices convert electricity into lumens at different efficiencies. The equivalent cost of kerosene wick lamps may be \$1/kWh, that for grid-supplied electricity \$0.12/kWh. However, the highest equivalent per kWh cost for households is for dry cells, which have costs of as much as \$890/kWh (Table M2.1).

Table M2.1: Dry Cell Battery Costs

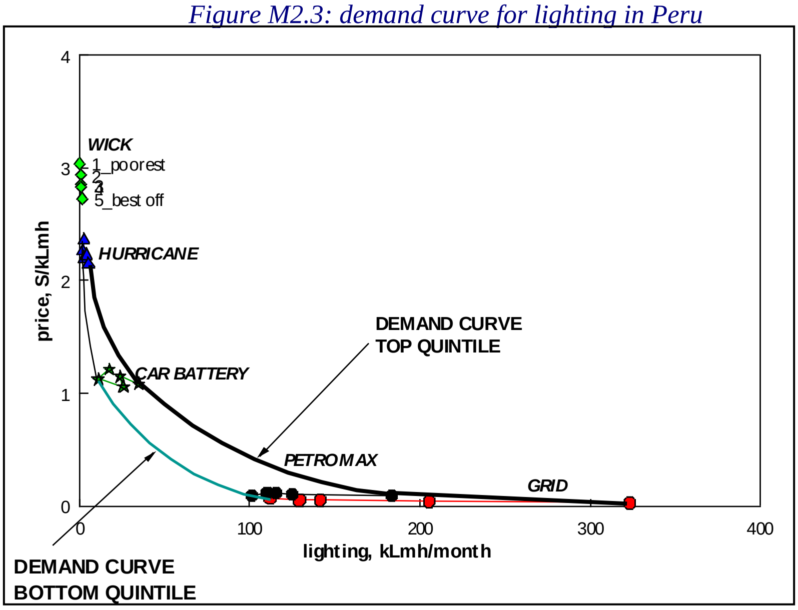
	Unit	AAA	AA	C	D
MilliAmpere Hour(1)	mAh	1,250	2,850	8,350	20,500
Watt-Hours At Nominal 1.5 Volts(1)	Watt-hour	1.9	4.3	12.5	30.8
Watt-Hour at Actual(2)	Watt-hour	1.4	3.2	9.4	23.1
Typical US Cost	$US/battery	1.25	1.00	1.60	1.80
Typical US Cost per kWh	$/kWh	890	310	170	80

(1) From Energizer battery website (high quality alkaline batteries)
(2) Actual watt-hours likely in practice, given fall in voltage over time
Source: P. Meier, V. Tuntivate, D. Barnes, S. Bogach and D. Farchy, *Peru: National Survey of Rural Household Energy use*, Energy and Poverty Special Report, August 2010, ESMAP, Aug 2010 (ESMAP Peru)

EXAMPLES OF EMPIRICALLY ESTIMATED DEMAND CURVES

216. Demand curves for household electricity prove to be highly concave. Figure M2.3 shows the estimated demand curves for lighting in rural households in Peru. These were estimated for each of the five household income quintiles: the points shown represent the five main ways in which lighting demand is served – from simple wick lamps, to hurricane lamps, car battery, Petromax (a high efficiency and more costly hurricane lamp-type device), and for grid-supplied electricity. The largest differences in use across income groups is for grid electricity ranging from 100 kLmh/month in the poorest quintile to 330 kLmh/month in the highest income quintile. Yet even in the best-off income quintile, wick lamps and hurricane lamps were extensively used.

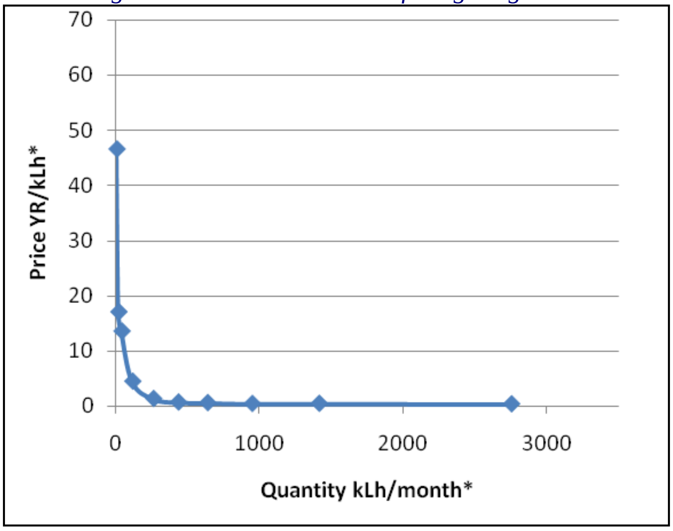
Figure M2.3: demand curve for lighting in Peru



Source: P. Meier, V. Tuntivate, D. Barnes, S. Bogach and D. Farchy, *Peru: National Survey of Rural Household Energy Use*, Energy and Poverty Special Report, August 2010, ESMAP, Aug 2010 (ESMAP Peru).

217. Figure M2.4 shows a similar result for lighting demand in Yemen.

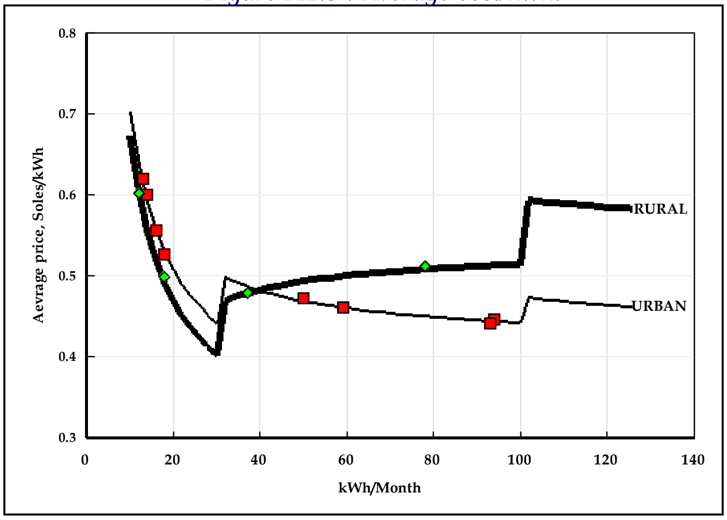
Figure M2.4: Demand curve for lighting in Yemen



Source: M. Wilson, J Besant-Jones and P Audinet: *A New Slant on Slopes: Measuring the Benefits of Increased Electricity Access in Developing Countries*, Report No. 53963-GLB, February 2011.

218. One of the problems of econometric estimation of data from household energy surveys (and price elasticities in particular) is that grid-electricity prices are often highly distorted by cross-subsidies and the block structure. For example, in Peru, Figure M2.5 shows the cost per kWh as a function of monthly consumption – which also shows significant differences between urban and rural tariffs.

Figure M2.5 : Average cost/kWh.



Source: P.Meier, V. Tuntivate, D. Barnes, S. Bogach and D. Farchy, *Peru: National Survey of Rural Household Energy use*, Energy and Poverty Special Report, August 2010, ESMAP, Aug 2010 (ESMAP Peru)

INCOME EFFECTS

219. Although such consumer surplus calculations are widely used, several problems arise (beyond the merely obvious issue of over-estimation by assuming linearity of the demand curve). In fact consumer surplus is known to be a close approximation of exact measures only when income elasticities are low and when relatively small price changes are being analyzed. Because the demand for electricity typically has very high income elasticities for countries with low levels of income, and because it is in just such countries that the very large price shifts occur in both the case of rural electrification (significant price reductions for electricity over the cost of non-electricity substitutes), simple consumer surplus calculations can be an unreliable indicator of welfare changes. The same is true when large tariff increases occur following large reductions in electricity subsidies.

220. Bacon[92] argues that more precise measures should be used. For a price decrease, the compensating variation (CV) is defined as the amount of money that can be taken away from the household, with the new prices holding, to leave it as well off as it was before the prices altered. Indeed it has been observed in many household energy surveys in poorer countries that when the price of lighting falls, households use less electricity than the demand curve would predict, preferring to use some of the additional disposable income on other goods and services: moreover, the ability of a poor household to consume larger amounts of electricity may be constrained by the affordability of additional appliances required to deliver increased services (which is the rationale for providing CFLs to households free of charge as part of rural solar home projects).

92 R. Bacon, *Measurement of Welfare Changes Caused by Large Price Shifts: an Issue in the Power Sector*. World Bank Discussion papers 273, 1995

Box M2.1: Using consumer surplus as a measure of benefits: Conclusions of the Yemen Study

Consumer surplus as the measure for estimating benefits of enlarged access by households to public electricity supply needs to be used with caution. Consumer surplus benefits from increased access to electricity supply may be less than has been postulated in earlier analyses. Evidence from Yemen indicates that the demand curve for utilities such as lighting and information/entertainment is highly concave.

Consumer surplus associated with induced consumption (e.g. use of additional lights, electric fans) may involve consumption of more units of electrical energy than before electrification, but the unit value of consumer surplus is small. The primary consumer surplus benefit from electrification programs comes from avoided expenditure on substitutes. While the unit value of these latter savings may be high, the number of units involved is typically small.

Benefits of increased access to electricity should be measured both in terms of gains in consumer surplus and gains in real income from electrification. Analysis of benefits from enlarged electricity access often focuses entirely on the consumer surplus benefits. However, the avoided expenditures by households on energy forms that are substituted by electricity are likely to yield high savings which in effect increase the real incomes of these households. This effect is not currently measured in the evaluation of household electrification programs, and its inclusion can strengthen the economic case for investment in household electrification.

Plan electrification along with accompanying measures to ease access to electricity consuming appliances. Low income households are highly sensitive to energy prices and could therefore be reluctant to modify rapidly their patterns of energy consumption once they gain access. Increased electricity access does not materialize in a large substitution effect because of households' high sensitivity to prices as well as to limitations on their ability to afford the purchase of electrical appliances.

In other words, access may not translate rapidly in a larger consumption of energy services by individual households. Patterns of energy demand evidenced in Yemen indirectly show that the cost of electricity consuming appliances may be a stronger barrier to higher consumption of electricity among low income households than commonly anticipated.

The energy demand curves for lighting and basic entertainment / information derived from the Yemen Household Energy Survey are downward sloping and highly concave, challenging the size of the consumer surplus. The shape is consistent with a demand function based on a constant and high level of price elasticity, i.e. a function of the form $\ln(Q) = A + e^{*}\ln(P)$. The coefficient that represents the price elasticity of demand for lighting is estimated at -0.81 and for entertainment / information is estimated at -0.92. The implications for the benefits associated with new or improved access to electricity are twofold: First, while the unit value of savings as a result of avoided use of non-electric substitutes may be high, the number of units replaced by access to electricity is small. Hence the amount of consumer's surplus associated with substitution is limited.

Second, The amount of consumer's surplus associated with additional demand induced by access to electricity for these two applications is also limited. Because the curve quickly approaches and parallels the x-axis, the area between the curve and the rectangle that represents the amount actually paid for the electricity (i.e. the Area **C** in Figure M2.1) is small.

Source: Extracted from M. Wilson, J. Besant Jones and P. Audinet: *A New Slant on Slopes: Measuring the Benefits of Increased Electricity Access in Developing Countries*, Report No. 53963-GLB, February 2011.

Suggested Reading

R. Bacon, *Measurement of Welfare Changes Caused by Large Price Shifts: an Issue in the Power Sector*. World Bank Discussion papers 273, 1995. Discusses the theoretical issues of Marshallian and Hicksian demand curves and their practical estimation.

R. Bacon, S. Bhattacharya and M. Kojima, 2009. *Changing Patterns of Household Expenditures on Energy: A Case Study of Indonesia and Pakistan*, World Bank, Extractive Industries and Development Series #6.

R. Bacon, S. Bhattacharya and M. Kojima, 2010. *Expenditure of low-income Households on Energy: Evidence from Africa and Asia*, World Bank, Extractive Industries and Development Series #16.

M. Wilson, J. Besant-Jones and P. Audinet: *A New Slant on Slopes: Measuring the Benefits of Increased Electricity Access in Developing Countries*, Report No. 53963-GLB, February 2011. The best discussion of the theoretical issues and practical problems of estimating residential electricity demand curves from household energy surveys.

Examples in Bank Economic Analysis

Yemen: Wilson, Besant-Jones & Audinet, *op.cit*. presents the demand curves for Yemen derived from the Yemen household energy survey; ESMAP, 2004. *Household Energy Supply and Use in Yemen*, World Bank, presents the full details of the household energy survey.

Peru: P. Meier, V.Tuntivate, D.Barnes, S.Bogach and D. Farchy: *Peru: National Survey of Household Energy Use*, World Bank, Energy and Poverty Special Report August 2010.

Philippines: Rural Electrification and Development in the Philippines: Measuring the Social and Economic Benefits, ESMAP Report 255/02, May 2002.

Best Practice recommendations 12: Demand curve estimation

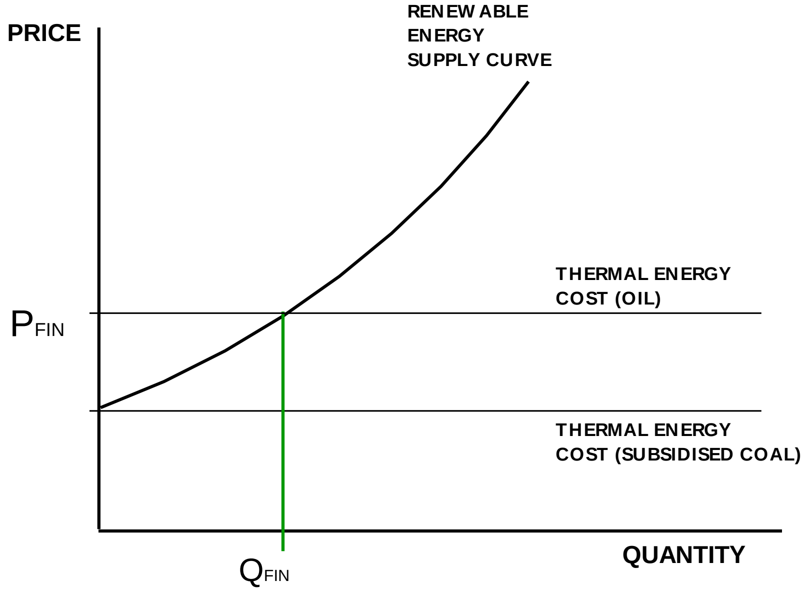
There is no better summary of best practice and the precautions that should be taken when estimating the benefits of electrification or off-grid renewable energy projects than the executive summary of Wilson *et al*. These are shown in Box M2.1

M3 SUPPLY CURVES

221. Supply curves are useful tools *when correctly derived*. They are particularly useful for assessing renewable energy targets on the basis of economic reasoning, rather than targets merely reflecting aspirational goals with little understanding of the implications of the incremental costs that follow. However, the first prerequisite for their construction is a realistic assessment of the resource endowment of all actually available renewable energy types: a very detailed supply curve for potential wind projects provides little guidance unless one can be sure there are no other renewable resources – hydro (small and large), geothermal or biomass - that may deliver the same benefits at lower cost.

222. The *economic* rationale for renewable energy is straightforward: the optimum amount of renewable energy for grid-connected generation is given by the intersection of the RE supply curve with the avoided cost of thermal electricity generation (Figure M3.1). Very little renewable energy will be competitive with the avoided thermal cost if that cost is based on financial prices: in almost all Asian countries that have their own fossil-fuel resources, subsidized prices to power utilities are widespread. Only where the marginal thermal resource is imported (and unsubsidized) oil, will renewable energy be competitive (as was the case in Sri Lanka in the early 2000s); where the thermal generation price is based on coal, little if any renewable energy will be competitive at financial prices.

Figure M3.1 Economic Rationale for Renewable Energy: Optimal Quantity (Q_{FIN}) at Financial Cost of Thermal Energy (P_{FIN})

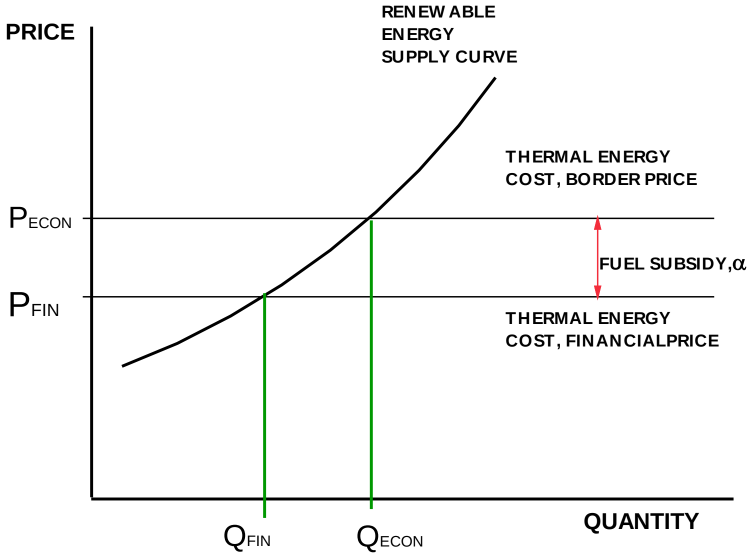


223. If thermal energy is correctly valued at the border price P_{ECON} (which equals $=P_{FIN}+\alpha$, the subsidy), then the optimal quantity of renewable energy increases, as depicted in Figure M3.2.

224. These principles constitute the basis for the original avoided cost tariffs in Sri Lanka, Indonesia, and Vietnam. In Sri Lanka, which has no domestic fossil resources, the marginal thermal production cost was set by imported diesel fuel, so the acceptance of a renewable energy tariff set at this avoided cost was easily achieved in 1998. In Vietnam this was more difficult, since at the time of its introduction in 2009 the avoided financial cost of thermal generation to the state-owned utility (Electricity of Vietnam,

EVN) was based on extensive subsidies to coal and domestic gas used for power generation. But as additional gas-fired combined-cycle-gas-turbine (CCGT) plants came online with prices linked to the international prices, EVN accepted a tariff based on the cost of the marginal thermal project.

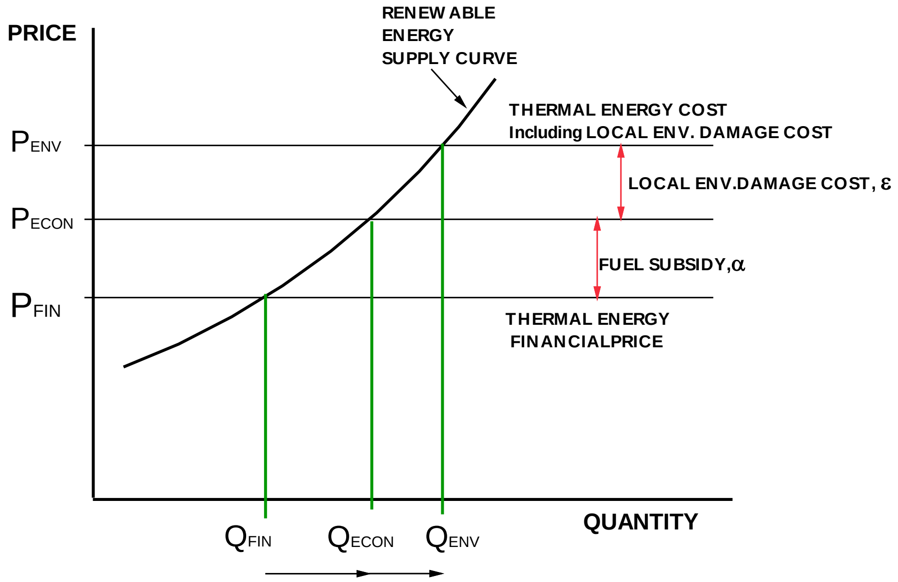
Figure M3.2 Optimal Quantity (Q_{ECON}) at the Economic Cost of Thermal Energy (P_{ECON})



225. But even if the cost of fossil energy is correctly valued at the border price, this needs to be further adjusted to reflect the local environmental damage costs of fossil energy—that is, the damage caused by local air pollutants (PM_{10}, SOx, NOx), or the environmental damage costs associated with coal mining (to the extent these are not already reflected in the economic cost of coal supplied to a coal-burning project).

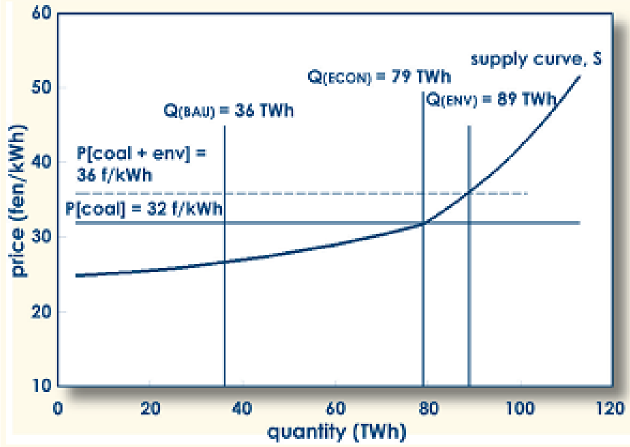
226. Such environmental damage costs represent real economic costs to the national economy, and their avoidance should be reflected as a benefit in the economic analysis of renewable energy. In effect, the real social cost of thermal generation is its economic price (that is, without subsidy) plus the per kilowatt-hour local environmental damage cost (*ε*). As shown in Figure M3.3, at this cost $P_{ENV} = P_{ECON} + \varepsilon$, the economic quantity of renewable energy increases further, to Q_{ENV}.

Figure M3.3 Optimal Quantity of Renewable Energy, Taking into Account the Environmental Damage Cost



227. In 2003, just this framework was used to underpin the case for renewable energy in China, as is summarized in Figure M3.4. The quantity of additional renewable energy increases from 79 terawatt-hours (TWh) to 89 TWh when the environmental damage cost of coal, estimated at 0.4 yuan/KWh (0.48 cents/KWh), is added to the economic cost of coal-fired generation.

Figure M3.4 The Economic Rationale for Renewable Energy: China

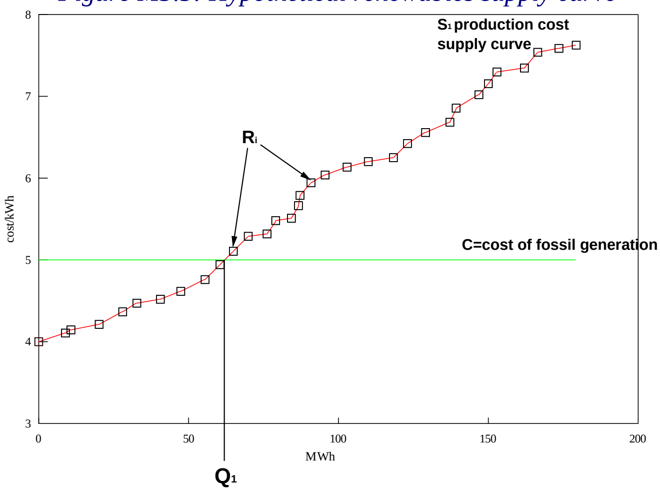


Source: Spencer, R., P. Meier, and N. Berrah. 2007. *Scaling Up Renewable Energy in China: Economic Modelling Method and Application*. ESMAP Knowledge Exchange Series #11, June Washington, DC.

CONSTRUCTING THE SUPPLY CURVE

228. The supply curve in Figure M3.5, denoted S_1, is based on the levelised cost of energy (LCOE) for different renewable projects, and then sorted from least to most costly. Each point on the supply curve represents a particular renewable energy project at a particular location, whose costs we denote R_i.[93] We also show the cost of thermal generation, calculated on the same basis. This is shown here for simplicity as a horizontal line, assuming that all fossil projects – say imported coal or CCGT – would all have roughly the same LCOE. None of the insights provided by the supply curve analysis differ if this were also upward sloping (as would be the case for a domestic fossil resource).

Figure M3.5: Hypothetical renewables supply curve



229. However, as noted in Technical Note C1, LCOE calculations require caution, and need to be adjusted to reflect the lack of capacity credit for non-dispatchable renewable

93 The numerical values implied by this Figure (and the remaining Figures of this Technical Note) are purely illustrative.

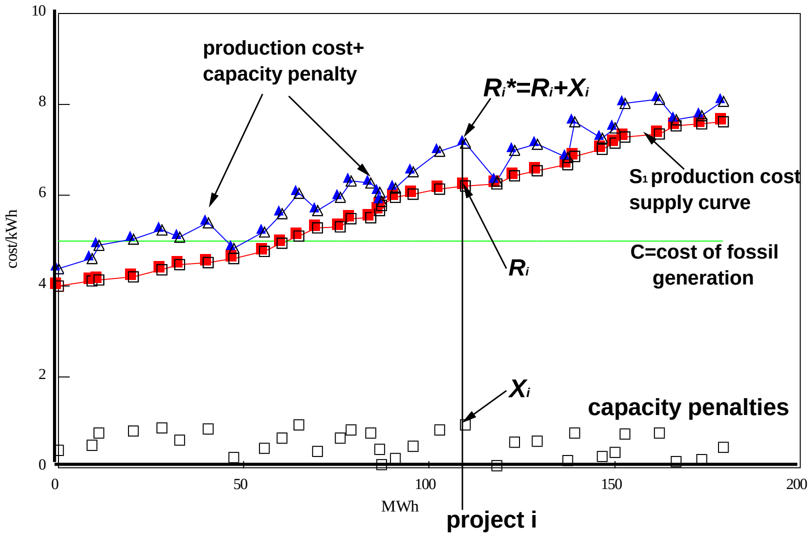
energy. When there are different technologies reflected in the supply curve, each technology may require a different adjustment – if the comparison were against coal as the replaced thermal generation, then the LCOE of geothermal projects needs no further adjustment – both provide base load. But where wind displaces CCGT, the capacity credit may quite small, so one needs to add a capacity *penalty* to the LCOE to make up for its lack of capacity value. The penalties would be lower for small hydro projects with storage, especially if its capacity value is enhanced by even a few hours of storage that allows it to operate at peak hours.. The calculation of the capacity credit is discussed in Technical Note T1.

230. A revised supply curve, S^*, can now be calculated which takes into account for each renewable energy project its capacity penalty X_i. The adjusted renewable energy cost for the i-th project, R_i^*, is:

$$R_i^* = R_i + X_I$$

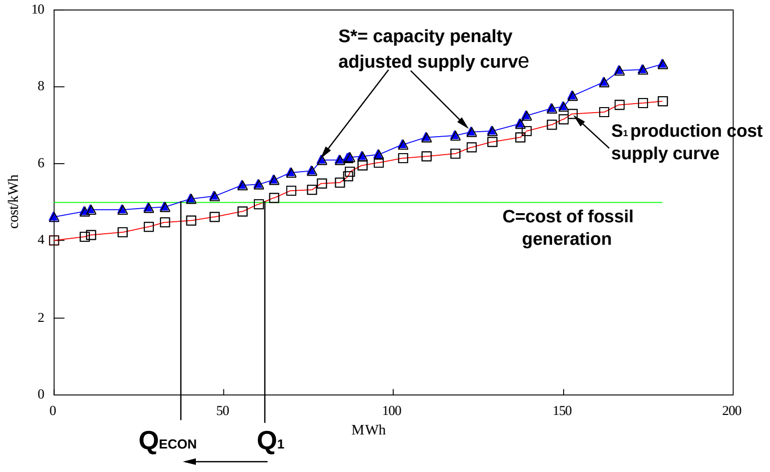
This revised supply curve is illustrated in Figure M3.6

Figure M3.6: Capacity penalty adjustments



231. These costs R_i^* must then be *re*sorted into ascending order to derive the new supply curve S^*, as shown in Figure M3.7. The curve S^* obviously lies *above* the curve S_1 – since (in this example), all of the renewable energy projects have some kind of capacity penalty. Consequently, the intersection of the adjusted supply curve S^* with the cost of fossil energy that is displaced is now to the *left* of Q_1, at Q_{ECON}. The latter represents the quantity of renewable energy that is economically efficient before consideration of the avoided externality costs.

Figure M3.7: Renewable energy supply curve adjusted for capacity penalty



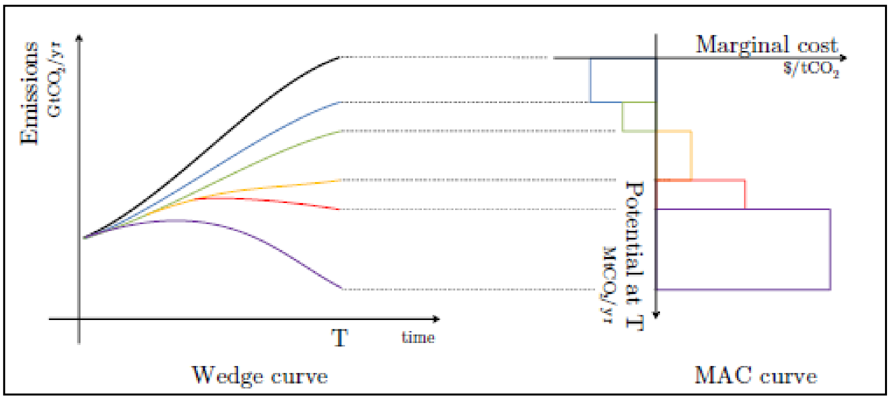
ISSUES

232. For supply curves to be useful several questions need to be asked: The first, as noted, is whether the renewable energy cost has been properly adjusted for capacity penalty. Second, one needs also to make sure that the cost of the thermal alternative is correctly calculated using the border price as the basis for fuel cost (or the relevant import parity price).

233. The above discussion of supply curves presumes that what is being "supplied" is a quantity of electricity, so the x-axis portrays kWh (or sometimes MW), with the objective being to supply the forecasted amount of electricity needed by the economy at least cost. Though based on a similar idea, a "marginal abatement cost" (MAC) curve is however something different, in which the x-axis portrays the quantity of pollutant to be removed, such as GHG emissions, or SOx emissions –reflecting the objective of a long-term objective of GHG emissions reduction. It does not necessarily follow that the cheapest option to add kWh is also the cheapest option to reduce GHG.

234. Moreover, Vogt-Schilb *et al* (2014) make the point that it does also not follow that the cheapest option in a MAC curve should necessarily be implemented first, because that may result in carbon-intensive lock-ins that would make it expensive to achieve the long-term objective. They propose a different graphical representation (Figure M3.8) to illustrate the linkage between the MAC curve and the trajectory of emissions ("wedge curves"), and propose an optimisation that accounts for constraints on implementation speeds (for Brazil).

Figure M3.8: MAC and wedge curve representation



Source: Vogt-Schilb. A., S. Hallegatte & C. de Gouvello, *Long-Term Mitigation Strategies and Marginal Abatement Cost Curves A Case Study on Brazil* World Bank Policy Research Paper 6808, 2014.

235. Supply curves could be constructed on the basis of financial costs as well, for which the relative position of projects may be different to that revealed by the economic supply curve. However, one should always start with the economic supply curve, and then ask how financial aspects distort the conclusions drawn For example, small hydro projects that pay significant water royalties may look less attractive than wind projects that pay no "wind" royalties.

236. Finally, one may note that supply curves, and the renewable energy targets as may follow from a supply curve analysis, are subject to uncertainty. How one deals with this problem is discussed in Technical Note **C4**.

Suggested Reading

Sargsyan, G., M. Bhatia, S. Banerjee, K. Raghunathan, and R.Soni. 2011. *Unleashing the Potential of Renewable Energy in India*. Washington, DC: World Bank.

World Bank. 2005. *Economic Analysis for the China Renewable Energy Scale-up Programme (CRESP)*. Washington, DC: World Bank.

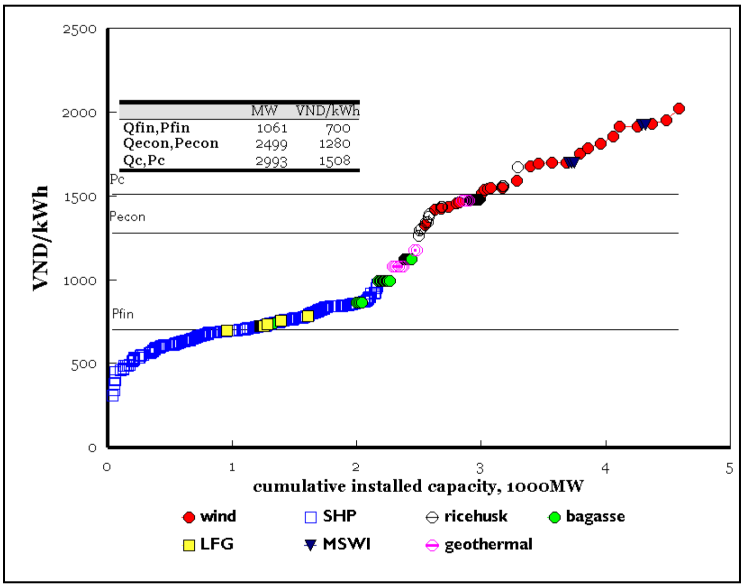
Vogt-Schilb. A., S. Hallegatte & C. de Gouvello, *Long-Term Mitigation Strategies and Marginal Abatement Cost Curves A Case Study on Brazil* World Bank Policy Research Paper 6808, 2014.

Examples in World Bank Economic Analysis

237. Figure M3.9 shows some examples from the literature. The Serbia curve also includes energy efficiency and thermal rehabilitation projects – which goes to the heart of the principles elaborated in the *Energy Directions Paper* that the Bank should seek least-cost solutions.[94]

Figure M3.9: Examples of renewable energy supply curves

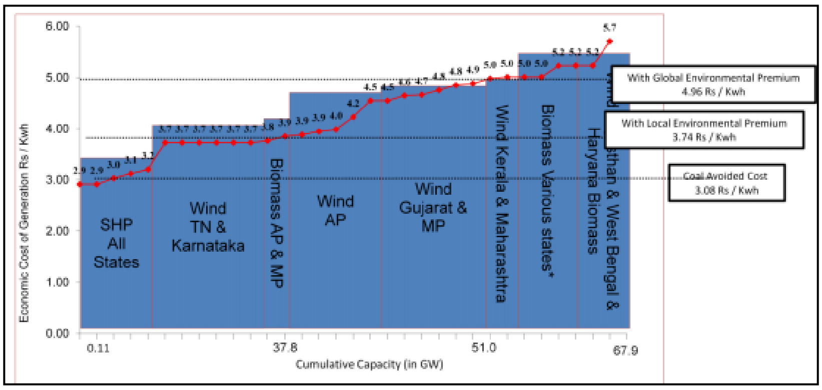
Vietnam



Source: Ministry of Industry and Trade, Vietnam Renewable Energy Masterplan, 2010 (cited in Meier, P., M. Vagliasindi, and M. Imran, 2015. *Design and Sustainability of Renewable Energy Incentives: An Economic Analysis*, World Bank, Directions in Development)

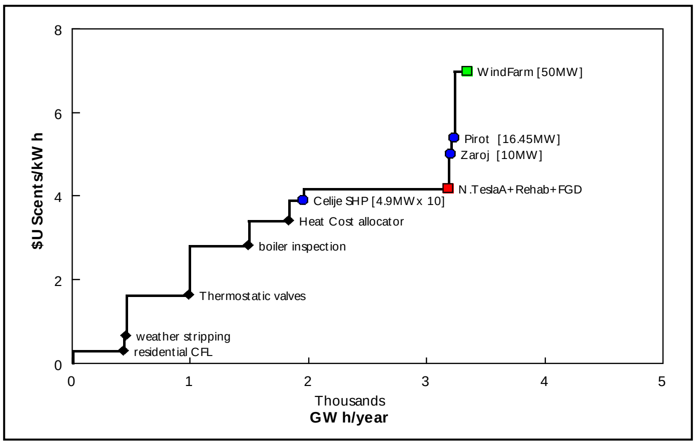
94 *Energy Directions*, ¶37 and, with respect to coal projects, ¶59 (WBG will support interventions that reduce GHG emissions associated with coal combustion plants)

India



Source: Sargsyan, G., M. Bhatia, S. Banerjee, K. Raghunathan, and R.Soni. 2011. *Unleashing the Potential of Renewable Energy in India*. World Bank, Washington, DC.

Serbia



Source: World Bank, *Serbia: Analysis of Policies to Increase Renewable Energy Use*, 2007.

The analytical work on which this note is based is presently being updated in the ongoing World Bank project *Assessing the Economic Costs of Air Pollution,* with the results expected to be available in December 2015. This note and its calculations will be revised once that work is complete.

M4 LOCAL DAMAGE COSTS OF FOSSIL GENERATION

238. The damage costs associated with air pollution constitute an important negative externality of thermal generation; and their avoidance in the case of renewable energy, energy efficiency, thermal rehabilitation, and loss reduction projects constitute a potentially important benefit.

239. Most of the focus to date has been on the damage costs associated with air pollution on human health. A range of other impacts associated with local air pollution include damage on crops and forests, and further damages arise from water pollution related to coal mining (acid mine drainage), and, at coal projects, from the disposal of ash and FGD scrubber sludge. However, these other impacts are generally considered to be small by comparison, and in the case of water pollution, extremely difficult to value. A US study estimates health damages associated with outdoor air pollution at $100 billion (at 1990 price levels), damages to field crops at $550 million and damages to timber yields at $600 million – in other words, health damages are two orders of magnitude greater than these other damages.[95]

240. Unlike damage cost estimates associated with GHG emissions, for which only the quantity of emissions matters, and for which all projects can use the same damage cost function,[96] local air pollution damage costs are strongly dependent on the location of emissions, the complexities of local and regional weather patterns, of the patterns of population around a power plant, of the dose-response functions that determine the health consequences, and of the valuation of human morbidity and mortality. This makes the estimation of damage costs complex.

241. A large literature documents the impacts of ambient pollution levels on human health, and on the methodology of valuing human mortality and morbidity. But including such damage costs in the context of a project CBA requires the additional step of estimating the incremental change in ambient exposure attributable to the incremental emissions of a power project.

CALCULATIONS

242. High uncertainty characterises every step of the calculations that links incremental pollutions emissions from a specific project to its ultimate damage costs. There are four main steps in such calculations

(i) Calculation of emissions:

243. This is generally straightforward, and will largely be a function of the quality of the fuel, the heat rate, and the pollution control technology in place. However, while emission factors per kWh for GHG and SO_2 are reliably calculated from basic stochiometry, those for PM_{10} and NOx emissions show wide variations, some by an order of magnitude (Table M4.1).

95 USEPA, 1999. *The Benefits and Costs of the Clean Air Act 1990*, United States Environmental Protection Agency, Washington, DC

96 See Technical Note **M5.**

Table M4.1: Emission factors for power generation: g/kWh

	Source	NOx	PM_{10}	SO_2
coal	India (1)	2.09	0.227	1.44
coal	India (2) (2009-2010)	3.72-4.67		
coal	Indonesia (Bukit Assam, Sumatra)(3)	4.39	0.67	4.36
coal	Indonesia (Kalimanthan)(3)	3.99	0.61	3.64
coal	Typical US plant (4)	0.2	0.046	
coal	Typical UK with FGD (5)	2.2	0.16	1.1
lignite	Loy Yang(Australia) (5)	2.1	.113	2.8
gas	gas steam cycle(3)	2.26	negligible	negligible
gas	gas combined cycle (3)	1.79	negligible	negligible
gas	UK, combined cycle, low NOx	1.4		
gas	US, combined cycle, SCR	0.57		
gas	open cycle gas (3)	2.67	negligible	negligible
gas	gas engines (diesel) (3)	4.56	0.10	2.46
diesel	diesel generators (3)	8.67	0.32	2.01
HFO	Indonesia (3)	2.3	0.29	11.7
HFO	UK, FGD	.98	.016	1.03
HFO	Greece	1.45	.31	3.63

Notes

(1) Cropper, M., S. Gamkhar, K. Malik, A Limonov, and I Partridge, *The Health Effects of Coal Electricity Generation in India*, Resources for the Future, June 2012

(2) M. Mittal, 2012. *Estimates of Emissions from Coal Fired Thermal Plants in India*.

(3) A. Widiyanto and others 2003. *Environmental Impacts Evaluation of Electricity Mix Systems in Four Selected Countries using a Life Cycle Assessment Point of View*. Proceedings, Ecodesign 2003: Third International Symposium, Tokyo, Japan.

(4) Black&Veatch, 2012. *Cost and Performance Data for Power Generation Technologies*, Report to NREL.

(5) World Energy Council, 2004, *Comparison of Energy Systems Using Life Cycle Assessment*, A Special Report of the World Energy Council, World Energy Council, London, UK, July, 61p. http://www.worldenergy.org/documents/lca2.pdf

ii) Linking emissions to changes in ambient concentrations:

244. In the case of a CBA for a thermal generation project, detailed air quality modelling will likely be available as part of the environmental impact assessment which takes into account the complexities of dispersion, local weather patterns, and stack height. But when the object of a CBA is a renewable energy project, or a T&D loss reduction project, whose impact would be to reduce thermal emissions from a variety of thermal projects for which such detailed modelling is rarely available, estimating such impacts is more difficult (particularly since the marginal project that is displaced may be an older project with for which no modern air quality modelling was ever done).

(iii) Linking changes in ambient concentrations to changes in health effects (mortality and morbidity)

245. Only in very few developing countries are there reliable studies of dose-response functions, which require fairly detailed epidemiological and hospital admissions data. Indeed, many studies show that a disproportionate number of deaths are associated with acute episodes (for example as associated with inversions), and there is much uncertainty about thresholds and the functional relationship (linear or on-linear above the threshold).

246. There are many reasons why extrapolation of the relationship of mortality and morbidity to ambient concentrations of pollutants do not easily transfer from developed countries where such studies are in fact available, to developing countries where

- The general level of public health is less good than in developed countries, and so populations are less resistant to the effects of pollution induced health problems;
- In many places, populations spend a greater proportion of time outdoors, and ventilation levels of houses in typical developing countries is much greater than

in developed countries – so exposure to outdoor ambient concentrations will be greater (and to indoor sources lower);

- Lower incomes limit the more costly avoidance options available in the US or Europe;
- The evidence suggests that the elderly are more sensitive to life-shortening effects of particulates than the young. So developing countries with a much younger age structure may have a lower propensity to premature mortality associated with respiratory diseases.

(iv) Valuation of mortality and morbidity

247. Monetising the value of human life is inherently difficult, so it should not surprise that estimates show high variation. Country-specific studies of the value of statistical life (VSL), used as a basis for valuing deaths caused by pollution, reveal orders of magnitude variation: for example as reported by Cropper *et al* (2012), for India these include an estimate of Rs 1.3 million (2006 Rs) based on a stated preference study of Delhi residents; Rs 15 million (2007) based on a compensating wage study of workers in Calcutta and Mumbai, and a 1990 study of Rs 56 million (in other words a range of $30,000 to $1.2 million). Different methods used in recent EU reports vary by a factor of three.

248. It is generally accepted that VSL estimates can be transferred from one country to another using the so-called benefits transfer method, which posits that

$$VSL_x = VSL_{USA}\left(\frac{Y_X}{Y_{USA}}\right)^{\varepsilon} \qquad \text{Eq.[1]}$$

where

VSL_X	=	VSL in country x
Y_X	=	Per capita income in country x
ε	=	elasticity (when ε =1, the ratio of VSL to per capita income is the same in both countries)

249. This equation is consistent with a simplified version of the so-called life cycle model, which holds that consumption is proportional to per capita income, which in turn assumes that people have the same discount rate, survival probabilities and risk preferences – requirements that are not likely to be strictly true.[97]

Comparator selection

250. While the above equation may well be valid for adjusting VSL across countries (i.e. step 4), it has no relevance to adjusting the relationships of steps 2 and 3. This is illustrated in Figure M4.1, which shows damage cost estimates for NOx in various European countries as a function of per capita GDP.[98]

251. It is clear that the correlation between these two variables is poor, which simply illustrates the many other factors that determine damage costs (location, population density, dispersion patterns). Adjusting European damage cost estimates from one country to another using *only* the ratio of per capita GDP is therefore unreliable.

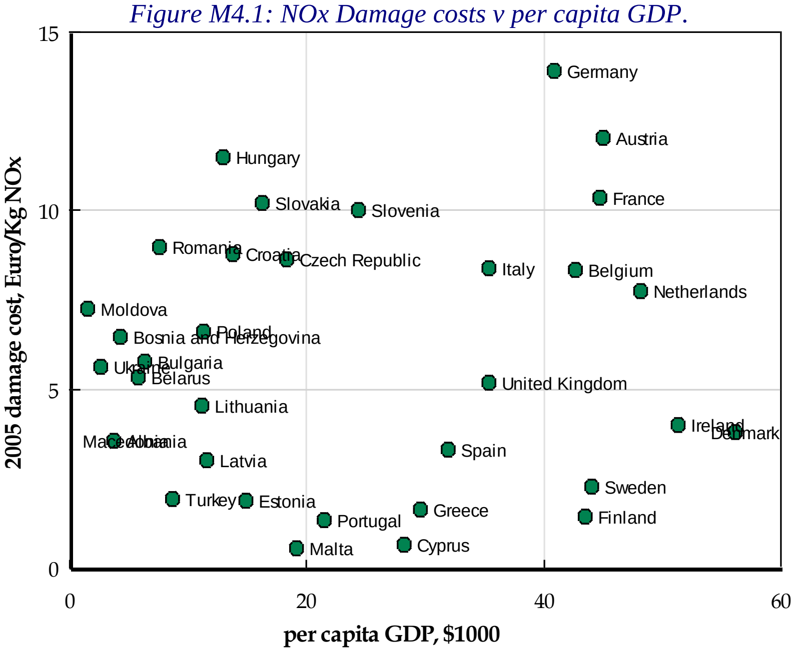
252. Moreover, even within countries there may be large differences in per capita income between urban and rural areas: so when assessing, say, the impact of a coal burning power plant located near Jakarta, the per capita income for the affected

97 This is discussed further in M. Cropper and S. Khanna, 2014. *How should the World Bank Estimate Air Pollution Damages*, Resources for the Future.

98 The values shown are for the VOLY (Value of Life Years) basis of valuation of mortality and morbidity.

population may be an order of magnitude greater than the national average, or that of a poor remote Island. [99]

Figure M4.1: NOx Damage costs v per capita GDP.



253. The importance of population density and location as explanations for the wide dispersion of the results are noted in a recent EU report[100]

- The density of sensitive receptors (people, ecosystems) varies significantly around Europe. Finland, for example, has a population density of 16 people/km^2, compared to Germany with 229/km^2.
- Some emissions disperse out to sea and do not affect life on land, an issue clearly more prominent for countries with extensive coastlines such as the United Kingdom or Ireland compared to landlocked countries such as Austria or Hungary.

Application of the benefit-transfer method

254. Table M4.1 shows an application of the benefit transfer method for estimating the local damage costs of a coal power generation project in Indonesia, using the UK as the comparator country. The total avoided local health damage cost – say from a geothermal project that displaces base load coal - is $1.25 USc/kWh. This compares to 2.73 USc/kWh as the valuation of avoided GHG emissions based on $30/ton.[101]

255. It is generally acknowledged that the EU Extern-e studies (from which the estimates shown in Table M4.2 are based) have generally high valuations of damage costs. Indeed, the damage costs based on VSL would be around 2.9 times higher.

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99 That is no less true of many of the larger European countries

100 European Environment Agency, 2011. *Revealing the Costs of Air Pollution from Industrial Facilities in Europe*. Technical Report 15/2011, Luxembourg

101 Most studies that use this approach make no further adjustments for population density. For the illustrative example used here, we note that the UK population density (2010) is 255 persons/km^2, as against 126 persons/km^2 in Indonesia. But both countries have wide variations in population density (in the UK, high densities in the Southeast, low densities in Scotland; in Indonesia, high density in Java, low density in Kalimantan)

Table M4.2: Benefit transfer method, based on UK damage costs

			NOx	PM_{10}	SOx	Total	CO_2
Damage cost (EU) (5)		2005 Euro/kg	5.18	15.5	7.8		
Exchange rate		2005$US/Euro	1.6	1.6	1.6		
Damage cost		2005$US/kg	8.288	24.8	12.48		
at 2013 price levels (1)		2013$US/kg	10.7744	32.24	16.224		
UK 2013 GDP (2)	39337	2013$US/cap					
Indonesia 2013 GDP(2)	3475	2013$US/cap					
GDP adjustment	0.088	[ ]					
Damage costs, Indonesia		$2013US/Kg	0.95	2.85	1.43		0.03
Emission factors (3)		gms/kWh	4.56	0.67	4.34		910
Damage costs		2013$/kWh	0.0043	0.0019	0.0062	0.0125	0.0273
		USc/kWh	0.43	0.19	0.62	1.25	2.73

Notes
(1) US GDP deflator (available from the World Bank MUV index forecast)[102]
(2) World Bank WDI database
(3) see Table M4.1
(4) Based on $30/ton
(5) European Environment Agency, 2011. *Revealing the Costs of Air Pollution from Industrial Facilities in Europe*. Technical Report 15/2011, Luxembourg

256. If adjusting damage costs per Kg of emissions is difficult, even greater are the hazards of using (or adjusting) estimates specified as $/kWh. For example, Table M4.3 shows local externality damage cost estimates for South Africa, developed for use in integrated resource planning (IRP) to evaluate alternative resource plans. In this study, by far the biggest local externality – which is a *positive* externality - derives from the avoidance of indoor air pollution associated with self-generation and kerosene for lighting. It also shows the largest single damage cost is attributable to acid mine drainage.

Table M4.3: Local externalities of coal power generation: South Africa

	RandCents/kWh	UScents/kWh
Positive externalities (avoided health damages of indoor air pollution – kerosene lighting, diesel self generation)	18	2.40
Negative externalities		
Combustion air pollution	-1.35	-0.18
Biodiversity loss	-0.7	-0.09
Acid mine drainage	-2.1	-0.28
Fuel production health impacts[103]	-0.36	-0.05
Total negative externalities	-4.51	-0.60
Net benefit	13.49	1.80

Source: Edkins, H. Winkler, A Marquard, R. Spalding-Fecher, *External Cost of Electricity Generation*, Contribution to the Integrated Resource Plan 2 for Electricity. Report to the Department of Environment and Water Affairs, Energy Research Centre, University of Capetown, July 2010

257. Such average aggregate $/kWh estimates of coal generation damage costs may be useful for IRP, but their application to a project specific CBA is problematic. For any particular displaced coal project, the location, fuel and technology specific factors may account for order of magnitude differences from a national average in damage costs. We would always recommend that the starting point for any damage cost monetisation be a separate calculation for each major pollutant (PM_{10}, SOx, NOx), as based on fuel quality, the emission control performance, and the technology specific heat rate, and expressed

102 The EU report provides figures of damage costs for 2010 and 2020, expressed at 2005 prices: these are adjusted to 2013 prices in this example.

103 Whether these health impacts (which are mainly due to mortality and morbidity in coal mining) should count as an externality is discussed in Technical Note T5.

as Kg per net kWh at the plant meter. Table M4.4 shows such a calculation for SOx emissions from different coal projects and coal qualities.

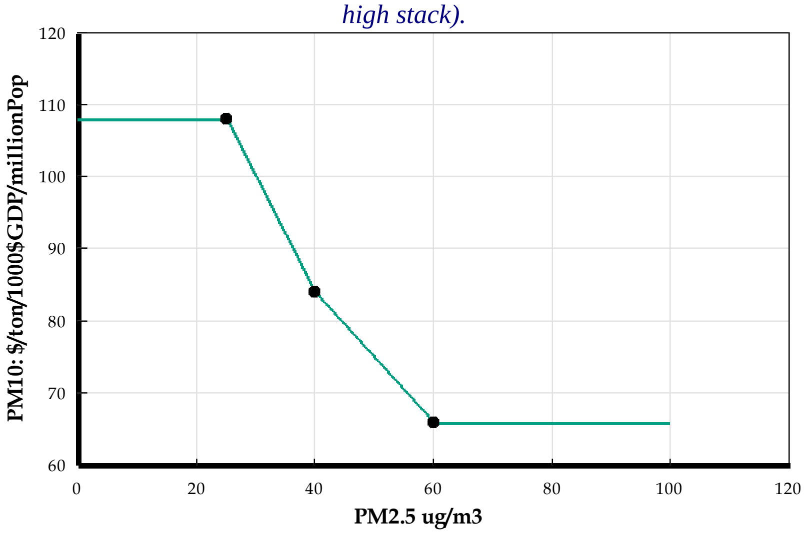
Table M4.4: SOx emissions: coal projects

technology		subcritical no FGD	subcritical FGD	subcritical FGD	supercritical FGD
Coal		Indonesia	Indonesia	Australian	Australian
Efficiency	[ ]	0.36	0.35	0.35	0.38
Heat rate	[BTU/kWh]	9,478	9,749	9,749	8,979
	[KCal/kWh]	2,389	2,457	2,457	2,263
Coal calorific value	KCal/kg	4,500	4,500	6,300	6,300
	Kg/kWh	0.531	0.546	0.390	0.359
Sulfur content	[ ]	0.60%	0.60%	1.00%	1.00%
Uncontrolled SOx emissions	g/kWh	6.36	6.54	7.79	7.18
FGD removal fraction	[ ]	0	0.85	0.85	0.85
Controlled emissions	gSOx/kWh	6.36	0.98	1.17	1.08

THE RECOMMENDED METHODOLOGY

258. These various issues were recognized in a 2000 World Bank study that estimated health damage costs from air pollution in six major developing-country cities.[104] Damage costs were estimated per ton of emissions per million affected population and per capita GDP, and take into account the height at which emissions are released. This study is currently being updated, but the new damage cost estimates (Table M4.5) also take into account the average air quality into which the incremental emissions are emitted: the incremental damage costs of an additional kg emitted into relatively pristine air-shed will be higher than those emitted in already highly polluted airsheds: this is illustrated in Figure M4.2, which shows damage costs per kg of PM_{10} as a function of the annual average $PM_{2.5}$ concentration (in the case of the upper end of the range of emissions of typical grid-connected power project with a high stack).

Figure M4.2: PM10 damage costs v. annual average $PM_{2.5}$ (grid connected power plant with a high stack).



104 Lvovsky, K., G. Hughes, D. Maddison, B. Ostrop, and D. Pearce. 2000. *Environmental Costs of Fossil Fuels: A Rapid Assessment Method with Application to Six Cities*. Environment Department Paper 78, World Bank, Washington, DC. The six cities were: Mumbai, Shanghai, Manila, Bangkok, Santiago and Krakow.

Table M4.5: Damage Cost Estimates ($/ton emission per million population per $1000 of per capita GDP income)

		High stack (modern power plants) (1)	Medium stack (large industry)	Low stack (small boilers and vehicles)
$PM_{2.5}$: 60µg/m³				
PM_{10}	Range	10-66	30-305	148-2,489
	Average	38	168	1,319
Sox	Range	3-21	10-97	47-797
	Average	12	54	422
NOx	Range	2-16	7-73	36-597
	Average	9	40	317
$PM_{2.5}$: 40µg/m³				
PM_{10}	Range	13-84	37-386	186-2,954
	Average	49	212	1,570
Sox	Range	4-27	12-123	59-945
	Average	16	68	502
NOx	Range	3-20	9-93	45-709
	Average	12	51	377
$PM_{2.5}$: 25µg/m³				
PM_{10}	Range	24-108	107-496	781-4,011
	Average	66	302	2,396
Sox	Range	8-34	34-159	150-1,284
	Average	21	97	767
NOx	Range	6-26	26-119	187-963
	Average	16	73	575
Radius defining affected population, km		15	3	0.2 (2)

Source: Lvovsky, K., G. Hughes, D. Maddison, B. Ostrop, and D. Pearce. 2000. *Environmental Costs of Fossil Fuels: A Rapid Assessment Method with Application to Six Cities*. Environment Department Paper 78, World Bank, Washington, DC; updated in 2015.
(1) For high stack projects, what matters is the location of populations relative to the dispersion plume. (In monsoonal climates there is often a prevailing wind direction for significant part of the year. See discussion of wind roses, below).
(2) These are multiple and dispersed, so use the area in which they are located.

259. Significant variations in annual average ambient $PM_{2.5}$ concentrations are evident from the data presented in Table M4.6: major cities typically have much higher pollution levels than the country averages. Typically, new coal projects are built in relatively rural areas, for which the national averages may be used.

Table M4.6: Selected locations: Annual average ambient $PM_{2.5}$ concentrations, µg/m³

country	source	$PM_{2.5}$	country	source	$PM_{2.5}$
Afghanistan	WDI	24	Pakistan	WDI	38
Afghanistan	Mazar-e Sharif	68	Pakistan	Lahore	68
Afghanistan	Kabul	86	Pakistan	Rawalpindi	107
Cape Verde	WDI	43	Pakistan	Peshawar	111
China	WDI	73	Pakistan	Karachi	117
Egypt	WDI	33	Sierra Leone	WDI	18
Egypt	Delta cities	76	South Africa	WDI	8
Egypt	Cairo	73	South Africa	Johannesburg	51
India	WDO	32	Sri Lanka	WDI	9
India	Patna	149	Sri Lanka	Colombo	28
Indonesia	WDI	14	Turkey	WDI	17
Indonesia	Jakarta	21	Vietnam	WDI	30
Morocco	WDI	20	Yemen	WDI	30
Nepal	WDI	33			

Source: Country averages: World Bank WDI *World Development Indicators* database
Cities: WHO *Ambient Air Pollution in Cities* database

.260. Table M4.7 shows the application of the Six Cities study to the same Indonesian coal power plant as above – now assumed to be located in the East Java province (with a population density of 828 persons/km^2. The emissions correspond to a modern plant with state of the art pollution emission controls. One observes that the total damage cost, 0.045 USc/kWh, is an order of magnitude lower than that derived in Table M4.1.

Table M4.7: Damage costs, Indonesian Coal Power Plant

				NOx	PM_{10}	SOx	Total	CO_2
[1]	Damage costs, Six Cities Study (1)		[$/ton]	16	66	21		
[2]	adjustment to 2013 price levels	1.064	[ ]					
[3]	adjusted damage costs		[$/ton]	17	70	22		
[4]	Area affected, radius (2)	15	[km]					
[5]	area	707	[km^2]					
[6]	population density [average]	828	[persons/km^2]					
[7]	population affected	0.59	[millions]	0.59	0.59	0.59		
[8]	adjustment for wind direction (3)	1						
[9]	adjusted population affected		[millions]	0.59	0.59	0.59		
[10]	2013 GDP per capita	3.48	$1000/capita					
[11]	Multiplier [1=national average]	1						
[12]	GDP per capita, affected area	3.48	1000$/capita	3.5	3.5	3.5		
[13]	Damage cost		$/ton	35	143	46		30
[14]			$/kg	0.035	0.143	0.046		0.030
[15]	Emission factors		g/kWh	4.56	0.67	4.34		910
[16]	Damage costs		$/kWh	0.0002	0.0001	0.0002	0.0005	0.0273
[17]			USc/kWh	0.016	0.010	0.020	0.045	2.73
[18]	installed capacity	1,000	MW					
[19]	load factor	0.9	[ ]					
[20]	energy per year	7,884	GWh					
[21]	total damage costs		$USm	1.25	0.76	1.56	3.56	215.23
[22]	total generating costs	0.05	$/kWh					
[23]			$USm	394.2	394.2	394.2	394.2	394.2
[24]	total social cost		$USm	613.0	613.0	613.0	613.0	613.0
[25]	damage costs as a fraction of generating cost		[ ]	0.2%	0.1%	0.3%	0.6%	35.1%

Notes:

(1) from Table M4.5.
(2) Area corresponding to a 15 km radius from the project.
(3) See text discussion, below.

261. The following should be noted:

- The basis for the health damage valuation (the VSL_{USA} in Eq.[1]) is set at $5.46 million at 2009 prices. If the country (or city) per capita GDP is stated for, say, 2013, then the damage costs in row [1] must be first escalated to 2013 (using the US GDP deflator), as shown in row [2]. The per capita GDP estimate should be at market exchange rates, not purchase-power-parity adjusted.
- The typical Indonesia power plant on Java is located on the coast relatively distant from Jakarta: hence the average population density and per capita GDP is used (row [6])
- Absent specific information about prevailing wind directions and population distributions in the vicinity of the project in question, no adjustment is made in row [8]. On a monsoonal Island, it could well be that for almost half the year the prevailing wind direction blows emissions out to sea (see Figure M4.3).

262. The total local damage cost is 0.045 USc/kWh. This compares to the damage costs of 2.73 USc/kWh for GHG emissions (assuming $30/ton CO_2). Nevertheless, as calculated in rows [18]-[24], the total damage cost for a typical 1,000 MW coal-based power plant is $3.56 million per year. Indonesia has a target of some 6,000 MW of

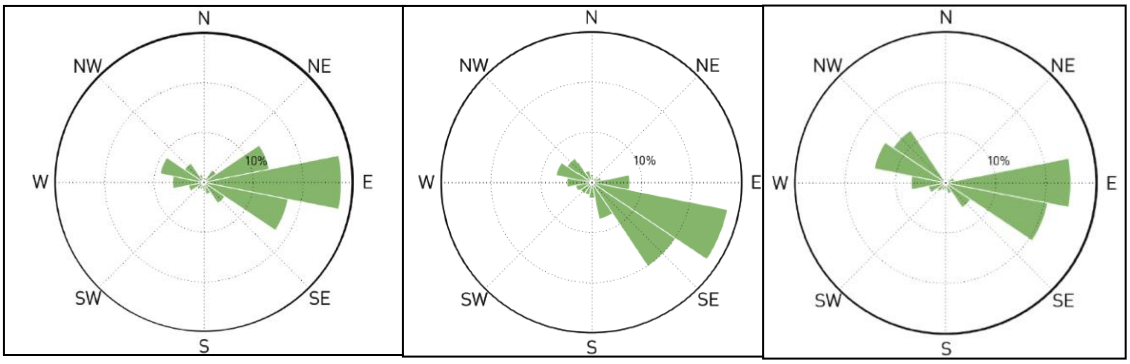
geothermal generation by 2025: the health benefit of achieving this target would therefore be $21 million per year.

263. Location is everything. For the same 1,000 MW coal project were it located in Jakarta itself, the annual damage cost computes to around $100 million (1.4 USc/kWh); old plants with poorly functioning pollution controls would have damage costs 3-4 times this amount.

264. Useful guidance on population exposure can also be derived from wind data: Figure M4.3 shows wind roses for some Indonesian locations, all of which show a highly unequal distribution of prevailing winds, with obvious implications for the number of persons likely to be affected by local air pollutants.

Figure M4.3: Wind roses for Indonesian locations

Sumba (eastern Island) **Sukabumi (Java)** **South Sulawesi**



LOCAL DAMAGE COST STUDIES

265. The value of local health damage studies is illustrated by Cropper and others, who estimated the damage costs of coal fired power generation in India (Table M4.8). The total damage cost from human mortality calculates to 1.11 USc/kWh.

Table M4.8: Damage costs for India

			NOx	$PM_{2.5}$	SOx	total
India, average values (2)		gm/kWh	2.091	0.227	1.44	
India, std deviation		gm/kWh	*0.299*	*0.389*	*1.024*	
deaths/GWh		[ ]	0.019	0.005	0.074	
VSL	3.6	$USm(1990)				
	4.0	$USm(2013)				
US GDP (2013) (1)	53,143	2013$US/cap				
India GDP (2013)(1)	1,499	2013$US/cap				
GDP adjustment	0.028	[ ]				
Damage cost		$USm/GWh	0.0021	0.0006	0.0083	0.01
		USc/kWh	0.21	0.06	0.83	1.11

(1) World Bank WDI database.
(2) Cropper, M., S. Gamkhar, K. Malik, A Limonov, and I Partridge, *The Health Effects of Coal Electricity Generation in India*, Resources for the Future, June 2012.

Avoided damage costs from self generation

266. In many cases, the most significant local health benefits from power sector emissions will be from avoided self-generation: the Tarbela Hydro extension project,

designed to reduce extensive summer peak power shortages, is an example here.[105] The main question is the size of the affected population.

267. Table M4.9 shows damage cost estimates for such self-generation in Indonesia, assuming that 1,000 MW of total diesel self generation capacity would be avoided in Jakarta. Assuming an average generator size of 1 MW, 1,000 self-generators would be displaced. Each has a zone of influence of radius 200 metres, so the total affected area is 12.6 km^2. The per capita GDP in Jakarta is taken as twice the national average. The total local air pollution damage cost calculates to 1.67USc/kWh, 37 times greater than of the coal project in East Java. Unlike the case of grid-connected coal generation, the local damage costs are comparable to the avoided GHG damage costs (of 1.8USc/kWh).

Table M4.9: Damage costs, diesel self generation in Jakarta

				NOx	PM_{10}	SOx	Total	CO_2
[1]	Damage costs, Six Cities Study (1)		[$/ton]	575	2396	767		
[2]	adjustment to 2013 price levels	1.06	[ ]					
[3]	adjusted damage costs		[$/ton]	612	2551	817		
[4]	Area affected, radius	0.2	[km]					
[5]	area	13	[km2]					
[6]	population density [average]	12800	[persons/km2]					
[7]	population affected	0.16	[millions]	0.16	0.16	0.16		
[8]	adjustment for wind direction	1						
[9]	adjusted population affected		[millions]	0.16	0.16	0.16		
[10]	2013 GDP per capita	3.48	$1000/capita					
[11]	Multiplier [1=national average]	2						
[12]	GDP per capita, affected area	6.96	1000$/capita	7.0	7.0	7.0		
[13]	Damage cost		$/ton	686	2858	915		30
[14]			$/kg	0.686	2.858	0.915		0.030
[15]	Emission factors (2)		g/kWh	18.8	1.34	0(3)		600
[16]	Damage costs		$/kWh	0.0129	0.0038	0.0000	0.0167	0.0180
[17]			USc/kWh	1.289	0.383	0.000	1.672	1.80
[18]	installed capacity	1000	MW					
[19]	load factor	0.2	[ ]					
[20]	energy per year	1752	GWh					
[21]	total damage costs		$USm	22.6	6.7	0.0	29.3	31.5
[22]	total generating costs	0.05	$/kWh					
[23]			$USm	87.6	87.6	87.6	87.6	87.6
[24]	total social cost		$USm	148.4	148.4	148.4	148.4	148.4
[25]	damage costs as a fraction of generating cost		[ ]	15.2%	4.5%	0.0%	19.7%	21.2%

Notes:
(1) See Table M4.5, for low stacks.
(2) Local pollutant emission factors from US EPA AP42. GHG emissions from oil are significantly lower than from coal (see Technical Note M5).
(3) Taken as zero, assuming use of low sulphur auto diesel (in Indonesia HSD, high speed diesel). Larger industrial self generating plants often use marine fuel oil (MFO) of significantly higher sulphur content.

Avoided cost tariffs for renewable energy

268. The question of avoided local environmental damage costs has been raised by Governments formulating avoided cost tariffs for renewable energy, but this has been hampered by the question of the reliability of the estimates. In Vietnam, the regulator (ERAV) concluded there were no credible, Vietnam-specific damage cost estimates available for a corresponding charge to be included in Vietnam's avoided cost tariff. In Indonesia, the Ministry of Energy and Mineral Resources (MEMR) included a small "de minimus" charge 0.1 USc/kWh charge in the new avoided cost tariff for geothermal projects issued in June 2014, on grounds that the damage costs were not likely to be zero,

105 World Bank, *Project Appraisal Document, Tarbela Fourth Extension Hydro Power Project (T4HP)*, February 2012, 60963-PK.

but that a *de minimus* charge would serve as a placeholder until such time as a reliable study for Indonesia was available.

269. However, even were such country specific studies available, there are still too many uncertainties (and too much geographical variability) for a reliable premium to be included in a renewable energy tariff. From a broader policy perspective, the control of ambient air pollution levels from thermal power projects is best achieved directly through suitable emission standards and their strict enforcement, rather than indirectly (and with considerable uncertainty) through renewable energy tariffs.

Suggested reading

Lvovsky, K., G. Hughes, D. Maddison, B. Ostrop, and D. Pearce. 2000. *Environmental Costs of Fossil Fuels: A Rapid Assessment Method with Application to Six Cities*. Environment Department Paper 78, World Bank, Washington, DC. This report is the basis for the approach recommended in this Guidance.

Atkinson, G., and S. Maurato. 2008. *Environmental Cost-benefit Analysis*, Annual Review Environmental Resources, 2008, 33:317-44. An excellent review of environmental valuation methods, and in particular of contingent valuation methods that underlie most studies of the value of human life.

Cropper, M., S. Gamkhar, K. Malik, A Limonov, and I Partridge, 2012. *The Health Effects of Coal Electricity Generation in India*, Resources for the Future.

Cropper, M and S. Khanna, *2014. How Should the World Bank Estimate Air Pollution Damage.* Resources for the Future.

Best Practice recommendations 13: Local air pollution damage costs

(1) Proceed with care. The range of uncertainty is high. A prudent and conservative approach when calculating benefits of renewable energy projects would be to use the lower bound estimates of Table M4.5; when estimating the externality costs of thermal projects one may use the higher bound estimates. In the case of gas projects, the avoided local damage costs, and the resulting impact on the NPV calculations, will be quite small, and rarely worth any extensive data collection. However, prudence requires that such the calculations *should* always be presented where coal projects are affected

(3) In the absence of relevant country specific sources, use the updated damage cost estimates in the Six Cities study as the starting point (Table M4.5), following the sample calculation of Table M4.7. For a reliable calculation, this will require items of information not customarily collected for an economic analysis, including population distributions around thermal power plants whose output is assumed to be backed down by a renewable energy project; and any environmental impact assessments that would have been prepared for newer thermal facilities which provide much detailed information.

(3) In the calculation of damage costs in the table of economic flows (see Annex A4), the damage costs should be escalated each year by the rate of GDP growth.

M5 CARBON ACCOUNTING

Background

270. The Bank has issued guidelines for GHG accounting to be used in renewable energy generation projects.[106] Although these guidelines include an EXCEL tool to facilitate the calculations, the use of the tool use is optional, provided the calculations follow the essential methodology points of the Guidance note. We recommend that GHG accounting be integrated into the calculations for the economic analysis, but following the principles of the GHG accounting note.

271. In September 2014 the Bank also issued a Guidance Note on the value of carbon in project appraisal[107] the note suggests that the economic analysis be done with and without the social value of carbon. The "base" values suggested (Table M5.1) are very close to the values used by the European Investment Bank (EIB).[108]

Table M5.1 Social Value of Carbon (SVC)

	2015	2020	2030	2040	2050
Low	15	20	30	40	50
Base	30	35	50	65	80
High	50	60	90	120	150

Source: *Social Value of Carbon in Project Appraisal*, Guidance Note to World Bank Group Staff, September 2014.

EMISSION FACTORS

272. Absent detailed information about the specific characteristics of fossil fuels, IPCC default values for CO_2 emissions from combustion may be used (Table M5.2).

Table M5.2: IPCC defaults: emissions per unit of heat value in the fuel

	IPCC default		
	Kg/TJ	Kg/GJ	Kg/mmBTU
Anthracite	98,300	98.3	93.21
Bituminous coal	94,600	94.6	89.70
Sub-bituminous coal	96,100	96.1	91.12
Lignite	101,000	101	95.77
Diesel	74,100	74.1	70.26
Fuel oil	77,400	77.4	73.39
Gas	56,100	56.1	53.20

273. Heat values for the IPCC defaults are on a *net* calorific basis (i.e. LHV). Consequently when calculating emission per kWh, efficiencies and heat rates should also be specified on an LHV basis.

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106 World Bank Sustainable Energy Department, Guidance Note: *GHG Accounting for Energy Investment Operations*, Version 2: January 2015.

107 *Social Value of Carbon in Project Appraisal*, Guidance Note to World Bank Group Staff, September 2014.

108 However (according to the guidance note), the EIB values appear to have been chosen "to include the carbon prices that would be needed to make the EU long-term decarbonisation targets viable". In other words, the EIB values are *not* the result of some economic reasoning and modeling, but simply chosen to meet a politically correct result ("Because several lignite-fired power generation projects previously passed the economic viability test even with high carbon prices, the EIB shareholders decided to raise the bar for coal projects").

274. The Bank's new GHG accounting guidelines provide a table of default values for GHG emission per kWh (Table M5.3)

Table M5.3: default values for emissions

		g/kWh			g/kWh
Wind	Onshore	1.1	Coal	Coal	1,055
	Offshore	0.61		Ultra-supercritical PC w/o CCS	738
Solar PV	a-Si	0		Ultra-supercritical PC w/ CCS	94
	m-Si	0		Supercritical w/o CCS	830
	p-Si	0		Supercritical PC w/ CCS	109
	CdTe	0		Subcritical PC w/o CCS	931
	CIGS	0		Subcritical w/ CCS	127
Solar thermal	Tower	0		Subcritical CFB w/o CCS	1,030
	Trough	9.93		Subcritical CFB w/ CCS	141
Geothermal	Geothermal	25.87		SC PC-OXY w/CCS	104
Biomass	Residue—cofiring	35.17		IGCC w/o CCS	832
	Residue—combustion	31.17		IGCC w/ CCS	102
	Woody—cofiring	52.17	Diesel	Diesel generators	650
	Woody—combustion	50.17	Gas	Simple cycle	577
	Herbacious—cofiring	51.17		Combined cycle w/o CCS	354
	Herbacious—combustion	47.17	Thermal	Heavy fuel oil	677
	Bagasse—cofiring	34.77	Gasoline	Reciprocating engine	661
Hydro	Run of river	1.18	Diesel	Reciprocating engine	704
	Electric dam	1.18			

275. However, in general, it is always preferable (given the necessary information) to calculate emissions from the underlying fuel quality and technology performance data. Table M5.4 shows the impact of the SVC on different fossil fuel price (based on IPCC default emission factors and typical heat rates).

Table M5.4: Impact of carbon valuations on the cost of energy

		large coal	gas combined cycle	gas open cycle	MFO	diesel HSD
		USc/kWh	USc/kWh	USc/kWh	USc/kWh	USc/kWh
IPCC default	Kg/GJ	96.1	56.1	56.1	80	74.1
	efficiency	0.38	0.50	0.34	0.34	0.34
heat rate	KJ/kWh	9474	7200	10588	10588	10588
	Kg/kWh	0.910	0.404	0.594	0.847	0.785
$/ton	0	0.00	0.00	0.00	0.00	0.00
	10	0.91	0.40	0.59	0.85	0.78
	20	1.82	0.81	1.19	1.69	1.57
	30	**2.73**	**1.21**	**1.78**	**2.54**	**2.35**
	40	3.64	1.62	2.38	3.39	3.14
	50	4.55	2.02	2.97	4.24	3.92
	60	5.46	2.42	3.56	5.08	4.71
	70	6.37	2.83	4.16	5.93	5.49
	80	7.28	3.23	4.75	6.78	6.28
	90	8.19	3.64	5.35	7.62	7.06

MFO=marine fuel oil (diesels); HSD = high speed (auto) diesel

276. Table M5.5 shows the corresponding impact on the variable cost of a coal project. When the world crude oil price is around $70/bbl, the coal price will be around $64/ton, and the variable cost of generation (in a supercritical plant) will be around 2.3 USc/kWh. At $30/ton CO_2, the total cost will be 2.73 USc/kWh (from Table M5.2) plus the 2.3 USc/kWh, for a total of 5USc/kWh – in other words, roughly *double*.

Table M5.5: Variable cost of coal generation as a function of coal price and SVC.

		Social Value of carbon (SVC), \$/ton CO_2							
oil price	coal price	0	10	30	40	50	60	70	80
\$/bbl	\$/ton	USc/kWh	USc/kWh	USc/kWh	USc/kWh	USc/kWh	USc/kWh	USc/kWh	USc/kWh
50	40	**1.4**	2.3	**4.2**	5.1	6.0	6.9	7.8	8.7
60	48	**1.7**	2.6	**4.5**	5.4	6.3	7.2	8.1	9.0
70	56	**2.0**	2.9	**4.7**	5.6	6.6	7.5	8.4	9.3
80	64	**2.3**	3.2	**5.0**	5.9	6.8	7.8	8.7	9.6
90	72	**2.6**	3.5	**5.3**	6.2	7.1	8.0	9.0	9.9
100	80	**2.9**	3.8	**5.6**	6.5	7.4	8.3	9.2	10.1
110	88	**3.2**	4.1	**5.9**	6.8	7.7	8.6	9.5	10.4
120	96	**3.4**	4.3	**6.2**	7.1	8.0	8.9	9.8	10.7
130	104	**3.7**	4.6	**6.5**	7.4	8.3	9.2	10.1	11.0
140	112	**4.0**	4.9	**6.7**	7.7	8.6	9.5	10.4	11.3
150	120	**4.3**	5.2	**7.0**	7.9	8.8	9.8	10.7	11.6

Avoided GHG emissions

277. Following the simplified UNFCCC methodologies for calculating avoided carbon emissions, many of the worked examples in the Bank's new GHG accounting guidelines use "average grid emission factors". That may be appropriate in certain circumstances where data is limited, but the reality of merit order dispatch is that when an additional kWh of electricity is injected into the grid, emissions are ***not*** reduced by the grid average. Nor do dispatchers pay any attention to the UNFCCC constructs of "build margins" and "operating margins". Rather, the project that gets backed down is that project with the most expensive variable cost. Therefore in a system that has coal (baseload) and gas (peak and intermediate) generation, renewable energy first displaces open cycle gas turbines, then combined cycle, and only very rarely coal.

278. Where a project lies in the merit order will depend on a combination of its heat rate and its fuel price – which may vary from plant to plant. Even if the relevant fuel price for economic analysis is the border price, the plant that is actually backed down first is decided by the variable *financial* cost as seen by the dispatcher.

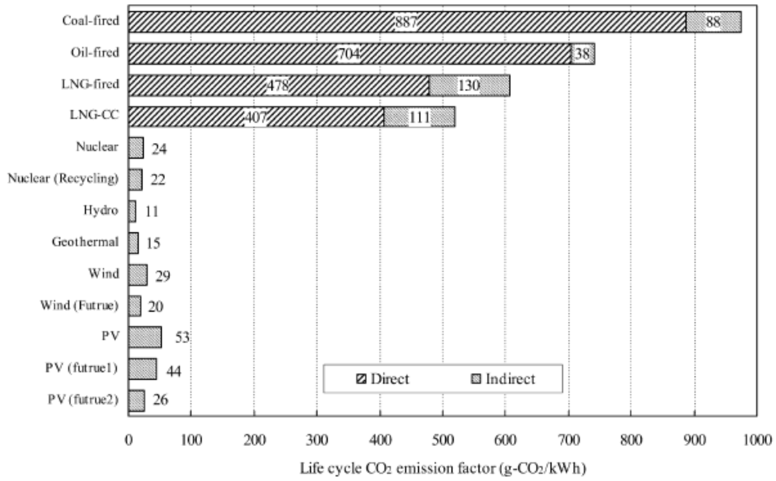
LIFE CYCLE EMISSIONS

279. The minimum mandatory requirement under the Bank's carbon accounting guidelines is the calculation of GHG emissions from combustion ("operational emissions within the project boundary"). An "optional" calculation is to also include upstream emissions associated with fuel supply and transport, and to report total "life-cycle emissions." Other authorities are unequivocal about the need to include life-cycle impacts: "ignoring this will lead to wrong assessments and misperceptions about the environmental credentials of a fuel, a technology or a product"[109]

280. Many RE projects replace gas-fired generation in CCGT based on LNG. GHG emissions from LNG combustion are much lower than from coal (per kWh, due to high efficiencies), but it is generally accepted that upstream emissions associated with LNG liquefaction, transportation (over often very long distances) and regasification together increase total GHG emissions by as much as 20%. For example, the Japanese study estimates combustion emissions of 407 gm/kWh, fuel cycle emissions add another 111 gm/kWh (Figure M5.6). The avoidance of such life-cycle emissions is a significant additional benefit of renewable energy, which should be recognised in the economic flows. However, if life-cycle emissions are used, they should be applied consistently, including for RE projects (particularly for large concrete dams in the case of hydro).

109 Australian Academy of Technological Sciences and Engineering, *The Hidden Costs of Electricity: Externalities of Power Generation in Australia*, 2009.

Figure M5.6: Lifecycle GHG emission factors



Source: Hondo, H., 2005. *Life cycle GHG Emission Analysis of Power Generation Systems: The Japanese Case*, Energy, 30, 2042-2056.

281. The most comprehensive study in the literature of life-cycle emissions in the LNG value chain is that by Heede for the Cabrillo deepwater port that was part of a proposal for an LNG project in California (importing LNG from Australia).[110] This study shows that consideration of the LNG supply chains adds some 38% to the GHG combustion emissions of both CO_2 and methane (Table M5.6).[111]

Table M5.6: GHG emissions in the LNG supply chain (1,000 tons CO_2 equivalent)

	methane	CO_2	total	percent
Gas production (Scarborough)	297	494	791	3.5
Gas pipeline	135	264	399	1.7
Liquefaction (Onslow)	175	2,512	2,687	11.8
LNG carrier fleet (Australia to California)	47	2,048	2,095	9.2
Cabrillo deepwater port	85	261	346	1.5
Ultimate distribution and combustion	650	15,852	16,502	72.3
Total	1,389	21,434	22,823	
(percent)	6.1%	93.9%		100

Source: A Heede, *LNG Supply Chain GHG Emissions for the Cabrillo Deepwater Port: Natural Gas from Australia to California*, Report by Climate Mitigation Services, 2006.

282. Life Cycle Assessments (LCAs) have been criticized for their variability and reliability, with assessments for some technologies spanning on order of magnitude in some cases. This variability can be attributed to the specific characteristics of the technologies evaluated (e.g., differing system designs, commercial versus conceptual systems, system operating assumptions, technology improvements over time) and LCA methods and assumptions. Analysts at NREL have developed and applied a systematic approach to review the LCA literature, identify primary sources of variability and, where possible, reduce variability in GHG emissions estimates through a procedure

110 A Heede, *LNG Supply Chain GHG Emissions for the Cabrillo Deepwater Port: Natural gas from Australia to California*, Report by Climate Mitigation Services, 2006. Of course, the fracking revolution in the US means that the anticipated need for LNG *imports* has been replaced by the possibility of LNG *exports*.

111 For combustion emissions of 16.5million tons, there are supply chain emissions of 6.3 million tons, so for every kg of GHG emissions in combustion, there is an additional 6.3/16.5=0.38Kg from the supply chain.

called "harmonization." This methodology is based on a two-step meta-analytical approach, which statistically combines the results of multiple studies, as follows:

- *Systematic Literature Review*. NREL considered more than 2,100 published LCA studies on utility-scale electricity generation from wind, solar photovoltaic (PV), concentrating solar power (CSP), biomass, geothermal, ocean energy, hydropower, nuclear, natural gas, and coal technologies. Systematic review, comprising three rounds of screening by multiple experts, narrowed the field to select references that met strict criteria for quality, relevance, and transparency. Less than 15% of the original pool of references passed this review process.
- *Harmonization and Data Analysis.* After the systematic review, NREL applied harmonization to adjust the published GHG emission estimates to a consistent set of methods and assumptions, specific to the technology under investigation, in two main stages: *System harmonization* ensured studies used a consistent set of included processes (e.g., system boundary, set of evaluated GHGs) and metrics (e.g., global warming potentials). *Technical harmonization* of key performance parameters (e.g., capacity factor, thermal efficiency) or primary energy resource characteristics (e.g., solar resource, fossil fuel heating value) ensured consistent values that reflect a modern reference system (typically a modern facility operating in the United States).

283. To date, NREL has completed harmonization of life cycle GHG emissions for wind, PV, CSP, nuclear, and coal technologies, with analysis of natural gas technologies forthcoming. Table M5.7 shows the NREL harmonized values assessed to date.

Table M5.7: NREL Harmonized LCA values

	Photovoltaics (C-Si and Thin Film)	Concentrating Solar Power (Trough and Tower)	Wind (Offshore and Onshore)	Nuclear (Light Water)	Coal (Sub- and Supercritical, IGCC, Fluidized Bed)
Estimates	46	36	126	99	164
References	17	10	49	27	53

Electricity Generation Technology	Photovoltaics (C-Si and Thin Film)	Concentrating Solar Power		Wind (Onshore and Offshore)	Nuclear (Light Water)	Coal (Sub- and Supercritical, IGCC, Fluidized Bed)
		Trough	Tower			
Driving Parameter	Solar Irradiation (kWh/m²/year)	Solar Fraction (%)	Operating Lifetime (years)	Capacity Factor (%)	Operating Lifetime (years)	Carbon Dioxide Emission Factor (kg CO_2/kWh)
Definition	Amount of solar energy incident upon a unit area of collector in the solar field during one year	Percentage of electricity produced only from solar energy	Assumed lifetime for the LCA or facility	Ratio of actual electricity generated to the maximum potential electricity generation	Assumed lifetime for the LCA or facility	Mass of carbon dioxide emitted per kilowatt-hour of net electricity generated—a function of thermal efficiency, coal carbon content, and coal lower heating value
Published Range	900-2,143	75-100	25-40	9-71	25-60	0.64-1.64
Harmonized Value	1700	100	30	Onshore: 30 Offshore: 40	40	0.97

Source: NREL, *Life Cycle Greenhouse Gas Emissions from Electricity Generation*

CARBON FINANCE

284. In Box C1.2 we presented switching values for carbon for South Africa, which can be compared to the social value of carbon in Table M5.1. Indeed, as noted in Technical Note **M1** (Sensitivity Analysis), calculation of carbon switching values is one of the minimum requirements for power sector projects that potentially incur incremental costs in the interest of carbon emission reduction. However, that switching value calculation tells only part of the story, and should also be accompanied by a calculation of the incremental carbon finance requirement.

285. Table M5.8 shows the analysis of switching values and incremental carbon finance requirement for the Medupi coal project. The capital costs (total financial cost) have been adjusted so that all of the alternatives produce the same amount of energy as

Medupi (which in the case of wind is without adjustment for any capacity penalty). So the wind or CSP equivalents would require a total up-front financial resources of between $46.3 - $48.7, compared to $14.8 billion for Medupi. This implies an additional carbon finance requirement of $31.5 - $33.9 billion, an amount that is clearly far beyond what is actually available to South Africa. It illustrates the fundamental problem of the transition to a low-carbon power sector for developing countries. Even nuclear power at current costs requires capital outlays of more than double that for coal.

Table M5.8: Carbon switching values and incremental carbon finance requirements

	production cost	switching value for CO_2	lifetime GHG emissions	total financial cost	incremental carbon finance requirement
	UScents/ kWh	$/ton$CO_2$	million tons	$billion	$billion
Medupi	5.8	0	769	14.8	
Hydro(Inge-III)	6.3	7	0	10.1	
CCCT (HFO)	9.9	156	534	6.4	
CCGT (LNG)	9.5	105	387	5.5	
nuclear	11.0	67	0	34.4	19.6
CCCT(gasoil)	13.1	275	511	5.5	
UGC (2)	14.5	223	508	13.0	
CSP, 25%LF (1)	14.8	115	0	40.2	25.4
wind	**15.5**	**124**	**0**	**46.3**	**31.5**
CSP storage, 40%LF (1)	17.0	143	0	35.4	20.6
CSP storage ESKOM (3)	17.9	155	0	48.7	33.9

Source: World Bank, 2010. *ESKOM Investment Support Project*. Project Appraisal Document, Report 53425-ZA
(1) CSP cost estimates from the international literature (in 2010)
(2) UGC=underground coal gasification
(3) ESKOM CSP study.

Marginal Abatement Costs

286. There is often confusion about the difference between marginal abatement cost (MAC) as calculated for Clean Technology Fund (CTF) projects, and the avoided carbon cost as a switching value (i.e. that value of carbon that brings the NPV to zero, and the ERR to the hurdle rate).[112] CTF requires that funding goes only to projects whose MAC is less than $200/ton CO_2 as set out in the 2008 IEA Energy Technologies Perspectives Report.[113]

287. This report does not in fact contain a rigorous definition of MAC (Annex E of the IEA report on definitions is silent on MAC). The report also states, in Annex B, somewhat unhelpfully, that

112 There is also confusion about the difference between a supply curve and a MAC. The former plots cost against the cumulative development impact (GWh or MW additions), the latter against the cumulative amount of pollutant that can be abated (see also Technical Note **M3** and the discussion of Figure M3.8).

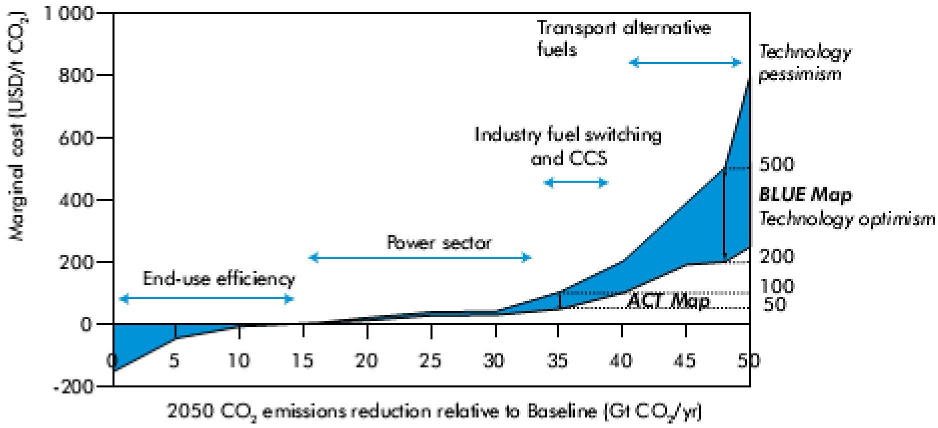
113 The relevant CTF regulation states:

Each project/program proposal will include a calculation of the CTF investment per ton of CO_2-equivalent reduced. In order to ensure the greatest impact of the CTF's limited resources, CTF co-financing will ordinarily not be available for investments in which the marginal cost of reducing a ton of CO_2-equivalent exceeds US$200, which according to the International Energy Agency's Energy Technology Perspectives 2008 Report, is the lower-end estimate of the incentive needed to achieve the objectives of the "BLUE Map Scenario"

The abatement cost curve does not really represent marginal cost/marginal CO_2 effects, because oil and gas prices are static, while they change in the ACT and BLUE scenarios.

288. The report notes that the MAC depends on the discount rate used, but it is not clear what discount rate is used for the curve presented in the IEA Executive Summary where the $200/ton figure used by CTF is mentioned. Most likely it is 10%.

Figure M5.2: Marginal emission reduction costs for the global energy system, 2050



Source: IEA *2008 Energy Technology Perspective*

289. Most CTF projects define MAC as

$$MAC = \frac{NPV}{LGHG}$$

Where LGHG is the undiscounted estimate of lifetime GHG emissions, and NPV is the net present value of the benefit stream. It necessarily follows that the MAC is a function of the discount rate.

290. The resulting values of MAC will be much lower than the calculation of switching value. Table M5.9 shows the values of MAC and switching value for CO_2 valuation in the case of the Noor II&III CSP projects.

Table M5.9: MAC and switching values, Noor II&III CSP projects

	Discount rate basis>		Govt. Opportunity Cost	ONEE
	Discount rate		5%	10%
[1]	Lifetime GHG emissions (LGHG)	Million tons	12.8	12.8
[2]	NPV (no environmental benefits)	$USm	-733	-1005
[3]	MAC =[2]/[1]	$/ton CO_2	57	78
[4]	Discounted GHG emissions	Million tons	6.4	3.7
[5]	Local environmental benefits	$USm	25	13
[6]	NPV (including local environmental benefits)	$USm	-708	-993
[7]	Switching value	$/ton CO_2	-111	-272

Source: World Bank, 2014. *Morocco: Noor-Ouarzazate Concentrated Solar Power Project*, Project Appraisal Document, PAD 1007

Consistency

291. Economic analysis requires the evaluation of alternatives, which in the case of a proposed renewable energy project means:

(1) The no project alternative – which means treating the additional grid-connected electricity as incremental, with benefits based on WTP, and the alternative being self-generation (or in the case of lighting, based on lighting kerosene).

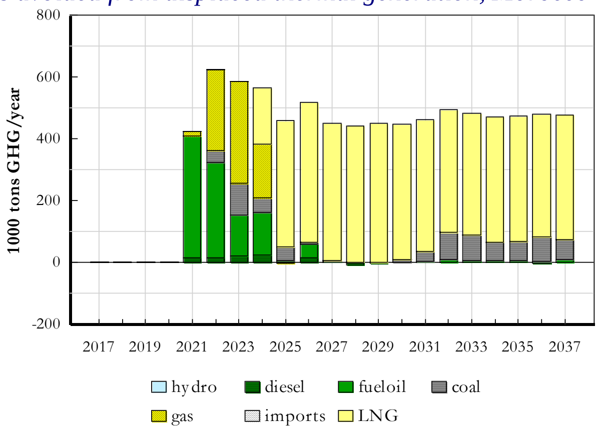
(2) Comparisons with other alternatives (to demonstrate the project is the least cost option for meeting the incremental demand): for example, in the case of Indonesian geothermal project, against base load coal; or in the case of a North African CSP, against imported LNG CCGT.

292. The displaced GHG emissions will be different in these two cases. For the no project alternative, the relevant avoided emissions are the avoided emissions from kerosene (lighting), diesel and HFO (for industrial self-gen); and for the comparison with other grid-generation options, the calculations will be according to the estimates of the various thermal projects displaced.

Box M5.1: Best practice example: calculation of the GHG emissions for the Morocco CSP projects

In the ideal case when power systems modelling is available (e.g. from WASP), the avoided GHG emissions should be calculated from the mix of displaced thermal energy as calculated by the model (as the difference between the "with" and "without project" runs). The composition of the displaced energy will rarely be constant over time: as shown in the figure, in the case of the NoorII&III CSP projects, in the first few years mainly oil is displaced, then LNG in years following, and in later years even some coal. The annual energy displaced is one of the standard WASP model outputs, which is easily imported into the economic analysis spreadsheet, wherein GHG emissions can then be calculated.

GHG emissions avoided from displaced thermal generation, Morocco CSP (Noor II&III)



Source: World Bank, 2014. *Morocco: Noor-Ouarzazate Concentrated Solar Power Project*, Project Appraisal Document, PAD 1007

Best Practice recommendation 14: GHG accounting

(1) For renewable energy projects, GHG accounting should be conducted as part of the economic analysis, and integrated into the spreadsheet that calculates the economic returns. Combustion emissions of the avoided thermal alternative are generally sufficient, but where the counter-factual is LNG in CCGT, an additional calculation of the life-cycle emissions (and corresponding changes in EIRR) should also be included. NREL harmonised LCA values may be used as a reliable source.

(2) Both MAC and switching values should be calculated, and presented in a table of the general format shown above in Table M5.9.

(3) GHG emissions from new hydro reservoirs are discussed in the special GHG guidance document issued by the Bank's Water Department.

M6 MULTI-ATTRIBUTE DECISION ANALYSIS

293. Multi-attribute decision analysis (MADA) encompasses a set of tools designed to facilitate an understanding of trade-offs between multiple objectives that cannot be combined into a single attribute. However, this approach does require that each objective be captured by a numerical indicator – such as NPV to measure the performance of the economic efficiency objective, or lifetime GHG emissions to measure the performance of the climate change attribute. For many environmental attributes this may not be straight-forward, since scales and utility functions may not be linear, and may involve thresholds.[114]

294. The first use of MADA in the Bank's power sector planning work was to examine the trade-offs between return (expected value of generation cost) and risk.[115] This was followed by work in the Bank's Environment Department to illustrate trade-offs with environmental objectives in Sri Lanka.[116] This methodology was subsequently adopted in 1998 for a major World Bank study on environmental issues in the Indian power sector, which included detailed assessments for the States of Rajasthan and Karnataka.[117] Such techniques were long part of the integrated resource planning (IRP) procedures adopted by many utility regulatory commissions in North America in the 1990s, based on the pioneering work of Ralph Keeney and Howard Raiffa.[118]

295. More recent applications in the Bank include a 2009 study of alternatives to coal-based power generation in Sri Lanka, and an economic analysis of the controversial Medupi coal-fired project in South Africa. The academic literature on MADA applications has grown rapidly since 2000: Wallenius and others[119] found 267 MADA studies in the energy and water resources literature.

An example

296. The World Bank Study of generation options in Sri Lanka illustrates a typical analysis.[120] It defined the following non-monetized attributes to complement the usual economic efficiency variable of the NPV of total system cost

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114 Hobbs, B. and P. Meier, *Energy Decisions and the Environment: A Guide to the Use of Multi-criteria Methods*, Kluwer Academic, Boston. Most of the case studies were drawn from North American IRP practice of the 1990s (including BCHydro, Seattle City Light, and Centerior Energy of Ohio).

115 Crousillat, E., and H. Merrill, 1992. *The Trade-off/risk Method: a Strategic Approach to Power Planning*. World Bank Industry and Energy Department Working Paper, Energy Series Paper 54.

116 Meier, P., and M. Munasinghe. 1995. *Incorporating Environmental Concerns into Power-Sector Decision-making: Case Study of Sri Lanka*. World Bank Environment Department Paper 6.

117 The original study (World Bank, 1999. *India: Environmental Issues in the Power Sector - Manual for Environmental Decision Making,* ESMAP Paper 213) included two detailed assessments of Bihar and Andhra Pradesh. This was followed a few years later by two further State assessments (World Bank, 2004. *Environmental Issues in the Power Sector: Long-Term Impacts and Policy Options for Karnataka,* ESMAP Paper 293, and World Bank, 2004. *Environmental Issues in the Power Sector: Long-Term Impacts and Policy Options for Rajasthan,* ESMAP Paper, 292).

118 Keeney, R., and H. Raiffa. 1993. *Decisions with Multiple Objectives*, Cambridge University Press, New York, Wiley, New York.

119 Wallenius and others, 2008. *Multiple Criteria Decision-making, Multi-Attribute Utility Theory: Recent Accomplishments and What Lies Ahead*. *Management Science* 54: 1360–49

120 Economic Consulting Associates and others, 2010. *Sri Lanka: Environmental Issues in the Power Sector*. Report to the World Bank.

- *Local air pollution impacts*. Population and stack-height-weighted sulphur dioxide (SO_2) emissions.
- *Energy security (diversity)*. The Herfindahl Index of generation mix (an index used in economics to measure the concentration of firms in an industry):

$$H = \sum_n s_i^2$$

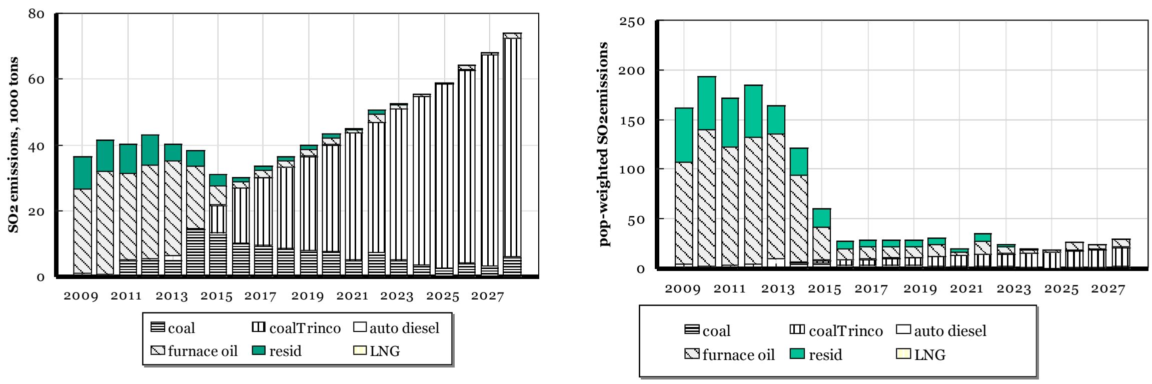
where s_i is the share of generation from the *i*-th supply source (the lower the value of *H*, the greater is the diversity of supply).[121]

- *Consumer impact*. Levelised average consumer tariff, Rs/kilowatt-hour (kWh).
- *Undiscounted lifetime GHG emissions.*

297. When framing such attributes, the first priority is to make sure that the attribute is a meaningful indicator of the underlying goal. For example, the simplest proxy for local air emissions is tons emitted per year—now a routine output of most power systems models. But *tons* of emissions say very little about actual impacts on human health, or about the costs—fiscal, social, and other—of health care. In the case of GHG emissions, it matters not where in the world the emission takes place, but in the case of local pollutants such as particulate matter, where and at what height the emission takes place is of crucial importance. One kg of PM_{10} emitted at ground level by a diesel bus in the centre of Colombo has an impact on human health several orders of magnitude greater than a kg of PM_{10} emitted from a tall utility stack in a remote and sparsely populated area (and where most emissions are in any event blown out to sea).[122] The difference between gross emissions, and population-weighted SO_2 emissions as a more meaningful proxy for actual damage costs, is illustrated in Figure M6.1. When location is taken into account, even though gross emissions increase (with the addition of many new coal projects), damage costs will decrease as the location shifts to less densely populated areas.

Figure M6.1 Emissions vs. stack height and population weighted index

A. Total SO_2 emissions **B. Stack height and population-weighted**



Source: Economic Consulting Associates and others, 2010. *Sri Lanka: Environmental Issues in the Power Sector*. Report to the World Bank, Washington.

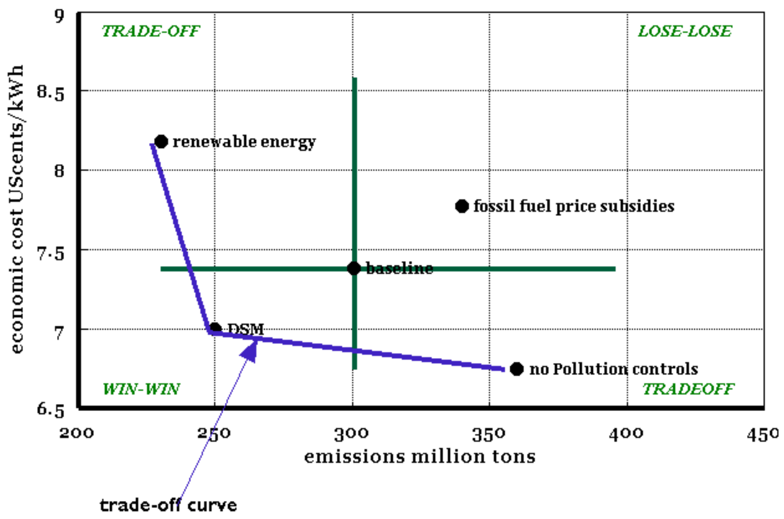
Note: resid = residual oil-fired projects (with no sulphur controls, typically burning high sulphur oil); coalTrinco = coal-fired projects with flue gas desulphurization (FGD) on Trincomalee Bay on the eastern coast, sparsely populated; **coal** = coal projects with FGD sited north of Colombo on the west coast; LNG = liquefied natural gas; SO_2 = sulphur dioxide.

298. Trade-off curves are simply *XY* plots of attributes, two at a time. Typically one shows quadrants relative to the baseline, into which fall the options that may be defined as perturbations of that baseline.

121 See the discussion of energy security indicators in Technical Note **C7**

122 See the discussion of damage costs by height of emission in Technical Note M4.

Figure M6.2 Illustrative trade-Off chart



299. Each quadrant of Figure M6.2 contains different types of projects:

- *Quadrant I* contains solutions best described as "*lose-lose*"—options that have higher emissions and higher costs. Typical options in this quadrant would be those involving fossil-fuel price subsidies (assuming the baseline is at economic prices), or building subcritical coal units (if the baseline includes supercritical units).[123]
- *Quadrant II* contains solutions involving trade-offs—costs decrease, but emissions increase. Not installing flue gas desulphurization (FGD), or use of pumped storage, are two options that typically occupy this quadrant.[124]
- *Quadrant III* contains solutions that are "*win-win*," of which demand-side management (DSM) and reduction in transmission and distribution (T&D) losses are typical examples. Here both attributes improve—that is, characterised by both lower emissions *and* lower economic costs.
- *Quadrant IV* again contains options that require a trade-off—emissions decrease but only at an increased cost. Renewable energy options and the substitution of coal by liquefied natural gas (LNG) are typical options to be found here.

300. 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 Figure M6.2, DSM dominates the baseline—and because it is better in both attributes, a rational decision maker would never prefer the baseline over DSM. Intuitively, one may say that options that lie on this trade-off curve are "closest" to the origin, but they all require trade-offs.

301. If, as in this illustrative example, there is a sharp corner in the trade-off curve (the so-called "knee set"), the option that occupies that corner (or one that may be close to it) would receive special attention. In this example, "no pollution controls" has greater emissions than DSM, but only a very small cost advantage—so a decision maker would have to give enormous weight to cost and almost no weight at all to emissions to

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123 Subcritical units have lower efficiencies than supercritical units. However supercritical units are generally available only in very large sizes (500 MW), so they are not always appropriate for smaller system.

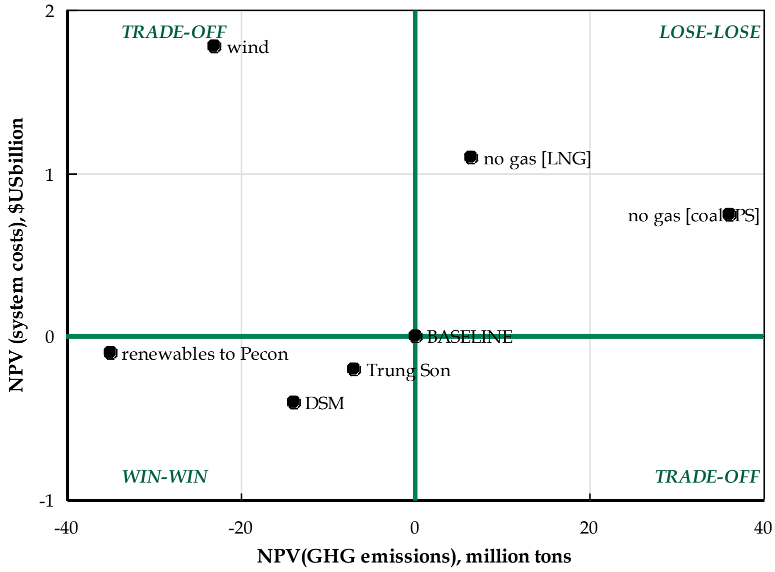
124 If the pumping energy is provided by base-load coal, then every kWh of pumped storage peaking power will have higher GHG emissions than if the same peaking energy were provided by gas turbine units.

choose this option. Similarly, "renewable energy" (as drawn here) has only slightly lower emissions, but a much higher cost than DSM—so again, to prefer renewable energy over DSM would require that huge weight be given to emissions, and not much to cost. Not all trade-off plots have such knee sets, or even any win-win options, in which case decisions are more difficult to make.

302. Figure M6.3 shows a trade-off plot for Vietnam, depicting the performance of various power sector options on the attributes of cost and GHG emissions. Trung Son is a World Bank–financed 260 megawatt (MW) hydro project.[125] The baseline in this case, which defines the quadrants, is the least-cost capacity expansion plan *without* Trung Son. The system cost and GHG emissions are plotted relative to the baseline: negative amounts indicate improvements to the objectives (cost reductions, GHG emission reductions).

303. In the **lose-lose** quadrant of Figure M6.3 are scenarios in which the assumed availability of domestic gas in the baseline is not realized, and must therefore be replaced either by imported LNG, or by coal plus pumped storage to meet the intermediate and peaking demand of the system.

Figure M6.3: Power sector options in Vietnam



Source: World Bank, 2011. *Trung Son Hydropower Project*. Project Appraisal Document, Report 57910-VN.
Note: DSM = demand-side management; GHG = greenhouse gas; LNG = liquefied natural gas; PS = pumped storage.

304. In the **trade-off** quadrant is wind—which in Vietnam is expensive (because the wind regime is at best modest), though it does of course reduce GHG emissions.

305. Trung Son is in the **win-win** quadrant by virtue of lower lifetime power production costs, *and* lower GHG emissions since it displaces gas-fired combined-cycle plants. Also in the win-win quadrant are non-wind renewables: "Renewables to P_{econ}" refers to the point at which the avoided social cost of thermal generation intersects the renewable energy supply curve, which defines the optimal level of renewable energy.[126] Most of this win-win renewable energy in Vietnam is small hydro and bagasse. DSM

125 World Bank, 2011. *Trung Son Hydropower Project*. Project Appraisal Document, Report 57910-VN.

126 See Figure M3.9 for the Vietnam renewable energy supply curve. .

(demand-side management and efficiency improvement) is also in this quadrant. Both DSM and renewables (mainly small hydro) are also being financed by the World Bank.[127]

Examples in Bank Economic Analysis

Sri Lanka: Meier, P., and M. Munasinghe. 1995. *Incorporating Environmental Concerns into Power-Sector Decision-making: Case Study of Sri Lanka*. Environment Department Paper 6, World Bank.

Economic Consulting Associates. 2010. *Sri Lanka: Environmental Issues in the Power Sector*. Report to the World Bank.

India: World Bank 2004. *Environmental Issues in the Power Sector: Long-Term Impacts and Policy Options for Karnataka*, ESMAP Paper 293; and World Bank, 2004. *Environmental Issues in the Power Sector: Long-Term Impacts and Policy Options for Rajasthan*, ESMAP Paper 292.

Suggested reading

Keeney, Ralph, and Howard Raiffa. 1993. *Decisions with Multiple Objectives*, Cambridge University Press, New York. Original edition published by Wiley, New York, 1976.

Hobbs, B. and P. Meier, 2000. *Energy Decisions and the Environment: A Guide to the Use of Multi-criteria Methods*, Kluwer Academic, Boston.

Crousillat, E., and H. Merrill, 1992. *The Trade-off/risk Method: a Strategic Approach to Power Planning*. World Bank Industry and Energy Department Working Paper, Energy Series Paper 54.

[127] In other words, DSM is not, strictly speaking, a mutually exclusive option (in the sense of the old OP10.04 guidelines for economic analysis): rather, it is a *complement* to supply-side options, and is part of any portfolio of win-win options.

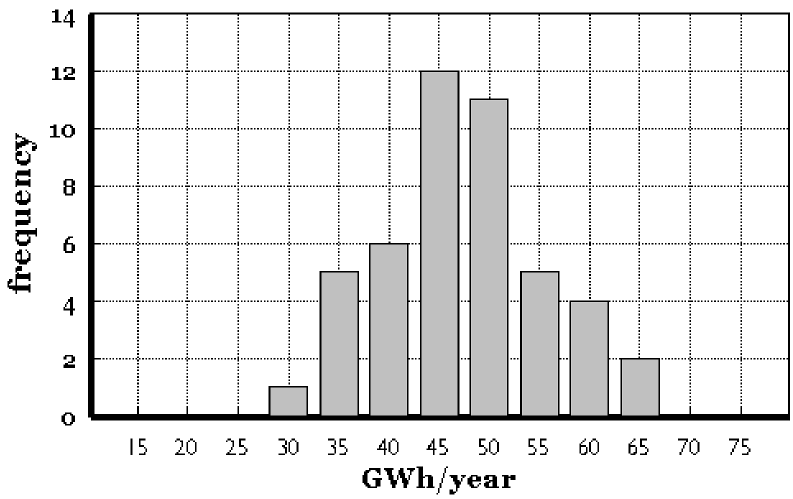
M7 MONTE CARLO SIMULATION

306. Monte Carlo Simulation is a useful technique for quantitative risk assessment. The basic idea is that since the individual assumptions in a CBA are not known with certainty, they are better treated as random variables distributed according to some probability distribution. The ERR calculation is repeated a large number of times (typically 5,000-10,000), at each calculation taking different values for each of the random variables, and thereby generating a probability distribution of the ERR. From this distribution one may calculate the probability of not reaching the hurdle rate. [128]

Specifying probability distributions

307. Some of the required probability distributions can be derived directly from resource data. For example to assess hydrology risk, one can use the annual energy generation from the reservoir operations simulation model for each year of the hydrology record – in Figure M7.1 illustrated with the distribution of annual generation in a Vietnamese small hydro project.

Figure M7.1: Annual generation, Vietnamese small hydro project



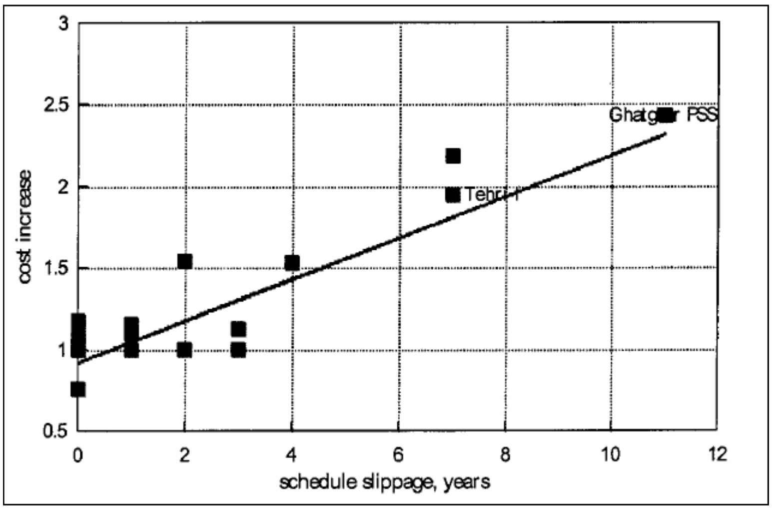
308. The extent to which variations in the variables are themselves correlated needs to be considered (which means that multivariate probability density functions may be required). Fortunately, in most cases of renewable energy project appraisal, the main input assumptions are independent: for example, there is little reason to believe that the world oil price, hydrology variation, and the pattern of construction cost overruns are correlated – so the probability distributions for these variables can reasonably be assumed to be independent.

309. However, a good example of variables likely to be correlated is the relationship between construction cost overruns and delays: long project delays often also increase capital costs – as in Indian hydro projects, shown in Figure M7.2. [129]

128 The technique was first used at the Bank in the energy sector for the 1997 India Coal Mine Rehabilitation Project (World Bank, *Staff Appraisal Report, Coal Sector Rehabilitation Project*, July 1997. Report 16473-IN).

129 World Bank, 2006. *Rampur Hydroelectric Project*, Project Appraisal Document. Report 38178-IN.

Figure M7.2: Cost increase v. delay, Indian Hydro projects

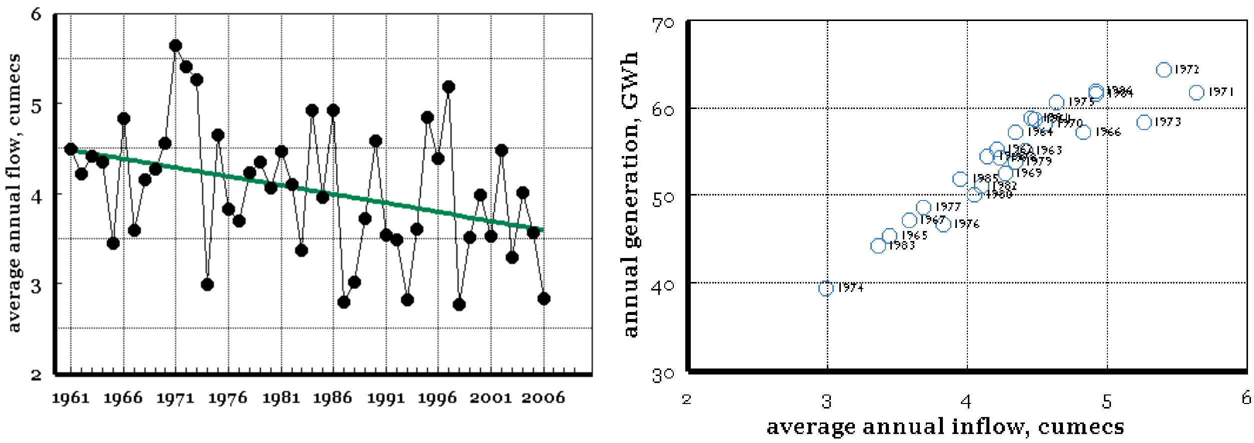


Source: World Bank, 2006. *Rampur Hydroelectric Project*, Project Appraisal Document. Report 38178-IN

310. Hydrology records always need careful scrutiny, as shown by the inflow record for typical Vietnamese small hydro projects in Figure M7.3: clearly there is an additional risk here that the downward inflow trend is a reflection of basin management issues, rather than a long-term cycle that would eventually return to the long-term average. Moreover, the relationship between inflows and generation is not linear: once a facility is built, extra flow available in wet years is spilled (no change in generation), but in dry years generation falls – a good example of downside risk.[130]

Figure M7.3: The Nam Khanh small hydro project, Vietnam

Inflows generation v. annual inflows

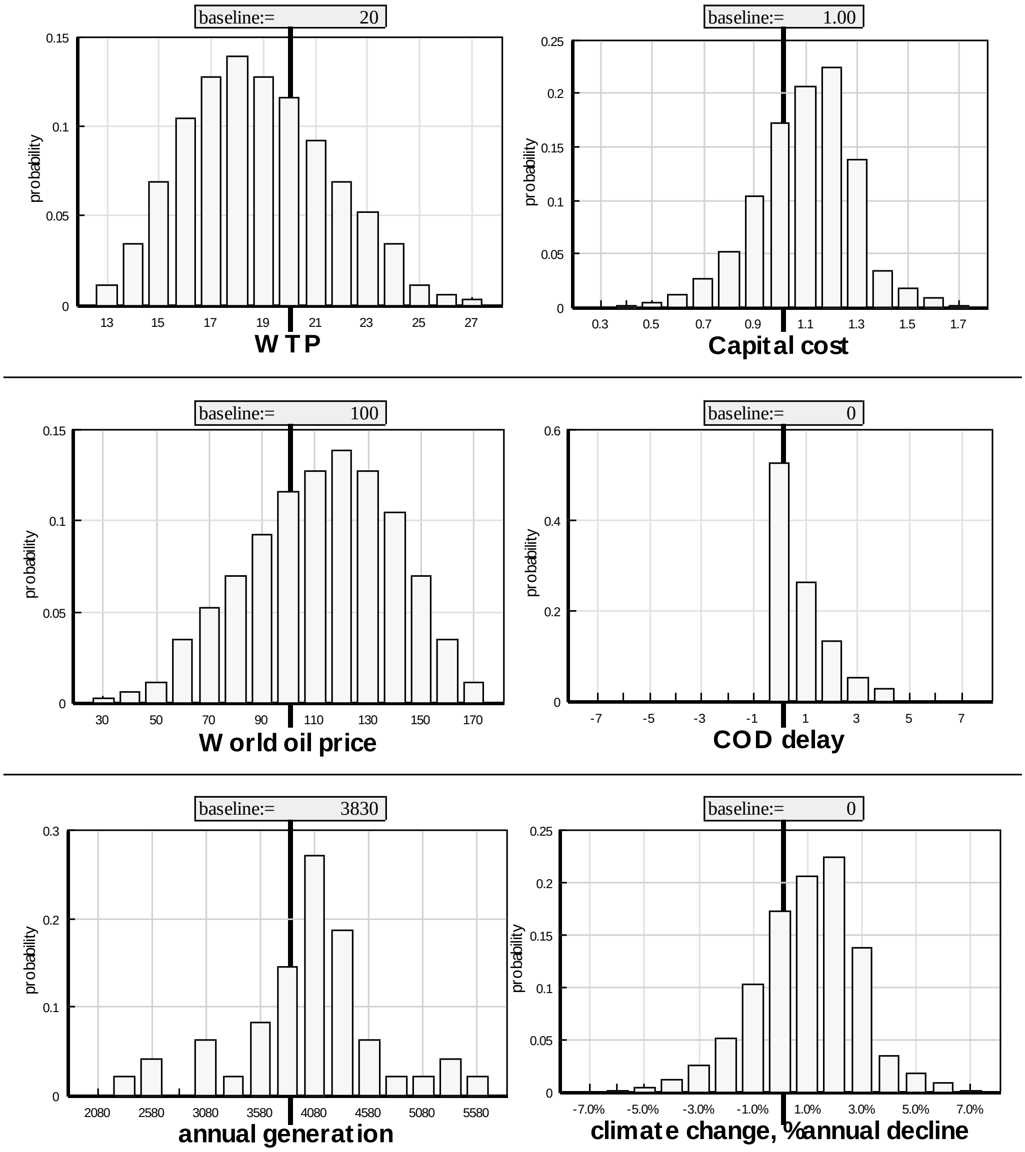


Illustrative example: Tarbela Hydropower extension

311. Figure M7.4 shows an example of a set of assumed probability distributions for the input assumptions of a Monte Carlo simulation. Each of these distributions is specified as a multiplier relative to the baseline estimate.

130 See Technical Note **C5**.

Figure M7.4: Assumed probability distributions for risk assessment: Tarbela Hydro Extension



312. The rationale for the hypothesised distributions is as follows:

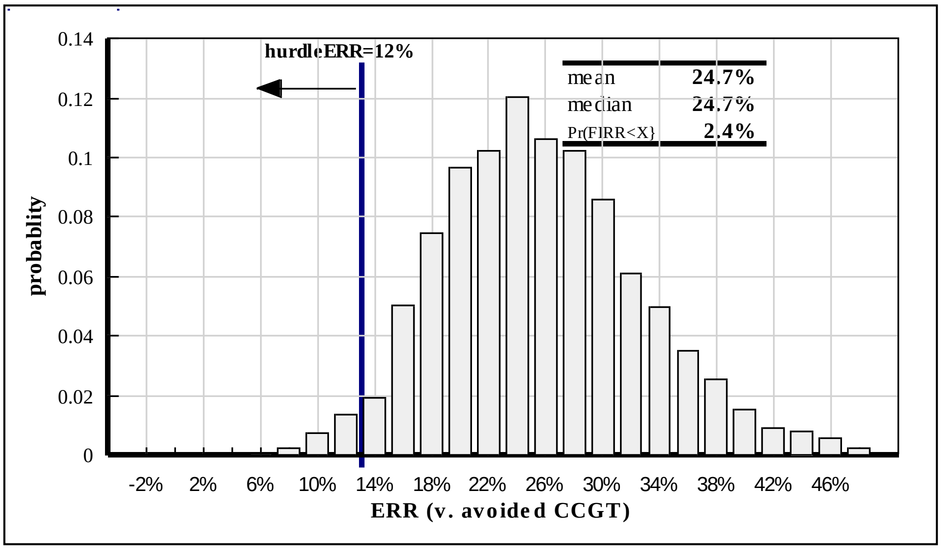
- *World Oil Price*: Given that the likelihood of higher oil prices is greater than of lower oil prices, skewed to the right.[131]
- *Capital cost*: skewed to the right, given the experience that capital cost estimates tend to be higher than assumed at appraisal, rather than lower than assumed.
- *Consumer Willingness to Pay (WTP)*: skewed to the left of the baseline estimate, reflecting the downside risk associated with small sample surveys.

131 The recent collapse of the international oil price (since this analysis was prepared in 2012) demonstrates the difficulties of making such probability statements about future oil prices. For this reason the RDM approach described in Technical Note **C4** (and the scenario discovery process used in the climate risk assessment of the Nepal Upper Arun hydro project) has the important advantage that it requires no prior probability assumptions to assess the vulnerability of proposed investment decisions.

- *Commercial operation date (COD)*: specified as the probability of delay in the operating date under the (worst case) assumption that the entire investment has already been made at the start of the delay (as discussed in the previous section). These delays vary from zero (i.e. no delay, the most likely) to increasingly longer delays, to a maximum of 4 years.
- *Annual generation (as long term average)*: The probability distribution shown reflects the actual historical variation in annual generation. This is not a smooth distribution, but is representative of the outcomes of the actual inflow hydrology.
- *Climate change impact*, specified as the annual rate of *decline* in annual generation. Negative values imply an increase in generation (recall that some studies suggest *increases* in wet season precipitation an inflows, implying the possibility of higher than forecast wet season generation). However, as can be seen in Figure M7.4, such outcomes are assumed to be relatively less likely than *decreases* in generation.

313. The resulting probability distribution of ERR is shown in Figure M7.5. The probability that returns (assessed against CCGT) fall below the hurdle rate is a low 2.4% (i.e. the area under the curve to the left of the 12% hurdle rate).

Figure M7.5: Probability distribution of economic returns



314. The mean of the ERR probability function is lower than the baseline estimate of 27.2%. This is a consequence of the asymmetry of the uncertainty around the baseline values: downside risks tend to be greater than the upside. One should always be mindful of the IEG assessment of World Bank cost-benefit analysis that notes such "optimism bias" as one of the causes of the general over-estimation of economic returns.[132]

Software

315. Several commercial providers offer uncertainty analysis Excel add-ins. Crystal Ball and @Risk are the more popular and are high quality but are also relatively expensive. A non-exhaustive list of similar add-ins is provided below in Table M7.1

132 World Bank, 2010. *Cost-Benefit Analysis in World Bank Projects*, Independent Evaluation Group.

Table M7.1:Software options for risk assessment

Add-in	Provider	Website	Approximate price
Crystal Ball	Oracle	www.oracle.com	$1,000
@risk	Palisade	www.palisade.com	$1,600
Risk Solver	Frontline Systems Inc.	www.solver.com	$1,000
DFSS master	Sigma Zone	www.sigmazone.com/dfssmaster.htm	$400
Risk AMP	Structured Data LLC, USA	www.thumbstacks.com	$130-250
Risk Analyzer	Add-ins.com	WWW.add-ins.com/analyzer/	$50

Source: Chubu Electric Power Company & Economic Consulting Associates, *Model for Electricity Technology Assessments (META)*: User Manual July 2012, ESMAP, World Bank.

316. Monte Carlo simulation is most reliable where many of the input assumptions are indeed readily defined as probability distributions (input hydrology in hydro projects, forced outage rates at thermal generation projects, distribution of construction costs). But some argue that making probabilistic assumptions related to assumptions such as the future oil price tend to be arbitrary, and that scenario analysis may be more effective to explore the implications of uncertain futures.

Suggested Reading

M. Baker, S. Mayfield and J.Parsons, 1998. *Alternative Models of Uncertain Commodity Process for Use with Modern Asset Pricing Methods*, Energy Journal,19,1,115-148. Examines the evidence for oil prices as a random walk or as a reversionary process.

M8 MEAN-VARIANCE PORTFOLIO ANALYSIS

317. Mean-variance portfolio theory is one of the best-known models in finance, best illustrated by simple example. Suppose there are two stocks, A and B, which have expected returns of E_A and E_B, and standard deviations of returns σ_A and σ_B. Then a portfolio of these two stocks, held in the proportions X_A and X_B, would have an expected portfolio return, $E(P)$ of

$$E(P) = X_A E_A + X_B E_B \qquad \text{Eq.[1]}$$

i.e. the weighted average of the expected returns.

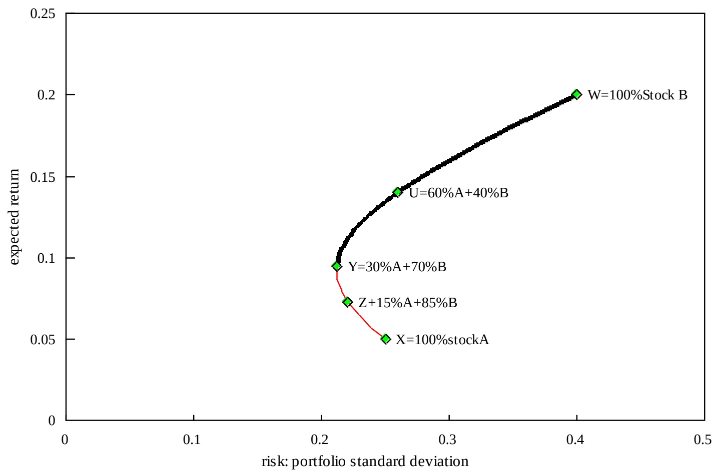
318. The portfolio risk, σ_P, is also a weighted average of the risk of the individual securities, but adjusted for the correlation between the two returns:

$$\sigma_P = \sqrt{X_A^2\sigma_A^2 + X_B^2\sigma_B^2 + 2X_A X_B \rho_{AB}\sigma_A\sigma_B}$$

where ρ_{AB} is the correlation coefficient between the returns of A and B.

319. Figure M8.1 plots expected return and expected portfolio risk for combinations of the two stocks, ranging from portfolio W (100% stock B) to portfolio X (100% stock A). The maximum return is indeed portfolio W (100% stock B), but the minimum risk portfolio is a combination of 30%A and 70%B. Clearly it makes no sense for an investor to hold portfolios Z or X, which have lower returns than Y, *and* higher risk. Thus the "efficient" portfolios lie between Y and W (shown as the bold section of the curve in Figure M8.1); this defines the highest earning portfolio for any given level of risk.

Figure M8.1: Risk and return for a 2-stock portfolio (assuming ρ_{AB}=0)



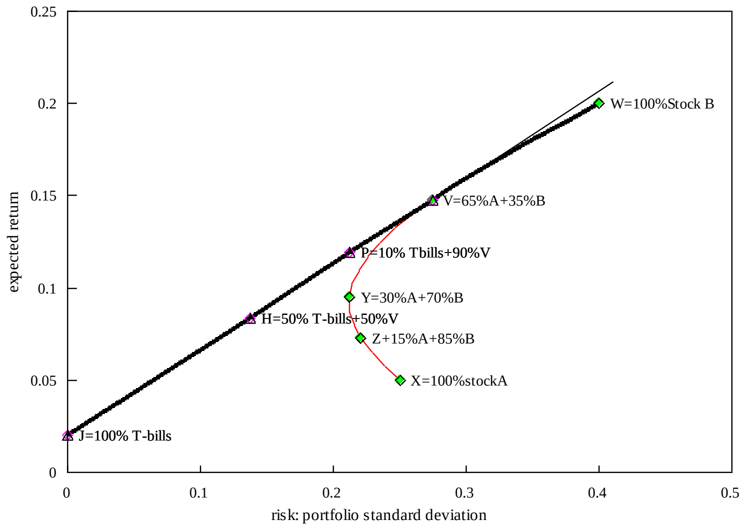
320. The effect of adding riskless assets to this portfolio of stocks A and B, which in a financial portfolio generally means US Treasury Bills or government bonds, has profound implications. T-bills are not totally risk-free because their value may fluctuate in response to changing interest rates, but they represent the highest degree of financial security (and a corresponding low rate of return).

321. Suppose, then, for sake of argument, that treasuries offer a guaranteed return of 3.5% (i.e. E_T=.035, σ_T=0). In Figure M8.2 we draw the line of tangency to the curve shown in Figure M8.1, which intersects at the portfolio V (65% A + 35%B). Then the line

connecting portfolio J (100% T-bills) represents combinations of t-bills and the efficient portfolio V: for example, portfolio H represents a portfolio of 50% T-bills and 50% of portfolio V (i.e. 50% T-bills,, 32.5%A, and 17,5% B). The efficient frontier is again shown by the bold line, and runs from J to H to V to W.

322. We note that portfolio Y is no longer an efficient portfolio, because by adding about 10% treasuries, for the same level of risk, expected returns *increase:* Portfolio P, which contains 10% T-bills, has higher expected returns than portfolio Y *for the same level of risk*.

Figure M8.2: Impact of a riskless asset



323. Auerbuch[133] proposed that this model be used to capture the benefit of renewable energy to a portfolio of (risky) fossil fuel generating assets. The analogy requires that renewable energy be seen as the "riskless" asset (akin to US Treasuries), while the risk associated with the fossil generating assets derives from fossil fuel volatility. Under this presumption, Auerbuch shows that for the United States, adding between 3-6% renewables to a portfolio of gas and coal generation will serve to reduce cost or risk or both. In a subsequent analysis Auerbuch applies the model to the EU, where he argues that an efficient generating portfolio would include as much as 12% wind energy[134].

324. However, the validity of the analogy depends critically on the notion of renewables (and wind energy in particular) as having constant cost – i.e. once built, the costs are fixed (since there is no fuel variability as with fossil fuels that causes fossil generation costs to vary from month to month).[135] Auerbuch acknowledges that

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133 Awerbuch, S. 2000. *Getting it Right: the Real Cost Impacts of a Renewables Portfolio Standard*, Public Utilities Fortnightly, February 15.Auerbuch (2004)

134 Awerbuch, S., and M. Berger, 2003. *Energy Diversification and Security in the EU: Mean-Variance Portfolio Analysis of Electricity Generating Mixes and its Implications for Renewables.* IEA Technical Report IEA/EET Working Paper EET/2003/03, Paris

135 Portfolio theory is based on a series of assumptions regarding efficient markets, including easily tradable assets at low transaction costs, perfect information about assets and normally distributed probability returns of investments in assets. While these assumptions can be deemed to be a sufficient approximation of reality in highly liquid, large, developed financial markets, it is hard to argue that this would be the case for the generating portfolios of the Bank's client countries. Moreover, optimal financial portfolio selections require infinite divisibility of assets, again unlikely in the case of small, or isolated, systems. Nevertheless, one could argue that because of the modular nature of

renewables are not entirely free of risk, but presumes that this can be diversified away by owning geographically dispersed sites or, perhaps by using two or more technologies such as PV and wind.[136]

renewable energy technologies, renewable project investments have inherently better portfolio-management attributes than the larger and more "lumpy" fossil fuel projects.

136 Discussed further in Technical Note **T1**, *Portfolio diversification*)

M9 SCENARIO DISCOVERY[137]

325. This Note describes the scenario discovery process used in the study of hydro planning in Nepal and the Upper Arun Hydro project (UAHP, summarized in Technical Note **C4**).[138] This process is an integral part of the Robust Decision Making methodology: it uses statistical cluster-finding algorithms to provide concise descriptions of the combination of future conditions that lead a strategy to fail to meet its objectives.[139] This technique has also been used in the ESMAP Study of energy-security tradeoffs.[140]

326. The description of these conditions helps focus decision makers' attention on the most important uncertain future conditions to the problem at stake. They can be thought of as decision relevant scenarios[141], because they help decision makers discuss the acceptability of the risks involved with the various options available.

327. Scenario discovery begins with the creation of the database which contains the model's results. Each row of results reports a future (or case), which is a combination of particular levels of each of the uncertainties considered (i.e., a certain price of electricity, capital cost increase, precipitation and temperature changes, discount rates, plant load factor, and lifetime of the plant) and the resulting performance of the project according to the chosen metrics, in our case the NPV. This database creation is akin to the Monte Carlo simulation procedure, which creates several thousand simulations of a project's performance, but with the important distinction that Monte Carlo simulation makes prior assumptions about probability distributions (from which the values are sampled), whereas the RDM process doe not – it looks at *all* futures and requires only a definition of the plausible ranges of uncertainty. For example, in the case of future oil prices, a Monte Carlo simulation might hypothesize an expected value of future price of $100/bbl, with some specified variance and skewness. In RDM one would examine *all* futures in the range of $30/bbl to $200/bbl.

328. Scenario discovery works well when stakeholders agree on a threshold for the performance metric. This allows the analyst to proceed with differentiating the futures in which the project meets its objectives from the ones in which it does not. In this analysis, it was agreed that the project(s) failed to meet its (their) objective in those futures where NPV was negative (i.e., threshold = 0). The study used the 500 futures for five of the six parameters and a full factorial design for including the stream flows (i.e, the climate dimension).

329. The UAHP study then used the Patient Rule Induction Method (PRIM)[142] to analyze the database of futures and identify the set(s) of conditions (which we will call a

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137 This note was contributed by Laura Bonzanigo.

138 World Bank, 2015. *Programmatic Approach to Impacts of Climate Risks on Water, Hydropower and Dams.*

139 R. Lempert and others, 2013. *Making Good Decisions Without Predictions* (No. RB-9701), Research Brief. RAND Corporation.

140 P. Meier, Irving, J. and C.Wnuk, *Energy Security Trade-Offs under High Uncertainty: Resolving Afghanistan's Power Sector Development Dilemma* ,World Bank ESMAP, June 2015.

141 Groves, D.G., and Lempert, R.J., 2007. *A New Analytic Method for Finding Policy-relevant Scenarios*. Glob. Environ. Change, Uncertainty and Climate Change Adaptation and Mitigation 17, 73–85. doi:10.1016/j.gloenvcha.2006.11.006

142 Friedman, J.H., Fisher, N.I., 1999. *Bump hunting in high-dimensional data*. Stat. Comput. 9, 123–143. doi:10.1023/A:1008894516817

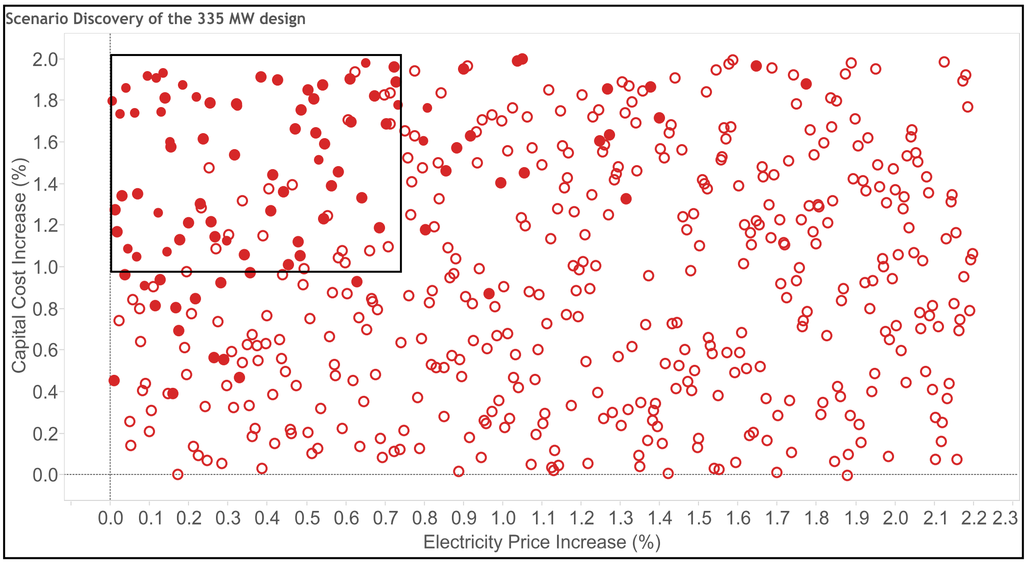
"scenario") that differentiates the vulnerable futures from the successful ones. These sets of conditions describe some combination of constraints on one or more of the uncertainties. For instance, a set may indicate that the NPV is negative if the discount rate is higher than a certain level and the stream flows decrease by a certain percentage. PRIM helps identify the main uncertainties that may affect the project's performance and focus the attention on these relevant parameters.

330. PRIM uses three measures to evaluate the different sets of conditions it identifies:

- **Coverage**: the fraction of vulnerable futures out of all futures captured by the scenario. Ideally, we would want a coverage of 100% - but this is rarely obtainable.
- **Density**: the fraction of all the vulnerable futures captured by the scenario, out of all futures captured. Again, ideally all futures captured should be vulnerable and density should be 100%.
- **Interpretability**: the ease with which users can understand the information conveyed by the scenario. The number of uncertain conditions used to define the scenario serves as a proxy for interpretability. The smaller the number of conditions, the higher the interpretability.

331. PRIM generates a set of scenarios and presents tradeoff curves that help the users choose the one scenario with the best combination of density, coverage, and interpretability.

Figure M9.1 Example of Scenario Discovery.



Note: Filled red circles=failure; open circle=success

332. Figure M9.1 illustrates an example of scenario discovery analysis for the 335 MW design of the Upper Arun hydro project (UAHP). It represents all 6,500 futures as red circles; the filled red circles represent the futures in which the project has a negative NPV (and thus fails to comply with the decision-maker's objective). The black box is the best scenario describing the futures in which the project has a negative NPV: electricity price increase of less than 70% than the initial price and capital costs more than 100% higher than the initial costs. This figure shows only the constraints on capital cost increase and electricity price that define each scenario, because they are the two most important variables for defining scenarios, i.e. they are the parameters that matter most for the sign of the NPV.

333. However, they do not *fully* explain all future conditions under which the project may fail to meet the decision makers' objectives. In other words, in the highlighted box of Figure M9.1, which represents the values of the two variables most likely to cause the

project to fail (solid red dots), there also occur some futures in which the project will succeed. Similarly, in the area outside the box, which is dominated by open circles representing success, there are some (though not many) futures in which the project will fail. Note that the other parameters still play a small role in explaining the future conditions under which the project may fail. And given that this scenario does not have a coverage and density of 100 %, other scenarios are needed to more fully define vulnerable futures. However, the decision-maker can now be presented with information about the conditions under which the project may be vulnerable, which can improve the confidence with which a project decision can be made.

334. In some cases where coverage and density are low, no single scenario can provide adequate coverage and density. In such cases, as is the case for the AUHP's analysis, the PRIM algorithm allows the user to iterate this process on the database. The user identifies a scenario and the algorithm removes the cases within that scenario from the database. The user then reruns PRIM and identifies another scenario from the remaining data. This process can be repeated as many times as needed. The resulting set of multiple scenarios may reduce interpretability, but can increase coverage and density.

335. A more complete description of RDM and scenario discovery can be found in the two studies in which the approach has been used:

World Bank, 2015. *Programmatic Approach to Impacts of Climate Risks on Water, Hydropower and Dams.* Which examines the vulnerability of hydro projects in Nepal to climate change and other risks.

Meier, P., J. Irving, J. and C. Wnuk, 2015. *Energy Security Trade-Offs under High Uncertainty: Resolving Afghanistan's Power Sector Development Dilemma*, World Bank. This includes a case study looking at the robustness of a decision to proceed with a 50MW gas engine power generation project in Northern Afghanistan, as compared to reliance on electricity imports from Turkmenistan and Uzbekistan.

PART IV ANNEXURES

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A2 INDEX

A3 GLOSSARY

Avoided cost tariff (ACT)	A tariff based on the costs that the buyer avoids when an additional kWh of renewable energy is purchased from the renewable energy producer. In theory, the buyer would reduce the dispatch of the most expensive thermal unit in operation, and therefore the avoided cost would be based on the variable operating cost – mainly fuel – of that highest cost (or "marginal") plant. In addition, the buyer avoids capacity costs, particularly when there is a portfolio of renewable energy projects, whose capacity value is non-zero even if the capacity value of individual projects is zero.
Basis Point (bp)	A term used in banking and finance to describe small variations in interest rates: 100 basis points = 1%. For example, 40 basis points=0.4%
Border price	The value of a traded good at a country's border, namely free on board (fob) for exports; or cost, insurance, freight (cif) for imports.
Capesize	Dry bulk carrier with capacity of 100,000 dwt or more. The typical Capesize vessel used in coal trade has a capacity of 140,000 dwt.
Certified Emission Reductions	A Kyoto Protocol unit equal to 1 tonne of CO_2 equivalent. CERs are issued for emission reductions from CDM projects.
Elasticity of marginal utility of consumption	The percentage change in individuals' marginal utility corresponding to each percentage change in consumption.
Emission reduction units (ERUs)	The European Union Emissions Trading Scheme is based on an EU wide emissions cap (and allocated across countries by the EU): it trades in allowances called *Emission Reduction Units* (ERUs).
Feed-in tariff	A fixed tariff for renewable energy (named after the German Law (*Einspeisungsgesetz)* that first introduced such tariffs for renewable energy in the early 1990s). Most often determined by the estimated production cost of a technology including some "fair" rate of return on equity and assumptions about the financial structure of projects.
HHV	The higher heating value: (also known as gross calorific value) of a fuel is defined as the amount of heat released by a specified quantity (initially at 25°C) once it is combusted and the products have returned to a temperature of 25°C. HHV includes the latent heat of vaporization of water in the combustion products. It is mainly used in the US. See also LHV.
ISO conditions	Nameplate capacity of a thermal generating project under the conditions defined by the International Standards Organization (namely at sea level and 15°C).
Japan Crude Cocktail (JCC)	The average monthly cif price of all crude oil imported into Japan. Used as a basis for LNG contracts in the Asia-Pacific market.
LHV	The lower heating value (also known as net calorific value) of a fuel is defined as the amount of heat released by combusting a specified quantity (initially at 25°C) and returning the temperature of the combustion products to 150°C. This assumes that the latent heat of vaporization of water in the reaction products is *not* recovered (in contrast to HHV). The LHV is generally used in Europe. The difference between LHV and HHV is greatest for natural gas (LHV = 47.1 MJ/kg, HHV 52.2 MJ/kg, about 10% higher), smallest for solid fuels (e.g. for a typical coal, LHV=22.7 MJ/kg, HHV=23.9, about 5% higher)
LIBOR	The London Inter-bank Offer Rate is the interest rate that the London banks charge each other. Different rates apply to different currencies and terms (overnight, 30 day, six month, etc.) The rates are published daily by the British Banking Association (www.bba.org.uk) based on a survey of a panel of banks. LIBOR rates are widely used as the reference for variable interest commercial loans (e.g. "six month LIBOR+2%").

A3. GLOSSARY

Mandated market share (MMS)	Sometimes termed "renewable portfolio standard". A requirement (or mandate) that distribution companies must purchase some percentage share of their total energy purchases from renewable energy sources (in some countries, this obligation is imposed on the generating companies).
Opportunity cost	The benefit lost from not using a good or resource in its best alternative use. Opportunity costs measured at economic prices should be used in economic analysis as the measure of benefits.
Panamax	Dry bulk carrier with typical capacity of 60,000-99,999 dwt (The maximum size that can pass through the Panama canal).
Q_{ECON}	The economically optimal quantity of renewable energy (namely that quantity of renewable energy whose production costs are below the avoided cost of the system when fossil fuels are priced at their economic costs (either based on border prices, or on production cost plus depletion premium).
Q_{FIN}	The quantity of renewable energy enabled at the avoided financial cost of thermal generation (as under Vietnam's present avoided cost tariff).
$Q_{G.ENV}$	The economically optimal quantity of renewable energy including the avoided *global* environmental damage costs of greenhouse gas emissions.
Q_{SOC}=Q_{ENV}	The socially optimal quantity of renewable energy including consideration of the avoided local environmental damage costs of fossil-fuel generation (from air emissions such as SOx, NOx and particulates), and fossil fuels priced at their economic cost.
Ramsey Formula	According to the noted British economist Frank Ramsey, the social rate of time preference (SRTP) is the sum of two terms: first is a utility discount rate reflecting the *pure* time preference (ρ), and the second is the product of the elasticity of the marginal utility of consumption (θ) and the annual growth rate of the growth of per capita real consumption (g): thus SRTP= ρ+ θg.
Social rate of time preference SRTP	The rate at which society is willing to postpone a unit of current consumption in exchange for more future consumption.. The use of the SRTP as the social discount rate is based on the argument that public projects displace current consumption, and streams of costs and benefits to be discounted are essentially streams of consumption goods either postponed or gained. There are two general methods in use for its empirical estimation (1) the after tax return on government bonds (or other low risk marketable securities), and (2) use of the Ramsey Formula.
Pure rate of time preference (ρ)	Considered to consist of two components: individuals' impatience or myopia (though this component is ignored in many studies because of the difficulty of measuring it); and the risk of death (or as argued by Nicholas Stern, the risk of the extinction of the human race).
Shadow exchange rate (factor)	The inverse of the SCF. The SER is often greater than the official exchange rate, indicating domestic consumers place a higher value on foreign exchange than is given by the official exchange rate.
Standard conversion factor (SCF)	The ratio of the economic price of goods in an economy (at their border price equivalents) to their domestic market price. It represents the extent to which economic prices, in general, are lower than the domestic market values.
Switching value	In a sensitivity analysis, the value of an input data assumption that brings the ERR to the hurdle rate (NPV to zero)
Value of statistical life(VSL)	Willingness to pay for a given reduction in mortality risk. USEPA uses $7.4million (2006$) as the default value for valuing mortality risk changes. In the US this is based largely on wage-risk studies (see http://yosemite.epa.gov/EE%5Cepa%5Ceed.nsf/webpages/MortalityRiskValuation.html for a full discussion).

A4 SAMPLE ECONOMIC ANALYSIS TABLES: INDONESIAN WIND FARM

This annex presents the set of Tables that should be included an economic analysis, here for a wind farm, extracted from a typical economic analysis spreadsheet. Table 1& 2 are data tables and summary of results (not shown here).

Table 3 contains forecasts for the future world oil price (IEA, World Bank, user-defined constant growth rate).

{oilprice} {iwop}

select scenario> 5 Uniform, 2%

0.02

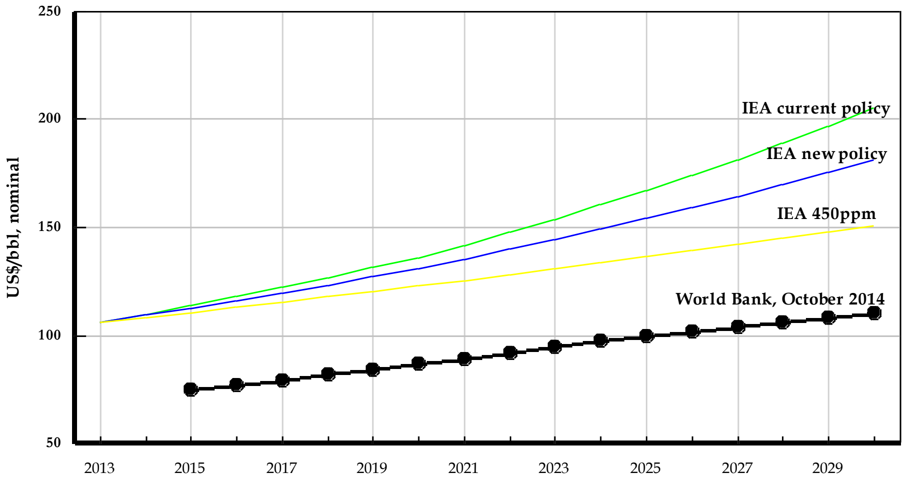
Table 3: World Oil Price Scenarios [nominal]

	source	2013	*2014*	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
1 World Bank	(1)			75.0	77.2	79.4	81.8	84.1	**86.6**	89.1	91.7	94.4	97.2	100.0	102.0
2 IEA current policies	(2)	106	109.8	113.8	117.9	122.2	126.7	131.2	**136.0**	141.7	147.63	153.82	160.26	166.97	173.97
3 IEA new policies	(2)	106	109.3	112.6	116.1	119.6	123.3	127.1	**131.0**	135.3	139.75	144.34	149.09	153.98	159.04
4 IEA 450ppm Scenario	(2)	106	108.3	110.6	113.0	115.4	117.9	120.4	**123.0**	125.5	128.15	130.81	133.52	136.28	139.11
5 Uniform growth rate	(3)			65.0	75.0	85.0	86.7	88.4	90.2	92.0	93.8	95.7	97.6	99.6	101.6

Sources:

(1) World Bank Commodity Price Forecast, (average Brent, Dubai, WTI)

(2) IEA World Energy Outlook, 2014



Macroeconomic assumptions

- For sake of transparency in the underlying assumptions, every economic analysis needs a table of macroeconomic assumptions, including the baseline scenario for international fossil fuel prices which drive the avoided thermal generation benefits of almost all renewable energy projects.

- The oil price scenario is selected in Table 3, and transferred into this Table. Prices of MFO and diesel are taken as fixed percentages of the crude oil price (e.g. 0.85 of the oil price for MFO).

- Rows [11]-[35] build up the economic and financial prices, including domestic transport costs and margins, import taxes, VAT and subsidies. All fuel prices are converted into a common unit (here $/mmBTU because that is what is used by PLN).

Table 4: Macroeconomic assumptions INDONESIA [nominal prices]

				2014	2015	2016	2017	2018	2019	2020
1	OECD inflation		[ ]		0.025	0.025	0.025	0.025	0.025	0.025
2	$deflator		[ ]	1	1.025	1.051	1.077	1.104	1.131	1.160
3	local inflation		[ ]		0.050	0.050	0.050	0.050	0.050	0.050
4	local deflator		[ ]	1	1.050	1.103	1.158	1.216	1.276	1.340
5	Exchange rate		IRP:US$	12500	12805	13117	13437	13765	14101	14445
6	***oil price scenario***	Uniform, 2%								
7	Crudoil		[$/bbl]		65.0	75.0	85.0	86.7	88.4	90.2
8	MFO	0.9	[$/bbl]		55.3	63.8	72.3	73.7	75.2	76.7
9	diesel	1.2	[$/bbl]		78.0	90.0	102.0	104.0	106.1	108.2
10	coal	0.8	[$/ton]		52.0	60.0	68.0	69.4	70.7	72.2
11	*border fuel prices, $/mmBTU*									
12	coal	13	[$/mmBTU]		4.0	4.6	5.2	5.3	5.4	5.6
13	gas[import parity price]		[$/mmBTU]		11.0	11.0	11.0	11.0	11.0	11.0
14	diesel	5	[$/mmBTU]		15.6	18.0	20.4	20.8	21.2	21.6
15	MFO	5	[$/mmBTU]		11.1	12.8	14.5	14.7	15.0	15.3
16	*transport&margins*									
17	coal		[$/mmBTU]		0.5	0.5	0.6	0.6	0.6	0.6
18	gas		[$/mmBTU]		1.0	1.1	1.1	1.2	1.2	1.3
19	diesel		[$/mmBTU]		0.5	0.5	0.6	0.6	0.6	0.6
20	MFO		[$/mmBTU]		0.5	0.5	0.6	0.6	0.6	0.6
21	*Subsidy/tax content*									
22	coal		[$/mmBTU]		0	0	0	0	0	0
23	gas		[$/mmBTU]		-6	-6	-6	-6	-6	-6
24	diesel		[$/mmBTU]		0	0	0	0	0	0
25	MFO		[$/mmBTU]		0	0	0	0	0	0
26	*Financial price to*	PLN								
27	coal		[$/mmBTU]		4.5	5.1	5.8	5.9	6.0	6.2
28	gas		[$/mmBTU]		6.0	6.1	6.1	6.2	6.2	6.3
29	diesel		[$/mmBTU]		16.1	18.5	21.0	21.4	21.8	22.3
30	MFO		[$/mmBTU]		11.6	13.3	15.0	15.3	15.6	16.0
31	*Economic price*									
32	coal		[$/mmBTU]		4.5	5.1	5.8	5.9	6.0	6.2
33	gas		[$/mmBTU]		12.0	12.1	12.1	12.2	12.2	12.3
34	diesel		[$/mmBTU]		16.1	18.5	21.0	21.4	21.8	22.3
35	MFO		[$/mmBTU]		11.6	13.3	15.0	15.3	15.6	16.0

Cost breakdown

- Table 5 presents the derivation of economic capital cost, with a breakdown of FOREX and local costs, and adjustments for local tax content, direct taxes and duties, and any corrections for SER/SCF (see Technical Note **C1**). In the example here, the total overnight cost is $220million, based on information from the wind farm developer. This was based on the cif cost for the imported components excluding import duties, and the local cost excluding VAT. In this illustrative example, these taxes and duties have been added to derive the financial cost of $253 million.

Table 5: Local/FOREX breakdown: economic& financial costs

			FOREX		Local		Total
1	Total overnight cost	[$USm]					220.0
2	Local/FOREX shares	[ ]					
3		[$USm]	0.80	176.0	0.20	44.0	220.0
4	Direct Import taxes, duties	[ ]	0.15	26.4	0.15	6.6	33.0
6	Financial cost (1)	[$USm]		202.4		50.6	253.0
7	Implicit tax content	[$USm]			0.10	-5.1	-5.1
8	SER/SCF adjustment	[$USm]	0.00	0.0	0.00	0.0	0.0
9	Economic cost (2)	[$USm]		176.0		-5.1	214.9
10	adjustment factor	[ ]					0.98

Notes
(1) Other financial costs, development fees, etc added in Table
(2) economic cost [9]=[3]+[7]+[8]

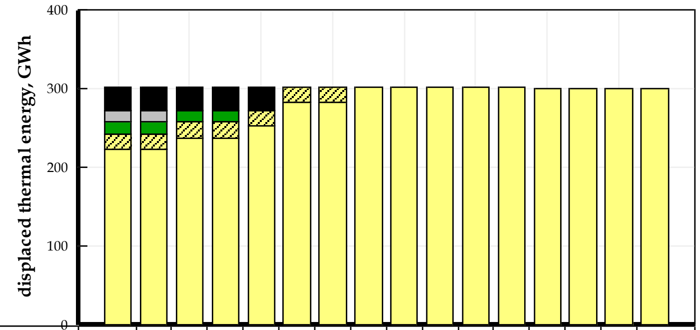
- The economic cost is the $220 million less the implicit tax content of local procured goods and services. This is a simplified presentation of the analysis shown in Technical Note **C1** (Costs) for the Tarbela Hydro project (Table C1.12).

- Obviously this table would need adjustment depending on the source of the baseline capital cost estimate.

Energy Balance

- Table 6 calculates the quantity of thermal generation displaced by the renewable energy projects, starting with gross production, adjusting for own-use and transmission.
- Many projects will displace a mix of generation types. It is important to keep track of each type/fuel of generation since the GHG emissions will depend on what mix of fuels is displaced.
- In the actual case of the Indonesia wind farm, no coal is displaced on Sulawesi - we have added some coal here simply for illustrative purposes.

Table 6: Energy Balance			INDONESIA	SulawesiWindFarm							
			NPV	2015	2016	2017	2018	2019	2020	2021	2022	2023
1 Installed capacity	100	[MW]										
2 gross capacity factors	0.39	[ ]										
3 energy reduction (3)	0.15%	[GWh]				0	0	0	0	0	0	0
4 annual gross energy		[GWh]	*2554*			341.6	341.6	341.6	341.6	341.6	341.6	341.6
5 own-use&lossses	0.097	[GWh]	*-248*			-33.2	-33.2	-33.2	-33.2	-33.2	-33.2	-33.2
6 net energy at meter		[GWh]	*2306*			308.5	308.5	308.5	308.5	308.5	308.5	308.5
7 incremental transmiss	0.02	[GWh]	*-46.1*			-6.2	-6.2	-6.2	-6.2	-6.2	-6.2	-6.2
8 displaced thermal energy		[GWh]	*2260*			302.3	302.3	302.3	302.3	302.3	302.3	302.3
9 *composition of displaced energy at the thermalplant meter (1)*												
10 gas CCGT	**80%**	[GWh]				222	222	237	237	252	282	282
11 gas CT	**10%**	[GWh]				20	20	20	20	20	20	20
12 MFO	**5%**	[GWh]				15	15	15	15			
13 HSD	**5%**	[GWh]				15	15					
14 coal	**3%**	[GWh]				30	30	30	30	30		
15 *displaced fuels, as mmB*net heat rates												
16 gas CCGT	6824	mmmBTU				1515.4	1515.4	1618.5	1618.5	1721.7	1926.4	1926.4
17 gas CT	10339	mmmBTU				206.8	206.8	206.8	206.8	206.8	206.8	206.8
18 MFO	9478	mmmBTU				143.3	143.3	143.3	143.3	0.0	0.0	0.0
19 HSD	9478	mmmBTU				143.3	143.3	0.0	0.0	0.0	0.0	0.0
20 coal	9222	mmmBTU				276.6	276.6	276.6	276.6	276.6	0.0	0.0
21 *fuels, physical units*												
22 MFO		[1000tons]										
23 HSD		[1000tons]										
24 coal	0.023	[1000tons]				6.5	0.0	0.0	0.0	0.0	0.0	0.0
21 *memo items:*												
22 energy share errors, if any		[GWh]	*0.000*			0.000	0.000	0.000	0.000	0.000	0.000	0.000
23 capacity factor at meter		[ ]				0.35	0.35	0.35	0.35	0.35	0.35	0.35



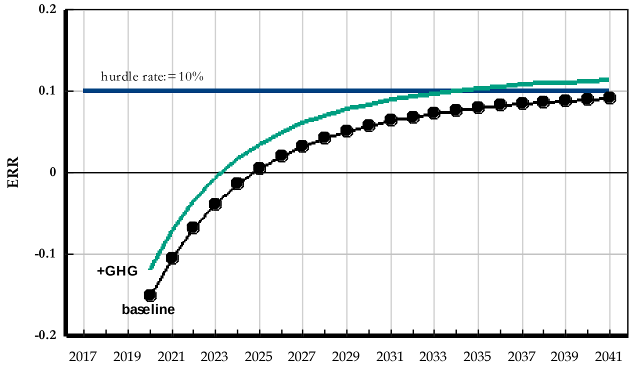
	2017		2019		2021		2023		2025		2027		2029		2031	
gas CCGT	222	222	237	237	252	282	282	302	302	302	301	301	300	300	300	299
gas CT	20	20	20	20	20	20	20									
MFO	15	15	15	15												
HSD	15	15														
coal	30	30	30	30	30											

Economic returns

- Table 7 calculates the economic returns (excluding externalities)
- All calculations are at constant 2015 prices. Other categories of operating costs are easily added by insertion of rows.
- The graph highlights that the usual citation of ERR in reality means ERR achieved at the *end* of its economic life.

Table 7: Economic returns (excluding externalities) SulawesiWindFarm

					2015	2016	2017	2018	2019	2020	2021	2022	2023
				NPV	1	2	3	4	5	6	7	8	9
1	Installed capacity	100	MW										
2	Capital cost	2200	$/kW										
3	adjustment factor	0.98	[ ]										
4	disbursement fractions		[ ]		1.00	0.00							
5	adjusted investment	215	$USm	*195.4*	214.9	0.0							
6	O&M fixed	3.65	$USm	*27.4*			3.7	3.7	3.7	3.7	3.7	3.7	3.7
7	O&M variable		$USm	*0.0*									
8	O&M major maintena	3.5	$USm	*0.0*									
9	system integration costs		$USm	*8.1*			1.1	1.1	1.1	1.1	1.1	1.1	1.1
10	Total cost		$USm	*230.9*	214.9	0.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7
11	Levelised cost (at meter)		$/kWh	0.1									
12	**Benefits**												
13	*Capacity benefit*		2020										
14	capital cost	28.5	$USm	*16.1*			0	0	0	28.5	0	0	0
15	Fixed O&M	1.05	$USm	*5.1*			0	0	0	0	1.05	1.05	1.05
16	*Avoided energy*												
17	gas CCGT		$USm	*175.7*			18.3	18.4	19.8	19.9	21.2	23.9	24.0
18	gas CT		$USm	*5.2*			1.3	1.3	1.3	1.3	1.3	1.3	1.3
19	MFO		$USm	*5.8*			2.1	2.2	2.2	2.3	0.0	0.0	0.0
20	HSD		$USm	*4.3*			3.0	3.1	0.0	0.0	0.0	0.0	0.0
21	coal		$USm	*5.2*			1.6	1.6	1.7	1.7	1.8	0.0	0.0
22	total benefits		$USm	*217.5*	0	0	26.4	26.6	25.0	53.7	25.4	26.3	26.4
23	levelised value of benefits		$/kWh	*0.094*									
24	economic flows		$USm	*-13.4*	-214.9	0.0	21.6	21.9	20.2	48.9	20.6	21.5	21.7
25	ERR		$USm	9.2%						-15.0%	-10.6%	-6.8%	-3.8%



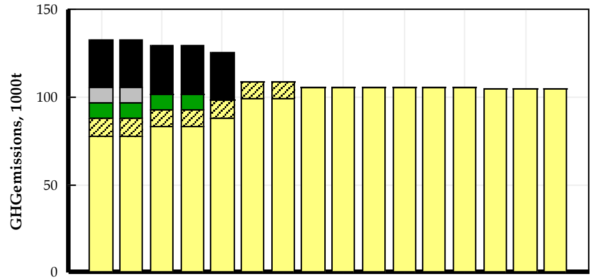
Carbon accounting

- Table 8 follows the Bank's guidelines for carbon accounting (see Technical Note **M5**). Emissions are calculated for each fuel and technology combination. The graph highlights the much higher emissions from coal than from gas.

- The values in row[16] are from the World Bank guidelines for the social value of carbon (see Table M5.1), adjusted to 2015 price levels, with intermediate years interpolated.

Table 7: Carbon accounting **SulawesiWindFarm**

				NPV	2015	2016	2017	2018	2019	2020	2021	2022	2023
							1	2	3	4	5	6	7
1	thermal energy		[GWh]				302.3	302.3	302.3	302.3	302.3	302.3	302.3
2	*GWh displaced*												
3	gas CCGT		[GWh]				222.1	222.1	237.2	237.2	252.3	282.3	282.3
4	gas CT		[GWh]				20.0	20.0	20.0	20.0	20.0	20.0	20.0
5	MFO		[GWh]				15.1	15.1	15.1	15.1	0.0	0.0	0.0
6	HSD		[GWh]				15.1	15.1	0.0	0.0	0.0	0.0	0.0
7	coal		[GWh]				30.0	30.0	30.0	30.0	30.0	0.0	0.0
8	*GHG emissions*	Kg/kWh											
9	gas CCGT	0.35	[1000tons]				78	78	83	83	88	99	99
10	gas CT	0.50	[1000tons]				10	10	10	10	10	10	10
11	MFO	0.58	[1000tons]				9	9	9	9	0	0	0
12	HSD	0.60	[1000tons]				9	9	0	0	0	0	0
13	coal	0.91	[1000tons]				27	27	27	27	27	0	0
14	total GHG emissions		[1000tons]				132.9	132.9	129.1	129.1	125.6	108.8	108.8
15	lifetime GHG emission		[million	*2.75*									
16	Value		[US$/ton]		30.6	31.6	32.6	33.7	34.7	35.7	37.2	38.8	40.3
17			[$USm]	*36.54*			4.3	4.5	4.5	4.6	4.7	4.2	4.4
18	levelised value@meter		[USc/kW	1.585									



	2017		2019		2021		2023		2025		2027		2029		2031	
gas CCGT	78	78	83	83	88	99	99	106	106	106	105	105	105	105	105	105
gas CT	10	10	10	10	10	10	10	0	0	0	0	0	0	0	0	0
MFO	9	9	9	9	0	0	0	0	0	0	0	0	0	0	0	0
HSD	9	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0
coal	27	27	27	27	27	0	0	0	0	0	0	0	0	0	0	0

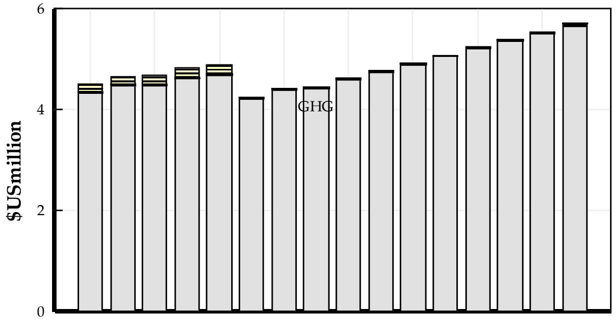
A4. Sample Economic Analysis Tables

Economic returns (including externalities)

- Follows the methodology of Technical Note M1.

Table 9: Economic returns (incl. externalities) SulawesiWindFarm

			NPV	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	Economic flows (table 6)	[$USm]	*-13.4*	-214.9	0.0	21.6	21.9	20.2	48.9	20.6	21.5	21.7
2	ERR	[ ]	*9.18%*						-15.0%	-10.6%	-6.8%	-3.8%
3												
4	**Local externalities**											
5	NOx	[$USm]	*0.21*	0.00	0.00	0.019	0.020	0.022	0.024	0.027	0.018	0.020
6	PM-10	[$USm]	*0.06*	0.00	0.00	0.015	0.017	0.018	0.019	0.021	0.000	0.000
7	SOx	[$USm]	*0.49*			0.142	0.153	0.162	0.175	0.156	0.000	0.000
8	total local externalities	[$USm]	*0.75*	0.00	0.00	0.176	0.190	0.202	0.219	0.204	0.018	0.020
9	total flows (incl. local extern	[$USm]	*-12.64*	-214.9	0.0	21.8	22.1	20.4	49.2	20.8	21.6	21.7
10	ERR	[ ]	*9.23%*						-14.9%	-10.4%	-6.7%	-3.7%
11	**Global externalities**											
12	avoided cost of GHG	[$USm]	*36.5*			4.3	4.5	4.5	4.6	4.7	4.2	4.4
13	total economic flows	[$USm]	*23.9*	-214.9	0.0	26.1	26.5	24.9	53.8	25.5	25.8	26.1
14	ERR	[ ]	*11.4%*						-11.9%	-7.2%	-3.5%	-0.6%
15	*memo items*											
16	hurdle rate	[ ]	10.0%									
17	damage cost, GHG	[USc/kWh]				1.43	1.48	1.48	1.52	1.55	1.40	1.45
18	damage cost, local	[USc/kWh]				0.06	0.06	0.07	0.07	0.07	0.01	0.01



	2017		2019		2021		2023		2025		2027		2029		2031	
GHG	4	4	4	5	5	4	4	4	5	5	5	5	5	5	6	6
NOx	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PM-10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SOx	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Local damage cost estimates

- Follows the methodology of Technical Note M4 (Six cities study).

Table 10: Damage cost estimates **SulawesiWindFarm**

				NPV	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	per Capita GDP	0.06	[1000US$]		3.48	3.68	3.90	4.14	4.39	4.65	4.93	5.23	5.54
2	affected popualtion	0.02	[million]		10.00	10.20	10.40	10.61	10.82	11.04	11.26	11.49	11.72
3	damage cost escalation		[ ]		1.00	1.08	1.17	1.26	1.37	1.48	1.60	1.73	1.87
4	**NOx**												
5	damage cost (table 20)		[$/kg]		0.099	0.107	0.116	0.125	0.136	0.147	0.159	0.171	0.185
6	NOx emission factorsgm/KWh												
7	gas CCGT	0.34	[1000kg]				75.5	75.5	80.6	80.6	85.8	96.0	96.0
8	gas CT	0.50	[1000kg]				10.0	10.0	10.0	10.0	10.0	10.0	10.0
9	MFO		[1000kg]										
10	HSD		[1000kg]										
11	coal	2.500	[1000kg]				75.0	75.0	75.0	75.0	75.0	0.0	0.0
12	total emissions		[1000 kg]		0.0	0.0	160.5	160.5	165.6	165.6	170.8	106.0	106.0
13	total NOx damage cost		[$USm]		0.00	0.00	0.0186	0.0201	0.0225	0.0243	0.0271	0.0182	0.0196
14			[USc/kWh]				0.0062	0.0067	0.0074	0.0080	0.0090	0.0060	0.0065
15	**PM-10**												
16	damage cost (table 20)		[$/kg]		2.084	2.253	2.436	2.634	2.848	3.079	3.329	3.599	3.891
17	PM-10 emission factog/kWh												
18	gas CCGT		[1000kg]										
19	gas CT		[1000kg]										
20	MFO		[1000kg]										
21	HSD		[1000kg]										
22	coal	0.21	[1000kg]				6.3	6.3	6.3	6.3	6.3	0	0
23	total emissions		[1000 kg]		0	0	6.3	6.3	6.3	6.3	6.3	0	0
24	total PM-10 damage cost		[$USm]		0	0	0.015	0.017	0.018	0.019	0.021	0	0
25			[USc/kWh]				0.005	0.005	0.006	0.006	0.007	0	0
26	**SOx**												
27	damage cost (table 20)		[$/kg]		0.298	0.322	0.348	0.376	0.407	0.44	0.476	0.514	0.556
28	SOx emission factors g/kWh												
29	gas CCGT		[1000kg]										
30	gas CT		[1000kg]										
31	MFO	8	[1000kg]				70.13	70.13	70.13	70.13	0.00	0.00	0.00
32	HSD	1	[1000kg]				9.07	9.07	0.00	0.00	0.00	0.00	0.00
33	coal	12	[1000kg]				327.60	327.60	327.60	327.60	327.60	0.00	0.00
34	total emissions		[1000kg]		0	0	406.80	406.80	397.73	397.73	327.60	0.00	0.00
35	total SOx damage cost		[$USm]		0	0	0.142	0.153	0.162	0.175	0.156	0.000	0.000
36			[USc/kWh]				0.047	0.051	0.054	0.058	0.052	0	0