STRANDED ASSETS

PROGRAMME

SMITH SCHOOL OF ENTERPRISE AND THE ENVIRONMENT

UNIVERSITY OF OXFORD

Stranded Assets and Thermal Coal

An analysis of environment-related risk exposure

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About the Stranded Assets Programme

The Stranded Assets Programme at the University of Oxford's Smith School of Enterprise and the Environment was established in 2012 to understand environment-related risks driving asset stranding in different sectors and systemically. We research how environment-related risks might emerge and strand assets; how different risks might be interrelated; assess their materiality (in terms of scale, impact, timing, and likelihood); identify who will be affected; and what impacted groups can do to pre-emptively manage and monitor risk.

We recognise that the production of high-quality research on environment-related risk factors is a necessary, though insufficient, condition for these factors to be successfully integrated into decision-making. Consequently, we also research the barriers that might prevent integration, whether in financial institutions, companies, governments, or regulators, and develop responses to address them. We also develop the data, analytics, frameworks, and models required to enable integration for these different stakeholders.

The programme is based in a world leading university with a global reach and reputation. We are the only academic institution conducting work in a significant and coordinated way on stranded assets. We work with leading practitioners from across the investment chain (e.g. actuaries, asset owners, asset managers, accountants, investment consultants, lawyers), with firms and their management, and with experts from a wide range of related subject areas (e.g. finance, economics, management, geography, anthropology, climate science, law, area studies) within the University of Oxford and beyond.

We have created the Stranded Assets Research Network, which brings together researchers, research institutions, and practitioners working on these and related issues internationally to share expertise. We have also created the Stranded Assets Forums, which are a series of private workshops to explore the issues involved. The Global Stranded Assets Advisory Council that guides the programme contains many of the key individuals and organisations involved in developing the emergent stranded assets agenda. The council also has a role in helping to informally co-ordinate and share information on stranded assets work internationally.

Global Advisory Council

The Stranded Assets Programme is led by Ben Caldecott and its work is guided by the Global Stranded Assets Advisory Council chaired by Professor Gordon L. Clark, Director of the Oxford Smith School. The Council is also a high-level forum for work on stranded assets to be co-ordinated internationally. Members are:

Jane Ambachtsheer, Partner and Global Head of Responsible Investment, Mercer Investment
Rob Bailey, Research Director, Energy, Environment and Resources, Chatham House
Vicki Bakhshi, Head of Governance & Sustainable Investment, BMO Global Asset Management (EMEA)
Morgan Bazilian, Affiliate Professor, The Royal Institute of Technology of Sweden
Robin Bidwell, Group President, ERM
David Blood, Co-Founder and Senior Partner, Generation IM
Yvo de Boer, Director-General, Global Green Growth Institute
Susan Burns, Founder and CEO, Global Footprint Network
James Cameron, Chairman, Overseas Development Institute
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Mike Clark, Institute and Faculty of Actuaries, also Director, Responsible Investment, Russell Investments
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University of Oxford Disclaimer

Executive Summary

The principal aim of this report is to turn the latest research on environment-related risk factors facing thermal coal assets into *actionable* investment hypotheses for investors. By examining the fundamental drivers of environment-related risk, creating appropriate measures to differentiate the exposure of different assets to these risks, and linking this analysis to company ownership, debt issuance, and capital expenditure plans, our research can help to inform specific investor actions related to risk management, screening, voting, engagement, and disinvestment. To our knowledge, this report contains the most comprehensive and up-to-date analysis of the environment-related risks facing thermal coal companies that is publicly available.

Our approach is a departure from how the vast majority of analysis concerning environment-related risks is usually undertaken. Researchers and analysts typically take a 'top down' approach. They look at company-level reporting and focus on measures of carbon emissions and intensity. Even if company-level reporting is accurate and up-to-date (in many cases it is not), this is an overly simplistic approach that attempts to measure a wide range of environment-related risk factors (often with widely varying degrees of correlation) through one proxy metric (carbon). While this might be a useful exercise, we believe that more sophisticated 'bottom up' approaches can yield improved insights for asset performance and if appropriately aggregated, company performance. In this report, we conduct a bottom up, asset-specific analysis of the thermal coal value chain and we look well beyond the relative carbon performance of different assets.

We have examined the top 100 utilities by coal-fired power generation capacity, the top 20 thermal coal mining companies by revenue (for companies with ≥30% revenue from thermal coal), and the top 30 coal processing technology companies by normalised syngas production. In the case of coal-fired utilities, we examine their coal-fired power stations. The top 100 coal-fired power utilities own 42% of the world's coal-fired power stations, with 73% of all coal-fired generating capacity. In the case of thermal coal miners, we examine their mines. The top 20 thermal coal miners account for approximately 60% of listed coal company revenue (see Section 6). In the case of coal-to-gas and coal-to-liquids companies, we examine their processing plants. The top 30 coal-to-gas and –liquids companies own 34% of all coal processing plants, with 63% of all fuel product capacity. We also look at the capital expenditure plans of these companies and their outstanding debt issuance.

Our approach requires granular data on the specific assets that make up a company's portfolio. For each sector we have attempted to find and integrate data to secure enough information on asset characteristics to enable an analysis of environment-related factors. Our approach also requires us to take a view on what the environment-related risks facing thermal coal assets could be and how they could affect asset values. We call these Local Risk Hypotheses (LRHs) or National Risk Hypotheses (NRHs) based on whether the risk factor in question affects all assets in a particular country in a similar way or not. For example, water stress has variable impacts within a country and so is an LRH, whereas a country-wide carbon price is an NRH. The list of LRHs and NRHs considered in this report can be found in Table 1 below.

As part of the process we have undertaken an assessment of how these environment-related risk factors, whether local or national, might affect assets over time. We find that the environment-related risks facing the thermal coal value chain are substantial and span physical environmental impacts, the transition risks of policy and technology responding to environmental pressures, and new legal liabilities that may arise from either of the former. These environment-related factors have the potential to create stranded assets, which are assets which have suffered from unanticipated or premature write-downs, devaluations, or conversion to liabilities[1].

[1] See Caldecott, B., Howath, N., & McSharry, P. (2013). Stranded Assets in Agriculture: Protecting Value from Environment-Related Risks. Smith School of Enterprise and the Environment, University of Oxford (Oxford, UK).

For each of the environment-related risk factors we examine in this report, we identify appropriate measures that could indicate levels of exposure and assess how each specific asset (i.e. power station, coal mine, or processing plant) is exposed to these measures. We have then linked these assets back to their company owners. This allows us to see which companies have portfolios that are more or less exposed, and allows investors to interrogate individual company portfolios for environment-related risks.

***Table 1:** Local risk hypotheses (LRHs) and national risk hypotheses (NRHs)*

#	Name	Source
Coal-Fired Power Utilities		
LRH-U1	Carbon Intensity	CARMA/CoalSwarm/WEPP/Oxford Smith School
LRH-U2	Plant Age	CARMA/CoalSwarm/WEPP
LRH-U3	Local Air Pollution	Boys et al. (2015)/NASA's SEDAC
LRH-U4	Water Stress	WRI's Aqueduct
LRH-U5	Quality of Coal	CoalSwarm/WEPP
LRH-U6	CCS Retrofitability	CARMA/CoalSwarm/WEPP/Geogreen
LRH-U7	Future Heat Stress	IPCC AR5
NRH-U1	Electricity Demand Outlook	IEA
NRH-U2	'Utility Death Spiral'	Oxford Smith School
NRH-U3	Renewables Resource	Lu et al. (2009)/ McKinsey & Co/SolarGIS
NRH-U4	Renewables Policy Support	EY's Renewables Attractiveness Index
NRH-U5	Renewables Generation Outlook	BP/REN21
NRH-U6	Gas Resource	BP/IEA
NRH-U7	Gas Generation Outlook	IEA
NRH-U8	Falling Utilisation Rates	Oxford Smith School
NRH-U9	Regulatory Water Stress	WRI's Aqueduct
NRH-U10	CCS Legal Environment	Global CCS Institute
Thermal Coal Mining Companies		
LRH-M1	Proximity to Populations and Protected Areas	NASA's SEDAC/UNEP-WCMC
LRH-M2	Water Stress	WRI's Aqueduct
NRH-M1	Remediation Liability Exposure	Oxford Smith School
NRH-M2	Environmental Regulation	Oxford Smith School
NRH-M3	New Mineral Taxes or Tariffs	Oxford Smith School
NRH-M4	Type of Coal Produced	IEA
NRH-M5	Domestic Demand Outlook	IEA
NRH-M6	Export Sensitivity	IEA
NRH-M7	Protests and Activism	CoalSwarm
NRH-M8	Water Regulatory Stress	WRI's Aqueduct

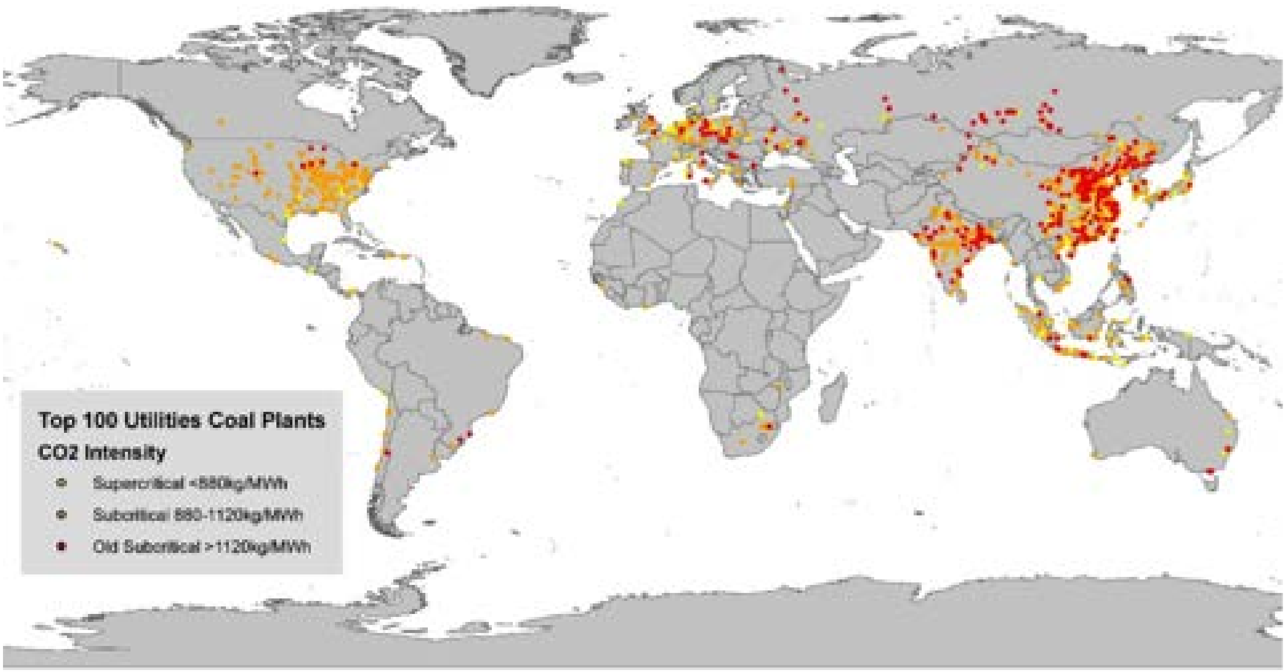
Table 1: *(Continued)*

Coal Processing Technology Companies		
LRH-P1	Plant Age	World Gasification Database
LRH-P2	Water Stress	WRI's Aqueduct
LRH-P3	CCS Retrofitability	World Gasification Database/GeoGreen
NRH-P1	CPT Policy Support	Oxford Smith School
NRH-P2	Oil and Gas Demand Outlook	IEA
NRH-P3	Oil and Gas Indigenous Resources	BP
NRH-P4	Other Local Environmental	Oxford Smith School
NRH-P5	Regulatory Water Stress	WRI's Aqueduct
NRH-P6	CCS Policy Outlook	Global CCS Institute

Coal-fired power utilities

Figure 1 shows the location and carbon intensity of the power stations of the world's top 100 coal-fired power utilities.

Figure 1: *Coal-fired power stations of the top 100 coal-fired power utilities*



Exposure to environment-related risk of the top 100 coal-fired power utilities is summarised in Figure 2 below. Companies from the United States carry the most exposure to ageing plants (LRH-U2), CCS retrofitability (LRH-U6), and future heat stress (LRH-U7). Companies in China and India are most exposed to conventional air pollution concentration (LRH-U3) and physical water stress (LRH-U4). Table 62 in Appendix A provides further details of company exposure to all LRHs and NRHs.

Figure 2: *LRH rankings for coal-fired utilities*

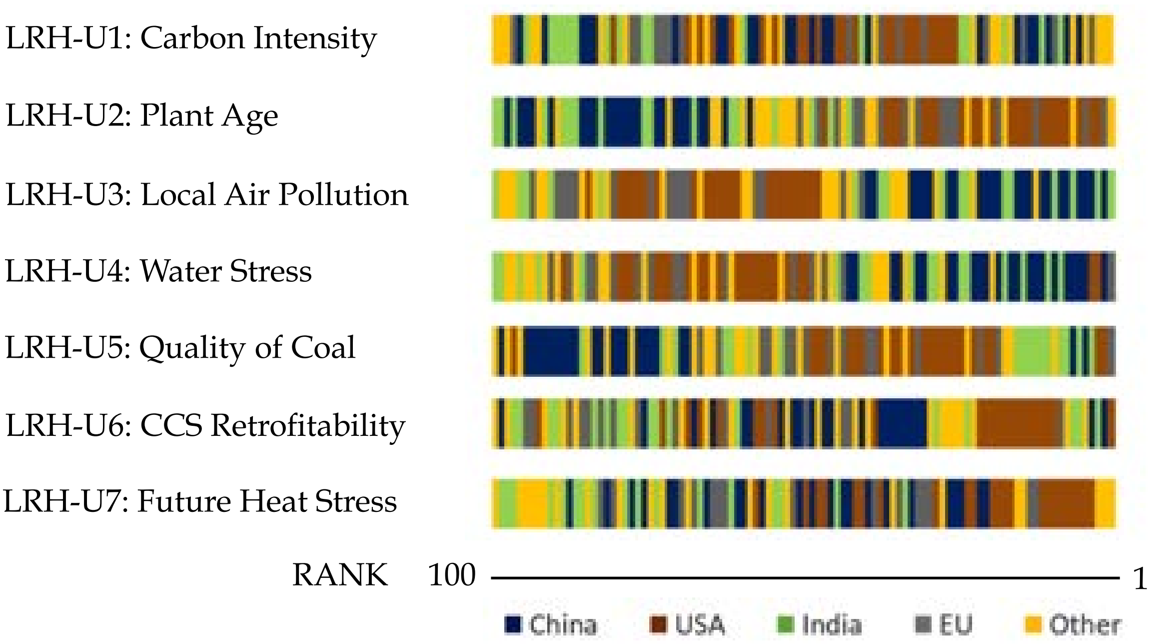


Table 2 below shows the top 20 coal-fired utilities ranked by coal-fired generation capacity. The top 100 list can be found in Appendix A.

Table 2: *Summary of top 20 coal-fired power utilities*

#	PARENT OWNER	COUNTRY	Coal-Fired Electricity: Generation [GWh]	Coal-Fired Electricity: Capacity OPR [MW]	Capacity CON [MW]	Capacity PLN [MW]	DEBT/EQUITY	CURRENT RATIO	(EBITDA-CAPEX)/INTEREST	LRH-U1 'Carbon Intensity' [RANK]*	LRH-U2 'Plant Age' [RANK]*	LRH-U3 'Local Air Pollution' [RANK]*	LRH-U4 'Water Stress' [RANK]*	LRH-U5 'Quality of Coal' [RANK]*	LRH-U6 'CCS Retrofitability' [RANK]*	LRH-U7 'Future Heat Stress' [RANK]*	ASSET BASE	NRH-AGGREGATE**
1	CHINA HUANENG GROUP CORP	China	471,139	160,212	5,360	91,968	3.28	0.45x	0.42x	57	53	37	25	27	83	51	CH-100%	60%
2	CHINA GUODIAN CORP	China	455,038	148,539	20,140	111,360	3.38	0.24x	0.85x	53	52	33	21	32	78	37	CH-100%	60%
3	CHINA DATANG CORP	China	415,118	123,635	12,230	89,521	3.69	0.47x	1.16x	45	100	39	18	35	90	43	CH-100%	60%
4	CHINA HUADIAN GROUP CORP	China	369,511	119,808	21,101	95,628	3.22	0.37x	3.02x	63	100	41	20	39	84	54	CH-100%	60%
5	CHINA POWER INVESTMENT CORP	China	293,658	82,819	16,028	35,590	-	-	-	50	100	49	14	16	76	44	CH-99%	60%
6	SHENHUA GROUP CORP LTD	China	292,107	89,021	42,520	67,710	0.49	0.96x	0.62x	87	100	42	29	30	96	47	CH-100%	60%
7	ESKOM HOLDINGS SOC LTD	South Africa	214,924	36,678	19,375	3,000	1.69	1.09x	-10.67x	20	36	92	100	100	1	27	SA-100%	55%
8	NTPC LTD	India	208,588	41,532	46,520	91,056	1.24	1.16x	-0.48x	80	49	40	40	24	71	65	IN-100%	45%
9	CHINA RESOURCES POWER HOLDINGS	China	171,178	55,342	13,410	24,340	1.12	0.58x	3.65x	40	100	25	16	36	85	61	CH-100%	60%
10	KOREA ELECTRIC POWER CORP	Korea	128,189	23,481	30,459	7,880	0.92	1.03x	1.68x	38	46	14	48	42	1	48	OTHER	-
11	GUANGDONG YUDEAN GROUP CO LTD	China	126,689	43,441	9,850	13,300	-	-	-	69	100	36	100	34	1	66	CH-100%	65%
12	NRG ENERGY INC	USA	99,685	29,576	-	-	1.66	1.86x	1.76x	30	8	78	100	31	1	42	US-94%, AU-6%	60%
13	STATE GRID CORP OF CHINA	China	97,603	22,218	-	10,000	0.53	0.39x	0.00x	15	48	32	11	14	66	30	CH-100%	60%
14	GDF SUEZ SA	France	89,977	20,424	1,715	5,059	0.69	1.06x	4.67x	76	37	59	42	20	91	80	NOTE-1	47%
15	VATTENFALL GROUP	Sweden	83,646	15,719	1,730	-	0.97	1.35x	-1.16x	84	47	53	100	9	79	57	CH-81%	60%
16	SOUTHERN CO	USA	71,669	27,819	600	-	1.23	0.65x	-0.15x	49	21	87	100	40	69	53	US-100%	60%
17	DUKE ENERGY CORP	USA	67,730	22,492	-	-	1.07	0.97x	1.68x	51	17	71	100	41	67	50	US-99%	60%
18	PT PLN PERSERO	Indonesia	66,467	16,763	6,730	18,350	3.42	0.84x	0.88x	19	100	30	33	33	87	89	ID-100%	40%
19	ENEL SPA	Italy	62,916	17,937	-	2,900	1.03	0.99x	2.65x	37	24	68	46	23	1	56	OTHER	-
20	AMERICAN ELECTRIC POWER CO INC	USA	60,917	22,577	-	-	1.14	0.64x	0.76x	35	13	80	100	38	1	17	US-100%	60%

*: Companies are ranked by exposure, with 1 being the most at risk.

**: NRHs have been aggregated to a single outlook percentage based on the sum of high risk (+2) and medium risk (+1) evaluations relative to the maximum possible and weighted by asset locations.

Figure 3 and Figure 4 show planned and under construction new coal-fired generating capacity as a proportion of existing capacity. Utilities in the United States have largely abandoned new coal-fired capacity. Utilities in China and India continue to build and plan power stations. Seven of the 16 Indian utilities in the top 100 are more than doubling their current coal-fired generating capacity. Other outliers include J-Power, Gazprom, Inter RAO UES, Taiwan's Ministry of Economic Affairs, Elektroprivreda Srbije, and Electricity of Vietnam.

Figure 3: *Planned coal-fired capacity as a percentage of current capacity*

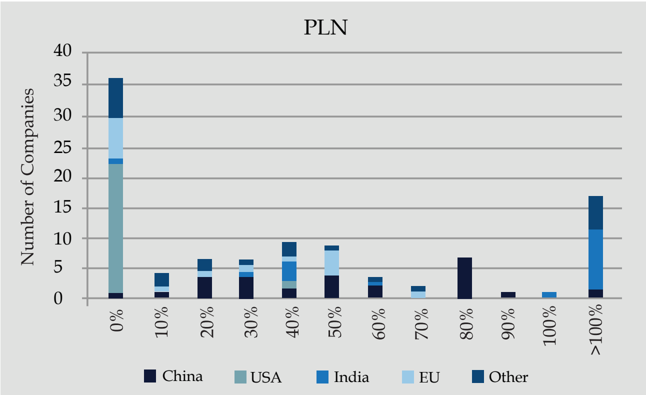


Figure 4: *Coal-fired capacity under construction as a percentage of current capacity*

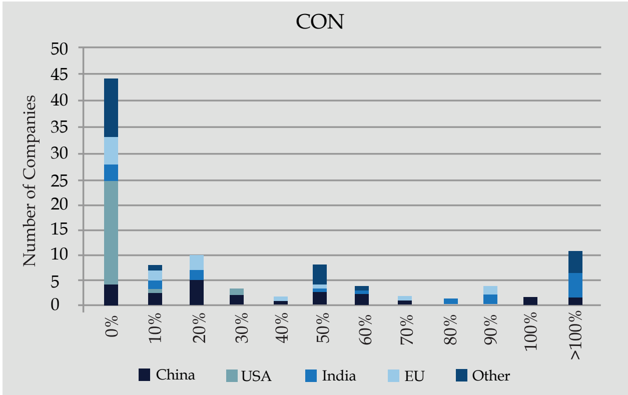


Figure 5 shows the ratios of (EBITDA less CAPEX) / debt repayment for the top 100 coal-fired power utilities. Companies with a ratio less than unity cannot currently service their existing debt. Companies with a negative ratio are expending CAPEX in excess of EBITDA. The five companies with a ratio less than -1 are Vattenfall Group, Eskom Holdings SOC Ltd, Comision Federal de Electricidad, Tauron Polska Energia SA, and Andhra Pradesh Power Gen Corp.

Figure 5: *Histogram of (EBITDA-CAPEX)/Interest*

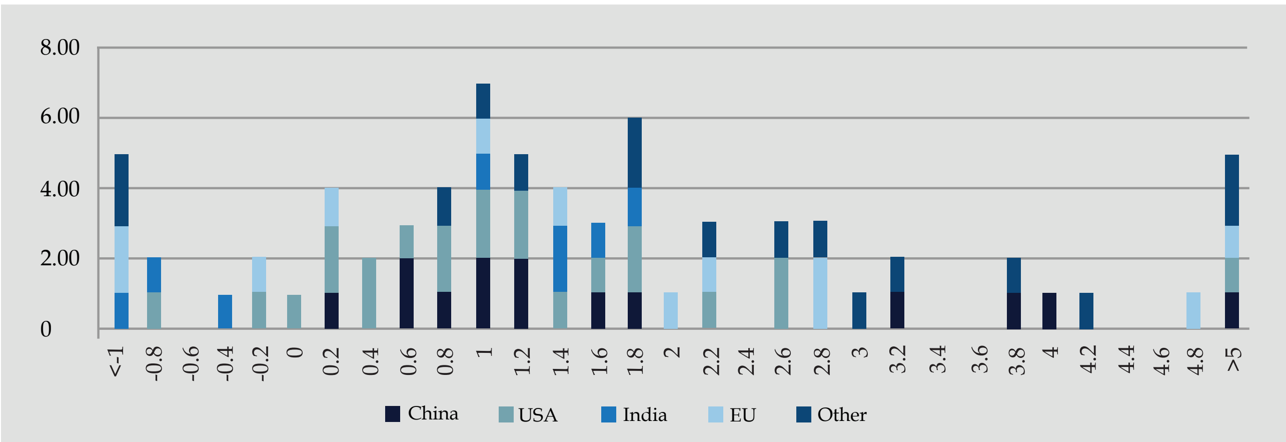


Figure 6 shows the current ratios of the top 100 coal-fired power utilities. European coal-fired utilities have higher current ratios than coal-fired utilities in the United States, which in turn have higher current ratios than Chinese coal-fired power utilities.

Figure 6: *Histogram of current ratios*

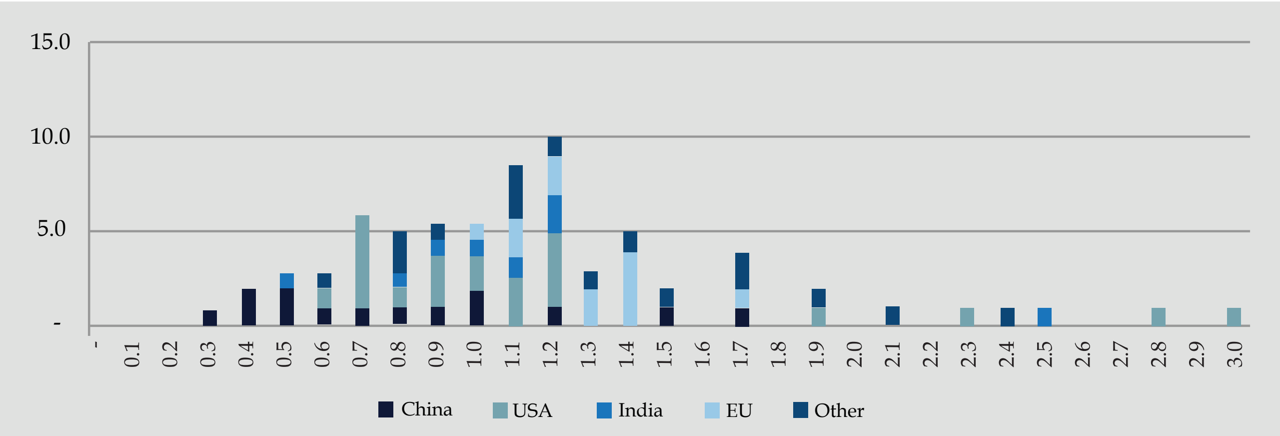


Figure 7 shows the debt-to-equity (D/E) ratios of the top 100 coal-fired power utilities. Utilities in the US are generally more leveraged than utilities in China or Europe. Outliers include Tohoku Electric Power Corp and AES Corp, the only public companies with D/E ratios over 300%.

Figure 7: *Histogram of D/E ratios*

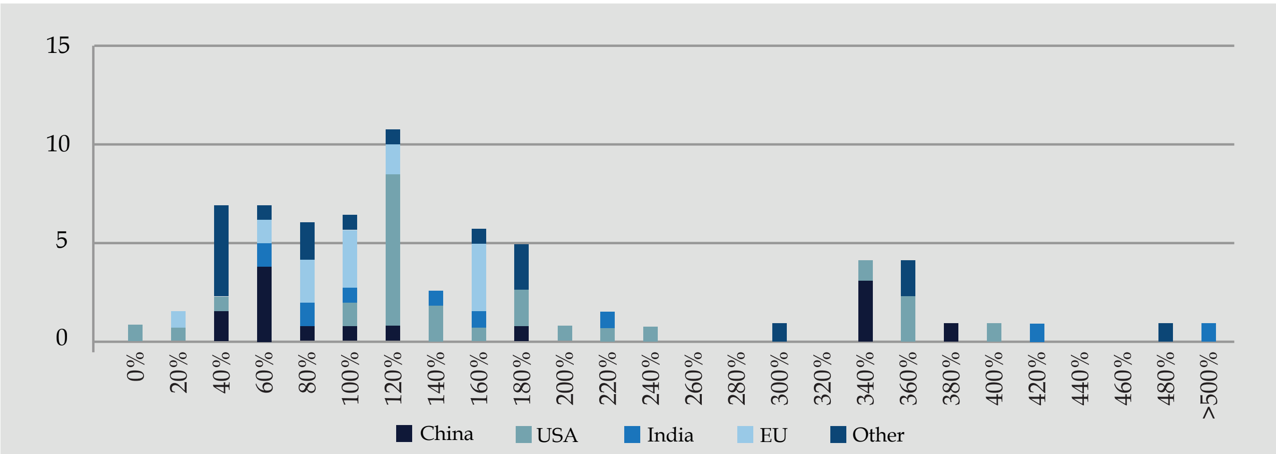
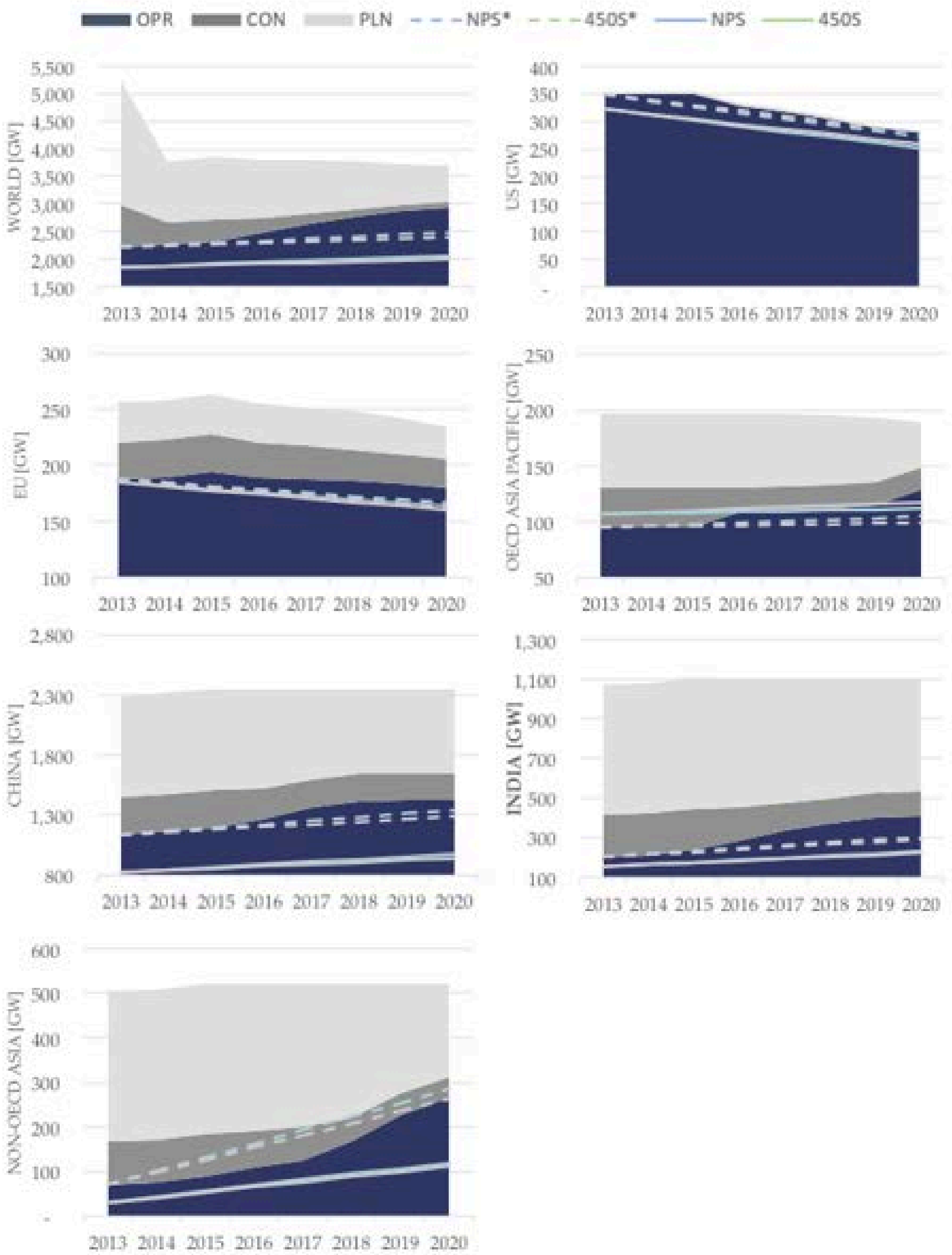


Figure 8 shows global and regional projected coal-fired power generating capacity, operating, in construction, and planned from datasets compiled by the Oxford Smith School. Generating capacity from this new dataset is compared with scenarios from the IEA WEO 2015. Because of differences in database coverage, IEA projections have also been benchmarked to 2013 data, shown in the dashed series denoted by "*". Plant life is assumed to be 40 years on average.

Figure 8: *Projection of operational, in construction, and planned coal-fired power stations, all companies, from composite database with comparison to IEA projections*

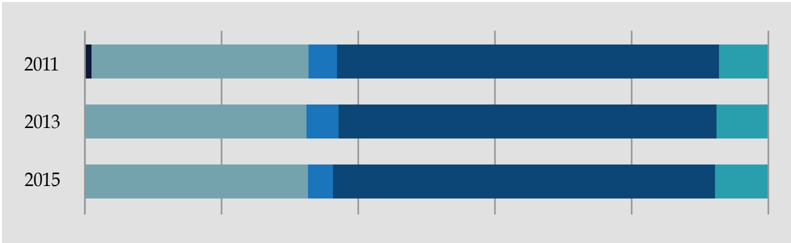


The ownership of coal-fired power utilities is shown for selected regions in Figure 9. Widely-held public companies are likely to have different decision-making processes than entirely state-owned companies.

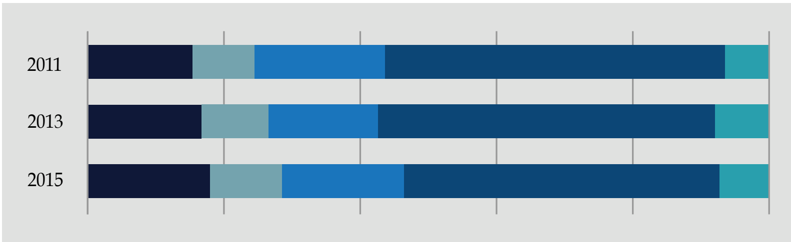
***Figure 9:** Coal-fired power utility ownership changes by region*[2]

Individuals/Insiders | Corporates | Institutions | ESOP | State | Pubic/Other

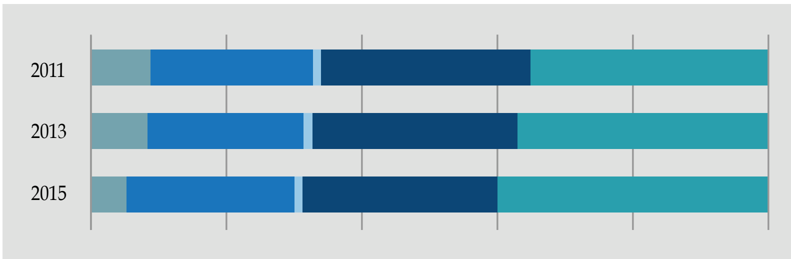
China – Ownership of coal-fired utilities is dominated by the state and has remained stable for the last five years. Investors owning portions of Chinese utilities are often ultimately state-owned.



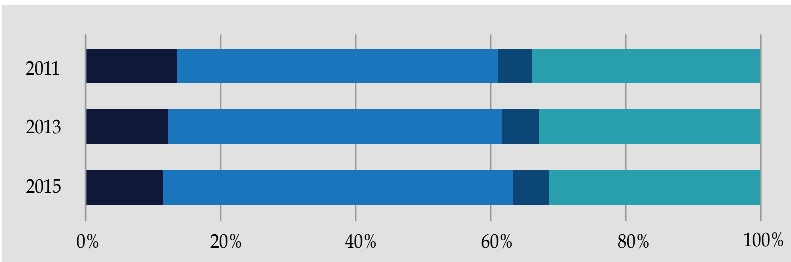
India – Ownership of coal-fired utilities has growing insider/ individual ownership. The state also owns a significant and stable portion of coal-fired power utilities.



EU – European coal-fired power utilities still retain a significant portion of state ownership. They are otherwise owned by institutional and retail investors.



US – Coal-fired power utilities in the United States are mostly widely-held public companies. Individual and insider ownership tends to be dominated by the executives of the companies.



[2] Data from Standard & Poor's Capital IQ, November 2015.

Thermal coal miners

Figure 10 shows the location of the mines of the world's top 20 thermal coal mining companies with ≥30% revenue from thermal coal.

***Figure 10:** Mines of the world's top 20 thermal coal mining companies with revenue ≥30% from thermal coal*

The capital expenditure projections of the top 20 thermal coal mines is shown in Table 65 in Appendix B. Emerging environment-related risks may expose capital spending to risk of stranding. Table 66 in Appendix B shows ownership information for the 20 top thermal coal mining companies.

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***Table 3:** Summary of top 20 thermal coal miners with revenue ≥30% from thermal coal*

#	PARENT OWNER	COUNTRY	2014 THERMAL COAL REV	NUMBER OF MINES	PRODUCTION	Diversification [% rev from coal]	Projected Capex / EBITDA	Debt/EQUITY	Current Ratio	(EBITDA-CAPEX) /Interest	LRH-M1: 'Proximity to Populations and Protected Areas'	LRH-M2: 'Water Stress'	ASSET BASE	NRH-ALL**
			[US$mn]		[Mt (#)]						[RANK]*			[%]
1	CHINA SHENHUA ENERGY CO	China	14,006	23	305 (23)	35%	45%	28%	1.30x	7.66x	9	6	CH-100%	31%
2	SASOL	South Africa	11,050	6	41 (6)	58%	75%	22%	2.58x	7.10x	14	14	SA-100%	44%
3	COAL INDIA LTD	India	10,251	13	494 (8)	89%	46%	1%	3.15x	1,728.94x	2	17	IN-100%	31%
4	CHINA COAL ENERGY COMPANY	China	5,966	11	107 (6)	52%	201%	113%	1.36x	-	6	1	CH-100%	31%
5	ADANI ENTERPRISES LTD	India	5,068	6	8 (2)	55%	28%	142%	1.08x	2.71x	12	15	Note 1	38%
6	PEABODY ENERGY CORPORATION	USA	4,890	28	232 (28)	72%	31%	481%	1.02x	0.23x	16	13	AU-39%, US-61%	49%
7	INNER MONGOLIA YITAI COAL CO., LTD.	China	3,397	13	51 (13)	85%	282%	109%	1.63x	-6.26x	10	5	CH-100%	31%
8	YANZHOU COAL MINING COMPANY LIMITED	China	3,045	23	73 (19)	31%	150%	119%	1.21x	-1.34x	8	7	AU-43%, CH-57%	42%
9	PT ADARO ENERGY TBK	Indonesia	2,909	4	56 (4)	91%	23%	49%	2.10x	5.34x	13	19	ID-100%	44%
10	ALPHA NATURAL RESOURCES	USA	2,837	3	84 (3)	66%	163%	141%	0.40x	-0.28x	19	9	US-100%	44%
11	PT UNITED TRACTORS	Indonesia	2,826	1	6 (1)	66%	39%	7%	1.90x	105.39x	20	20	ID-100%	44%
12	BANPU PUBLIC COMPANY LIMITED	Thailand	2,638	10	39 (9)	85%	69%	156%	1.23x	1.38x	7	10	ID-70%, CH-30%	40%
13	ARCH COAL	USA	2,350	12	264 (11)	80%	32%	-849%*	2.66x	0.59x	18	8	US-100%	44%
14	YANG QUAN COAL INDUSTRY (GROUP) CO., LTD.	China	2,337	25	13 (4)	70%	113%	-	-	-	5	1	CH-25%	31%
15	PINGDINGSHAN TIANAN COAL MINING CO	China	2,324	10	6 (1)	45%	-	114%	0.85x	-0.34x	21	26	CH-100%	31%
16	SHANXI LU'AN ENVIRONMENTAL ENERGY DEVELOPMENT	China	2,301	5	30 (5)	90%	162%	69%	0.89x	-2.66x	3	1	CH-5%	31%
17	ALLIANCE RESROUCE PARTNERS	USA	1,861	13	41 (11)	100%	29%	92%	1.01x	18.26x	17	18	US-13%	44%
18	THE TATA POWER COMPANY	India	1,741	3	27 (1)	31%	19%	195%	0.69x	2.40x	1	11	ID-3%	44%
19	INDO TAMBANGRAYA MEGAH TBK PT	Indonesia	1,600	6	29 (6)	94%	39%	0%	1.88x	121.77x	4	12	ID-6%	44%
20	CONSOL ENERGY INC	USA	1,356	5	32 (5)	46%	67%	76%	0.52x	-1.11x	15	16	US-5%	44%

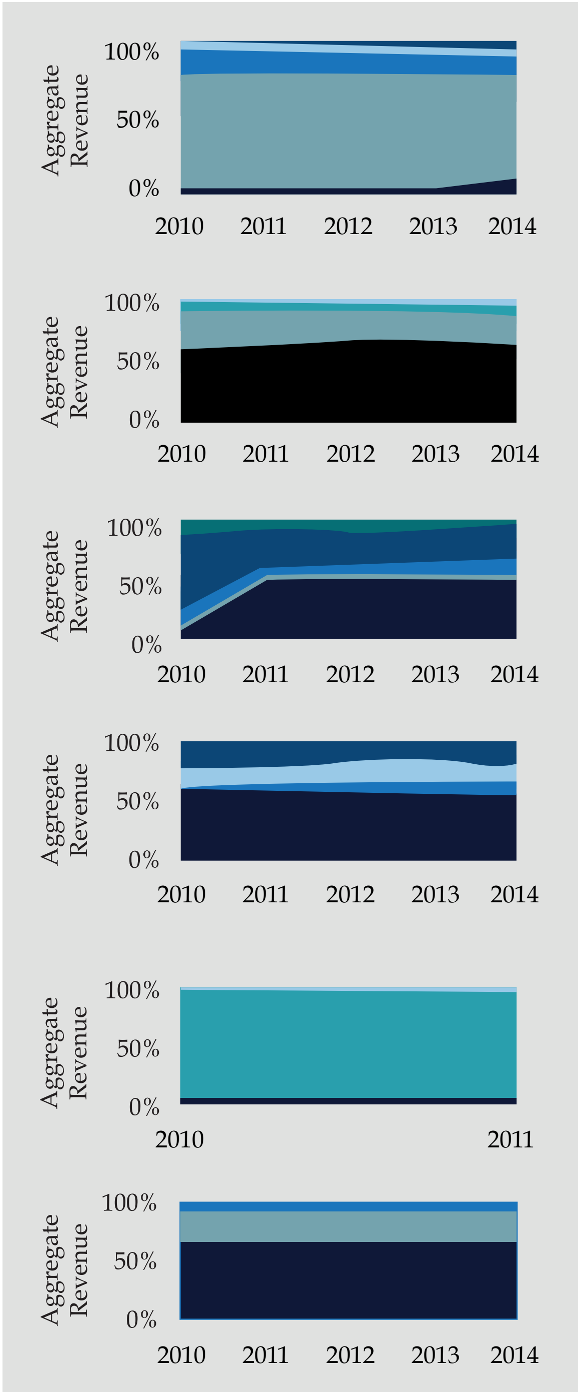
Note 1: ID-17%, AU-17%, IN-66%

*: Companies are ranked by exposure, with 1 being the most at risk

**: NRHs have been aggregated to a single outlook percentage based on the sum of high risk (+2) and medium risk (+1) evaluations relative to the maximum possible and weighted by asset locations.

Thermal coal miners might be more resilient to environment-related risks if their business activities are diversified. The revenue sources of 18 of the top 20 thermal coal miners (by ultimate corporate parent) have been obtained from Trucost and weighted by company EBITDA, see Figure 11.

***Figure 11:** Coal mining diversification trends*[3]



China (6/7*) – Chinese coal miners have made the mainstay of their revenue from underground coal mining and a small portion of coal-fired power generation. Petrochemical and surface mining activities are slowly emerging.

*Number of companies for which data was available

US (4/5) – Underground mining is giving way to surface mining in the United States. Coal mining companies are also becoming increasingly involved in petrochemical activities.

India (3/3) – Indian thermal coal miners for which data are available have diversified activities: power generation, coal-fuelled or otherwise, and other activities. Most coal is surface mined.

Indonesia (3/3) – Indonesia's thermal coal miners conduct surface mining almost exclusively and are diversified into power generation with fuels other than coal and non-related business activities. Coal power generation activities have begun recently.

South Africa (1/1) – Most of the revenue of South Africa's thermal coal miners is derived from petrochemical processing activities. These companies are therefore highly exposed to the CPT risks discussed below.

Thailand (1/1) – The revenue of Banpu Public Company ltd has been shifting slowly from surface coal mining to underground coal mining, with consistent power generation revenue.

Surface Coal Mining | Underground Coal Mining | Coal Power Generation | Other
Other - Petrochem | Other - Mining | Other Power Generation

[3] Data from Trucost, November 2015; and MSCI, October 2015.

Coal processing technology companies

Coal processing technologies (CPTs) are a suite of technologies used to convert coal into a wide range of useful fuels. These technologies have had a nascent presence for decades, but interest has recently grown, based on policy objectives for energy security and reducing conventional air pollutants, and economic opportunities for arbitrage with gas or liquid fuels. Common CPTs include coal to gas technology (CTG), coal to liquids (CTL) including Fisher-Tropsch synthesis, and underground coal gasification (UCG), also called coal seam methanation. Figure 12 shows the location of the plants of the global top 30 CPT companies.

Figure 12: *Top 30 coal processing technology plants*

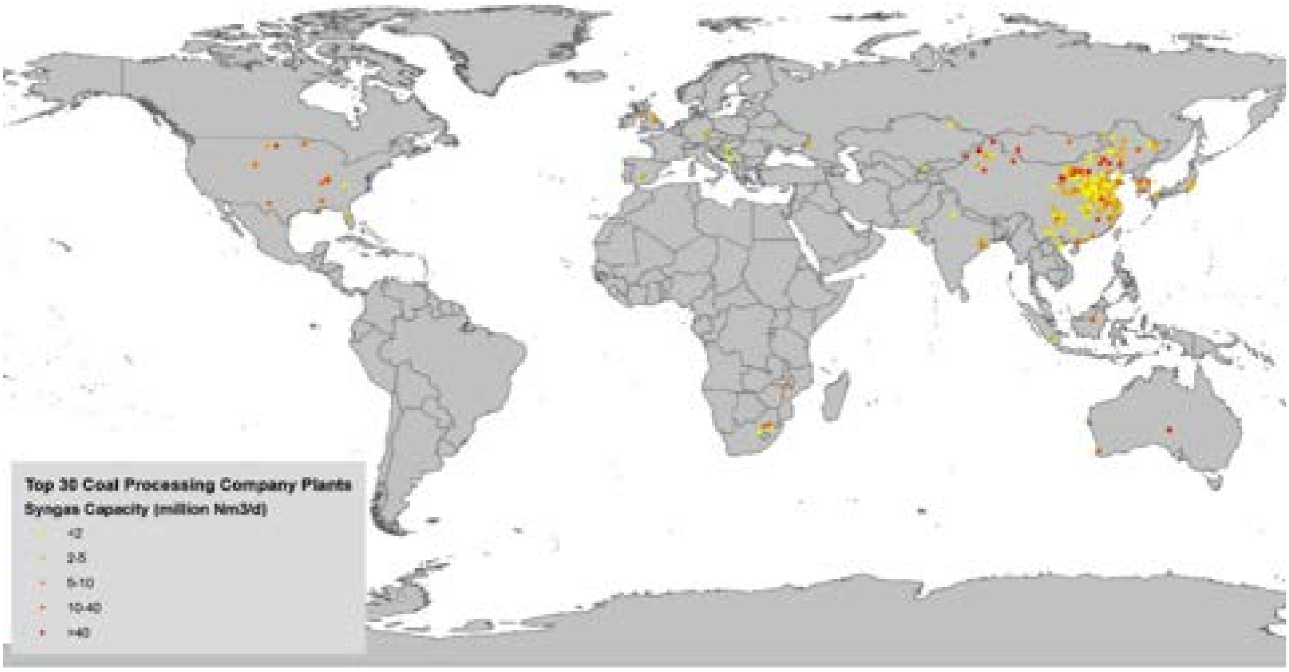


Table 4 below shows the top 20 coal processing technology companies ranked by normalised syngas capacity. The top 30 list can be found in Appendix C.

***Table 4:** Top 20 coal processing technology companies*

			CAPACITY [kNm³/day]			DEBT/EQUITY	CURRENT RATIO	(EBITDA – CAPEX) INTEREST	LRH-P1: 'Plant Age'	LRH-P2: 'Water Stress'	LRH-P3: 'CCS Retrofitability'	NRH-ALL**
#	PARENT OWNER	COUNTRY	OPR	CON	PLN				[RANK]*			
1	SASOL	South Africa	90,260	-	2,046	0.22	2.58x	7.10x	1	27	1	29%
2	DATANG	China	48,550	-	-	2.71	0.34x	0.91x	10	13	17	43%
3	SHENHUA GROUP	China	43,360	-	-	0.49	0.96x	0.62x	12	8	20	43%
4	YITAI COAL OIL MANUFACTURING CO (INNER MONGOLIA YITAI GROUP	China	33,700	9,420	113,080	-	-	-	30	10	30	43%
5	SINOPEC	China	29,481	8,400	-	0.32	0.76x	3.90x	9	19	19	43%
6	CHINACOAL GROUP	China	24,100	3,336	73,442	-	-	-	20	16	30	43%
7	DAKOTA GASIFICATION CO	USA	13,900	-	-	-	-	-	2	22	30	29%
8	QINGHUA GROUP	China	13,860	-	-	-	-	-	17	5	1	43%
9	YANKUANG GROUP	China	13,415	-	-	-	-	-	4	15	1	43%
10	GUANGHUI ENERGY CO	China	12,600	840	63,400	1.79	0.41x	-1.86x	15	7	1	43%
11	PUCHENG CLEAN ENERGY CHEMICAL CO	China	12,100	-	-	-	-	-	21	17	1	43%
12	XINHU GROUP	China	12,000	68,000	-	-	-	-	22	11	30	43%
13	WISON (NANJING) CLEAN ENERGY CO	China	11,932	-	-	-	-	-	14	29	30	43%
14	TOKYO ELECTRIC POWER COMPANY (TEPCO)	Japan	11,566	-	-	2.86	1.17x	4.79x	26	25	1	21%
15	CHINA NATIONAL OFFSHORE OIL CORPORATION (CNOOC)	China	9,975	-	72,000	0.43	1.18x	0.00x	24	26	1	43%
16	SANWEI RESOURCE GROUP	China	9,744	-	-	-	-	-	6	9	18	43%
17	INNER MONGOLIA ZHUOZHENG COAL CHEMICAL CO	China	9,040	-	-	-	-	-	16	12	30	43%
18	TIANJIN BOHAI CHEMICAL GROUP	China	8,787	-	3,125	-	-	-	5	4	30	43%
19	KOREA SOUTH EAST POWER CO (KOSEP)	South Korea	8,400	-	-	0.88	1.03x	4.11x	27	1	1	-
20	KOREA SOUTHERN POWER CO (KOSPO)	South Korea	8,400	-	-	1.3	0.98x	-6.41x	28	21	1	-

*: Companies are ranked by exposure, with 1 being the most at risk.
**: NRHs have been aggregated to a single outlook percentage based on the sum of high risk (+2) and medium risk (+1) evaluations relative to the maximum possible and weighted by asset locations.

The ownership trends of coal-based energy processing companies vary significantly by country. The majority of CPT plants are either in planning or under construction. Several projects have faced funding shortages or the withdrawal of companies due to low financial returns on trial projects, bureaucratic hurdles during planning and permitting stages, regulatory uncertainty, and environmental liabilities. A summary of key capital projects and their owners and funders is provided in Table 5.

Table 5: *CPT capital projects*

Country	Demonstration / operating projects	Pipeline projects	Key companies	Funding source
Australia	Monash Energy (CTL), Arckaringa (CTL), Chinchilla (UCG) - closed down in 2013	Additional CTM project for Arckaringa	Anglo Coal, Shell, Altona Energy, Linc Energy	Private sector funding and government subsidies
China	Several CTG/CTL/UCG demonstration projects in place since 2010	50 new CTG plants in Northwestern China	Datang, China Guodian Corporation, China Power Investment, CNPC, CNOOC and Sinopec	Subsidies from local governments and loans from the Chinese Development Bank
India	UCG plant applications for Katha (Jharkhand), Thesgora (Madya Pradesh) Tata Group's application for a CTL plant in Odisha rejected by government	New UCG pilot projects for West Bengal and Rajasthan	Coal India Limited, Tata Group, the Oil and Natural Gas Corporation Ltd (ONGC) and the Gas Authority of Indian Ltd.	Subsidies from local government, and private funding
South Africa	Operating 6 coal mines producing feedstock for Secunda Synfuels and Sasolburg Operations	New growth plans for the Project 2050, replacing 4 old coal mines for CTL projects	Sasol Ltd	Public and private funding; investment and pension funds
United States	Great Synfuels CTG Plant in North Dakota	12 new CTL project proposals in Wyoming, Illinois, Arkansas, Indiana, Kentucky, Mississippi, Missouri, Ohio and West Virginia	Shell, Rentech, Baard, DKRW	Public and private funding

Table 71 in Appendix C shows ownership information for the 30 coal-processing technology companies.

Scenarios

The IEA's WEO scenarios are referenced in this report to provide consistency with the broader literature. While organisations have critiqued a number of assumptions that underlie the IEA scenarios, including technology penetration rates, world growth rates, and future energy demand, the IEA's WEO scenarios are widely referenced in industry and policymaking and are used as the primary reference scenarios in this study. We find that:

- Policy actions by key countries in the thermal coal value exceed the New Policies Scenario (NPS) in the reduction of coal in global total primary energy demand.
- The Paris Agreement offers a strong indicator that the direction of policy and technology deployment will continue to exceed the NPS in ambition to mitigate climate change.

Carbon Capture and Storage

It is our view that CCS is unlikely to play a significant role in mitigating emissions from coal-fired power stations. Deployment of CCS has already been too slow to match IEA and IPCC scenarios. CCS compares unfavourably with other power sector mitigation options, especially considering that CCS also reduces plant efficiency, exacerbating existing merit-order challenges for conventional generators. CCS should remain an attractive option for industrial and process emitters that have few other mitigation options, and may be significant as a long-term option for delivering negative emissions with BECCS.

Implications for reporting and disclosure

We have undertaken a comprehensive data integration process, bringing together a wide range of different datasets and sources for the first time. This is a work in progress, but our work to date has highlighted some of the challenges associated with turning an understanding of environment-related factors facing particular sectors into analysis that is decision-relevant for financial institutions. These experiences are germane to extant processes on disclosure and corporate reporting, particularly the Task Force on Climate-related Financial Disclosures (TCFD) chaired by Michael Bloomberg, that was launched at COP21 in Paris during December 2015.

To take one specific example, without accurate geo-location data for assets it is very hard to accurately overlay spatial datasets or to use remote sensing and satellite data to further research assets. Existing datasets for coal-fired power stations only have precise geo-location data for 30% of power stations and city level geo-location data for the remaining power stations. This means that spatial datasets representing certain types of risk (e.g. air pollution) are not uniformly accurate – and become less useful for power stations with inaccurate geo-location data. It also means that when, for example, we wanted to use satellite imagery to identify the type of cooling technology installed on a power station (for assets where cooling data was missing from existing datasets), we could only do this for assets with exact coordinates. Unfortunately, tracking down power stations on satellite imagery when the geo-location data is inaccurate is challenging and time consuming. This means that we have only been able to secure 71% coverage for the type of cool technology installed on coal-fired power stations, though we aim to improve this through further work.

One simple way around this particular problem would be for companies that are signed up to voluntary or mandatory reporting frameworks to disclosure the precise coordinates of their key physical assets. But a more general principle would be for companies, especially those with portfolios of large physical assets, to disclose asset specific characteristics so that researchers and analysts can undertake their own research on the risks and opportunities facing company portfolios. Natural resources companies, particularly those involved in upstream fossil fuel production, appear reluctant to disclose any asset specific information, instead suggesting that their investors should simply trust their judgement[4]. We would suggest that this is a highly questionable approach and one that the TCFD and other related processes should take on. Introducing a new 'Principle of Asset-level Disclosure' into reporting frameworks would significantly enhance the ability of investors to understand the environmental performance of companies.

More generally, it is noteworthy that very little of our analysis has actually depended on existing corporate reporting or data disclosed through voluntary disclosure frameworks. This is both a cause for hope and concern. It demonstrates that significant strides can be made to understand company exposure to environment-related risks even in the absence of consistent, comprehensive, and timely corporate reporting on these issues. But it also highlights how existing frameworks on environment-related corporate disclosure might be asking the wrong questions – they generally attempt to support and enable top down analysis, but might not do enough to support a bottom up, asset-specific approach. Reporting needs to link back to a fundamental understanding of risk and opportunity and to specific assets within company portfolios, especially for companies with portfolios of large physical assets (e.g. power stations, mines, oil and gas fields, processing plants, and factories). In the absence of that, what is reported may not be actionable from an investor perspective.

The other task is to reduce the cost of accessing and using data that can underpin the analytical approach we have used here. Where possible we use non-proprietary datasets, but this is insufficient. The cost is really the cost of data integration – to have all the relevant data points on asset characteristics merged from a variety of data sources, as well as overlays that allow us to measure the relative exposure of assets to different risks and opportunities. The costs associated with assuring datasets and finding novel datasets are also significant. Fortunately, these are all areas where costs can be reduced and this could be a significant public good.

Company Data Intelligence Service

An initiative to find and integrate all the relevant asset-specific data points for companies in key sectors would almost certainly yield much more (and probably more accurate) investor-relevant information than what is currently disclosed. The initiative, call it the Company Data Intelligence Service (CDIS), would have the benefit of transcending mandatory and voluntary schemes as all companies would be in scope. CDIS would seek out data on company assets in key sectors, make this public where possible, and give companies the opportunity to correct mistakes and provide enhanced disclosure. It would operate in a completely transparent and accountable way and could collaborate with researchers and civil society to track down, assure, and release data on company assets.

[4] See Rook, D. & Caldecott, B.L. (2015) Evaluating capex risk: new metrics to assess extractive industry project portfolios. Working Paper. Smith School of Enterprise and the Environment, University of Oxford. Oxford, UK.

Critically, CDIS would not be dependent on companies disclosing data. Such a public goods initiative focused on putting into the public domain accurate and relevant information to improve the analysis of company environmental performance, would not be particularly costly – it would certainly be much cheaper, quicker, and more plausible than all companies actually disclosing all the asset specific data needed for bottom analyses of environment-related factors.

CDIS could support the development of new techniques and approaches to secure data that was hard to get or inaccessible due to cost or other barriers, whether through 'big data' or remote sensing, and foster the developments of new techniques to analyse data. CDIS could also have the task of integrating all existing corporate reporting into one system, allowing for analysis of data provided via a wide range of initiatives. The development of a CDIS type initiative is something that the TFCD should consider recommending as part of its deliberations.

1 Introduction

The principal aim of this report is to turn the latest academic and industry research on environment-related risk factors facing thermal coal assets into *actionable* investment hypotheses for investors. By examining the fundamental drivers of environment-related risk, creating appropriate measures to differentiate the exposure of different assets to these risks, and linking this analysis to company ownership, debt issuance, and capital expenditure plans, our research can help to inform specific actions related to risk management, screening, voting, engagement, and disinvestment. This report contains a thorough and up-to-date assessment of the key environment-related risk factors facing thermal coal assets and may also be of use for policymakers, companies, and civil society. The typology of environment-related risks is described in Table 6. Another aim of this work is for the datasets that underpin our analysis, as well as the analysis itself, to enable new lines of academic research and inquiry.

Table 6: *Typology of environment-related risks*

Set	Subset
Environmental Change	Climate change; natural capital depletion and degradation; biodiversity loss and decreasing species richness; air, land, and water contamination; habitat loss; and freshwater availability.
Resource Landscapes	Price and availability of different resources such as oil, gas, coal and other minerals and metals (e.g. shale gas revolution, phosphate availability, and rare earth metals).
Government Regulations	Carbon pricing (via taxes and trading schemes); subsidy regimes (e.g. for fossil fuels and renewables); air pollution regulation; voluntary and compulsory disclosure requirements; changing liability regimes and stricter licence conditions for operation; the 'carbon bubble' and international climate policy.
Technology Change	Falling clean technology costs (e.g. solar PV, onshore wind); disruptive technologies; GMO; and electric vehicles.
Social Norms and Consumer Behaviour	Fossil fuel divestment campaign; product labelling and certification schemes; and changing consumer preferences.
Litigation and Statutory Interpretations	Carbon liability; litigation; damages; and changes in the way existing laws are applied or interpreted.

The vast majority of analyses that concern environment-related risks facing different sectors of the global economy are 'top down'. They look at company-level reporting and usually focus on measures of carbon intensity or carbon emissions. Even if this company level reporting is accurate and up-to-date (in many cases it is not), this is an overly simplistic approach that attempts to measure a wide range of environment-related risk factors (often with widely varying degrees of correlation) through one proxy metric (carbon). While this might be a useful exercise, we believe that more sophisticated 'bottom up' approaches can yield improved insights for asset performance and, if appropriately aggregated, company performance. In this report, we apply this bottom up, asset-specific approach to the thermal coal value chain.

The approach we use here is a significant extension of work pioneered in a previous report completed by the Stranded Assets Programme at the University of Oxford's Smith School of Enterprise and the Environment (the 'Oxford Smith School') from March 2015 entitled, 'Stranded Assets and Subcritical Coal: The Risk to Companies and Investors'.

Our methodology attempts to understand how specific assets could be affected by a wide range of environment-related risk factors and then to aggregate that analysis up to the level of the company portfolio. This is not particularly novel, but surprisingly, has not been applied to the questions we attempt to answer in this report. We believe that this is a much more promising approach for investors interested in understanding and anticipating the real risks and opportunities that companies face from environment-related factors.

The approach requires data on the specific assets that make up a company's portfolio. In this report we focus on companies involved in producing and using thermal coal. In the case of coal-fired utilities, we examine their coal-fired power stations. In the case of thermal coal miners, we examine their mines. And in the case of coal-to-gas and coal-to-liquids companies, we examine their processing plants. These different assets have different characteristics and for each sector we have attempted to find and integrate data that provide enough information on asset characteristics relevant to our analysis of environment-related factors. We also look at the capital expenditure pipeline of companies and their outstanding debt issuance.

Our approach also requires us to take a view on what the environment-related risks facing thermal coal assets could be and how they could affect asset values. We call these Local Risk Hypotheses (LRHs) or National Risk Hypotheses (NRHs) based on whether the risk factor in question affects all assets in a particular country in a similar way or not. For example, water stress has variable impacts within a country and so is an LRH, whereas a country-wide carbon price is an NRH.

It then requires an assessment of how these environment-related risk factors, whether local or national, might affect assets over time. We find that the environment-related risks facing the thermal coal value chain are substantial and span physical environmental impacts, the transition risks of policy and technology responding to environmental pressures, and new legal liabilities that may arise from either of the former. These environment-related factors may create stranded assets, which are assets that have suffered from unanticipated or premature write-downs, devaluations, or conversion to liabilities[5].

For each of the environment-related risk factors we examine in this report, we identify appropriate measures that indicate levels of exposure and assess how each specific asset (i.e. power station, coal mine, or processing plant) is exposed to these measures. We have then linked these assets back to their company owners. This allows us to see which companies have portfolios that are more or less exposed, and allows investors to interrogate individual company portfolios for environment-related risks. In this report we examine the top 100 utilities by coal-fired power generation capacity, the top 20 coal mining companies by revenue (for companies with ≥30% revenue from thermal coal), and the top 30 coal processing technology companies by production.

We believe this bottom up analysis is preferable to a top down one and can be replicated in a wide range of other sectors. The extent to which this type of analysis could improve investment decisions and result in better financial performance could be significant, but is unknown and could be a topic of future research.

[5] See Caldecott, B., et al. (2013). Stranded Assets in Agriculture: Protecting Value from Environment-Related Risks.

As part of our research we have undertaken a comprehensive data integration process, bringing together a wide range of different datasets and sources for the first time. This is a work in progress, but our work to date has highlighted some of the challenges associated with turning an understanding of environment-related factors facing particular sectors into analysis that is decision-relevant for financial institutions. These experiences are germane to extant processes on disclosure and corporate reporting, particularly the Task Force on Climate-related Financial Disclosures (TCFD) chaired by Michael Bloomberg, that was launched at COP21 in Paris during December 2015.

It is noteworthy that very little of our analysis has depended on existing corporate reporting or data disclosed through voluntary disclosure frameworks. This is both a cause for hope and concern. It demonstrates that significant strides can be made to understand company exposure to environment-related risks even in the absence of consistent, comprehensive, and timely corporate reporting on these issues. But it also highlights how existing frameworks on environment-related corporate disclosure might be asking the wrong questions – they try to enable top down analysis, but do little to support a bottom up one. Reporting needs to link back to a fundamental understanding of risk and opportunity and to specific assets within company portfolios. In the absence of that, what is reported may not be actionable from an investor perspective.

The report is accompanied by two technology briefings. The first addresses a clear gap in the available literature on existing and emerging coal processing technologies (CPTs). Ambitious deployment of CPTs would impact future coal demand, but the state of these technologies is largely uncertain.

The second briefing emerges out of the necessity to address the role of carbon capture and storage (CCS) in the future of coal. The rapid deployment of cost-efficient CCS could alter possible future coal demand pathways. CCS has particular technical synergies with CPTs and the role that each may play in the future of the other has been scarcely discussed.

Sections 2 and 3 are the briefings of CPTs and the role of CCS respectively. Section 4 presents policy summaries of the selected countries heavily involved in the global coal value chain. Section 5 presents analysis of the top 100 coal-fired utility companies. Section 6 presents analysis of the top 20 thermal coal miners with thermal coal revenue ≥30%. Section 7 presents analysis of identified CPT companies. Section 8 considers potential impact the future of thermal coal will have on other industries and markets. Section 9 concludes and identifies the implications of our research for extant corporate reporting and disclosure processes.

1.1 Coal Value Chain

Coal is a combustible sedimentary rock that provides 30% of the world's primary energy supply, fuels 40% of the world's electricity, and is used to produce 70% of the world's steel[6]. The coal value chain is described in Figure 13.

Figure 13: *Coal value chain*

Prospecting	Mining	Preparation	Transportation	End Market
• Securing mineral rights from government or land owners • Exploration and surveying	• Open Cast' surface mining • Underground 'deep' mining	• Optional step to remove impurities and improve material consistency • Also called 'beneficiation', washing	• By rail • By ship	• See Table 7

Table 7 describes coal types and their various end uses. Coal is standardised by ASTM International according to energy, carbon, and volatile compound contents[7].

Table 7: *Coal types and uses*

Coal Type		Primary Use
Black/Hard Coal	Anthracite	Domestic and industrial uses, especially as a low-smoke fuel
	Bituminous	Metallurgical/coking coal for manufacture of iron and steel
Brown Coal	Sub-bituminous	Thermal/steam coal for power generation, industrial boilers, and cement production
	Lignite	Predominantly power generation in close proximity to the coal mine

[6] World Coal Institute (2013). The Coal Resource. London, UK.
[7] See ASTM International (2015). ASTM D388-15: Standard Classification of Coals by Rank. West Conshohocken, US.

Major coal exporting countries include Australia, Indonesia, South Africa, and the United States. Coal is traded worldwide in two dominant regional markets – Pacific and Atlantic. Terminals in South Africa act as transfer points between the two markets. Most traded coal is thermal coal, and lignite is seldom transported large distances due to its low energy content. Coal reserves for selected countries are shown in Table 8.

Table 8: *Proven coal reserves for select countries*[8]

Country	Anthracite and Bituminous [Mt]	Sub-bituminous and Lignite [Mt]	Share of World Total
Australia	37,100	39,300	8.6%
China	62,200	52,300	12.8%
Germany	48	40,500	4.5%
Indonesia	-	28,017	3.1%
India	56,100	4,500	6.8%
Japan	337	10	0%
Poland	4,178	1,287	0.6%
South Africa	30,156	-	3.4%
United States	108,501	128,794	26.6%
United Kingdom	228	-	0%

[8] BP plc (2015). Statistical Review of World Energy 2015. London, UK.

1.2 Scenario Development

The International Energy Agency (IEA) was founded by the OECD in response to the first oil shock in the 1970s. The IEA publishes the annual World Energy Outlook (WEO) of energy market projections and analysis. The WEO provides a third-party alternative to corporate and national publications, though it is informed by these studies. The IEA scenarios below are widely used as benchmarks for private and public planning and are used in this study. Table 9 describes the three IEA scenarios from the IEA World Energy Outlook 2015, published in November 2015.

Table 9: *IEA scenarios*

Scenario	Description
Current Policies (CPS)	The conservative scenario of the WEO, the CPS projects energy markets based on existing and implemented policy only.
New Policies (NPS)	The central scenario of the WEO, the NPS projects energy markets based on all current existing and committed policy measures.
450S	A scenario used to illustrate the policy necessary to achieve a peak atmospheric concentration of 450ppm $C^{O2}e$, limiting long-term climate change to 2°C of warming with 50% likelihood.

This study briefly references two other scenario sets in the outlook for CCS: the IEA's Energy Technology Perspective (ETP) scenarios, which include the 2°C Warming Scenario (2DS), 4°C Warming Scenario (4DS), and 6°C Warming Scenario (6DS), and the Intergovernmental Panel on Climate Change's (IPCC) aggregate scenarios for mitigation and technology pathways. The Carbon Tracker Initiative (CTI)[9] has critiqued a number of assumptions which underlie the IEA's and corporate scenarios, including technology penetration rates, world growth rates, and future energy demand. The IEA's WEO scenarios are, however, widely referenced in industry and policymaking and are used as the primary reference scenarios in this study.

[9] The Carbon Tracker Initiative (CTI) (2015). Lost in Transition. London, UK.

Table 10: *2020 Coal demand IEA scenarios*[10]

					Coal-Fired Electricity							
Country	Total Primary Energy Demand – Coal [Mtoe]				Capacity [GW}				Generation [%][iv,v]			
	2013	CPS	NPS	450S	2013	CPS	NPS	450S	2013	CPS	NPS	450S
Australia[i]	46	46	45	43	27	33	33	30	75%			
China	2,020	2,144	2,060	1,906	826	1,030	979	941	75%	65%	63%	61%
Germany[ii]	81	73	69	63	49	44	43	42	44%			
Indonesia[iii]	34	41	40	47	18	32	30	28	50%			
India	341	499	476	442	154	238	230	223	73%	72%	69%	65%
Japan	117	114	111	103	50	51	49	49	32%	30%	29%	28%
Poland[ii]	53	47	45	41	31	28	27	27	90%			
South Africa	99	96	94	91	39	46	44	43	94%	88%	87%	86%
United States	430	421	368	303	322	281	252	259	40%	36%	33%	28%
United Kingdom[ii]	36	32	31	28	22	20	20	19	30%			
IEA World	3,929	4,228	4,033	3,752	1,851	2,168	2,064	1,997	41%	39%	37%	35%

i: Imputed from IEA OECD Asia Pacific; ii: Imputed from IEA European Union; iii: Imputed from IEA Non-OECD Asia; iv: See Table 11 for references; v: due to imputation from IEA regions, no 2020 generation % is available for Australia, Germany, Indonesia, Poland, or the United Kingdom.

1.3 Scenario Outlook

This report examines environment-related risks to thermal coal utility, mining, and coal-processing technology assets. Where possible these environment-related risks are presented in the context of the IEA WEO scenarios for consistency with analysis in the broader literature. An opinion is developed in this section regarding the most probable IEA scenario and the general 'direction of travel' of policy development.

1.3.1 Coal in 2015

According to the IEA's Coal Medium-Term Market Report (MTMR)[11], world thermal coal consumption peaked in 2013. China, the consumer of over half the world's coal, has experienced slowing growth and decoupling of energy consumption from GDP. The only regions where coal use grew was in India and the Association of South East Asian Nations (ASEAN) countries including Indonesia. Coal use in Europe and the US continued structural decline.

[10] International Energy Agency (IEA) (2015). World Energy Outlook (WEO) 2015. Paris, France.

[11] IEA (2015). Coal Medium-Term Market Report (MTMR). Paris, France.

The global coal market has been substantially affected by falling demand and over-supply. Since 2011, coal prices have fallen from over US$120/t to less than US$60/t[12]. Despite low commodity prices, coal power generation has faced difficulty expanding. Direct climate change policies like carbon pricing or emissions trading have negatively impacted plant profitability. Competition from gas and renewables has led both to decreasing utilisation rates and lower wholesale electricity prices. In some countries distributed energy resources have combined with efficiency improvements leading to lower overall power demand.

The IEA's MTMR estimates that OECD coal demand will continue to fall by 1.5% per year through 2020. Coal demand will increase in China by 0.9%, India by 3.7%, ASEAN by 7.7%, and other non-OECD 1.9% per year. World coal demand will increase by 0.8%, which is slightly more than the IEA's WEO 2015 NPS outlook of 0.4% annual growth through 2020.

Table 11: *2014 Coal production, trade, consumption, and power generation for selected countries*[13]

Country	Production		Trade	Consumption			Coal-fired Electricity	
	Hard [Mt]	Brown [Mt]	(Exports) [Mt]	Hard [Mt]	Brown [Mt]	Change in 2015 [%][i]	Capacity [GW][ii]	Generation [%]
Australia	431	61	(376)	55	61	+0.3%	27	75%
China	3650	-	271	3921	-	-6%	826	75%
Germany	8	178	51	59	177	-3%	49	44%
Indonesia	471	-	(409)	62	-	-2%	18	50%
India	621	47	238	859	47	+3 to 6%	154	73%
Japan	0	-	187	187	-	-5%	50	32%
Poland	73	64	0	73	64	ND*	31	90%
South Africa	253	-	(75)	178	-	-2.1%	39	94%
United States	844	72	(79)	765	70	-11%	322	40%
United Kingdom	12	-	36	48	-	-16%	22	30%

* No Data
i) Data from Institute for Energy Economics and Financial Analysis (IEEFA) (2015) *Past Peak Coal in China*.
ii) Data from IEA (2013) *World Energy Atlas; Australian Electricity Regulator* (AER) (2014) *State of the Electricity Market 2014;* Sakya, I. (2012) *Electricity Power Developments in Indonesia*, PT PLN; EMIS (2014) *Electricity Sector Poland;* Federal Ministry for Economic Affairs and Energy (BMWi) (2015) *An electricity market for Germany's energy transition;* Department of Energy & Climate Change (DECC) (2015) *Digest of UK Energy Statistics (DUKES)* 2015.

[12] IEA (2015). MTMR.
[13] Data from IEA (2015). MTMR unless otherwise noted.

1.3.2 COP21 and the Paris Agreement

The validity and relevance of these scenarios is increased by the Paris Agreement, which was adopted on 12th December 2015. The agreement calls on parties to the UNFCCC to hold warming levels substantially below 2°C, while aligning finance flows with sustainable and climate-resilient development. To meet the 2°C commitment, the agreement calls on countries to achieve net-zero global greenhouse gas emissions by the second half of the 21st century. The Paris Agreement also calls on nations to 'pursue efforts' to limit warming to 1.5°C and a coalition of higher-ambition countries, both developed and developing, emerged during the conference in support of the more stringent target. For a 50% chance of meeting this more ambitious target, countries would need to limit cumulative emissions from 2011 to 550 $GtC^{O2}eq$[15], less than half the emissions budget for 2°C of warming. The concentration of greenhouse gases would need to be limited to <430ppm by 2100, with emissions reductions of 70% to 95% below 2010 levels by 2050[16].

A departure from previous top-down 'grand coalitions' to limit climate change, the agreement takes a 'bottom up' approach. Countries remain responsible for setting their own greenhouse gas mitigation targets, called Intended Nationally Determined Contributions (INDCs). By the end of COP21, 185 countries representing 97% of global population and 94% of global emissions had submitted INDCs. Climate Action Tracker estimates that the current INDCs collectively limit warming to 2.7°C, with upper and lower bounds of 3.4°C and 2.2°C respectively[17]. To meet warming limit targets, the agreement establishes an 'ambition mechanism' for countries to increase their INDC commitments every five years beginning in 2020. A 'global stocktake' of emissions reduction progress will occur two years preceding each recommitment, providing a recurring time period for countries to negotiate their new INDCs. A transparency framework was agreed to in principle which will allow countries to observe their mutual mitigation efforts, discouraging hollow commitments and free-riding. The negotiation of this framework will be one of the key tasks of the UNFCCC.

1.3.3 WEO Scenario Alignment

The WEO scenarios provide a static snapshot of energy demand, technology development, and relevant policy. The CPS and NPS are benchmarked to implemented and emerging policies, and are thus only descriptive of existing policies. The 450S prescribes a policy pathway that limits end-of-century warming to 2°C. The IEA currently has no scenario which describes alignment with the higher-ambition 1.5°C warming limit.

Figure 14 shows the change of the IEA World Energy Outlook scenarios over time. Actual coal demand exceeded projections in 2010 to 2013, however, taken over time, the IEA scenarios indicate a tightening policy environment for coal as a primary energy source. Since WEO 2011, the NPS compound annual growth rate (CAGR) for coal total primary energy demand (TPED) through 2020 has fallen every year from 2.0% in 2011 to 0.3% in 2015. Significant policy developments took place between WEO 2014 and WEO 2015 and the 2014 NPS 2020 projection is now the 2015 CPS 2020 projection, showing how new policy can create a year-on-year change in scenario projections.

[15] Intergovernmental Panel on Climate Change (IPCC) (2014). Climate Change 2014 Synthesis Report. Geneva, Switzerland.
[16] Ibid.
[17] Climate Action Tracker (2015). Tracking INDCs. http://climateactiontracker.org/indcs.html.

Figure 14: *IEA world energy outlook historic scenarios*[18]

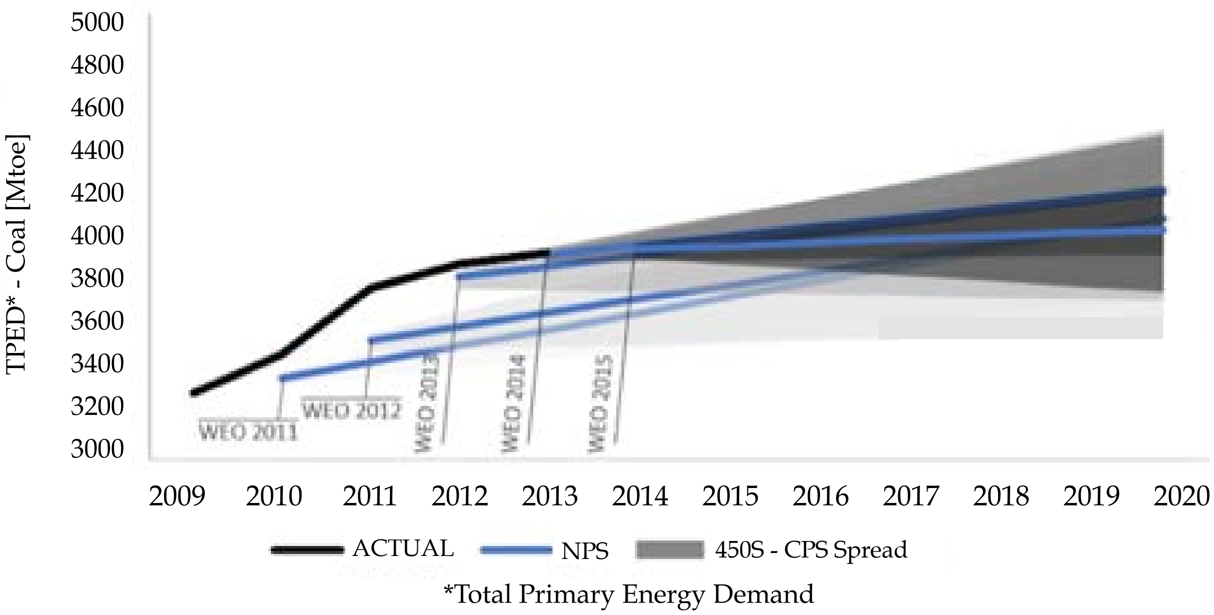


Table 12 benchmarks recent policy developments against selected policy measures from the IEA's WEO 2015. More details regarding policy developments in scope countries is available in Section 4. An opinion is provided on which scenario best describes the direction of policy development for each jurisdiction. Taken in aggregate, it is clear that the ambitions of policymakers now likely exceed the WEO NPS and are approaching the 450S. Several critical uncertainties remain, which are discussed in Box 1.

In the remainder of this report, IEA scenario projections are used to inform the development of hypotheses of environment-related risks. Based on the evidence in the preceding sections, the IEA 2015 NPS is referred to as the lower bound of policy action on climate change. The hypotheses developed in this report using the 2015 NPS thus underestimate the materiality of environment-related risks on the thermal coal value chain. This has been done to provide a conservative outlook and to reflect the IEA's consideration of the NPS as their central scenario.

[18] Data from IEA (2011). WEO 2011; IEA (2012). WEO 2012; IEA (2013). WEO 2013; IEA (2014). WEO 2014; IEA (2015). WEO 2015.

Table 12: Selected policy measures cross-referenced with IEA scenario assumptions[19]

Region	Scenario	Assumptions	Evaluation	Outlook Opinion
All OECD	450S	Staggered introduction of CO2 prices in all countries US$100bn in annual financing provided to non-OECD countries by 2020	CO2 pricing growing, see below US$100bn included in Paris Agreement	450S
All Non-OECD	NPS	Fossil-fuel subsidies are phased out within the next ten years in net-importing countries	G20 commitment to phase out fossil fuel subsidies, see below	NPS
	450S	Fossil-fuel subsidies are phased out within the next twenty years for net-exporting countries		
United States	NPS	Clean Power Plan Carbon Pollution Standards	Carbon Pollution Standards Rule and Clean Power Plan launched August 2015[20][21] US wind production tax credit and solar investment credit extended through to 2019 and 2021 respectively[22]	450S
	450S	Extended support for renewables, nuclear, and CCS Efficiency and emissions standards close plants CO2 pricing implemented from 2020		
Japan	NPS	Achieve 2030 renewables power generation target of 22-24%, with nuclear generating 20-22%. Harmonised support for renewables generation	Government targets on track for 23% renewables, 21% nuclear generation by 2030[23] CO2 pricing pilot programmes established[24]	NPS
	450S	CO2 pricing implemented from 2020 Share of low-carbon electricity generation to increase by 2020 and expand by 2030 Introduction of CCS		
EU	NPS	Removal of barriers to CHP 2030 Climate and Energy framework Partial implementation of the Energy Efficiency Directive reducing primary energy consumption by 20% by 2020 EU ETS reducing GHG emissions by 43% below 2005 level	Member states mostly on track with renewable energy deployment, energy efficiency improvement, and greenhouse gas reductions[25] ETS revisions issued July 2015 in line with 2030 framework and 2050 roadmap[26]	450S
	450S	EU ETS strengthened in line with 2050 roadmap Reinforcement of government support for renewables Expanded support for CCS		

[19] IEA (2015). WEO 2015.
[20] US Environmental Protection Agency (EPA) (2015). Clean Power Plan for Existing Power Plants. Washington, US.
[21] US EPA (2015). Carbon Pollution Standards for New, Modified and Reconstructed Power Plants. Washington, US.
[22] Crooks, E. (2015). 'Wind and solar groups cheer US budget tax breaks', Financial Times. New York, US.
[23] Iwata, M., & Hoenig, H. (2015). 'Japan struggles to find balanced energy strategy', Wall Street Journal. Tokyo, Japan.
[24] Tokyo Metropolitan Government (2015). Tokyo Cap and Trade, https://www.kankyo.metro.tokyo.jp/en/climate/cap_and_trade.html
[25] European Environment Agency (2015). Trends and projections in Europe 2015. Copenhagen, Denmark.
[26] European Commission (2015). Questions and answers on the proposal to revise the EU ETS. Brussels, Belgium.

Region	Scenario	Assumptions	Evaluation	Outlook Opinion
China	NPS	Restructuring of the economy away from investment and export growth towards services and domestic consumption ETS covering power and industry from 2017 Expended use of natural gas Energy price reform – increase in natural gas prices and oil product price adjustments Exceed 12th FYP renewables targets Establishment of ETS Emissions from coal new-builds of 300 g/kWh By 2020: 58GW nuclear, 420GW hydro, 200GW wind, 100GW solar, and 30GW bioenergy	C^{O2} pricing pilot programmes established 12th FYP 2015 targets (260GW hydro, 100GW wind, 10GW solar) exceeded by 2014 (280GW hydro, 114GW wind, 28GW solar) Natural gas pricing reform was introduced in 2013, energy pricing reform will continue as part of nation-wide changes to market economy[27] Nationwide ETS expected 2017-2020[28]	450S
	450S	Strengthen power and industry ETS Reduce local air pollution by 2015 (8% SO_2, 10% NO_x) ETS in accordance with overall targets Enhanced support for renewables and nuclear Deployment of CCS from 2020		
India	CPS	National Solar Mission, aiming to deploy 20GW by 2022 National Clean Energy Fund based on coal levy of INR 100/tonne of coal	20.2GW PV expected by the end of 2017[29] February 2015 Minister of Finance proposed to double the coal levy to 200 INR/tonne to increase National Clean Energy Fund[30] Privatisation of coal mining met with labour resistance in 2015[31] Planned and in-construction coal power stations have lower emissions intensity (902 kg/MWh) relative to existing fleet (1100 kg/MWh)[32]	NPS
	NPS	Increase in the National Clean Energy Fund Open the coal sector to private and foreign investors By 2022: competitive bidding for 100GW solar, 75GW non-solar Increased uptake of supercritical coal-fired power plants Strengthen grid and electricity markets; reduce losses		
	450S	Renewables reach 15% of installed capacity by 2020 Extended support for renewables, nuclear, efficient coal Deployment of CCS from 2025		

[27] Paltsev, S., & Zhang, D. (2015). 'Natural Gas Pricing Reform in China', Energy Policy, 86:43-56.
[28] Shu, W. (2015). Update on Chinese National-Wide ETS Development, National Development and Reform Commission. Beijing, China.
[29] Ministry of New and Renewable Energy (2015). Status of implementation of various schemes to achieve 1,00,000 MW Solar Plan. New Delhi, India.
[30] Jaitley, A. (2015). Minister of Finance Speech: Budget of 2015-16. New Delhi, India.
[31] Australian Government (2015). Coal in India, Department of Industry and Science. Canberra, Australia.
[32] Smith School Analysis, see Section 5.

Box 1: *Critical uncertainties from WEO policy tables*

- *US$100bn in financing* – Continuing from the Copenhagen Accord, the provision of US$100bn per year for climate change mitigation and adaptation is referred to in the text of the Paris Agreement, but uncertainty remains regarding the source and additionality of the funding. A report by the OECD in advance of COP21 estimated that US$62bn per year in climate finance was already being provided by developed countries[33]. This caused controversy as developing countries, India in particular, critiqued the estimation methodology. The provision of this financing is not directly material to all aspects of the energy transition, just to developments in international climate policy.

- *Fossil-fuel subsidy phase-out* – The IMF estimates that, excluding externalities, over US$480bn is spent by governments each year on oil, gas, coal, and electricity subsidies, 40% in developed countries and 33% in oil exporting countries[34]. In 2009, G20 members agreed to phase out all fossil-fuel subsidies, which includes all the scope countries of this study. India and Indonesia have the largest fossil fuel subsidies of the scope countries, and Indonesia made substantial progress in 2014 reducing fuel and electricity subsidies. With continuing low oil prices, an opportunity exists for countries to accelerate their subsidy reductions without damaging social interests[35].

- *Carbon pricing* – Carbon pricing, from either a tax or quota, now covers approximately 12% of the world's emissions[36] and is present in 30% of the world's jurisdictions, weighted by emissions[37]. Total and jurisdictional emissions coverage is set to double with the inclusion of the Chinese ETS and the US Clean Power Plan. The Chinese ETS is expected to be designed for potentialfuture linkage with the EU ETS, establishing the beginnings of a global carbon price and beginning to capture emissions leakage from international trade[38]. What remains uncertain is the speed at which carbon pricing coverage will be able to extend to sectors beyond power generation and heavy industry.

- *CCS deployment* – CCS deployment to date has not been consistent with the low-warming scenarios of the IEA or the IPCC. Because CCS has implications for negative emissions technology and industrial process mitigation, the deployment of CCS can be a critical parameter in outlook scenarios. Mixed perspectives on the significance of CCS as a technology for power sector mitigation warranted the inclusion of a separate briefing on the subject, see Section 3.

- *Coal-processing technology deployment* – Coal-processing technologies (CPTs) have yet to be accommodated into energy, technology, and climate scenarios. CPTs offer an arbitrage opportunity between coal and gas or liquid fuels, or can be used for power generation without certain conventional air pollution drawbacks. There is little literature available on CPTs and their role in scenario projections, a briefing is included in this report in Section 2.

[33] OECD, Climate Policy Initiative (CPI) (2015). Climate finance in 2013-14 and the USD 100 billion goal. London, UK.
[34] International Monetary Fund (IMF) (2013). Energy Subsidy Reform: Lessons and Implications. Washington, US.
[35] Van der Hoeven, M. (2015). Fossil Fuel Subsidy Reform: Recent Trends, IEA. Paris, France.
[36] World Bank Group (2015). State and Trends of Carbon Pricing. Washington, US.
[37] Whitmore, A. (2015). 'The spread of carbon pricing and other climate legislation', On Climate Change Policy. https://onclimatechangepolicydotorg.wordpress.com/carbon-pricing/the-spread-of-carbon-pricing/
[38] Carbon Market Watch (2015). Towards a global carbon market. Brussels, Belgium.

SMITH SCHOOL OF ENTERPRISE AND THE ENVIRONMENT

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1.4 Data Availability

This report uses a number of data sources to provide analysis of coal-fired power utilities, thermal coal mining companies, and coal processing technologies. Table 13 summarises the main sources of data. Where the data was not available for all plants and mines, the remainder was either estimated from available data or completed by the Oxford Smith School as noted. For example, 74% of all coal-fired generating assets had generation data (in MWh) from CARMA, and the remaining 26% was estimated by the Oxford Smith School.

Table 13: *Data sources and completeness*

Data	Data Source (in order of seniority)	Completion %	Notes
Number of Coal-Fired Generating Assets (N = 1,445 coal-fired power stations)			
Location	CoalSwarm's Global Coal Plant Tracker (CoalSwarm, Q4 2015), Enipedia, Carbon Monitoring for Action Database (CARMA, v3.0 released Jul 2012), Platts' World Electric Power Plant Database (WEPP, Q4 2015)	100%	
Capacity [MW]	CoalSwarm, WEPP, Enipedia, CARMA	100%	
Generation [MWh]	Enipedia, CARMA, Oxford Smith School	100%	26% estimated by regression
Plant Age	CoalSwarm, WEPP, Enipedia, CARMA, Oxford Smith School	100%	31% estimated by regression
CO2 Intensity	CoalSwarm, WEPP, CARMA, Oxford Smith School	100%	22% estimated by regression
Cooling Technologies	WEPP, Oxford Smith School	71%	12 percentage points added from GoogleEarth searching
Pollution Abatement Technologies	WEPP	73%	
Coal Type	CoalSwarm, WEPP, Oxford Smith School	71%	29 percentage points estimated based on proximity to reserves
Number of Thermal Coal Mining Assets (N = 274 thermal coal mines)			
'Top 20' coal mining companies	MSCI	-	
% Rev by Activity	MSCI, Trucost	97%	Data unavailable
Mine Production	Oxford Smith School	69%	Data unavailable
Location	Oxford Smith School	100%	
Number of Coal Processing Technology Assets (N = 63 coal processing technology plants)			
Location	World Gasification Database (Nov 2015)	100%	
Capacity [Nm^3/day]	World Gasification Database, Oxford Smith School	100%	14% estimated from product energy content
Plant Age	World Gasification Database	100%	
Market Analysis			
General Information	S&P CapitalIQ, Trucost	-	
Capital Spending Trends	S&P CapitalIQ	-	
Bond Issuances	S&P CapitalIQ	-	
Ownership Trends	S&P CapitalIQ	-	

Data	Data Source (in order of seniority)	Completion %	Notes
Local Risk Hypotheses			
$PM_{2.5}$ Emissions 2012-2014 Average	Atmospheric Composition Analysis Group, Dalhousie University	Global	
NO_2 Emissions 2015	NASA GES DISC OMNO2	Global	
Mercury Emissions 2010	AMAP, UNEP 2010	Global	
Water Stress 2015	WRI Aqueduct	Global	
Water Stress Change 2016-2030	WRI Aqueduct	Global	
Heat Stress Change 2016-2035	IPCC AR5 WGII	Global	
CCS Geologic Suitability	Geogreen	Global	
Population Density 2015	NASA SEDAC GPWv3 2015	Global	
Protected Areas 2015	UNEP-WCMC	Global	
National Risk Hypotheses			
Water Regulatory Risk 2015	WRI Aqueduct	10/10 Scope Countries	
CCS Legal Environment	Global CCS Institute Legal and Regulatory Indicator	10/10 Scope Countries	
Energy Scenario Projections	International Energy Agency World Energy Outlook	Note	
Renewables Outlook	EY Renewable Energy Country Attractiveness Index	10/10 Scope Countries	
Renewables Policy	REN21 Global Status Report	See NRHs for details	

Note: Germany, Poland, UK comingled among EU; Indonesia comingled among Non-OECD Asia; Australia comingled among South Korea and New Zealand.

1.5 Dataset Preparation

Individual power station information is taken from the most recent version (v3) of the Carbon Monitoring for Action (CARMA) database, Enipedia, and CoalSwarm's Global Coal Plant Tracker (CPT). These databases are merged, and when power station matches occur, we preferentially use fields from CoalSwarm, then Enipedia, and finally CARMA. The Platts World Electric Power Plants Database (WEPP) is used to exclude power stations that have been closed, but not reported as such in CARMA, Enipedia, or CPT. We also use WEPP to identify non-coal-fired power stations that are operational, but not included in CARMA.

CARMA contains data on existing and planned plants and was last systematically updated to the end of 2009, CPT has data on coal-fired power plants planned and added to the global stock since the start of 2010 onwards (we currently used the most recent December 2015 update), and Enipedia is continuously updated on an individual power plant basis. WEPP is updated quarterly (we currently use data from the Q4 2015 release). The merger between these datasets has produced a database that effectively defines the locations of all the world's power plants, their ownership, the annual megawatt hours of electricity produced, plant age, fuel type, capacity, and carbon intensity. It is particularly current and comprehensive for coal-fired power stations.

Information on the accuracy of the CoalSwarm, Enipedia, and WEPP databases are not available, but the CARMA data has a number of caveats that are thoroughly enumerated on its website (carma.org), two of which are particularly relevant to this database. The first is that CARMA estimates electricity generation and CO2 emissions using statistical models that have been fitted from detailed US plant data. CARMA reports that fitted CO2 emissions values are within 20% of the true value 60% of the time, and that electricity generation is within 20% of the true value 40% of the time. Second, CARMA geographical location data varies in its degree of precision. For almost all power plants the state/province location is known, for 80% of power plants at least the city location is known, for 40% county/district data is known, and for 16% of power stations a unique postal code is assigned. Comparisons of approximate and precise coordinates suggest that the average spatial error is about 7 km, which is well within the bounds of all our geographical analyses (scales of 40km and 100km used).

International Securities Identification Numbers (ISINs) which uniquely identify securities have been matched to the equities of top coal-fired utilities, thermal coal miners, and coal processing technology companies where possible. Equity ISINs are not available for private companies. Multiple bond ISINs could be matched to each company, however that has not been completed at this time. ISINs were acquired directly from the public database[39] and through internet research.

[39] Accessible at http://www.isin.org

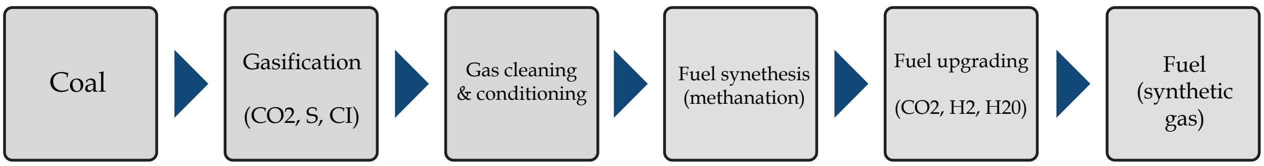
2 Briefing: Coal Processing Technologies

Coal processing technologies (CPTs) are a suite of technologies used to convert coal into a wide range of useful fuels. These technologies have had a nascent presence for decades, but interest has recently grown, based on policy objectives for energy security and reducing conventional air pollutants, and economic opportunities for arbitrage with gas or liquid fuels. Common CPTs include coal to gas technology (CTG), coal to liquids (CTL) including Fisher-Tropsch synthesis, and underground coal gasification (UCG), also called coal seam methanation. Some authors refer to CTG, CTL, and UCG collectively as 'CTX'. We use CPT in this report.

2.1 Technology Summary

Coal to gas (CTG) produces synthetic/substitute natural gas through a four-step process, see Figure 15[40]. First, coal is gasified with the addition of steam and/or oxygen, producing what is known as producer gas. Second, this gas is cleaned and conditioned, removing impurities such as sulphur and chlorine. Methanation[41] follows, at low temperature, high pressure, and with the addition of a catalyst. The final step is fuel upgrading, which removes water and carbon dioxide to fulfil required quality specifications. A major advantage of CTG is the generation of a concentrated stream of carbon dioxide as a by-product from the fuel-upgrading step. This can be utilised in other processes without the additional costs that are associated with carbon dioxide separation in coal-fired power stations[42].

Figure 15: *CTG four-step process chain from coal to synthetic gas*[43]



Coal to liquids (CTL) are produced through two major methods – direct and indirect coal liquefaction[44]. Direct liquefaction (DCL) converts (see Figure 16) coal to liquid fuels, requiring high heat, high pressure, and a catalyst to initiate hydro-cracking[45]. This takes place in two stages, and has a liquid yield of up to 70% of the dry weight of the coal. These liquids can be directly utilised in power generation or petrochemical processes, but require further refining before use as transport fuel. Indirect liquefaction (ICL) converts coal to a mixture of carbon monoxide, and hydrogen, known as syngas, and from this intermediate step, to liquid hydrocarbons. Fuels produced through this process, a.k.a. Fischer-Tropsch synthesis (see Figure 17), do not require further refining for use.

[40] Kopyscinski, J., Schildhauer, T., & Biollaz, S. (2010). 'Production of Synthetic Natural Gas (SNG) from Coal and Dry Biomass', Fuel 89:1763-1783.

[41] Methanation process converts carbon oxides and hydrogen from syngas to methane and water through chemical catalysts in fixed-bed reactors. See US Department of Energy (DOE) (2010). Hydrogen and synthetic natural gas from coal. Washington, US.

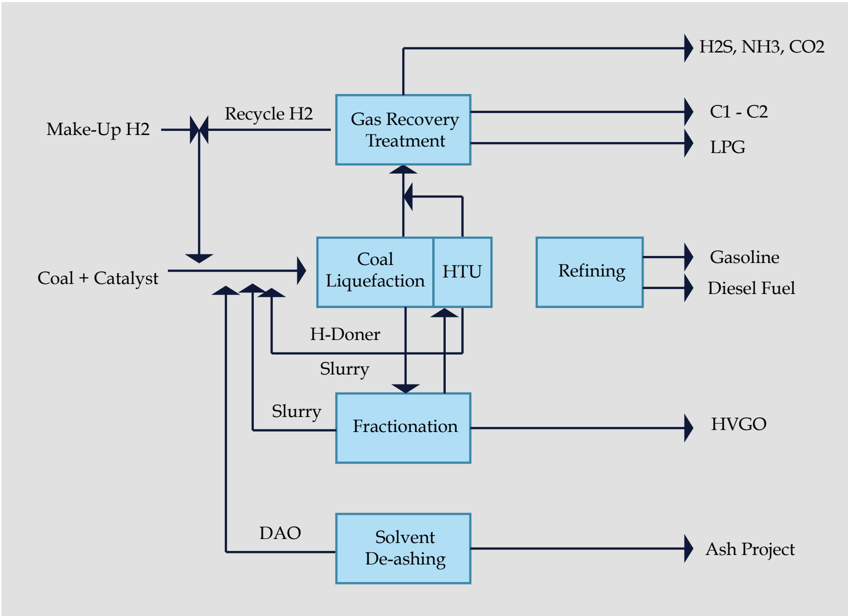
[42] Kopyscinski et al. (2010). Op. Cit.

[43] Adapted from Kopyscinski et al. (2010). Op. Cit.

[44] Höök, M., Fantazzini, D., Angelantoni, A., et al. (2014). 'Hydrocarbon Liquefaction: Viability as a Peak Oil Mitigation Strategy', Philosophical Transactions. Series A: Mathematical, Physical, and Engineering Science 372:1–36.

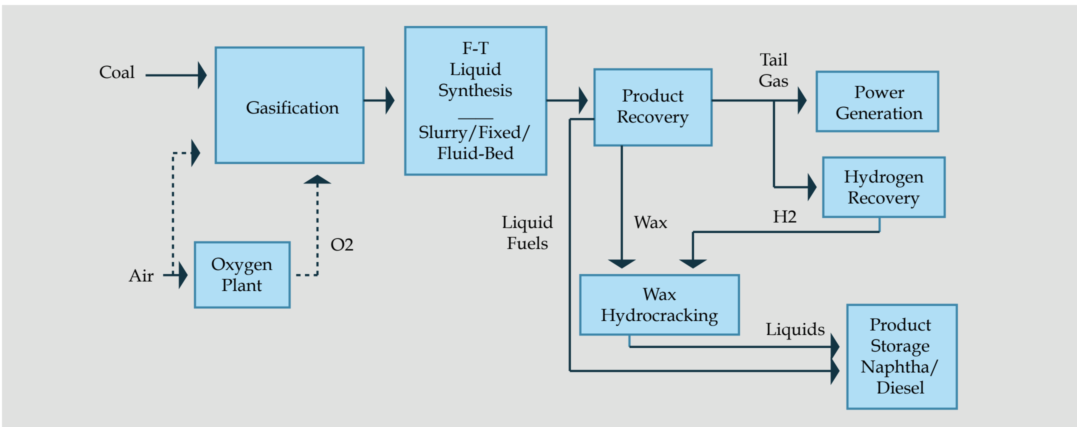
[45] Hydro-cracking refers to a catalytic chemical process, during which H_2 is reacted with heavy petroleum products to produce lighter and commercially usable hydrocarbons. See US DOE (2009). Gasification. Washington, US.

Figure 16: Simplified direct coal liquefaction (DCL) Process[46]



DCL is commonly regarded as more efficient for production of liquid fuels, as it requires only partial breakdown of the coal. However, ICL fuels are cleaner, as they are essentially free from nitrogen, sulphur and aromatics, and thus emit fewer contaminants when combusted[47]. As well as a reduced environmental impact, ICL has greater variability and flexibility in outcome products, and stronger supporting infrastructure and past knowledge – and has been put forward as the more likely option for CTL development[48]. Moreover, if hydrogen fuel cells gain importance and utilisation in the future, ICL processes can produce hydrogen, rather than hydrocarbons, creating another potential future application[49].

Figure 17: Simplified fischer-tropsch synthesis scheme for indirect coal liquefaction (ICL)[50]



Underground Coal Gasification (UCG) is a process of converting coal that is unworked, and still in the ground, into a gas that can be utilised in power generation, industrial heating, or manufacture of synthetic fuels, see Figure 18.

[46] Taken from DoE (2011). Direct Liquefaction. Washington, US.

[47] Höök, M., & Aleklett, K. (2010). 'A Review on Coal-to-liquid Fuels and its Coal Consumption', International Journal of Energy Research 34:848–864.

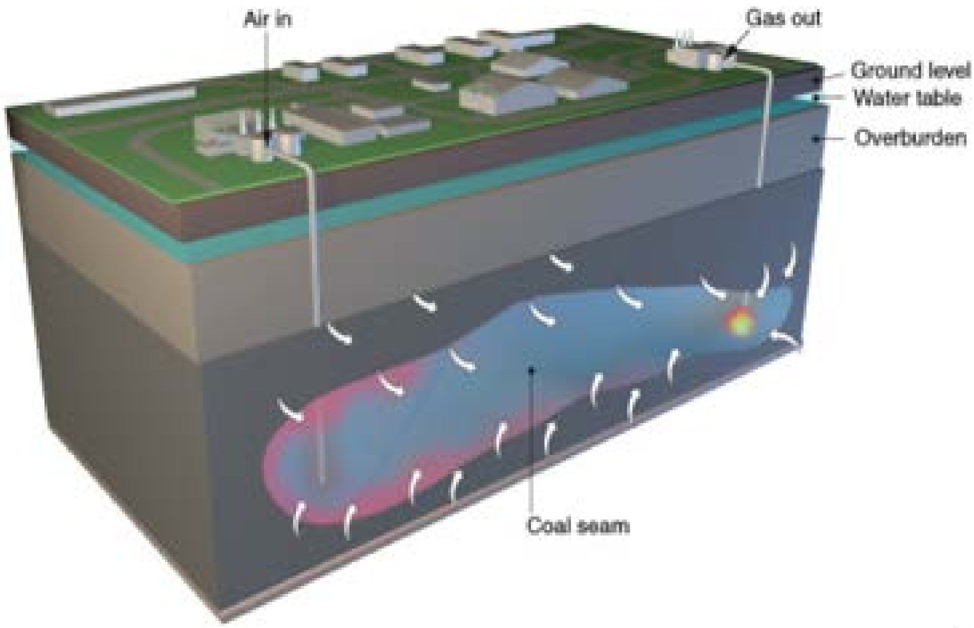
[48] Höök et al. (2014). Op. Cit.

[49] Höök, M., & Aleklett, K. (2010). Op. Cit.

[50] Taken from DoE (2011). Op. Cit.

The UCG process requires drilling two wells into the coal seam, which are then heated to a high temperature with oxidants injected through one well[51]. Water is also needed and may be pumped from the surface or may come from the surrounding rock. The coal face is ignited and, at high temperatures (1,500 kelvin) and high pressures, this combustion generates carbon monoxide, carbon dioxide, and hydrogen. Oxidants react with the coal to create syngas, which is then drawn out through the second well.

Figure 18: *Simplified version of general UCG process*[52]

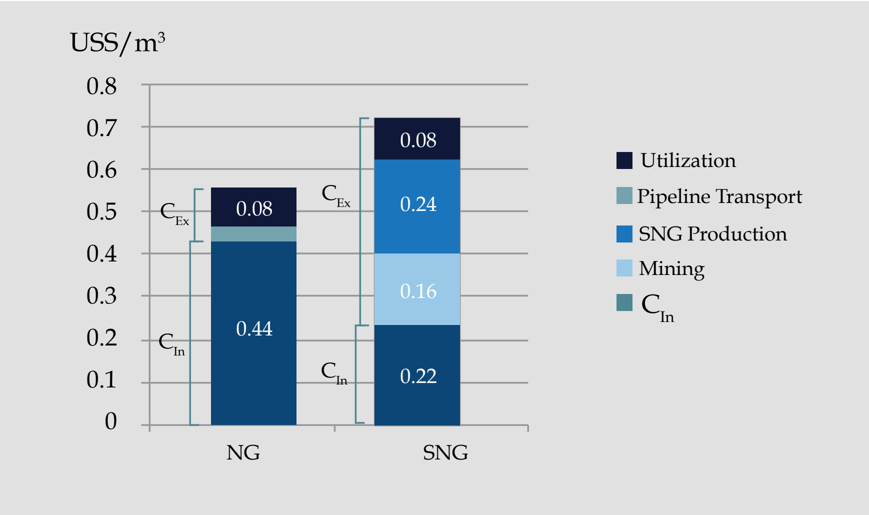


CTL/CTG are more technically advanced than UCG, and compete directly with each other. However, there are several problems associated with these technologies. First, very low thermal efficiencies are associated with hydrocarbon liquefaction – in the range of 45-55%. Given that substantial volumes of coal are required to generate fuels in any useful amount, these technologies are only viable in areas with abundant coal reserves, limiting large-scale production to six nations globally (Australia, China, India, South Korea, South Africa, United States) and creating infrastructure issues. Second, coal must be carefully quality controlled for low sulphur to prevent denaturing of expensive catalysts[53]. Third, CTL/CTG plant is very costly to build, and construction takes four to five years[54]. Moreover, since a long plant life is crucial to guaranteeing a return for investors, local coal reserves must be sufficient to ensure this is possible[55].

Although UCG has certain advantages over CTL/CTG in terms of lower plant costs, less surface emission of sulphur and nitrous oxides, and potential synergies with CCS post-extraction period, this technology also has several disadvantages. One key concern is associated with utilising new low-quality coal reserves that yield low quality gas with too much hydrogen.

[51] Anderson, R. (2014). 'Coal gasification: The clean energy of the future?' BBC News. London, UK.
[52] Taken from DoE (2014). Op. Cit.
[53] Xu, J., Yang, Y., & Li, Y. (2015). 'Recent Development in Converting Coal to Clean Fuels in China', Fuel 152: 122-130.
[54] Höök, M. et al. (2014). Op. Cit.
[55] Ibid.

Figure 19: *Life cycle cost comparison*



A comparative life cycle cost analysis[56] of conventional natural gas and synthetic gas shows that the environmental and societal costs of SNG production are much higher than that of natural gas. The majority of these costs derive from the SNG production stage and coal mining. Although natural gas costs (0.44 USD/m^3) are twice as high as those of synthetic gas (0.22 USD/m^3), analysis suggests that the life cycle cost of synthetic gas and conventional natural gas is 0.71 USD/m^3 and 0.55 USD/m^3, respectively (see Figure 19).

2.2 Development

During the Second World War, the German military produced 90% of their jet fuel, and 50% of their diesel, through CTL[57]. After the war, the technological lead enjoyed by Germany was assumed by South Africa, which decided to rely on coal conversion projects in response to its fuel shortage as a result of apartheid-era isolation[58]. Development has predominantly been by the oil and gas company Sasol, and the country has a daily capacity of 160,000 bbl[59] and meets 30% of South Africa's fuel demand using CTL[60].

In the United States, investments in CTG were made during the 1970s and 1980s, as a result of the global oil shocks. The 'normalisation' of oil prices in the 1990s reduced interest in CTG and decreased investment. Only one US-based company, Dakota Gas, had significant experience with CTG processes during this period[61]. At the time, natural gas prices were volatile and on the rise. The recent large-scale commercialisation of shale gas resources has pushed down the natural gas prices in the US. As a result, producing synthetic natural gas (SNG)[62] from CTG has become economically less attractive due to competition from shale gas[63].

[56] Li, S. Ji, X., Zhang, X., et al. (2014). 'Coal to SNG: Technical Progress, Modelling and System Optimization through Exergy Analysis', Applied Energy 136: 98–109.

[57] Höök, M. et al. (2014). Op. Cit.

[58] Becker, P. (1981). 'The Role of Synthetic Fuel In World War II Germany - Implications for Today?' Air University Review, 32:45-53.

[59] Perineau, S. (2013). 'Coal Conversion to Higher Value Hydrocarbons: A Tangible Acceleration' Cornerstone Magazine. World Coal Association. Hoboken, US.

[60] Höök, M., & Aleklett, K. (2010). Op. Cit.

[61] Perineau, S. (2013). Op. Cit.

[62] Synthetic natural gas (SNG) is a syngas derived from coal conversion based on the methanation process. See DoE (2011). Op. Cit.

[63] Institute for Energy Research (IER) (2014). China to Build 50 Coal Gasification Facilities. Washington, US.

In China, increasing demand for cleaner energy products like natural gas is the chief driving force behind development of coal conversion processes[64]. According to Chinese state-owned power companies, these plants are considered 'new energy' that would satisfy China's natural gas shortage problem[65]. Apart from energy security concerns, the Chinese government has 'declared war'[66] on air pollution in major city centres. Part of the response is to reduce coal use in cities and instead transport gas from coal conversion projects planned to be built in sparsely populated regions of north-western China, where there are large coal deposits[67]. However, building new coal-processing plants will generate additional water stress for already arid regions in north-western China and contribute to China's net carbon emissions[68].

Section 7 will discuss commercial uses of CTG/CTL/UCG technologies, capital expenditures and ownership trends globally, as well as other technical, economic and environmental factors that impact the value of coal-based energy processing companies.

[64] Xu, J. et al. (2015). Op. Cit.
[65] Wong, E. (2014). 'China's Energy Plans Will Worsen Climate Change, Greenpeace Says', New York Times. Beijing, China.
[66] Blanchard, B., & Stanway, D. (2014). 'China to declare war on pollution, premier says' Reuters. Beijing, China.
[67] IER (2014). Op. Cit.
[68] Ibid.

3 Briefing: Role of CCS

3.1 Feasibility Update

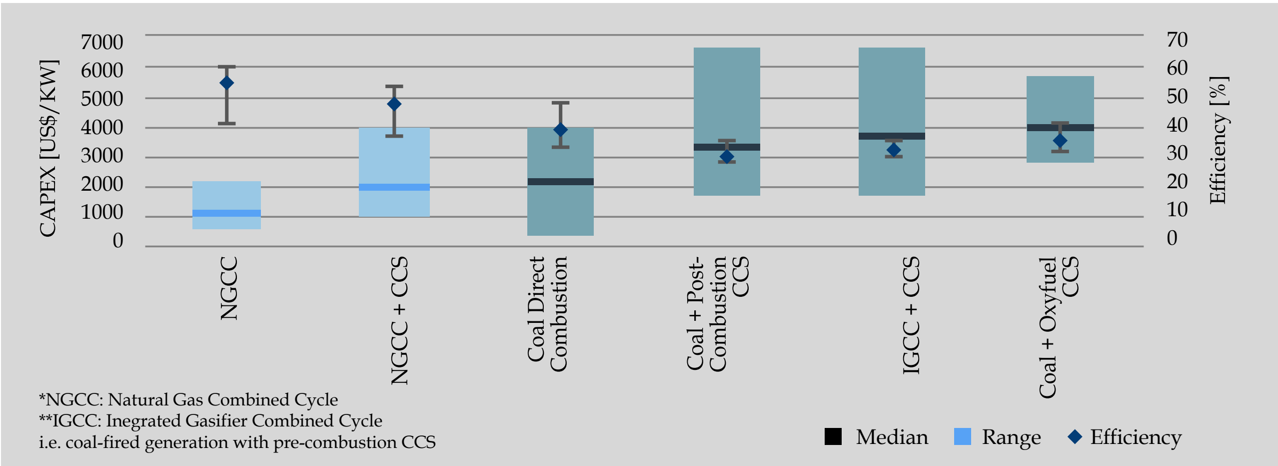
Carbon capture and storage (CCS) is a combination of three separate processes: carbon capture, transport, and storage. Carbon capture technologies are described in Table 14. Of the 15 power generation CCS projects proposed to 2025, seven use post-combustion capture, six use pre-combustion capture, and two use oxy-fuel capture[69].

***Table 14:** Carbon capture technologies*

Technology	Description
Post-combustion	Post-combustion carbon capture involves the separation of low-concentration CO_2 from other combustion gases, predominantly N_2. Chemical or physical solvents are used to absorb CO_2.
Pre-combustion	Fuels are gasified and steam shifted to create medium concentration CO_2 and H_2. Physical solvents are used to absorb CO_2 prior to combustion.
Oxy-fuel	Cryogenic distillation is used to separate O_2 from N_2 in combustion air prior to combustion. Combustion with oxygen only gives high-concentration CO_2 combustion gases.
Other Industrial	Certain industrial processes (e.g. ammonia production, natural gas processing) release CO_2 as a by-product at various levels of concentration.

Figure 20 shows the incremental capital expenditure and efficiency penalty for CO_2 capture and compressing equipment in typical coal- and gas-fired power stations, excluding other transport and storage equipment. The addition of CCS reduces the efficiency of an average coal-fired power station by 4 to 9%, oxy-fuel capture having the least efficiency losses[70]. For post-combustion capture, compressor power comprises 25% to 40% of overall plant efficiency losses, with the remainder of the losses attributable to the capture process itself[71].

***Figure 20:** Conventional generation CCS options*[72]



[69] Global CCS Institute (2015). Large Scale CCS Projects. Docklands, Australia. https://www.globalccsinstitute.com/projects/large-scale-ccs-projects.

[70] Bruckner, T., Fulton, L., Hertwich, E., et al. (2014a). 'Annex III: Technology-specific Cost and Performance Parameters', in IPCC, Fifth Assessment Report. Geneva, Switzerland.

[71] IEA Greenhouse Gas R & D Programme (2005). Retrofit of CO2 Capture to Natural Gas Combined-Cycle Power Plants. Cheltenham, UK.

[72] Data from Bruckner, T. et al. (2014a). Op. Cit.

Transport of CO_2 typically involves the compression and pumping of liquid CO_2 from the capture plant to the storage area. Saline aquifers, depleted oil and gas fields, and unmineable coal seams are suitable for geological CO_2 storage. See Section 5.2.1 for a map of global storage-suitable reservoirs. Enhanced Oil Recovery (EOR) is the process of injecting CO_2 into a producing oil or gas field to enhance output, a well-understood practice in the oil and gas industry[73]. The IEA estimates the cost of transporting and storing CO_2 may vary from US$1/t up to $100/t, with examples of <US$5/t for onshore storage in the US, to >US$25/t in offshore saline aquifers in Europe[74]. The IPCC uses a central estimate of US$10/t$CO_2$[75].

CCS implementation is hindered by its high capital costs and plant efficiency penalty. Both increase the levelised cost of electricity (LCOE) of a CCS-equipped power station relative to an equivalent unabated power station. The Global CCS Institute recently estimated a carbon abatement cost for coal with CCS of US$48 to $109/t and US$74 to $114/t for gas with CCS, including transport and storage, for a typical project in the US[76].

3.2 Scenario Inclusion

CCS is included as a mitigation and negative emissions technology in several future energy and climate scenarios. Projected CCS deployment of select 2°C warming scenarios are shown in Table 15 below.

***Table 15:** Projections of CCS deployment by 2040 of select 2°C warming scenarios*

Scenario	Projected Deployment
IEA WEO: 450S	5 GtCO_2/yr, 60% in power
IEA ETP: 2DS	4 GtCO_2/yr, 57% in power
IPCC AR5: Cost-efficient 430-530 ppm	5.5 to 12.1 GtCO_2/yr (imputed)

The IPCC synthesises technology uptake modelling subject to climate and economic constraints. A 450 scenario without CCS increases the mitigation costs by 138%, requires substantial afforestration and land-use change, and requires more mitigation early in the century. A 450 scenario with CCS makes substantial use of BECCS by mid-century to offset slower mitigation in other sectors[77].

In the IEA NPS, less than 5% of global coal-fired power stations are equipped with CCS by 2040 as the technology has not had the chance to proceed down cost curves. Between the CPS and the NPS, CCS only adds 2% additional carbon abatement, and only 1% before 2025. In the IEA's 450S, 75% of coal-fired power stations are equipped with CCS in 2040, although the total capacity of operating stations is substantially less.

[73] See IEA (2015). Storing CO2 Through Enhanced Oil Recovery. Paris, France.
[74] IEA (2015). Energy Technology Perspectives (ETP) 2015. Paris, France.
[75] Bruckner, T., Bashmakov, I., Mulugetta, Y, et al. (2014b). '7: Energy Systems', in IPCC, Fifth Assessment Report. Geneva, Switzerland.
[76] Global CCS Institute (2015). The costs of CCS and other low-carbon technologies in the United States – 2015 Update. Docklands, Australia.
[77] Field, C., Barrows, V., Mastrandrea, M., et al. (2014). 'Summary for Policy Makers', in IPCC, Fifth Assessment Report. Geneva, Switzerland.

In 2012, the IEA ETP estimated that 8 $GtCO2$/yr would need to be stored by CCS by 2050 to ensure a 2DS. The Carbon Tracker Initiative (CTI) used this target to estimate that 2DS greenhouse gas budgets might be extended by 12-14% with this level of CCS investment[78]. Oxford Smith School extended this methodology to bioenergy-enhanced CCS (BECCS) and other Negative Emissions Technologies (NETs), finding these technologies could further extended greenhouse gas budgets by 11-13%[79]. Both the CTI CCS and NETs carbon budget impacts are highly uncertain and imply extreme levels of technology adoption that are very unlikely.

3.3 Deployment Update

In October 2014, the first commercial power stations equipped with CCS began operation in Saskatchewan, Canada. Two additional CCS operations began in 2015, and the next power station equipped with CCS is expected to come online in the United States in 2016. To date, there are 15 operational CCS projects, 11 of which are used for enhanced oil recovery (EOR), and only seven of which include the monitoring of stored carbon[80]. An additional 30 projects are in planning till 2025, half of which are associated with power stations[81].

3.4 CCS in the Coal Value Chain

3.4.1 Thermal Coal Mining

Because CCS is best applied to stationary point sources of emissions, few opportunities are available to mitigate emissions of coal mining operations with CCS.

3.4.2 Coal-Fired Power Utilities

Coal-fired power stations have potential for both retrofit and the application of CCS to new power stations. In retrofit applications, post-combustion capture is likely the most appropriate and is currently the furthest developed[82]. For new builds, integrated gasification with pre-combustion capture, and oxy-fuel capture are more efficient[83].

In 2012, the OECD examined the global fleet of power stations retrofitable with CCS[84]. This study combines their methodology with geological suitability and policy outlooks from the Global CCS Institute, see Section 5.2.1 for details.

3.4.3 CPT

Emerging opportunities for CCS are available in CPTs. CPTs often involve an interim gasification step – ideal for capture similar to pre-combustion capture. Overall, CCS technologies can also help the reduction of emissions by up to 11% if employed in coal-processing plants[85].

[78] CTI (2013) Unburnable Carbon 2013: Wasted Capital and Stranded Assets. London, UK.

[79] Caldecott, B., Lomax, G., & Workman, M. (2014). Stranded Carbon Assets and Negative Emissions Technologies. Smith School of Enterprise and the Environment, University of Oxford. Oxford, UK.

[80] IEA (2015). ETP 2015. Op. Cit.

[81] Global CCS Database (2015). Op. Cit.

[82] IEA GHG (2011). Retrofitting CO2 Capture to Existing Power Plants. Op. Cit.

[83] Bruckner, T. et al. (2014a). Op. Cit.

[84] Finkenrath, M., Smith, J., & Volk, D. (2012). CCS Retrofit, IEA. Paris, France.

[85] Perineau, S. (2013). Op. Cit.

There are potential synergies between UCG and CCS, as CO_2 can be stored in the coal cavity after extraction and gasification[86]. Although a combination of UCG and CCS has been proposed as a 'green solution' for capturing CO_2 underground, maximum achievable carbon dioxide storage in coal voids left after in situ coal gasification is estimated as being only 14%[87]. Moreover, methods of heating and extraction during UCG generate significant thermal stresses in the coal voids, which could lead to roof collapse and leakage of stored carbon dioxide[88]. See Section 7 for details.

3.5 Policy and Legal Developments

Leading examples for CCS policy support include the EU's Enabling Directive on CCS (2009/31/EC), and the CCS legislation of Alberta, Canada and Victoria, Australia. Among other things, these regulations describe the conditions and extent of liability transfer after storage is found to be stable.

In September 2015, the Global CCS Institute surveyed the development of legal and regulatory frameworks for approving and managing CCS projects worldwide. They find that Australia, Canada, Denmark, the UK, and the US all have well developed legal and regulatory frameworks under which CCS projects may be developed[89].

3.6 Emerging Issues

3.6.1 Long-term Storage Suitability and Leakage

Even in high-deployment scenarios, the physical availability of geological storage is unlikely to be an issue for the deployment of CCS. However, the availability of geological storage that is both economically viable is likely to be. Concerns over potential leakage and the long-term stability of stored carbon may also prevent the political acceptance of CCS, presenting further barriers to the uptake of the technology.

The potential leakage of CO_2 from storage reservoirs presents a source of major uncertainty for the uptake of CCS. Issues include safety from CO_2 asphyxiation, leading to environmental or human catastrophe; the migration of CO_2 within storage reservoirs, leading to unforeseen leakages; seismic impacts on stored carbon; and the slow leakage of stored carbon eroding the climate benefit of storage. Even if technical and economic challenges can be overcome, local resistance to long-term storage may prevent the successful deployment of the technology.

3.6.2 Liability

Liabilities around the long-term storage of CO_2 are an emerging concern for CCS implementation. Issues include economic damages for escaped CO_2, interactions between regulation and liability, extended claim limitation periods due to the geological timescale of CO_2 storage, inactionable injunctions against continuing emissions leakage, financial security against emissions pricing for escaped CO_2, jurisdictional issues in administrative responsibilities of CCS projects, and the extent to which liability for a CCS project may be transferred (e.g. from a company to the state at the conclusion of a project)[90]. New CCS legislation and existing legislation applied in a CCS context are both yet to be tested. New interpretations and case law specific to CCS will clarify legal liabilities, but while these are in development, liability will remain a risk for CCS developers and operators.

[86] Anderson, R. (2014). Op. Cit.

[87] Schiffrin, D. (2015). 'The Feasibility of in-situ Geological Sequestration of Supercritical Carbon Dioxide Coupled to Underground Coal Gasification', Energy and Environmental Science 8: 2330-2340.

[88] Ibid.

[89] Global CCS Institute (2015). CCS Legal and Regulatory Indicator. Docklands, Australia.

[90] Havercroft, I., & Macrory, R., (2014). Legal Liability and Carbon Capture and Storage, Global CCS Institute. Docklands, Australia.

3.6.3 Perception

Cumulative emissions are responsible for the warming of the climate and the IPCC AR5 determined that some emissions pathways will require negative emissions to constrain cumulative emissions to safe levels. In spite of this, the IPCC calls the future availability of carbon dioxide removal technologies 'uncertain'. On CCS specifically, the IPCC notes that experts have only moderate agreement and insufficient evidence to evaluate whether CCS can limit the lifetime emissions of fossil fuel plants; whether BECCS can effectively deliver net negative emissions; and if sequestered carbon can be securely stored long-term[91].

The World Energy Council reports on the perceptions of 1,045 global energy leaders in the private and public sectors. Since 2010, energy leaders have reported a declining awareness of the impact of CCS, while uncertainty remains high[92]. Mixed opinions and insufficient evidence are barriers to the wide adoption of CCS as a key technology for mitigating climate change.

3.7 Opinion

Several additional factors may prevent the scale adoption of CCS as a mitigation technology. First, CCS is not currently developing at the pace necessary to meet the 2°C scenarios of the IEA and the IPCC. Second, other mitigation substitutes are becoming cost-competitive much more quickly than CCS. Third, a technology pathway which necessarily includes enhanced oil recovery is subject to additional economic and reputational risks.

By 2040, in the IEA's 450S, CCS is deployed to store 4000 MtCO_2 per year (Mtpa). The 15 currently operating projects are anticipated to store 28.4 Mtpa. The 30 additional projects planned to operate before 2025 will bring the total storage to 80 Mtpa, an annual growth rate of 11%. To reach 4000 Mtpa by 2040 will require a 48% growth rate from the 2025 planned fleet, or 22% growth from the operating fleet this year. This growth rate is unrealistic given the current state of deployment and technical progress.

The IEA foresees substantial deployment of CCS under the 450S only if policy supports CCS to become more affordable. As a mitigation technology for power generation, CCS will need to compete with falling prices of wind and solar power, and widespread efforts to improve grid flexibility. McKinsey estimates that by 2030, the abatement cost of solar and high-penetration wind power will be €18.0 and €21.0 per tCO_2 respectively, while CCS coal retrofits, new builds, and gas new builds will be €41.3, €42.9, and €66.6 per tCO_2 respectively[93]. Bloomberg New Energy Finance (BNEF) estimates that the global average LCOE for onshore wind power is US$83/MWh, $122 for crystalline solar PV, and $174 for offshore wind[94], while the Global CCS Institute estimates the US levelised cost of electricity (LCOE) for coal with CCS is US$115/MWh to $160, and $82 to $93 for CCS-equipped gas-fired power[95]. For markets and policymakers seeking abatement options in the context of finite public funds, CCS may remain a low priority for support.

[91] Field, C. et al. (2014). Op. Cit.

[92] World Energy Council (2015). 2015 World Energy Issues Monitor. London, UK.

[93] McKinsey & Company (2010). Impact of the Financial Crisis on Carbon Economics. New York, US.

[94] Zindler, E. (2015). 'Wind and solar boost cost-competitiveness versus fossil fuels', Bloomberg New Energy Finance (BNEF). London, UK and New York, US.

[95] CTI (2015). Op. Cit.

The IEA suggests that the technology development pathway for power generation with CCS begins with collocating the power station with EOR projects to enable commercial viability[96]. The IEA admits that the public are already 'sceptical of end-of-pipe solutions apparently promoted by the same industries they hold responsible for the problem'[97]. When co-located with EOR the stored carbon is used to extract additional hydrocarbons. Critics would argue any purported climate change merit of these projects is greenwashing – a reputational risk for the companies involved. Moreover, dependence on EOR also exposes power stations with CCS to oil price commodity risks. If the price of oil falls, then the profitability of EOR falls, and the profitability of the power station is reduced.

In conclusion, CCS is unlikely to be significant in mitigating power sector emissions. Deployment of CCS has already been too slow to match IEA and IPCC scenarios. CCS compares unfavourably with other power sector mitigation options, especially considering that CCS also reduces plant efficiency, exacerbating existing merit-order challenges for conventional generators. CCS should remain an attractive option for industrial and process emitters that have few other mitigation options, and may be significant as a long-term option for delivering negative emissions with BECCS.

[96] IEA (2013). Technology Roadmap – Carbon Capture and Storage. Paris, France.
[97] Ibid.

4 Policy Summaries

Detailed policy summaries have been prepared for the ten countries where most of the economic activity in the thermal coal value chain occurs: Australia, China, Germany, Indonesia, India, Japan, Poland, South Africa, the United States, and the United Kingdom. Between them these countries produce 86%, and consume 84%, of the world's thermal coal[98].

In this section, an analysis of policy relevant to coal-fired utilities, thermal coal miners, and CPT companies has been conducted. For each country, climate change and energy policy is examined, the state of environmental regulations is summarised, any CPT developments are discussed, and emerging issues are identified.

4.1 Australia

4.1.1 Climate Change and Energy Policy

Australia is the twelfth largest economy in the world and the world's second largest coal exporter. In 2014, Australia exported five times more coal than it consumed domestically.

With growing interest in climate change through the 2000s, the Clean Energy Act 2011 was passed by Julia Gillard's Labour government in February 2011. The Act established a carbon tax on facilities directly emitting over 25ktCO_2e per year. The tariff would begin at A$23/t in FY2012-13 and rise to A$24.15/t in FY 2013-14[99]. The carbon tax became an election issue in the run up to the 2013 election. The new Liberal government under Tony Abbott repealed the carbon tax in July 2014 with the Clean Energy Legislation (Carbon Tax Repeal) Act 2014[100].

The new government instead issued a Direct Action Plan to achieve a 5% reduction of emission levels below 2000 levels by 2020. Central to the plan is an A$2.55bn Emissions Reduction Fund which targets efficiency upgrades, land use change, and methane capture to deliver low marginal-cost emissions reductions. The Emissions Reduction Fund includes a safeguarding mechanism to ensure economy-wide emissions fall to meet the target. The safeguarding mechanism constrains facilities emitting over 100ktCO_2e to a baseline level of emissions, capturing over half of the country's emissions[101].

The Renewable Energy (Electricity) Act 2000 mandates demand for Large-scale Generation Certificates (LGCs) and Small-scale Technology Certificates (STCs). Electricity retailers must surrender a mandated amount of LGCs and STCs to the Clean Energy Regulator. LGCs are created with every MWh of large-scale renewable electricity generation. STCs are created on the installation of small-scale domestic and commercial renewable energy and efficiency technology. Taken together, it is expected that 23.5% of Australia's electricity will come from renewable sources by the year 2020[102].

Since 2009, black and brown coal-fired power generation has fallen at an average of 4.6% and 3.9% a year respectively. Wind power has grown at an average of 24.5% while gas-fired and hydro generation over the same period have been constant. Rooftop photovoltaic solar generation provided 2% of Australia's electricity in 2014, and is expected to grow 24% per year for the next three years.

[98] IEA (2015). Coal MTMR. Op. Cit.

[99] Australian Government (2011). Australia Clean Energy Act 2011. Canberra, Australia.

[100] Australian Government (2014a). Clean Energy Legislation (Carbon Tax Repeal) Act 2014. Canberra, Australia.

[101] Australian Government (2014b). Emissions reduction fund: Overview. Canberra, Australia.

[102] Hunt, G. & Macfarlane, I. (2015). 'Certainty and growth for renewable energy', Media Release. Canberra, Australia.

Growth in renewable generation and falling electricity demand have caused a decline in coal-fired generation, especially black coal. In 2014, renewable sources provided 15.1% of Australia's electricity[103].

Short-term and spot markets for natural gas have existed in the state of Victoria since 1999, but only since 2010 and 2011 in Sydney, Adelaide, and Brisbane. In 2014, average spot prices for natural gas were approximately A$4/GJ (US$5.92/MMBTU), and were A$2.5/GJ (US$3.70/MMBTU) in Brisbane. Liquefied natural gas became Australia's third largest export in 2014, with major export terminals approaching completion. Future gas prices are expected to rise and be linked with international LNG prices in the future[104].

4.1.2 Environmental Regulations

Australia has robust permitting and environmental protection legislation[105]. Environmental assessment is part of the site permitting process and includes provisions for environmental impact statements; land, water, and air contamination; threatened species; noise and waste management; materials transport; and remediation standards and insurance. Permitting and enforcement are typically conducted by state and territory authorities, but recent legislation has made certain environmental issues federal concerns.

In Australia, mineral rights are wholly owned by the Australian States and Territories. The governments of those states and territories may grant companies extraction and disposal rights subject to royalties for the state and territory governments and taxes at multiple levels of governance. In all states, companies are subject to special regulations for mining activities and environmental protection. Companies must obtain tenements for exploration, production, and retention of minerals as well as environmental authorities for environmentally relevant activities, subject to state level mining and environmental protection departments.

The Environmental Protection and Biodiversity Conservation (EPBC) Act 1999 brought certain environmental and heritage risks under federal jurisdiction due to their national significance. World Heritage Sites, offshore marine areas, and threatened species are protected under the EPBC Act. In 2013, the EPBC Act was amended to reprioritise water resources as a matter of national environmental significance and to add water triggers to the coverage of the EPBC Act specifically for coal seam gas projects and large coal mining projects[106].

State-level water protection legislation establishes the process for licensing and regulating water resources. The Water Act 2007 established the Murray-Darling Basin Authority, to manage the water resources of the basin on behalf of the five states and territories it supplies. The pollution of water resources is prohibited by state environmental protection legislation. For offshore resources and coal seam gas and large coal mining projects, federal legislation prohibits the pollution of water resources.

Conventional air pollutants are managed by jurisdictional environmental protection departments according to National Environmental Protection Measures for air quality and air toxins[107]. No pollution abatement technologies are currently required for Australian power stations[108]. The Australian Academy of Technological Sciences and Engineering has estimated that the unabated emission of PM_{10}, SO_2, and NOx cost an additional A$2.6bn in health care a year[109].

[103] AER (2014) State of the Energy Market 2014. Melbourne, Austrlia.

[104] Ibid.

[105] For a summary, see Clifford Chance LLP (2013). Q & A on Environmental Law in Australia. London, UK.

[106] The Australian Government (2013). EPBC Amendment Bill 2013. Canberra, Australia.

[107] Standing Council on Water and Environment (2014). National Environment Protections Measures. Canberra, Australia. http://www.scew.gov.au/nepms.

[108] CSIRO (2012) Environmental Impact of Amine-based CO2 Post- combustion Capture (PCC) Process, Australian National Low Emissions Coal Research and Development Project. Canberra, Australia.

[109] The Australian Academy of Technological Science and Engineering (2009). The hidden costs of electricity. Melbourne, Australia.

4.1.3 CPT Developments

Despite being the world's largest coal exporter, Australia imports 40% of its oil and oil products[110]. Monash Energy CTL Project, jointly supported by Anglo Coal and Shell, the Arckaringa CTL Power Project, proposed by Altona Energy, and Chinchilla UCG trial by Linc Energy,[111] are the chief demonstration CPT projects in Australia. The Monash Energy project is based on a long-term plan for converting brown coal resources to cleaner liquids[112]. Although the Arckaringa project was originally proposed as a CTL project, a new feasibility study shows that decreasing power demand in the South Australian grid has made funding of the project difficult[113]. A new Coal to Methanol (CTM) Plant is proposed alongside the CTL project to overcome funding restrictions and to produce commercially valuable methanol.

Operating the first commercially successful pilot UCG plant in Chinchilla, Linc Energy originally was founded in 1998 as a joint venture company with CS Energy, a government-owned company in Queensland to develop UCG for power generation[114]. After developing the UCG process and before commercialisation, CS Energy sold its shares in the plant[115]. In 2013, Linc Energy ceased its operations in Chinchilla, citing regulatory uncertainty in Queensland, which favoured the rival CSG sector over UCG[116], and high costs[117] of working in Australia. The company is also facing liabilities up to A$32.5m for environmental harm caused at this UCG plant[118]. On the other hand, Altona Energy PLC regained full ownership of the Arckaringa CTL Project after ending its joint venture partnership with CNOOC New Energy in in 2014, and later entered into another partnership with Sino-Aus Energy Group and Wintask Group Ltd, which would provide a maximum of A$33 million in the project[119].

4.1.4 Emerging issues

Changing attitudes to climate change

In the 2013 federal election, Tony Abbott's Liberals defeated Kevin Rudd's Labour Party. Repealing Australia's carbon tax was central to the campaign, a promise Abbott delivered in July 2014. Abbott has since been replaced as Prime Minister by Malcolm Turnbull after an internal party leadership vote in September 2015. Turnbull is recognised for having a progressive stance on climate change, but commentators have been sceptical as to whether the Australian government will adopt any policy changes under his leadership[120]. The next Australian federal election will be held on or before January 14, 2017.

Coal Seam Gas Opposition

Coal seam gas continues to attract opposition in parts of Australia, both from protestors[121] and legislators[122].

[110] Fraser, A. (2010). 'Underground coal gasification the next big thing in energy mix', The Australian Business Review. Brisbane, Austrlia.

[111] Ibid.

[112] MacDonald-Smith, A. (2008). 'Shell, Anglo to delay a $5 billion clean fuels project', Bloomberg.

[113] Altona Energy plc (2013). 'Australia: Altona Energy announces results of Arckaringa coal to methanol technical feasibility study', Energy-pedia News. St. Albans, UK.

[114] Fraser, A. (2010). Op. Cit.; Garcia, E. (2015). 'Underground coal gasification plant poisons community', greenleft weekly. Broadway, Australia.

[115] Garcia, E. (2015). Op. Cit.

[116] Validaki, V. (2013). 'Linc Energy dumps coal gasification project', Australian Mining.

[117] Garvey, P. (2013). 'Linc Energy calls it quits on UCG project', The Australian Business Review.

[118] Milman, O. and Evershed, N. (2015). 'Mining company being sued over gas leaks gave money to LNP and Labor', The Guardian.

[119] Unsted, S. (2015). 'Altona Energy agreement on Arckaringa amendment', Alliance News.

[120] e.g. Butler, M., (2015). 'Malcolm Turnbull's Faustian pact on climate change is heartbreaking' The Guardian.

[121] e.g. TM (2015). 'Stop coal seam gas banners', ABC.

[122] e.g. Gerathy, S. (2015). 'CSG bill: Shooters join NSW Government to kill off proposal', ABC.

Export Sensitivity

With a commodities-based export economy, Australian miners carry significant exposure to both commodity prices and policy and disaster risks all around the world. Examples include China's coal import tax, a bargaining chip imposed in October 2014 during free trade negotiations, and the Fukushima Daiichi nuclear accident. The former had severe impacts on Glencore PLC[123] and BHP Billiton PLC , and the latter caused a 35% drop overnight in the share price of Paladin Energy PLC, an Australian uranium producer[124]. Japan's change in energy policy post-Fukushima, however, proved to be a boon for Australian coal producers who provided 63% of Japan's enlarged post-Fukushima coal imports in 2014[125].

The Utility Death Spiral

A large country with dispersed populations, plentiful sun, and falling electricity demand spells the perfect storm for Australian utilities – see Box 2 The 'Utility Death Spiral'. In June 2015, the Australian Senate completed an inquiry into the performance and management of electricity network companies[126]. They address the problem of the utility death spiral directly and also highlight the moral hazard of delegating infrastructure responsibility to the network service providers[127]. The authors call on the regulator to take steps to prevent inefficiencies of the network operators and on governments to anticipate and respond to the utility death spiral in Australia.

Box 2: *The 'Utility Death Spiral'*

The 'Utility Death Spiral' describes the disruption to conventional power utility companies in Europe, North America, and elsewhere[128]. The 'spiral' is the virtuous cycle of distributed energy resources (e.g. rooftop solar PV) eroding the distribution network business model of the central utility, which in turn raises retail electricity prices making distributed energy resources even more competitive. A wider description also includes:

- Falling electricity demand caused by efficiency and retreat of electricity-intensive industries
- Intermittent renewables generate at peak load times when prices might be highest
- Low marginal cost centralised generation, especially renewables, receive grid priority, decreasing market prices and stranding conventional generation

Utilities exposed to the utility death spiral and related market forces face losses of profitability, lower credit ratings, and falling share prices. Specific observations on the utility death spiral are made in the appropriate countries' policy summaries.

4.2 China

4.2.1 *Climate Change and Energy Policy*

China is the world's second largest economy, and the largest producer and importer of coal. In November 2014, the Presidents of both China and the United States made a historic joint

[123] Paton, J. (2014). 'China Coal Tariffs Add to Pressure on Producers in Australia', Bloomberg.

[124] Pool, T. (2013). Uranium supply, demand & prices, International Nuclear Inc. Vienna, Austria.

[125] IEA (2015). Coal MTMR. Op. Cit.

[126] The Australian Senate (2015). Performance and management of electricity network companies, Environment and Communications References Committee. Canberra, Australia.

[127] In this case, the network service providers 'gold plated' their infrastructure investments, knowing that they would be better compensated for a larger asset base. The assets underperformed, due also in part to the utility death spiral, but the Australian taxpayer bore the costs – the moral hazard in question.

[128] CTI (2015). Coal: Caught in the EU Utility Death Spiral. London, UK.

announcement of cooperation to meaningfully address climate change[129]. China submitted its intended Nationally Determined Contribution (INDC) ahead of COP21 to the UN on June 30, 2015[130]. The INDC follows on substantial clean energy progress made by China under its 12th Five-Year Plan (FYP) (2011-15), its National Climate Change Plan, and its Air Pollution Prevention and Control (APPC) Law[131].

By 2014, non-fossil fuel primary energy supply had reached 11.2%. Solar and wind power capacity reached 28 and 95GW respectively, exceeding the initial outlooks of the 12th FYP. Between 2011 and 2015, growth in new-build coal-fired power stations fell from 9% to under 5%[132]. Since 2008, utilisation rates for thermal power stations has fallen from 60% to 54%[133]. Projected growth of renewables is shown in Table 16. Seven cap-and-trade pilot projects have also begun in Chinese cities, with a nationwide emissions trading scheme expected for 2017[134]. A wide range of mitigation and adaptation activities are underway in China[135].

Table 16: *China renewables targets 2017 from APPC*

	2014 Installed Capacity [GW][136]	2017 Target Capacity [GW]	CAGR
Hydro	301	330	4.5%
Wind	95	150	25.6%
Solar	28	70	58.1%

By the end of 2014, 19.9 GW of nuclear power had been installed in China, likely falling below the levels of investment necessary to achieve 50GW by 2017 as called for in the APPC. The installation of renewables has proceeded faster than necessary to achieve the 12th FYP – the growth projections to meet the APPC target are conservative.

Natural gas is being supported as an energy form which can displace carbon-intensive and air-polluting intensive coal. The EIA estimates that China has over 31 trillion cubic meters of technically recoverable shale gas – more than any other country[137]. In 2011 and 2012, China auctioned exploration rights for shale gas with mixed success, reducing shale gas subsidies in April 2015[138]. China is currently constructing four LNG regasification facilities and import contracts are expected to provide the mainstay of Chinese gas needs[139]. At the beginning of 2014, coal-to-gas projects producing 83 bcm per year of gas were approved. Reuters estimates China's gas demand in 2014 was 184 bcm[140].

Gas prices are set by the Chinese central government. The slowing of the Chinese economy to a 'new normal' has diminished recent gas demand, reduced LNG imports. The central government is expected to cut natural gas prices in the near future[141].

[129] The White House (2015). 'U.S.-China Joint Presidential Statement on Climate Change', Office of the Press Secretary. Washington, US.
[130] People's Republic of China (PRC) (2015). Enhanced actions on climate change: China's INDC, NDRC. Beijing, China.
[131] PRC (2013). Law on Air Pollution Prevention and Control, Clean Air Alliance of China. Beijing, China.
[132] Cornot-Gandolphe, S. (2014). China's Coal Market: Can Beijing tame King Coal? Oxford Institute for Energy Studies, University of Oxford. Oxford, UK.
[133] Myllyvirta, L. (2015). 'New coal plants in China – a (carbon) bubble waiting to burst', Greenpeace Energy Desk. London, UK.
[134] Hornby, L. (2015). 'Doubt cast over start of China emissions trading scheme', The Financial Times.
[135] See NDRC (2015). China's Policies and Actions on Climate Change. Beijing, China.
[136] National Energy Board (2015). National Electric Power Industry Statistics. Beijing, China.
[137] US Energy Information Agency (EIA) (2015). Technically recoverable shale oil and gas resources: China. Washington, US.
[138] Guo, A. (2015) 'China cuts subsidies for shale gas developers thoruhg 2020', Bloomberg.
[139] Global LNG Ltd (2015). World's LNG Liquefaction Plants and Regasification Terminals. London, UK.
[140] Hua, J. & Rose, A. (2015). 'China's sputtering economy crimps gas demand, cuts spot LNG buys', Reuters. Beijing, China.
[141] Tham, E. (2015). 'China plans up to 30 pct cut in natural gas prices', Reuters. Shanghai, China.

4.2.2 Environmental Regulations

Historical reliance on coal for domestic and industrial energy supply has caused crisis-levels of conventional air pollution in China. For a period between 2008 and 2014, China Real Time found that air pollution levels in Beijing exceeded unhealthy levels for sensitive individuals at least 50% of the time (by Chinese standards)[142]. Chinese Premier Li Keqiang 'declared war' on pollution in 2014, and Chinese policy has followed.

Chinese policy actions like the 12 FYP and the APPC address conventional air pollution levels and carbon pollution simultaneously. Beyond the decarbonisation measures above, the APPC banned the import of high-ash and high-sulphur content from January 2015 and expanded coal washing to 70% by 2017. In the regions of Beijing-Tianjin-Heibei, Yangtze River Delta, and Pearl River Delta, coal consumption is capped and expected to decline, all heavy industries and coal-fired power stations must be fitted with flue-gas desulphurisation, and urban and suburban zones will be banned from consuming coal from 2020 onwards.

Responsibility for environmental protection in China is complex. The Environment and Resources Protection Commission (ERPC), Ministry of Land and Resources (MLR), and Ministry of Environmental Protection (MEP) all have national coverage and provincial and sub-provincial offices. These offices are not directly subordinate to national level authorities, and establish their own jurisdiction, monitoring, and enforcement conventions in each area [143]. In April 2014, a new law was passed which establishes more stringent rules for environmental enforcement, but does little to resolve power and coordination problems in the vertical and horizontal relationship of Chinese environmental enforcement organisations [144].

China faces severe water scarcity and quality challenges. In 2010 the State Council issued a policy intention to establish 'three red lines': standards for water use efficiency, minimum water quality, and total aggregate use[145]. After efficiency targets in consecutive FYPs, and the world's largest river diversion project[146], Chinese urban water prices were substantially reformed in 2014 – for execution by the end of 2015. In January 2014, the Ministry of Water Resources (MWR) issued a guidance for water reform which indicated that water pricing would move towards a market mechanism[147]. A month earlier, the MWR announced a plan which would not allow the development of large coal bases to threaten water resource availability[148].

4.2.3 CPT Developments

China plans to build 50 CTG plants in less populated northwestern parts of the country – 80% of new CTG plants will be in provinces or regions of Xinjang, western Inner Mongolia, Ningxia and Gangsu[149]. Shrinking profits in the coal sector and demand for clean energy products have been major force in China's coal conversion projects[150]. In 2013, the country was assessed to have a natural gas shortage[151] of 22 billion m^3, however, it is coal-rich[152].

[142] Wayne, M. & Chen, T. (2015). 'China's bad air days, finally counted', The Wallstreet Journal. Beijing, China.
[143] Zhang, B. & Cao, C. (2015). 'Policy: Four gaps in China's new environmental law', Nature 517:433-434.
[144] PRC (2014). People's Republic of China Environmental Protection Law. Beijing, China.
[145] Moore, S. (2013). 'Issue Brief: Water Resource Issues, Policy and Politics in China', The Brookings Institute.
[146] Aibing, G. (2015). Op. Cit.
[147] Ministry of Water Resources (MWR) (2014). 'Ministry of Water Resources on deepening the reform of water conservation', China Water Resource News.
[148] Yongjing, W. (2014). 'MWR of the General Office on efforts to develop water resources planning', MWR. Beijing, China.
[149] IER (2014). Op. Cit.
[150] Liu, C. (2015). 'Chinese companies plunge into coaltoliquids business, despite water and CO2 Problems', ClimateWire. Yulin, China; Xu, J. et al. (2015). Op. Cit.
[151] Li, H., Yang, S., Zhang, J., et al. (2016). 'Coal-based Synthetic Natural Gas (SNG) for Municipal Heating in China', Journal of Cleaner Production 112:1350-1359.
[152] Bai, J. & Aizhu, C. (2011). 'China Shenhua coal-to-liquids project profitable –exec', Reuters. Tianjin, China.

Since 2010, a number of CTL and CTG demonstration projects have been implemented, and many are due to be expanded. Moreover, a Chinese firm, Shenhua Group, is collaborating with the highly experienced South African firm Sasol on a CTL project[153]. Over the past 20 years, international and local gasifier vendors have been competing to licence their technology for use in China – the biggest international companies include Shell, Siemens GSP, General Electric Energy, and Lurgi. China is expected to reach a capacity of 310,000 bbl/day of CTL and CTG by 2016[154].

In China, leading power generation companies, such as Datang, China Guodian Corporation and China Power Investment, and other major state-owned oil and gas companies – China National Petroleum Corporation (CNPC), Sinopec and China National Offshore Oil Corporation (CNOOC) – have shown great interest in the coal conversion sector[155]. Most of funding for these projects comes from subsidies given by local governments and loans from the Chinese Development Bank, which offers RMB50 billion for four to five coal conversion projects until 2018[156]. However, regulatory uncertainties surrounding CTG/CTL projects in China have affected investment in the coal conversion sector; in particular the Chinese government's concerns about overcapacity and the environmental impact of a loosely regulated sector have slowed down the approval of these projects[157]. Moreover, their economic profitability has shrunk due to falling returns in the power business, and high technical and other operational costs.

4.2.4 Emerging Issues

Domestic Coal Production Tax and Moratorium

Small-scale coal mining operations grew rapidly in the 1980s with a lasting legacy of local pollution and enforcement challenges. Chinese policymakers have been attempting to reduce small-scale mine operations, shutting 1,725 such mines in 2014, and preferring to consolidate coal production in large-scale remote 'coal bases'[158]. In January 2015, a nationwide value-added tax on coal production was introduced. Local governments enforced a rate of 2% to 8% to reduce reliance on land sales for government revenue[159].

At the end of 2015, China issued a moratorium on approvals for new coal mines. From 2016 to 2018, no new coal mines will be approved. It also plans to close another 1,000 mines in 2016[160].

Conventional Air Pollutants

China continues to take a strong stance on the mitigation of conventional air pollutants, mitigating health and environmental impacts. By 2012, 680 GW of the country's 826 GW of coal-fired power had been fitted with flue gas desulphurisation technology[161]. Imports of high ash and high sulphur coal were banned in 2015[162]. China may seek additional options for decreasing conventional air pollutants, which will impact both end-users of coal in China and their global suppliers.

[153] Ibid.

[154] Perineau (2013). Op. Cit.

[155] The Economist (2014). "Coal gasification in China: Unconverted", The Economist.

[156] Cornot-Gandolphe, S. (2014). Op. Cit.

[157] The Economist (2014). Op. Cit.

[158] Stanway, D. (2014). 'China to close nearly 2000 small coal mines', Reuters. Beijing, China.

[159] Stratfor (2015). 'China Imposes a new Coal Production Tax', Stratfor Global Intelligence.

[160] Bloomberg News (2015). 'China to halt new coal mine approvals amid pollution fight', Bloomberg.

[161] McIlvaine Company (2012). Flue Gas Desulfurization, Denitration Industry for Coal-fired Power Plants in 2012. http://www.mcilvainecompany.com/Decision_Tree/new%20chinese%20fgd.htm

[162] Wong, F. (2014). 'China to ban imports of high ash, high sulfur coal from 2015', Reuters. Shanghai, China.

Emerging Water Stress

China's actions to mitigate water stress may have large implications for the coal industry as its massive coal bases are being built in areas of high water stress (see Section 5.2.1). A recent PNAS study finds that water is being exported from these areas both physically and virtually in the embedded water of products made in these areas[163]. China may face difficult policy decisions as water stress impacts coal productivity.

4.3 Germany

4.3.1 *Climate Change and Energy Policy*

Germany is a founding member of the European Union (EU) and is the fourth-largest economy in the world. Germany imports and produces coal in roughly equal proportions, ranking seventh in the world for total primary energy supply of coal. As a member of the EU, Germany has binding climate targets and is a signatory of the Kyoto Protocol. See Box 3 for climate change and renewable energy policy elements common to all EU member states.

Box 3: *European union common measures*

The EU takes coordinated action on certain policy matters like climate change. The EU Emissions Trading Scheme (ETS) was established by EC Directive 2003/87/EC. The EU ETS covers approximately 45% of the EU's emissions, mostly from large stationary sources (e.g. power plants, industry), and commercial aviation. As a cap-and-trade mechanism, EU member states receive decreasing emissions quotas which they allocate or auction to their domestic emitters. The ETS is the main policy tool designed to achieve the EU's target of 20% GHG reductions below 1990 levels by 2020. The EU ETS was also designed to accommodate the flexibility mechanisms of the Kyoto Protocol, which were synchronised with the EU ETS (2004/101/EC).

Now in its third phase of coverage and allocation iterations, the price of an emissions allowance (1 tonne of CO_2e) has fallen since 2008 from €20-30/t to less than €10/t in 2015. The fall in prices is generally believed to be caused by an over-allocation of emissions allowances and slow growth[164]. Combined with the increasing difference in spark spread between gas and coal-fired power, the fall in carbon price had the opposite of the desired effect. New gas-fired power stations were stranded at the high end of the merit order and old coal-fired generation assets had their lives extended[165].

The Renewable Energy Roadmap of 2007 set an EU-wide policy target of 20% greenhouse gas (GHG) reductions on 1990 levels by 2020, to have 20% of all primary energy provided by renewables, and to achieve 10% biofuel use. These targets were passed on to member states in the 2009 Renewable Energy Directive (2009/28/EC) and associated Effort Sharing Decision (406/2009/EC). EU member states have different targets under the directive.

In its INDC, the EU has committed to emissions reductions of 40% below 1990 levels by 2030. Member states have enacted the EU directives and their own climate and energy policies, which are discussed in the appropriate sections.

[163] Zhao, X. (2015). Physical and virtual water transfers for regional water stress alleviation in China, Proceedings of the National Academy of Sciences (PNAS) 112: 1031-1035.

[164] Oliver, C. & Clark, P. (2015). 'EU plan to revive lifeless carbon market', The Financial Times. London, UK and Brussels, Belgium.

[165] Caldecott, B. & McDaniels, J. (2014). Financial Dynamics of the Environment: Risks, Impacts, and Barriers to Resilience, Smith School of Enterprise and the Environment, University of Oxford. Oxford, UK.

The AGEB reports that since 2009, wind, biomass, and photovoltaic power have grown at 9%, 10%, and 42% respectively, displacing nuclear and gas-fired power[167]. In 2014, 25.8% of Germany's power came from renewable sources. Coal power consumption has remained relatively constant, providing approximate 43% of the country's power. According to its National Action Plan drawn up in response to the Renewable Energy Directive, Germany expects to exceed its target reduction by 2020, achieving 19.6% of all primary energy from renewable sources, with 38.6% of all electricity generated renewably[168].

The German energy transition, the *Energiewende*, has existed in name since the 1980s, however it became a mainstream state policy in September 2010 with the publication of the government's future energy concept[169], a policy plan which described the transition away from nuclear and coal power with the uptake of renewables, efficiency, and flexibility. Under this plan, nuclear power was called a 'bridging technology' and the lives of Germany's nuclear power fleets were to be extended up to several decades. However, faced with public unrest about nuclear power after the Fukushima accident in Japan, the government announced a moratorium on nuclear power generation. The closure of nuclear power was reprioritised in the *Energiewende* and Germany carbon emissions through the early 2010s remained relatively constant as renewables displaced nuclear power instead of coal[170]. 8.4GW of nuclear power generation were phased out by 2011, and 12.5GW are expected to be phased out between 2015 and 2022[171].

The German electricity market is dominated by the Big Four: RWE, EnBW, E.ON, and Vattenfall. In 2013, RWE and Vattenfall, with the two largest generating fleets in Germany, posted losses of US$3.8bn and $2.3bn respectively, see the 'Utility death spiral' in Box 2. Share prices of the Big Four have fallen accordingly and E.ON has split into two companies. E.ON's nuclear and fossil fuel fleet will go to new subsidiary Uniper, while E.ON's renewable and smart-energy interests will remain under the former brand[172].

In response to the death spiral (see Box 2), utilities have been curtailing base-load capacity investments. Governments and regulators are considering market reforms to ensure sufficient generation capacity is available to prevent shortfalls. In Germany, the government has decided to enact market reforms rather than a capacity market[173]. A capacity reserve however, may act as a 'retirement plan' for German lignite power stations which would have otherwise faced a steep emissions penalty and would have been retired early by principal operators RWE and Vattenfall[174].

4.3.2 Environmental Regulations

Germany is a developed country with strong environmental regulations. As an EU member state, Germany's environmental policy is harmonised with that of the greater EU, see Box 4.

Box 4: *European Common Environmental Policy*

> The EC's 7th Environmental Action Programme (1386/2013/EU) binds member states to the protection of air, water, soil, health, climate, and biodiversity, with collective goals for the period of 2014 to 2020.

[166] European Commission (2008). 'Annex – Germany' in Environment Policy Review. Brussels, Belgium.

[167] AG Energiebilanzen e.V. (2015). Bruttostromerzeugung in Deutschland ab 1990 nach nergieträgern. Berlin, Germany.

[168] Federal Republic of Germany (2009). National Renewable Energy Action Plan in accordance with Directive 2009/28/EC on the promotion of the use of energy from renewable sources. Berlin, Germany.

[169] BMWi (2010). Energy Concept. Berlin, Germany.

[170] Appunn, K. & Russell, R. (2015). 'Germany utilities and the Energiewende', Clean Energy Wire.

[171] Heinrich Boll Foundation (2015). Energy Transition. http://energytransition.de/ .

[172] Steitz, C. (2014). 'German utility E.ON to split focus on renewables, grids', Reuters. Frankfurt, Germany.

[173] BMWi (2014). An Electricity Market for Germany's Energy Transition. Berlin, Germany.

[174] Argus Media Ltd, (2015). 'Germany shelves climate levy for lignite reserve', Argus Media. London, UK.

The Environmental Impact Assessment Directive (2014/52/EU) requires the developers of any public or private project to complete an assessment of a wide range of potential environmental and human impacts of their project. Member states may refuse development consent on the basis of the submitted environmental impact assessment.

The EU Water Framework Directive (2000/60/EC) requires member states to manage water resources in their countries sustainably. Member states must monitor and manage all water use in their jurisdictions, reducing and remediating pollution, restoring ecosystems, charging polluters equitably for their use of ecosystem services, and ensuring sustainable access to water for individuals and businesses.

The Industrial Emissions Directive (2010/75/EU) requires member states to control pollutant emissions from large industrial sources in an integrated way, simultaneously protecting air, water, and land emissions. The directive contains special provisions for power plants. In a practical sense, all European coal-fired power stations must be fitted with flue gas desulphurisation, or must trade emissions permits or close by 2023[175].

The Environmental Liability Directive (2004/35/EC) establishes liability for organisations whose businesses cause harm to the environment or environmental resources. Organizations are always liable for specified activities which cause grievous environmental harm (e.g. release of heavy metals) and are more generally liable for environmental damage if they are found to be negligent or at fault.

In 2010, EU member states reached a decision (2010/787/EU) to phase out state aid to uncompetitive coal mines. The EU requires that all state aid to coal mining cease by 2018.

The German public and legislators have taken a cautious approach to hydraulic fracking for natural gas, waiting for sufficient evidence to demonstrate its health and environmental safety. Hydraulic fracturing for gas in Germany is effectively banned through to 2018[176].

4.3.3 Emerging Issues

4.3.3.1 Lignite generation in the capacity reserve

The creation of the capacity reserve has been criticised for its targeted support of Germany lignite assets. Critics argue that the reserve will protect the jobs of lignite miners and the profitability of lignite operators, delaying the transition away from emissions-intensive coal. Some commentators have questioned whether the capacity reserve is an illegal subsidy to the plant operators, or whether the capacity reserve will suppress electricity prices and prevent additional capacity investment.

4.4 Indonesia

4.4.1 Climate Change and Energy Policy

Indonesia is the world's largest exporter of coal, mostly to China. Summaries of Indonesia's current and expected electricity consumption are available from the IEA[177] and Indonesia's primary utility[178], the PT PLN.

[175] Sloss, L. (2009). Legislation in the European Union and the impact on existing plants, IEA Clean Coal Center. London, UK.
[176] Copley, C. (2015). 'Germany sets very high bar for fracking ', Reuters. Berlin, Germany.
[177] The Differ Group (2012). The Indonesian electricity system - a brief overview. Oslo, Norway.
[178] Sakya, I. (2012). Electricity Power Development in Indonesia, PT PLN. Jakarta, Indonesia.

Indonesia's power generation is expected to grow 9% through to 2019, leading economic growth of 6%. By the end of 2011 Indonesia had achieved an electrification rate of 74%, with 85% of the power coming from the state-run company PLN. Renewable and non-renewable off-grid power also provides electricity to approximately 2% of the population. Growth in renewable power generation through 2020 for southeast Asia is shown in Table 17.

Table 17: *Renewable power growth in Southeast Asia to 2020*[179]

Source	CAGR
Hydro	1.1%
Geothermal	5.1%
Bioenergy	12%
Wind/Solar	29%

Among southeast Asian countries, Indonesia has notable geothermal and hydro power resources, and marginal wind resources. Renewable energy is expected to grow from 11% of all grid-connected power generation in 2011 to 19% in 2020. Coal power generation in the same period is expected to grow from 90 TWh to 233 TWh, driven by economic growth and displacing diesel power.

Over half of the investment in new generation assets in Indonesia by 2020 is expected to be provided by independent power producers. The PLN has a regulated monopoly on the transmission and distribution of electricity, with the right-of-first-refusal on the sale of electricity as well. The PLN is obligated to purchase power on feed-in-tariffs which differ according to technology and region, the maximum of which is US$0.30 for solar PV[180]. While the Indonesian government has been reducing subsidies for liquid fuels, the operating budget of the PLN receives direct support from the Ministry of Finance, amounting to a subsidy of 40% of the value of a kWh.

While coal power capacity is expected to grow in Indonesia, PLN has prioritised high-efficiency boilers for its planned generating capacity increases. 2GW of supercritical coal-fired generating capacity were expected for completion before 2015, and 11GW of ultra-supercritical coal-fired generating capacity are expected before 2020[181]. PLN's fleet currently includes 18GW of subcritical coal-fired generating capacity, one third of which burns lignite, the other two sub-bituminous coal.

The IEA has drawn attention to the growing reluctance of international financial institutions to finance coal-fired power stations (e.g. the World Bank, the US Treasury[182]). Independent power producers are expected to provide over half of the generation additions to 2020, but Indonesia may have difficulty attracting foreign investment to finance these additions. The shortfall may be made up by investment from China.

The IEA estimates that under a variety of pricing scenarios, combined cycle gas turbines in southeast Asia are unlikely to be competitive with supercritical coal-fired power.

[179] IEA (2015). Southeast Asia Energy Outlook 2015. Paris, France.
[180] Halstead, M., Mikunda, T., & Cameron, L. (2014). Policy Brief: Indonesian Feed-in-Tariffs, MitigationMomentum. Amsterdam, Netherlands.
[181] Sakya, I. (2013). Current Status and Future Development of Coal Thermal Power Plant in Indonesia, PT PLN. Tokyo, Japan.
[182] US Department of the Treasury (2013). 'U.S. Takes A Significant Step Toward A Clean Energy Future', Press Center. Washington, US.

4.4.2 Environmental Regulations

Businesses wanting to conduct activities which will impact the environment in Indonesia must conduct an environmental impact assessment (ADMAL) and an environmental management and monitoring plan (UKL-UPL) to receive an environmental licence from the Ministry of Environment[183]. In order to receive a licence, funds to guarantee environmental remediation must be paid to the ministry. The Ministry of Environment and subsidiary regional and local authorities are poorly coordinated and lack the resources to perform their current functions. The ministry relies on companies to self-report their compliance, and even under self-reporting, less than half of the companies comply with air, water, and land pollution regulations[184].

Businesses wanting to mine coal or minerals may obtain a (special) mining business permit (IUP(K)) for either exploration or operation from the Ministry of Energy and Mineral Resources. From 2012 to 2015 the coal and mining industry have been subject to a series of reforms, see a summary by Ashurst and Oentoeng Suria & Partners[185]. Mining companies have been given legal limits to foreign ownership and progressive divestment requirements through operational life. An export ban has been imposed on raw materials, requiring in-country processing and upgrading to stimulate Indonesian development. For coal this restriction may manifest itself in calorific upgrading but the details are as yet uncertain. Finally, a cap on total coal exports has been imposed.

Indonesia is well endowed with renewable water resources, having the fifth most renewable fresh water per capita in the world[186]. However highly populated areas of Java face water shortages in the dry seasons. Water scarcity is most acute on the island of Java, where 60% of Indonesia's population consumes 50% of all irrigation water. By 2020, the islands of Java, Bali, and Nusa Tenggara will all have dry season deficits.

Water planning is administered by the Ministry of Public Works. Industrial water excluding agriculture accounted for 24.6km^3 in 2005, approximately 5% of all of Indonesia's water use[187]. In February 2015, Indonesia's Constitutional Court overturned legislation which gave private interests powerful access rights to water resources[188].

4.5 India

4.5.1 Climate Change and Energy Policy

India is a large producer, importer, and consumer of coal. The Ministry of Power summarises the state of energy development in India[189]. In 2015, 24% of India's population did not have basic access to electricity[190], and those that did were subject to capacity shortfalls. India has aggressive plans for renewable energy deployment but currently plans for coal-fired power to support much of its ongoing growth. India is targeting a large increase in coal electricity generation[191], but is hindered by high transmission and distribution losses (20% to 30%), power theft, and coal shortages.

[183] World Services Group (2012). New Regulation on Environmental Licenses in Indonesia. http://www.worldservicesgroup.com/publications.asp?action=article&artid=4501.

[184] Li, W. & Michalak, K. (2008). Environmental Compliance and Enforcement in Indonesia, Asian Environmental Compliance and Enforcement Network. Bangkok, Thailand.

[185] Prior, S. & Riffdann, R. (2014). Indonesian Mining Law Update, Ashurst LLP and Oentoeng Suria & Partners LLP. Singapore and Jakarta, Indonesia.

[186] Hadipuro, W. (2010). 'Indonesia's Water Supply Regulatory Framework: Between Commercialisation and Public Service?', Water Alternatives, 3:475-491.

[187] Knoema (2015). World Data Atlas, Indonesia – Industrial Water Withdrawal, http://knoema.com/atlas/Indonesia/topics/Water/Water-Withdrawal/Industrial-water-withdrawal.

[188] Sundaryani, F. (2015). 'Court bans monopoly on water resources', Jakarta Post. Jakarta, Indonesia.

[189] Ministry of Power (2015). Power Sector – At a glance, http://powermin.nic.in/power-sector-glance-all-india. New Delhi, India.

[190] Australian Government (2015). Op. Cit.

[191] Das, K. (2015). 'India aims for big coal output boost next fiscal year', Reuters. New Delhi, India.

In June 2008, India's government released the first National Action Plan on Climate Change. The plan detailed eight 'missions' which would form the core of India's response to climate change, ranging from renewable energy to the built environment[192]. The Jawaharlal Nehru National Solar Mission was launched in January 2010 to deploy solar power across India. The mission supports long-term policy, domestic production, large-scale installations, and research and development to achieve 20GW of installed capacity by 2022 and grid parity in the same year[193]. In the 2015-16 Union budget, the 2022 target for solar power was increased to 100GW as well at 60GW of wind power and 10GW of other renewables[194]. The Climate Policy Initiative[195] estimates that onshore wind power has already reached grid parity with Indian coal-fired power, and solar power will reach grid parity by 2019.

India currently has 173GW of coal-fired and 24GW of gas-fired power capacity[196]. It still has an overall deficit of power generation, although that deficit has fallen to less than 5% since 2013. India currently has 36GW of renewable power capacity, of which 24GW are wind-generated and 4GW by solar. In their INDC, India projects that 40% of its power will be derived from non-fossil sources by 2040, and commits to shrinking emissions intensity per unit of GDP by 33% to 35% by 2030[197].

The IEA projects that coal-fired power will be critical for India's endeavours to provide electricity for its population and meet growing demand[198]. In 2015, 113GW of coal-fired generation capacity were in construction or planned. Approximately half of all capacity additions before 2017 are expected to employ supercritical combustion, after which it becomes mandatory. Supercritical combustion requires high-calorific value, low-ash coal, while Indian reserves are mostly low-quality, high-ash. India would have to rely on imports to provide this coal despite ambitious domestic production programmes targeting self-sufficiency[199].

Despite a strong outlook at the beginning of the decade, India's total primary energy demand for natural gas has grown slowly, from 8% in 2008 to 8.7% in 2012[200]. The country faces an ongoing deficit of natural gas, with domestic production too low and LNG import prices too high for end-users. Four LNG regasification terminals are currently on-stream, with another four in construction or planning[201], but gas use will remain limited by domestic distribution infrastructure. Market prices and recently-revised state production prices are too high to allow gas-fired power to compete with coal-fired power.

4.5.2 Environmental Regulations

The Environmental Protection Act 1986 gives the government of India broad scope to protect the environment and acts as an umbrella for issue-specific legislation on water, air, forests, wildlife, and biodiversity protection. The Ministry of Environment, Forest and Climate Change issues environmental clearances based on Environmental Impact Assessments conducted according to regulations issued under the Environmental Protection Act. Like other emerging economies, India has challenges enforcing its environmental protections, caused by a lack of resources, inappropriate legal structures, and corrupt reporting[202].

[192] PEW Center (2008). National Action Plan on Climate Change, Government of India. Arlington, US.

[193] Ministry of New and Renewable Energy (2014). JNN Solar Mission. http://www.mnre.gov.in/solar-mission/jnnsm/introduction-2/.

[194] Nampoothiri, M. (2015). 'Union Budget 2015 - Highlights for the Indian Solar Sector', Intel Solar India.

[195] Shrimali, G., Srinivasan, S., Goel, S., et al. (2015). Reaching India's Renewable Energy Targets Cost-Effectively, CPI and Bharti Insistute of Public Policy. Mohali, India.

[196] Ministry of Power (2015). Power Sector at a Glance ALL INDIA. http://powermin.nic.in/power-sector-glance-all-india

[197] Government of India (2015). India's Intended Nationally Determined Contribution. New Delhi.

[198] IEA (2015). WEO 2015. Op. Cit.

[199] Australian Government (2015). Op. Cit.

[200] EY (2014). Natural gas pricing in India. New Delhi, India.

[201] Global LNG Ltd (2015). Op. Cit.

[202] OECD (2006). Environmental Compliance and Enforcement in India: Rapid Assessment. Hanoi, Vietnam.

Water resources in India are governed by a patchwork of legislation and regulations, some issued by the Ministry of Water Resources, River Development & Ganga Rejuvenation, and others by state and local governments[203]. Industries in India draw water from both ground and surface sources, but these two sources have different legal interpretations, further exacerbating resource mismanagement[204 205]. 89% of all water use is for irrigation purposes; only 4% of water is used by industry[206]. Indian coal will need to be washed to upgrade it to the quality required for supercritical combustion, adding significantly to the water consumption of the fuel[207].

In April 2015, the Ministry of Environment, Forestry, and Climate Change proposed new regulations under the Environment Protection Act. These require cooling technology upgrades and water intake limits, and proposes SO_2, NO_x, and Hg limits in India for the first time[208].

4.5.3 CPT Developments

Several less-developed projects are being considered[209]. A 2015 study showed that the country's commercial energy requirement will increase four to five times by 2032, electricity generation requirements would increase six to seven times, and oil demand would increase three to six times from current levels. UCG was put forward as a potential solution to projected growth in energy demand, as it would allegedly allow inaccessible and uneconomical coal reserves to be utilised. India has almost 300,000 billion tonnes of geological reserves of coal – but over 120,000 billion tonnes of these are deeper than 300 metres. It has been argued that UGC has the potential to bring these reserves into service[210]. Coal India Limited is proposing UCG plants for Katha (Jharkhand) and Thesgora (Madya Pradesh) area[211]. Additional UCG pilot projects in West Bengal and Rajasthan have been initiated by the Oil and Natural Gas Corporation Ltd (ONGC) and the Gas Authority of Indian Ltd.[212]

4.6 Japan

4.6.1 Climate Change and Energy Policy

Japan is the world's third-largest economy and relies almost exclusively on imported fuel. Japan has been the world's largest importer of LNG since the 1990s[213], and is second only to China in coal imports, with no domestic production.

On the March 11th, 2011, Tohoku earthquake and tsunami occurred off the Eastern coast of Japan severely damaging the reactors of Fukushima Daiichi Nuclear Power Plant. The tsunami destroyed back-up generators for cooling equipment, and nuclear meltdowns occurred in the worst nuclear disaster since Chernobyl in 1986. In response, the government suspended 26GW of Japan's 49GW of nuclear reactors, a decision which has had a profound impact on the development of Japan's energy mix[214].

[203] Cullet, P. (2007). Water Law in India, International Environmental Law Research Center. Geneva, Switzerland.

[204] Preveen, S., Sen, R., & Ghosh, M. (2012). India's Deepening Water Crisis? Columbia Water Center, Columbia University. New York, US.

[205] Aguilar, D. (2011). Groundwater Reform in India: An Equity and Sustainability Dilemma, Texas International Law Journal 46:623-653.

[206] KPMG (2010). Water sector in India: Overview and focus areas for the future. Delhi, India.

[207] IEA (2015). WEO 2015. Op. Cit.

[208] Ministry of Environment, Forestry, and Climate Change (2015). Environment (Protection) Ammendment Rules, 2015. New Delhi, India.

[209] Perineau (2013). Op. Cit.

[210] Khadse, A. (2015) 'Resources and Economic Analyses of Underground Coal Gasification in India', Fuel 142: 121–128.

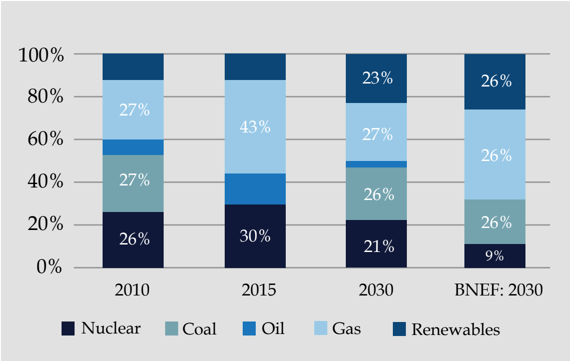
[211] Future Market Insights (FMI) (2015). Underground Coal Gasification Market: Asia-Pacific Industry Analysis and Opportunity Assessment 2014-2020. Pune, India.

[212] Khadse, A., Qayyumi, M., Mahajani, S., et al. (2007). 'Underground Coal Gasification: A New Clean Coal Utilization Technique for India', Energy 32: 2061-2071.

[213] International Gas Union (2014). World LNG Report – 2014 Edition. Vevey, Switzerland.

[214] Berraho, D. (2012). Options for the Japanese electricity mix by 2050, MSc Thesis, KTH School of Industrial Engineering and Management. Stockholm, Sweden.

Figure 21: *Japanese generating mix*[215]



Japanese utilities turned to fossil fuels to make up for the generation shortfall. The transition caused a jump in the Japanese retail price of electricity – a 25% and 40% increase over 2010 for residential and industrial prices respectively[216]. In response to the nuclear accident, LNG imports grew 24% between 2010 and 2012. Asian LNG prices rose over 50%, falling only recently with the drop in oil price[217].

In 2012, Japan introduced a generous feed-in-tariff scheme which, combined with high retail prices, led to a rapid expansion of PV capacity, reaching over 24GW of solar capacity by mid-2015, up from 5GW before the FIT scheme started[218]. The subsidy was reduced gradually and in 2014 the government indicated that it would begin to re-open nuclear power stations[219]. Japan's solar growth finally slowed in Q2 2015, however it will remain one of the largest PV markets in the world[220]. Japan's current generating mix and the government's proposed future generating mix are shown in Figure 21. BNEF projects nuclear generation will not recover to the extent the government predicts, rather that the shortfall will be provided by gas[221].

In its INDC, Japan has committed to reducing greenhouse gas emissions by 25.4% below 2005 levels by 2030[222]. Japan's GHG emissions in 2013 were 1408 $MtCO_2e$, up from 1304 $MtCO_2e$ in 2010 largely due to a re-carbonisation of energy in the aftermath of the Fukushima Daiichi disaster[223]. Japan also has two regional cap-and-trade systems, in Tokyo and Saitama[224], and a carbon tax on liquid fuels, LPG, LNG, and coal[225].

4.6.2 Environmental Regulations

Japan has a robust framework of environmental law, regulations, and permitting[226]. The Basic Environmental Law of 1993 established Japan in a modern era of environmental management, building on earlier laws for pollution control and nature conservation. The Environmental Impact Assessment Law requires large projects including power stations to conduct an extensive environmental impact assessment prior to construction consent.

The Water Pollution Control Law protects all Japanese freshwater resources, regulating industrial effluents either by concentration or volume. The Air Pollution Control Law established controls on conventional air pollutants including SO_2, NO_x, and PM. Japan has taken strong measures to control

[215] Iwata, M. & Hoenig, H. (2015). 'Japan Struggles to Find Balanced Energy Strategy', Wall Street Journal. Tokyo, Japan.
[216] Jiji Press (2015) 'Nuclear power plant restarts part of wider plan to meet 2030 'best energy mix', The Japan Times.
[217] Bradley, S. & Zaretskaya, V. (2015). 'Natural gas prices in Asia mainly linked to crude oil, but use of spot indexes increases', EIA Today in Energy. Washington, US.
[218] Tsukimori, O. (2015). 'Solar power supplies 10 percent of Japan peak summer power: Asahi', Reuters. Tokyo, Japan.
[219] Topham, J. & Sheldrick A. (2014). 'Future grows darker for solar energy growth in Japan', Reuters. Tokyo, Japan.
[220] Watanabi, C. (2015). 'Solar Shipments in Japan Drop First Time Since 2012 Incentives', Bloomberg.
[221] Izadi-Najafabadi, A. (2015). 'Japan's likely 2030 energy mix: more gas and solar', BNEF.
[222] Government of Japan (2015). Submission of Japan's INDC. Tokyo, Japan.
[223] Ministry of the Environment (2015). National Greenhouse Gas Inventory Report of Japan, Greenhouse Gas Inventory Office of Japan. Tokyo, Japan.
[224] The World Bank (2013). 'Tokyo's Emissions Trading System', Directions in Urban Development, June.
[225] IEA (2015). WEO 2015. Op. Cit.
[226] For a summary see Ozawa, H. & Umeda, S. (2015). 'Environmental law and practice in Japan: overview', Thomson Reuters. Tokyo, Japan.

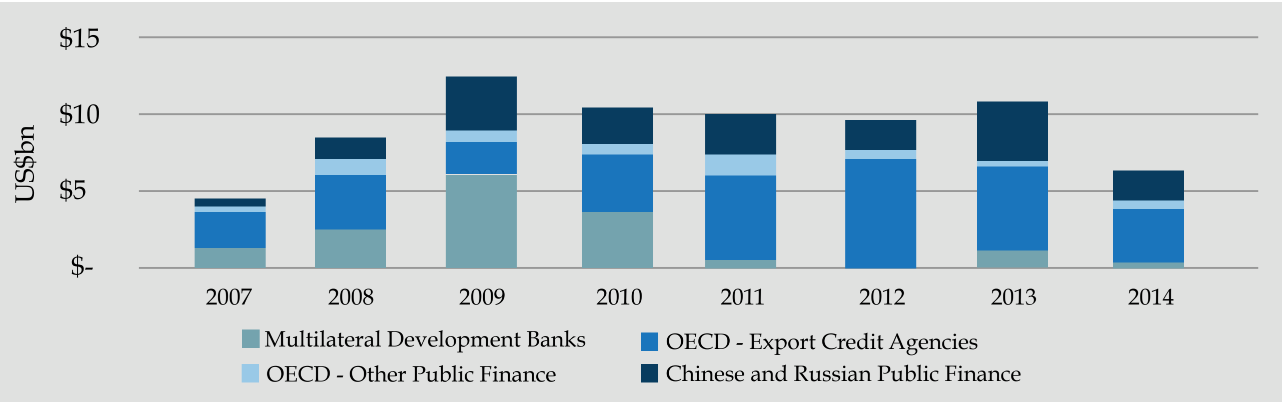
conventional air pollutants since the 1970s[227]. With few indigenous mineral resources, remediation and extraction policies are a low priority in Japan.

4.6.3 Emerging Issues

OECD Agrees to end export credit to coal-fired power

In November 2015, OECD countries agreed to substantially restrict export credit finance for coal-fired power stations. Several international development banks, including the World Bank, the European Investment Bank, and the European Bank for Reconstruction and Development have already committed to restricting financing for low-efficiency, high-carbon power stations, typically power stations with emissions in excess of 500g/kWh., The Natural Resources Defence Council (NRDC) reports that export credit agencies of OECD countries have largely filled this gap[228], see Figure 22. The November agreement imposes a similar criteria on OECD export credit agencies.

Figure 22: *International public finance of coal*[229]



Japan has provided more public coal investment than any other OECD nation. Japan, Korea, and Australia were the loudest voices of opposition to the US-led initiative to restrict public foreign coal financing[230].

4.7 Poland

4.7.1 Climate Change and Energy Policy

Poland is eighth in the world in production of coal and is a minor coal exporter. In its total primary energy, Poland is substantially dependent on oil and gas imports, 85% of which come from Russia. Electricity generation was liberalised in the 1990s with natural gas following in the 2010s, but competition has been difficult to establish[231]. Energy security remains one of Poland's top priorities, so it has remained dedicated to its indigenous coal energy resources. Greenpeace estimates that Poland spends €1.43bn/yr subsidising coal-fired power[232].

Poland has emissions and renewable energy obligations as a member of the EU, see Box 3. Under the Renewable Energy Directive, Poland must meet 15% of its energy needs with renewable sources by 2020[233]. In 2012, Poland met 11% of its energy needs with renewable sources. Renewable energy

[227] Maxwell, M. et al. (1978). 'Sulphur Oxides Control Technology in Japan', Interagency Task Force Report. Washington, US.

[228] Bast, E, Godinot, S., Kretzmann, S., et al. (2015). Under the Rug. Natural Resources Defense Counil (NRDC), Oil Change International, and World Wide Fund for Nature.

[229] Reproduced from NRDC (2015). Under the Rug. Op. Cit.

[230] Sink, J. & Nussbaum, A. (2015). 'In coal setback, rich nations agree to end export credits', Bloomberg.

[231] European Commission (2014). EU Energy Markets in 2014. Brussels, Belgium.

[232] Ogniewska, A. (2012). Subsidising the Past, Greenpeace. Warsaw, Poland.

[233] Ministry of Economy (2009). Energy Policy of Poland until 2030. Warsaw, Poland.

provided 10.7% of Poland's electricity, approximately half of which was biomass-fired power generation[234]. Almost 90% of all electricity in Poland is still provided by coal power. Poland plans to introduce nuclear (10%) and gas (10%) power and expand renewables (17%) by 2030 to increase its energy security and reduce carbon emissions[235]. The Emerging Markets Information Service (EMIS) estimates that renewable generation may provide 17% of Poland's electricity by 2020[236].

Poland faces a substantial infrastructure challenge. Over 40% of Poland's thermal generating plants are over 30 years old. LNG regasification and interconnectors will allow more competition in Polish energy markets. The LNG regasification plant under construction at Swinoujscie is expected to begin commercial imports in 2016[237]. A 1000MW interconnector with Lithuania is expected to be complete by the end of 2015[238]. The first of two nuclear power stations are expected to be operating by 2023[239].

The coal mining industry in Poland continues to face upheaval. Polish coal mining only began privatisation in 2009 when it joined the EU[240]. Poland's mines are not profitable and the wages and pensions of the miners are heavily subsidised by the government[241]. Despite Polish coal demand, competition with low-price imports is causing Polish production to fall.

Between 2011 and 2015, 70 wells were drilled in Poland for shale gas. Polish protestors took a strong stance against companies drilling and fracking despite enthusiasm from politicians about the prospect of energy supplies secure from Russia. Geological conditions and environmental approvals proved much more difficult than in the US and the falling price of oil hurt project outlooks. In June 2015 ConocoPhillips, the last IOC exploring for shale gas in Poland, announced it would be ceasing operations in Poland and no commercial production of shale gas has occurred[242].

4.7.2 Environmental Regulations

Poland is an EU member state and is required to harmonise its national legislation with directives from the EU, see Box 4. As a post-communist state heavily dependent on coal, Poland has been resistant to climate and other environmental policies which may be detrimental to its economy[243].

In 2012, Poland issued a Transitional National Plan which avoided imposing environmental penalties on its coal-fired power stations that should have begun in 2016. Poland now has until 2020 to comply with the EU Industrial Emissions Directive (2010/75/EU)[244].

4.7.3 Emerging Issues

Water pricing

There is speculation that the Ministry of the Environment will introduce an industrial water price. This would affect the profitability of Polish power stations which would need to pay for their water use.

[234] Ministerstwo Gospodarki (2012). Interim Report on progress in the promotion and use of energy from renewable sources in Poland in 2011–2012. Warsaw, Poland.

[235] The Economist, (2014). 'A different Energiewende', The Economist.

[236] EMIS (2014). Energy Sector Poland. London, UK.

[237] Strzelecki, M. (2015). 'Poland Opens LNG Terminal, Pledges to End Russian Dependence', Bloomberg.

[238] LitPol Link (2015). Progress of Work. http://www.litpol-link.com/about-the-project/progress-of-works/.

[239] Ministry of economy (2012). Diversification of energy sources in Poland: Nuclear energy option. Warsaw, Poland.

[240] The Economist (2015). 'Striking contrast', The Economist. Warsaw, Poland.

[241] Vorutnikov, V. (2014). 'Polish Coal Industry Faces Tough', CoalAge.

[242] Barteczko, A. (2015). 'Conoco the last global oil firm to quit Polish shale gas', Reuters. Warsaw, Poland.

[243] For a summary see Jankielewicz , K. (2015). 'Environmental law and practice in Poland: Overview', Thomson Reuters. London, UK.

[244] Easton, A, (2012). 'Poland defers emissions restrictions to 2020 from 2016', Platts. Warsaw, Poland.

Political significance of coal mining subsidies

The Polish government is attempting to restructure the Polish coal mining industry so it can continue to subsidise the sector, evading EU state aid rules (see Box 4). Polish coal mining unions continue to hold substantial political clout in the country despite Polish mines being economically uncompetitive[245]. The winner of the October 2015 election was the conservative Law and Justice Party, which campaigned on a Eurosceptic platform and support for the Polish coal industry[246].

4.8 South Africa

4.8.1 Climate Change and Energy Policy

South Africa is the world's sixth largest consumer of coal and the sixth largest exporter. 25% of South Africa's coal production is exported, 40% is used to produce electricity, and 25% for coal processing technologies. Electricity production in South Africa is dominated by the main public utility Eskom, which produces 95% of South Africa's power, 45% of all African power, and exports to Botswana, Lesotho, Mozambique, Namibia, Swaziland, Zambia and Zimbabwe[247]. While 85% of South Africans have grid access[248], Eskom's first new generation capacity in two decades just became active in 2015, and South Africa's population and industries remain subject to frequent rolling blackouts[249].

Since 2011, South Africa has committed to a 'peak, plateau, and decline' emissions curve, with emissions peaking between 398 and 614 MtCO2e between 2020 and 2025 and plateauing for up to ten years[250]. South Africa maintains this commitment in their INDC, despite their mitigation efforts falling short of a 'fair' allocation according to various studies[251].

In 2011, the South African government published an Integrated Resource Plan, which lays out policy objectives and activities for the long term, subject to regular review. Having had its first review in 2013, renewables are projected to take a more significant role in South Africa's capacity additions[252]. Following a short-lived feed-in-tariff system, the Department of Energy announced a new Renewable Energy Independent Power Procurement Program (REIPPP). Between 2011 and 2013, 64 projects were awarded for 3.9 GW generating capacity, mostly in wind (2.0 GW), solar PV (1.5 GW), and concentrated solar power (0.4 GW)[253]. Major utility Eskom is currently building 4.8GW of new coal capacity and returning-to-service another 3.7GW[254].

With few other indigenous power resources besides coal, South Africa made early use of coal processing technologies, especially to advance energy security interests during the apartheid era. Sasol, a large South African coal processing technology company uses coal and the Fischer-Tropsch process to produce liquid fuels and other chemicals from coal gasification[255]. Sasol's facility at Secunda can produce 150 bbl/day from coal and gas feedstocks, 21.7% of South Africa's total

[245] Oliver, C. & Foy, H. (2015). 'Poland to push EU on coal mine subsidies', Financial Times. Warsaw, Poland.
[246] Schveda, K. (2015). 'Poland lurches to the right: What does it mean for the climate?', Greenpeace Energy Desk. London, UK.
[247] Eskom (2015). Company Information. http://www.eskom.co.za/OurCompany/CompanyInformation/Pages/Company_Information.aspx.
[248] The World Bank (2015). Access to electricity - % of population. http://data.worldbank.org/indicator/EG.ELC.ACCS.ZS
[249] Wexler, A. (2015). 'Power Outages Mar South Africa's Economic Expansion', Wall Street Journal. Brakpan, South Africa.
[250] Government of South Africa (2015). National Climate Change Response. Pretoria, South Africa.
[251] Government of South Africa (2015). South Africa's INDC. Pretoria, South Africa.
[252] South Africa Department of Energy (DOE) (2013). Integrated Resource Plan for Electricity, Update Report. Pretoria, South Africa.
[253] Eberhard, A., Kolker, J., & Leigland, J. (2014). South Africa's Renewable Energy IPP Procurement Program: Success Factors and Lessons, World Bank Group. Washington, US.
[254] Gross, C. (2012). Electricity Generation Options considered by Eskom, Eskom.
[255] South Africa Coal Roadmap (SACRM) (2011). Overview of the South Africa Coal Value Chain, Fossil Fuel Foundation. Sandton, South Africa.

production[256]. South Africa also has a large infrastructure of upgrade refineries which supply domestic demand from imported crude oil.

4.8.2 Environmental Regulations

South Africa has made significant progress in developing environmental protection laws and regulations, especially regarding biodiversity. Challenges remain for South Africa to embed principles of environmental stewardship across its wider government – both in the other services which regulate energy, mining, and infrastructure, and to disseminate responsibility appropriately to provincial and local authorities[257].

The country's current fleet of generating stations are not fitted with conventional air pollution control measures. In order to comply with the government's minimum emissions standards, these plants will need to be fitted with emissions control technology before 2020[258].

South Africa carries a large exposure to the physical risks of climate change. Increases in temperature and decreases in precipitation are expected to be particularly severe in southern Africa. Climate change will exacerbate existing human health and resource challenges which will delay or disrupt development and poverty alleviation[259].

4.8.3 CPT Developments

In South Africa, continued Sasol CTL operations are due to a number of factors: i) availability of cheap low-grade coal, ii) large capital investments in the sector, and iii) adequate economies of scale for producing feedstock for high value chemicals[260]. In 2013, Sasol revealed its new growth plans under 'Project 2050', where four new coal mining projects – Thubelisha, Impumelelo, Shondoni and Tweedraai— will be replacing old mining sites and expected to secure the required coal reserves till mid-century[261]. Sasol has also been actively pursuing international cooperation and investment opportunities across a range of countries, including Australia, Canada, China, India, Nigeria, Mozambique, Qatar, and Uzbekistan, where there are substantial deposits of low grade coal and potential for large-scale development[262].

Johannesburg-based South African company Sasol Ltd is an integrated energy and chemicals company, whose major shareholders include Allan Gray Investment Council, Coronation Fund Managers, Investec Asset Management, the South African Government Employees Pension Fund, and the Industrial Development Corporation of South Africa Limited (IDC)[263]. In recent years, Sasol has withdrawn from several joint-partnerships in China due to regulatory delays. Sasol was planning to invest US$10 billion on CTL plant together with Shenhua Ningxia Coal Industry, however the company cancelled the project after Chinese government failed to respond to an application in 2011[264]. A CTL joint venture between Sasol and Tata Group costing US$20bn and expected to produce 160,000 barrels of oil equivalent per day was proposed for the eastern state of Odisha in India[265]. In 2014, however, the project was cancelled by the Indian government due to delays[266].

[256] South Africa DOE (2013). Op. Cit.

[257] OECD (2013). OECD Environmental Performance Review – South Africa 2013. OECD Publishing.

[258] Stephen, C., Godana, P., Moganelwa, A. et al. (2014). Implementation of de-SOx technologies in an Eskom context & the Medupi FGD plant retorfit project, Eskom Holdins SOC

[259] Niang, I., Ruppel, O., Abdrabo, M., et al. (2014). 'WGII, Chapter 22: Africa', in IPCC, Fifth Assessment Report. Geneva, Switzerland.

[260] IEA Clean Coal Center (2009). Review of worldwide coal to liquids R, D, & D activities and the need for further initiatives within Europe. London, UK.

[261] Creamer, M. (2013). 'Sasol Mining's coal-to-liquids horizon extending to 2050', Mining Weekly.

[262] IEA Clean Coal Center (2009). Op. Cit.; Sasol Ltd (2015). Overview, http://www.sasol.com/about-sasol/company-profile/overview.

[263] Sasol Ltd (2015). Historical milestones. http://www.sasol.com/about-sasol/company-profile/historical-milestones.

[264] Marais, J. (2011). 'Sasol quits China coal-to-liquids plant as approval stalled', Bloomberg.

[265] Singh, R. (2013). 'Coal-to-Oil $20 billion projects said to stall: corporate India', Bloomberg.

[266] Business Standard Reporter (2014). 'Government cancels coal blocks of 8 companies', Business Standard. New Delhi, India.

4.8.4 Emerging Issues

Proposed Carbon Tax
The South African Government has proposed a carbon tax which will become active in 2017. The tax is planned to be US$8.50/t$CO_2$e and would increase 10% per year until 2019. The draft carbon tax bill was open for public comment until December 15, 2015[267].

South African Mining Tax Reform
In 2012, the government issued a report entitled 'State Intervention in the Minerals Sector' which proposed a number of tax reforms that would increase the state's benefits from mining activities[268]. The Davis Tax Committee is a committee of experts consulted for the alignment of South African tax proposals with overarching growth and development goals. Although the committee broadly recommended the status quo be maintained for mining taxes[269], this is likely to be an issue that will be revisited.

Discard and Duff Coal
As a result of coal beneficiation, it is estimated that South Africa discards 60Mt of degraded discard or 'duff' coal per year. An official survey in 2001 by the Department of Minerals and Energy estimated that over 1000Mt of discard coal exists in uncontrolled stockpiles around the country[270]. This coal presents immediate environment-related risks from spontaneous combustion and groundwater leaching, and long-term risks as a source of substantial carbon emissions. Remediation of these stockpiles may involve combusting the discard as fuel in modern boilers[271].

4.9 United Kingdom

4.9.1 Climate Change and Energy Policy

The United Kingdom is the world's fifth largest economy and the seventh largest importer of coal. In 2014, 24% of the UK's coal was produced domestically. Coal provided 36% of the UK's electricity in 2013, dropping to 30% in 2014[272] and 28% in the first three quarters of 2015[273].

The UK has a number of targets for energy- and economy-wide decarbonisation, set domestically and linked to EU targets (see Box 3). The UK's pioneering Climate Change Act 2008 established a legally-binding target of limiting emissions to 80% below 1990 levels by 2050. The Act established five-year carbon budgets to achieve interim progress. The fourth carbon budget targets a 35% reduction below 1990 levels by 2020[274]. The fifth carbon budget was published November 2015 and calls for a 57% cut in emissions by 2030[275].

[267] Deprtment of National Treasury (2015). 'Publication of the Draft Carbon Tax Bill for public comment', media statement. Pretoria, South Africa.
[268] PMG Asset Management (2013). Mining Taxation, the South African Context. Birmginham, UK.
[269] Ajam, T., Padia, N., et al. (2012). First interim report on mining, The Davis Tax Committee.
[270] Department of Minerals and Energy (2001). National inventory discard and duff coal. Pretoria, South Africa.
[271] Belaid, M., Falcon, R., Vainikka, P. et al. (2013). 'Potential and Technical basis for Utilising Coal Beneficiation Discards in Power Generation by Applying Circulating Fluidised Bed Boilers', ICEES, 2:260-265.
[272] DECC (2015). Digest of UK Energy Statistics (DUKES) 2015. London, UK.
[273] DECC (2015). Energy Trends December 2015. London, UK.
[274] The Committee on Climate Change (2015). Carbon budgets and targets. https://www.theccc.org.uk/tackling-climate-change/reducing-carbon-emissions/carbon-budgets-and-targets
[275] The Committee on Climate Change (2015). The fifth carbon budget – The next step towards a low-carbon economy, https://www.theccc.org.uk/publication/the-fifth-carbon-budget-the-next-step-towards-a-low-carbon-economy/

Under the Renewable Energy Directive, the UK must achieve 15% of its total primary energy from renewable sources by 2020[276]. The UK has responded with policy support for the expansion of onshore and offshore wind and bioenergy, and domestic policy to achieve 116TWh of generation from renewable sources by 2020. In 2014, the UK generated approximately 65TWh of electricity from renewable sources and another 35GW of renewable electricity generation was given consent, with an additional 18GW in planning[277]. In spite of this, the UK remains at risk of missing its target, due to slow adoption of renewable heating and transport fuels.

In 2012 the UK began a process of electricity market reform (EMR)[278]. EMR established a number of policy directions for the UK in addressing the energy trilemma, including a carbon floor price, an emissions performance standard, a capacity market, and a contracts-for-difference (CfD) feed-in-tariff system.

The Big Six utilities in the UK have yet to feel the utility death spiral to the same extent as their German peers (or parent companies, as in the case of E.ON and npower (RWE))[279]. Distributed energy resources have yet to erode power loads to the same extent. However must-run renewables and increasing carbon prices further supressed coal asset utilisation rates, which dropped 7.8 percentage points in 2014 to 51.2%[280].

4.9.2 Environmental Regulations

The UK is an EU member state, with substantial environmental policy harmonised with broader EU environmental policy (see Box 4).

The last UK deep coal mine was closed on December 18, 2015[281]. UK coal mines have struggled for market share against low price imports. At the end of 2014, there were still 26 coal surface mines, producing 7.9Mt of coal per year in approximately equal portions in England, Wales, and Scotland. Of nine extension applications filed in 2014, only three were approved[282].

In early 2015, the parliaments of Scotland and Wales both passed moratoriums on hydraulic fracturing. Across the UK, challenges with infrastructure, environmental oversight and mineral rights, and local opposition have made shale gas exploration very difficult[283].

4.9.3 Emerging Issues

UCG moratorium in Scotland

In October 2015, the Scottish government passed a moratorium on UCG in Scotland. The ban is separate to an existing ban on hydraulic fracturing but both will require consultative processes and further health and environment impact studies before they can be lifted. Most affected is Cluff Natural Resources which had planned to use UCG to produce gas from the coalbeds beneath the Firth of Forth[284].

Changes to the Climate Change Levy Exemption

Changes to the Climate Change Levy were announced in July 2015. From August 2015, renewable energy suppliers would no longer be eligible for exemption from the climate change levy – a levy placed on all energy supplies with separate rates for electricity, gas, and solid and liquid fuels.

[276] DECC (2009). National Renewable Energy Action Plan for the United Kingdom. London, UK.

[277] Constable, J. & Moroney, L. (2014). An Analysis of Data from DECC's Renewable Energy Planning Database Overview, Renewable Energy Foundation. London, UK.

[278] UK DECC (2012). Electricity Market Reform: Policy Overview. London, UK.

[279] Friends of the Earth (2014). The big six on the run. London, UK.

[280] Costello, M. & Jamison, S. (2015). 'Is the utility death spiral inevitable for energy companies?', UtilityWeek.

[281] Macalister, T. (2015). 'Kellingley colliery closure: 'shabby end' for a once mighty industry', The Guardian.

[282] Planning Officers' Society (2014). Surface coal mining statistics 2014. Nottingham, UK.

[283] Stevens, P. (2013). Shale Gas in the United Kingdom, Chatham House. London, UK.

[284] Dickie, M. (2015). 'Scotland widens fracking moratorium', The Financial Times. Edinburgh, UK.

Coal phase out by 2025
On November 18, 2015, Amber Rudd, Secretary of State for Energy and Climate Change, delivered a major speech in which she articulated the government's priorities in addressing the energy trilemma. Among other things, she indicated that gas would be preferred to coal in the design of the capacity market; total phase-out of coal would be targeted for 2025; and auctions for additional offshore wind contracts would be subject to cost reduction targets[285].

Bank of England Prudential Regulation Authority Climate Change Adaptation Report
In April 2014, the Prudential Regulatory Authority (PRA) of the Bank of England accepted an invitation from the Department of Environment, Food and Rural Affairs (DEFRA) to examine the impact of climate change on the UK insurance sector. In late September 2015 the PRA published its draft response and found that the UK insurance sector is exposed to three forms of risk worthy of further consideration.[286]

- Physical risks: The direct risks from extreme weather and a changing climate, and also secondary indirect risks resulting from such events, such as supply chain disruptions and resource scarcity.
- Transition risks: The financial risks inherent in the transition to a low-carbon economy, such as the repricing of carbon-intensive assets under various changes to policy or substitute technologies.

Liability risks: Risks arising from the compensation of damages which may have occurred as a result of a failure to appropriately respond to climate change.

- See Box 5 for more details.

The UK is a leader in global finance and insurance. Changing perceptions of climate change risks within finance have impacts well beyond the UK's borders.

Box 5: *Emerging climate change liabilities*

The PRA report found that company directors and fiduciaries (e.g. pension fund trustees) could be at risk from litigation as a result of the following actions (or inactions)[287],[288]:

- *Contributing to climate change*: companies that have contributed to climate change may be liable for the economic damages caused by climate change. Developments in the climate science underpinning attribution and the apportioning of responsibility mean that such cases may become possible.
- *Failing to manage climate risk*: company directors and fiduciaries may be held liable for not adequately managing or responding to climate risks.
- *Failing to disclose risks to shareholders and markets*: listed companies are required to disclose information, including on material risks, to capital markets. Companies that have failed to disclose material climate risks could have cases brought against them by investors and regulators.

[285] UK Government (2015). Amber Rudd's speech on a new direction for energy policy. https://www.gov.uk/government/speeches/amber-rudds-speech-on-a-new-direction-for-uk-energy-policy.
[286] Bank of England (2015). The impact of climate change on the UK insurance sector, Prudential Regulatory Authority (PRA). London, UK.
[287] Bank of England (2015). Op. Cit.
[288] See also Barker, S. (2013). Directors' duties in the anthroposcene, UNPRI.

4.10 United States

4.10.1 Climate Change and Energy Policy

The United States is second in the world in coal production and consumption, and is also a major net exporter. A coordinated response to climate change has been slow to develop in the United States, and instead a patchwork of federal, state, and municipal policy has developed to address both greenhouse gas emissions and to incentivise renewable energy.

Policy support for renewable energy is provided by a mixture of state and federal regulatory policies, fiscal incentives, and grants and public investment[289]. Twenty-nine states have a Renewables Portfolio Standards (RPS) or similar, which require investor-owned utilities (IOUs) to generate or purchase a certain amount of their electricity from renewable sources. The legislation often also includes multipliers and/or targets for certain renewable sources, targets for distributed generation, provisions for utility size, and caps on overall spending[290]. An additional eight states also have voluntary Renewables Portfolio Goals.

In August 2015, the federal government released the Clean Power Plan, to be enacted by the Environment Protection Agency under the Clean Air Act[291]. The plan is the most substantial effort ever undertaken by the United States federal government to address climate change. Under the plan, states are given emission intensity and state-wide emissions targets, and states must meet one of the targets in whichever way it chooses. The EPA suggests three building blocks for a state-level policy, including improving the efficiency of coal-fired power stations, and replacing power stations with natural gas-fired power stations and renewables. The EPA has provided states with an example emissions-trading model, which it will enforce if the states fail to provide their own plans[292]. In aggregate the Clean Power Plan will reduce emissions by 32% below 2005 levels by 2030.

The Clean Power Plan follows earlier regional cap-and-trade initiatives in the United States: the Regional Greenhouse Gas Initiative (RGGI) and the Western Climate Initiative (WCI). The RGGI is a cap-and-trade plan of nine north-east US States operating since 2008. Under the RGGI, fossil fuel power stations must surrender emissions certificates to cover the extent of their emissions. The states auction the certificates and allocate the proceeds towards energy efficiency and renewable energy incentives[293]. The WCI began with wide support but by the time of its adoption membership had declined to California and the Canadian provinces of Québec and Ontario. The WCI envisions multi-sector participation and currently covers electricity utilities and large industrial emitters. California held its first auction of allowances in January 2012[294].

The growth of unconventional oil and gas substantially lowered gas prices in the US and oil prices around the world. US utilities are rapidly diverting capital into gas-fired power stations rather than coal. Table 18 shows a number of growth projections to 2020, all of which were made before the final announcement of the Clean Power Plan.

[289] REN21 (2015). Renewables 2015 Global Status Report. Paris, France.

[290] Durkay, J. (2015). State renewable portfolio standards and goals, National Conference of State Legislature. http://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx#az.

[291] US EPA (2015). Overview of the Clean Power Plan, in The Clean Power Plan. Washington, US.

[292] US EPA (2015). Proposed Federal Plan and Proposed Model Rules, in The Clean Power Plan. Washington, US.

[293] Regional Greenhouse Gas Initiative (2015). Programme Overview. http://www.rggi.org/design/overview.

[294] California Air Resources Board (2011). Overview of ARB Emissions Trading Program. Sacramento, US.

***Table 18:** US electricity source CAGR projections to 2020*[295,296]

Generation Growth to 2020	EIA: Reference Case	EIA: High Oil and Gas Resource	BNEF Medium-Term Outlook
Coal	0.9%	-1.6%	-2.2%
Gas	-1.0%	3.0%	2.9%
Renewables	3.6%	3.6%	7.3%

Before the shale gas revolution, the US was poised to become a large LNG importer. Thirteen planned regasification terminals have been cancelled, while four liquefaction plants are now in construction with another 15 in planning or proposal stages[297]. The Brookings Institute warns that with a low oil price, falling demand, and strong Asian competition, none of the proposed US liquefaction plants will reach completion[298]. Some of the terminals are being converted to export or bi-directional terminals, allowing US shale gas to access higher priced markets in Europe and Asia[299,300].

4.10.2 Environmental Regulations

The United States Environmental Protection Agency (EPA) was created in the 1970s, consolidating many previous federal environmental agencies into one organisation. The EPA is responsible for the protection of human health and the environment and is empowered to write regulations and enforce compliance across the US.

The Clean Air Act (1963) empowers the EPA to make and enforce regulations to control air pollution. The act has been used effectively to manage ozone depleting substances and motor vehicle emissions, among other things. In the 1990s, over concerns of acid rain, the EPA began regulation of SO2 emissions from large power stations, implementing a cap-and-trade emissions trading scheme. In 2014, the IEA reported that 69% of US coal-fired power stations met their conventional air pollution targets using abatement technology, 10% were planned to retire, and 20% were undecided whether to retrofit to ensure compliance or plan retirement[301].

The Clean Water Act (1977) empowers the EPA to make regulations which manage and mitigate pollution of US water resources. It empowers the EPA to grant or withhold permits for a number of environmentally invasive activities. In August 2014, the EPA issued regulations regarding cooling water intake for manufacturing and power generation industries. The regulations establish a wide range of criteria to protect local environments against heat, chemical, and resource stress from cooling water effluent[302].

US states have different requirements for remediation bonding. The US coal industry is regulated by the Surface Mine Control and Reclamation Act (SMCRA), however states may enact their own regulations provided they meet or exceed the stringency of the SMCRA. The SMCRA expressly allows self-bonding by coal companies, but some states may disallow this practice in their own jurisdictions. Self-bonded coal miners are becoming liabilities for US states who may be obligated to remediate environmental damage if the company goes bankrupt, see discussion below[303].

[295] EIA (2015). Annual outlook with projections to 2040. Washington, US.
[296] Annex, M. (2015). Medium-term outlook for US power, BNEF White Paper.
[297] Global LNG Ltd (2015). Op. Cit.
[298] Boersma, T., Ebinger, C., & Greenly, H. (2015). An assessment of US natural gas exports, The Brookings Institute. Washington, US.
[299] Armistead, T. (2015). 'LNG Ready for Export', Energybiz, Jan/Feb 2012.
[300] Richards, B. (2012). 'The Future of LNG', Oil and Gas Financial Journal.
[301] EIA (2014). Electricity – Detailed State Data. http://www.eia.gov/electricity/data/state/.
[302] US EPA (2015). 'National Pollutant Discharge Elimination System—Final Regulations for Cooling Water Intake Structures at Existing Facilities', Federal Register 158:48300-48439.
[303] Miller, G. (2005). Financial Assurance for Mine Closure and Reclamation, International Council on Mining and Metals. Ottawa, Canada.

4.10.3 CPT Developments

In the US, although there is no CTL production unit in operation, a significant number of projects in Wyoming, Illinois, Arkansas, Indiana, Kentucky, Mississippi, Missouri, Ohio and West Virginia are being considered.[304] In 2010, 12 CTL projects were proposed or under development, which would increase production from nothing to 250,000 barrels per day in 2035.[305] The projected cost of these projects range from US$2 billion to $7billion, which is being financed by major oil companies, such as Shell, and other large companies like Rentech (the Natchez Project in Mississippi), Baard (CTL project in Ohio), and DKRW (CTL facility in Wyoming)[306].

In the US, the Great Plains Synfuels Plant in North Dakota was funded by government subsidies and bankruptcy procedures, which covered the capital cost of the project[307]. In fact, a partnership of five energy companies behind the project defaulted on a US$1.54 billion loan provided by the US DOE in 1985[308]. Despite the default, DOE continued operating the plant through the ANG Coal Gasification Company (ANG), and then sold the project to two subsidiaries of Basin Electric Power Cooperative in 1989.

4.10.4 Emerging Issues

RPS repeal

Despite wide progress in the adoption of RPSs, states have recently been repealing or reducing their commitments to sustainable power generation. Ohio froze its RPS goals in May 2014. In February 2015, West Virginia repealed its RPS outright. In May 2015, Kansas reduced its portfolio standard from mandatory to voluntary. North Carolina is also considering a freeze of its RPS, and the legislation is currently under review by the North Carolinian senate[309].

The decline of coal and the utility death spiral (see Box 2) have given fresh incentives to companies to lobby for the repeal of RPSs. The rapid deployment and growing cost-competitiveness of renewables have also fed arguments that renewables deployment is approaching self-sufficiency. Repeal lobbyists observe that electricity prices are higher in states with active RPSs and argue that it is the high cost of renewables that burdens consumers in these states.

Emerging Liability concerns

Peabody Energy Corp and Exxon Mobil Corp Public Disclosure of Risk

In November 2015, the New York State Office of the Attorney General (NYAG) released the result of its investigation into Peabody Energy Corp.'s public disclosure of climate change risk under the Martin Act, which protects shareholders and the public from fraudulent disclosures. The NYAG found[310] that Peabody's annual reporting between 2011 and 2014 had:

i) claimed ignorance of the impact of climate change policy on its business activities when it had in fact conducted analysis of the impact of a carbon tax on some of its business activities
ii) misrepresented the IEA's CPS as the central or only projection of global energy demand and supply, when in fact the IEA NPS is the IEA's central scenario and both the NPS and 450S project weaker outlooks for future coal demand.

[304] IEA Clean Coal Center (2009). Review of worldwide coal to liquids R, D, & D activities and the need for further initiatives within Europe. London, UK.
[305] David Gardiner & Associates LLC (2010). Investor risks from development of oil shale and coal-to-liquids, CERES. Washington, US.
[306] Ibid.
[307] Yang, C. & Jackson, R. (2013). 'China's Synthetic Natural Gas Revolution', Nature Climate Change 3: 852–854.
[308] United States General Accounting Office (GAO) (1989). Synthetic Fuels: An Overview of DOE's Ownership and Divestiture of the Great Plains Project. Washington, US.
[309] Dyson, D. & Glendening, J. (2015). 'States are unplugging their renewable energy mandates', Wall Street Journal.
[310] New York Attorney General (2015). 'A.G. Scheiderman Secures Unprecedented Agreement with Peabody Energy ', Press Release. New York, US.

Peabody and the NYAG reached a settlement via an 'assurance of discontinuance' for Peabody's 2015 filing[311]. Peabody's settlement reflects a failure to disclose climate change risk exposure, see Box 5. In November 2015, the NYAG issued a similar subpoena to Exxon Mobil Corp[312]. Exxon is alleged to have misrepresented climate change risks to its shareholders and the public.

Changing ability to self-bond for remediation liability

The Surface Mining Control and Reclamation Act 1974 requires coal mining companies to post bonds to guarantee their ability to reclaim disrupted land at the conclusion of mining activities. Companies meeting certain financial criteria have been able to self-guarantee their ability to reclaim disrupted land[313]. With years of consecutive losses and falling share prices, state regulators are beginning to investigate US coal miners that self-guarantee their remediation liability[314].

In May 2015, the Wyoming Department of Environmental Quality told Alpha Natural Resources Inc that they no longer qualify for self-bonding[315]. The department is also investigating Arch Coal and Peabody Energy. Controversy surrounds the practice of the miners to self-bond by affiliate or subsidiary companies and the book vs. market value of shareholder equity on the company's balance sheet[316]. Alpha Natural Resources filed for bankruptcy in August 2015 with liabilities 2.5 times greater than its asset base[317].

Shareholder Responsibility to Bear Regulatory Costs

Evidence from the past suggests that shareholders that own generation capacity in competitive markets will be expected to bear the costs of regulatory changes on coal-fired power stations. For those power stations in rate-of-return regulated markets, it is also likely that shareholders will have to bear at least some costs of regulatory changes; however, both literature and precedent suggest that there may be an argument for passing some costs of stranded assets to taxpayers.

Federal Energy Regulatory Commission (FERC) Order 888 introduced competition into power generation in the US electricity industry. Electric utilities and shareholders argued that they made investments because of specific government policies or because of incentives encouraging such investments. With the introduction of competition, many assets, including power stations, were assumed to become stranded costs (the difference between the net book value of a generating plant limited to government-specified returns under rate-of-return regulation and the market value of that plant if it were required to sell its output in a competitive market) as competition drove electricity rates down and lower cost power stations entered the market[318]. This was acknowledged in 1994 by the FERC, which agreed that stranded costs should be compensated if they were verifiable and directly related to the government's introduction of competition[319].

311 Peabody Energy Corp. (2015). Assurance of Discontinuance. New York, US.

312 Rosenberg, M. (2015). 'NY attorney general wields powerful weapon in Exxon climate case', Reuters. New York, US.

313 Miller, G. (2005). Op. Cit.

314 Bonogofsky, A. Jahshan, A., Yu, H., et al. (2015). Undermined Promise II. National Wildlife Federation, NRDC, WORC.

315 Jarzemsky, M. (2015). 'Alpha Natural Resources Creditors Ready for Possible Restructuring Talks', Wall Street Journal.

316 Williams-Derry, C. (2015). 'How coal "self-bonding" puts the public at risk', Sightline Institute.

317 Paterson, L. (2015). 'In Coal Country, No Cash in Hand for Billions in Cleanup', Inside Energy.

318 Joskow, P. (2000). 'Deregulation and Regulatory Reform in the U.S. Electric Power Sector', in Deregulation of Network Industries: What's Next?, The Brookings Institute. Washington, US.

319 Martín, A. (2000). Stranded Costs: An Overview, Center for Monetary and Financial Studies. Madrid, Spain.

Since Order 888, deregulation has taken place in seven of ten regional US markets[320]. Taxpayers paid full compensation to firms for the introduction of competition into power generation; however, compensation was limited to stranded assets that were the direct result of state or federal government policies[321].

Nevertheless, there are strong arguments against taxpayers compensating shareholders, so shareholders should expect to bear at least some costs of clearly anticipatable regulatory changes with the potential to strand assets. The delay between the global recognition of the need to reduce GHG emissions (taking the 1992 UN Conference on Environment and Development as a starting point), and the potential realisation of this goal will have provided investors ample time for 'the realisation of value from previous investments and the opportunity to alter new investments'.[322]

[320] Woo, C. et al. (2003). 'Stranded Cost Recovery in Electricity Market Reforms in the US', Energy 28:1–14.

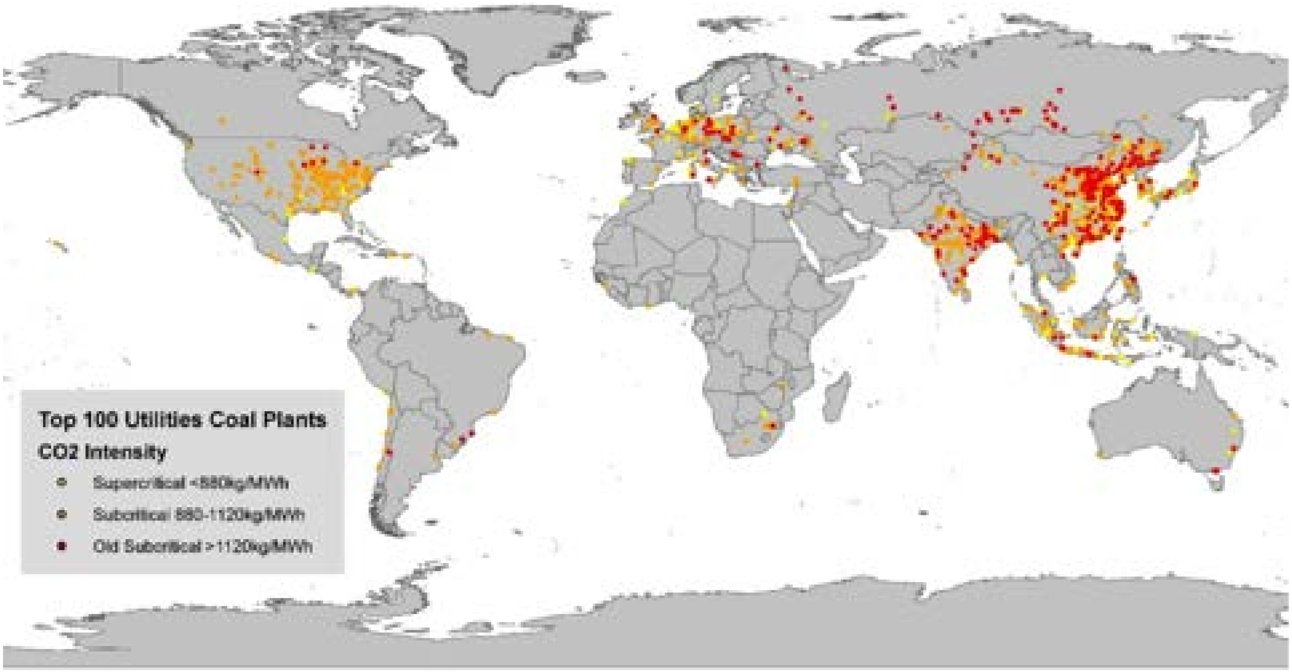
[321] Brennan, T. & Boyd, J. (1996). Stranded Costs, Takings, and the Law and Economics of Implicit Contracts, Resources for the Future. Washington, US.

[322] Burtraw, D. & Palmer, K. (2008). 'Compensation Rules for Climate Policy in the Electricity Sector', Journal of Policy Analysis and Management 27:819–847.

5 Coal-Fired Power Utilities

Coal-fired power utilities are examined for their exposure to environment-related risks. We examine the capital expenditure plans, ownership structures, and debt obligations of coal-fired power utilities. We then develop and test a number of hypotheses pertaining to the environment-related risk exposure of these companies. With these hypotheses, we develop an opinion on how environment-related risks could alter companies' capital plans and debt position. Figure 23 shows the location of the power stations of the world's top 100 coal-fired power utilities. The top 100 coal-fired power utilities 42% of the world's coal-fired generating stations, and 73% of all coal-fired generating capacity.

***Figure 23:** Coal-fired power stations of the top 100 coal-fired power utilities*



5.1 Market Analysis

This section surveys available data and estimates of company capital planning, ownership, and bond issuances.

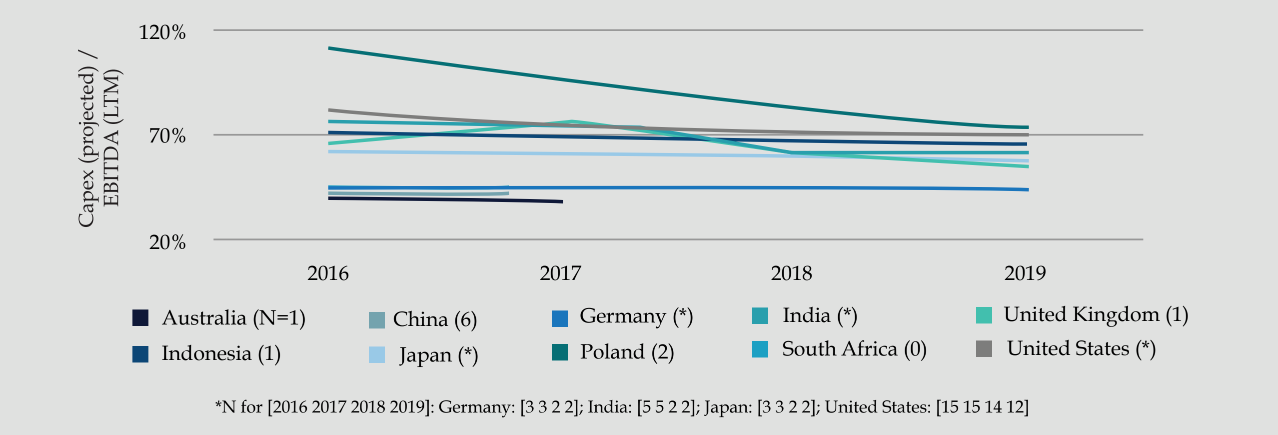
5.1.1 Capital Projects Pipeline

The capital plans of companies help determine future exposure to environment-related risks. For utilities, these capital plans are especially significant given the decades-long life and payback time of generation assets. Box 6 identifies how environment-related uncertainties should be accommodated in capital planning.

Figure 24 shows aggregate capex projections by region (as a percentage of EBITDA) for the top 100 coal-fired power utilities (where data was available[323]). German and Australian utilities are planning the least capex as a ratio of their EBITDA, while the United States leads the grouping and Polish companies are clear outliers in their near-term capex spending relative to EBITDA.

[323] Data was available for 49 of the 100 companies from Standard & Poor's Capital IQ, November 2015.

***Figure 24:** Aggregate capex projections normalised by EBITDA (last 12 months)*[324]



***Box 6:** Uncertainty in capital planning*

As company directors maximise shareholder value, they must accommodate a wide range of risks and uncertainties over a project lifecycle. These include:

- Near-term cost overruns, e.g. during construction
- Risks to operating profitability, including changing commodity prices, labour and fuel/material costs, and maintenance frequency
- End-of-life remediation costs
- Total useful economic life

Allessandri et al argue[325] that conventional risk management techniques like discounted-cash-flow analysis are unsuited to projects with long timeframes and high uncertainty. They argue instead that decision-makers should incorporate qualitative techniques like scenario planning into decisions made under high levels of uncertainty. Courtney et al similarly argue[326] that traditional approaches to planning under uncertainty can be 'downright dangerous'.

EY's Business Pulse[327] lists the top four impacts on power and utility companies as compliance and regulation, commodity price volatility, political intervention in markets, and uncertainty in climate change policy. These factors are typically 'uncertain' – the probability distribution of their occurrence or impact is unknown.

Table 59 in Appendix A shows the total coal-fired generation and fleet-wide capacity for the top 100 coal-fired power utilities. Operating plant capacity is disaggregated by fuel source and capacity in construction or planning is shown by fuel source as a percentage of total operating capacity.

Figure 25 shows global and regional projected coal-fired power generating capacity, operating, in construction, and planned from datasets compiled by the Oxford Smith School. Generating capacity from this new dataset is compared with scenarios from the IEA WEO 2015. Because of differences in database coverage, IEA projections have also been scaled to 2013 data, shown in the dashed series denoted by "*". Plant life is assumed to be 40 years on average.

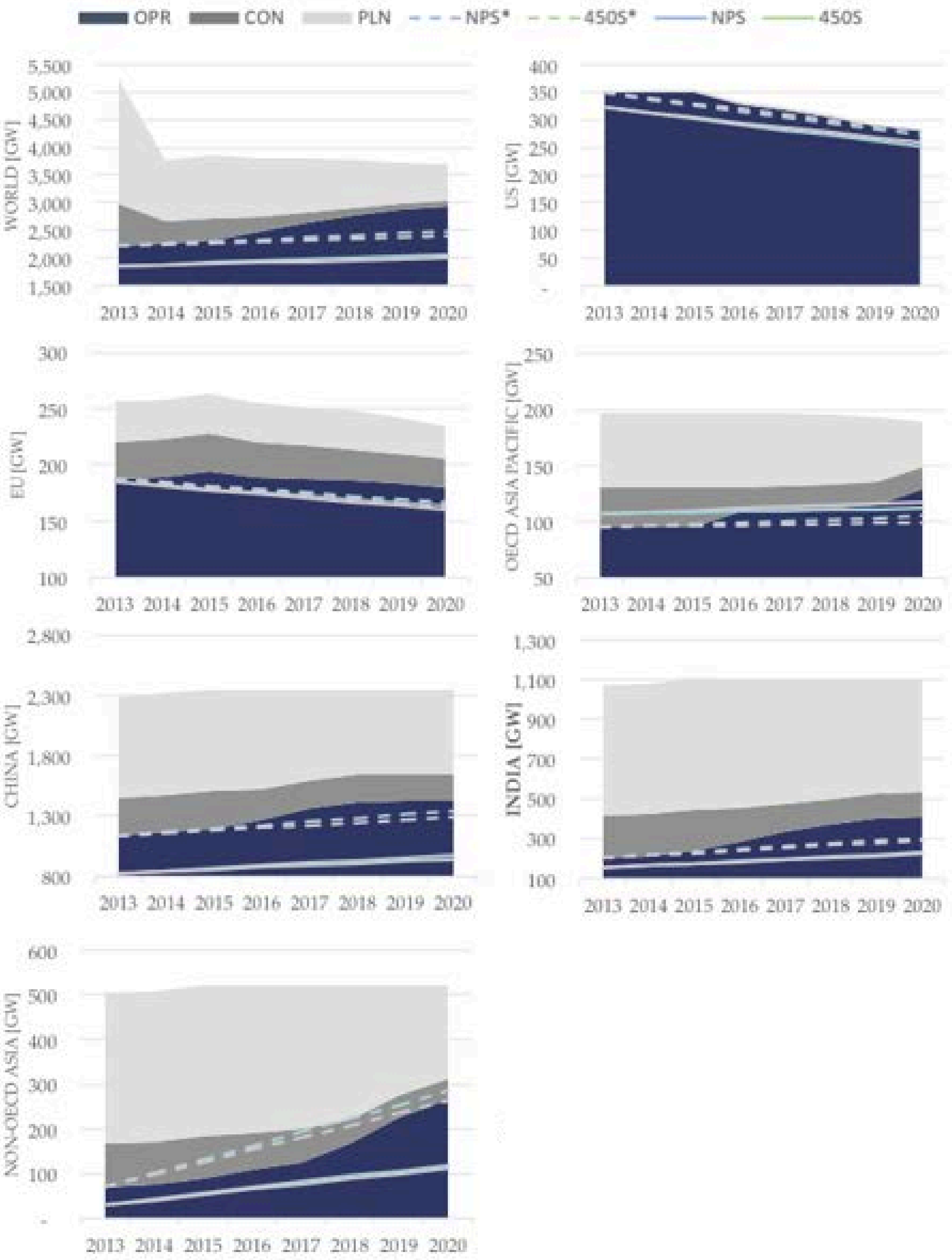
[324] Data taken from Standard & Poor's Capital IQ, November 2015.

[325] Alessandri, T., Ford, D., Lander, D., et al. (2004). 'Managing risk and uncertainty in complex capital projects', The Quarterly Review of Economics and Finance, 44:751-767.

[326] Courtney, H. et al. (1997). 'Strategy Under Uncertainty', Harvard Business Review.

[327] EY (2013) Power and utilities report, Business Pulse.

Figure 25: *Projection of operational, in construction, and planned coal-fired power stations, all companies, from composite database with comparison to IEA projections*

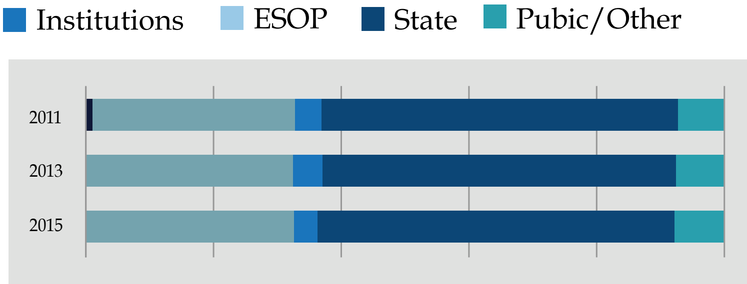


5.1.2 *Ownership Trends*

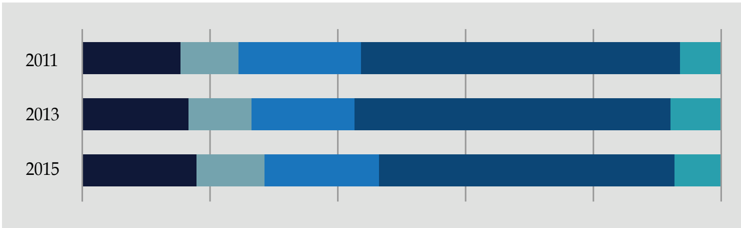
The ownership of coal-fired power utilities is shown for selected regions in Figure 26. Widely-held public companies are likely to have different decision-making processes than entirely state-owned companies.

Figure 26: *Coal-fired power utility ownership changes by region*[328]

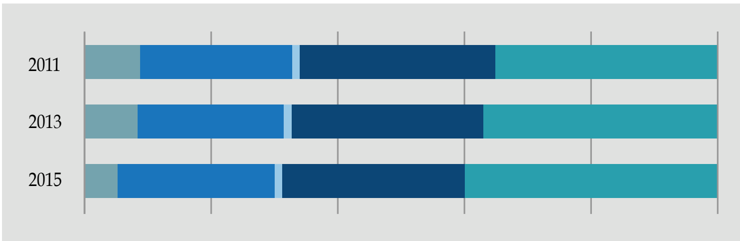
China – Ownership of coal-fired utilities is dominated by the state and has remained stable for the last five years. Investors owning portions of Chinese utilities are often ultimately state-owned.



India – Ownership of coal-fired utilities has growing insider/ individual ownership. The state also owns a significant and stable portion of coal-fired power utilities.



EU – European coal-fired power utilities still retain a significant portion of state ownership. They are otherwise owned by institutional and retail investors.



US – Coal-fired power utilities in the United States are mostly widely-held public companies. Individual and insider ownership tends to be dominated by the executives of the companies.

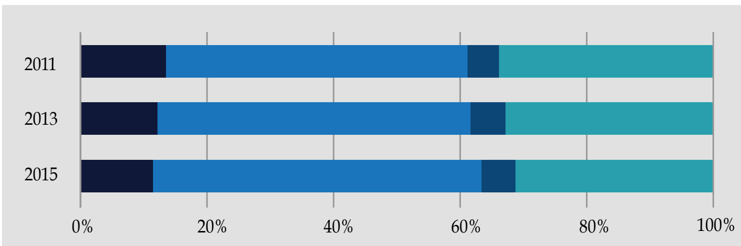


Table 60 in Appendix A shows ownership information for the 100 top coal-fired power utilities. For each company, the location of the head office, the ultimate corporate parent, corporate parent's ownership type, and the aggregate market value (in billion USDs) of the various holders' positions is shown.

The distribution of ultimate corporate parents varies at regional level. Both China and India represent the two regions with the largest proportion of privately owned corporate parents; 79% and 63% respectively. The US and Europe are predominantly publicly owned. For US utilities, 69.6% are ultimately owned by public companies, and 4.3% are owned by public investment firms. For the EU, 80% of companies are ultimately owned by public companies. Regarding state ownership, US governments own 13% of US utilities, while 6.3% of Indian utilities are state owned.

[328] Data from Standard & Poor's Capital IQ, November 2015.

Table 19 summarises the ultimate corporate parent ownership structure. Data is extracted from Table 60. Results include percentages. Numbers in parentheses represent the number of observations.

***Table 19:** Distribution of ownership for coal-fired power utilities, by region*

	Government	Private Company	Private Investment Firm	Public Company	Public Investment Firm
(A) Total	5.0% (5)	45.0% (45)	1.0% (1)	48.0% (48)	1.0% (1)
(B) China	0.0% (0)	79.2% (19)	4.2% (1)	16.7% (4)	0.0% (0)
(C) US	13.0% (3)	13.0% (3)	0.0% (0)	69.6% (16)	4.3% (1)
(D) India	6.3% (1)	62.5% (10)	0.0% (0)	31.3% (5)	0.0% (0)
(E) EU	0.0% (0)	20.0% (3)	0.0% (0)	80.0% (12)	0.0% (0)
(F) Other	4.5% (1)	45.5% (10)	0.0% (0)	50.0% (11)	0.0% (0)

5.1.3 Bond Issuances

Exposure to high levels of debt increases risk for both debt and equity holders of coal-fired power utilities as the priority of either is further diluted in the event of the company's insolvency. Table 61 in Appendix A shows bond issuances of the top 100 coal-fired power utilities.

To build a general picture of the future direction for bond issuances in the coal-fired power utility industry, fixed-income securities are examined through ratio analysis. A number of financial ratios are examined, including those related to profitability, capital expenditure, liquidity, leverage, debt coverage, and the ability for utilities to service existing debt. The analyses are conducted between 1995 and 2014 to represent the last 20 years of data.[329] The dataset for 2015 was limited, thus was omitted. Some financial data were unavailable for private coal-fired utilities. Thus, the analysis only includes securities which could be publicly traded. Table 62 in Appendix A reports the median values for the financial ratios across time, while Figure 27 presents the median ratios with 25th and 75th percentiles to illustrate the distribution of observed ratios.

[329] Data were taken from Thomson Reuters Datastream, November 2015; and Standard & Poor's Capital IQ, November 2015.

Box 7: *Environment-related risks and rating downgrades of coal-fired utility companies*

Ratings analyses were obtained from Standard & Poor's Rating Services (S&P) for coal-fired generating companies that suffered a rating action due to climate or environmental factors between September 2013 and September 2015 S&P analyses the business and financial risk exposure of companies.

For business risks, S&P examines factors like the company's regulatory environment, diversification, market outlook, market share, and exposure to 'environmental compliance'. Where companies operate in a strong regulatory environments (e.g. regulated retail power markets), have a diversified customer base and/or a dominant market share, and manage their exposure to or compliance with 'environmental regulation' they are found to be less at risk. Changes in market outlooks are also included in company business risks, though they are not attributed to any underlying environment-related risk.

For financial risk, S&P examines a company's cash position, including their capital spending; mergers, acquisitions, and sales; leverage; and liquidity. S&P evaluates financial risk using a few key metrics, including the ratios of funds-from-operations (FFO) to debt and debt to EBITDA, and liquidity ratios. Environment-related risks are included in financial risk as well, either directly or indirectly. Southern Co.'s impending spending on environmental compliance, for example, was seen as a risk to its financial profile. Indirectly, Duke Energy's sale of 6GW of coal- and gas-fired generating assets to Dynergy in 2014, which may have been motivated by environment-related risks, resulted in an improvement in credit rating. Finally, S&P has observed where changing market conditions can hurt a company's FFO. The available ratings are shown in Table 20.

Table 20: *Credit ratings for coal-fired power utilities*[330]

Company	Business Risk	Financial Risk	Rating	Date
Alliant Energy Corp	Excellent	Significant	A-/Stable/A-2	2014/11/10
American Electric Power Co. Inc	Strong	Significant	BBB/Stable/A-2	2014/05/02
CEZ a.s.	Strong	Significant	A-/Stable/--	2014/12/07
DTE Energy	Excellent	Significant	BBB+/Positive/A-2	2014/10/14
Duke Energy	Excellent	Significant	BBB+/Positive/A-2	2014/11/05
Dynegy Inc.	Weak	Highly Leveraged	B/Stable/NR	2014/03/31
Formosa Plastics Corp	Satisfactory	Intermediate	BBB+/Stable/--	2014/12/04
Great Plains Energy Inc	Excellent	Significant	BBB+/Stable/A-2	2015/03/28
NRG Energy Inc	Fair	Aggressive	BB-/Stable/NR	2014/09/16
RWE AG	Strong	Significant	BBB+/Stable/A-2	2014/09/22
Southern Co	Excellent	Significant	A/Negative/A-1	2014/10/31
The AES Corp	-	-	BB-/Stable/--	2014/07/17
Vattenfall AB	Strong	Significant	A-/Stable/A-2	2014/10/09

[330] From Standard & Poor's RatingsDirect Reports, various.

In October 2015, S&P reported on how environment and climate (E&C) risks have entered global corporate ratings since November 2013[331]. In those two years, S&P overserved 299 instances when E&C factors were significant in ratings analysis. In 56 of the cases, the E&C factor resulted in a ratings action, 80% of which were negative in direction. The sectors most exposed to ratings action were oil refining and marketing, regulated utilities, unregulated power and gas, and oil and gas exploration and production.

S&P incorporates E&C risks into their ratings in several ways. S&P assesses the management and governance response of companies to emerging ESG risks. E&C risks are included within ESG risks and in 117 of 299 of the review period results, the management response to emerging E&C risks was material to the analysis of the companies in question (both positive and negative). In one case the mismanagement of an environmental compliance requirement led to a credit downgrade (Volkswagen AG).

S&P also considers the impact of extreme weather on companies' real economy assets, supply chains, and markets. As climate change increases the likelihood of extreme weather, companies face potential shut downs, lost work hours, damaged equipment, disrupted supply chains, and volatile markets. Companies with diverse geographies and low chances of extreme weather are insulated from these risks.

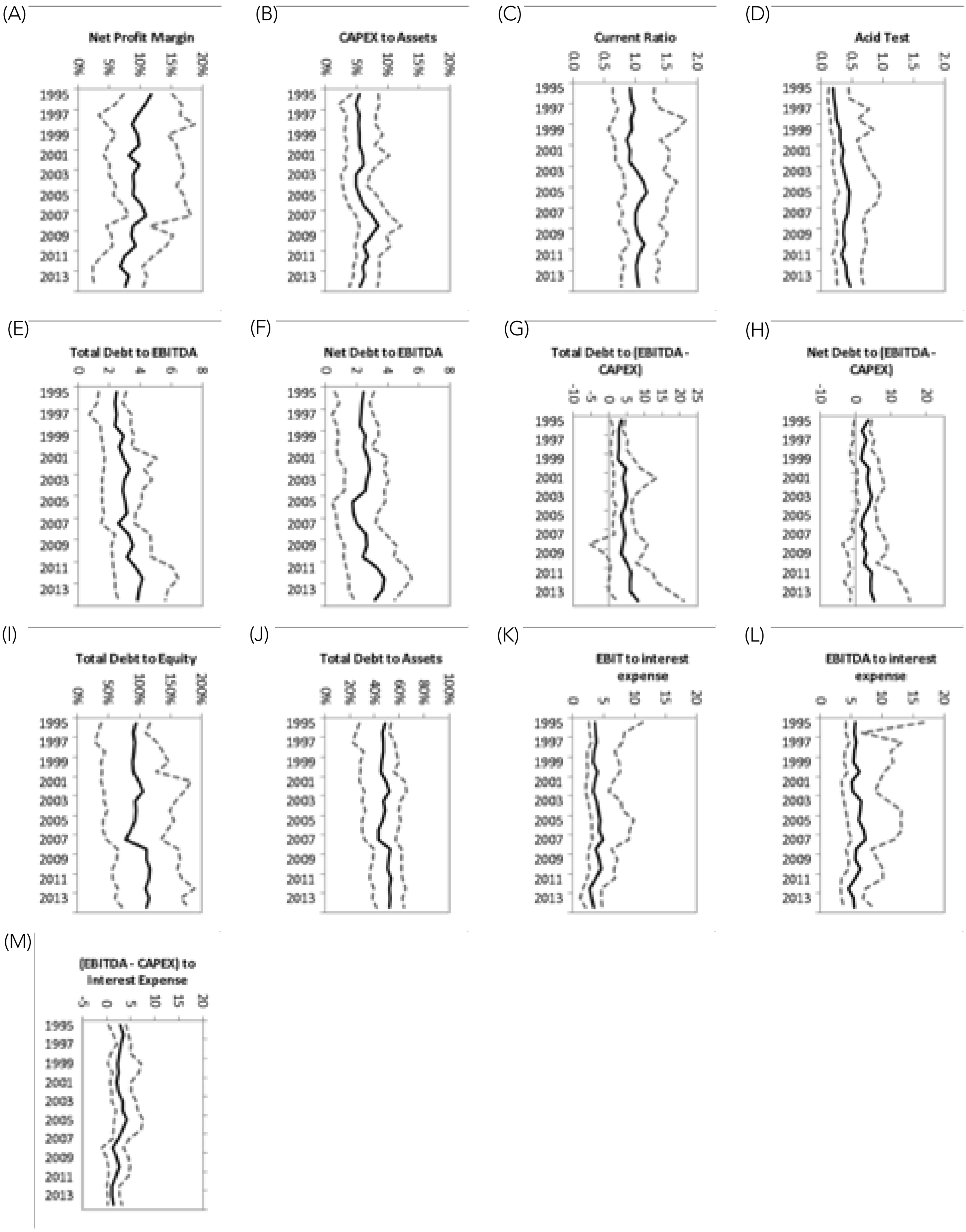
Three examples illustrate how S&P uses E&C factors to evaluate company risk. Volkswagen AG was downrated to A- from A for failure of environmental compliance leading to a substantial penalty and indicative of underlying mismanagement. Tenneco Inc was upgraded to BB+ from BB for their positioning in clean-air products, which are likely to be in higher demand in the future. Energy XXI was downgraded to B- from B because its business activities are primarily in the US Gulf Coast, where climate change is likely to result in more extreme weather.

For the utility sector specifically, S&P plays close attention to how government policy and regulations may expose companies to new risks. In liberalized power markets, government policies have substantial potential to disrupt incumbent positions with new entrants, new technologies, and distributed generation. The majority of business risks identified are risks to profits and growth, and risk of substitution. Even how company management maintains cash flow while responding to new regulatory requirements can inform the risk outlook for the company.

S&P expects the ratings actions due to E&C risks to continue to rise in the near future as extreme weather increases risk to weather-exposed companies, and governments introduce more stringent policies to address climate change.

[331] Standard & Poor's RatingDirect (2015). How Environmental And Climate Risks Factor Into Global Corporate Ratings.

Figure 27: *Ratio analysis for all coal-fired power utilities, with median, 25th, and 75th percentiles*



The first two ratios examined report general profitability and capital expenditure in the coal-fired power utility industry, both of which are relevant to the industries' ability to service its debt commitments. Chart (A) of Figure 27 presents the profit margins for coal-fired power utilities. Margins were greatest in 1995, at 11.8%, and the pre-global financial crisis (GFC) between 2006 and 2007, at 11.0%. The latter is unsurprising considering the peak in global coal prices pre-GFC. After these dates, profit margins generally trended below 10%; 2012 was the worst performing year due to a drop in global coal prices: profit margins were 6.8%. Overall, the results suggest a slow decline in profitability through time.

Capital expenditure represents the funds required to acquire, maintain, or upgrade existing physical assets. Chart (B) shows that capital expenditure relative to total assets has been relatively constant through time. Capital expenditure fluctuates between 4.8% and 8.5% of total assets. The higher capital expenditures were typically observed following the GFC. This could be the result of various corporate actions: first, investment in infrastructure; second, compliance with environmental mandates; or third, greater spending on projects to boost bottom-line profits. The latter is only applicable in regions where profit margins are regulated relative to expenses.

The current ratio and acid test are used as a proxy for liquidity in the industry. The former ratio measures the ability to service current liabilities using current assets, while the latter measures the ability to service current liabilities using cash, near-cash equivalents, or short-term investments. Charts (C) and (D) show both liquidity ratios have increased through time. From 2003 onwards, the current ratio exceeded unity, indicating that the industry would be able to pay all short-term liabilities using its current assets. The acid test ratio has also increased, from 0.19 (1995) to 0.48 (2014). The change indicates an increase in the holdings of cash, near-cash equivalents, or short-term investments or decrease in current liabilities.

Two financial leverage ratios are examined: the debt/equity ratio in Chart (I) and the debt/assets ratio in Chart (J). Both ratios have increased over time, suggesting the industry is financing its growth with debt and/or may be retiring equity. Whereas total shareholder equity previously outweighed total debt, this relationship has reversed in recent years. Similarly, Chart (J) shows that debt now typically represents more than half of total assets. While leveraging can be beneficial, servicing debt can become increasingly difficult with decreasing profit margins. Overall, the industry is increasing its financial leverage, which can translate to greater financial risk, interest expenses, and volatile earnings.

Coverage ratios measure the industry's ability to meet its financial obligations. Three ratios are considered: 1) EBIT/interest, 2) EBITDA/interest, and 3) (EBITDA-CAPEX)/interest. The EBIT/interest ratio in Chart (K) shows that the operating income of the industry is typically between 2.73 and 4.92 times greater than interest expense. As the utility industry is capital-intensive, Chart (L) considers EBITDA which accounts for large depreciation and amortisation on assets. Consequently, the EBITDA/interest ratios range from 4.65 to 7.37 times interest expense. Both ratios are relatively constant through time. Chart (M) considers the impact of capital expenditures on the industry's ability to cover interest expenses. When deducting annual CAPEX, the industry only just generates enough cash to meet interest payments. The ratios range from 1.16 to 4.20 times interest expense. The GFC decreased the (EBITDA-CAPEX)/interest to a mere 1.23x. In 2012-13, the ratio was as low as 1.16 times interest expense. In 2014, the EBITDA-CAPEX had a small rebound to 1.42 times interest expense. Overall, the ratios suggest that the coal-fired power utility industry can cover its interest expenses but some utilities have little cash remaining after capital expenditures. Figure 27 indicates that the ratio becomes negative for some utilities, indicating that interest expenses exceed cash flows.

The final four ratios represent the industry's ability to retire incurred debt. The ratios can be broadly interpreted as the amount of time needed to pay off all debt, ignoring interest, tax, depreciation and amortisation. The ratios are divided into two groups: group 1 considers the numerators: 'total debt' and 'net debt', where the latter subtracts cash and near-cash equivalents for total debt; group 2 considers the denominators: EBITDA and (EBITDA-CAPEX), where the latter controls for capital expenditures.

Considering Charts (E) and (F), both ratios indicate the compounding effects of increasing debt and decreasing profitability. Overall, the industry's ability to retire its debt is declining. In 2014, Chart (E) shows that it would take 3.85 years to pay off total debt using current operating income; Chart (F) shows 3.20 years excluding when utilising near-cash equivalents. When deducting CAPEX, these ratios dramatically increase. In 2014, Chart (G) indicates that the industry will take approximately 8.34 years to pay off its total debt at current levels of profitability and capital expenditure. Over the same period, Chart (H) reports 5.41 years after utilising near-cash equivalents. In conclusion, all four ratios indicate that the industry is taking on increasing amount of debt, which will take longer to retire. Accordingly, we examine the maturity schedule of the industry.

Figure 28 illustrates the maturity schedule for the coal-fired power utility industry. Data were available for 78 of the 100 coal-fired power utility companies. The schedule is divided into total amount outstanding (USD) in Plot (A) and the maturity dates of various contracts in Plot (B). Both graphs are delineated by major region: China, US, Europe, and 'other regions'[332].

Plot (A) of Figure 28 shows that the majority of the total debt amount is due between 2016 and 2025, and Chinese and the US-based utilities are among the largest debt-issuers. US-based utilities have borrowed heavily until 2045. Notably, both Plots (A) and (B) illustrate a small amount of borrowing until 2095-2100. Plot (B) shows that the US-based utilities issued considerably more contracts in comparison to other regions. In combination, it suggests that the average contract size for the US is smaller than other regions, but more numerous.

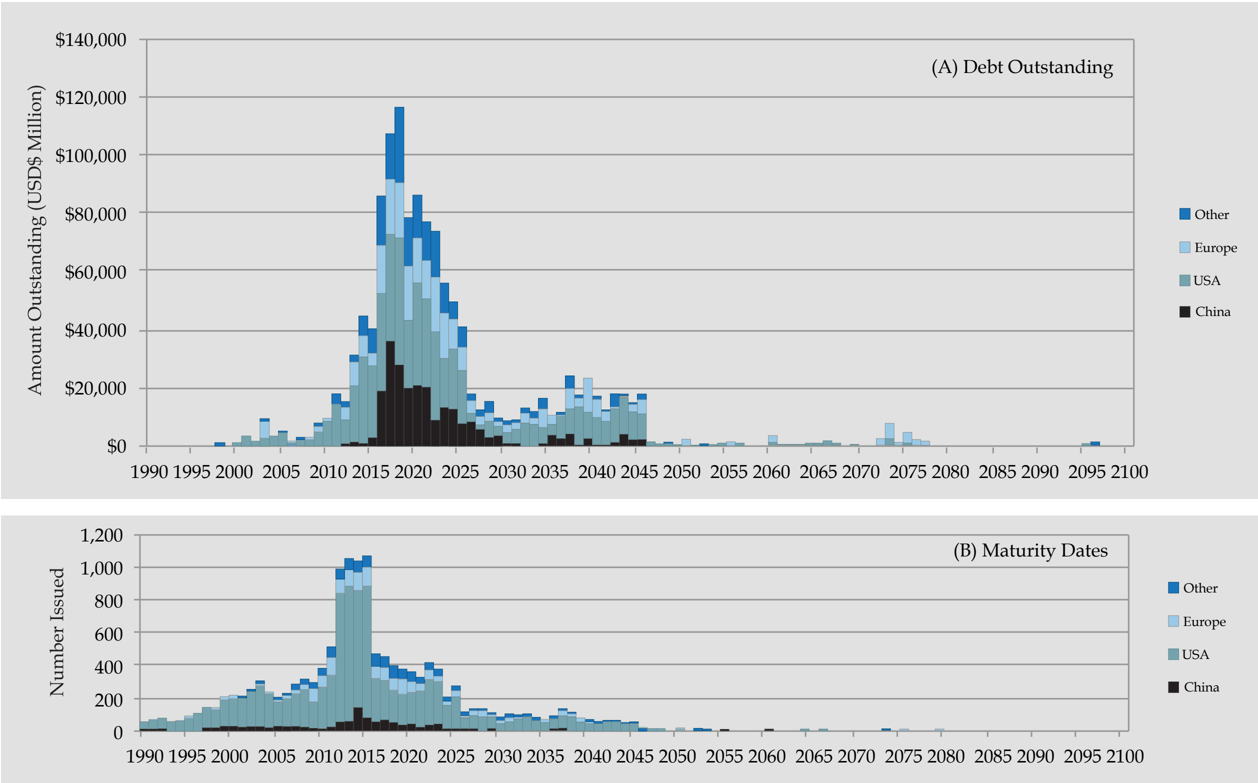
Table 21 examines perpetual debt across the regions. US- and European-based utilities have issued the largest number of perpetual contracts. Similar to the results above, the US utilities has issued a larger number of contracts, but of smaller value. The total amount of European utilities' perpetual debt is more than double that of other regions. Of European utilities' total perpetual debt, France, Germany, and Italy have issued US$20,964m, $1,229m, and $500m, respectively.

Table 21: *Coal-fired power utilities' perpetual debt*

	China	US	Europe	Other
Amount outstanding (US$m)	$6,104	$9,081	$22,693	$3,985
Number issued	30	1,281	973	16

[332] Note, for the 'other' amount outstanding series, we omit $455 billion of debt for Tenaga Nasional Berhad (Malaysia) in 2021. The data point significantly skewed the series. After investigation, S&P Capital IQ confirmed that the amount of debt outstanding is indeed valid and correct.

Figure 28: *Maturity schedules for the utility industry's debt: amount outstanding (A) and maturity dates (B)*



5.2 Investment Risk Hypotheses

In this section, we take a view on what the environment-related risks facing coal-fired power stations could be and how they could affect asset values. We call these Local Risk Hypotheses (LRHs) or National Risk Hypotheses (NRHs) based on whether the risk factor in question affects all assets in a particular country in a similar way or not. For example, water stress has variable impacts within a country and so is an LRH, whereas a country-wide carbon price is an NRH. The hypotheses are coded for easier reference. For example, LRH-U1 refers to carbon intensity of coal-fired power stations and NRH-U1 refers to the overall demand outlook for electricity.

Hypotheses for different environment-related risks have been developed through an informal process. We produced an initial long list of possible LRHs and NRHs. This list was reduced to the more manageable number of LRHs and NRHs contained in this report. We excluded potential LRHs and NRHs based on two criteria. First, we received feedback from investors and other researchers in meetings, roundtables, and through correspondence, on the soundness, relevance, and practicality of each hypothesis. Second, we assessed the data needs and analytical effort required to link the hypotheses with relevant, up-to-date, and where possible, non-proprietary, datasets.

The current list of hypotheses and the datasets used to measure asset exposure to them are in draft form. Other datasets may have better correlations and serve as more accurate proxies for the issues we examine. Important factors may not be represented in our current hypotheses. We are aware of these potential shortcomings and in subsequent research intend to expand the number of hypotheses we have, as well as improve the approaches we have used to analyse them.

The summary table that shows the exposure of the top 100 coal-fired utilities to each NRH and LRH can be found in Section 5.3.

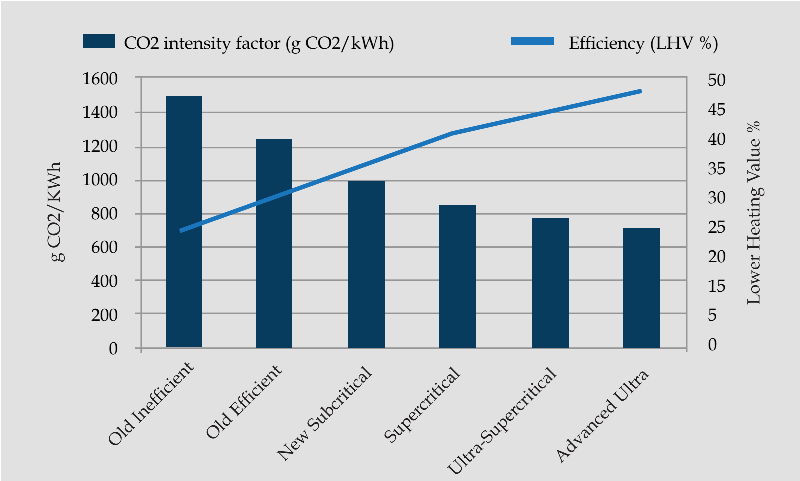
5.2.1 *Local Risk Hypotheses*

LRH-U1: Carbon Intensity

The hypothesis is that the more carbon intensive a coal-fired power station, the more likely it is to be negatively impacted by climate policy, whether carbon pricing, emissions performance standards, or other similar measures.

More carbon-intensive power stations are more exposed to transitional risk from climate change mitigation policy. Carbon intensity is directly dependent on power station efficiency, see Figure 29.

Figure 29: *Emissions intensity and efficiencies of coal-fired power stations*[333]



The carbon intensity of power stations can vary widely based on the efficiency of the boiler technology used. Power stations with lower thermal efficiencies are more vulnerable to carbon policies because such policies will more heavily impact inefficient power stations relative to other power stations[334]. This is highly relevant to coal-fired power generation because it is the most emissions-intensive form of centralised generation[335]. Inefficient coal-fired power stations, such as subcritical coal-fired power stations (SCPSs), are the most vulnerable to such policies.

To identify these risks, the emissions intensity of each power station globally is identified in kg.CO_2/MWh using CoalSwarm's Global Coal Plant Tracker database and the Carbon Monitoring for Action (CARMA) database. For the top 100 coal-fired power utilities, CO_2 intensities for 12% of all power plants and 22% of coal-fired power stations was not available. CO_2 intensity for these missing data points was estimated from coefficients derived from a log-log regression of matched data, using fuel type, MW capacity, age, and a country or regional dummy[336] as regressors. This functional form was chosen as it allows for proportional rather than absolute coefficient values, thereby corresponding more closely with the way in which our regressors should affect CO_2 intensity in practice.

[333] Taken from IEA (2013). ETP 2013. Op. Cit.

[334] Caldecott, B. & Mitchell, J. (2014). 'Premature retirement of sub-critical coal assets: the potential role of compensation and the implications for international climate policy.' Seton Hall Journal of Diplomacy and International Relations, no. fall/winter.

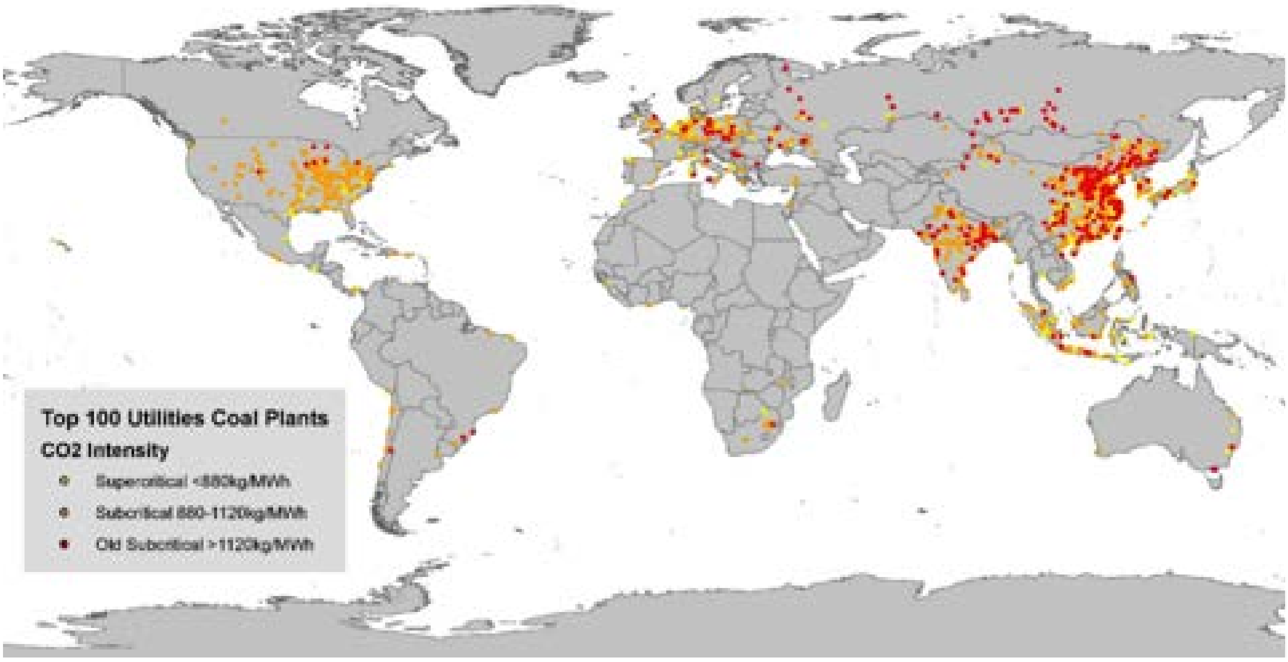
[335] Moomaw, W., Burgherr, P., Heath, G. et al. (2011). 'Annex II: Methodology' in IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation.

[336] Regional dummies are employed where there are fewer than 30 observations of plants in a given country.

Annual generation data (in MWh) was unavailable for 27% of all top-100 power stations (all fuel sources) and 26% of top-100 coal-fired power stations. This data and plant utilisation rates (in MWh/MW) for missing data points were similarly estimated from coefficients derived from a log-log regression. The regressors employed were fuel type, plant age, and country or region[337]. Similar to CO_2 intensity, this functional form was chosen as it should correspond more closely with the way in which our regressors are likely to affect MWh of generation in practice.

Power stations were then aggregated by utility and weighted by MW and MWh to determine the carbon intensity of the coal-fired power stations owned by the top 100 global utilities. Figure 30 shows coal-fired power station emissions intensities around the world.

***Figure 30:** Coal-fired power station emissions intensities*



LRH-U2: Plant Age

The higher age of power stations creates risks for owners in two ways. First, ageing power stations are more vulnerable to regulations that might force their closure. It is financially and politically simpler to regulate the closure of ageing power stations. Power stations typically have a technical life of 40 years and recover their capital costs after 35 years[338]. Once power stations have recovered capital costs and have exceeded their technical lives, the financial need to compensate is greatly reduced or eliminated[339]. Second, utilities with significant ageing generation portfolios have a higher risk of being required to cover site remediation costs after power station closures and outstanding worker liabilities (i.e. pension costs). Finally, older power stations are more susceptible to unplanned shutdowns and maintenance needs, resulting in the costs of repairs and secondary losses or opportunity costs of underperformance on contracted power delivery.

The age of each generating unit within each power station is identified using CoalSwarm, the World Electric Power Plant (WEPP) database, and CARMA. These are then aggregated to the plant level by weighting the MW capacity of each generating unit.

[337] Regional dummies are employed where there are fewer than 30 observations of plants in a given country.
[338] IEA (2014). Energy, Climate Change, and the Environment. Paris, France.
[339] Caldecott, B. & Mitchell, J. (2014). Op. Cit.

For power stations which lack age data (17% in total, 25% for coal), the average age of stations with the same fuel type across the complete dataset is used. Power stations are then further aggregated by utility company to determine the average age of their coal-fired power generation portfolios as well as the percentage of generation capacity exceeding 40 years of age.

LRH-U3: Local Air Pollution

The hypothesis is that coal-fired power stations in locations with high population density and serious local air pollution are more at risk of being regulated and required to either install emission abatement technologies or cease operation. Thus, owners of assets in areas of high population density and high local pollution will have a greater risk of bearing the financial impacts of such possibilities.

There is strong evidence to support this hypothesis from China, the EU, and the US. In China, a number of non-GHG emission policies are forcing the closure of coal-fired power generation in the heavily polluted, heavily populated eastern provinces[340].

Power stations without abatement technologies (e.g. flue gas desulphurisation units and electrostatic precipitators) installed are more at risk of being stranded by having to make large capital expenditures to fit emission abatement technologies. This risk is exacerbated by power station age because investments are harder to justify closer to the end of a power station's technical life.

This is illustrated by the effects of the Mercury and Air Toxics Standards in the United States. Implemented under the 1990 Clean Air Act amendments, the MATS limit emissions of mercury, toxic metals, and acidic gases. 70% of coal-fired power stations are compliant with the regulations. While 6% have plans to comply with the regulation, 16% plans to cease operation instead of comply and another 8% is undecided. The EIA attributes this to the capital expenditure necessary to comply as well as competition from renewables and gas[341].

The following approach is taken to identify risks to utilities that may be created by the co-location of coal-fired power stations with high population densities and serious local air pollution.

- All coal-fired power stations are mapped against a geospatial dataset of global $PM_{2.5}$ pollutionand NASA's SEDAC gridded population dataset. $PM_{2.5}$ data is taken from the analysis of Boys, Martin et al. (2015), and consists of annual ground-level $PM_{2.5}$ averages between 2012 and 2014 derived from satellite observation.
- Average $PM_{2.5}$ pollution within a radius of 100km of each power station is identified. The average population density within a 100km radius of each power station is identified. Then, all power stations are ranked on both factors separately.
- Power stations exposed to $PM_{2.5}$ emissions above the World Health Organisation's annual average $PM_{2.5}$ limit (10 μg/m^3) are classified as 'at risk'. Those power stations that rank in the top quintile for population density are classified as 'at risk'. In the case that a power station is 'at risk' for both indicators, it is classified as 'seriously at risk'.
- Power stations with pollution abatement technologies installed are identified using the World Electric Power Plant (WEPP) database. If power stations have one or more emission abatement technologies installed, their pollution abatement risk factors are downgraded one level (i.e. 'seriously at risk' to 'at risk' and 'at risk' to 'not at risk')
- Power stations are then aggregated by utility to identify the percentage of capacity that is 'at risk' or 'seriously at risk'.

[340] Caldecott, B., Dericks, G., & Mitchell, J. (2015). Stranded Assets and Subcritical Coal: The Risk to Companies and Investors, Smith School of Enterprise and the Environment, University of Oxford. Oxford, UK.

[341] Johnson, E. (2014). Planned coal-fired power plant retirements continue to increase, U.S. EIA.

In this hypothesis, $PM_{2.5}$ is used as a proxy for the other conventional air pollutants. Mercury has toxic neurological impacts on humans and ecosystems, but $PM_{2.5}$ is responsible for a more significant range of respiratory and cardiac health impacts associated with coal-fired power[342]. NO_x and SO_x form additional PM pollution once suspended in the atmosphere, and so are included in an evaluation of exposure to $PM_{2.5}$ alone. Figure 31, Figure 32, Figure 33, and Figure 34 show global conventional air pollutant concentrations.

Figure 31: *Global average PM2.5 concentration, 2012-2014*[343]

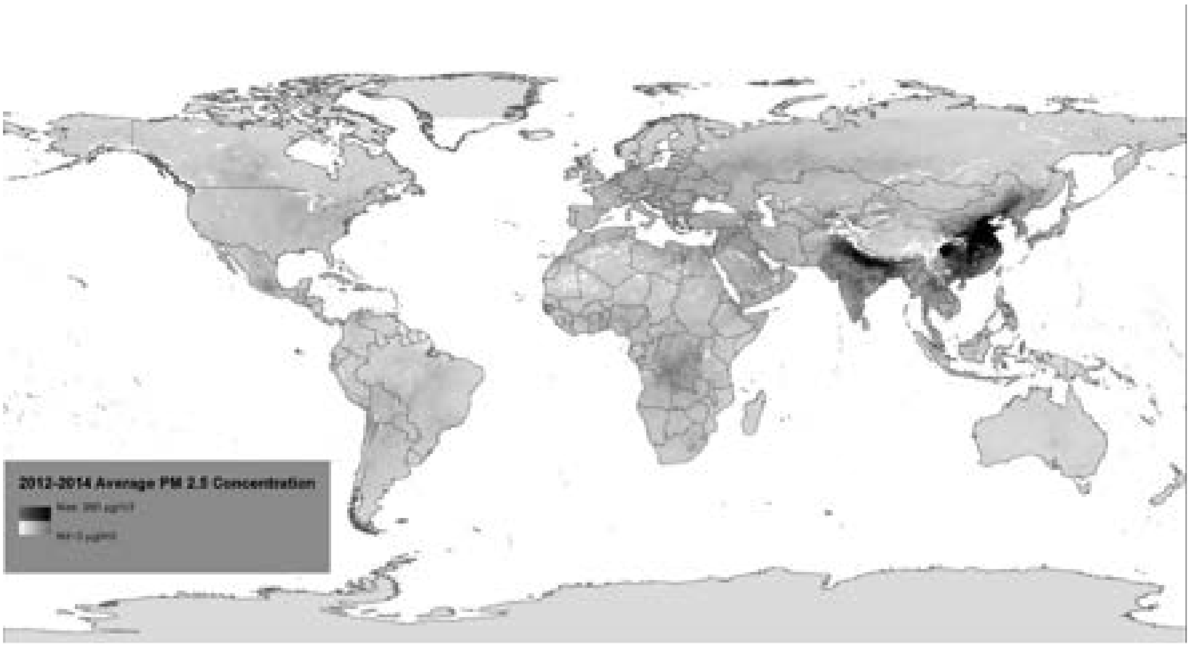
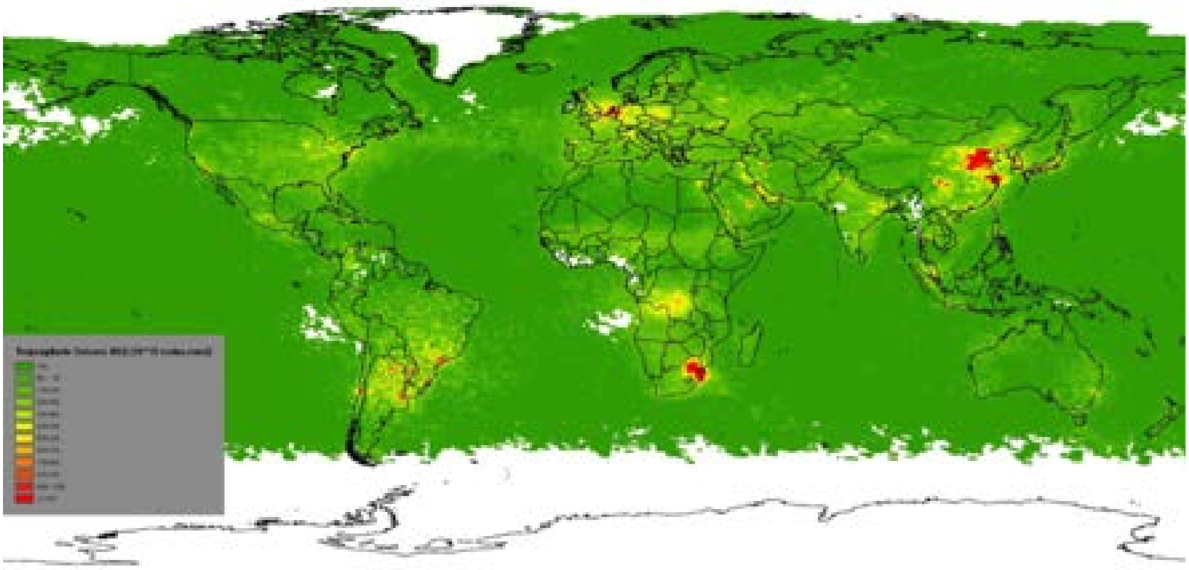


Figure 32: *Global NO_2 concentration, 2015*[344]



[342] Lockwood, A., Welker-Hood, K., Rauch, M., et al. (2009). Coal's Assault on Human Health, Physicians for Social Responsibility. Washington, US.

[343] Boys, B.L., Martin, R.V., van Donkelaar, A., et al. (2014). 'Fifteen-year global time series of satellite-derived fine particulate matter', Environ. Sci. Technol, 48:11109-11118.

[344] Boersma, K., Eskes, H., Dirksen, R., et al. (2011). 'An improved retrieval of tropospheric NO2 columns from the Ozone Monitoring Instrument', Atmos. Meas. Tech., 4:1905-1928.

***Figure 33:** Global SO_2 concentration, 2011-2014*[345]

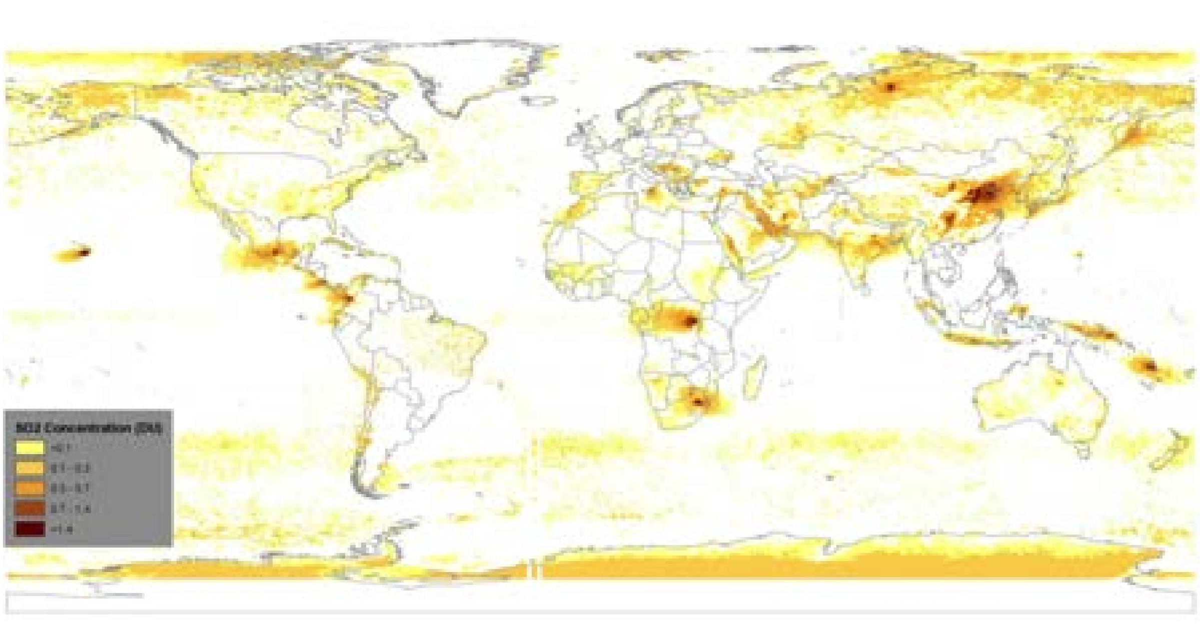
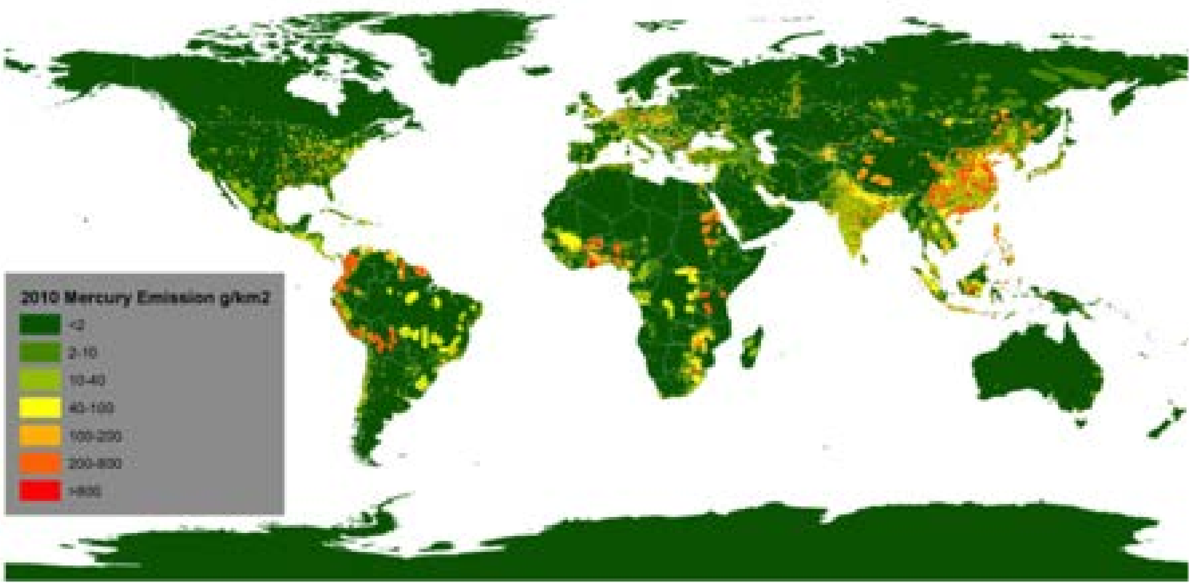


***Figure 34:** Global mercury emissions, 2010*[346]



LRH-U4: Water Stress

The hypothesis is that power stations located in areas with higher physical baseline water stress or in areas with water conflict or regulatory uncertainty are at higher risk of being forced to reduce or cease operation, of losing licence to operate, or of having profits impaired by water pricing. These risks can be mitigated to an extent by the use of closed-cycle, hybrid, or dry cooling technology.

[345] Krotkov, N. A., McLinden, C. A., Li, C., et al. (2015). 'Aura OMI observations of regional SO2 and NO2 pollution changes from 2005 to 2014', Atmos. Chem. Phys. Discuss., 15:26555-26607.

[346] AMAP/UNEP (2013). 'AMAP/UNEP geospatially distributed mercury emissions dataset 2010v1' in Datasets. http://www.amap.no/mercury-emissions/datasets

These risks can be exacerbated by policy in two ways. First, water-use hierarchies that give residential or agricultural water use precedence over industrial use might worsen impacts of physical scarcity on power generation. Second, areas with high water stress and low industrial water pricing are more vulnerable to policy change.

Coal-fired Rankine-cycle (steam) power stations are second only to nuclear power stations in water use. Cooling is by far the largest use of water in these power stations. The largest factor in determining the water-efficiency of stations is the type of cooling system installed. Secondary factors are the ambient temperature and station efficiency[347].

***Table 22:** Water use in electric power generation*[348]

		Cooling Technology		
Fuel-Type	Once-Through	Closed-Cycle (Wet)	Hybrid (Wet/Dry)	Dry Cooling
Coal	95,000-171,000	2,090-3,040	1,045-2,755	~0
Gas	76,000-133,000	1,900-2,660	950-2,470	~0
Oil	76,000-133,000	1,900-2,660	950-2,470	~0
Nuclear	133,000-190,000	2,850-3,420	Applicability[1]	Applicability[1]

Previous research shows that there is strong evidence to suggest that unavailability of water resources is a legitimate concern to the profitability of power stations[349]. In India, coal-water risks have forced nationwide blackouts and water shortages that restrict plants from operating at full capacity and have been shown to quickly erode the profitability of Indian power stations[350]. In China, attempts to abate local air pollution in eastern provinces have pushed coal-fired power generation into western provinces, where there is extreme water scarcity and shortages are expected[351].

The following approach is taken to identify risks to utilities that may be created by physical water stress as well as social or regulatory water risks. The Baseline Water Stress geospatial dataset from WRI's Aqueduct is used to assess physical water stress-related risks. Social and regulatory risks are assessed at the national level in NRH-U9 . Power station cooling technology is taken from the WEPP database and visual inspection of satellite imagery provided via Google Earth during late 2015. It was not possible to identify the cooling technology of 29% of coal plants.

The measure for water stress used in this report is Baseline Water Stress (BWS) from Aqueduct created by the World Resources Institute (WRI). BWS is defined as total annual water withdrawals (municipal, industrial, and agricultural) expressed as a percentage of the total annual available flow within a given watershed. Higher values indicate greater competition for water among users. Extremely high water stress areas are determined by WRI as watersheds with >80% withdrawal to available flow ratios, 80-40% as high water stress, 40-20% as high to medium, 20-10% as medium to low, and <10% as low.[352]

[347] Caldecott, B., Dericks, G., & Mitchell, J. (2015). Op. Cit.

[348] Electric Power Research Institute (EPRI) (2008). Water Use for Electric Power Generation. Palo Alto, US.

[349] EPRI (2008). Op. Cit.

[350] IEA (2012). Op. Cit.

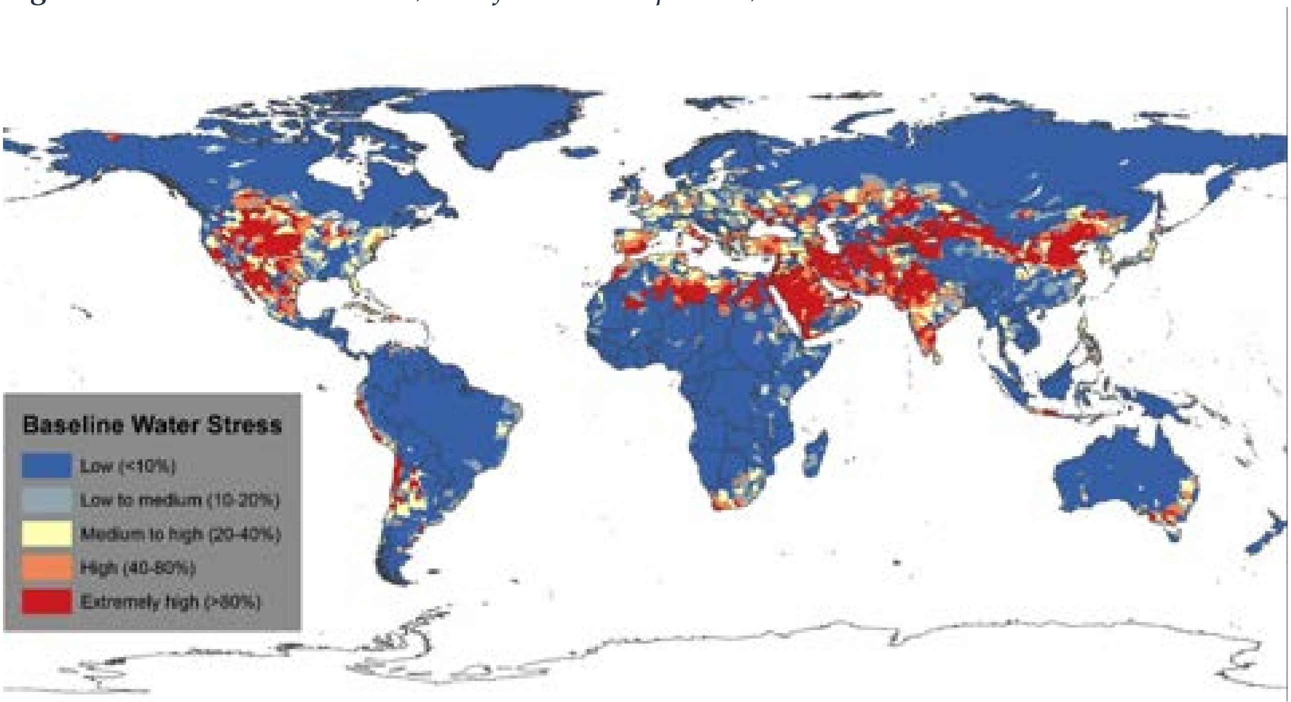
[351] CTI (2014). Op. Cit.

[352] Gassert, F., Landis, M., Luck, M., et al. (2014). Aqueduct global maps 2.1: Constructing decision-relevant global water risk indicators, World Resources Institute. Washington, US.

All coal-fired power stations are mapped against the Aqueduct Baseline Water Stress geospatial dataset. Those power stations that are in watersheds that have 'extremely high water risk'[353] for baseline water stress are identified as 'at risk'. If a power station uses dry cooling technology, it is reclassified as 'not at risk'.

Power stations are then aggregated by utility to identify the percentage of capacity that is 'at risk'. Figure 35 shows global baseline water stress.

Figure 35: *Baseline water stress, data from WRI aqueduct, 2015*



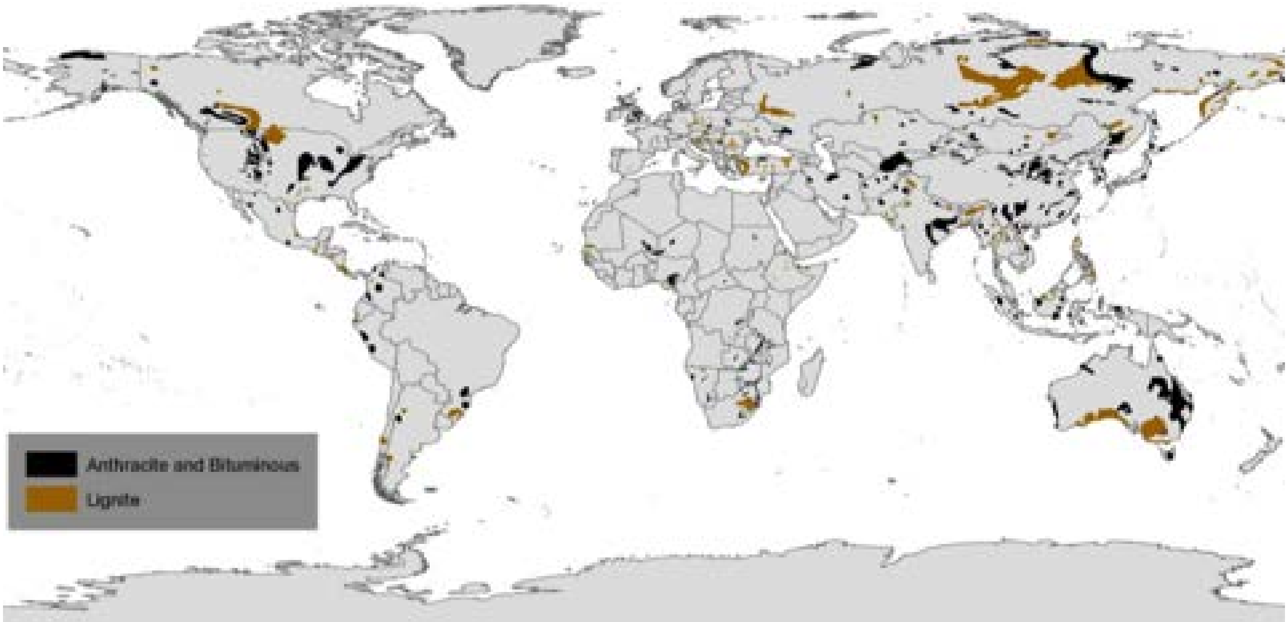
LRH-U5: Quality of Coal

The hypothesis is that coal-fired power stations that use lignite are more at risk than those that use other forms of coal. This is because their greater pollution impact makes them more exposed to regulatory risk.

Coal from different deposits varies widely in the quality and type of pollutants it will emit when combusted. With regards to CO_2, lignite uniformly emits the most for a given unit of power. Therefore, power stations that burn lignite exclusively are likely to be more vulnerable to carbon regulations. Data on individual power station use of lignite was compiled from CoalSwarm and WEPP. However, for 29% of coal plants the coal type could not be identified from these sources. These remaining power stations were classified as burning lignite if they are co-located with lignite reserves according to Figure 36.

[353] Baseline water stress measures the ratio of total annual water withdrawals to total available annual renewable supply, accounting for upstream consumptive use. Extremely high water risk signifies that >80% of renewable supply is withdrawn.

Figure 36: *World coal deposits by type, data from various sources: compiled by Oxford Smith School.*



LRH-U6: CCS Retrofitability

The hypothesis is that coal-fired power stations not suitable for the retrofit of carbon capture and storage (CCS) technology might be at more risk of premature closure. These power stations do not have the option of CCS retrofit in the case of strong GHG mitigation requirements on coal-fired power utilities, enforced either with targeted policy or with carbon pricing. Because CCS plays a large part in in the IPCC and IEA's 2°C scenarios (IPCC AR5 2DS) as well as the IEA's 2°C scenarios[354] (IEA ETP, IEA WEO 450S), it is necessary to evaluate the retrofitability of power stations to assess the resilience of utilities' generation portfolio to policies aiming to align power generation emissions with a 2DS.

No dataset exists for CCS retrofitability.[355] Instead, this is defined as a function of power station size, where only boilers larger than 100MW are economic to retrofit;[356,357] age, where only power stations <20 years old are worth making significant investments in;[358,359] efficiency, where more efficient power stations are more suitable for CCS economically; location, where power stations are within 40km of geologically suitable areas are economically suitable;[360] and policy, where nations with a favourable levels of interest and favourable policy frameworks.[361]

The following approach is taken to identify the percentage of utilities' coal-fired power generation portfolios that may be suitable for CCS retrofits. CCS policy support is considered separately as a NRH.

[354] Refers specifically to the IPCC AR5 430-480PPM, IEA ETP 2DS, and IEA WEO 450S.

[355] IEA (2012). Op. Cit.

[356] National Energy Technology Laboratory (NETL) (2011). Coal-Fired Power Plants in the United States: Examination of the Costs of Retrofitting with CO2 Capture Technology, DOE. Washington, US.

[357] Although MITei (2009). Retrofitting of Coal-fired Power Plants for CO2 Emission Reductions. suggests that 300MW is the threshold for power stations generally, 100MW is taken as a conservative case.

[358] NETL (2011). Op. Cit.

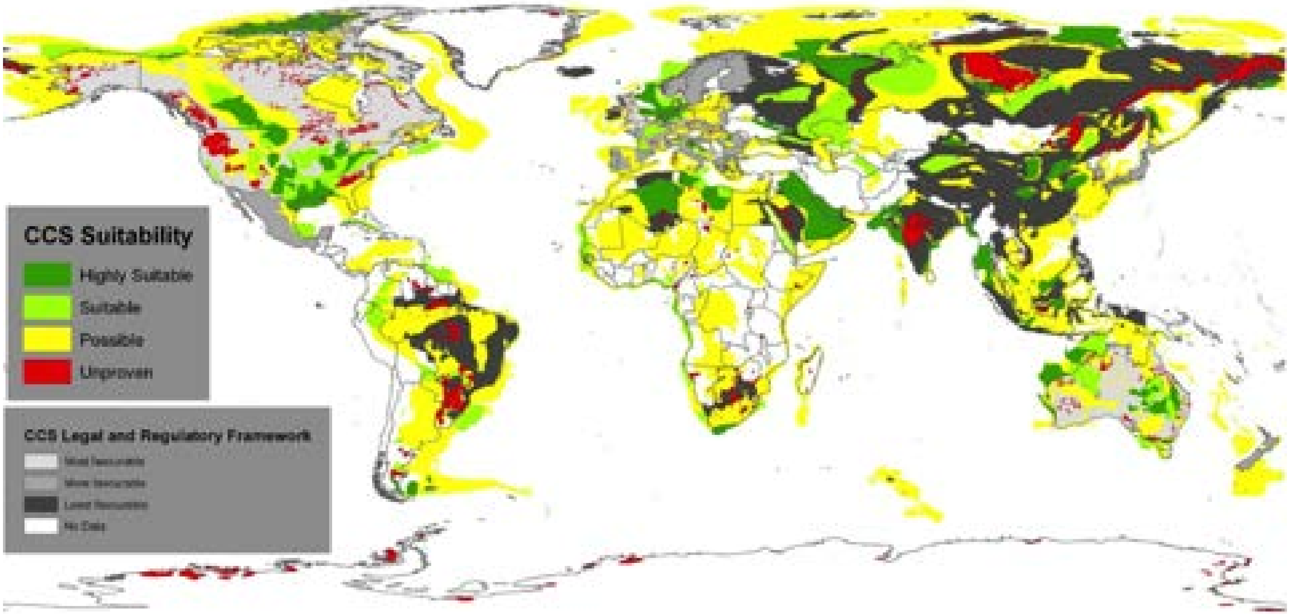
[359] This is the central scenario of the OECD CCS retrofit study.

[360] 40km has been suggested as the distance to assess proximity to geological reservoirs, see NETL (2011).

[361] As defined by Global CCS Institute (2015). CCS Legal and Regulatory Indicator. Op. Cit.

Power stations with generators larger than 100MW, that are younger than 20 years, and emit <1000g CO_2/KWh are deemed technically suitable for CCS retrofit, and are then mapped against the Global CCS Suitability geospatial dataset to determine whether they are within 40km of areas highly suitable for CCS, and therefore geographically suitable. Power stations that are both technically and geographically suitable are aggregated by utility to identify the percentage of utilities' generation portfolio that is 'suitable' for CCS retrofit. Figure 37 shows global CCS geological suitability and policy support.

Figure 37: *CCS geological suitability*[362]



LRH-U7: Future Heat Stress

The hypothesis is that physical climate change will exacerbate heat stress on power stations. Higher ambient local temperatures decrease power station efficiency and exacerbate water stress, which causes physical risks, such as forced closure or reduced operation, and social risks, such as unrest and increased potential for regulation.

There is strong evidence that warming risks should be taken into account. In Australia, there is evidence that climate change poses direct water-related risks to Australian coal-fired power generation. During a heat wave in the 2014 Australian summer, electricity demand increased in tandem with water temperatures. Loy Yang power station's generating ability was greatly reduced because it could not cool itself effectively[363]. This caused the spot price to surge to near the market cap price[364]. Inability to produce power at peak demand times has the capacity to significantly impact power stations' profits in competitive energy markets.

To assess vulnerability of power stations to climate change-related temperature increases, the Intergovernmental Panel on Climate Change's AR5 2035 geospatial dataset is used. This dataset gives a spatial representation of expected temperature change over in 2035.

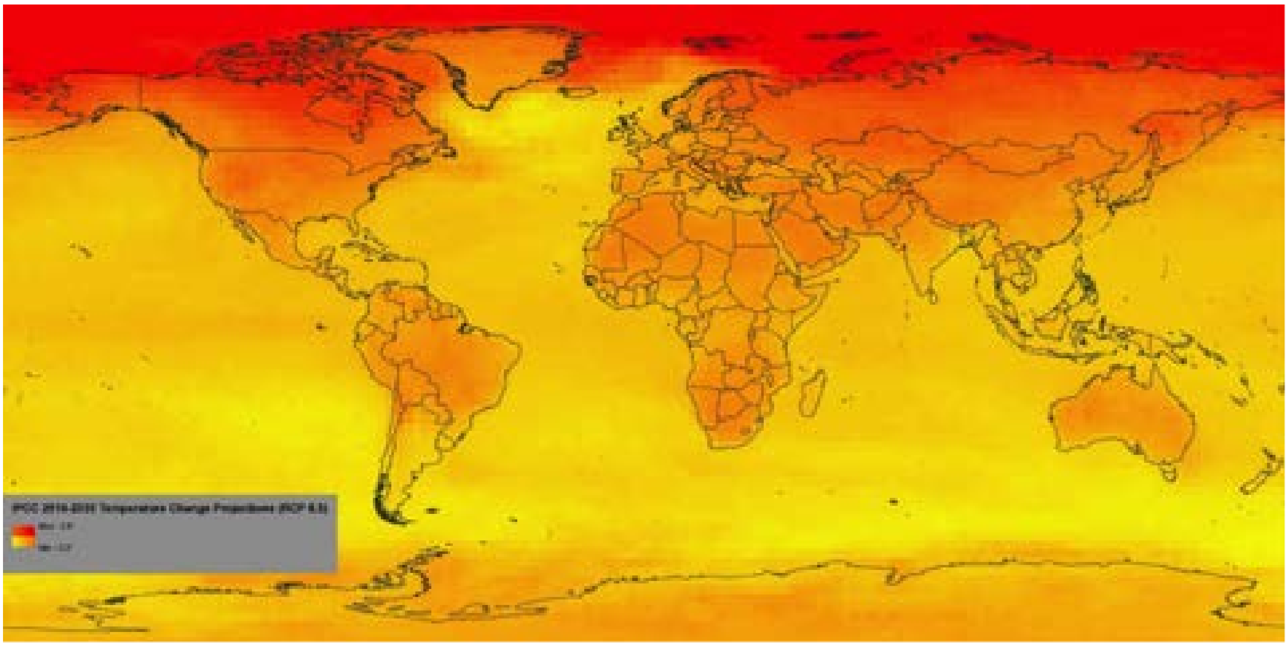
[362] Reproduced with permission of IEA GHG and Geogreen

[363] Australian Energy Market Operator (AEMO) (2014). Heatwave 13-17 January 2014.

[364] Robins, B. (2014). 'Electricity market: Heatwave generates interest in power', The Sydney Morning Herald.

Average local temperature change is matched with the location of each power station globally. Those power stations in the top quintile of temperature change are classified as 'at risk'. Power stations are then aggregated by utility to identify the percentage of capacity at risk from heat stress induced by climate change. Figure 38 shows global near-term future temperature changes.

Figure 37: *2016-35 temperature change*[365]



5.2.2 National Risk Hypotheses

The hypotheses below have been developed on a country-by-country basis, affecting all the generating assets in that country. A simple traffic light method has been used to conduct analysis for these risk hypotheses. Traffic-light methods are well suited to complex situations where more formal analysis is unavailable or unnecessary, and are particular prevalent in environmental and sustainability analysis, e.g. DEFRA[366], the World Bank[367]. The hypotheses developed below draw on the IEA NPS as a conservative scenario and add extra evidence to give a more complete policy outlook for coal-fired utilities. The time horizon for these risk indicators is near- to mid-term, using the IEA's 2020 projections where appropriate.

An effective traffic light method clearly describes threshold values or criteria for each colour that are testable by analysis or experiment[368]. Criteria are developed below for each hypothesis, with conclusions as to whether coal-fired utilities in that country are at high risk (red), medium risk (yellow) or low risk (blank). Based on each of these criteria, an aggregate outlook is given after scoring each (+2 for high risk criteria, +1 for medium risk criteria). These scores can be used for an aggregate outlook for coal-fired power generation in each country. Table provides a summary of all the country-level environment-related risk hypotheses for coal-fired utilities.

[365] Data from IPCC AR5 WGII, RCP8.5 P50.

[366] UK Department for Food, Environment, and Rural Affairs (DEFRA) (2013). Sustainable Development Indicators. London, UK.

[367] The World Bank (2016). RISE Scoring Methodology. http://rise.worldbank.org/Methodology/Scoring-methodology.

[368] Halliday, R., Fanning, L., & Mohn, R. (2001). 'Use of the Traffic Light Method in Fishery Management Planning', Fisheries and Ocean Science, Canadian Science Advisory Secretariat. Dartmouth, Canada.

Table 23: *Summary of national risk hypotheses*

High Risk (+2) Medium Risk (+1) Low Risk (+0)	Australia	China	Germany	Indonesia	India	Japan	Poland	South Africa	United Kingdom	United States
NRH-U1: Electricity Demand Outlook	Medium	Low	High	Low	Low	High	High	Medium	High	Medium
NRH-U2: Utility Death Spiral	High	Low	High	Low	Low	High	Low	Low	Medium	High
NRH-U3: Renewables Resource	High	Low	Low	Medium	Medium	Low	Medium	High	Medium	Medium
NRH-U4: Renewables Policy Support	Medium	High	High	Low	High	High	Low	Medium	Medium	High
NRH-U5: Renewables Generation Outlook	Medium	Medium	High	Low	Low	Medium	High	High	High	Low
NRH-U6: Gas Generation Outlook	Medium	High	Low	High	Medium	Medium	Low	Low	Low	High
NRH-U7: Gas Resource	High	High	Low	Medium	Low	Low	Low	Low	Low	High
NRH-U8: Falling Utilisation Rates	High	High	Medium	Low	High	Low	High	High	High	High
NRH-U9: Regulatory Water Stress	Low	Medium	Low	High	Medium	Low	Low	Medium	Low	Low
NRH-U10: CCS Legal Environment	Low	High	Medium	High	High	Medium	Medium	High	Low	Low
TOTAL (/20)	12	12	10	8	9	9	8	11	9	12

NRH-U1: Electricity Demand

The hypothesis is that the greater the growth in demand for electricity, the less likely other forms for generation (e.g. solar, wind, gas, and nuclear) are to displace coal-fired power. Growth in overall electricity demand might allow coal-fired generators to maintain or increase their current share of power generation.

We examine electricity demand outlooks from the IEA WEO 2015. As described in Section 1.3, the NPS is used here as a conservative scenario. Due to the IEA's country groupings, single-country outlooks are not available for all countries. The outlook for Australia is comingled with outlooks for New Zealand and South Korea. The outlook for Indonesia is comingled with a number of other countries in southeast Asia. The outlooks for the UK, Germany, and Poland are identical, all having been derived from the outlook for the EU.

Countries which have 0% projected electricity demand growth between 2013 and 2020 are considered 'high risk'. Countries with 1% or 2% growth are considered 'medium risk'. Countries with >2% growth are considered 'low risk'.

Table 24: 2013-20 electricity demand outlook from IEA WEO 2015 NPS[369]

2013 - 2020	Australia	China	Germany	Indonesia	India	Japan	Poland	South Africa	United Kingdom	United States
CAGR	2%	4%	0%	4%	6%	0%	0%	1%	0%	1%
RISK	🟡	🟢	🔴	🟢	🟢	🔴	🔴	🟡	🔴	🟡

NRH-U2: 'Utility Death Spiral'

The hypothesis is that if utility death spirals (see Box 2) are taking place, coal-fired power stations are more likely to face lower wholesale electricity prices and other forms of power sector disruption.

The utility death spiral is a phenomenon which can lead to the rapid, unforeseen erosion of a coal-fired utility's business model. Companies experiencing the utility death spiral are likely to have to adapt to the new risks and opportunities of energy transition. A utility death spiral is arguably one of the reasons why German utility E.On SE decided to separate its renewable and conventional power interests, with its rival RWE AG to follow suit in December 2015. For the different countries in scope we have looked for evidence for whether power markets are experiencing a utility death spiral and these are summarised below.

Table 25: Countries showing evidence of the utility death spiral

Country	Reference	RISK
Australia	Strong evidence of the utility death spiral[370]	🔴
China	No evidence of the utility death spiral	🟢
Germany	Strong evidence of the utility death spiral[371]	🔴
Indonesia	No evidence of the utility death spiral	🟢
India	No evidence of the utility death spiral	🟢
Japan	Strong evidence of the utility death spiral[372]	🔴
Poland	No evidence of the utility death spiral	🟢
South Africa	No evidence of the utility death spiral	🟢
United Kingdom	Low evidence of the utility death spiral[373]	🟡
United States	Strong evidence of the utility death spiral[374]	🔴

[369] IEA (2015). WEO 2015. Op. Cit.

[370] AER (2014). Op. Cit.

[371] Lacey, S. (2014). 'This Is What the Utility Death Spiral Looks Like', Greentech Media.

[372] Rising rates and falling costs leading to grid parity for solar PV, see Kimura, K. (2015). 'Grid Parity – Solar PV Has Caught Up with Japan's Grid', Japan Renewable Energy Foundation.

[373] Costello, M. & Jamison, S. (2015). Op. Cit.

[374] Moody's Investor Service (2014). 'Moody's: Warnings of a utility 'death spiral' from distributed generation premature', Global Credit Research. New York, US.

NRH-U3: Renewables Resource

The hypothesis is that the availability of strong renewable resources is a key determinant of the competiveness of renewables relative to conventional generation. Countries with larger renewables resources could see larger and faster rates of deployment. This would result in coal-fired power stations being more likely to face lower wholesale electricity prices and other forms of power sector disruption.

Wind resource potential is drawn from Lu et al. (2009) and is normalised by 2014 total electricity generation. Solar resource potential is drawn from McKinsey & Company and SolarGIS. Where either solar resource exceeds 1400 kWh/kWP or wind resource exceeds ten times the annual electricity demand of the country, coal-fired power generation in the country is considered at 'medium risk' of displacement by renewables. Where both exceed these thresholds, coal-fired power is considered at 'high risk'.

***Table 26:** Renewables resources*

	Australia	China	Germany	Indonesia	India	Japan	Poland	South Africa	United Kingdom	United States
Wind resource [TWh/TWh][375,376]	405.0	7.8	6.5	4.4	3.3	3.8	22.0	31.7	29.8	20.5
Solar resource [kWh/kWP][377,378]	1425	1300	950	1400	1450	1175	~950	1500	875	1250
RISK	🔴	🟢	🟢	🟡	🟡	🟢	🟡	🔴	🟡	🟡

NRH-U4: Renewables Policy Support

The hypothesis is that countries with robust regimes for supporting renewables will see greater renewables deployment. This would result in coal-fired power stations being more likely to face lower wholesale electricity prices and other forms of power sector disruption.

Renewables deployment has become a policy priority as governments seek to mitigate the climate impact of power generation. Some countries offer stronger support regimes than others. Support for renewables can come at the detriment of coal-fired power generation, as renewable power displaces the market share of coal-fired power and potentially lowers wholesale market prices.

EY's renewables indicator is used to determine country-specific renewables support. EY's indicator is comprehensive and includes policy support and readiness. Further details of policy in individual countries policy are given in Section 4. Renewables support indicates a risk for coal-fired utilities. Where EY's aggregate ranking is above 60, the countries are considered 'high risk'. Where over 50 they are considered 'medium risk'.

[375] Lu, X., McElroy, M., & Kiviluoma, J.. (2009). 'Global potential for wind-generated electricity', PNAS 106: 10933-10938.
[376] BP plc (2015). Op. Cit.
[377] SolarGIS (2015). 'Global Horizontal Irradiation', GeoModel Solar. http://solargis.info/doc/free-solar-radiation-maps-GHI
[378] Frankel, D., Ostrowski, K., & Pinner, D. (2014). 'The disruptive potential of solar power', McKinsey Quarterly, McKinsey & Company.

***Table 27:** Renewables policy support*[379]

	Australia	China	Germany	Indonesia	India	Japan	Poland	South Africa	United Kingdom	United States
EY: Renewable Energy Country Attractiveness Index	56.0	75.6	66.3	41.8	62.15	64.5	45.8	53.2	58.5	73.3
RISK	●	●	●	●	●	●	●	●	●	●

NRH-U5: Year-on-Year Renewables Growth
The hypothesis is that rapid renewables deployment would result in coal-fired power stations being more likely to face lower wholesale electricity prices and other forms of power sector disruption.

High year-on-year renewables growth indicates that these pressures might be increasing in particular power markets. We use the growth in installed renewables capacity (GW) and the growth in the proportion of renewable power generation to estimate exposure to year-on-year renewables growth. Data for installed capacity of renewables were collected from a number of sources, but principally the annual REN21 Global Status Reports. Data for renewable and total power generation were drawn from the BP Statistical Energy Outlook 2015.

Where the CAGR in renewable power generation as a portion of total generation exceeds 10%, and where CAGR in renewable power capacity exceeds 10%, the country is considered 'high risk'. Where only one exceeds 10%, the country is 'medium risk'.

[379] EY (2015). Renewable Energy Country Attractiveness Index.

Figure 39: *Proportion of total electricity generated by renewables*[380]

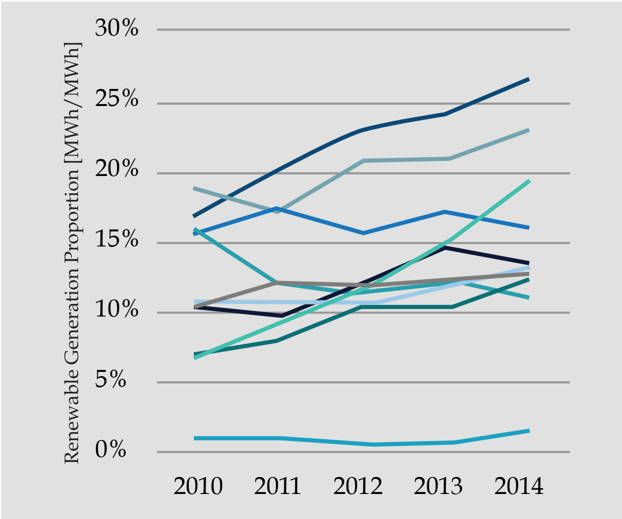


Figure 40: *Total capacity of renewable power generation*[381]

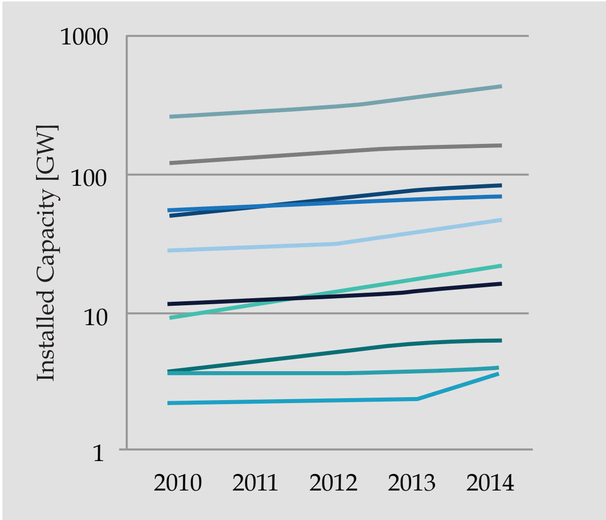


Table 28: *Year-on-year growth of renewables capacity and generation*

2010 - 2014 CAGR	Australia	China	Germany	Indonesia	India	Japan	Poland	South Africa	United Kingdom	United States
Renewables Capacity	11%	13%	14%	2%	7%	15%	15%	14%	23%	8%
Renewables Generation	8%	6%	12%	-8%	1%	6%	16%	25%	30%	7%
RISK	🟡	🟡	🔴	🟢	🟢	🟡	🔴	🔴	🔴	🟢

NRH-U6: Gas-fired Generation Outlook

The hypothesis is that the growth of gas-fired generation, particularly in markets where electricity demand growth is lower or negative, could harm the economics of coal-fired generation and result is coal-to-gas switching.

Historic and projected gas-fired generation data are drawn from the IEA WEO. The NPS is chosen as a conservative scenario. If either historic or projected CAGR of gas-fired power generation is positive, then the outlook for coal-fired power in that country is considered 'medium risk'. If both are positive, then the outlook is considered 'high risk'.

[380] BP plc (2015). Op. Cit.

[381] REN21 (2015). Op. Cit.

Table 29: Natural gas-fired power generation outlook[382]

CAGR	Australia	China	Germany	Indonesia	India	Japan	Poland	South Africa	United Kingdom	United States
2010-13 Historic	11%	10%	-13%	2%	-18%	10%	-13%	N/A	-13%	4%
2013-20 NPS	0%	17%	0%	2%	6%	-4%	0%		0%	2%
RISK	🟡	🔴	🟢	🔴	🟡	🟡	🟢	🟢	🟢	🔴

NRH-U7: Gas Reserves and Production Growth
The hypothesis is that the growth of gas-fired generation, particularly in markets where electricity demand growth is low or negative, could harm the economics of coal-fired generation and result in coal-to-gas switching. Gas-fired generation is more likely to be competitive in countries where there are large domestic reserves and growing domestic gas production.

Gas can compete directly with coal in the supply of dispatchable, baseload electricity. Gas-fired electricity also has the advantage of being less carbon intensive and more efficient than coal-fired power. We examine data on proven natural gas reserves and the growth in gas production drawn from the BP Statistical Energy Review 2015. Coal-fired utilities are more at risk in countries which have large reserves of gas and growing gas production. Countries which have either >1% of global reserves or a CAGR in gas production of >0% are considered 'medium risk'. Countries with both are considered 'high risk'.

Table 30: Natural gas reserves and production growth[383]

CAGR	Australia	China	Germany	Indonesia	India	Japan	Poland	South Africa	United Kingdom	United States
Natural gas reserves	2.0%	1.8%	0.0%	1.5%	0.8%	0.0%	0.1%	0.0%	0.1%	5.2%
Production growth (2010-14 CAGR)	5%	8%	-8%	-4%	-11%	N/A	0%	N/A	-11%	5%
RISK	🔴	🔴	🟢	🟡	🟢	🟢	🟢	🟢	🟢	🔴

NRH-U8: Falling Utilisation Rates
The hypotheses is that under-utilised coal-fired power stations will be financially vulnerable and more prone to stranding.

[382] Ibid.
[383] IEA (2015). WEO 2015; IEA (2014). WEO 2014; IEA (2013). WEO 2013; IEA (2012). WEO 2012; IEA (2011). WEO 2011.

The entrance of new generating options may reduce the utilisation rates of coal-fired generating assets. The utilisation rate of a power generating asset is the ratio of its actual annual output to its maximum potential annual output according to its nameplate capacity. Competition on marginal costs, or must-run regulation for renewables, can displace coal-fired generation, reducing utilisation rates. Generating stations with falling utilisation rates are less able to cover fixed costs with operating profit. Generating stations in countries with continuously falling utilisation rates are considered 'at risk'.

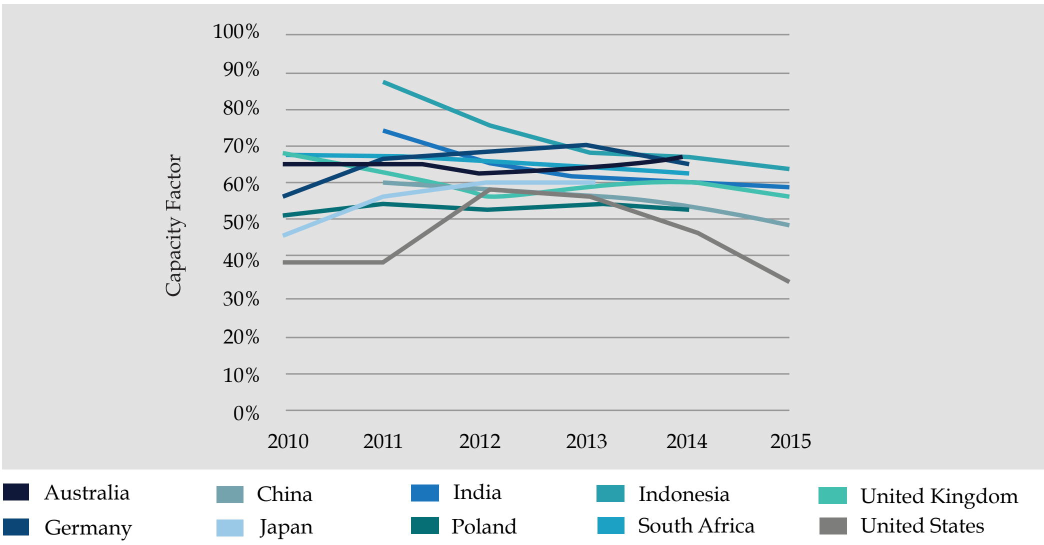
Utilisation rates have been identified for scope countries in Figure 41 and Table 31.

***Table 31:** Coal-fired utilisation rates showing data completion*[382]

Country	2010	2011	2012	2013	2014	2015
Australia	67%	66%	63%	64%	66%	
China		60%	58%	58%	54%	50%e
Germany	57%	66%	68%	70%	66%	
Indonesia		88%	76%	69%e	68%e	65%e
India		74%	66%	62%	61%	59%e
Japan*	47%	57%	60%	60%		
Poland*	51%	54%	53%	55%	54%	
South Africa*	68%	68%	65%	64%	63%	
United Kingdom	40%	41%	57%	57%	48%	34%i
United States	68%	64%	57%	60%	61%	56%ii

* Comingled with all thermal generation, i Up to Q3 2015, ii Up to November 2015, e: Estimate.

***Figure 41:** Coal-fired utilisation rates*



Policy research has also been conducted to identify the countries where the marginal growth of either renewables or gas directly replaces existing or new coal-fired power capacity. A subjective judgement of risk to coal-fired utilities is made. See the policy summaries in Table 32 for detail.

[382] Data sources: various; Oxford Smith School calulation

__Table 32:__ Power displaced by emerging renewables and gas

Country	Generation Displaced	Reference	RISK
Australia	Coal	Natural gas and renewables expected to continue past trend of displacing coal-fired power[384]	🔴
China	Coal	Renewables and natural gas deployment align well with Chinese interests in reducing conventional air pollution	🔴
Germany	Nuclear	Post-Fukushima, the political environment for nuclear power changed – nuclear power is now prioritised for decommissioning under the Energiewende, followed by coal[385]	🟢
Indonesia	Oil	Indonesia has many islands with disconnected grids powered by oil engines. Indonesia's immediate priority is to reduce oil-fired power[386]	🟢
India	Coal	India has little other generation which could be disrupted by renewables and gas	🔴
Japan	Oil	In Fukushima's aftermath, Japan's priority was to close nuclear power stations. Renewables, gas, and re-opening nuclear are clawing back reactivated oil-fired generating capacity[387]	🟢
Poland	Coal	Poland has little other generation which could be disrupted by renewables and gas	🔴
South Africa	Coal	South Africa has little other generation which could be disrupted by renewables and gas	🔴
United Kingdom	Coal	The UK government has committed to phasing out coal-fired power stations by 2025[388]	🔴
United States	Coal	Inexpensive natural gas and renewable energy policies ensures that both gas-fired and renewable power displace coal-fired power.	🔴

Where both historic utilisation rates and policy research indicate risk, the country is considered 'high risk'. Where one of either indicates risk, the country is considered 'medium risk'.

[384] AER (2014). Op. Cit.
[385] Appunn, K. & Russell, R. (2015). Op. Cit.
[386] Sakya, I. (2012). Op. Cit.
[387] Iwata, M. & Hoenig, H. (2015). Op. Cit.
[388] UK Government (2015). Op. Cit.

Table 33: Utilisation rate risk hypothesis

CAGR	Australia	China	Germany	Indonesia	India	Japan	Poland	South Africa	United Kingdom	United States
Utilisation rate - Historic	🟢	🟡	🟢	🟡	🟡	🟢	🟢	🟡	🟢	🟢
Utilisation rate - Outlook	🟡	🟡	🟢	🟢	🟡	🟢	🟡	🟡	🟡	🟡
RISK	🟡	🔴	🟢	🟡	🔴	🟢	🟡	🔴	🟡	🟡

NRH-U9: Regulatory Water Stress

The hypothesis is that coal-fired power stations in countries that have strict water use requirements and an awareness of water issues are more likely to be affected by water scarcity through direct or indirect water pricing.

Coal-fired power generation has a substantial water footprint, described in hypothesis LRH-U4: Water Stress. This water footprint exposes coal-fired power utilities to regulatory risks, as policymakers may take action to restrict or price a utility's access to water. Public opinion on the water footprint of power generation may also put pressure on policymakers to restrict water use, exposing utilities to a reputational risk as well.

The World Resources Institute (WRI) maintains the Aqueduct Water Risk Indicator maps. The WRI's Regulatory & Reputational Risk indicator aggregates indicators from the World Health Organization (WHO) concerning water access, the International Union for Conservation of Nature (IUCN) for threatened amphibians, and Google keyword searches for water supply media coverage[389]. With few exceptions, this indicator is provided at the national level.

WRI provides an indicator in five groupings, with low risk in group 1 and very high risk in group 5. In this report, WRI groups 1 and 2 will be considered 'low risk', group 3 will be considered 'medium risk' and group 4 and 5 'high risk'. Of the scope countries, only the United States has multiple subnational stress indicators, however none exist outside groups 1 and 2, allowing consistency with this method.

Table 34: Regulatory water stress[390]

CAGR	Australia	China	Germany	Indonesia	India	Japan	Poland	South Africa	United Kingdom	United States
Risk grouping	1	3	1	4	3	1	2	3	2	1
RISK	🟢	🟡	🟢	🔴	🟡	🟢	🟢	🟡	🟢	🟢

[389] Gassert, F. et al. (2014). Op. Cit.
[390] IEA (2015) WEO 2015. Op. Cit.

NRH-U10: CCS Legal Environment

The hypothesis is that CCS could be a way for coal-fired power stations to keep running under stricter carbon constraints, but CCS will not happen without a supportive legal framework.

CCS faces substantial uncertainty with regards to current and future liabilities for the unique aspects of a CCS project, see Section 3.6.2. These uncertainties can present barriers to the development of CCS projects, which in turn present a risk to coal-fired utilities which may not have CCS as an option for future GHG mitigation.

Certain countries have been proactive in developing policy and law specifically for CCS. This progress is periodically evaluated by the Global CCS Institute and published as an indexed indicator. The institute groups countries into three performance bands, which are used here as an indicator for CCS liability risk. Band A, the most CCS-ready, is considered 'low risk', Band B 'medium risk', and Band C 'high risk'.

Table 35: *CCS legal environment indicator*[391]

CAGR	Australia	China	Germany	Indonesia	India	Japan	Poland	South Africa	United Kingdom	United States
Band	A	C	B	C	C	B	B	C	A	A
RISK	●	●	●	●	●	●	●	●	●	●

[391] Global CCS Institute (2015). CCS Legal and Regulatory Indicator. Op. Cit.

5.3 Summary of Top 100 Coal-Fired Power Utilities

Exposure to environment-related risk of the top 100 coal-fired power utilities is shown in Figure 42 below. For the Local Risk Hypotheses, Table 64 in Appendix A provides further details of the results. Table 36 shows the top 100 coal-fired utilities ranked by risk exposure, with the most exposed ranked the highest. Companies from the United States carry the most exposure to ageing plants (LRH-U2), CCS retrofitability (LRH-U6), and future heat stress (LRH-U7). Companies in China and India are most exposed to conventional air pollution concentration (LRH-U3) and physical water stress (LRH-U4).

Figure 42: *LRH rankings for coal-fired utilities*

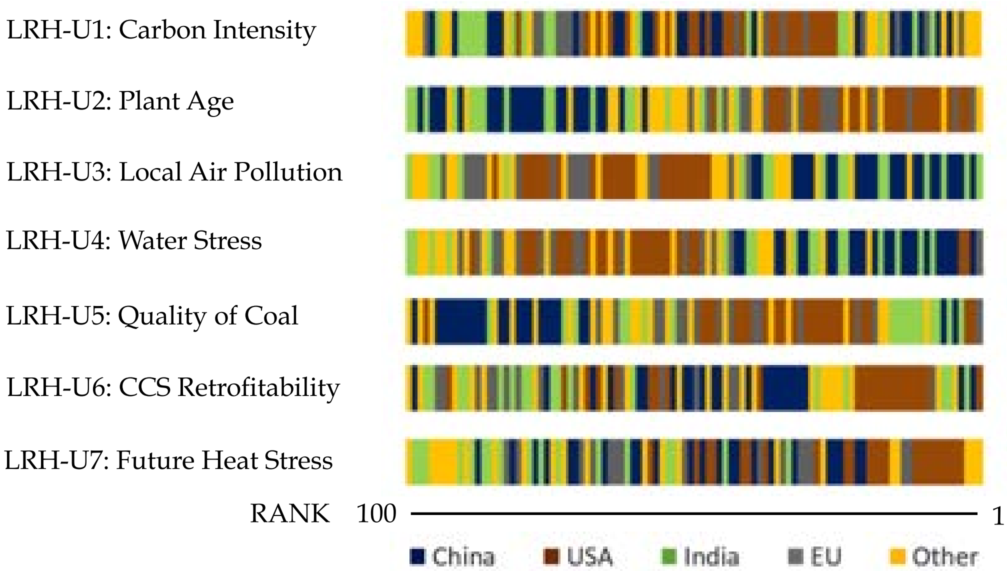


Figure 43 and Figure 44 show planned and under construction new coal-fired generating capacity as a proportion of existing capacity. Utilities in the United States have largely abandoned new coal-fired capacity. Utilities in China and India continue to build and plan power stations. Seven of the 16 Indian utilities in the top 100 are more than doubling their current coal-fired generating capacity. Other outliers include J-Power, Gazprom, Inter RAO UES, Taiwan's Ministry of Economic Affairs, Elektroprivreda Srbije, and Electricity of Vietnam.

Figure 43: *Planned coal-fired capacity as a percentage of current capacity*

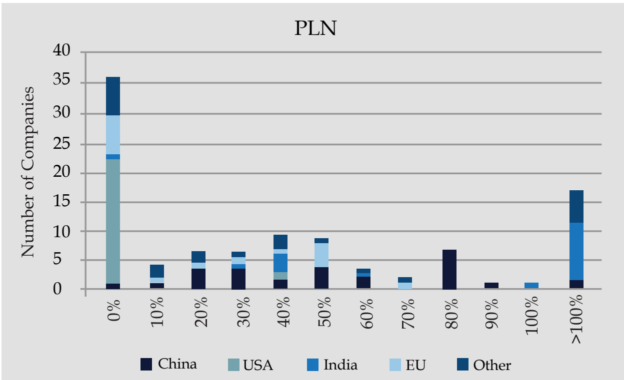


Figure 44: *Coal-fired capacity under construction as a percentage of current capacity*

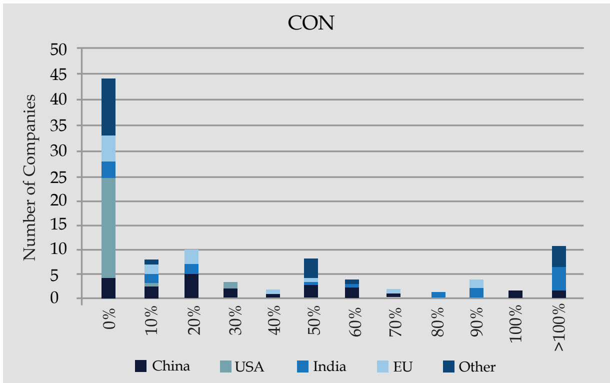


Figure 45 shows the ratios of (EBITDA less CAPEX) / debt repayment for the top 100 coal-fired power utilities. Companies with a ratio less than unity cannot currently service their existing debt. Companies with a negative ratio are expending CAPEX in excess of EBITDA. The five companies with a ratio less than -1 are Vattenfall Group, Eskom Holdings SOC Ltd, Comision Federal de Electricidad, Tauron Polska Energia SA, and Andhra Pradesh Power Gen Corp.

Figure 45: *Histogram of (EBITDA-CAPEX)/interest*

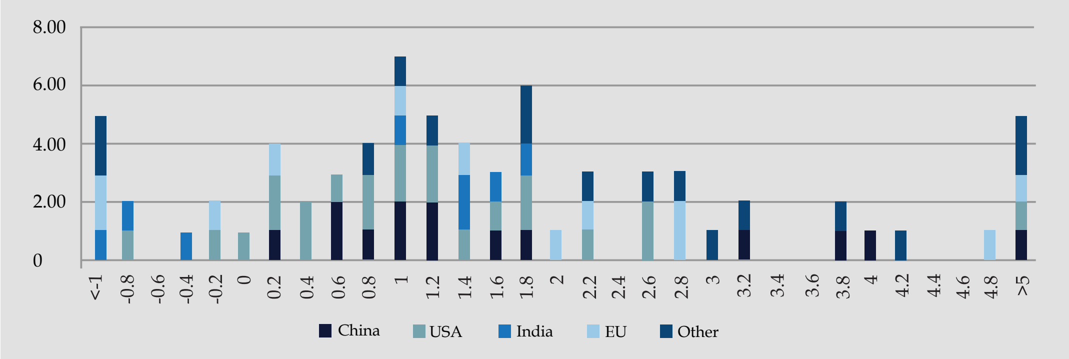


Figure 46 shows the current ratios of the top 100 coal-fired power utilities. European coal-fired utilities have higher current ratios than coal-fired utilities in the United States, which in turn have higher current ratios than Chinese coal-fired power utilities.

Figure 46: *Histogram of current ratios*

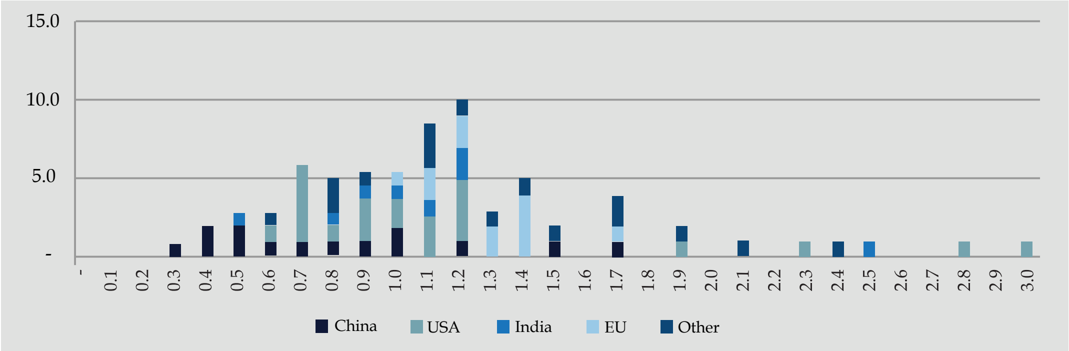


Figure 47 shows the debt-to-equity (D/E) ratios of the top 100 coal-fired power utilities. Utilities in the US are generally more leveraged than utilities in China or Europe. Outliers include Tohuku Electric Power Corp and AES Corp, the only public companies with D/E ratios over 300%.

Figure 47: *Histogram of D/E ratios*

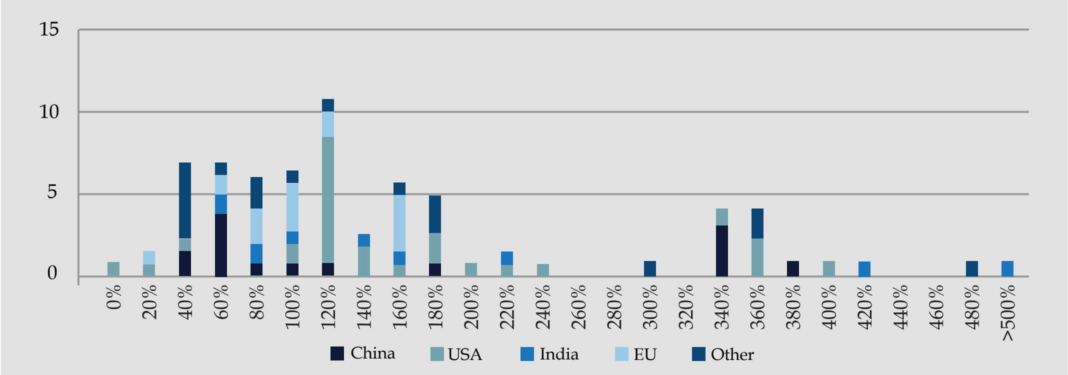


Table 36: Summary of environment-related risk exposure of top 100 coal-fired power utilities, companies

#	PARENT OWNER	COUNTRY	Coal-Fired Electricity GENERATION [GWh]	CAPACITY OPR [MW]	CAPACITY CON [MW]	CAPACITY PLN [MW]	DEBT/EQUITY	CURRENT RATIO	(EBITDA-CAPEX) /INTEREST	LRH-U1 'Carbon Intensity' [RANK]*	LRH-U2 'Plant Age' [RANK]*	LRH-U3 'Local Air Pollution' [RANK]*	LRH-U4 'Water Stress' [RANK]*	LRH-U5 'Quality of Coal' [RANK]*	LRH-U6 'CSS Retrofitability' [RANK]*	LRH-U7 'Future Heat Stress' [RANK]*	ASSET BASE	NRH-AGGREGATE**
1	CHINA HUANENG GROUP CORP	China	471,139	160,212	5,360	91,968	3.28	0.45x	0.42x	57	53	37	25	27	83	51	CH-100%	60%
2	CHINA GUODIAN CORP	China	455,038	148,539	20,140	111,360	3.38	0.24x	0.85x	53	52	33	21	32	78	37	CH-100%	60%
3	CHINA DATANG CORP	China	415,118	123,635	12,230	89,521	3.69	0.47x	1.16x	45	100	39	18	35	90	43	CH-100%	60%
4	CHINA HUADIAN GROUP CORP	China	369,511	119,808	21,101	95,628	3.22	0.37x	3.02x	63	100	41	20	39	84	54	CH-100%	60%
5	CHINA POWER INVESTMENT CORP	China	293,658	82,819	16,028	35,590	-	-	-	50	100	49	14	16	76	44	CH-99%	60%
6	SHENHUA GROUP CORP LTD	China	292,107	89,021	42,520	67,710	0.49	0.96x	0.62x	87	100	42	29	30	96	47	CH-100%	60%
7	ESKOM HOLDINGS SOC LTD	South Africa	214,924	36,678	19,375	3,000	1.69	1.09x	-10.67x	20	36	92	100	100	1	27	SA-100%	55%
8	NTPC LTD	India	208,588	41,532	46,520	91,056	1.24	1.16x	-0.48x	80	49	40	40	24	71	65	IN-100%	45%
9	CHINA RESOURCES POWER HOLDINGS	China	171,178	55,342	13,410	24,340	1.12	0.58x	3.65x	40	100	25	16	36	85	61	CH-100%	60%
10	KOREA ELECTRIC POWER CORP	Korea	128,189	23,481	30,459	7,880	0.92	1.03x	1.68x	38	46	14	48	42	1	48	OTHER	-
11	GUANGDONG YUDEAN GROUP CO LTD	China	126,689	43,441	9,850	13,300	-	-	-	69	100	36	100	34	1	66	CH-100%	65%
12	NRG ENERGY INC	USA	99,685	29,576	-	-	1.66	1.86x	1.76x	30	8	78	100	31	1	42	US-94%, AU-6%	60%
13	STATE GRID CORP OF CHINA	China	97,603	22,218	-	10,000	0.53	0.39x	0.00x	15	48	32	11	14	66	30	CH-100%	60%
14	GDF SUEZ SA	France	89,977	20,424	1,715	5,059	0.69	1.06x	4.67x	76	37	59	42	20	91	80	NOTE-1	47%
15	VATTENFALL GROUP	Sweden	83,646	15,719	1,730	-	0.97	1.35x	-1.16x	84	47	53	100	9	79	57	CH-81%	60%
16	SOUTHERN CO	USA	71,669	27,819	600	-	1.23	0.65x	-0.15x	49	21	87	100	40	69	53	US-100%	60%
17	DUKE ENERGY CORP	USA	67,730	22,492	-	-	1.07	0.97x	1.68x	51	17	71	100	41	67	50	US-99%	60%
18	PT PLN PERSERO	Indonesia	66,467	16,763	6,730	18,350	3.42	0.84x	0.88x	19	100	30	33	33	87	89	ID-100%	40%
19	ENEL SPA	Italy	62,916	17,937	-	2,900	1.03	0.99x	2.65x	37	24	68	46	23	1	56	OTHER	-
20	AMERICAN ELECTRIC POWER CO INC	USA	60,917	22,577	-	-	1.14	0.64x	0.76x	35	13	80	100	38	1	17	US-100%	60%
21	MINISTRY OF ECONOMIC AFFAIRS	Taiwan	59,572	10,114	17,248	-	-	-	-	94	100	1	100	100	1	60	OTHER	-
22	TENNESSEE VALLEY AUTHORITY	USA	58,991	20,756	-	-	3.81	0.89x	0.59x	27	9	79	100	100	1	19	US-100%	60%
23	E.ON SE	Germany	53,995	13,664	6,366	5,448	0.88	1.25x	2.12x	70	23	48	45	29	1	78	DE-45%, UK-15%	49%
24	ZHEJIANG ENERGY GROUP CO LTD	China	53,906	13,992	7,490	2,660	-	-	-	92	100	15	37	100	1	58	CH-100%	60%
25	FORMOSA PLASTICS CORP	Taiwan	52,212	9,328	-	-	0.38	2.35x	10.37x	67	100	43	44	100	1	100	CH-43%	60%
26	EDF GROUP	France	51,803	17,288	1,000	375	1.5	1.22x	1.36x	74	34	65	39	100	72	69	NOTE-2	45%
27	BEIJING ENERGY INVEST HOLDING	China	51,504	13,180	2,020	2,720	-	-	-	61	100	58	26	100	89	25	CH-100%	60%
28	TATA GROUP	India	46,454	8,468	1,320	21,145	-	-	-	90	100	1	34	19	1	85	IN-100%	45%
29	CLP GROUP	Hong Kong	45,835	10,118	4,500	4,272	0.72	0.58x	4.03x	54	100	47	30	22	75	77	NOTE-3	58%
30	ADANI POWER LTD	India	45,703	8,220	600	13,760	9.31	0.46x	1.29x	91	100	27	100	17	1	86	IN-100%	45%
31	RWE AG	Germany	42,639	10,793	4,268	4,926	1.59	1.16x	0.89x	31	22	18	100	5	1	88	DE-96%, 4%UK	50%
32	VEDANTA RESOURCES PLC	India	39,973	6,448	3,720	-	1.47	1.13x	0.94x	78	100	50	15	25	70	26	IN-100%	45%
33	J-POWER	Japan	39,407	6,805	2,900	12,072	-	-	-	98	100	61	32	100	1	91	JP-98%, US-2%	45%
34	HEBEI CONSTR & INVEST GROUP	China	38,874	10,362	1,400	2,100	-	-	-	12	100	56	5	100	88	29	CH-100%	60%
35	SHANXI INTL ELEC GROUP CO LTD	China	38,501	9,100	9,040	7,300	-	-	-	47	100	51	35	100	77	14	CH-100%	60%
36	DYNEGY HOLDINGS INC	USA	37,808	14,541	-	-	2.29	2.24x	1.05x	28	5	75	100	100	1	22	US-100%	60%
37	RELIANCE INFRASTRUCTURE LTD	India	36,846	9,320	7,920	5,040	0.88	1.04x	1.33x	95	100	38	6	100	1	52	IN-100%	45%
38	STATE DEV INVESTMENT CORP	China	35,269	12,325	17,226	6,570	1.61	1.10x	1.09x	72	100	28	41	100	94	28	CH-100%	60%
39	AES CORP	USA	35,246	11,216	2,356	3,542	3.2	1.10x	1.07x	36	29	69	38	100	1	68	US-62%	60%
40	PUBLIC POWER CORP (DEI)	Greece	34,147	5,597	-	2,550	0.9	1.17x	1.97x	10	42	66	100	2	1	39	OTHER	-
41	DTEK	Ukraine	33,049	13,526	1,960	6,050	-	-	-	13	11	67	24	37	1	15	OTHER	-
42	AGL ENERGY LTD	Australia	32,727	5,238	-	2,000	0.45	1.46x	2.09x	7	20	86	100	26	1	100	AU-100%	60%
43	PGE POLSKA GRUPA ENERGETYCZNA	Poland	32,687	8,784	7,595	3,934	0.12	1.60x	-0.40x	41	35	70	100	7	1	21	PD-100%	40%
44	ISRAEL ELECTRIC CORP	Israel	31,995	6,185	-	1,260	2.93	1.19x	0.71x	93	100	52	4	100	1	49	OTHER	-
45	XCEL ENERGY INC	USA	31,401	9,712	-	-	1.25	1.08x	0.25x	60	41	95	27	100	1	46	US-100%	60%
46	STEAG GMBH	Germany	31,388	7,984	-	-	-	-	-	75	39	29	100	100	73	73	DE-89%	50%
47	BERKSHIRE HATHAWAY ENERGY COMPANY	USA	30,613	11,875	-	-	0.34	1.05x	8.78x	42	32	90	17	100	1	1	US-100%	60%
48	DAMODAR VALLEY CORP (DVC)	India	30,198	8,313	6,070	7,500	0.73	0.73x	1.62x	23	100	12	100	100	1	74	IN-100%	45%
49	MP POWER GENERATING CO LTD	India	28,989	6,613	-	2,230	-	-	-	18	100	1	100	100	1	100	IN-100%	45%

*NRHs have been aggregated into one indicator, in %.
Note-1: DE-14%, IN-10%, JP-7%, PD-5%, UK-9%, US-4%;
Note-2: PD-21%, CH-7%, UK-32%;
Note-3: AU-43%, CH-37%, IN-13%;
Note-4 to: ID-72%, JP-24%, AU-4%;

Table 36: *Summary of environment-related risk exposure of top 100 coal-fired power utilities, companies continued*

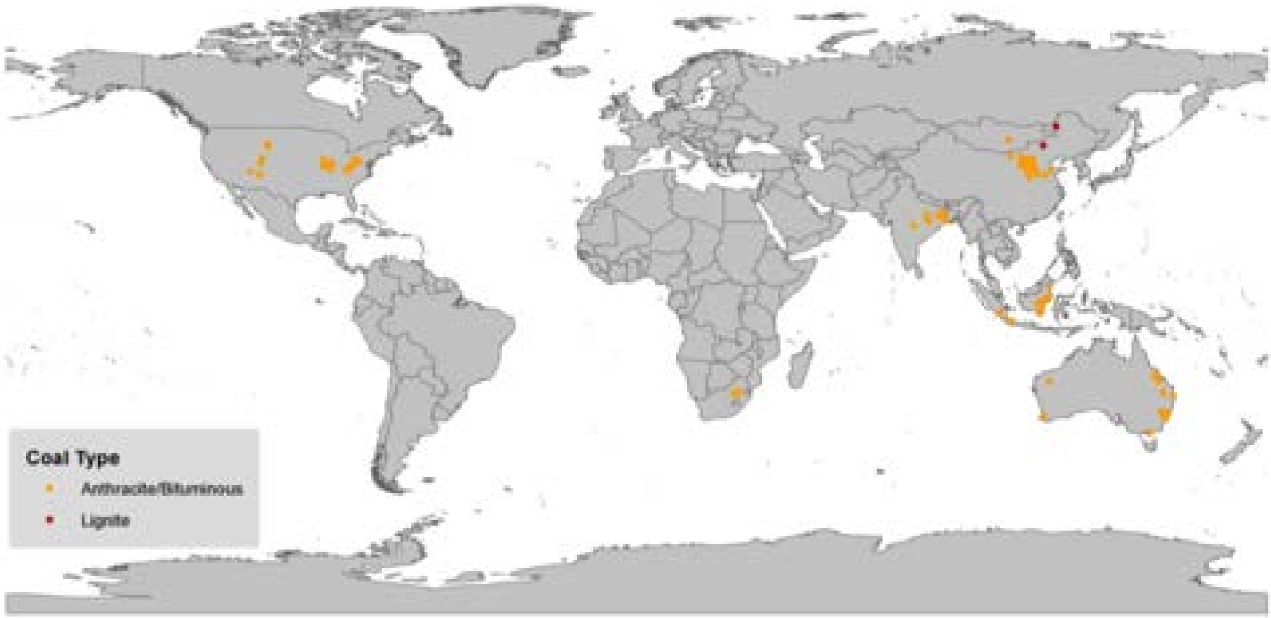
#	PARENT OWNER	COUNTRY	Coal-Fired Electricity: GENERATION [GWh]	CAPACITY: OPR [MW]	CAPACITY: CON [MW]	CAPACITY: PLN [MW]	DEBT/EQUITY	CURRENT RATIO	(EBITDA-CAPEX) /INTEREST	LRH-U1 'Carbon Intensity' [RANK]*	LRH-U2 'Plant Age' [RANK]*	LRH-U3 'Local Air Pollution' [RANK]*	LRH-U4 'Water Stress' [RANK]*	LRH-U5 'Quality of Coal' [RANK]*	LRH-U6 'CSS Retrofitability' [RANK]*	LRH-U7 'Future Heat Stress' [RANK]*	ASSET BASE	NRH-AGGREGATE**
50	SHENERGY COMPANY LTD	China	27,337	7,584	2,640	-	0.36	0.90x	0.57x	56	100	1	100	100	1	31	CH-100%	60%
51	JIANGSU GUOXIN INVEST GROUP	China	27,304	16,665	-	3,100	-	-	-	11	100	31	19	100	95	84	CH-100%	60%
52	COMISION FEDERAL DE ELEC	Mexico	27,259	4,700	2,100	1,146	4.79	1.08x	-1.28x	16	100	97	100	100	1	24	OTHER	-
53	CITIC PACIFIC LTD	China	26,846	6,309	-	350	0.96	1.46x	1.47x	22	100	13	23	100	99	64	CH-100%	60%
54	TRANSALTA CORP	Canada	26,173	5,078	-	-	1.05	1.31x	1.72x	77	33	91	100	100	1	55	US-28%	60%
55	FIRSTENERGY CORP	USA	25,844	9,950	-	-	1.76	0.65x	0.12x	34	14	81	100	100	68	20	US-100%	60%
56	GUJARAT STATE ELEC CORP LTD	India	25,757	6,094	740	2,400	-	-	-	44	100	16	9	12	81	33	IN-100%	45%
57	PPL CORP	USA	25,334	8,385	-	-	1.95	0.67x	0.73x	68	44	96	100	100	80	35	US-100%	60%
58	DOMINION	USA	24,647	6,583	-	-	2.07	0.61x	-0.30x	43	6	76	100	100	1	67	US-100%	60%
59	ANDHRA PRADESH POWER GEN CORP	India	24,602	6,980	600	12,800	4.14	0.98x	-2.43x	89	51	45	31	100	98	82	IN-100%	45%
60	CHUBU ELECTRIC POWER CO INC	Japan	24,545	4,100	-	4,265	1.64	0.73x	6.22x	100	100	100	100	100	1	100	JP-100%	45%
61	JINDAL STEEL & POWER LTD	India	24,430	7,077	-	19,570	2.06	0.84x	1.58x	81	100	46	100	100	1	72	IN-100%	45%
62	TENAGA NASIONAL BERHAD (TNB)	Indonesia	22,771	8,680	-	1,000	0.66	1.21x	3.63x	46	100	24	100	100	1	76	OTHER	-
63	OOO SIBERIAN GENERATING CO	Russia	21,894	8,308	-	340	-	-	-	5	31	63	100	15	1	12	OTHER	-
64	ENERGY FUTURE HOLDINGS CORP	USA	21,640	8,496	-	-	-1.82	0.54x	2.42x	55	40	94	100	3	86	16	US-100%	60%
65	RIVERSTONE HOLDINGS	USA	21,534	8,309	-	-	0	2.96x	-	32	15	82	22	100	1	32	US-100%	60%
66	CEZ AS	Czech	21,279	6,235	4,010	-	0.64	1.30x	6.65x	4	25	60	100	6	1	59	PD-11%	40%
67	NEYVELI LIGNITE CORP LTD	India	20,946	4,615	6,960	18,775	0.43	2.47x	-0.89x	64	100	17	1	4	92	79	IN-100%	45%
68	CHEUNG KONG INFRASTRUCTURE	Hong Kong	20,753	6,306	-	-	0.26	2.00x	3.00x	65	100	10	43	28	1	87	CH-100%	60%
69	DTE ENERGY CO	USA	20,622	7,909	-	-	1.08	1.19x	1.34x	29	3	73	100	100	1	1	US-100%	60%
70	HARYANA POWER GEN CO (HPGC)	India	20,554	6,145	-	2,120	-	-	-	9	100	20	2	13	1	41	IN-100%	45%
71	ELECTRICITY OF VIETNAM (EVN)	Vietnam	20,273	5,434	11,002	600	-	-	-	58	45	34	100	100	1	83	OTHER	-
72	GREAT PLAINS ENERGY INC	USA	19,533	5,647	-	-	1.11	1.00x	0.84x	62	16	83	100	100	1	1	US-100%	60%
73	WEST BENGAL POWER DEV CORP	India	19,160	5,480	2,600	6,500	-	-	-	14	43	1	100	100	1	100	IN-100%	45%
74	HENAN INVESTMENT GROUP CO LTD	China	18,830	6,530	6,640	1,670	-	-	-	17	100	26	8	100	82	36	CH-100%	60%
75	WISCONSIN ENERGY CORP	USA	18,779	4,493	-	-	1.15	0.82x	2.43x	79	26	88	100	100	1	34	US-100%	60%
76	INTER RAO UES	Russia	18,007	8,030	3,235	11,624	0.26	1.69x	2.81x	59	27	57	100	10	1	18	OTHER	-
77	TAMIL NADU GEN & DIST CORP LTD	India	16,842	4,320	3,590	6,880	-	-	-	73	100	1	13	100	97	100	IN-100%	45%
78	ZHEJIANG PROV ENERGY GROUP CO	China	16,476	6,260	6,020	2,460	0.48	1.68x	0.85x	83	100	22	7	100	1	81	CH-100%	60%
79	DATONG COAL MINE GROUP CO LTD	China	16,426	6,670	4,540	5,080	-	-	-	85	100	11	10	100	1	1	CH-100%	60%
80	TOHOKU ELECTRIC POWER CO	Japan	15,663	2,701	-	1,800	3.48	0.71x	2.74x	99	100	99	100	100	1	75	JP-100%	45%
81	AMEREN CORP	USA	15,222	5,829	-	-	1	0.80x	0.82x	26	4	74	100	100	1	1	US-100%	60%
82	RAJASTHAN RV UTPADAN NIGAM	India	15,128	6,580	10,020	1,570	-	-	-	24	100	44	3	18	1	13	IN-100%	45%
83	SHENZHEN ENERGY GROUP CO LTD	China	15,105	3,744	-	12,100	0.64	0.83x	1.66x	8	100	1	100	100	1	100	CH-100%	60%
84	SUMITOMO CORP	Japan	14,876	5,514	500	7,545	1.58	1.65x	2.56x	82	50	19	100	100	100	90	NOTE-4	42%
85	MAHARASHTRA STATE POWER GEN CO	India	14,776	5,550	5,940	13,210	-	-	-	88	100	1	100	100	1	63	IN-100%	45%
86	CHINA PETRO & CHEM (SINOPEC)	China	14,747	4,074	2,300	600	0.32	0.76x	3.90x	6	100	21	36	21	74	45	CH-100%	60%
87	ECU - ENERGY CO OF UKRAINE	Ukraine	14,068	5,475	-	-	-	-	-	21	10	62	47	43	1	1	OTHER	-
88	ENBW ENERGIE BADEN-WURTTEMBERG	Germany	13,096	6,301	708	-	1.57	1.36x	0.03x	97	100	35	100	100	1	62	DE-100%	50%
89	TAURON POLSKA ENERGIA SA	Poland	12,954	4,242	3,595	2,594	0.45	1.39x	-1.22x	33	30	54	100	45	1	40	PD-100%	40%
90	ENTERGY CORP	USA	12,880	4,997	-	-	1.51	1.19x	1.48x	48	28	89	100	100	1	1	US-100%	60%
91	ALLIANT ENERGY CORP	USA	11,666	3,950	-	-	1.01	1.10x	0.28x	25	18	84	100	100	1	1	US-100%	60%
92	UTTAR PRADESH RAJYA VIDYUT	India	11,270	3,490	5,690	3,845	-	-	-	86	100	1	100	100	1	71	IN-100%	45%
93	SCOTTISH AND SOUTHERN ENERGY	United Kingd	11,049	4,206	-	-	1.1	1.01x	2.65x	71	2	72	100	100	1	100	UK-100%	45%
94	BASIN ELECTRIC POWER COOP	USA	10,806	3,688	-	-	3.41	0.77x	-0.98x	52	38	93	12	11	1	1	US-100%	60%
95	EUROSIBENERGO	Russia	10,072	3,979	-	-	-	-	-	1	12	64	100	44	1	11	OTHER	-
96	WENERGY-ANHUI PROV ENERGY	China	10,054	4,345	1,800	3,320	0.5	0.67x	7.29x	96	100	23	28	100	93	70	CH-100%	60%
97	SANTEE COOPER	USA	9,129	3,620	-	-	3.53	2.74x	2.05x	66	100	98	100	100	1	100	US-100%	60%
98	SALT RIVER PROJECT (AZ)	USA	8,356	3,231	-	-	0.94	0.98x	0.01x	39	7	77	100	100	1	23	US-100%	60%
99	GAZPROM	Russia	7,100	3,786	9,705	2,130	0.24	1.86x	1.08x	2	19	85	100	8	1	1	OTHER	-
100	ELEKTROPRIVREDA SRBIJE (EPS)	Serbia	2,041	446	-	6,439	-	-	-	3	1	55	100	1	1	38	OTHER	-

*: Companies are ranked by exposure, with 1 being the most at risk.
**: NRHs have been aggregated to a single outlook percentage based on the sum of high risk (+2) and medium risk (+1) evaluations relative to the maximum possible and weighted by asset locations.

6 Thermal Coal Miners

The top 20 thermal coal miners by revenue, with thermal coal revenue ≥30%, are examined for their exposure to environment-related risks. First, the capital expenditure plans, ownership structures, and debt obligations of thermal coal miners are examined. Then a number of hypotheses pertaining to the environment-related risk exposure to the companies are developed and tested. With these hypotheses, an opinion is developed on the environment-related risks facing the companies' capital plans and debt obligations. Figure 48 shows the location of the mines of the world's top 20 thermal coal mining companies. The top 20 thermal coal mining companies in this study had US$85bn in revenue in 2014, approximately 60%[392] of all listed company thermal coal revenue.

***Figure 48:** Mines of the world's top 20 thermal coal mining companies with thermal coal revenue ≥30%*



[392] Approximate total revenue for top 44 thermal coal companies (>75% revenue from thermal coal) and top 16 'balanced' (i.e. met and thermal coal companies) taken from CTI & Energy Transition Advisors (2014). Coal Financial Trends. Assuming a 50/50 split for 'balanced' companies, total revenue for listed coal companies with market cap ≥US$200mn and thermal coal revenue ≥25% is approximately US$140bn.

6.1 Market Analysis

6.1.1 Capital Projects Pipeline

The capital expenditure projections of the top 20 thermal coal mines is shown in Table 65 in Appendix B. Emerging environment-related risks may expose capital spending to risk of stranding.

6.1.2 Ownership Trends

Table 66 in Appendix B shows ownership information for the top 20 thermal coal mining companies. For each company, the location of the head office, the ultimate corporate parent, corporate parent's ownership type, and the aggregate market value (in billion US$s) of the various holders' positions are shown.

Table 37 summarises ownership type of the coal mining companies' ultimate corporate parents. Across all companies, the ultimate corporate parents are 65% publicly owned companies, and 35% privately owned companies. At a regional level, China's coal mining companies are owned mostly by private firms. The US's and Indonesia's coal mining companies are all publicly owned. Of the three mining companies in India, two are publicly owned. The two remaining companies, Sasol and Banpu Public Company, are publicly owned. Table 66 shows all ownership data for thermal coal miners.

Table 37: *Distribution of ownership for coal mining companies, by region**

	Government	Private Company	Private Investment Firm	Public Company	Public Investment Firm
(A) Total	0.0%	35.0%	0.0%	65.0%	0.0%
	(0)	(7)	(0)	(13)	(0)
(B) China	0.0%	85.7%	0.0%	14.3%	0.0%
	(0)	(6)	(0)	(1)	(0)
(C) US	0.0%	0.0%	0.0%	100.0%	0.0%
	(0)	(0)	(0)	(5)	(0)
(D) India	0.0%	33.3%	0.0%	66.7%	0.0%
	(0)	(1)	(0)	(2)	(0)
(E) Indonesia	0.0%	0.0%	0.0%	100.0%	0.0%
	(0)	(0)	(0)	(3)	(0)
(F) Other	0.0%	0.0%	0.0%	100.0%	0.0%
	(0)	(0)	(0)	(2)	(0)

*Numbers in parentheses represent the number of observations

6.1.3 *Diversification Trends*

Thermal coal miners might be more resilient to environment-related risks if their business activities are diversified. The revenue sources the top 20 thermal coal miners (by ultimate corporate parent) have been obtained from Trucost and weighted by company EBITDA, see Figure 49.

***Figure 49:** Coal mining diversification trends*[393]

China (6/7*) – Chinese coal miners have made the mainstay of their revenue from underground coal mining and a small portion of coal-fired power generation. Petrochemical and surface mining activities are slowly emerging.

*Number of companies for which data was available

US (4/5) – Underground mining is giving way to surface mining in the United States. Coal mining companies are also becoming increasingly involved in petrochemical activities.

India (3/3) – Indian thermal coal miners for which data are available have diversified activities: power generation, coal-fuelled or otherwise, and other activities. Most coal is surface mined.

Indonesia (3/3) – Indonesia's thermal coal miners conduct surface mining almost exclusively and are diversified into power generation with fuels other than coal and non-related business activities. Coal power generation activities have begun recently.

South Africa (1/1) – Most of the revenue of South Africa's thermal coal miners is derived from petrochemical processing activities. These companies are therefore highly exposed to the CPT risks discussed below.

Thailand (1/1) – The revenue of Banpu Public Company ltd has been shifting slowly from surface coal mining to underground coal mining, with consistent power generation revenue.

[393] Data from Trucost, November 2015; and MSCI, October 2015.

6.1.4 Bond Issuances

For thermal coal mining companies, exposure to high levels of debt increases risk for both debt and equity holders as the priority of either is further diluted in the event of the company's insolvency. Table 67 in Appendix B shows bond issuances of the top 20 thermal coal mining companies.

To build a general picture of the future direction for the thermal coal mining industry, fixed-income securities are examined through ratio analysis. Table 68 in Appendix B presents financial ratios relating to: profitability, capital expenditures, liquidity, leverage, debt coverage, and the ability for utilities to service existing debt. Figure 50 illustrates the same ratios through time, including the 25th and 75th percentile ranges to capture the ratio distributions across firms. Analysis is conducted between 1995 and 2014 to represent the last 20 years of data[394]. The dataset for 2015 was limited, and is thus omitted to prevent bias in ratios. The majority of coal-mining companies were publicly traded, although some financial data for private miners were unavailable.

Box 8 presents credit rating evaluations for three of the top thermal coal mining companies.

***Box 8:** Environment-related risks and rating downgrades of thermal coal mining companies*

Ratings services such as Standard & Poor's and Moody's provide opinions of risk for investible companies. Ratings analyses were obtained from Standard & Poor's Rating Services (S&P) of the top 20 thermal coal mining companies which suffered credit downgrades due to climate or environmental factors between 2013 and 2015.

In December 2013, S & P lowered Alpha Natural Resource's Corporate Credit Rating to 'B' from 'B+', citing the health of thermal and met coal markets and Alpha's position as a producer in the Central Appalachian coal basin (footnote). S & P cites competition from US natural gas as causing the structural decline of coal mining in this basin. In August 2014, the outlook for Arch Coal was similarly reduced to 'negative' from 'stable' based on the weak outlook of the met and thermal coal markets (footnote). S & P cites Arch coal's production of 'clean', low-sulphur coal as making Arch Coal more resilient to environmental regulations for coal-fired power utilities.

The business risks analysed for thermal coal mining companies are generally related to market outlook, diversification, and cost position. S&P examines a company's cash position, including its profitability, leverage, and liquidity, to provide an opinion on the financial risk of the company.

From the analyses available of thermal coal miners, very little reference is made to environment-related risk factors. If at all, it is aggregated generally with 'regulatory' risk exposure. Reduced sales and prices are related to commodity cycles rather than any structural change in long-term demand. How environment and climate risks have entered S&P credit rating has been discussed in Box 7.

The available ratings are shown in Table 38.

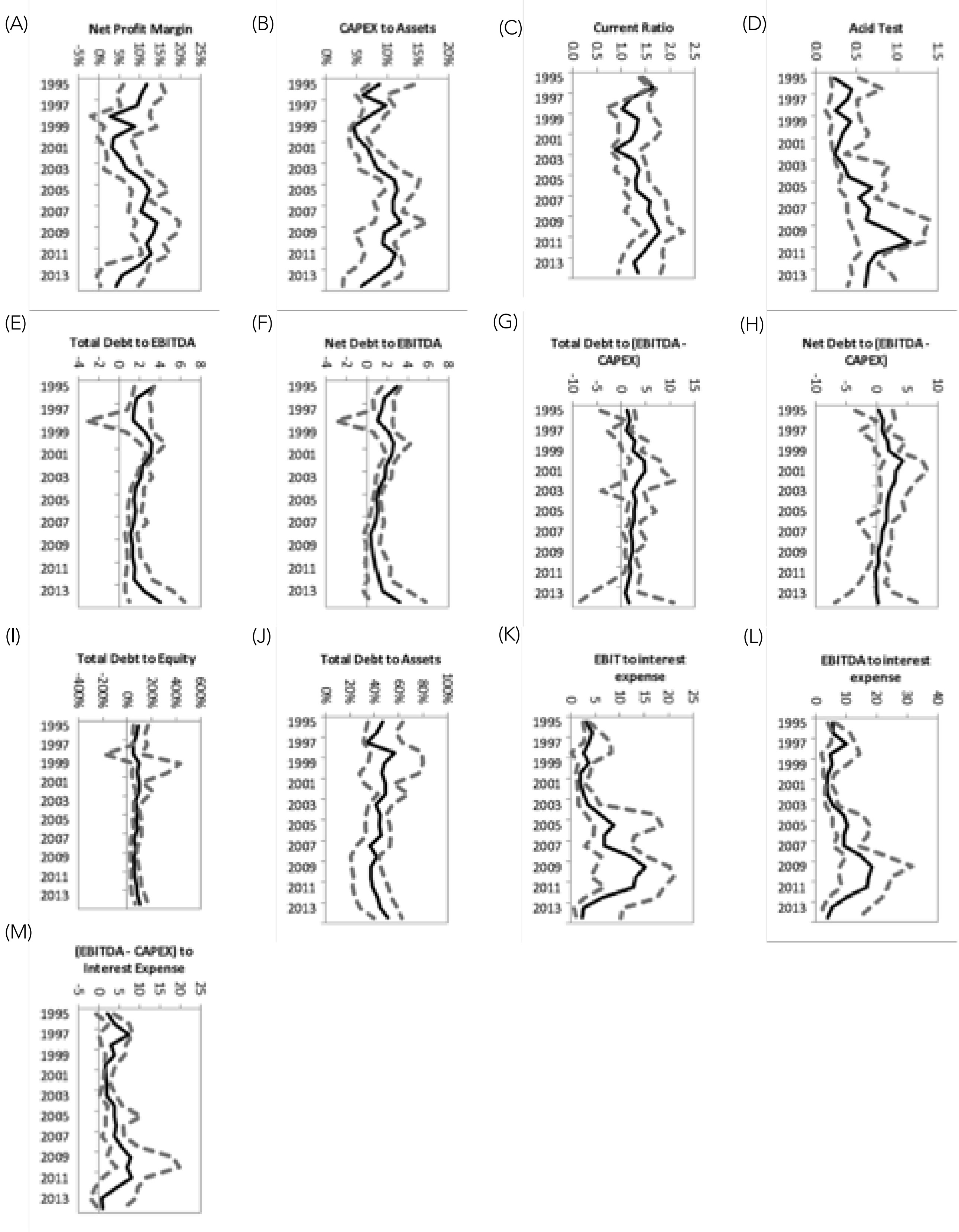
***Table 38:** Available credit ratings for thermal coal miners*[395]

Company	Business Risk	Financial Risk	Rating	Date
Alpha Natural Resources Inc	Weak	Highly Leveraged	B/Stable/--	2014/06/10
Arch Coal Inc	Fair	Highly Leveraged	B/Negative/--	2014/10/29
China Shenhua Energy Co Ltd	Strong	Modest	AA-/Stable/--	2015/01/06

[394] Standard & Poor's RatingDirect (2013). Research Update: Arch Coal Inc. Corporate Credit Rating Lowered To 'B' From 'B+', Outlook Stable; Debt Ratings Lowered To 'B+' And 'CCC+'.

[395] Standard & Poor's RatingDirect (2014). Research Update: Alpha Natural Resources Inc. Corporate Credit Rating Lowered To 'B' From B+', Outlook Stable; Debt Ratings Lowered.

Figure 50: *Ratio analysis for all thermal coal mining companies, with median, 25th and 75th percentiles*



The first two ratios examined report general profitability and capital expenditure in the thermal coal mining industry, which are both relevant to the industries' ability to service its debt commitments. Profit margins are shown in Figure 50, Chart (A), which have been volatile through time, ranging from 2.8% to 14.2%. Since 2013, profit margins have remained as low as 4.4%. The spike in profit margins between 2004 and 2012 appears to coincide with the spike in global coal prices.

Capital expenditure represents the funds required to acquire, maintain, or upgrade existing physical assets. Chart (B) shows that capital expenditure, relative to total assets, has also been volatile through time, ranging from 4.5% to 12.2% of total assets. The ratio suggests that the coal mining industry is relatively expensive to maintain compared to the coal-fired power utilities. Equally, it could be the result of a smaller asset-base. Similar to the coal-fired utility industry, the peak in capital expenditure mostly occurs following the GFC. In 2013 and 2014, respective capital expenditure was 8.2% and 5.8%.

The current ratio and acid test are used as proxies for liquidity in the industry. The former measures the ability to service current liabilities using current assets, the latter measures the ability to service current liabilities using cash, near-cash equivalents, or short-term investments. Charts (C) and (D) show both liquidity ratios have increased through time. The coal mining industry has greater liquidity than the coal-fired power utility industry. The greatest liquidity in the coal mining industry occurs between 2007 and 2011, where the current ratios range between 1.56 and 1.78. The acid test ratio shows a similar trend, suggesting thermal coal mining firms are holding a greater amount of cash, near-cash equivalents, or short-term investments. Despite volatile profitability, the coal mining industry is relatively liquid in comparison to the coal-fired power utility industry.

Two financial leverage ratios are examined: the debt/equity ratio in Chart (I) and the debt/assets ratio in Chart (J). Chart (I) shows that the debt/equity ratio has been volatile across time. In particular, there is a large change in leverage ratios in the late-1990s, which coincides with a large number of firms entering the market. The leverage ratios have been on an upward trajectory towards parity since 2010, suggesting increasing use of debt to fund operations. Chart (J) shows debt typically represented less than half of total assets, but achieved parity in 2014. The increases in leverage suggest the industry is financing its growth with debt and/or may be retiring some equity, which can translate to greater financial risk, interest expenses, and volatile earnings.

Coverage ratios measure the industry's ability to meet its financial obligations. Three ratios are considered: 1) EBIT/interest, 2) EBITDA/interest, and 3) (EBITDA-CAPEX)/interest. Compared to the utility industry, coverage ratios have greater volatility. All three coverage ratios for the coal mining industry peak in 2009, when interest expenses were relatively low compared to operating income. Since 2009, the ratios have been on an accelerated downward trajectory. In 2014, Chart (K) shows that the operating income of the industry was only 2.28 times interest expense in 2014. Accounting for depreciation and amortization of assets, Chart (L) shows the 2014 EBITDA/interest ratio increases to 4.00, suggesting depreciation and amortization of assets. Capital expenditures also represents a major expense for the mining industry. When deducting annual CAPEX, Chart (M) shows that industry only just generates enough cash to meet interest payments. In 2013, the mining industry's interest expense was greater than (EBITDA-CAPEX), resulting in a ratio less than 1. The ratio remains less than unity in 2014. The ratios indicate that the mining industry becoming increasingly distressed and income is now beginning to trend below the cost of debt.

Four ratios represent the mining industry's ability to retire incurred debt. The ratios can be broadly interpreted as the amount of time needed to pay off all debt, ignoring interest, tax, depreciation and amortization.

The ratios are divided into two groups: group 1 considers the numerators 'total debt' and 'net debt', where the latter subtracts cash and near-cash equivalents for total debt; group 2 considers the denominators EBITDA and (EBITDA-CAPEX), where the latter controls for capital expenditures.

In contrast to the utility industry, the mining industry's debt remains relatively low in comparison to earnings. Considering Charts (E) and (F), the 2014 ratios suggest the industry can pay off its debt between 3.20 and 4.06 years. The spread between the two ratios suggest that the industry is holding a reasonable amount of cash equivalents which can contribute to retiring debt. When deducting CAPEX, the ratios decline. Charts (G) and (H) suggest the industry could pay off its existing debt, subject to the conditions outlined above, between 1.56 and 0.22 years. Rapidly increasing levels of debt and high CAPEX represent major factors in the industry's ability to retire debt.

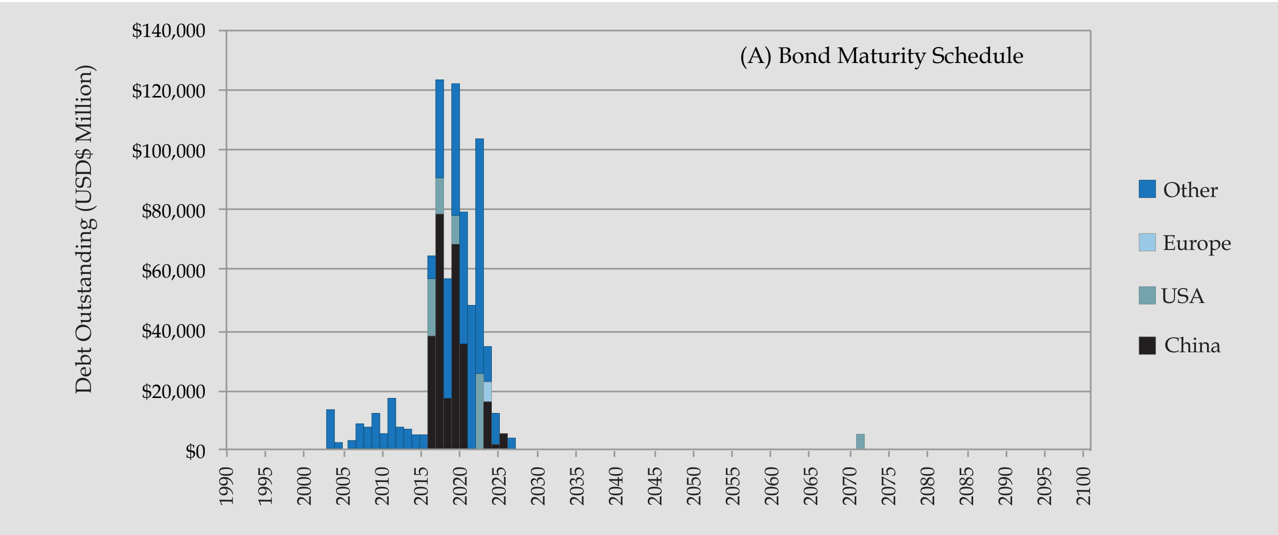
Figure 51 illustrates the maturity schedule for the thermal coal mining industry, using available data from 20 of the 30 thermal coal mining companies. The schedule is divided into total amount outstanding (USD) and the maturity dates of various contracts. Both graphs are delineated by major region, including: China, US, Europe, and 'other'.

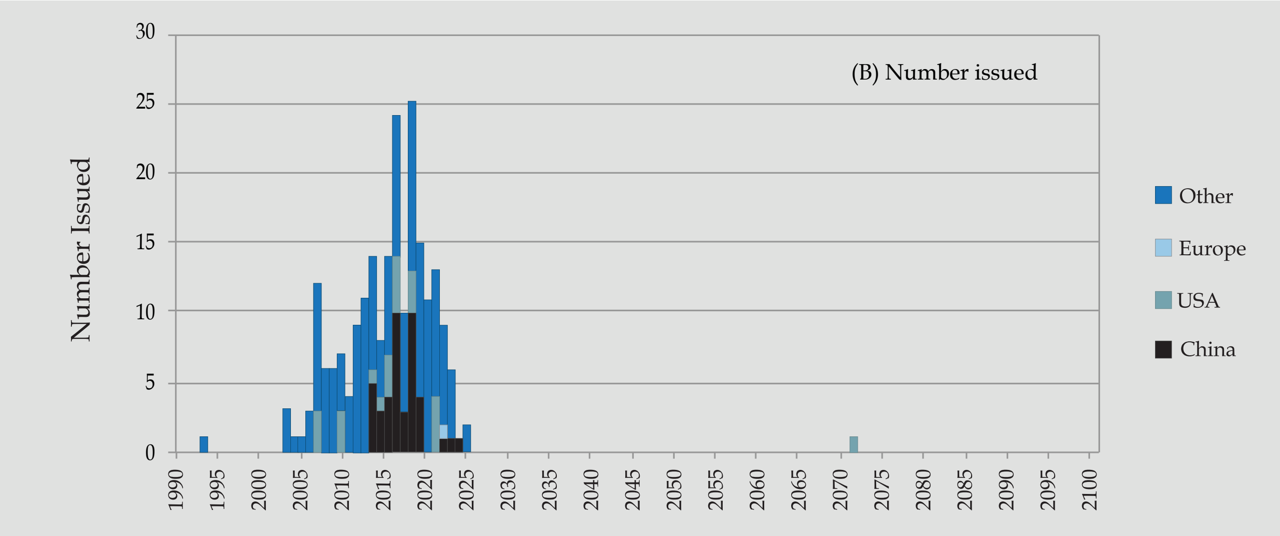
Plot (A) of Figure 51 shows that the majority of the total debt is due between 2016 and 2026. There is almost no borrowing beyond this date in our sample. Whereas borrowing for European and US thermal coal miners is low, companies in China and the other regions represent the majority of debt obligations. Plot (B) shows a similar trend. Companies in China and 'other regions' have issued a large number of contracts until 2025-26. This could signal that either the industry is unable to borrow, or prefers to issue debt which typically matures within 10 years. Table 39 shows that companies in the US and India represent the only two countries with perpetual debt in our sample.

Table 39: *Thermal coal mining companies' perpetual debt*

	China	US	Europe	Other
Amount outstanding (US$m)	0	$300	0	$125
Number issued	0	1	0	1

Figure 51: *Maturity schedules for industry debt: debt outstanding (A) and maturity dates (B)*





6.2 Investment Risk Hypotheses

In this section, we take a view on what the environment-related risks facing thermal coal miners could be and how they could affect asset values. We call these Local Risk Hypotheses (LRHs) or National Risk Hypotheses (NRHs) based on whether the risk factor in question affects all assets in a particular country in a similar way or not. For example, water stress has variable impacts within a country and so is an LRH, whereas a country-wide carbon price is an NRH. The hypotheses are coded for easier reference. For example, LRH-M1 refers to proximity to populations and protected areas and NRH-M1 refers to remediation liability exposure.

Hypotheses for different environment-related risks have been developed through an informal process. We produced an initial long list of possible LRHs and NRHs. This list was reduced to the more manageable number of LRHs and NRHs contained in this report. We excluded potential LRHs and NRHs based on two criteria. First, we received feedback from investors and other researchers in meetings, roundtables, and through correspondence, on the soundness, relevance, and practicality of each hypothesis. Second, we assessed the data needs and analytical effort required to link the hypotheses with relevant, up-to-date, and where possible, non-proprietary, datasets.

The current list of hypotheses and the datasets used to measure asset exposure to them are in draft form. Other datasets may have better correlations and serve as more accurate proxies for the issues we examine. Important factors may not be represented in our current hypotheses. We are aware of these potential shortcomings and in subsequent research intend to expand the number of hypotheses we have, as well as improve the approaches we have used to analyse them.

The summary table that shows the exposure of the top 20 thermal coal miners to each NRH and LRH can be found in Section 6.3.

6.2.1 Local Risk Hypotheses

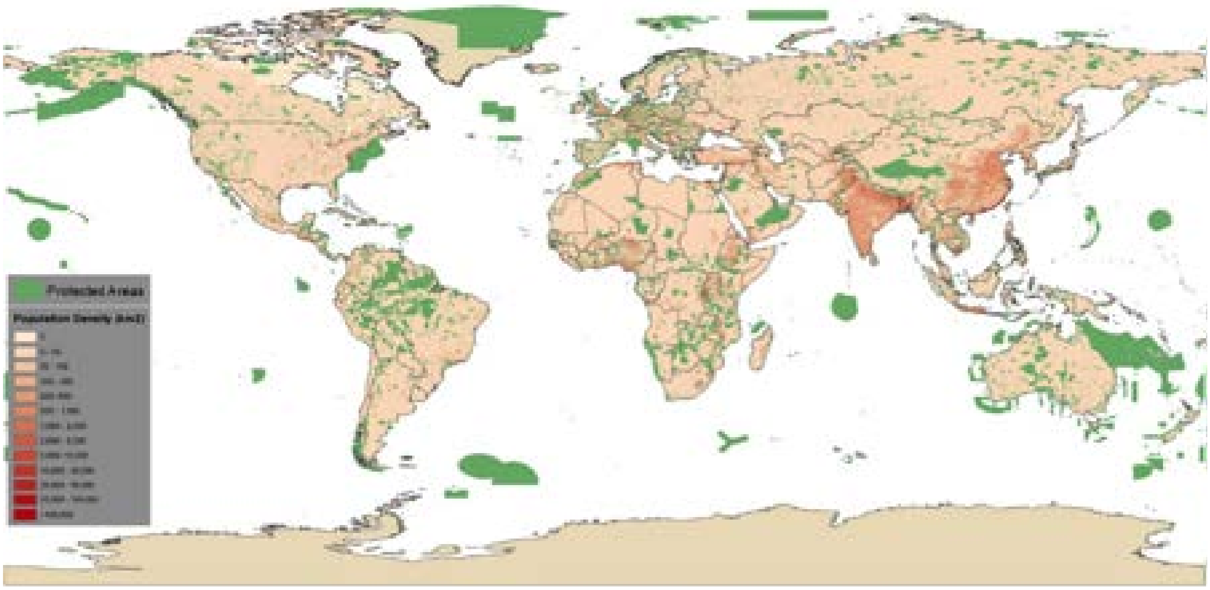
Local risk indicators have been developed to provide a view of environment-related risk exposure due to conditions local to each thermal coal mine. Risk indicators have been developed and informed by geographic analysis using publicly available datasets. Table 70 in Appendix B describes the local risk indicators aggregated for the top 20 thermal coal miners with more detail.

6.2.1.1 LRH-M1: Proximity to Populations and Protected Areas

Thermal coal mining has extensive local environmental impacts. Where a densely populated area or a sensitive ecosystem is exposed to these impacts, the mining company could be more vulnerable to reputational and regulatory risk. Policymakers may intervene to protect either the natural environment or local population. An example is the Carmichael Coal Mine and Rail Project in Australia which was assessed under the EPBC Act for its impact on protected species[396]. Media coverage of such impacts can affect a company's reputation, which may, in turn, influence its negotiation positions with contractors and suppliers or stock price compression multiples[397].

To assess exposure to this risk, the dataset of thermal coal mine assets developed by the Oxford Smith School has been geographically matched with the UNEP-WCMC World Database on Protected Areas and the SEDAC Gridded Population of the World version 3, 2015 dataset. Thermal coal mining companies are assessed for the number of mines they have within 40km of a protected area and the average local population density. The ranking within the top 20 thermal coal mining companies is averaged for both these categories to provide an aggregate view of risk exposure due to proximity to human populations and protected areas.

Figure 52: *World population density and protected areas*



6.2.1.2 LRH-M2: Water Stress

The hypothesis is that thermal coal mines located in areas with high physical baseline water stress or in areas with water conflict or regulatory uncertainty are at greater risk of being forced to reduce or cease operation, of losing their licence to operate, or of having profits impaired by water pricing.

[396] Australian Government (2015). Carmichael Coal Mine and Rail Project, Department of the Environment.

[397] Ansar, A., Caldecott, B., & Tilbury, J. (2013). Stranded assets and the fossil fuel divestment campaign: what does divestment mean for the valuation of fossil fuel assets?, Smith School of Enterprise and the Environment, University of Oxford. Oxford, UK.

Water is used in coal mining for coal cutting and dust suppression, washing (beneficiation), and slurry pipeline transport[398]. Underground mining requires less water than surface mining, and coal washing and slurry transport can substantially increase the water footprint per unit of energy. Approximately 40% of mined coal in China is washed[399] and raising standards for advanced coal-fired power stations may exacerbate water demand from coal washing. Advanced combustion technologies require higher quality coals which can be created by upgrading lower quality coals through beneficiation.

The measure for water stress used in this report is Baseline Water Stress (BWS) from Aqueduct created by the World Resources Institute (WRI). BWS is defined as total annual water withdrawals (municipal, industrial, and agricultural) expressed as a percentage of the total annual available flow within a given watershed. Higher values indicate greater competition for water among users. Extremely high water stress areas are determined by WRI as watersheds with >80% withdrawal to available flow ratios, 80-40% as high water stress, 40-20% as high to medium, 20-10% as medium to low, and <10% as low.[400]

All coal mines are mapped against the Aqueduct Baseline Water Stress geospatial datasets. Those mines that are in watersheds that have 'extremely high water risk'[401] for baseline water stress are identified as 'at risk'. Mines are then aggregated by mining company to identify the percentage of mines that are 'at risk'. Insufficient data is available to assess whether a mine washes coal on site, and these complexities are therefore omitted.

See Figure 35 for a graphic of global baseline water stress.

6.2.2 *National Risk Hypotheses*

The hypotheses below have been developed on a country-by-country basis, affecting all the coal mines in that country. A simple traffic light method has been used to conduct analysis for these risk hypotheses. They are well suited to complex situations where more formal analysis is unavailable or unnecessary and are often used in environmental and sustainability analysis, e.g. DEFRA[402], the World Bank[403]. The hypotheses developed below draw on the IEA NPS as a conservative scenario and add additional evidence to give a more complete policy outlook for coal-fired utilities.

An effective traffic light method clearly describes threshold values or criteria for each colour, which are testable by analysis or experiment [404]. Criteria are developed below for each hypothesis, with conclusions as to whether coal mining companies in a country are at high risk (red), medium risk (yellow) or low risk (blank). An aggregate outlook is arrived at after scoring each criteria (+2 for high risk criteria, +1 for medium risk criteria).

[398] Mielke, E. Anadon, L., & Narayanamurti, V. (2010). Water consumption of energy resource extraction, processing, and conversion, Harvard Kennedy School. Cambridge, US.

[399] Wang, W. (2013). 'China thermal coal washing rate remains low', China Coal Resource.

[400] Gassert, F. et al. (2014). Op. Cit.

[401] Baseline water stress measures the ratio of total annual water withdrawals to total available annual renewable supply, accounting for upstream consumptive use. Extremely high water risk signifies that >80% of renewable supply is withdrawn.

[402] DEFRA (2013). Op. Cit.

[403] The World Bank (2016). Op. Cit.

[404] Halliday, R. (2001). Op. Cit.

Table 40: National-level environment related risk indicators

Indicator	Australia	China	Germany	Indonesia	India	Japan	Poland	South Africa	United Kingdom	United States
NRH-M1: Remediation Liability Exposure	Medium Risk (+1)	Low Risk (+0)	Low Risk (+0)	Low Risk (+0)	Low Risk (+0)	Low Risk (+0)	Low Risk (+0)	Low Risk (+0)	Low Risk (+0)	High Risk (+2)
NRH-M2: Environmental Regulation	High Risk (+2)	Low Risk (+0)	Low Risk (+0)	Low Risk (+0)	Low Risk (+0)	Low Risk (+0)	Low Risk (+0)	High Risk (+2)	Low Risk (+0)	Low Risk (+0)
NRH-M3: New Mineral Taxes or Tariffs	Low Risk (+0)	High Risk (+2)	Low Risk (+0)	High Risk (+2)	Medium Risk (+1)	Low Risk (+0)	Low Risk (+0)	Medium Risk (+1)	Low Risk (+0)	Low Risk (+0)
NRH-M4: Type of Coal Produced	Medium Risk (+1)	Low Risk (+0)	High Risk (+2)	Low Risk (+0)	Medium Risk (+1)	Low Risk (+0)	High Risk (+2)	Low Risk (+0)	Medium Risk (+1)	Low Risk (+0)
NRH-M5: Domestic Demand Outlook	Medium Risk (+1)	Medium Risk (+1)	High Risk (+2)	Low Risk (+0)	Low Risk (+0)	High Risk (+2)	High Risk (+2)	Medium Risk (+1)	High Risk (+2)	High Risk (+2)
NRH-M6: Export Sensitivity	High Risk (+2)	Low Risk (+0)	Low Risk (+0)	High Risk (+2)	Low Risk (+0)	Low Risk (+0)	Low Risk (+0)	Medium Risk (+1)	Low Risk (+0)	Medium Risk (+1)
NRH-M7: Protests and Activism	High Risk (+2)	Medium Risk (+1)	Medium Risk (+1)	Medium Risk (+1)	High Risk (+2)	Low Risk (+0)	Medium Risk (+1)	Medium Risk (+1)	High Risk (+2)	High Risk (+2)
NRH-M8: Water Regulatory Stress	Low Risk (+0)	Medium Risk (+1)	Low Risk (+0)	High Risk (+2)	Medium Risk (+1)	Low Risk (+0)	Low Risk (+0)	Medium Risk (+1)	Low Risk (+0)	Low Risk (+0)
TOTAL (/16)	9	5	5	7	5	2	5	7	5	7

NRH-M1: Remediation Liability Exposure

The hypothesis is that stricter remediation liability regulation or enforcement would negatively affect mine economics and potentially create new liabilities.

Coal miners are often liable for the remediation of land impacted by their mining activities. In some countries, thermal coal mining companies have been allowed to self-guarantee their ability to remediate their activities, which state regulators allow on the basis of the financial health of the company (see e.g. Section 4.10.4 and related report from the International Council on Mining & Metals [405]). Recently, policymakers have begun to re-examine the financial health of companies they allow to self-guarantee remediation. Additionally, even where self-guarantees are allowed, the amount of remediation liability that a thermal coal mining company must carry is regulated and might be increased by regulators who anticipate increasing remediation costs.

We examined scope countries for any change in remediation liability regulation or enforcement. The United States is identified as a 'high risk' country, where regulators in Wyoming are investigating whether Alpha Natural Resources, Arch Coal, and Peabody Energy may continue to self-guarantee their remediation liabilities [406]. In Australia, the governments of Queensland and New South Wales hold remediation bonds for coal miners in those states, but the value of the bonds may not be sufficient to cover remediation costs[407]. Australia is considered 'medium risk'.

NRH-M2: Environmental Regulation

The hypothesis is that stricter environmental regulation or enforcement would negatively affect mine economics and potentially create new liabilities.

[405] Miller, G. (2005). Op. Cit.

[406] Jarzemsky, M. (2015). Op. Cit.

[407] Main, L. & Schwartz, D. (2015). 'Industry insider warns taxpayers may foot bill for mine rehabilitation unless government, industry step up', ABC News.

The environmental impacts of thermal coal mining can be significant, including water, air, and land pollution and impacts on wildlife. Efforts by governments to protect the environment and natural capital can have material impacts on the ability of thermal coal mining companies to conduct their business, especially when that business has unmitigated environmental impacts. This hypothesis captures the potential impact of emerging environmental regulations on coal mining companies in the scope countries.

Australia and South Africa were found to have emerging environmental regulation which places thermal coal mining companies at 'high risk'. In Australia, some coal mining projects have been referred to new national regulations under the EPBC act [408]. In South Africa, biodiversity protection has become a national environmental priority, with policy development beginning to address conflicts between mining and biodiversity[409].

NRH-M3: New Mineral Taxes and Tariffs

The hypothesis is that new or higher mineral taxes, tariffs, and levies would negatively affect mine economics.

Governments use fiscal policies like taxes, export tariffs, levies, caps, and bans to influence industry activity. These policies may be implemented to remedy a market failure, to influence investment, or domestic market prices. New or existing fiscal policies could reduce thermal coal mine profitability.

Mineral taxes, royalties, export tariffs and other policies are examined in the scope countries. Where proposed mineral taxes or tariffs have been identified, these are noted in Table 41. Where the proposed policy is highly likely, thermal coal mining companies in that country are considered to be at 'high risk'. Where proposed policy is less certain, the companies are considered to be at 'medium risk'. See also the policy summaries in Section 4 for details.

Table 41: *Countries with (and without) proposed mineral taxes and tariffs*

Country	Reference	RISK
Australia	No emerging taxes or tariffs identified	●
China	New coal tax – 2% to 8%[410]	●
Germany	No emerging taxes or tariffs identified	●
Indonesia	Industry reforms, export bans and caps[411]	●
India	Proposed doubling of coal levy for the National Clean Energy Fund[412]	●
Japan	No emerging taxes or tariffs identified	●
Poland	No emerging taxes or tariffs identified	●
South Africa	Since 2012 the South African government has pursued mineral sector tax reform to raise government revenue[413]	●
United Kingdom	No emerging taxes or tariffs identified	●
United States	No emerging taxes or tariffs identified	●

[408] Australian Government (2016). About the EPBC Act. https://www.environment.gov.au/epbc/about.
[409] OECD (2013). Op. Cit.
[410] Stratfor (2015). Op. Cit.
[411] Prior, S. & Riffdann, R. (2014). Op. Cit.
[412] Jaitley, A. (2015). Op. Cit.
[413] PMG Asset Management (2013) Op. Cit.

NRH-M4: Type of Coal Produced

The hypothesis is that mines producing lignite have fewer potential customers and therefore could be at higher risk due to a lack of diversification.

Lignite is less energy dense and contains more moisture than bituminous or sub-bituminous coal, making it a less-efficient energy source. It is too bulky export; an international market exists only for hard coals. The low price of imported coal may cause coal-fired power stations to import higher quality coal directly from international markets. Additionally, as pressure on coal-fired power stations increases to control conventional and greenhouse gas pollution, lignite-producing countries will be at a disadvantage relative to countries producing higher quality coals.

The type of coal mined in each scope country is taken from the IEA MCMR[414]. Countries with production of over 25% lignite coal by mass are considered 'high risk'. Countries with any production of lignite coal are considered 'medium risk'.

Table 42: *Coal type produced*[415]

2014	Australia	China	Germany	Indonesia	India	Japan	Poland	South Africa	United Kingdom	United States
% Lignite	12%	0%	96%	0%	7%	0%	47%	0%	8%	0%
RISK	🟡	🟢	🔴	🟢	🟡	🟢	🔴	🟢	🟡	🟢

NRH-M5: Domestic Demand Outlook

The hypothesis is that coal miners will be exposed to lower profit margins and higher costs if domestic demand for coal falls. Falling domestic demand for coal-fired power will increase the local and global over-supply of thermal coal. Thermal coal mining companies may have to accept lower prices from domestic buyers or will need to internalise transport costs and compete on the global market. Either option reduces the profitability of thermal coal mining.

Table 43: *2013-2020 Coal power demand outlook from IEA WEO 2015 NPS*[416]

2013 - 2020	Australia	China	Germany	Indonesia	India	Japan	Poland	South Africa	United Kingdom	United States
CAGR	0%	1%	-3%	8%	5%	-1%	-3%	0%	-3%	-2%
RISK	🟡	🟡	🔴	🟢	🟢	🔴	🔴	🟡	🔴	🔴

[414] IEA (2015). Coal MTMR. Op. Cit.
[415] IEA (2015). Coal MTMR. Op. Cit.
[416] IEA (2015). WEO 2015. Op. Cit.

NRH-M5: Export Sensitivity

The hypothesis is that the more thermal coal a country exports, the more exposed its mining companies will be to the risk of falling global demand for coal. Even in the IEA's conservative NPS, total coal demand is only expected to grow at 0.4% through 2020[417]. Companies must pay transport costs, compete for transport infrastructure, and expose themselves to price volatility on international commodity markets.

Table 44 shows 2014 coal imports (exports) relative to each country's coal consumption. Australia and Indonesia are clear outliers. They are considered 'high risk'. The other coal exporters are South Africa and the United States which are considered 'medium risk'.

Table 44: *2014 coal exports*[418]

	Australia	China	Germany	Indonesia	India	Japan	Poland	South Africa	United Kingdom	United States
Imports (Exports)	(325%)	7%	22%	(663%)	26%	100%	0%	(42%)	75%	(9%)
RISK	red	green	green	red	green	green	green	yellow	green	yellow

6.2.2.1 NRH-M6: Protests and Activism

The hypothesis is that mines targeted by protests and activism may suffer from reputational risk and temporary production disruptions due to disputes. They might also be at higher risk of policies and regulations that could harm the economics of mines in their country.

The local and global environmental impacts of the thermal coal value chain have attracted significant attention from civil society and activist groups around the world. Protests against coal assets create a reputational risk for the associated companies as local and national policymakers may feel more able to regulate company activities. Using data from Sourcewatch, non-violent direct action against thermal coal companies are delineated by country[419]. Comprehensive data were available from 2003 to 2013.

Figure 53 shows that the majority of protests occurred in the US, which experienced 115 coal-related protests between 2003 and 2013. Other significant activity occurred in the UK, Australia, and India. These countries are all considered 'high risk'. If any protests were observed in the sample at all, those countries are considered 'medium risk' – see Table 45.

[418] IEA (2015). Coal MTMR. Op. Cit.

[419] Coalswarm (2015). 'Non-violent direct actions against coal', Sourcewatch. http://www.sourcewatch.org/index.php/Nonviolent_direct_actions_against_coal

Figure 53: Cumulative number of protests, delineated by coal-based operation

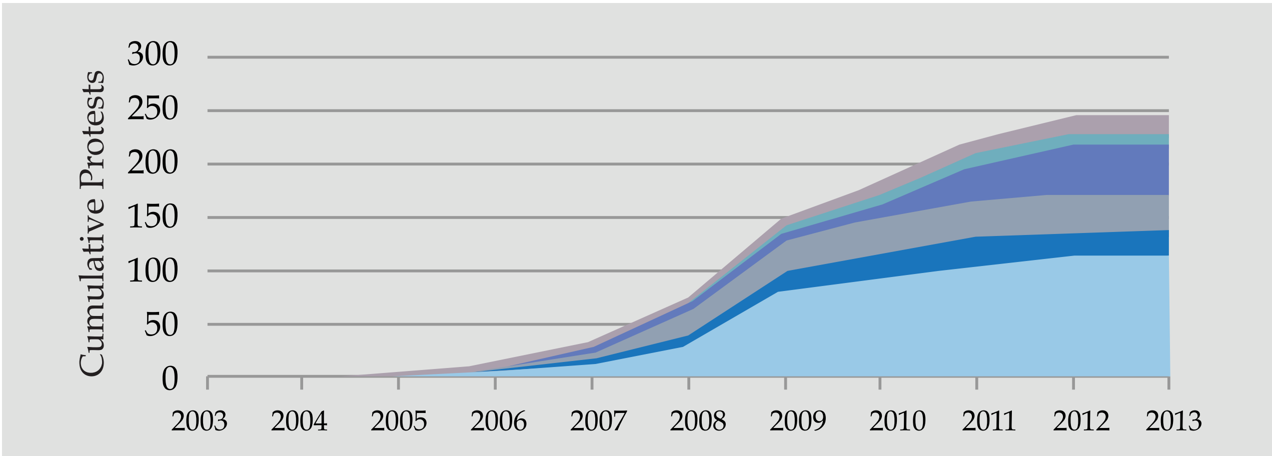


***Table 45:** Coal-related protest occurrence 2003 – 2013*[420]

Protests	Australia	China	Germany	Indonesia	India	Japan	Poland	South Africa	United Kingdom	United States
2003 - 2013	35	3	2	2	49	0	1	2	22	115
RISK	🔴	🟡	🟡	🟡	🔴	🟢	🟡	🟡	🔴	🔴

6.2.2.2 NRH-M7: Regulatory Water Stress

Thermal coal mining has a substantial water footprint, described below in hypothesis LRH-2M: Water Stress. This water footprint exposes thermal coal mining companies to regulatory risks, as policymakers may take action to restrict utility access to water. Public opinion on the water footprint of power generation may also put pressure on policymakers to restrict water use, exposing utilities to a reputational risk as well.

This risk hypothesis is identical to the Regulatory Water Stress hypothesis described for coal-fired power utilities (see NRH-U9) and uses the same data and analysis, see above for details.

***Table 46:** Regulatory Water Stress*[421]

	Australia	China	Germany	Indonesia	India	Japan	Poland	South Africa	United Kingdom	United States
Risk bin	1	3	1	4	3	1	2	3	2	1
RISK	🟢	🟡	🟢	🔴	🟡	🟢	🟢	🟡	🟢	🟢

[420] Ibid.
[421] World Resources Institute (2016). 'Regulatory & Reputational Risk' in Water Risk Atlas, Aqueduct.

6.3 Summary of Top 20 Thermal Coal Mining Companies

***Table 47:** Environment-related risk indicators summary, top 20 thermal coal mining companies*

NRH AGGREGATION**	31%	31%	31%	31%	31%	31%	42%	44%	44%	44%
ASSET BASE	CH-100%	CH-100%	CH-4%	CH-100%	CH-5%	CH-25%	AU-43%, CH-57%	US-13%	US-100%	US-100%
LRH-M2: 'Water Stress' [Rank]*	27	19	23	20	30	28	18	6	16	17
LRH-M1: 'Proximity to Populations and Protected Areas' [Rank]*	22	16	13	14	28	24	18	6	4	5
(EBITDA-CAPEX) / INTEREST	-	7.66x	-4.01x	-6.26x	-2.66x	-	-1.34x	18.26x	-0.28x	0.59x
CURRENT RATIO	1.36x	1.30x	1.98x	1.63x	0.89x	-	1.21x	1.01x	0.40x	2.66x
DEBT / EQUITY	1.13	0.28	1.02	1.09	0.69	-	1.19	0.92	1.41	-849%*
PROJECTED CAPEX / EBITDA	2.01	0.45	3.55	2.82	1.62	1.13	1.5	0.29	1.63	0.32
[% REV FROM COAL]	0.52	0.35	0.97	0.85	0.9	0.7	0.31	1	0.66	0.8
PROD [Mt (#)]	107 (6)	305 (23)	15 (1)	51 (13)	30 (5)	13 (4)	73 (19)	41 (11)	84 (3)	264 (11)
NUM	11	23	4	13	5	25	23	13	3	12
2014 THERMAL COAL REV [US$MN]	14,006	11,050	10,251	5,966	5,068	4,890	3,397	3,045	2,909	2,837
COUNTRY[ii]	CH	ZA	IN	CH	IN	US	CH	CH	ID	US
PARENT OWNER	CHINA SHENHUA ENERGY CO	SASOL	COAL INDIA LTD	CHINA COAL ENERGY COMPANY	ADANI ENTERPRISES LTD	PEABODY ENERGY CORPORATION	INNER MONGOLIA YITAI COAL CO., LTD.	YANZHOU COAL MINING COMPANY LIMITED	PT ADARO ENERGY TBK	ALPHA NATURAL RESOURCES

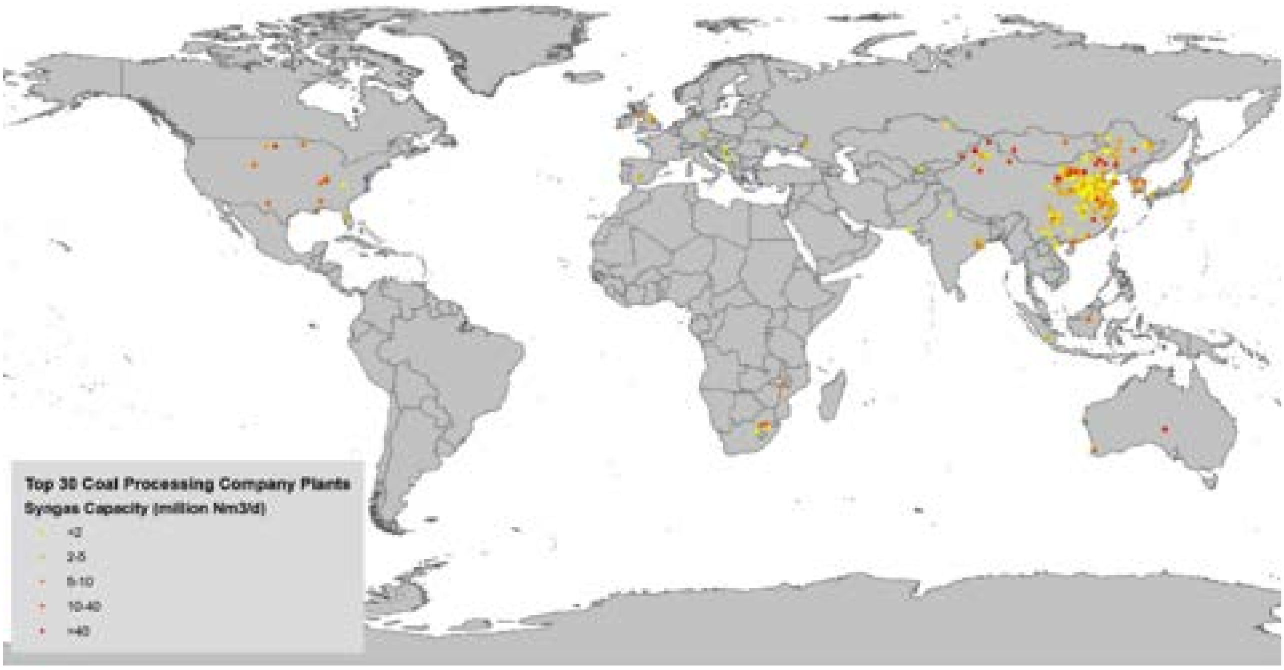
NRH AGGREGATION**	44%	49%	44%	44%	44%	38%	31%	44%	44%	40%
ASSET BASE	US-5%	AU-39%, US-61%	ID-6%	ID-100%	ID-100%	NOTE 1	IN-100%	ID-3%	SA-100%	ID-70%, CH-30%
LRH-M2: 'Water Stress' [Rank]*	8	12	13	3	2	9	7	14	10	15
LRH-M1: 'Proximity to Populations and Protected Areas' [Rank]*	8	7	27	11	2	12	29	30	9	20
(EBITDA-CAPEX) / INTEREST	-1.11x	0.23x	121.77x	5.34x	105.39x	2.71x	1,728.94x	2.40x	7.10x	1.38x
CURRENT RATIO	0.52x	1.02x	1.88x	2.10x	1.90x	1.08x	3.15x	0.69x	2.58x	1.23x
DEBT / EQUITY	0.76	4.81	0	0.49	0.07	1.42	0.01	1.95	0.22	1.56
PROJECTED CAPEX / EBITDA	0.67	0.31	0.39	0.23	0.39	0.28	0.46	0.19	0.75	0.69
[% REV FROM COAL]	0.46	0.72	0.94	0.91	0.66	0.55	0.89	0.31	0.58	0.85
PROD [Mt (#)]	32 (5)	232 (28)	29 (6)	56 (4)	6 (1)	8 (2)	494 (8)	27 (1)	41 (6)	39 (9)
NUM	5	28	6	4	1	6	13	3	6	10
2014 THERMAL COAL REV [US$MN]	2,826	2,638	2,350	2,337	2,324	2,301	1,861	1,741	1,600	1,356
COUNTRY[ii]	ID	TH	US	CH	CH	US	IN	ID	US	CH
PARENT OWNER	PT UNITED TRACTORS	BANPU PUBLIC COMPANY LIMITED	ARCH COAL	YANG QUAN COAL INDUSTRY (GROUP) CO., LTD.	SHANXI LU'AN ENVIRONMENTAL ENERGY DEVELOPMENT	ALLIANCE RESROUCE PARTNERS	THE TATA POWER COMPANY	INDO TAMBANGRAYA MEGAH TBK PT	CONSOL ENERGY INC	DATONG COAL INDUSTRY

*: Companies are ranked by exposure, with 1 being the most at risk.
**: NRHs have been aggregated to a single outlook percentage based on the sum of high risk (+2) and medium risk (+1) evaluations relative to the maximum possible and weighted by asset locations.

7 Coal Processing Technology Companies

Coal processing technology companies are examined for their exposure to environment-related risks. First, the market for coal processing technology companies is outlined, including capital project pipelines, ownership structures, and debt obligations. Then a number of hypotheses pertaining to the companies' environment-related risk exposure are developed and tested. As many of these companies are new or emerging, evaluation of their risk exposure will provide valuable insight into the future potential of these technologies. Figure 54 shows the location of the plants of the global top 30 CPT companies. The top 30 CPT companies own 34% of CPT plants and produce 63% of CPT products on a syngas-nominal basis.

Figure 54: *Top 30 coal processing technology plants*



7.1 Assessment of Available Information

The next section will discuss commercial uses of CTG/CTL/UCG technologies, capital expenditures and ownership trends globally, as well as other technical, economic and environmental factors that impact the value of coal-based energy processing companies. Considering the growing interest in coal conversion projects, the environment-related risks (e.g. related to GHG emissions and water intensity) of coal processing projects should be taken seriously if these projects are developed on a large-scale.

Box 9: *Roundtable review of coal processing technologies – November 2015, London*

On November 10, 2015, Stranded Assets Programme at the Oxford Smith School held a roundtable discussion involving researchers, practitioners, and policymakers on the global state of coal-to-liquids (CTL), coal-to-gas (CTG), and underground coal gasification (UCG) technologies. A number of key points were raised during the meeting, detailed below.

Renewed interest in CPTs is motivated by:

- High LNG costs making CPT more attractive.
- China is strategically expanding these technologies for (i) energy security, (ii) reducing air pollution in major cities, and (iii) resolving potential employment issues for coal mine workers.
- CPT by-products such as hydrogen, methane, and syngas are important feedstocks for the chemicals industry and can be used for power generation.

However, there are potential investment issues:

- Most CTL/CTG/UCG projects are in development stages and may not come to fruition. In addition, after years of rapid growth the market may be saturated.
- These projects are capital intensive, requiring large upfront capital investments and four- to five-year construction periods.
- Limited research and development investment in these technologies hinders cost reductions and efficiency gains.

Concerns were raised over environment-related risks:

- CTL/CTG/UCG are water intensive, generating additional water stress in arid regions such as northwestern China, South Africa, and the western US. Water pricing could be another challenge.
- The high carbon intensity of these technologies is a serious challenge for countries' 2°C targets. Fugitive methane emissions and volatile organic compounds (VOC) will present an additional regulatory risk in countries like the US.
- Underground water, land, and crop pollution, as well as waste disposal are other serious environment-related risks that might create remediation liabilities (e.g. UCG demonstration plant in Chinchilla, Australia).
- Potential reputational risks due to negative media exposure and local protests. For instance, Friends of the Earth Scotland campaigned effectively for a moratorium on UCG projects in Scotland, arguing that these projects have high CO_2 emissions and could generate environmental pollution.

7.2 Market Analysis

7.2.1 Capital Projects and Ownership

The ownership trends of coal-based energy processing companies vary significantly by country. The majority of CPT plants are either in planning or under construction. Several projects have faced funding shortages or the withdrawal of companies due to low financial returns on trial projects, bureaucratic hurdles during planning and permitting stages, regulatory uncertainty, and environmental liabilities. A summary of key capital projects and their owners and funders is provided in Table 48. For extensive discussion of the role of CPTs in each country, see the policy summaries in Section 4.

Table 48: *CPTs capital projects*

Country	Demonstration / operating projects	Pipeline projects	Key companies	Funding source
Australia	Monash Energy (CTL), Arckaringa (CTL), Chinchilla (UCG) - closed down in 2013	Additional CTM project for Arckaringa	Anglo Coal, Shell, Altona Energy, Linc Energy	Private sector funding and government subsidies
China	Several CTG/CTL/UCG demonstration projects in place since 2010	50 new CTG plants in Northwestern China	Datang, China Guodian Corporation, China Power Investment, CNPC, CNOOC and Sinopec	Subsidies from local governments and loans from the Chinese Development Bank
India	UCG plant applications for Katha (Jharkhand), Thesgora (Madya Pradesh) Tata Group's application for a CTL plant in Odisha rejected by government	New UCG pilot projects for West Bengal and Rajasthan	Coal India Limited, Tata Group, the Oil and Natural Gas Corporation Ltd (ONGC) and the Gas Authority of Indian Ltd.	Subsidies from local government, and private funding
South Africa	Operating 6 coal mines producing feedstock for Secunda Synfuels and Sasolburg Operations	New growth plans for the Project 2050, replacing 4 old coal mines for CTL projects	Sasol Ltd	Public and private funding; investment and pension funds
United States	Great Synfuels CTG Plant in North Dakota	12 new CTL project proposals in Wyoming, Illinois, Arkansas, Indiana, Kentucky, Mississippi, Missouri, Ohio and West Virginia	Shell, Rentech, Baard, DKRW	Public and private funding

Table 71 in Appendix C shows ownership information for the 30 coal-processing technology companies. For each company, the location of the head office, the ultimate corporate parent, corporate parent's ownership type, and the aggregate market value (in billion US$) of the various holders' positions is examined. Table 49 aggregates the data by region, illustrating the ownership distribution by region. Values presented represent total market value in US$bn.

Table 49 summarises ownership type of the CPT companies' ultimate corporate parents. Data for two companies were unavailable. Across the available 28 companies, the data shows that coal processing plants are 60.7% owned by private companies and 39.3% owned by public companies. The majority of the processing plants are Chinese-owned. In China, the proportion of private ownership is 80%, whereas only 20% of coal processing plants are ultimately owned by public companies. The sample contains two coal processing plants in the US; one privately owned and one publicly owned. The only Indian processing plant and plants across all 'other' regions were publicly owned. No European plants were included in the sample.

***Table 49:** Distribution of ownership for coal processing plants, by region*

	Government	Private Company	Private Investment Firm	Public Company	Public Investment Firm
(A) Total	0.0%	60.7%	0.0%	39.3%	0.0%
	(0)	(17)	(0)	(11)	(0)
(B) China	0.0%	80.0%	0.0%	20.0%	0.0%
	(0)	(16)	(0)	(4)	(0)
(C) US	0.0%	50.0%	0.0%	50.0%	0.0%
	(0)	(1)	(0)	(1)	(0)
(D) India	0.0%	0.0%	0.0%	100.0%	0.0%
	(0)	(0)	(0)	(1)	(0)
(E) EU	-	-	-	-	-
	(0)	(0)	(0)	(0)	(0)
(F) Other	0.0%	0.0%	0.0%	100.0%	0.0%
	(0)	(0)	(0)	(5)	(0)

7.2.2 Bond Issuances

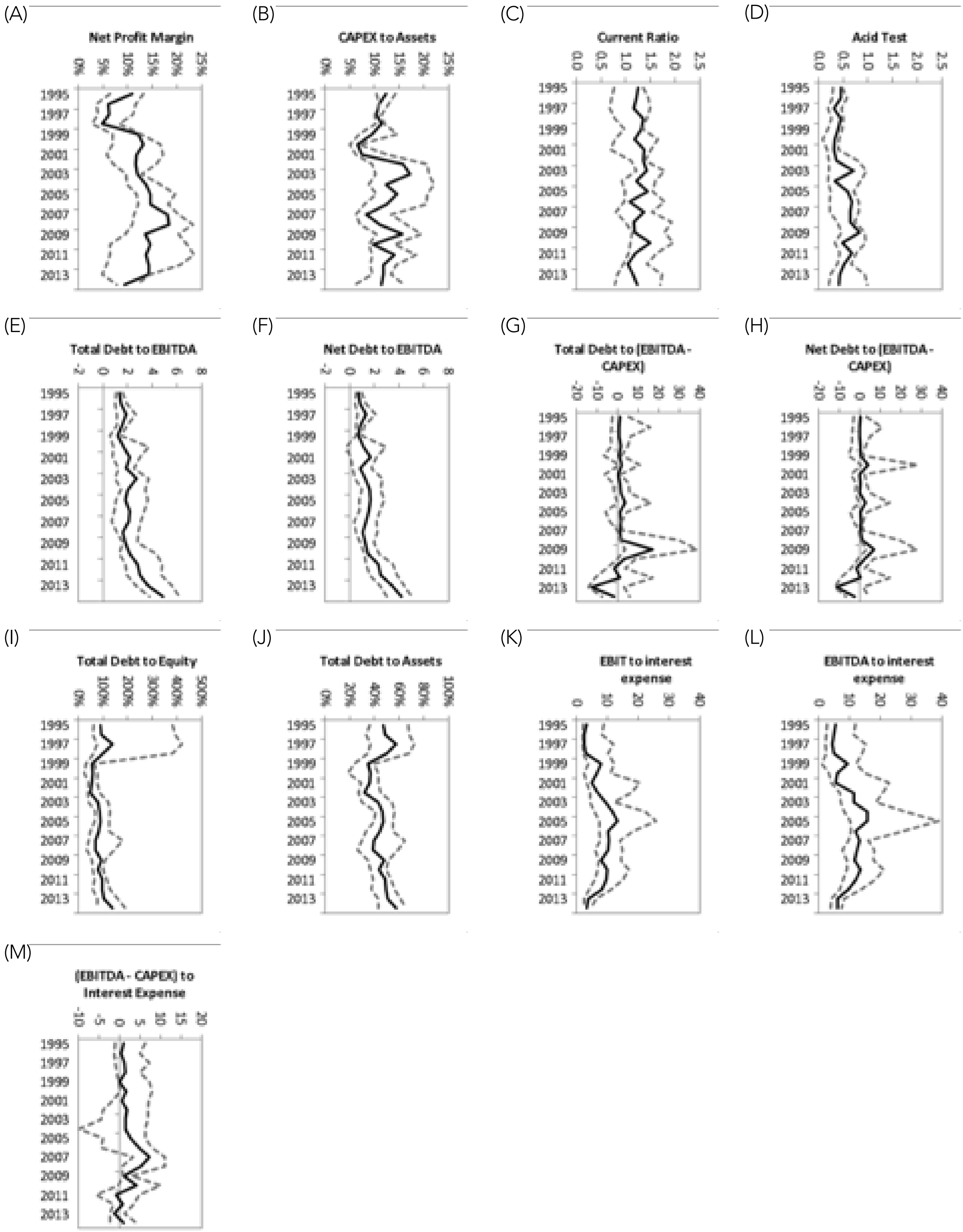
Coal-based energy processing companies' exposure to high levels of debt increases risk for both debt and equity holders of coal processing plants as the priority of either is further diluted in the event of the company's insolvency. Table 72 in Appendix B shows bond issuances of the top 30 coal processing companies.

To build a general picture of the future direction for bond issuances in the CPT industry, fixed-income securities are examined through ratio analysis. Table 73in Appendix B presents financial ratios relating to profitability, capital expenditures, liquidity, leverage, debt coverage, and the ability for utilities to service existing debt. Figure 55 illustrates the same ratios through time, including the 25th and 75th percentile ranges to capture the distribution of observed ratios across firms. The analysis was conducted for between 1995 and 2014 to represent the last 20 years of data[422]. The dataset for 2015 was limited, and was omitted from the analysis. Financial data were unavailable for many coal processing companies. Thus, the analysis is restricted to publicly traded companies.

Credit rating reports were unavailable for coal-processing technology companies.

[422] Data were taken from Thomson Reuters Datastream, November 2015 and Standard & Poor's Capital IQ, November 2015.

Figure 55: *Ratio analysis for all CPT companies, with median, 25th, and 75th percentiles*



The first two ratios examined report general profitability and capital expenditure in the coal processing industry, which are both relevant to the industry's ability to service its debt commitments. Chart (A) presents the profit margins for the processing industry, which were generally greater than those observed in the power utility and mining industries. At its peak, the industry's profit margin was 18.4% in 2008. Despite the decline in recent years, the industry's 2014 profit margin is still 9.3%. Figure 55 shows a large spread between the net profit margin's 25th and 75th percentile. Examination of the data showed that some processing plants had negative net income post-GFC.

However, the industry's profit margin must be balanced against capital expenditure. Chart (B) shows that capital expenditures are both large and volatile, ranging from 4.9% to 17.2% of total assets. Since 2012, CAPEX has trended between 11.6-11.8% of total assets. Acquiring, upgrading, and maintaining existing physical assets are relatively costly for coal processing plants in comparison to the other two industries examined in this report.

The current ratio and acid test are used as proxies for liquidity in the industry. The former measures the ability to service current liabilities using current assets, the latter measures the ability to service current liabilities using cash, near-cash equivalents, or short-term investments. The coal processing and coal-mining industries have relatively higher liquidity than the coal-fired power utilities. Charts (C) and (D) show both liquidity ratios have remained relatively stable through time. The acid test shows that the holding of near-cash equivalents has also generally increased through time, but suffered a decline in recent years.

Two financial leverage ratios are examined: the debt/equity ratio in Chart (E) and the debt/assets ratio in Chart (F). Chart (E) shows that the debt/equity ratio has been volatile across time. The coal processing industry has leveraged its position in recent years. In 2014, debt represented 58% of total assets. While profitability remains high, the high financial leverage could be of concern in years with abnormally high capital expenditures.

Coverage ratios measure the processing industry's ability to meet its financial obligations. Three ratios are considered: 1) EBIT/interest, 2) EBITDA/interest, and 3) (EBITDA-CAPEX)/interest. Charts (G) and (H) show that the coal processing industry generates sufficient operating income to cover interest expenses. In 2014, EBIT was 3.31 times greater than interest expenses, while EBITDA was 6.06 times greater. As stated, CAPEX is a major concern for the processing industry. Ratios less than unity suggest that the industry does not generate sufficient income to cover interest expenses; this occurs frequently throughout the series. Of major concern are 2011 and 2013, where the ratio turns negative – indicating that CAPEX exceeded EBITDA or the company made an operating loss. In both years, the negative ratios are a result of increasing CAPEX and greater financial leverage.

Four ratios represent the processing industry's ability to retire incurred debt. The ratios can be broadly interpreted as the amount of time needed to pay off all debt, ignoring interest, tax, depreciation and amortisation. The ratios are delineated in two groups: group 1 considers the numerators: 'total debt' and 'net debt', where the latter subtracts cash and near-cash equivalents for total debt; group 2 considers the denominators: EBITDA and (EBITDA-CAPEX), where the latter controls for capital expenditures.

Charts (J) and (K) show that the time taken to pay off incurred debt increases. In 2014, at current EBITDA, total debt would take 4.91 years to retire, while net debt takes 4.17 years – subject to conditions outlined previously.

Chart (L) shows that capital expenditures result in negative ratios, suggesting an inability to retire debt. The negative values observed from 2011, in conjunction with the CAPEX ratio in Chart (B), indicate that CAPEX has been greater than EBITDA. Further, Chart (M) shows that this inability to retire debt continues after exhausting near-cash assets.

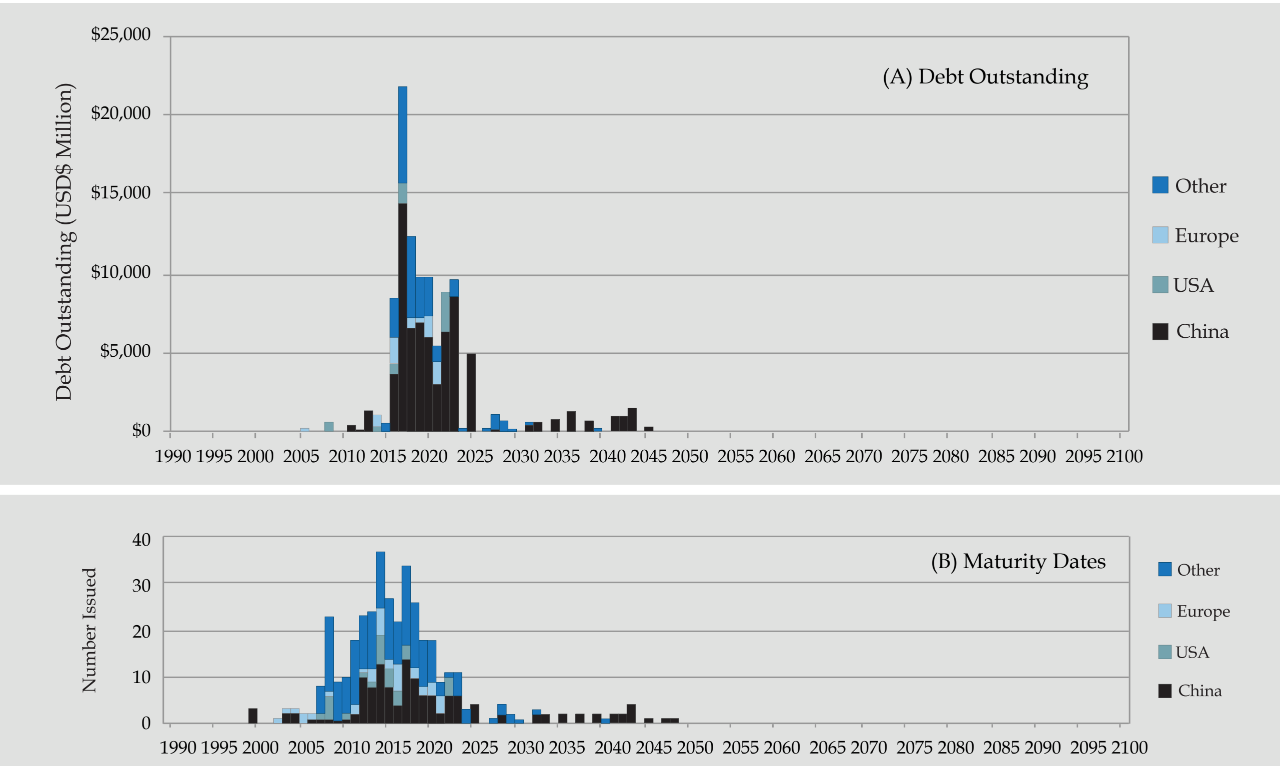
Figure 56 illustrates the maturity schedule for the coal processing industry, using available data from 12 of the 30 coal processing technology companies. The schedule is divided into total amount outstanding (US$) and the maturity dates of various contracts. Both graphs are delineated by major region, including: China, US, Europe, and 'other'.

Plot (A) of Figure 56 shows that the majority of the total debt is due between 2016 and 2023. There is little borrowing beyond this date in our sample. European and US coal processing companies have relatively little debt outstanding. In comparison, coal processing companies in China and 'other regions' issued a large proportion of debt until the 2010s and 2020s, while Chinese companies have some debt outstanding until 2045. Plot (B) shows a similar trend, with companies in China and 'other regions' issuing contracts until at least 2040. Table 50 shows that companies in the US and China have also issued some perpetual debt, however the number of contracts is relatively low.

Table 50: *Coal-based energy processing companies' perpetual debt*

	China	US	Europe	Other
Amount outstanding (US$m)	181	300	0	0
Number issued	2	1	0	0

Figure 56: *Maturity schedules for industry debt: amount outstanding (A) and maturity dates (B)*



7.3 Investment Risk Hypotheses

In this section, we take a view on what the environment-related risks facing coal-to-liquids and coal-to-gas processing plants could be and how they could affect asset values. We call these Local Risk Hypotheses (LRHs) or National Risk Hypotheses (NRHs) based on whether the risk factor in question affects all assets in a particular country in a similar way or not. For example, water stress has variable impacts within a country and so is an LRH, whereas a country-wide carbon price is an NRH. The hypotheses are coded for easier reference. For example, LRH-P1 refers to plant age and NRH-P1 refers to CPT policy support.

Hypotheses for different environment-related risks have been developed through an informal process. We produced an initial long list of possible LRHs and NRHs. This list was reduced to the more manageable number of LRHs and NRHs contained in this report. We excluded potential LRHs and NRHs based on two criteria. First, we received feedback from investors and other researchers in meetings, roundtables, and through correspondence, on the soundness, relevance, and practicality of each hypothesis. Second, we assessed the data needs and analytical effort required to link the hypotheses with relevant, up-to-date, and where possible, non-proprietary, datasets.

The current list of hypotheses and the datasets used to measure asset exposure to them are in draft form. Other datasets may have better correlations and serve as more accurate proxies for the issues we examine. Important factors may not be represented in our current hypotheses. We are aware of these potential shortcomings and in subsequent research intend to expand the number of hypotheses we have, as well as improve the approaches we have used to analyse them.

The summary table that shows the exposure of the top-30 coal processing technology companies to each NRH and LRH can be found in Section 7.4.

7.3.1 Local Risk Hypotheses

LRH-P1: Plant Age
Ageing CPT plants are more exposed to regulations that might force their closure. It is financially and politically simpler to regulate the closure of ageing plants. Once CPT plants have recovered capital costs and have exceeded their technical lives, the financial need to compensate is greatly reduced or eliminated[423]. Old CPT plants may also be more exposed to site remediation costs and significant worker liabilities (e.g. pension costs).

The age of each CPT plant is taken from the World Gasification Database. These are then aggregated to the company level, weighted by plant capacity.

LRH-P2: Water Stress
CPT plants located in areas with higher physical baseline water stress or in areas with regulatory uncertainty are at higher risk of being forced to reduce or cease operation, of losing their licence to operate, or of having profits impaired by water pricing.

[423] Caldecott, B. & Mitchell, J. (2014). Op. Cit.

CTL is highly water intensive. Studies from Hook[424], the US DOE[425], and RAND[426] estimate that coal liquefaction technologies require between five and 14 tonnes of freshwater per tonne of liquid fuel. For CTG, Yang and Jackson[427] finds that producing synthetic natural gas requires 50 to 100 times the amount of water needed to produce shale gas. See Section 2 for details.

Two WRI Aqueduct datasets are used to assess water stress-related risks to CPT plants. Aqueduct's measure of Baseline Water Stress (BWS) is the ratio of total annual withdrawals of water to availability of freshwater flow within a given watershed. Aqueduct produces the Regulatory and Reputational Risk indicator as a robust qualitative analysis of regulatory changes and social challenges to water use[428].

All CPT plants are mapped against the Aqueduct Baseline Water Stress and Regulatory and Reputational Risks geospatial datasets. Those plants that are in watersheds that have 'extremely high water risk' for baseline water stress are identified as 'at risk'. Those plants that are in watersheds that have 'extremely high regulatory and reputational risk' are identified as 'at risk'. In the case that a plant is 'at risk' for both indicators, it is classified as 'seriously at risk'.

Plants are then aggregated by CPT company to identify the percentage of capacity that is 'at risk' or 'seriously at risk'.

LRH-P3: CCS Retrofitability

CPT plants that are unsuitable for the retrofit of carbon capture and storage (CCS) technology are more at risk of premature closure in scenarios with stringent climate change policy. CCS retrofitability of CPT plants enables compatibility of the plants with 2°C warming scenarios of the IEA and IPCC[429].

Following the methodology of the OECD[430], CCS retrofitability is defined as an aggregate function of plant size, age, and efficiency. This analysis adds extra criteria of geographic proximity to suitable geological reservoirs, and a favourable national policy environment. The Global CCS Institute's Carbon Capture and Storage Policy Indicator is used to determine policy favourability for CCS.

The following approach is taken to identify the percentage of a CPT company's portfolio of plants that may be suitable for CCS retrofits. Suitable CPT plants are defined as those under 20 years of age and within 40km of highly geologically suitable areas.

CPT plant age is taken from the CoalSwarm dataset. Next, all CPT plants are mapped against the CCS geological suitability geospatial dataset[431] to identify whether they are within 40km of areas highly suitable for CCS; 40km has been suggested as an appropriate distance for assessing viable proximity to geological storage, e.g. by Bentham et al[432], NETL[433].

424 Höök, M. (2014). Op. Cit.

425 United States Department of Energy (DOE) (2013). Coal-to-liquids and Water Use, NETL. http://www.netl.doe.gov/research/coal/energy-systems/gasification/gasifipedia/ctl-water-use

426 Bartis, J. Camm, F., Ortiz, D. (2008). Producing Liquid Fuels from Coal: Prospects and Policy Issues, RAND. Santa Monica, US.

427 Yang, C. & Jackson, R. (2013). Op. Cit.

428 World Resources Institute (2016). Op. Cit.

429 Refers specifically to the IPCC AR5 430-480ppm, IEA ETP 2DS, and IEA WEO 450S.

430 Finkenrath, M., et al. (2012). Op. Cit.

431 Used with permission of IEA Greenhouse Gas R & D Programme and provided by Geogreen SA.

432 Bentham, M. et al. (2014). 'Managing CO2 storage resources in a mature CCS future', Energy Procedia 63: 5310-5324.

433 NETL (2011). Op. Cit.

Suitable plants are then aggregated by utility to identify the percentage of CPT companies' portfolios that are suitable for CCS retrofit.

7.3.2 National Risk Hypotheses

Table 51: *National-level environment related risk indicators*

🔴 High Risk (+2) 🟡 Medium Risk (+1) 🟢 Low Risk (+0)	Australia	China	Germany	Indonesia	India	Japan	Poland	South Africa	United Kingdom	United States
NRH-P1: CPT Policy Support	🟢	🟢	🟡	🟡	🟢	🟢	🟡	🟢	🔴	🟢
NRH-P2: Oil and Gas Demand Outlook	🟡	🟢	🔴	🟢	🟢	🔴	🔴	🟢	🔴	🟡
NRH-P3: Oil and Gas Indigenous Resources	🟡	🔴	🟡	🟢	🟢	🟢	🟢	🟢	🟢	🔴
NRH-P4: Other Local Environmental	🟡	🟡	🟢	🟢	🟢	🟢	🟢	🟡	🟢	🟡
NRH-P5: Regulatory Water Stress	🟢	🟡	🟢	🔴	🟡	🟢	🟢	🟡	🟢	🟢
NRH-P6: CCS Policy Outlook	🟢	🔴	🟡	🔴	🔴	🟡	🟡	🔴	🟢	🟢
TOTAL (/14)	3	6	5	5	3	3	4	4	3	4

NRH-P1: CPT Policy Support

The hypothesis is that CPTs are dependent on country-specific policy frameworks to succeed. Table 52 describes policy support for CPTs in each country. Where policy support is identified, the country is considered 'low risk'. Where specific policies have been enacted to prevent CPT projects, the country is considered 'high risk'. Where no policy information has been identified those countries are considered 'medium risk'.

Table 52: *Countries with CPT policies*

Country	Reference	RISK
Australia	Historic project uptake	🟢
China	Extensive emerging CPT projects	🟢
Germany	No information available	🟡
Indonesia	No information available	🟡
India	Emerging government support for CPT projects	🟢
Japan	N/A	🟢
Poland	No information available	🟡
South Africa	Historic government support of CPT	🟡
United Kingdom	UCG moratorium enacted in Scotland	🔴
United States	Historic government support of CPT projects	🟡

7.3.2.1 NRH-P2: Oil and Gas Demand Outlook

The hypothesis is that strong oil and gas demand in the country where CPT plants are located creates more favourable demand conditions for plants, improving their economics.

Coal processing technology companies compete in gas and liquid fuel markets, and are thus exposed to competition from substitute or existing products in these markets. Where growth in oil or gas demand is strong, a market may be available for CPT products. Where growth is weak, CPT products will need to compete more with existing supply and imports, which may damage the viability of CPT business models.

We use scenario data from the IEA WEO2015. The CAGR of total primary energy demand (TPED) for both oil and gas is shown in Table 53. As explained in Section 1.3 the WEO NPS is taken as a conservative scenario. Where both oil and gas have a negative growth projection, the country is considered 'high risk'. Where only one has a negative growth projection it is considered 'medium risk'. Using the WEO projections suffers from the same challenge in disaggregating individual outlooks from regional outlooks. EU countries remain comingled together, Australia is comingled with South Korea and New Zealand, and Indonesia is comingled with other non-OECD Asian countries.

***Table 53:** Oil and gas outlook from IEA WEO 2015 NPS*[434]

2013-2020 CAGR	Australia	China	Germany	Indonesia	India	Japan	Poland	South Africa	United Kingdom	United States
OIL	-0.3%	2.9%	-1.5%	1.8%	3.8%	-3.3%	-1.5%	0.6%	-1.5%	0.0%
GAS	1.3%	8.5%	-0.6%	2.0%	3.7%	-2.9%	-0.6%	4.2%	-0.6%	1.1%
RISK	🟡	🟢	🔴	🟢	🟢	🔴	🔴	🟢	🔴	🟡

NRH-P3: Oil and Gas Indigenous Reserves

Similar to the previous hypothesis, where CPTs need to compete with substantial indigenous oil and gas reserves, they may be less likely to get policy support and compete successfully for market share. Countries with indigenous reserves may have a greater interest in developing those reserves with conventional technology, rather than investing in CPTs.

This hypothesis uses data from the BP Statistical Energy Outlook 2015 to identify where countries have substantial oil and gas reserves, shown in Table 54. Where countries have over 1% global reserves of either oil or gas they are considered 'medium risk'. Where both exceed 1% they are considered 'high risk'.

[434] NPS from IEA (2015). WEO 2015. Op. Cit.

Table 54: Oil and gas indigenous reserves[435]

2014 Reserves % of world	Australia	China	Germany	Indonesia	India	Japan	Poland	South Africa	United Kingdom	United States
OIL	0.2%	1.1%	0.2%	0.3%	<0.1%	<0.1%	<0.1%	<0.2%	0.2%	2.9%
GAS	2%	1.8%	1.5%	0.80%	<0.05%	<0.2%	0.1%	<0.6%	0.1%	5.2%
RISK										

NRH-P4: Other Local Environmental

The hypothesis is that stricter environmental regulation or enforcement would negatively affect CPT plant economics and potentially create new liabilities.

CPT projects have local environmental impacts, see Section 0. In some countries these environmental impacts have become concerns for policymakers and the public. We identify where environmental impacts have been significant in the development of CPT projects. Subjective judgements are made as to whether the impacts should be considered 'high risk' or 'medium risk'.

Table 55: Other local environmental risk factors for CPT companies

Country	Reference	RISK
Australia	Emerging environmental liability case from Linc Energy's UCG project in Chinchilla, Queensland.[436]	
China	CPT projects increase conventional air pollutants[437]	
Germany	No information available	
Indonesia	No information available	
India	No information available	
Japan	No information available	
Poland	No information available	
South Africa	CPT projects have come in conflict with water availability[438]	
United Kingdom	No information available	
United States	US EPA is issuing new regulations regarding the emission of methane and volatile organic compounds (VOCs) which will impact future CPT projects[439]	

[435] BP plc (2015). Op. Cit.

[436] Bajkowski, J. (2014). 'Queensland government hits Underground Coal Gasification player Linc Energy with environmental damage charges', GovernmentNews.

[437] Hyder, Z., Ripepi, N., & Karmis, M.. (2014). 'A Life Cycle Comparison of Greenhouse Emissions for Power Generation from Coal Mining and Underground Coal Gasification', Mitigation and Adaptation Strategies for Global Change May:1-32.

[438] Shaio, T. & Maddocks, A. (2014). 'Finding Solutions for South Africa's Coal-Fired Energy and Water Problems', in Blog, World Resources Institute.

[439] US EPA (2015). 'Oil and Natural Gas Sector: Emission Standards for New and Modified Sources', Federal Register 80:56593-56698.

NRH-P5: Regulatory Water Stress

CPT plants have substantial water footprints, described below in hypothesis CPT-2 Water Stress. This water footprint exposes CPT companies to regulatory risks, as policymakers may take action to restrict processing plant access to water. Public opinion on the water footprint for CPT plants may also put pressure on policymakers to restrict water use, exposing CPT companies to a reputational risk as well.

The World Resources Institute (WRI) maintains the Aqueduct Water Risk Indicator maps. The WRI's Regulatory & Reputational Risk indicator aggregates indicators from the World Health Organization (WHO) concerning water access, the International Union for Conservation of Nature (IUCN) for threatened amphibians, and Google keyword searches for water supply media coverage[440]. With few exceptions, this indicator is provided at the national level.

This risk hypothesis is identical to the Regulatory Water Stress hypothesis described for coal-fired power utilities (see NRH-U9) and thermal coal miners (See NRH-M7) and uses the same data and analysis, see above for details.

Table 56: *Regulatory water stress*[441]

	Australia	China	Germany	Indonesia	India	Japan	Poland	South Africa	United Kingdom	United States
Risk bin	1	3	1	4	3	1	2	3	2	1
RISK	●	●	●	●	●	●	●	●	●	●

7.3.2.2 NRH-P6: CCS Legal Environment

The hypothesis is that CCS could be a way for CPT plants to keep running under stricter carbon constraints, but CCS will not happen without a supportive legal framework.

CPT has several technical synergies with CCS, presenting a pathway for GHG emissions mitigation using coal as an energy resource. CCS currently faces substantial uncertainty with regards to current and future liabilities for the unique aspects of a CCS project, see Section 3.6.2. These uncertainties can present barriers to the development of CCS projects, which in turn present a risk to CPT projects who may not have CCS as an option for future GHG mitigation.

Certain countries have been proactive in developing policy and legal interpretations specifically for CCS. This progress is periodically evaluated by the Global CCS Institute periodically and published as an indexed indicator. The institute groups countries into three performance bands, which are used here as an indicator for CCS liability risk. Band A, the most CCS-ready, is considered 'low risk', Band B 'medium risk', and Band C 'high risk'.

[440] Gassert, F. et al. (2014). Op. Cit.

[441] World Resources Institute (2016). Op. Cit.

Table 57: *CCS legal environment indicator*[442]

	Australia	China	Germany	Indonesia	India	Japan	Poland	South Africa	United Kingdom	United States
Band	A	C	B	C	C	B	B	C	A	A
RISK	🟢	🔴	🟡	🔴	🔴	🟡	🟡	🔴	🟢	🟢

7.4 Summary of CPT Companies

Table 58: *Summary of hypothesis risks for CPT companies*

COMPANY	COUNTRY	CAPACITY [kNm3/day] OPR	CON	PLN	DEBT / EQUITY	CURRENT RATIO	(EBITDA – CAPEX) / INTEREST	[RANK]* LRH-P1: 'Plant Age'	LRH-P2: 'Water Stress'	LRH-P3: 'CCS Retrofitability'	NRH AGGREGATION**
SASOL	South Africa	90,260	-	-	-	-	-	9	1	30	43%
DATANG	China	48,550	3336	73442	-	-	-	3	15	1	43%
SHENHUA GROUP	China	43,360	-	72000	0.43	1.18x	0.00x	2	5	30	43%
YITAI COAL OIL MANUFACTURING CO (INNER MONGOLIA YITAI GROUP)	China	33,700	-	-	2.71	0.34x	0.91x	10	18	29	43%
SINOPEC	China	29,481	840	63400	1.79	0.41x	-1.86x	5	24	30	43%
CHINACOAL GROUP	US	24,100	5000	-	-	-	-	17	12	30	43%
DAKOTA GASIFICATION CO	China	13,900	36000	-	0.58	1.30x	6.46x	12	25	25	43%
QINGHUA GROUP	China	13,860	-	-	-	-	-	5	19	1	43%
YANKUANG GROUP	China	13,415	2000	-	-	-	-	7	17	30	43%
GUANGHUI ENERGY CO	China	12,600	-	-	-	-	-	13	3	30	43%
PUCHENG CLEAN ENERGY CHEMICAL CO	China	12,100	-	-	-	-	-	3	14	30	43%
XINHU GROUP	China	12,000	-	-	-	-	-	5	26	30	43%
WISON (NANJING) CLEAN ENERGY CO	China	11,932	-	-	-	-	-	14	22	28	43%
TOKYO ELECTRIC POWER COMPANY (TEPCO)	Japan	11,566	-	-	0.49	0.96x	0.62x	8	23	26	43%
TOKYO ELECTRIC POWER COMPANY (TEPCO)	China	9,975	8400	-	0.32	0.76x	3.90x	11	12	27	43%
SANWEI RESOURCE GROUP	China	9,744	-	3125	-	-	-	15	27	1	43%
INNER MONGOLIA ZHUOZHENG COAL CHEMICAL CO	China	9,040	-	-	-	-	-	6	2	1	43%
TIANJIN BOHAI CHEMICAL GROUP	China	8,787	68000	-	-	-	-	3	20	1	43%
KOREA SOUTH EAST POWER CO (KOSEP)	South Korea	8,400	-	-	-	-	-	2	28	1	43%
KOREA SOUTHERN POWER CO (KOSPO)	South Korea	8,400	-	-	-	-	-	16	16	30	43%
JINDAL STEEL & POWER LTD	India	8,025	84136	19020	1.73	0.61x	-0.82x	3	29	30	43%
JIEHUA CHEMICAL	China	8,000	9420	113080	-	-	-	1	21	1	43%
POSCO	South Korea	6,934	-	-	2.06	0.84x	1.58x	4	7	30	36%
HUALU HENGSHENG CHEMICALS	China	6,890	-	-	2.86	1.17x	4.79x	2	6	30	21%
JIANGSU LINGGU CHEMICAL CO	China	6,090	-	2046	0.22	2.58x	7.10x	19	3	30	29%
HARBIN YILAN COAL GASIFICATION	China	5,750	-	-	0.88	1.03x	4.11x	2	30	30	-
ANHUI HUAYI CHEMICAL CO	China	5,040	-	-	1.3	0.98x	-6.41x	2	10	30	-
XINJIANG XINLIANXIN FERTILIZER CO. LTD.	China	5,040	-	56400	0.61	1.43x	3.96x	2	8	30	-
YANTAI WANHUA	China	5,040	-	-	-	-	-	18	9	1	29%
EAST CHINA ENERGY	US	5,000	-	51000	-	-	-	5	11	1	29%

*: Companies are ranked by exposure, with 1 being the most at risk.

**: NRHs have been aggregated to a single outlook percentage based on the sum of high risk (+2) and medium risk (+1) evaluations relative to the maximum possible and weighted by asset locations.

8 Indirect Impacts

Beyond thermal coal assets and the companies that own them, other sectors directly or indirectly dependent on them could be positively or negatively affected by the environment-related risks we have examined in this report. These could include shipping, freight railways, ports, power networks, pipelines, insurers, banks, institutional investors, upstream oil and gas producers, and renewables generators. Research and analysis of the exposure of these companies from risks facing the thermal coal value chain are well beyond the scope of this report, however, some of the potential indirect impacts are discussed below. We briefly review the implications for transport, financial institutions, and labour.

8.1 Transport

Approximately 90% of internationally traded coal is transported by ship[443]. In 2015, shipping fleets of 750mn dry weight tonnes (dwt) were engaged in the transportation of coal[444]. Bulker vessels range in size from 10,000dwt to 80,000dwt, implying a global coal shipping fleet of approximately 10,000 vessels[445]. In 2009, freight rates dropped substantially. Bulker charter rates have remained low since because of the significant amount of new build orders placed just before 2009. These orders have kept the bulk market oversupplied[446].

Environment-related risks have the potential to reduce international trade of coal, reducing demand for bulkers. It is highly likely that any such decrease in demand for bulkers would drive charter rates downward. If this happens near the bulker market trough, preliminary research suggests that vessel stranding is highly likely[447]. The total value of vessel stranding and the financial entities that it will impact will likely be determined by which entities financed the least efficient vessels, which are typically built at market peak, and when those vessels were built[448].

While internationally traded coal is transported by ship, most domestically traded and consumed relies on transport by rail. Over half of all US rail freight is transporting coal[449]. Freight rail carriers and export terminals will face pressure to adapt to new commodities or business models as environment-related risks decrease the amount of coal that is transported and consumed around the world. These risks have yet to be examined.

8.2 Workers and Labour Organisations

In 1920, two in every hundred US workers was a coal miner[450]. By 2013, coal miners had fallen to 0.06% of the US workforce or approximately 80,000 people[451]. In the UK, the first country to use coal for electricity (in 1882), by 1920 there were 1.2 million people employed as coal miners[452].

443 IEA (2015). Coal MTMR. Op. Cit.

444 Ibid.

445 Ibid.

446 Ibid.

447 Smith, T. et al. (2015). Stranded Assets in Shipping. Conference Proceedings Shipping in Changing Climates Conference 2015, Glasgow, UK.

448 Mitchell, J. & Rehmatulla, N. (2015). Dead in the Water: an analysis of industry practices and perceptions on vessel efficiency and stranded ship assets. Conference Proceedings Shipping in Changing Climates Conference 2015, Glasgow.

449 American Association of Railroads (2015). Freight rail traffic data. https://www.aar.org/Pages/Freight-Rail-Traffic-Data.aspx.

450 Coalswarm (2015). 'Coal and jobs in the United States', Sourcewatch. http://www.sourcewatch.org/index.php/Coal_and_jobs_in_the_United_States#Total_coal-related_jobs.

451 Ibid.

452 Stevenson & Cook (1988). The Longman Handbook of Modern British History 1714-1980.

By 2015 the number of working in coal mines fell below 3,000[453]. The transition away from coal mining as a major source of employment in the US and UK has taken many decades and it has not been straightforward or uncontroversial. The infamous UK miners' strike in the 1980s being one illustration of the disruption and social upheaval associated with the decline of coal mining.

The Paris Agreement and INDCs imply that carbon intensive sectors will need to quickly decline in order to achieve climate targets. But the faster the pace of decarbonisation, the greater the likely challenges associated with stranded assets in different sectors - a faster transition towards a low carbon economy, all things being equal, may increase the risk of political opposition. For example, the mere prospect of stranded carbon assets could result in the mobilisation of groups to oppose INDCs, which might result in these groups actively or passively frustrating or destabilising INDC implementation.

The issue of stranded labour frustrating INDC implementation is not generally considered by policymakers and this should be a priority for future research. The decline of large sectors, including coal, would create labour tensions that need to be managed in a much more sophisticated and purposeful way than has happened in the past. While very little was done in the 1980s UK to proactively pre-empt opposition to change in coal mining communities[454], we now have the data and analytics to do much more. We can know which assets will have to close, by when, who owns them, who is employed by them, which communities will be affected, and the impacts on the supply chain. With this information much more sensitive low carbon transition plans can be created that are designed to pre-empt opposition. This will improve the robustness of such plans and make them more likely to succeed.

8.3 Banks and Financial Institutions

This report has examined the direct exposure of companies in the thermal coal value chain to environment-related risks. Banks and the finance industry are exposed as owners of the debt and equity of companies in the thermal coal value chain. Their investors are in turn exposed to the same environment-related risks.

A recent report from the CEE Bankwatch Network examines spending on fossil fuel projects by the European Bank for Reconstruction and Development (EBRD) and the European Investment Bank (EIB). Bankwatch alleges that between 2007 and 2014 the EIB and EBRD spent €3.2bn and €990m on fossil fuel projects respectively in European neighbourhood countries[455]. Bankwatch argues that EU development funds should be allocated in alignment with the EU's own energy and climate goals.

In 2013, Banktrack.org examined the exposure of top commercial banks to investments in coal mining, and found Citigroup, Morgan Stanley, and Bank of America had the highest exposures with approximately €7bn each in loans and underwriting[456]. Bank of America, Crédit Agricole, and Citigroup have all announced their intention to end or substantially reduce financing of coal mining[457].

[453] UK Department of Energy and Climate Change (2015). See: https://www.gov.uk/government/collections/coal-statistics
[454] Stevenson & Cook (1988). Op. Cit.
[455] Kochladze, M. & Sikorova, K. (2015). European public money for the energy sector in countries of the European Neighbourhood Policy, 2007-2014, CEE Bankwatch Network. Liben, Czech Republic.
[456] Schücking, H. et al. (2013). Banking on Coal, urgewald; BankTrack; CEE Bankwatch Network; Polska Zielona Sieć
[457] Rainforest Action Network (2015). 'Citigroup Becomes Third Major Bank to Cut Financing to Coal Industry', EcoWatch.

9 Implications for disclosure and reporting

Financial disclosure and reporting is critical for the functioning of efficient capital markets. Disclosure and reporting comes from a wide array of voluntary and regulated activities, but generally seeks to resolve principal-agent problems of information asymmetry and agency[458]. Information asymmetry between investors and companies leads to the inefficient allocation of capital as investors do not know the relative merits of each company. Disclosure resolves agency problems as investors are able to evaluate the performance of the managers they have delegated to run their companies. Greater disclosure has been empirically observed to improve market liquidity, lower costs of capital, increase market valuations, and improve investment efficiency[459].

Companies with securities listed on regulated exchanges must submit the required information periodically to the regulator. This information is provided to the public so that they can make informed investment decisions. Companies may also voluntarily submit information to the regulator, public, or private investors. The Economist writes that it is the symmetry of information between investors that is important for functioning capital markets, not the degree of transparency[460].

In policy design, mandated disclosure or transparency is increasingly used in lieu of other regulations to incentivize or elicit changes in corporate behaviour[461]. The evidence for this approach to policy design is built largely on the informal and non-mandatory compliance literature base[462], as well as literature on consumer choice[463], corporate social responsibility[464], and company stakeholder obligations[465]. Where voluntary disclosure regimes have been successfully implemented by and for investors, the results linking ESG performance to corporate operating and financial performance are convincing[466].

9.1 Climate Change Risk Disclosure

Climate change risk disclosure has currently achieved acceptance as an objective in non-financial information disclosure. In these reports, climate change impacts are included as risk factors or topics of management discussion and analysis[467]. Non-financial disclosures may be regulated[468] however their content is discretionary to company management.

Voluntary sustainability and climate change risk reporting platforms have made progress attracting disclosure from early adopters. Frameworks from organisations like the CDP (formerly the Carbon Disclosure Project) and the Global Reporting Initiative connect investors with sustainability performance data from companies worldwide. A wide variety of reporting frameworks exist.

[458] Healy, P. & Palepu, K. (2001). 'Information asymmetry, corporate disclosure, and the capital markets: A review of the empirical disclosure literature', Journal of Accounting and Economics, 31: 405-440

[459] Leuz, C. & Wysocki, P. (2015). 'The Economics of Disclosure and Financial Reporting Regulation: Evidence and Suggestions for Future Research' SSRN.

[460] The Economist (2009) 'Full Disclosure: The case for transparency in financial markets is not so clear-cut', Economist.

[461] Leuz, C. & Wysocki, P. (2015). Op. Cit.

[462] US EPA (2014). 'Chapter 4: Regulatory and Non-Regulatory Approaches to Pollution Control' in Guidelines for Preparing Economic Analyses. Washington, US.

[463] For example, Brouhle, K. & Khanna, M. (2007). 'Information and the Provision of Quality Differentiated Products', Economic Inquiry, 45: 377-394.

[464] For example, Lyon, T. (2002). 'Voluntary Approaches to Environmental Protection: A Survey' (with John W. Maxwell), in Economic Institutions and Environmental Policy: Past, Present and Future.

[465] For example, Pargal, S., Hettige, H., Singh, M., et al. (1996). 'Formal and Information Regulation of Industrial Pollution', The World Bank Economic Review, 11:433-450.

[466] Clark, G., Feiner, A., & Veihs, M. (2015). From the Stockholder to the Stakeholder, University of Oxford, Arabesque Partners. London, UK.

[467] Securities and Exchange Commission (2010). Commission Guidance Regarding Disclosure Related to Climate Change.

[468] EU (2014). 'Directive 2014/95/EU', Official Journal of the European Union, 57:1-10; Institut RSE Management (2012). The Grenelle II Act in France: a milestone towards integrated reporting.

As accounting standards have become more globally aligned under the International Financial Reporting Standards, an opportunity has emerged to align account standards with sustainability risk disclosure. Organisations like the Sustainable Accounting Standards Board and the Climate Disclosure Standards Board are helping to align sustainability reporting with financial rigor. The challenge for investors remains that the multitude of standards produces insufficient 'decision-ready' information, and preparing and interpreting the reporting is burdensome for both companies and investors[469].

In November 2015, the World Federation of Exchanges (WFE) issued their guidance on ESG reporting[470]. WFE issued a list of 34 recommended ESG metrics to it 64 member exchanges, including 10 environmental metrics specifically. Many of the WFE's member exchanges already adopt some form of sustainability reporting[471].

Also in late 2015, the Financial Stability Board launched its Task Force on Climate-Related Financial Disclosures (TCFD). The Task Force is to develop consistent, comparable, reliable, clear, and efficient climate-related disclosures and is expected to release its recommendations by the end of 2016[472].

9.2 Insights from our research

As part of this research project we have undertaken a comprehensive data integration process, bringing together a wide range of different datasets and sources for the first time. This is a work in progress, but our work to date has highlighted some of the challenges associated with turning an understanding of environment-related factors facing particular sectors into analysis that is decision-relevant for financial institutions. These experiences are germane to extant processes on disclosure and corporate reporting, particularly the TCFD.

To take one specific example, without accurate geo-location data for assets it is very hard to accurately overlay spatial datasets or to use remote sensing and satellite data to further research assets. Existing datasets for coal-fired power stations only have precise geo-location data for 30% of power stations and only regional or city level geo-location data for the remaining power stations. This means that spatial datasets representing certain types of risk (e.g. air pollution) are not uniformly accurate – they become less useful for power stations with inaccurate geo-location data. It also means that when, for example, we wanted to use satellite imagery to identify the type of cooling technology installed on a power station (for assets where cooling data was missing from existing datasets), we could only do this for assets with accurate coordinates. Unfortunately, tracking down power stations on satellite imagery when the geo-location data is inaccurate is challenging and time consuming. This means that we have only been able to secure 71% coverage for the type of cool technology installed on coal-fired power stations, though we aim to improve this through further work.

One simple way around this particular problem would be for companies that are signed up to voluntary or mandatory reporting frameworks to disclosure the precise coordinates of their key physical assets. But a more general principle would be for companies, especially those with portfolios of large physical assets, to disclose asset specific characteristics so that researchers and analysts can undertake their own research on the risks and opportunities facing company portfolios.

[469] Thistelthwaite, J. (2015). The challenges of counting climate change risks in financial markets, Center for International Gonvernance Innovation. Waterloo, Canada.

[470] World Federation of Exchanges (2015). Exchange Guidance & Recommendation – October 2015, WFE Sustainability Working Group.

[471] Ibid.

[472] Financial Stability Board (2015). FSB to establish Task Force on Climate-related Financial Disclosures, Press Release.

Natural resources companies, particularly those involved in upstream fossil fuel production, appear reluctant to disclose any asset specific information, instead suggesting that their investors should simply trust their judgement.[473] We would suggest that this is a highly questionable approach and one that the TCFD and other related processes should take on. Introducing a new 'Principle of Asset-level Disclosure' into reporting frameworks would significantly enhance the ability of investors to understand the environmental performance of companies.

More generally, it is noteworthy that very little of our analysis has actually depended on existing corporate reporting or data disclosed through voluntary disclosure frameworks. This is both a cause for hope and concern. It demonstrates that significant strides can be made to understand company exposure to environment-related risks even in the absence of consistent, comprehensive, and timely corporate reporting on these issues. But it also highlights how existing frameworks on environment-related corporate disclosure might be asking the wrong questions – they generally attempt to support and enable top down analysis, but might not do enough to support a bottom up, asset-specific approach. Reporting needs to link back to a fundamental understanding of risk and opportunity and to specific assets within company portfolios, especially for companies with portfolios of large physical assets (e.g. power stations, mines, oil and gas fields, processing plants, and factories). In the absence of that, what is reported may not be actionable from an investor perspective.

The other task is to reduce the cost of accessing and using data that can underpin the analytical approach we have used here. Where possible we use non-proprietary datasets, but this is insufficient. The cost is really the cost of data integration – to have all the relevant data points on asset characteristics merged from a variety of data sources, as well as overlays that allow us to measure the relative exposure of assets to different risks and opportunities. The costs associated with assuring datasets and finding novel datasets are also significant. Fortunately, these are all areas where costs can be reduced and this could be a significant public good.

9.3 Company Data Intelligence Service

An initiative to find and integrate all the relevant asset-specific data points for companies in key sectors would almost certainly yield much more (and probably more accurate) investor-relevant information that what is currently disclosed. The initiative, call it the Company Data Intelligence Service (CDIS), would have the benefit of transcending mandatory and voluntary schemes as all companies would be in scope. CDIS would seek out data on company assets in key sectors, make this public where possible, and give companies the opportunity to correct mistakes and provide enhanced disclosure. It would operate in a completely transparent and accountable way and could collaborate with researchers and civil society to track down, assure, and release data on company assets.

Critically, CDIS would not be dependent on companies disclosing data. Such a public goods initiative focused on putting into the public domain accurate and relevant information to improve the analysis of company environmental performance, would not be particularly costly – it would certainly be much cheaper, quicker, and more plausible than all companies actually disclosing all the asset specific data needed for bottom analyses of environment-related factors.

[473] See Rook, D. & Caldecott, B.L. (2015) Evaluating capex risk: new metrics to assess extractive industry project portfolios. Working Paper. Smith School of Enterprise and the Environment, University of Oxford. Oxford, UK.

CDIS could support the development of new techniques and approaches to secure data that was hard to get or inaccessible due to cost or other barriers, whether through 'big data' or remote sensing, and foster the developments of new techniques to analyse data. CDIS could also have the task of integrating all existing environment-related corporate reporting into one system, allowing for analysis of data provided via a wide range of initiatives.

Through our research process it has become clear to us that the current company-level reporting paradigm – where some companies annually disclose data; where reported data might not actually be relevant for assessing real exposure to environment-related risk and opportunity; where reported data may be inaccurate and out of date; where companies that report spend a significant amount of time filling in forms for different reporting systems; and where third parties spend significant effort trying to assure reported data – could be significantly improved. Current reporting is slow moving, unable to achieve universal coverage of companies, and currently disconnected to the requirements of bottom up analysis. While current reporting efforts are an incredibly important contribution that we commend, much more can be done and more cost-effectively. In addition to putting more emphasis on asset specific disclosures in current and emerging reporting regimes, the development of a public goods CDIS-type initiative is something that the TFCD should consider recommending as part of its deliberations.

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Appendix A: Top Coal-Fired Power Utilities Tables

***Table 59:** Top 100 coal-fired utilities: Capital planning and general information*

COAL-FIRED GENERATION [GWh]	PARENT OWNER	COUNTRY	TOTAL CAP [MW]	FLEET EMISSIONS INTENSITY [kg CO2/MWh]	CAPEX PROJ [$USmn]
471,139	CHINA HUANENG GROUP CORP	China	192,987	828	N/A
455,038	CHINA GUODIAN CORP	China	162,572	879	N/A
415,118	CHINA DATANG CORP	China	123,635	974	N/A
369,511	CHINA HUADIAN GROUP CORP	China	144,693	820	N/A
293,658	CHINA POWER INVESTMENT CORP	China	98,430	848	N/A
292,107	SHENHUA GROUP CORP LTD	China	93,608	897	N/A
214,924	ESKOM HOLDINGS SOC LTD	South Africa	44,122	944	N/A
208,588	NTPC LTD	India	43,719	900	3,782
171,178	CHINA RESOURCES POWER HOLDINGS	China	58,778	899	2,424
128,189	KOREA ELECTRIC POWER CORP	Korea	70,342	471	11,375
126,689	GUANGDONG YUDEAN GROUP CO LTD	China	47,276	816	N/A
99,685	NRG ENERGY INC	USA	59,794	804	648
97,603	STATE GRID CORP OF CHINA	China	43,188	596	N/A
89,977	GDF SUEZ SA	France	90,428	483	6,848
83,646	VATTENFALL GROUP	Sweden	40,349	528	N/A
71,669	SOUTHERN CO	USA	52,706	659	4,467
67,730	DUKE ENERGY CORP	USA	64,413	537	8,123
66,467	PT PLN PERSERO	Indonesia	31,515	844	N/A
62,916	ENEL SPA	Italy	72,845	513	7,003
60,917	AMERICAN ELECTRIC POWER CO INC	USA	36,037	789	4,266
59,572	MINISTRY OF ECONOMIC AFFAIRS	Taiwan	26,167	676	N/A
58,991	TENNESSEE VALLEY AUTHORITY	USA	37,426	670	N/A
53,995	E.ON SE	Germany	62,928	419	3,959
53,906	ZHEJIANG ENERGY GROUP CO LTD	China	20,391	768	N/A
52,212	FORMOSA PLASTICS CORP	Taiwan	10,056	906	253
51,803	EDF GROUP	France	137,395	149	12,795
51,504	BEIJING ENERGY INVEST HOLDING	China	20,210	689	N/A
46,454	TATA GROUP	India	9,770	1033	N/A
45,835	CLP GROUP	Hong Kong	17,266	710	957
45,703	ADANI POWER LTD	India	8,264	914	184
42,639	RWE AG	Germany	22,274	611	2,463
39,973	VEDANTA RESOURCES PLC	India	6,712	913	1,406
39,407	J-POWER	Japan	19,175	616	N/A
38,874	HEBEI CONSTR & INVEST GROUP	China	10,647	1042	N/A
38,501	SHANXI INTL ELEC GROUP CO LTD	China	10,375	901	N/A
37,808	DYNEGY HOLDINGS INC	USA	27,314	820	N/A
36,846	RELIANCE INFRASTRUCTURE LTD	India	9,860	847	83
35,269	STATE DEV INVESTMENT CORP	China	14,464	794	N/A
35,246	AES CORP	USA	27,369	512	977
34,147	PUBLIC POWER CORP (DEI)	Greece	13,905	527	N/A
33,049	DTEK	Ukraine	14,359	1338	N/A
32,727	AGL ENERGY LTD	Australia	8,338	920	370
32,687	PGE POLSKA GRUPA ENERGETYCZNA	Poland	18,705	682	1,642
31,995	ISRAEL ELECTRIC CORP	Israel	13,783	693	N/A
31,401	XCEL ENERGY INC	USA	20,057	726	2,700
31,388	STEAG GMBH	Germany	8,581	1121	N/A
30,613	BERKSHIRE HATHAWAY ENERGY COMPANY	USA	29,922	466	N/A
30,198	DAMODAR VALLEY CORP (DVC)	India	8,584	1336	N/A
28,989	MP POWER GENERATING CO LTD	India	7,549	964	N/A

Table 59: *(Table continued)*

COAL-FIRED GENERATION [GWh]	PARENT OWNER	COUNTRY	TOTAL CAP [MW]	FLEET EMISSIONS INTENSITY [kg CO2/MWh]	CAPEX PROJ [$USmn]
27,337	SHENERGY COMPANY LTD	China	12,208	687	95
27,304	JIANGSU GUOXIN INVEST GROUP	China	18,146	904	N/A
27,259	COMISION FEDERAL DE ELEC	Mexico	37,572	537	N/A
26,846	CITIC PACIFIC LTD	China	6,809	982	3,913
26,173	TRANSALTA CORP	Canada	10,012	691	313
25,844	FIRSTENERGY CORP	USA	16,022	644	2,861
25,757	GUJARAT STATE ELEC CORP LTD	India	7,164	660	N/A
25,334	PPL CORP	USA	8,996	918	3,489
24,647	DOMINION	USA	21,714	420	4,468
24,602	ANDHRA PRADESH POWER GEN CORP	India	8,857	940	N/A
24,545	CHUBU ELECTRIC POWER CO INC	Japan	30,939	288	2,414
24,430	JINDAL STEEL & POWER LTD	India	7,116	849	464
22,771	TENAGA NASIONAL BERHAD (TNB)	Indonesia	16,182	384	2,256
21,894	OOO SIBERIAN GENERATING CO	Russia	8,308	2464	N/A
21,640	ENERGY FUTURE HOLDINGS CORP	USA	14,311	263	N/A
21,534	RIVERSTONE HOLDINGS	USA	17,816	597	18
21,279	CEZ AS	Czech	13,857	494	1,073
20,946	NEYVELI LIGNITE CORP LTD	India	4,665	1091	N/A
20,753	CHEUNG KONG INFRASTRUCTURE	Hong Kong	6,478	1167	56
20,622	DTE ENERGY CO	USA	12,590	619	2,293
20,554	HARYANA POWER GEN CO (HPGC)	India	6,209	1579	N/A
20,273	ELECTRICITY OF VIETNAM (EVN)	Vietnam	19,313	543	N/A
19,533	GREAT PLAINS ENERGY INC	USA	8,213	817	612
19,160	WEST BENGAL POWER DEV CORP	India	5,480	958	N/A
18,830	HENAN INVESTMENT GROUP CO LTD	China	6,530	1028	N/A
18,779	WISCONSIN ENERGY CORP	USA	7,250	1095	1,419
18,007	INTER RAO UES	Russia	57,614	93	416
16,842	TAMIL NADU GEN & DIST CORP LTD	India	7,108	531	N/A
16,476	ZHEJIANG PROV ENERGY GROUP CO	China	6,260	1188	N/A
16,426	DATONG COAL MINE GROUP CO LTD	China	6,670	5331	N/A
15,663	TOHOKU ELECTRIC POWER CO	Japan	13,845	376	2,355
15,222	AMEREN CORP	USA	11,236	878	N/A
15,128	RAJASTHAN RV UTPADAN NIGAM	India	7,350	1004	N/A
15,105	SHENZHEN ENERGY GROUP CO LTD	China	6,894	765	344
14,876	SUMITOMO CORP	Japan	8,441	858	1,465
14,776	MAHARASHTRA STATE POWER GEN CO	India	8,938	612	N/A
14,747	CHINA PETRO & CHEM (SINOPEC)	China	4,554	1089	19,607
14,068	ECU - ENERGY CO OF UKRAINE	Ukraine	5,476	1017	N/A
13,096	ENBW ENERGIE BADEN-WURTTEMBERG	Germany	10,824	638	926
12,954	TAURON POLSKA ENERGIA SA	Poland	4,549	872	1,009
12,880	ENTERGY CORP	USA	33,706	169	2,631
11,666	ALLIANT ENERGY CORP	USA	6,994	835	1,159
11,270	UTTAR PRADESH RAJYA VIDYUT	India	3,503	1584	N/A
11,049	SCOTTISH AND SOUTHERN ENERGY	UK	12,231	241	2,169
10,806	BASIN ELECTRIC POWER COOP	USA	4,751	1264	N/A
10,072	EUROSIBENERGO	Russia	19,219	152	N/A
10,054	WENERGY-ANHUI PROV ENERGY	China	4,401	1288	56
9,129	SANTEE COOPER	USA	5,227	727	N/A
8,356	SALT RIVER PROJECT (AZ)	USA	7,609	605	N/A
7,100	GAZPROM	Russia	27,620	735	25,472
2,041	ELEKTROPRIVREDA SRBIJE (EPS)	Serbia	2,094	416	N/A

Table 60: Ownership of coal-fired power utilities[474]

	PARENT OWNER	COUNTRY	TICKER	UTLTIMATE PARENT (IF DIFFERENT)	OWNERSHIP	INSIDERS [US$bn]	INSTITUTIONS [US$bn]	CORPORATE [US$bn]	ESOP [US$bn]	STATE [US$bn]	PUBLIC/OTHER [US$bn]
1	CHINA HUANENG GROUP CORP	China	-	-	PrC	-	-	-	-	-	-
2	CHINA GUODIAN CORP	China	-	-	PrC	-	-	-	-	-	-
3	CHINA DATANG CORP	China	-	-	PrC	-	-	-	-	-	-
4	CHINA HUADIAN GROUP CORP	China	-	-	PrC	-	-	-	-	-	-
5	CHINA POWER INVESTMENT CORP	China	-	State Power Investment Group Corp.	PrC	-	-	-	-	-	-
6	SHENHUA GROUP CORP LTD	China	-	-	PrC	-	-	-	-	-	-
7	ESKOM HOLDINGS SOC LTD	South Africa	-	-	PrC	-	-	-	-	-	-
8	NTPC LTD	India	NSEI:NTPC	-	PbC	0	2.8	-	-	12.73	1.36
9	CHINA RESOURCES POWER HOLDINGS	China	SEHK:836	China Resources National Corporation	PrC	0.01	1.3	5.74	-	-	2.06
10	KOREA ELECTRIC POWER CORP	Korea	KOSE:A01576	-	PbC	0	16.88	-	-	4.9	5.15
11	GUANGDONG YUDEAN GROUP CO LTD	China	-	-	PrC	-	-	-	-	-	-
12	NRG ENERGY INC	USA	NYSE:NRG	-	PbC	0.02	3.35	-	-	-	-
13	STATE GRID CORP OF CHINA	China	-	-	PrC	-	-	-	-	-	-
14	GDF SUEZ SA	France	ENXTPA:ENG	-	PbC	0	10.78	1.02	1.36	13.79	15.13
15	VATTENFALL GROUP	Sweden	-	-	PrC	-	-	-	-	-	-
16	SOUTHERN CO	USA	NYSE:SO	-	PbC	0.02	21.88	-	-	-	20.37
17	DUKE ENERGY CORP	USA	NYSE:DUK	-	PbC	0.05	27.7	-	-	-	20.78
18	PT PLN PERSERO	Indonesia	-	-	PrC	-	-	-	-	-	-
19	ENEL SPA	Italy	BIT:ENEL	-	PbC	-	10.26	-	-	11.15	19.13
20	AMERICAN ELECTRIC POWER CO INC	USA	NYSE:AEP	-	PbC	0.01	19.71	-	-	-	8.46
21	MINISTRY OF ECONOMIC AFFAIRS	Taiwan	-	-	Gov	-	-	-	-	-	-
22	TENNESSEE VALLEY AUTHORITY	USA	-	-	Gov	-	-	-	-	-	-
23	E.ON SE	Germany	DB:EOAN	-	PbC	-	5.88	-	-	-	12.33
24	ZHEJIANG ENERGY GROUP CO LTD	China	-	-	PrC	-	-	-	-	-	-
25	FORMOSA PLASTICS CORP	Taiwan	TSEC:1301	-	PbC	0.76	3.67	3.34	-	0.21	6.06
26	EDF GROUP	France	ENXTPA:EDF	-	PbC	0	1.56	-	0.38	21.92	2.08
27	BEIJING ENERGY INVEST HOLDING	China	-	Beijing Energy Investment (Group) Co. Ltd.	PrC	-	-	-	-	-	-
28	TATA GROUP	India	-	-	PrC	-	-	-	-	-	-
29	CLP GROUP	Hong Kong	SEHK:2	-	PbC	0	2.87	7.23	-	-	11
30	ADANI POWER LTD	India	BSE:533096	S.B. Adani Family Trust	PrC	0.59	0.36	0.6	-	-	-
31	RWE AG	Germany	DB:RWE	-	PbC	-	2.29	1.13	-	-	4.09
32	VEDANTA RESOURCES PLC	India	LSE:VED	-	PbC	0.74	0.22	-	0.01	-	0.11
33	J-POWER	Japan	-	-	PrC	-	-	-	-	-	-
34	HEBEI CONSTR & INVEST GROUP	China	-	-	PrC	-	-	-	-	-	-
35	SHANXI INTL ELEC GROUP CO LTD	China	-	Jinneng Co., Ltd.	PrC	-	-	-	-	-	-
36	DYNEGY HOLDINGS INC	USA	NYSE:DYN	-	PbC	0	1.34	0.05	-	-	-
37	RELIANCE INFRASTRUCTURE LTD	India	BSE:500390	-	PbC	0	0.5	0.86	-	0	0.42
38	STATE DEV INVESTMENT CORP	China	-	-	PrC	-	-	-	-	-	-
39	AES CORP	USA	NYSE:AES	-	PbC	0.01	6.18	-	-	-	-
40	PUBLIC POWER CORP (DEI)	Greece	ATSE:PPC	-	PbC	-	0.26	-	-	0.36	0.25
41	DTEK	Ukraine	-	-	PrC	-	-	-	-	-	-
42	AGL ENERGY LTD	Australia	ASX:AGL	-	PbC	0.02	1.39	0.02	-	-	6.95
43	PGE POLSKA GRUPA ENERGETYCZNA	Poland	WSE:PGE	-	PbC	0	1.11	-	-	3.44	1.34
44	ISRAEL ELECTRIC CORP	Israel	-	-	PrC	-	-	-	-	-	-
45	XCEL ENERGY INC	USA	NYSE:XEL	-	PbC	0.04	13.37	-	-	-	5.07
46	STEAG GMBH	Germany	-	**	PrC	-	-	-	-	-	-
47	BERKSHIRE HATHAWAY ENERGY COMPANY	USA	NYSE:BRK.A	-	PbI	67.06	148.84	-	-	-	114.5
48	DAMODAR VALLEY CORP (DVC)	India	-	-	PrC	-	-	-	-	-	-
49	MP POWER GENERATING CO LTD	India	-	M.S.E.B. Holding Co.Ltd	PrC	-	-	-	-	-	-
50	SHENERGY COMPANY LTD	China	SHSE:600642	Shenergy (Group) Company Limited	PrC	0.03	0.29	2.81	-	-	2.16
51	JIANGSU GUOXIN INVEST GROUP	China	-	-	PrC	-	-	-	-	-	-
52	COMISION FEDERAL DE ELEC	Mexico	-	-	PrC	-	-	-	-	-	-
53	CITIC PACIFIC LTD	China	SEHK:267	CITIC Group Corporation	PrC	-	3.35	40.17	-	-	7.9
54	TRANSALTA CORP	Canada	TSX:TA	-	PbC	0	0.47	-	-	-	0.4
55	FIRSTENERGY CORP	USA	NYSE:FE	-	PbC	0.04	10.51	-	-	-	2.8
56	GUJARAT STATE ELEC CORP LTD	India	-	Gujarat Electricity Board	PrC	-	-	-	-	-	-
57	PPL CORP	USA	NYSE:PPL	-	PbC	0.01	16.49	-	-	-	6.29
58	DOMINION	USA	NYSE:D	-	PbC	0.15	25.51	0	-	-	14.55
59	ANDHRA PRADESH POWER GEN CORP	India	-	-	PrC	-	-	-	-	-	-
60	CHUBU ELECTRIC POWER CO INC	Japan	TSE:9502	-	PbC	0	3.12	0	0.27	0.06	6.65
61	JINDAL STEEL & POWER LTD	India	NSEI:JINDALS	-	PbC	0.02	0.42	0.59	-	-	0.24
62	TENAGA NASIONAL BERHAD (TNB)	Indonesia	KLSE:TENAG	-	PbC	0	8.53	-	-	0.25	3.17
63	OOO SIBERIAN GENERATING CO	Russia	-	Linea Ltd.	PrC	-	-	-	-	-	-
64	ENERGY FUTURE HOLDINGS CORP	USA	-	Texas Energy Future Holdings Limited Partr	PrC	0.25	-	114.77	-	-	-

[474] Data taken from Standard & Poor's Capital IQ, November 2015.

Table 60: *(Table continued)*

	PARENT OWNER	COUNTRY	TICKER	UTLTIMATE PARENT (IF DIFFERENT)	OWNERSHIP*	INSIDERS [US$bn]	INSTITUTIONS [US$bn]	CORPORATE [US$bn]	ESOP [US$bn]	STATE [US$bn]	PUBLIC/OTHER [US$bn]
45	XCEL ENERGY INC	USA	NYSE:XEL	-	PbC	0.04	13.37	-	-	-	5.07
46	STEAG GMBH	Germany	-	**	PrC	-	-	-	-	-	-
47	BERKSHIRE HATHAWAY ENERGY COMPANY	USA	NYSE:BRK.A	-	PbI	67.06	148.84	-	-	-	114.5
48	DAMODAR VALLEY CORP (DVC)	India	-	-	PrC	-	-	-	-	-	-
49	MP POWER GENERATING CO LTD	India	-	M.S.E.B. Holding Co.Ltd	PrC	-	-	-	-	-	-
50	SHENERGY COMPANY LTD	China	SHSE:600642	Shenergy (Group) Company Limited	PrC	0.03	0.29	2.81	-	-	2.16
51	JIANGSU GUOXIN INVEST GROUP	China	-	-	PrC	-	-	-	-	-	-
52	COMISION FEDERAL DE ELEC	Mexico	-	-	PrC	-	-	-	-	-	-
53	CITIC PACIFIC LTD	China	SEHK:267	CITIC Group Corporation	PrC	-	3.35	40.17	-	-	7.9
54	TRANSALTA CORP	Canada	TSX:TA	-	PbC	0	0.47	-	-	-	0.4
55	FIRSTENERGY CORP	USA	NYSE:FE	-	PbC	0.04	10.51	-	-	-	2.8
56	GUJARAT STATE ELEC CORP LTD	India	-	Gujarat Electricity Board	PrC	-	-	-	-	-	-
57	PPL CORP	USA	NYSE:PPL	-	PbC	0.01	16.49	-	-	-	6.29
58	DOMINION	USA	NYSE:D	-	PbC	0.15	25.51	0	-	-	14.55
59	ANDHRA PRADESH POWER GEN CORP	India	-	-	PrC	-	-	-	-	-	-
60	CHUBU ELECTRIC POWER CO INC	Japan	TSE:9502	-	PbC	0	3.12	0	0.27	0.06	6.65
61	JINDAL STEEL & POWER LTD	India	NSEI:JINDAL:	-	PbC	0.02	0.42	0.59	-	-	0.24
62	TENAGA NASIONAL BERHAD (TNB)	Indonesia	KLSE:TENAG.	-	PbC	0	8.53	-	-	0.25	3.17
63	OOO SIBERIAN GENERATING CO	Russia	-	Linea Ltd.	PrC	-	-	-	-	-	-
64	ENERGY FUTURE HOLDINGS CORP	USA	-	Texas Energy Future Holdings Limited Partr	PrC	0.25	-	114.77	-	-	-
65	RIVERSTONE HOLDINGS	USA	SGX:AP4	-	PbC	0.42	0.05	-	-	-	0.13
66	CEZ AS	Czech	SEP:CEZ	-	PbC	-	1.32	-	-	6.31	1.34
67	NEYVELI LIGNITE CORP LTD	India	BSE:513683	-	PbC	0	0.08	-	-	1.97	0.02
68	CHEUNG KONG INFRASTRUCTURE	Hong Kong	SEHK:1038	CK Hutchison Holdings Limited	PbC	0	3.02	17.53	-	-	2.54
69	DTE ENERGY CO	USA	NYSE:DTE	-	PbC	0.07	9.51	-	-	-	4.76
70	HARYANA POWER GEN CO (HPGC)	India	-	NTPC Ltd.	PbC	-	-	-	-	-	-
71	ELECTRICITY OF VIETNAM (EVN)	Vietnam	-	-	PrC	-	-	-	-	-	-
72	GREAT PLAINS ENERGY INC	USA	NYSE:GXP	-	PbC	0.02	3.58	-	-	-	0.6
73	WEST BENGAL POWER DEV CORP	India	-	-	PrC	-	-	-	-	-	-
74	HENAN INVESTMENT GROUP CO LTD	China	-	-	PrI	-	-	-	-	-	-
75	WISCONSIN ENERGY CORP	USA	NYSE:WEC	-	PbC	0.03	11.3	-	-	-	4.85
76	INTER RAO UES	Russia	MICEX:IRAO	-	PbC	0	0.07	1.12	-	0	0.11
77	TAMIL NADU GEN & DIST CORP LTD	India	-	-	Gov	-	-	-	-	-	-
78	ZHEJIANG PROV ENERGY GROUP CO	China	-	Zhejiang Provincial Energy Group Company	PrC	-	-	-	-	-	-
79	DATONG COAL MINE GROUP CO LTD	China	-	-	PrC	-	-	-	-	-	-
80	TOHOKU ELECTRIC POWER CO	Japan	TSE:9506	-	PbC	0	1.23	0	0.17	0.31	4.27
81	AMEREN CORP	USA	NYSE:AEE	-	PbC	0.03	7.31	-	-	-	3.33
82	RAJASTHAN RV UTPADAN NIGAM	India	-	-	PrC	-	-	-	-	-	-
83	SHENZHEN ENERGY GROUP CO LTD	China	SZSE:000027	-	PbC	0.03	0.12	1.57	-	2.95	1.5
84	SUMITOMO CORP	Japan	TSE:8053	-	PbC	0.01	5.01	0.47	-	-	7.24
85	MAHARASHTRA STATE POWER GEN CO	India	-	-	PrC	-	-	-	-	-	-
86	CHINA PETRO & CHEM (SINOPEC)	China	SEHK:386	China Petrochemical Corporation	PrC	0	7.2	51.46	-	-	13.49
87	ECU - ENERGY CO OF UKRAINE	Ukraine	-	-	PrC	-	-	-	-	-	-
88	ENBW ENERGIE BADEN-WURTTEMBERG	Germany	DB:EBK	-	PbC	-	-	6.05	-	0.06	0.02
89	TAURON POLSKA ENERGIA SA	Poland	WSE:TPE	-	PbC	0	0.33	0.13	-	0.37	0.41
90	ENTERGY CORP	USA	NYSE:ETR	-	PbC	0.02	10.6	-	-	-	1.37
91	ALLIANT ENERGY CORP	USA	NYSE:LNT	-	PbC	0	4.87	-	-	-	2.35
92	UTTAR PRADESH RAJYA VIDYUT	India	-	-	PrC	-	-	-	-	-	-
93	SCOTTISH AND SOUTHERN ENERGY	UK	LSE:SSE	-	PbC	0.01	17.14	0.01	0.17	0.35	4.37
94	BASIN ELECTRIC POWER COOP	USA	-	-	PrC	-	-	-	-	-	-
95	EUROSIBENERGO	Russia	-	-	PrC	-	-	-	-	-	-
96	WENERGY-ANHUI PROV ENERGY	China	SZSE:000543	-	PbC	0.01	0.55	1.12	-	-	0.79
97	SANTEE COOPER	USA	-	-	Gov	-	-	-	-	-	-
98	SALT RIVER PROJECT (AZ)	USA	-	-	Gov	-	-	-	-	-	-
99	GAZPROM	Russia	MICEX:GAZP	-	PbC	0.01	17.22	5.47	-	17.74	4.21
100	ELEKTROPRIVREDA SRBIJE (EPS)	Serbia	-	-	PrC	-	-	-	-	-	-

*Gov: Government Institution; PrC: Private company; PrI: Private Investment Firm; PbC, Public company; PbI Public Investment Firm.

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Table 61: *Bond issuances of coal-fired power utilities*

	PARENT OWNER	COUNTRY	AVG. MATURITY	PERPETUITIES [US$mn]	DEBENTURES [US$mn]	TOTAL DEBT/EBITDA	CAPACITY [MW]
1	CHINA HUANENG GROUP CORP	China	2021	-	6,408	6.3	160,212
2	CHINA GUODIAN CORP	China	2018	400	4,915	6.2	148,539
3	CHINA DATANG CORP	China	2019	1,569	4,048	6.9	123,635
4	CHINA HUADIAN GROUP CORP	China	2017	-	1,899	6	119,808
5	CHINA POWER INVESTMENT CORP	China	2021	-	6,375	8.9	82,819
6	SHENHUA GROUP CORP LTD	China	2018	-	19,232	3.1	89,021
7	ESKOM HOLDINGS SOC LTD	South Africa	2026	-	14,810	14.6	36,678
8	NTPC LTD	India	2023	-	3,753	5.9	41,532
9	CHINA RESOURCES POWER HOLDINGS	China	2019	750	1,582	3.1	55,342
10	KOREA ELECTRIC POWER CORP	Korea	2021	-	27,545	3.4	23,481
11	GUANGDONG YUDEAN GROUP CO LTD	China	2020	-	1,413	none	43,441
12	NRG ENERGY INC	USA	2021	1,000	44,666	6.4	29,576
13	STATE GRID CORP OF CHINA	China	2021	-	86,657	none	22,218
14	GDF SUEZ SA	France	2026	4,101	37,325	3.6	20,424
15	VATTENFALL GROUP	Sweden	2035	-	8,456	5.1	15,719
16	SOUTHERN CO	USA	2032	865	24,293	4.1	27,819
17	DUKE ENERGY CORP	USA	2028	255	40,625	4.8	22,492
18	PT PLN PERSERO	Indonesia	2025	-	10,572	2.9	16,763
19	ENEL SPA	Italy	2031	500	59,955	3.7	17,937
20	AMERICAN ELECTRIC POWER CO INC	USA	2026	821	15,789	4.3	22,577
21	MINISTRY OF ECONOMIC AFFAIRS	Taiwan	0	-	-	none	10,114
22	TENNESSEE VALLEY AUTHORITY	USA	2033	-	24,481	6.3	20,756
23	E.ON SE	Germany	2026	89	29,999	2.1	13,664
24	ZHEJIANG ENERGY GROUP CO LTD	China	2017	-	300	none	13,992
25	FORMOSA PLASTICS CORP	Taiwan	2025	-	1,000	5.4	9,328
26	EDF GROUP	France	2031	16,862	101,097	3.6	17,288
27	BEIJING ENERGY INVEST HOLDING	China	2017	-	2,098	none	13,180
28	TATA GROUP	India	2018	35	140	none	8,468
29	CLP GROUP	Hong Kong	2023	500	3,708	3.4	10,118
30	ADANI POWER LTD	India	2020	-	1,864	8	8,220
31	RWE AG	Germany	2033	1,140	23,959	4.2	10,793
32	VEDANTA RESOURCES PLC	India	2018	-	10,333	5.7	6,448
33	J-POWER	Japan	0	-	-	none	6,805
34	HEBEI CONSTR & INVEST GROUP	China	2023	-	1,927	none	10,362
35	SHANXI INTL ELEC GROUP CO LTD	China	0	-	-	none	9,100
36	DYNEGY HOLDINGS INC	USA	0	-	-	9.5	14,541
37	RELIANCE INFRASTRUCTURE LTD	India	0	-	-	7.8	9,320
38	STATE DEV INVESTMENT CORP	China	2021	-	4,709	5.8	12,325
39	AES CORP	USA	2025	88	25,905	5.4	11,216
40	PUBLIC POWER CORP (DEI)	Greece	2018	-	1,492	4	5,597
41	DTEK	Ukraine	2018	-	1,660	9.2	13,526
42	AGL ENERGY LTD	Australia	2030	-	1,875	4	5,238
43	PGE POLSKA GRUPA ENERGETYCZNA	Poland	2019	-	536	0.6	8,784
44	ISRAEL ELECTRIC CORP	Israel	2023	-	10,317	8.9	6,185
45	XCEL ENERGY INC	USA	2030	71	13,726	4.2	9,712
46	STEAG GMBH	Germany	0	-	-	23.8	7,984
47	BERKSHIRE HATHAWAY ENERGY COMPANY	USA	2030	37	41,763	5.9	11,875
48	DAMODAR VALLEY CORP (DVC)	India	0	-	-	16.1	8,313
49	MP POWER GENERATING CO LTD	India	0	-	-	none	6,613
50	SHENERGY COMPANY LTD	China	2018	-	392	3.1	7,584
51	JIANGSU GUOXIN INVEST GROUP	China	2018	-	2,103	none	16,665
52	COMISION FEDERAL DE ELEC	Mexico	2028	-	10,498	18.4	4,700
53	CITIC PACIFIC LTD	China	2023	2,548	26,511	2.4	6,309
54	TRANSALTA CORP	Canada	2022	591	3,621	4.8	5,078
55	FIRSTENERGY CORP	USA	2028	25	28,033	6.9	9,950
56	GUJARAT STATE ELEC CORP LTD	India	0	-	-	none	6,094
57	PPL CORP	USA	2030	94	21,228	4.1	8,385
58	DOMINION	USA	2028	201	29,528	5.2	6,583
59	ANDHRA PRADESH POWER GEN CORP	India	0	-	-	14	6,980
60	CHUBU ELECTRIC POWER CO INC	Japan	2019	-	9,396	5.1	4,100
61	JINDAL STEEL & POWER LTD	India	0	-	-	8.1	7,077
62	TENAGA NASIONAL BERHAD (TNB)	Indonesia	2022	-	458,016	2.3	8,680
63	OOO SIBERIAN GENERATING CO	Russia	2023	-	231	none	8,308
64	ENERGY FUTURE HOLDINGS CORP	USA	2021	3,600	66,073	23.6	8,496
65	RIVERSTONE HOLDINGS	USA	0	-	-	0	8,309
66	CEZ AS	Czech	2024	-	6,362	2.6	6,235
67	NEYVELI LIGNITE CORP LTD	India	0	-	-	3.2	4,615
68	CHEUNG KONG INFRASTRUCTURE	Hong Kong	2021	300	2,677	8.6	6,306
69	DTE ENERGY CO	USA	2028	612	68,208	3.7	7,909
70	HARYANA POWER GEN CO (HPGC)	India	0	-	-	none	6,145

Table 61: *(Table continued)*

	PARENT OWNER	COUNTRY	AVG. MATURITY	PERPETUITIES [US$mn]	DEBENTURES [US$mn]	TOTAL DEBT/EBITDA	CAPACITY [MW]
71	ELECTRICITY OF VIETNAM (EVN)	Vietnam	2016	-	89	none	5,434
72	GREAT PLAINS ENERGY INC	USA	2027	39	3,982	4.5	5,647
73	WEST BENGAL POWER DEV CORP	India	0	-	-	none	5,480
74	HENAN INVESTMENT GROUP CO LTD	China	2020	-	1,014	none	6,530
75	WISCONSIN ENERGY CORP	USA	2037	-	9,494	5.9	4,493
76	INTER RAO UES	Russia	0	-	-	1.6	8,030
77	TAMIL NADU GEN & DIST CORP LTD	India	0	-	-	-3.7	4,320
78	ZHEJIANG PROV ENERGY GROUP CO	China	2018	-	2,469	3	6,260
79	DATONG COAL MINE GROUP CO LTD	China	2019	-	424	none	6,670
80	TOHOKU ELECTRIC POWER CO	Japan	2019	-	8,829	6.1	2,701
81	AMEREN CORP	USA	2027	315	6,660	3.9	5,829
82	RAJASTHAN RV UTPADAN NIGAM	India	0	-	-	none	6,580
83	SHENZHEN ENERGY GROUP CO LTD	China	0	-	-	3.5	3,744
84	SUMITOMO CORP	Japan	2021	-	5,009	1.9	5,514
85	MAHARASHTRA STATE POWER GEN CO	India	0	-	-	none	5,550
86	CHINA PETRO & CHEM (SINOPEC)	China	2019	-	21,860	1.7	4,074
87	ECU - ENERGY CO OF UKRAINE	Ukraine	none	none	none	none	5,475
88	ENBW ENERGIE BADEN-WURTTEMBERG	Germany	2045	-	5,895	5	6,301
89	TAURON POLSKA ENERGIA SA	Poland	0	-	-	2.4	4,242
90	ENTERGY CORP	USA	2028	320	11,643	3.7	4,997
91	ALLIANT ENERGY CORP	USA	2030	228	3,653	4.4	3,950
92	UTTAR PRADESH RAJYA VIDYUT	India	0	-	-	none	3,490
93	SCOTTISH AND SOUTHERN ENERGY	United Kingdom	2026	3,279	13,313	3.2	4,206
94	BASIN ELECTRIC POWER COOP	USA	2041	-	200	13.9	3,688
95	EUROSIBENERGO	Russia	0	-	-	none	3,979
96	WENERGY-ANHUI PROV ENERGY	China	0	-	-	1.7	4,345
97	SANTEE COOPER	USA	2035	-	9,203	none	3,620
98	SALT RIVER PROJECT (AZ)	USA	2031	-	5,179	none	3,231
99	GAZPROM	Russia	2022	-	46,144	1.6	3,786
100	ELEKTROPRIVREDA SRBIJE (EPS)	Serbia	none	none	none	none	446

Table 62: *Ratio analysis for coal-fired power utilities*

Year	Count	(A) Net Profit Margin	(B) CAPEX to Assets	(C) Current Ratio	(D) Acid Test	(E) Total Debt to Equity	(F) Total Debt to Assets	(G) EBIT to interest expense	(H) EBITDA to interest expense	(I) (EBITDA-CAPEX) to interest expense	(J) Total Debt to EBITDA	(K) Net Debt to EBITDA	(L) Total Debt to (EBITDA - CAPEX)
1995	33	11.80%	5.50%	0.92x	0.19x	94.70%	48.50%	3.69x	5.74x	2.87x	2.50x	2.42x	3.59x
1996	34	10.90%	4.80%	0.94x	0.21x	90.30%	46.90%	3.77x	5.61x	3.51x	2.41x	2.32x	2.95x
1997	37	9.60%	5.50%	0.99x	0.24x	92.70%	47.10%	3.88x	5.81x	2.92x	2.53x	2.27x	2.96x
1998	41	8.80%	5.40%	0.93x	0.25x	91.50%	47.10%	3.48x	5.53x	2.68x	2.42x	2.22x	2.92x
1999	44	9.70%	5.40%	0.95x	0.30x	88.60%	46.10%	3.32x	5.47x	2.31x	2.96x	2.54x	2.70x
2000	45	9.90%	5.50%	0.87x	0.31x	90.30%	45.20%	4.01x	6.38x	2.47x	2.65x	2.46x	4.82x
2001	45	8.20%	6.00%	0.92x	0.36x	99.50%	49.80%	3.62x	5.15x	2.15x	2.94x	2.71x	4.07x
2002	47	9.90%	6.10%	0.91x	0.33x	105.70%	52.20%	3.28x	5.26x	2.51x	3.32x	2.82x	4.51x
2003	49	9.00%	4.90%	1.02x	0.37x	93.20%	47.60%	3.93x	6.72x	3.34x	3.03x	2.66x	5.09x
2004	50	9.00%	4.80%	1.13x	0.42x	94.60%	48.60%	4.23x	6.59x	3.35x	2.91x	2.58x	4.53x
2005	51	8.90%	5.50%	1.18x	0.46x	93.50%	46.90%	4.40x	6.27x	4.20x	3.08x	1.73x	3.59x
2006	54	10.40%	6.20%	1.07x	0.45x	85.70%	43.30%	4.32x	7.17x	3.37x	3.15x	1.76x	4.13x
2007	55	11.00%	7.50%	1.00x	0.44x	78.20%	43.10%	4.92x	7.37x	2.50x	2.61x	2.02x	4.70x
2008	56	8.90%	8.50%	1.00x	0.38x	111.20%	52.60%	3.73x	5.85x	1.23x	3.26x	2.64x	4.06x
2009	56	8.70%	7.30%	1.05x	0.37x	112.00%	51.80%	4.28x	5.69x	2.18x	3.57x	2.68x	3.67x
2010	56	9.30%	6.10%	1.14x	0.39x	116.50%	51.20%	4.59x	6.57x	2.60x	3.18x	2.42x	5.08x
2011	56	7.50%	6.80%	1.06x	0.33x	115.20%	53.30%	3.78x	5.72x	2.01x	3.74x	3.29x	6.33x
2012	56	6.80%	6.10%	1.02x	0.41x	110.30%	52.30%	2.73x	4.65x	1.17x	4.16x	3.78x	6.10x
2013	56	8.20%	6.20%	1.02x	0.42x	116.10%	53.00%	3.08x	5.37x	1.16x	3.97x	3.66x	6.05x
2014	56	7.70%	5.50%	1.06x	0.48x	111.30%	52.30%	3.43x	5.58x	1.42x	3.85x	3.20x	8.34x

***Table 63:** Column descriptions for local risk hypotheses table*

Label	Unit	Description
NUM	-	Total number of coal-fired power stations
CAP	[MW]	Total power station capacity
CO2	[kgCO_2/MWh]	Average emissions intensity of generated power weighted by plant capacity
AGE	[Years]	Average plant age weighted by plant capacity
PM	[$\mu g_{PM}/m^3$]	Average plant exposure to 100km PM concentration weighted by plant capacity
PAT	[%]	Absence of pollution abatement technologies weighted by plant capacity
NOX	[10^{15} mol_{NO2}/cm^2]	Average plant exposure to 100km NO_2 concentration weighted by plant capacity
HG	[g_{HG}/km^2]	Average plant exposure to 100km Hg concentration weighted by plant capacity
BWS	[%]	Baseline physical water stress weighted by plant capacity
CWT	[%]	Proportion of once-through cooling
FWS	[%]	Future physical water stress weighted by plant capacity
QUC	[%]	Lignite-fired capacity as a percentage of total capacity
CCS	[%]	Access to CCS-suitable geological reservoir weighted by total capacity
FHS	[Δ^oC]	Average 2035 temperature increase weighted by plant capacity

Table 64: Summary table of local risk hypotheses for coal-fired power stations

##	PARENT OWNER	COUNTRY	NUM	CAP	UTI-1	UTI-2	UTI-3				UTI-4			UTI-5	UTI-6	UTI-7
				[MW]	CO2	AGE	PM	PAT	NOX	HG	BWS	CWT	FWS	QUC	CCS	FHS
1	CHINA HUANENG GROUP CORP	China	115	160,212	957	12	41	0.61	568	586	0.57	0.33	0.65	0.1	0.18	1.01
2	CHINA GUODIAN CORP	China	118	148,539	959	12	42	0.65	520	451	0.55	0.34	0.61	0.04	0.13	1.02
3	CHINA DATANG CORP	China	92	123,635	966	13	44	0.57	580	580	0.54	0.37	0.62	0.04	0.26	1.03
4	CHINA HUADIAN GROUP CORP	China	96	119,808	946	12	43	0.56	587	387	0.62	0.36	0.66	0.02	0.19	1.01
5	CHINA POWER INVESTMENT CORP	China	65	82,819	964	13	41	0.45	503	450	0.58	0.39	0.62	0.31	0.08	1.05
6	SHENHUA GROUP CORP LTD	China	54	89,021	909	10	34	0.54	465	368	0.59	0.24	0.71	0.07	0.37	1.07
7	ESKOM HOLDINGS SOC LTD	South Africa	12	36,678	1013	32	7	0	1118	1839	0.22	0	0.24	0	0	1.08
8	NTPC LTD	India	25	41,532	925	15	30	0.57	247	425	0.34	0.08	0.36	0.14	0.04	0.84
9	CHINA RESOURCES POWER HOLDINGS	China	41	55,342	970	9	55	0.74	582	649	0.54	0.38	0.57	0.04	0.2	0.93
10	KOREA ELECTRIC POWER CORP	Korea	15	23,481	974	18	19	0.93	541	157	0.3	0	0.31	0.01	0	0.91
11	GUANGDONG YUDEAN GROUP CO LTD	China	30	43,441	936	14	28	0.63	372	538	0.12	0	0.13	0.04	0	0.84
12	NRG ENERGY INC	USA	22	29,576	978	43	7	0	271	67	0.29	0	0.32	0.06	0	1.1
13	STATE GRID CORP OF CHINA	China	44	22,218	1029	18	32	0.66	410	336	0.7	0.47	0.75	0.34	0.01	1.08
14	GDF SUEZ SA	France	30	20,424	930	22	10	0.34	319	177	0.3	0.05	0.35	0.18	0.27	0.81
15	VATTENFALL GROUP	Sweden	14	15,719	921	22	12	0.43	430	190	0.35	0	0.29	0.59	0.13	0.97
16	SOUTHERN CO	USA	17	27,819	965	37	6	0	169	60	0.1	0	0.11	0.02	0.02	0.98
17	DUKE ENERGY CORP	USA	17	22,492	961	36	7	0.01	195	47	0.24	0	0.25	0.01	0.01	1.04
18	PT PLN PERSERO	Indonesia	35	16,763	1014	10	10	0.68	239	351	0.34	0.21	0.41	0.04	0.22	0.68
19	ENEL SPA	Italy	16	17,937	974	32	9	0.14	219	61	0.17	0.01	0.26	0.14	0	1.07
20	AMERICAN ELECTRIC POWER CO INC	USA	17	22,577	975	42	7	0	236	103	0.08	0	0.1	0.03	0	1.12
21	MINISTRY OF ECONOMIC AFFAIRS	Taiwan	2	10,114	896	22	13	1	302	287	0.22	0	0.15	0	0	0.69
22	TENNESSEE VALLEY AUTHORITY	USA	11	20,756	982	46	7	0	151	40	0.06	0	0.06	0	0	1.07
23	E.ON SE	Germany	21	13,664	934	34	10	0.47	534	120	0.27	0.01	0.31	0.07	0	0.91
24	ZHEJIANG ENERGY GROUP CO LTD	China	11	13,992	899	7	34	0.92	509	756	0.25	0.14	0.36	0	0	0.88
25	FORMOSA PLASTICS CORP	Taiwan	10	9,328	938	16	17	0.54	343	258	0.31	0.05	0.31	0	0	0.72
26	EDF GROUP	France	22	17,288	931	31	16	0.26	433	134	0.39	0.1	0.4	0	0.04	0.93
27	BEIJING ENERGY INVEST HOLDING	China	13	13,180	949	8	25	0.34	510	340	0.85	0.31	1	0	0.25	1.16
28	TATA GROUP	India	9	8,468	903	10	23	1	189	215	0.6	0.18	0.72	0.18	0	0.8
29	CLP GROUP	Hong Kong	8	10,118	959	22	24	0.51	412	418	0.38	0.24	0.42	0.15	0.06	0.57
30	ADANI POWER LTD	India	4	8,220	899	7	18	0.71	156	138	0.22	0	0.23	0.31	0	0.79
31	RWE AG	Germany	12	10,793	978	33	12	0.86	695	215	0.12	0	0.1	0.76	0	0.9
32	VEDANTA RESOURCES PLC	India	9	6,448	928	5	31	0.44	345	269	0.49	0.38	0.5	0.12	0.03	0.88
33	J-POWER	Japan	7	6,805	856	20	10	0.33	332	151	0.3	0.22	0.27	0	0	0.89
34	HEBEI CONSTR & INVEST GROUP	China	8	10,362	1063	14	67	0.36	1043	369	1	0.88	1	0	0.25	1.04
35	SHANXI INTL ELEC GROUP CO LTD	China	12	9,100	966	13	40	0.44	685	340	0.94	0.17	1	0	0.07	1.08
36	DYNEGY HOLDINGS INC	USA	14	14,541	981	43	8	0	213	59	0.26	0	0.38	0	0	1.17
37	RELIANCE INFRASTRUCTURE LTD	India	5	9,320	893	9	28	0.58	161	403	0.93	0.86	0.94	0	0	0.94
38	STATE DEV INVESTMENT CORP	China	8	12,325	933	13	41	0.69	601	548	0.39	0.07	0.44	0	0.32	1.01
39	AES CORP	USA	18	11,216	974	34	9	0.12	314	143	0.23	0.14	0.2	0	0	1
40	PUBLIC POWER CORP (DEI)	Greece	5	5,597	1073	29	10	0.21	168	310	0.59	0	0.77	1	0	1.07
41	DTEK	Ukraine	9	13,526	1039	41	10	0.17	265	86	0.39	0.34	0.44	0.03	0	1.21
42	AGL ENERGY LTD	Australia	3	5,238	1117	35	1	0	249	53	0.23	0	0.3	0.11	0	0.88
43	PGE POLSKA GRUPA ENERGETYCZNA	Poland	8	8,784	970	29	13	0.02	425	139	0.26	0	0.3	0.7	0	1.04
44	ISRAEL ELECTRIC CORP	Israel	2	6,185	898	19	13	0.43	269	144	1	1	1	0	0	0.96
45	XCEL ENERGY INC	USA	11	9,712	952	33	6	0	110	24	0.77	0.3	0.82	0	0	1.24
46	STEAG GMBH	Germany	14	7,984	930	32	12	0.68	610	169	0.18	0	0.22	0	0.05	0.92
47	BERKSHIRE HATHAWAY ENERGY COMPANY	USA	12	11,875	970	38	6	0	91	30	0.6	0.37	0.64	0	0	1.33
48	DAMODAR VALLEY CORP (DVC)	India	9	8,313	997	13	37	0.94	394	434	0.29	0	0.33	0	0	0.68
49	MP POWER GENERATING CO LTD	India	4	6,613	1022	13	23	1	116	96	0.45	0	0.48	0	0	0.91
50	SHENERGY COMPANY LTD	China	3	7,584	957	14	57	1	1256	3151	0.22	0	0.95	0	0	0.9
51	JIANGSU GUOXIN INVEST GROUP	China	11	16,665	1065	11	57	0.66	767	1027	0.66	0.36	0.79	0	0.26	0.92
52	COMISION FEDERAL DE ELEC	Mexico	3	4,700	1026	25	8	0	147	140	0.11	0	0.19	0	0	0.98
53	CITIC PACIFIC LTD	China	6	6,309	1003	15	66	0.94	1037	1250	0.36	0.34	0.4	0	0.63	0.94
54	TRANSALTA CORP	Canada	3	5,078	928	29	5	0	98	40	0.17	0	0.23	0	0	1.19
55	FIRSTENERGY CORP	USA	6	9,950	975	42	8	0	314	106	0.09	0	0.1	0	0.02	1.16
56	GUJARAT STATE ELEC CORP LTD	India	6	6,094	969	22	24	0.92	100	286	0.78	0.65	0.88	0.42	0.14	0.97
57	PPL CORP	USA	6	8,385	938	30	8	0	272	91	0.03	0	0.03	0	0.13	1.16

Table 64: (Table continued)

##	PARENT OWNER	COUNTRY	NUM	CAP [MW]	UTI-1 CO2	UTI-2 AGE	UTI-3 PM	PAT	NOX	HG	UTI-4 BWS	CWT	FWS	UTI-5 QUC	UTI-6 CCS	UTI-7 FHS
58	DOMINION	USA	6	6,583	969	38	7	0	224	37	0.16	0	0.17	0	0	1
59	ANDHRA PRADESH POWER GEN CORP	India	5	6,980	904	8	17	0.53	202	97	0.67	0.23	0.74	0	0.57	0.74
60	CHUBU ELECTRIC POWER CO INC	Japan	1	4,100	760	19	9	0	499	126	0.53	0	0.53	0	0	0.84
61	JINDAL STEEL & POWER LTD	India	6	7,077	922	4	27	0.52	373	483	0.12	0	0.13	0	0	0.8
62	TENAGA NASIONAL BERHAD (TNB)	Indonesia	3	8,680	966	12	16	0.76	438	127	0.11	0	0.15	0	0	0.72
63	OOO SIBERIAN GENERATING CO	Russia	17	8,308	1198	37	7	0.3	95	50	0.1	0	0.11	0.32	0	1.43
64	ENERGY FUTURE HOLDINGS CORP	USA	5	8,496	959	30	5	0	121	88	0.14	0	0.17	1	0.2	1.02
65	RIVERSTONE HOLDINGS	USA	7	8,309	976	41	8	0	251	31	0.6	0.34	0.73	0	0	1.19
66	CEZ AS	Czech	12	6,235	1200	37	13	0.34	386	217	0.18	0	0.21	0.72	0	1.03
67	NEYVELI LIGNITE CORP LTD	India	5	4,615	945	18	20	0.89	211	253	0.9	1	1	1	0.27	0.76
68	CHEUNG KONG INFRASTRUCTURE	Hong Kong	5	6,306	939	21	19	0.97	434	303	0.3	0.05	0.17	0.1	0	0.77
69	DTE ENERGY CO	USA	5	7,909	981	45	8	0	357	77	0.23	0	0.25	0	0	1.25
70	HARYANA POWER GEN CO (HPGC)	India	4	6,145	1082	17	50	0.8	246	284	1	1	1	0.4	0	1.05
71	ELECTRICITY OF VIETNAM (EVN)	Vietnam	8	5,434	957	9	21	0.65	308	217	0.13	0	0.13	0	0	0.8
72	GREAT PLAINS ENERGY INC	USA	6	5,647	947	32	7	0	178	38	0.17	0	0.21	0	0	1.21
73	WEST BENGAL POWER DEV CORP	India	5	5,480	1038	20	37	1	331	381	0.23	0	0.25	0	0	0.66
74	HENAN INVESTMENT GROUP CO LTD	China	5	6,530	1023	9	75	0.71	809	757	0.94	0.71	1	0	0.18	1.01
75	WISCONSIN ENERGY CORP	USA	6	4,493	928	31	8	0	267	71	0.36	0	0.38	0	0	1.3
76	INTER RAO UES	Russia	6	8,030	952	37	9	0.35	191	21	0.16	0	0.25	0.54	0	1.04
77	TAMIL NADU GEN & DIST CORP LTD	India	3	4,320	933	17	18	1	182	211	0.75	0.42	0.79	0	0.42	0.67
78	ZHEJIANG PROV ENERGY GROUP CO	China	2	6,260	921	9	57	0.8	980	1991	0.77	0.8	0.87	0	0	0.9
79	DATONG COAL MINE GROUP CO LTD	China	6	6,670	912	5	32	0.96	485	409	0.79	0.61	0.88	0	0	1.13
80	TOHOKU ELECTRIC POWER CO	Japan	2	2,701	807	23	8	0	249	38	0.29	0	0.29	0	0	0.95
81	AMEREN CORP	USA	4	5,829	984	46	8	0	214	81	0.02	0	0.02	0	0	1.22
82	RAJASTHAN RV UTPADAN NIGAM	India	4	6,580	997	11	23	0.54	173	127	1	1	0.99	0.26	0	1.01
83	SHENZHEN ENERGY GROUP CO LTD	China	3	3,744	1098	16	29	1	535	942	0.33	0	0.32	0	0	0.82
84	SUMITOMO CORP	Japan	9	5,514	921	14	10	0.81	255	218	0.56	0	0.61	0	0.76	0.72
85	MAHARASHTRA STATE POWER GEN CO	India	4	5,550	907	11	25	1	134	99	0.42	0	0.6	0	0	0.88
86	CHINA PETRO & CHEM (SINOPEC)	China	16	4,074	1148	15	46	0.8	621	868	0.22	0.14	0.24	0.16	0.06	0.78
87	ECU - ENERGY CO OF UKRAINE	Ukraine	4	5,475	1005	45	10	0.33	237	44	0.23	0	0.31	0	0	1.21
88	ENBW ENERGIE BADEN-WURTTEMBERG	Germany	8	6,301	857	22	12	0.63	516	124	0.14	0	0.12	0	0	0.93
89	TAURON POLSKA ENERGIA SA	Poland	9	4,242	975	29	15	0.4	468	176	0.18	0	0.28	0	0	1.06
90	ENTERGY CORP	USA	3	4,997	965	37	7	0	123	25	0.17	0	0.18	0	0	1.03
91	ALLIANT ENERGY CORP	USA	10	3,950	986	42	9	0	136	30	0.31	0	0.32	0	0	1.32
92	UTTAR PRADESH RAJYA VIDYUT	India	3	3,490	910	19	31	1	254	458	0.35	0	0.38	0	0	0.94
93	SCOTTISH AND SOUTHERN ENERGY	United Kingdom	3	4,206	934	46	7	0	425	85	0.35	0	0.3	0	0	0.84
94	BASIN ELECTRIC POWER COOP	USA	4	3,688	960	32	5	0	97	64	0.66	0.46	0.68	0.42	0	1.29
95	EUROSIBENERGO	Russia	14	3,979	1303	45	4	0.28	56	47	0.03	0	0.03	0	0	1.34
96	WENERGY-ANHUI PROV ENERGY	China	4	4,345	868	13	59	0.78	615	819	0.33	0.3	0.34	0	0.29	0.95
97	SANTEE COOPER	USA	2	3,620	938	24	4	0	191	38	0.11	0	0.11	0	0	0.95
98	SALT RIVER PROJECT (AZ)	USA	2	3,231	970	40	4	0	83	51	0.11	0	0.2	0	0	1.23
99	GAZPROM	Russia	5	3,786	1301	29	7	0	77	37	0.04	0	0.04	0.65	0	1.42
100	ELEKTROPRIVREDA SRBIJE (EPS)	Serbia	3	446	1276	48	11	0.39	235	55	0.1	0	0.14	1	0	1.2

Appendix B: Top Thermal Coal Mining Companies Tables

Table 65: *Capital expenditure projection of top thermal coal miners with ≥30% revenue from thermal coal*

Parent Owner	Country	% Rev Thermal Coal[1]	EBITDA LTM [US$mm]	Capital Expenditure Projection [CY US$mm]			
				2016	2017	2018	2019
CHINA COAL ENERGY COMPANY	China	52%	1,049	2,505	1,722	-	-
CHINA SHENHUA ENERGY CO	China	35%	10,877	4,869	4,883	-	-
DATONG COAL INDUSTRY	China	97%	22	78	78	-	-
INNER MONGOLIA YITAI COAL CO., LTD.	China	85%	515	1,561	1,348	-	-
SHANXI LU'AN ENVIRONMENTAL ENERGY DEVELOPMENT	China	90%	179	288	291	-	-
YANG QUAN COAL INDUSTRY (GROUP) CO., LTD.	China	70%	208	233	239	-	-
YANZHOU COAL MINING COMPANY LIMITED	China	31%	481	761	685	-	-
ALLIANCE RESROUCE PARTNERS	US	100%	817	222	228	250	250
ALPHA NATURAL RESOURCES	US	66%	83	150	120	-	-
ARCH COAL	US	80%	373	127	112	-	-
CONSOL ENERGY INC	US	46%	987	647	684	-	-
PEABODY ENERGY CORPORATION	US	72%	546	172	183	145	-
INDO TAMBANGRAYA MEGAH TBK PT	Indonesia	94%	168	53	52	77	79
PT ADARO ENERGY TBK	Indonesia	91%	717	161	175	-	-
PT UNITED TRACTORS	Indonesia	66%	729	303	314	255	255
ADANI ENTERPRISES LTD	India	55%	1,509	185	671	-	-
COAL INDIA LTD	India	89%	2,747	1,016	1,187	1,420	1,482
THE TATA POWER COMPANY	India	31%	1,184	275	256	144	-
SASOL	South Africa	58%	4,992	5,603	4,019	3,105	2,324
BANPU PUBLIC COMPANY LIMITED	Thailand	85%	336	245	222	-	-

[475] MSCI

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Table 66: *Ownership of top thermal coal minters with ≥30% revenue from thermal coal*[476]

Parent Owner	Country	Ticker	Ultimate Parent (if different)	Ownership*	Insiders	Institutions	Corporate	ESOP	State	Public/Other
China Coal Energy Company Limited	China	SEHK:1898	China National Coal Group Corporation	PrC	0	1.12	3.02	-	-	1.01
China Shenhua Energy Co. Ltd.	China	SEHK:1088	Shenhua Group Corporation Limited	PrC	-	3.18	21.96	-	-	4.89
DaTong Coal Industry Co.,Ltd.	China	SHSE:601001	Datong Coal Mine Group Co., Ltd.	PrC	0	0.06	0.88	-	-	0.51
Inner Mongolia Yitai Coal Co. Ltd.	China	SHSE:900948	-	PbC	-	0.24	1.59	0.01	-	0.62
Shanxi Lu'an Environmental Energy Development Co., Ltd.	China	SHSE:601699	Shanxi Lu'an Mining Industry (Group) Company Ltd.	PrC	-	0.13	1.9	-	-	0.96
Yang Quan Coal Industry (Group) Tiantai Investment Limited	China	-	YANGQUAN COAL INDUSTRY(GROUP)CO.,LTD	PrC	-	-	-	-	-	-
Yanzhou Coal Mining Co. Ltd.	China	SEHK:1171	Yankuang Group Co., Ltd.	PrC	0	0.38	1.27	-	-	0.6
Alliance Resource Partners LP	United States	NasdaqGS:ARLP	-	PbC	0.01	0.22	0.41	-	-	0.28
Alpha Natural Resources, Inc.	United States	OTCPK:ANRZ.Q	-	PbC	0	0	-	-	-	0
Arch Coal Inc.	United States	NYSE:ACI	-	PbC	0	0.01	-	-	-	0.01
CONSOL Energy Inc.	United States	NYSE:CNX	-	PbC	0.01	1.55	-	-	-	-
Peabody Energy Corporation	United States	NYSE:BTU	-	PbC	0	0.07	-	-	-	0.07
PT Indo Tambangraya Megah Tbk	Indonesia	JKSE:ITMG	Banpu Public Company Limited	PbC	0	0.07	0.32	-	0	0.09
PT Adaro Energy Tbk	Indonesia	JKSE:ADRO	-	PbC	0.18	0.6	-	-	-	0.39
PT United Tractors Tbk	Indonesia	JKSE:UNTR	Jardine Matheson Holdings Limited	PbC	0	0.55	2.49	-	-	1.14
Adani Enterprises Limited	India	BSE:512599	S.B. Adani Family Trust	PrC	0.12	0.23	0.88	-	-	0.09
Coal India Limited	India	NSEI:COALINDIA	-	PbC	0	4.23	-	-	23.97	1.89
The Tata Power Company Limited	India	BSE:500400	-	PbC	0	1.05	0.86	-	0	0.72
Sasol Ltd.	South Africa	JSE:SOL	-	PbC	0	5.85	-	-	1.33	6.81
Banpu Public Company Limited	Thailand	SET:BANPU	-	PbC	0.16	0.21	0.14	-	0.02	0.69

*Gov: Government Institution; PrC: Private company; PrI: Private Investment Firm; PbC, Public company; PbI Public Investment Firm.

[476] Data from Standard & Poor's Capital IQ, November 2015.

***Table 67:** Debt positions of thermal coal miners with ≥30% revenue from thermal coal* [477]

Parent owner	Country	Average Maturity	Perpetuities [US$mm]	Corporate Debentures [US$mm]	Total Debt/ EBITDA	Thermal Coal Rev [US$mm]
CHINA COAL ENERGY COMPANY	China	2018	0	4709	17.1	5,966.30
CHINA SHENHUA ENERGY CO	China	0	0	0	1.5	14,006.39
DATONG COAL INDUSTRY	China	0	0	0	83	1,355.73
INNER MONGOLIA YITAI COAL CO., LTD.	China	2018	0	549	9	3,397.46
SHANXI LU'AN ENVIRONMENTAL ENERGY DEVELOPMENT	China	0	0	0	11.6	2,323.84
YANG QUAN COAL INDUSTRY (GROUP) CO., LTD.	China	2016	0	2170	5.4	2,336.67
YANZHOU COAL MINING COMPANY LIMITED	China	2019	300	3273	16.1	3,044.72
ALLIANCE RESOURCE PARTNERS	US	0	0	0	1.2	2,300.72
ALPHA NATURAL RESOURCES	US	2020	0	5724	45	2,836.85
ARCH COAL	US	2022	0	6853	13.8	2,349.70
CONSOL ENERGY INC	US	2021	0	11895	3.8	1,599.70
PEABODY ENERGY CORPORATION	US	2023	0	11023	11.5	4,890.38
INDO TAMBANGRAYA MEGAH TBK PT	Indonesia	0	0	0	0	1,740.86
PT ADARO ENERGY TBK	Indonesia	2019	0	800	2.3	2,908.70
PT UNITED TRACTORS	Indonesia	0	0	0	0.3	2,826.15
ADANI ENTERPRISES LTD	India	0	0	0	1.9	5,067.80
COAL INDIA LTD	India	0	0	0	0	10,250.88
THE TATA POWER COMPANY	India	2047	0	826	4.5	1,861.31
SASOL	South Africa	2022	0	1000	0.7	11,050.28
BANPU PUBLIC COMPANY LIMITED	Thailand	2020	0	320	9.6	2,637.96

[477] Data from Standard & Poor's Capital IQ, November 2015.

Table 68: Ratio analysis for thermal coal mining industry

This table represents the median ratios across all firms available. For the thermal coal mining companies, we obtain data for 28 of the 30 coal companies listed in Table 21.

Year	Count	(A) Net Profit Margin	(B) CAPEX to Assets	(C) Current Ratio	(D) Acid Test	(E) Total Debt to Equity	(F) Total Debt to Assets	(G) EBIT to interest expens	(H) EBITDA to interest expen	(I) (EBITDA-CAP to interest exp	(J) Total Debt to EBITDA	(K) Net Debt to EBITDA	(L) Total Debt to (EBITDA - CA	(M) Net Debt to (EBITDA - CA
1995	5	11.70%	8.70%	1.44x	0.23x	87.50%	46.70%	3.21x	5.70x	2.24x	3.45x	3.01x	1.19x	0.33x
1996	6	10.40%	6.10%	1.67x	0.45x	74.40%	42.40%	4.41x	5.79x	3.98x	1.70x	1.68x	1.81x	1.11x
1997	7	9.60%	9.80%	1.20x	0.39x	51.40%	34.00%	3.66x	10.10x	7.33x	1.49x	1.44x	1.08x	0.90x
1998	8	2.80%	7.00%	1.02x	0.25x	48.70%	56.90%	2.62x	4.78x	2.98x	1.36x	1.07x	2.77x	1.79x
1999	12	8.80%	4.50%	1.35x	0.43x	94.80%	48.40%	3.70x	5.40x	3.96x	2.58x	2.16x	2.38x	2.04x
2000	13	3.60%	5.00%	1.31x	0.34x	87.40%	46.60%	1.94x	3.93x	1.62x	3.23x	2.60x	4.67x	4.22x
2001	15	3.30%	6.70%	1.21x	0.29x	95.80%	48.90%	2.02x	3.89x	1.72x	3.17x	2.50x	4.80x	3.16x
2002	17	5.50%	7.60%	0.87x	0.24x	96.70%	49.20%	2.65x	3.99x	1.95x	2.33x	1.93x	3.42x	3.02x
2003	21	6.90%	8.50%	1.26x	0.35x	70.80%	41.50%	3.58x	5.69x	2.00x	2.18x	1.78x	2.51x	2.12x
2004	23	10.70%	11.30%	1.36x	0.40x	82.60%	45.20%	6.23x	9.41x	3.86x	1.65x	1.19x	3.05x	1.81x
2005	24	12.40%	11.60%	1.29x	0.70x	80.00%	44.40%	8.73x	10.42x	3.90x	1.45x	0.95x	2.61x	1.58x
2006	25	11.50%	10.90%	1.31x	0.54x	84.70%	45.80%	6.82x	9.21x	4.33x	1.66x	1.04x	2.56x	1.59x
2007	26	10.30%	11.00%	1.59x	0.67x	58.10%	36.70%	6.86x	9.45x	3.81x	1.47x	0.92x	1.90x	0.86x
2008	26	14.20%	12.20%	1.56x	0.62x	71.80%	41.80%	12.05x	15.00x	5.46x	1.13x	0.42x	2.34x	0.84x
2009	27	13.50%	9.60%	1.69x	0.92x	58.90%	37.00%	15.27x	18.54x	7.75x	1.28x	0.50x	2.28x	0.22x
2010	28	11.70%	9.30%	1.78x	1.16x	58.80%	37.00%	13.28x	17.42x	7.05x	1.28x	0.61x	1.77x	0.40x
2011	28	12.90%	11.30%	1.62x	0.74x	63.80%	38.50%	12.87x	16.82x	8.01x	1.58x	0.89x	1.97x	-0.17x
2012	28	10.20%	10.60%	1.45x	0.65x	75.20%	42.80%	6.50x	10.03x	4.26x	1.48x	1.19x	1.32x	0.01x
2013	28	5.80%	8.20%	1.26x	0.63x	80.80%	44.70%	2.66x	5.56x	0.76x	2.51x	1.58x	0.84x	0.03x
2014	28	4.40%	5.80%	1.35x	0.61x	104.20%	50.90%	2.28x	4.00x	0.91x	4.06x	3.20x	1.56x	0.22x

Table 69: *Thermal coal miners local risk hypotheses column labels*

Label	Unit	Description
NUM	-	Total number of coal mines
PROD	[Mt (#)]	Total coal production capacity and number of data points available
PROT	-	Number of mines with protected areas within 40km
POP	[People/km^2]	Average local population density weighted by mine production
BWS	-	Baseline physical water stress indicator
FWS	-	Future physical water stress indicator

Table 70: *Thermal coal miners local risk hypotheses*

GENERAL INFORMATION				MIN-1		MIN-2	
PARENT OWNER	COUNTRY	NUM	PROD	PROT	POP	BWS	FWS
CHINA COAL ENERGY COMPANY	China	11	107 (6)	73%	125	100%	100%
CHINA SHENHUA ENERGY CO	China	23	305 (23)	30%	100	44%	93%
DATONG COAL INDUSTRY	China	4	15 (1)	0%	446	100%	100%
INNER MONGOLIA YITAI COAL CO., LTD.	China	13	51 (13)	8%	69	44%	100%
SHANXI LU'AN ENVIRONMENTAL ENERGY DEVELOPMENT	China	5	30 (5)	100%	451	100%	100%
YANG QUAN COAL INDUSTRY (GROUP) CO., LTD.	China	25	13 (4)	68%	202	100%	100%
YANZHOU COAL MINING COMPANY LIMITED	China	23	73 (19)	22%	163	68%	45%
ALLIANCE RESROUCE PARTNERS	US	13	41 (11)	0%	34	13%	14%
ALPHA NATURAL RESOURCES	US	3	84 (3)	0%	23	44%	39%
ARCH COAL	US	12	264 (11)	0%	25	38%	40%
CONSOL ENERGY INC	US	5	32 (5)	0%	48	17%	17%
PEABODY ENERGY CORPORATION	US	28	232 (28)	0%	45	30%	32%
INDO TAMBANGRAYA MEGAH TBK PT	Indonesia	6	29 (6)	33%	1,697	32%	37%
PT ADARO ENERGY TBK	Indonesia	4	56 (4)	0%	79	1%	1%
PT UNITED TRACTORS	Indonesia	1	6 (1)	0%	11	1%	1%
ADANI ENTERPRISES LTD	India	6	8 (2)	0%	238	16%	22%
COAL INDIA LTD	India	13	494 (8)	38%	1,912	15%	18%
THE TATA POWER COMPANY	India	3	27 (1)	67%	1,689	36%	38%
SASOL	South Africa	6	41 (6)	0%	55	17%	21%
BANPU PUBLIC COMPANY LIMITED	Thailand	10	39 (9)	10%	589	52%	23%

Appendix C: Top Coal-Processing Technology Companies Tables

Table 71: Ownership of coal processing technology plants[478]

Parent Owner	Country	Ticker	Ultimate Parent (if different)	Ownership*	Insiders	Institutions	Corporate	ESOP	State	Public/Other
Anhui Huayi Chemical Co. Ltd.	China	-	-	PrC	-	-	-	-	-	-
China National Offshore Oil Corporation	China	-	-	PrC	-	-	-	-	-	-
Chinacoal Group Shanxi Huayu Energy Co., Ltd.	China	-	-	PrC	-	-	-	-	-	-
Datang International Power Generation Co., Ltd.	China	SEHK:991	-	PbC	0	0.26	2.49	-	-	0.97
Guanghui Energy Co., Ltd.	China	SHSE:600256	-	PbC	0.11	0.4	2.39	-	-	2.44
Harbin yilan coal gasification	China	-								
Shandong Hualu-Hengsheng Chemical Co., Ltd.	China	SHSE:600426	-	PbC	0.03	0.37	0.74	-	-	0.99
SES—GCL (Inner Mongolia) Coal Chemical Co., Ltd	United States	-	Synthesis Energy Systems, Inc.	PbC	-	-	-	-	-	-
Jiangsu Linggu Chemical Co., Ltd.	China	-	-	PrC	-	-	-	-	-	-
Shangyu Jiehua Chemical Co., Ltd.	China	-	-	PrC	-	-	-	-	-	-
Pucheng Clean Energy Chemical Co., Ltd	China	-	-	PrC	-	-	-	-	-	-
Inner Mongolia Qinghua Group Co., Ltd.	China	-	-	PrC	-	-	-	-	-	-
Inner Mongolia Sanwei Resources Group Co., Ltd.	China	-	-	PrC	-	-	-	-	-	-
Shenhua Group Corporation Limited	China	-	-	PrC	-	-	-	-	-	-
China Petroleum & Chemical Corp.	China	SEHK:386	China Petrochemical Corporation	PrC	0	7.2	51.46	-	-	13.49
Tianjin Bohai Chemical Industry Group Corporation	China	-	-	PrC	-	-	-	-	-	-
Wison (Nanjing) Clean Energy Co. Ltd.	China	-	Beijing Qingkong Jinxin Investment (	PrC	-	-	-	-	-	-
Zhejiang Xinhu Group Co., Ltd.	China	-	-	PrC	-	-	-	-	-	-
Xinjiang Xin Lian Xin Chemical Energy Co., Ltd.	China	-	China XLX Fertiliser Ltd.	PbC	-	-	-	-	-	-
Yankuang Group Co., Ltd.	China	-	-	PrC	-	-	-	-	-	-
Wanhua Chemical Group Co., Ltd.	China	SHSE:600309	Wanhua Industrial Group Co., Ltd.	PrC	-	0.9	3.12	-	-	2.05
Inner Mongolia Yitai Group Co., Ltd.	China	-	-	PrC	-	-	-	-	-	-
Korea South-East Power Co., Ltd.	South Korea	-	Korea Electric Power Corp.	PbC	-	-	-	-	-	-
Korea Southern Power Co., Ltd.	South Korea	-	Korea Electric Power Corp.	PbC	-	-	-	-	-	-
POSCO	South Korea	KOSE:A005490	-	PbC	0	7.01	0.79	0.21	0.29	2.8
Dakota Gasification Company Inc.	United States	-	Basin Electric Power Cooperative	PrC	-	-	-	-	-	-
EAST CHINA ENERGY	United States	-								
Jindal Steel & Power Ltd.	India	NSEI:JINDALSTE	-	PbC	0.02	0.42	0.59	-	-	0.24
Tokyo Electric Power Company, Incorporated	Japan	TSE:9501	-	PbC	0	1.42	0.02	0.29	0.26	7.63
Sasol Ltd.	South Africa	JSE:SOL	-	PbC	0	5.85	-	-	1.33	6.81

*Gov: Government Institution; PrC: Private company; PrI: Private Investment Firm; PbC, Public company; PbI Public Investment Firm.

[478] Data from Standard & Poor's Capital IQ, November 2015.

Table 72: Debt positions of coal processing technology companies[479]

Owner	Country	Average Maturity	Perpetuities [US$mm]	Corporate Debentures [US$mm]	Total Debt/ EBITDA	Syngas capacity [kNm3/d]
ANHUI HUAYI CHEMICAL CO	China	0	0	0	none	5,040
CHINA NATIONAL OFFSHORE OIL CORPORATION (CNOOC)	China	2025	180	30666	1.3	9,975
CHINACOAL GROUP	China	2016	0	141.3	none	24,231
DATANG	China	2022	0	622	6.9	48,550
GUANGHUI ENERGY CO	China	0	0	0	11.6	12,600
HARBIN YILAN COAL GASIFICATION	China	none	none	none	none	5,750
HUALU HENGSHENG CHEMICALS	China	0	0	0	1.8	6,890
INNER MONGOLIA ZHUOZHENG COAL CHEMICAL CO	China	none	none	none	none	9,040
JIANGSU LINGGU CHEMICAL CO	China	0	0	0	none	6,090
JIEHUA CHEMICAL	China	0	0	0	none	8,000
PUCHENG CLEAN ENERGY CHEMICAL CO	China	none	none	none	none	12,100
QINGHUA GROUP	China	0	0	0	none	13,860
SANWEI RESOURCE GROUP	China	0	0	0	none	9,744
SHENHUA GROUP	China	2018	0	19232	3.1	43,360
SINOPEC	China	2020	0	12072	1.7	32,036
TIANJIN BOHAI CHEMICAL GROUP	China	0	0	0	none	8,787
WISON (NANJING) CLEAN ENERGY CO	China	0	0	0	none	11,932
XINHU GROUP	China	2016	0	470	none	12,000
XINJIANG XINLIANXIN FERTILIZER CO. LTD.	China	none	none	none	none	5,040
YANKUANG GROUP	China	2019	300	3273	none	13,415
YANTAI WANHUA	China	0	0	0	5.1	5,040
YITAI COAL OIL MANUFACTURING CO (INNER MONGOLIA YITAI GROUP	China	2018	0	549	9	33,700
KOREA SOUTH EAST POWER CO (KOSEP)	South Korea	2019	0	1842	3.5	8,400
KOREA SOUTHERN POWER CO (KOSPO)	South Korea	2020	0	1541	6.2	8,400
POSCO	South Korea	2019	0	5635	4.6	6,934
DAKOTA GASIFICATION CO	US	0	0	0	none	13,900
EAST CHINA ENERGY	US	none	none	none	none	5,000
JINDAL STEEL & POWER LTD	India	0	0	0	8.1	8,025
TOKYO ELECTRIC POWER COMPANY (TEPCO)	Japan	2019	0	19142	6.7	11,566
SASOL	South Africa	2022	0	1000	0.7	90,260

[479] Data from Standard & Poor's Capital IQ, November 2015.

Table 73: *Ratio analysis for coal processing technology companies*

This table represents the median ratios across all firms available. For the coal-fired power utilities, data was available for 11 of the 30 companies listed in Table 72

Year	Count	(A) Net Profit Margin	(B) CAPEX to Assets	(C) Current Ratio	(D) Acid Test	(E) Total Debt to Equity	(F) Total Debt to Assets	(G) EBIT to interest expense	(H) EBITDA to interest expense	(I) (EBITDA-CAPEX) to interest expense	(J) Total Debt to EBITDA	(K) Net Debt to EBITDA	(L) Total Debt to (EBITDA – CAPEX)
1995	3	11.00%	12.30%	1.25x	0.45x	91.20%	47.70%	3.27x	5.51x	1.07x	1.31x	0.74x	1.19x
1996	3	6.10%	11.00%	1.22x	0.45x	95.70%	48.90%	2.53x	5.01x	0.41x	1.51x	0.87x	0.98x
1997	3	6.30%	10.40%	1.17x	0.31x	137.50%	57.90%	2.50x	4.32x	1.21x	1.91x	1.37x	0.80x
1998	3	4.90%	11.50%	1.35x	0.44x	99.50%	49.90%	3.11x	4.90x	1.46x	1.53x	0.86x	1.91x
1999	5	12.20%	9.50%	1.32x	0.41x	54.20%	35.10%	8.16x	9.37x	0.00x	1.19x	0.69x	0.70x
2000	7	13.20%	6.60%	1.18x	0.33x	59.70%	37.00%	6.74x	6.07x	1.61x	1.72x	1.16x	2.20x
2001	7	11.80%	7.50%	1.37x	0.31x	56.90%	36.20%	4.89x	5.57x	0.58x	2.16x	1.70x	0.43x
2002	7	11.70%	15.90%	1.36x	0.36x	47.80%	32.30%	6.93x	11.52x	1.81x	1.91x	0.87x	1.30x
2003	7	12.10%	17.20%	1.43x	0.72x	78.70%	43.40%	9.39x	11.51x	1.48x	2.76x	1.24x	1.62x
2004	7	13.70%	12.30%	1.22x	0.33x	87.30%	46.50%	11.68x	15.89x	1.56x	2.05x	1.65x	3.75x
2005	7	14.50%	14.60%	1.45x	0.59x	90.40%	47.20%	13.27x	15.76x	2.75x	1.82x	1.67x	1.44x
2006	7	14.60%	12.50%	1.08x	0.68x	82.60%	44.70%	10.34x	11.97x	4.78x	2.21x	1.58x	1.53x
2007	7	18.20%	8.40%	1.38x	0.64x	67.90%	40.00%	10.49x	13.32x	7.37x	2.08x	1.31x	1.14x
2008	7	18.40%	11.20%	1.17x	0.64x	69.10%	39.00%	10.42x	12.44x	5.29x	1.60x	1.03x	1.89x
2009	7	13.50%	15.60%	1.17x	0.83x	92.40%	48.00%	8.20x	11.66x	1.12x	1.83x	1.30x	17.38x
2010	7	14.60%	9.70%	1.50x	0.49x	79.30%	44.20%	10.11x	13.59x	4.20x	2.18x	1.46x	3.33x
2011	7	13.70%	14.20%	1.20x	0.68x	95.70%	48.90%	9.87x	12.26x	-0.78x	2.79x	2.33x	-1.70x
2012	8	14.30%	11.80%	1.05x	0.52x	99.00%	49.70%	8.32x	9.85x	0.90x	3.03x	2.54x	1.32x
2013	8	14.20%	11.90%	1.14x	0.43x	105.30%	51.20%	3.88x	6.10x	-1.33x	3.66x	3.41x	-12.70x
2014	8	9.30%	11.60%	1.24x	0.42x	138.60%	57.70%	3.31x	6.06x	0.99x	4.91x	4.17x	-1.45x

Table 74: *Coal processing technology company local risk hypotheses column labels*

Label	Unit	Description
NUM	-	Total number of coal mines
PROD	[Mt (#)]	Total coal production capacity and number of data points available
PROT	-	Number of mines with protected areas within 40km
POP	[People/km^2]	Average local population density weighted by mine production
BWS	-	Baseline physical water stress indicator
FWS	-	Future physical water stress indicator

Table 75: *Coal processing technology company local risk hypotheses exposure*

GENERAL INFO				CPT-1	CPT-2		CPT-3
COMPANY	COUNTRY	CAP	NUM	AGE	BWS	FWS	CCS
ANHUI HUAYI CHEMICAL CO	China	5,040	1	3	4.00%	5.10%	100%
CHINACOAL GROUP	China	24,100	2	1	44.70%	59.20%	0%
CHINA NATIONAL OFFSHORE OIL CORPORATION (CNOOC)	China	9,975	1	0	14.50%	16.80%	100%
DATANG	China	48,550	4	3	95.80%	96.00%	92%
GUANGHUI ENERGY CO	China	12,600	1	2	100.00%	100.00%	100%
HARBIN YILAN COAL GASIFICATION	China	5,750	1	22	31.10%	35.60%	100%
HUALU HENGSHENG CHEMICALS	China	6,890	3	4	100.00%	100.00%	29%
INNER MONGOLIA ZHUOZHENG COAL CHEMICAL CO	China	9,040	1	2	38.50%	100.00%	0%
JIANGSU LINGGU CHEMICAL CO	China	6,090	2	3	69.10%	83.40%	100%
JIEHUA CHEMICAL	China	8,000	1	4	7.60%	9.20%	100%
PUCHENG CLEAN ENERGY CHEMICAL CO	China	12,100	1	1	33.60%	94.10%	100%
QINGHUA GROUP	China	13,860	1	2	100.00%	100.00%	100%
SANWEI RESOURCE GROUP	China	9,744	2	4	76.10%	100.00%	86%
SHENHUA GROUP	China	43,360	3	3	91.60%	100.00%	71%
SINOPEC	China	29,481	10	4	32.30%	33.80%	79%
TIANJIN BOHAI CHEMICAL GROUP	China	8,787	2	5	100.00%	100.00%	0%
WISON (NANJING) CLEAN ENERGY CO	China	11,932	4	3	4.00%	5.10%	0%
XINHU GROUP	China	12,000	1	1	38.50%	100.00%	0%
XINJIANG XINLIANXIN FERTILIZER CO. LTD.	China	5,040	1	0	100.00%	100.00%	0%
YANKUANG GROUP	China	13,415	5	6	66.70%	68.30%	100%
YANTAI WANHUA	China	5,040	1	1	100.00%	100.00%	100%
YITAI COAL OIL MANUFACTURING CO (INNER MONGOLIA YITAI GROUP	China	33,700	2	0	38.50%	100.00%	0%
JINDAL STEEL & POWER LTD	India	8,025	2	2	14.80%	18.80%	100%
TOKYO ELECTRIC POWER COMPANY (TEPCO)	Japan	11,566	2	0	15.20%	15.30%	100%
SASOL	South Africa	90,260	4	36	6.60%	10.50%	100%
KOREA SOUTH EAST POWER CO (KOSEP)	South Korea	8,400	1	0	100.00%	100.00%	100%
KOREA SOUTHERN POWER CO (KOSPO)	South Korea	8,400	1	0	23.10%	22.80%	100%
POSCO	South Korea	6,934	1	0	22.40%	22.10%	100%
DAKOTA GASIFICATION CO	US	13,900	1	31	21.30%	23.10%	0%
EAST CHINA ENERGY	US	5,000	1	2	23.70%	26.40%	0%

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