UNITED NATIONS ECONOMIC COMMISSION FOR EUROPE

Mitigating climate change through investments in fossil fuel technologies

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UNECE Energy Series

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Mitigating climate change through investments in fossil fuel technologies

A synthesis report based on national case studies from Afghanistan, China, India, Kazakhstan, Kyrgyzstan, Mongolia, Tajikistan, Ukraine, and Uzbekistan

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NOTE

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United Nations Economic Commission for Europe

The United Nations Economic Commission for Europe (UNECE) is one of the five United Nations regional commissions administered by the Economic and Social Council (ECOSOC). It was established in 1947 with the mandate to help rebuild post-war Europe, develop economic activity and strengthen economic relations among European countries, and between Europe and the rest of the world.

During the Cold War, UNECE served as a unique forum for economic dialogue and cooperation between East and West. Despite the complexity of this period, significant achievements were made, with consensus reached on numerous harmonization and standardization agreements. In the post-Cold War era, UNECE acquired not only many new Member States, but also new functions. Since the early 1990s the organization has focused on analyses of the transition process, using its harmonization experience to facilitate the integration of Central and Eastern European countries into the global markets.

Today UNECE is the forum where the countries of whole Europe, Central Asia and North America—56 countries in all—come together to forge the tools of their economic cooperation. That cooperation concerns economics, statistics, environment, transport, trade, sustainable energy, timber and habitat.

UNECE offers a regional framework for the elaboration and harmonization of conventions, norms and standards. UNECE's experts provide technical assistance to the countries of South-East Europe and the Commonwealth of Independent States. This assistance takes the form of advisory services, training seminars and workshops where countries can share their experiences and best practices.

UNECE Sustainable Energy

The UNECE Sustainable Energy sub-programme promotes a sustainable energy development strategy for the region, with the objective to:

- Provide sustained access to high quality energy services for all individuals in the UNECE region
- Secure energy supplies in the short-, medium- and long-term
- Facilitate a transition to a more sustainable energy future and introduce renewable energy sources to reduce health and environmental impacts resulting from the production, transport and use of energy
- Develop well-balanced energy network systems across the UNECE region, tailored to optimise operating efficiencies and overall regional cooperation
- Sustain improvements in energy efficiency, in production and use, particularly in countries with economies in transition
- Help promote, in the context of post-EU enlargement, the energy restructuring, legal, regulatory and energy pricing reforms,
- Assist UNECE Member States in incorporating the social and environmental dimensions into their energy policy making

For more than twenty years, the UNECE Committee on Sustainable Energy has provided a platform for intergovernmental dialogue on energy efficiency, natural gas, fossil fuel classification, clean electricity, and coal methane management.

The sustainable energy sub-programme is designed to take into account the Secretary-General's initiative "Sustainable Energy for All" and catalyse action in all UNECE Member States needed to achieve by 2030 the three interlinked objectives: provide universal access to modern energy services; double the global rate of improvement in energy efficiency; double the share of renewable energy in the global energy mix.

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List of Abbreviations

bcm	billion cubic metres (of gas)
BLT	Build Lease Transfer
BOOT	Build Own and Operate or Transfer
BOT	Build Operate Transfer
BROT	Build Rehabilitate Lease Transfer
BTU	British thermal unit (1,055 joule)
cbm	Coalbed methane
CCGT	Combined Cycle Gas Turbines
CCS	Carbon capture and storage
CHP	Combined heat and power
CHPGT	Combined Heat and Power gas turbines
CNOOC	China National Offshore Oil Corporation
CO_2	Carbon dioxide
EBRD	European Bank for Reconstruction and Development
EIA	Energy Information Administration
EPC	engineering, procurement and construction
FDI	Foreign direct investments
GDP	Gross Domestic Product
GHG	greenhouse gas
GW	Gigawatt
GWe	Gigawatt (electric output)
ICGCC	Integrated Coal Gasification combined cycle plants
IEA	International Energy Agency
IPP	Independent Power Producers
kWh	kilowatt-hour
LNG	Liquefied natural gas
MHI	Mitsubishi Heavy Industries
Mpa	Megapascal
MW	Megawatt
MWh	Megawatt-hour
PPA	Power purchasing agreement
RLT	Rehabilitate Lease Transfer
ROC	Return on Capital
ROI	Return on Investment
ROT	Rehabilitate Operate Transfer
SBM	Single buyer model
SCPC	Supercritical pulverized coal burning steam generators
SOE	State-owned enterprises
tcm	trillion cubic meters
ton	metric ton (1,000 kg)
TWh	Terawatt-hour
UNDA	United Nations Development Account
UNECE	United Nations Economic Commission for Europe
UNESCAP	Economic and Social Commission for Asia and the Pacific
USCPC	Ultra-supercritical pulverized coal burning steam generators

Executive summary

About the project

This report is the principal written deliverable of the project "Mitigating climate change through attracting foreign direct investment in advanced fossil fuel technologies", financed from the United Nations Development Account (UNDA)[1]. The project, implemented in 2010-2012, covered nine countries: Afghanistan, China, India, Kazakhstan, Kyrgyzstan, Mongolia, Tajikistan, Ukraine, and Uzbekistan.

The report takes into account findings of the national baseline studies, drafted for each of the nine countries between November 2011 and August 2012. The report summarizes and interprets the experiences, policies, and plans for the future of each country in developing a thermal electricity sector using advanced technologies that reduce carbon dioxide (CO_2) emissions and exploit the countries' fossil fuel resources.

Climate change and electricity generation

According to the recently released portion of the Fifth Assessment Report of the United Nations Intergovernmental Panel on Climate Change (Working Group I)[2], the concentration of greenhouse gases in the atmosphere has increased to levels unprecedented on earth in 800,000 years. Carbon dioxide (CO_2) is the principal greenhouse gas. Thermal electricity generation emits a substantial share of the world's CO_2 emissions. Coal-fired plants are especially large contributors. The rapid growth in installed coal-fired electricity generation capacity in the past 15 years has raised concerns about their deleterious effect on climate change. China and India, in particular, have very large coal-burning electricity sectors and are the world's first and third largest CO_2 emitters. Their emissions have shown very strong growth in the past decade.

The nine countries range from large and high-growth countries such as China and India—with large and rapidly modernized electricity sectors—to smaller and relatively low-growth countries such as Tajikistan, Afghanistan, Mongolia, and Kyrgyzstan—with small and rather obsolete fleet of power plants. In between are Kazakhstan, Ukraine, and Uzbekistan, which inherited planned economies, electricity infrastructure, and fuel resources from a centralized planning.

In all nine countries the electricity sector was developed, built, and operated by the state. The policy-makers in these countries have long recognized that overall economic growth is supported and driven by the development of electricity generation and distribution.

Advanced fossil fuel technologies

The advanced technologies for electricity generation from fossil fuels which currently offer the most promise for delivering higher efficiencies and lower CO_2 emissions are:

- Combined Cycle Gas Turbines (CCGT)
- Combined Heat and Power gas turbines (CHPGT)
- Supercritical pulverized coal burning steam generators (SCPC)
- Ultra-supercritical pulverized coal burning steam generators (USCPC)
- Integrated Coal Gasification combined cycle plants (ICGCC)

[1] The Development Account is a capacity development programme of the United Nations Secretariat aiming at enhancing capacities of developing countries in the priority areas of the United Nations Development Agenda. The Development Account is funded from the Secretariat's regular budget and its projects are implemented by 10 entities; UNECE is one of them.

[2] More details as they become available can be found at: http://www.ipcc.ch/report/ar5/.

Over the past two decades there has been intensive research and development in making cleaner, more efficient fossil fuel combustion technologies. Supercritical pulverized coal (SCPC) and ultra-supercritical pulverized coal (USCPC) steam generators have been increasingly introduced into the world's coal-fired electricity generation fleet replacing less efficient sub-critical generators. Rapid advances in gas turbines used along with combined cycle generators have increased efficiencies. These advanced technologies are expensive, however. For example, the planned development program for new generation capacity for the current Five-Year plan in China is estimated to cost $444 billion; in India the current 12th Five-Year Plan calls for $265 billion for the electricity sector.

China adopted a policy of introducing SCPC and USCPC generators in the 10th Five-Year plan (2000-2005), and since 2004 has been building them rapidly. By 2010 SCPC and USCPC power plants represented 54 per cent of China's total coal-burning electricity generation fleet. India mandated that 40 per cent of all new plants shall be SCPC, while it has projected that in 2017-2022, 100 per cent of new coal plants must be SCPC or USCPC. In Kazakhstan, Ukraine, and Mongolia, policy makers have recognized that there are issues with the levels of CO_2 that they emit from their coal based electricity generation. They have not yet committed to a policy of adopting the advanced coal combustion technologies or in replacing their older coal-fired fleets. Afghanistan, Tajikistan, and Kyrgyzstan all need more electricity than they currently generate, but these countries can rely on hydro power.

Role of Foreign Direct Investments

Foreign direct investments (FDI) can have a positive effect on the economic development of a country through the introduction of new, advanced technologies and production processes into an economy. Today FDI plays a very important role in the economies of China and India; they are the first and third largest destinations for FDI. On the other end, Uzbekistan, Kyrgyzstan, Tajikistan have received very little FDI in all sectors over the past seven years.

China since 1985, India since 1991, Kazakhstan since 1995, and Ukraine since 1999 all have received FDI in the electricity generation sector and all still have foreign investments in it. At this time all nine project countries except China do need FDI to develop electricity sector based on advanced technologies. Unfortunately, nowhere has FDI in electricity sector been on the scale required to impact the overall CO_2 emissions. Here is how FDI inflows in the electricity sector are estimated: since 1985 China has received about $16 billion in FDI, while India since 2000 has received $5.9 billion. Kazakhstan has received since 1992 less than $700 million; Ukraine $420 million; Tajikistan $280 million; Uzbekistan possibly $200 million. FDI into the electricity sectors of Afghanistan and even Tajikistan have been more in the form of foreign development aid, which is not considered FDI. Mongolia has to date not received any FDI.

All of the countries have laws and regulations which permit foreign direct investment in principal. But not all of the countries actively promote FDI into the electricity generation. Based on the past performance, FDI is not likely to deliver enough investment into advanced fossil fuel technologies to make a significant abatement impact on the CO_2 emissions of either China or India. It is still possible that Kazakhstan and Mongolia could attract enough foreign investment in the coming decade in new large-scale high efficiency coal-fired power plants that would make a contribution to the abatement of their CO_2 emissions.

Risks, opportunities, investment climate

There are many general risks for a foreign investor into any industry of any developing economy; risks which do not have anything to do with the legal or regulatory rules governing industry-specific FDI. These macro risk factors which may inhibit FDI inflows include:

- Security
- Payments/exchange rate risk
- Rule of law
- Corruption
- Political risk

In most of the nine countries the fundamental obstacle to foreign investments is the very low profitability of the thermal electricity industry coupled with the relatively high risks of investing. The high risks are related to a weakness in the enforcement of the rule of law—which may cause arbitrary rulings, project delays, inadequate contract enforcement, confiscations, and general uncertainties. The very low profitability is tied, in every country, to the lack of a market basis for building up electricity tariffs and ultimately to tariffs offered to investors which are just too low and do not reflect the full costs of fuel, capital, operations, and returns.

The pricing of electricity is the fundamental problem. In none of the countries studied were tariffs flexible enough to allow the pass-through of changing fuel costs. Instead, tariffs are set by fiat, often by local authorities (meaning political considerations determine tariffs), and they most often reflect a political belief that the end consumers cannot afford the full cost of energy, which should therefore be subsidized.

For investors into electricity generation there are a number of criteria that are more specific than the general investment climate and that have the greatest impact on their investment decision. The criteria can be reduced to six:

- Regulatory system
- Market framework
- Commercial operations
- Private sector involvement
- Network access
- Electricity tariffs

These six criteria represented the reference framework used to compare investment climate in the nine countries. By these assessments, the two countries with the best terms for the investments in electricity generation are India and Kazakhstan.

Chapter I: Background

The project was implemented in a vast region of Eurasia that some 2.5 billion people call home. The nine countries covered by the project vary greatly in size and level of economic and social development, which is reflected in their electricity sectors.

Five of the countries covered by the project—Kazakhstan, Kyrgyzstan, Tajikistan, Ukraine, and Uzbekistan—are UNECE Member States. These countries became independent from the Soviet Union in 1992; today, they are considered by the United Nations as the countries with economies in transition. Their electricity sectors were built before or immediately after the Second World War, as part of the Soviet electrification programme. In 1992 they inherited an electricity infrastructure that was built through centralized planning using standardized generating technologies. The fuel for these plants was often sourced outside those countries (e.g., gas from Russia was used in Ukraine). The bulk of this huge surge in state-sponsored electricity investment was put into power plants that burned fossil fuels, and to a much lesser extent into nuclear power generation and hydropower.

All project countries except Ukraine are Member States of the Economic and Social Commission for Asia and the Pacific (UNESCAP). For this reason UNESCAP actively participated in project implementation. The four non-UNECE countries covered by the project—Afghanistan, China, India, and Mongolia—are considered Asian developing or emerging countries. After the Second World War and with the end of colonialism most of them built up their electricity sectors as an integral part of their economic development to escape from poverty and accelerate industrial development. From the 1950s through 1970s these countries built power plants that were not the most advanced technologically but were the least expensive option based on the domestically available fuel. During most of the past fifty years these countries have been investing heavily in the expansion of electricity generation, trying to keep up with surging demand. Lately, this trend has accelerated tremendously: according to the Global Warming Policy Foundation, China and India together are building three to four coal-fired power plants every week[3].

The substantial development of the fuel and electricity sectors was in most cases conducted by socialist or centralized economies. The power plants and utilities were state owned enterprises which depended on government budget financing and investment, pricing subsidies to plants and consumers, and fuel supplies. As said before, the greatest need in this initial period of building was to keep ahead of demand. Output was the overriding goal. Policy- and decision-makers were not concerned with market fundamentals or, least of all, with the profits of the sectors and returns to investors. Indeed, electric power was almost deemed to be a fundamental right and not a market commodity for which consumers—industrial or residential—had to pay the full cost. There was a great deal of waste in power plant investment and operation, as well as in use of electricity and energy in general. In the beginning state budgets were adequate and were dedicated to this massive developmental effort. Efficiency and ecological "cleanliness" and "sustainability" were not priorities at that time.

By the 1980s all project countries had already built up a substantial electric power infrastructure and generating capacity. Their electricity sectors, however, were still lagging behind demand growth for electricity. In most cases, the electricity sectors in these countries were huge industries commanding huge and growing amounts of capital, fuel, and resources.

The costs of maintaining these sectors—much less expanding them—had become onerous on national budgets, especially as economic growth began to take off in countries such as China and India. This pressure was increased when global fuel prices—especially oil—increased dramatically and security of energy supply became a serious determinant of national energy policy and further electricity development. Energy self-sufficiency—meaning the priority use of local fuels such as coal instead of costly imports—became an important criterion for further development of the electricity sectors. Increased economic development throughout Asian countries,

[3] http://www.thegwpf.org/china-india-building-4-coal-power-plants-week/

even in market-oriented ones, was constrained by the heavy burden of continuing investment in and expansion of the national electricity sectors.

At the same time, in the United States in the early 1980s, a major reform and deregulation of the electricity sector released large amounts of investment capital. A new investment wave was created by the movement for Independent Power Producers (IPP). These IPPs looked globally for opportunities to invest in new, latest technology electricity generation plants. The demand for foreign investment in new electricity generation capacity throughout Asia was enormous. The only requisite for the IPP movement was that the investors required market conditions for the electricity sector in the country they invested in and market investment returns from those plants they decided to build. There was very much an ideological motivation in the American drive to invest in IPP in developing countries: namely, that was to break the socialist industrial development model, to privatize state owned electricity enterprises, and to make a profit. In the 1980s and early 1990s, American companies, such as the AES Corporation, Destec Energy, Mission Energy, AEI Energy, Consolidated Electric Power Asia, and Enron, and Hong Kong-based companies such as Hopewell Holdings and CLP, began investing in electricity generation plants in, for example, India, China, Ukraine, and Kazakhstan.

Simultaneously to this wave of IPP investments in developing countries, two initiatives began which have shaped the electricity sector ever since. In the 1980s, as a result of regulatory pressures in the US, the clean coal research and development movement began. A major thrust of this research was to develop the technologies to reduce or remove altogether the carbon dioxide (CO_2) emissions from coal-fired power plants. This latter objective has become in itself a strong theme and development goal of power plant construction ever since, namely the reduction of the absolute levels of CO_2 emissions, whether through technologies such as clean coal, or replacing coal-fired power plants with cleaner gas-fired ones, or through adopting renewable non-fossil fuel energy resources, such as hydropower, solar, wind, or other low- or non-carbon emitting technologies.

The movement to reduce CO_2 emissions from power plants gained ground throughout the 1980s and 1990s, and found systematic, coordinated, global, and institutional structure and support in 1997 Kyoto Protocol. Ever since then there has been increasing worldwide efforts to develop cleaner electricity generation through the development and adoption of cleaner fossil fuel technologies and through the accelerated adoption of alternative non-fossil fuel burning electricity generation technologies. This movement also gave a strong impetus to the clean coal research and development movement, leading to the more rapid development and adoption of advanced combustion technologies, research in the technologies of carbon capture and storage (CCS), and research into technologies that removed carbon from the combustion stage altogether (such as use of syngas).

Both of these developments have had a major impact in electricity sector investment in the developing countries of Asia and the transition economy countries (former USSR) of Eurasia. They have put pressure on countries to adopt and build the new technologies, but adoption has come at a very high price. The new technologies are expensive and require engineering skills, materials, and equipment which are not available in most developing countries. And the economics of replacing fossil fuel-fired power plants—which provide the base-load power in most of the world—with non-fossil fuel ones is staggering. Especially if the developing countries possess within their borders extensive reserves of these fossil fuels, in particular coal and natural gas, which can cheaply and rapidly be exploited for energy generation.

For all these reasons the United Nations General Assembly, through its Development Account capacity-building programme, decided to support a project that would promote investments in advanced fossil fuel technologies in electricity generation as a way to encourage developing countries and countries with economies in transition to continue to develop their electricity sectors while keeping in mind the need to reduce overall CO_2 emissions. In particular, this project would promote adopting cleaner electricity technologies that would: use indigenous fuel resources; reduce significantly emissions; and mitigate the financial burden of continued expansion of the electricity sector. Further, recognizing the financial burden on national budgets, this project would promote in these developing countries foreign direct investment as a means of financing the future costs of adopting the new advanced technologies.

China, India, Ukraine, Kazakhstan, and Mongolia possess large reserves of coal, which they use as the principal fuel for electricity generation. Uzbekistan and Kazakhstan possess large natural gas reserves, while in Tajikistan and Afghanistan there are substantial but still potential natural gas resources. Electricity generation in Afghanistan, Kyrgyzstan and Tajikistan—all being resource-poor, landlocked mountainous countries—is dominated by hydropower. In nearly all project countries there is strong demand growth for electricity and thus continuing demand to steadily expand electricity generation capacity for many years to come. Furthermore, in China and India there is also an urgent need to reduce CO_2 emissions, particularly those from thermal power plants. In 2010, according to IEA estimates, China and India were the first and third CO_2 emitters in the world.

The project consisted of several components. In each country, a study on the country's electricity sector was written. This study of the "baseline" condition of the electricity sector as of 2010-2011 would include a survey of the role of coal in the country's overall energy balance, plans and efforts to expand the thermal electricity sector and to increase its efficiency and thus reduce CO_2 emissions, a review of the country's policies for future power development and the technologies that will be adopted to best reduce emissions and fulfil demand, and the country's policies regarding foreign direct investment in the electricity sector. Along with these reports, a number of regional and technical workshops were held, with the aim to promote foreign direct investment in advanced technologies for low-CO_2 electricity generation.

This report is a synthesis of findings of the "baseline" studies, drafted for each of the nine countries by national consultants between November 2011 and August 2012. As such, the report aims to clarify, summarize and interpret the experiences, policies, and plans for the future of each country in developing a thermal electricity sector using advanced technologies that reduce CO_2 emissions and exploit the countries' fossil fuel resources. It looks at the policies that have been put in place to encourage the investment in these technologies, from both domestic and foreign investors. It also looks at the remaining obstacles to adoption of the low carbon technologies and to foreign direct investment in them.

Chapter II: Electricity sector overview

Structure of electricity industry

The nine project countries range from large and high-growth countries with large and rapidly expanding electricity sectors such as China and India to smaller and relatively low-growth countries with small electricity sectors such as Tajikistan, Afghanistan, Mongolia, and Kyrgyzstan. In between are Kazakhstan, Ukraine, and Uzbekistan, which inherited planned economies, substantial electricity infrastructure, and sizeable fuel resources from centralized Soviet planning. (Of course Tajikistan, Kyrgyzstan, and to a certain extent Mongolia are also former socialist economies with infrastructures built primarily by Soviet centralized planning.)

In all project countries policy-makers have long recognized that overall economic growth is supported and driven by the development of electricity generation and distribution. In project countries with a socialist past, developing electricity sector was not only an economic imperative but also an ideological one. As Lenin put it, "communism is Soviet power plus the electrification of the whole country."

Today the electricity sector remains a key infrastructure needed to raise national wealth and make modern life possible. In the past decade the economic growth in project countries correlated with the growth of electricity generating capacity; when investment in new power plants lagged, economic growth slowed. For example, in the five years immediately before the 2008 financial crisis, China's electric generating capacity growth averaged 15.1 per cent, while Gross Domestic Product (GDP) average yearly growth was 11.9 per cent. From 2008, annual investment in new capacity fell and capacity growth averaged only 11.0 per cent, while annual GDP growth fell to 9.6 per cent. In India a similar correlation was noted.

The electricity sectors of all nine countries were built by state owned enterprises (SOEs). Only in the past fifteen or so years have some of the project countries begun either to privatize the sector or allow direct private investment in new power plants. Countries that opened the electricity sector to private investors include India, Kazakhstan, and Mongolia. China, in reforming the electricity industry in the 1990s, first corporatized the power SOEs and then allowed these new entities to offer shares to the public. Ukraine during the past four years has begun a program of privatization of the sector, although its privatization program has not completely sold all of its power companies and only sold the stakes to one Ukrainian private investor. In the remaining countries the electricity sector remains in state hands although there have been policy discussions to allow private ownership as an incentive for foreign direct investment.

Table 1 - Size of electricity sectors in the nine countries

		Capacity, GWe	Electricity Output, TWh	Capacity (load) factor
China	2011	984.6	4,690	54.4%
India	2012	231.4	877	43.3%
Ukraine	2011	53.3	194	41.5%
Uzbekistan	2009	12.4	50	46.1%
Afghanistan*	2009	1.03	0.75	20.8%
Kazakhstan	2010	19.1	84	50.0%
Tajikistan	2010	5.1	16	36.9%
Kyrgyzstan	2009	3.6	12	37.6%
Mongolia	2010	0.9	5	60.5%

Source: Baseline studies prepared by National Consultants, * For Afghanistan not including imports

Historically, with the exception of Norway and Switzerland, the electricity generation industry was built upon combustion of fossil fuels—primarily coal, but also natural gas and diesel fuel. This was so often the case because fossil fuels were abundant and cheap. Fossil fuel combustion technologies were also easily built, lent themselves to economies of scale, and did not have excessively expensive capital costs. Furthermore, in many countries the environmental pollution caused by fossil fuel combustion was not considered to be an excessive social cost. This has also been the experience of the project countries, especially those where there have been large, easily extracted coal resources such as in China, India, Mongolia, Kazakhstan, and Ukraine. The "baseload" generating capacity in these countries has been built on coal combustion, while in Uzbekistan, which has rich resources of natural gas, it has been built up on natural gas.

Six out of nine project countries generate electricity primarily from fossil fuels, while the other three (Afghanistan, Tajikistan, and Kyrgyzstan), having insufficient fossil fuel resources, rely heavily on hydropower. With the exception of Ukraine, nuclear power contributes a negligible share or nothing at all to electricity generation. Furthermore, plans to expand nuclear capacity in all of these countries (with the possible exception of China) appear to be undeveloped. Thermal power plants based on the combustion of fossil fuels will remain the baseload in the future in six project countries (China, India, Ukraine, Uzbekistan, Kazakhstan, and Mongolia). Indeed in four of these countries –China, India, Kazakhstan, and Mongolia—coal provides more than half of electricity generated.

Burning fossil fuels releases carbon dioxide into the atmosphere and thus contributes to climate change. The rapid growth of the thermal power sectors in China and India especially in the past two decades has elevated these two countries to the top ranks of global polluters and CO_2 emitters. This dire environmental problem has been the incentive for developing electricity generated from diversified, more environmental friendly sources, such as nuclear power, hydropower, and from renewable sources such as wind and solar power. The costs of these alternative sources for now are higher than the capital and fuel costs of using coal or natural gas so going forward there will be a constant debate over investment priorities.

While most investment in new capacity will continue going into thermal power plants in the coming years, there will be growth in new hydropower and renewables capacity. And in China, India, and possibly Kazakhstan, in the coming decade there will be new electricity generating capacity added from nuclear power.

Table 2 - Sources of commercial power generating capacity, percentage of the total

Data 2010	Coal	Nat. gas	Hydro	Nuclear	Renewable	Other
China	70.0	2.4	17.5	0.9	9.3	nm
India	56.2	9.0	19.1	2.3	12.3	1.1
Ukraine	40.8	22.2	8.5	25.9	2.2	0.4
Uzbekistan	4.3	82.3	11.7	nm	nm	1.7
Afghanistan	nm	9.5	62.5	nm	nm	28.0
Kazakhstan	66.1	22.1	11.4	nm	0.5	nm
Tajikistan	nm	nm	94.1	nm	nm	5.9
Kyrgyzstan	18.6	nm	80.2	nm	nm	1.4
Mongolia	97.0	nm	nm	nm	nm	3.0

Source: National baseline studies, for Afghanistan US DOE EIA; nm=no meaningful data

In the past ten years growth in both generating capacity and electricity output has been strong in both China and India. In this period China overcame the United States to become the largest electricity producer and consumer in the world. Its electricity sector is still growing fast. In the same decade India has beco
me the fifth largest electricity producer in the world. In other project countries, there has been little or no growth in electric generating capacity and only modest growth in electricity output. Investment in these countries has primarily gone to capital maintenance and upgrading of older thermal capacity. In Afghanistan there has actually been a loss in generating capacity because the insurgency there has diverted investment and sometimes even blocked the operations of the country's hydropower plants.

In China capacity has grown at an average of 12.5 per cent per year from 2002 to 2011, while output grew by 12.0 per cent a year. Most of that growth came from construction of coal-fired plants, as there has been a program to retire smaller, less efficient plants from the fleet and to replace them with larger, more efficient ones. In this program, since 2006 more than 70 GW of coal-fired capacity was taken out of service and replaced by 569 GW of more efficient coal plants, 65 per cent of which included supercritical and ultra-supercritical generating plants. It is built into the current development plan that China will need to grow its electricity generating capacity by 9.5 per cent a year in order to support the targeted GDP growth rates that the country needs and desires. Most of that growth will be in coal-fired capacity.

Hydropower in China also grew over this period, but it witnessed growth in a step-wise fashion as the Three Gorges Dam was finished and commissioned. For example, between the beginning of 2009 and the end of 2010 hydropower capacity grew by 22 per cent to 210 GW (the rated capacity of Three Gorges dam is 22.5 GW, but its effective operating capacity will be more likely around 18.3 GW because of seasonal fluctuations). Nuclear power capacity has grown more slowly in China in the past decade, but a new plan has put greater emphasis on nuclear power development. As of 2011, China's nuclear power capacity stood at 8.8 GW, but currently under construction or in the final approval processes more than 26 GW of new nuclear plants are under way. Nuclear power plants take much longer to design, to win approvals, to build and commission than thermal power plants do, even in China.

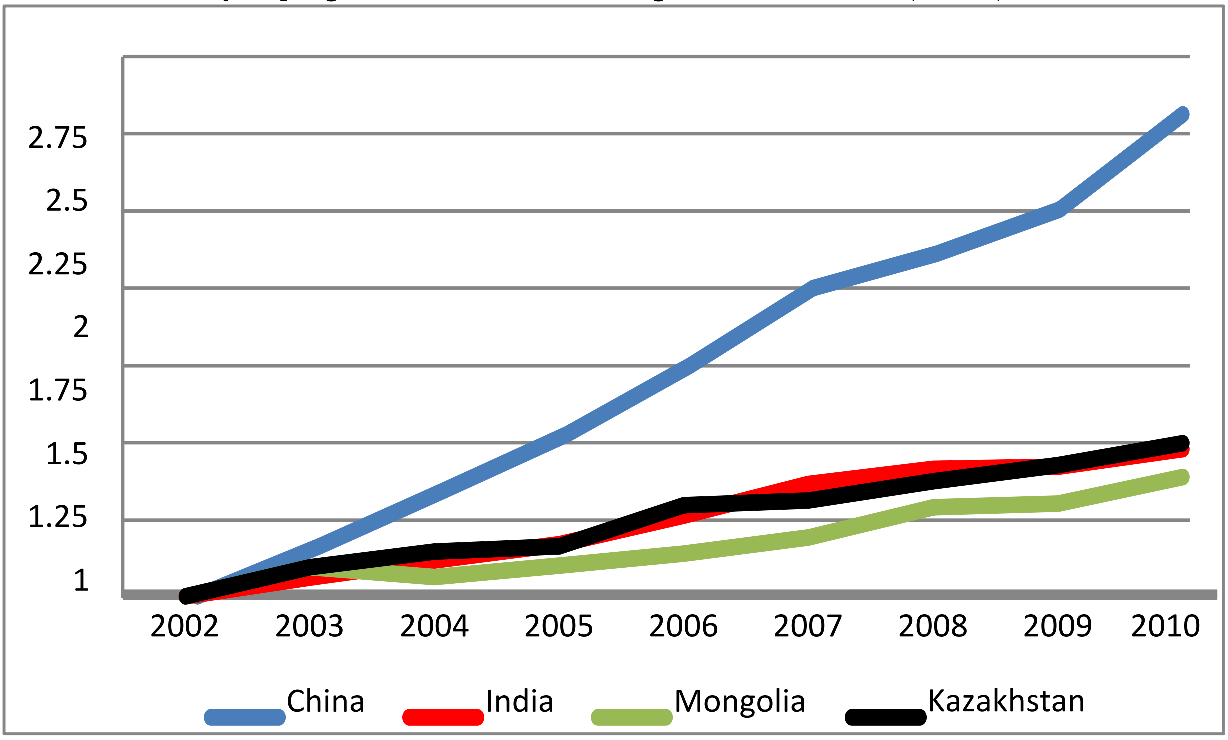
India has seen slower and more variable growth in electricity generating capacity and output over the ten years from 2002 to 2011. In this period, investments in new capacity grew by an average annual growth rate of 5.5 per cent, which resulted in a growth of annual electricity output of 4.7 per cent. While this appears to be a favourable growth rate, this rate was much slower than estimated electricity demand growth in the same period. The slower than hoped for growth rate is widely attributed to the increasing difficulties, delays, and bureaucratic hurdles faced by developers of power plants both in getting proposals approved and in construction. Nearly all of the new added capacity in this past decade was in thermal generation, mostly in coal-fired plants. At the present time there is a back-log of new projects totalling many GWs still awaiting approvals, construction, and completion. In recent years much of the investment in new thermal capacity has been in "captive" power plants. Captive electricity capacity grew by 57 per cent in the period 2002-2009, while publicly owned utilities only added 41 per cent of new capacity in the same time period.

Nearly all project countries that used to be part of the former Soviet Union began their independence in 1992 with inherited high energy intensities. This was compounded in the past two decades by periods of economic decline or slow economic growth. As a result, there have been low levels of new investment in electricity generation. Most new investment in the decade 2002-2011 in these countries went into upgrading or modernizing the legacy capacity that had been built in Soviet times, or went to electricity generation that was "captive" to industrial complexes, that is, electricity produced in a plant linked to and aimed for a single specific industrial site (such as a metallurgical plant) and not for the general wholesale market. This has been the experience especially of Kazakhstan. In Kazakhstan in the past decade, electricity output has grown by an average annual rate of 4.9 per cent from 58.2 TWh per year in 2002 to 83.8 TWh in 2011. This was achieved without a significant growth in generating capacity or with very little new capacity additions. Between 2003 and 2011, electricity generating capacity grew overall by only 3.1 per cent; nearly all of this came in the upgrading of existing coal-fired plants. Increased output of electricity resulted primarily from higher capacity utilization (a higher capacity factor) and more efficient operations of the coal-fired generators. There were some new additions to Kazakhstan's hydropower capacity in this period.

In Ukraine, Uzbekistan, and the countries dependent on hydropower—Kyrgyzstan, Tajikistan, and Afghanistan—there was virtually no investment in the electricity generating capacity during the period 2002-2011. Not surprisingly there was also very little growth in electricity generated. This is not a sustainable situation as the facilities get older and run less efficiently as they suffer from wear and tear.

Mongolia was in the period 2002-2010, like Kazakhstan, able to raise its electricity output with no increase in its generating capacity. As there was strong demand growth in this period, the power plants ran at higher factor capacity and electricity production grew at 4.8 per cent per year, while capacity remained at around 855 MWs throughout the decade.

Chart 1 – Electricity output growth in China, India, Mongolia and Kazakhstan (2002=1)



Coal's share of the electricity output is often even higher than its share of the generating capacity (see Table 2 above). This is because coal-fired plants are usually run at higher capacity factor (or capacity utilization rates, see Table 1) than natural gas plants (which are often run as peaking power plants[4]) and hydroelectric stations which often fall prey to fluctuating or seasonal water levels. So in China, while coal-fired plants comprise 70.0 per cent of the installed capacity, in 2008 according to the IEA, coal burning supplied 79.1 per cent of the net electricity produced in the country. In India coal burning plants produced 68.6 per cent in 2009 while the coal-fired plant capacity was only 56.2 per cent, while in Kazakhstan coal produced 74 per cent of net electricity in 2009 while representing 66.1 per cent of capacity. By contrast, in Ukraine, the capacity factor of coal is lower than that of the nuclear power plants. Although the thermal installed generating capacity amounted to 62.2 per cent in 2010, these plants produced a bit less than 45 per cent of Ukraine's net electricity, while nuclear, with 25 per cent of the fixed capacity, produced nearly 50 per cent of electricity.

Ownership of the electricity sector

In all project countries, the electricity sector was developed, built, and operated by the state. The objective was to build as rapidly as possible the infrastructure needed to support rapid economic development. This effort took a global view where the state built the entire system, from fuel sources, to generating units, from transmission and distribution networks to transformers and local heating and electricity distribution networks. In the process, huge bureaucracies were also built up with very large fixed costs and considerable political clout. Neither economic nor energy efficiencies were high priorities; competition and market forces were not considered at all.
By the 1980s as world fuel prices rose to historic highs, the cost of supporting such huge industrial sectors—much less the costs of further developing the sector and building new infrastructure—became increasingly unsupportable. The state owned electrical utility was failing badly in its primary task: producing and distributing enough electricity to satisfy growing demand. There was tremendous pressure to introduce competition and market principles into the sector. The first step was to corporatize the electric utilities, effectively breaking

[4] Peaking power plants are power plants that run only when there is a high demand, known as the peak demand.

operating units out of the governing energy or electricity ministries. Once this was completed, the ministries could more accurately measure the economics of the industry—the capital, fuel, and operating costs versus the sales revenues and returns, if any—and also have better means of calculating what the electricity and heating tariffs should be for the consumers. Generally, this initial step of corporatization was not followed in the nuclear power and hydropower segments of the industry which have remained mainly in the hands of the state.

Still, in the thirty or so years since 1980, it was clear that the state-owned electricity generation, whether corporatized or not, were not delivering the required goods. Competition and market principles needed to be introduced into the system, and a means of introducing foreign investment and financing needed to be found. In the 1990s the electricity generation sectors in India, then China began to be privatized.

India led the way with the reforms of 1991. Ironically, India has developed its electricity industry initially out of private investment. The Calcutta Power Company (now CESC Ltd) was founded in 1897, Tata Power not long afterwards. Only after independence in 1947 did the central governments nationalize the sector, although it did not take over all of the privately owned generators and utilities. The socialist principles of early India–inspired by the intensive heavy industrialization program of the Soviet Union—took over hydropower, transmission, and thermal generation and built new facilities widely. Initially centralized in the Federal government, the ownership of industry was then divided between the Central and local authorities with the foundation of the state owned and run State Energy Boards (SEBs) in each regional Indian state. The SEBs were especially profligate and politicized, and although they still operate, they are financially incapable of growing the sector or meeting electricity demand growth. At the same time as the establishment of the SEBs, India set up a national power generation company, NTPC, which now remains the largest single electricity generation operator in India providing 27 per cent of India's electricity output from 19 per cent of its installed capacity. It controls 29 power plants (including joint ventures) with 39.2 GW of capacity located in all parts of the country, and has the largest future construction plans of any group. Since 2009 the state retains 84.5 per cent stake, having offered the balance of shares on the Bombay Stock Exchange. With the 1991 reform, the central government of India allowed for private ownership (independent power producers or IPPs) and foreign investment into the generation sector (including into hydro but not in nuclear power).

The first two foreign investors from 1992 were Enron and AES, both American corporations. The 1991 reform also opened the door to Indian private entrepreneurs to new investment in privately held generation companies. But after Enron's failures, foreign investment has remained insignificant and has not contributed much to India's financing needs or electricity demand. Further reform in 2003, the Electricity Act, stimulated private (local) investment, and power construction became major arms of the biggest entrepreneurial Indian industrial groups. Private firms like the Adani Power, Reliance Infrastructure, Lanco, Tata Power, and Essar Power have invested heavily and still have very ambitious future building plans. For the first time just recently, India's central power commission has allowed private investment into the transmission sector. But still the sector is predominated by the state-owned enterprises (SOEs); state ownership, regulation, and control actually impedes investment. Many of the electricity generating companies cannot run profitably, and further reform is needed.

In China, the first reforms occurred in the 2002 when the monopoly State Power Corporation was broken up into eleven different SOEs; among them, in power generation, five major power corporations were set up on regional lines. Likewise, there are regionally owned provincial power companies. Hydropower and nuclear power remained wholly central state owned. Once corporatized, these five regional leaders—Chinese Datang Corporation, China Guodian Corporation, China Huadian Group, China Huaneng Group, and China Power Investment Corporation (CPI)—subsequently offered minority stakes for sale to public stock markets. Many of the secondary SOEs—such as China Shenhua Energy Company, or China Resources Power Holdings—and some of the provincial companies like the operator of the Three Gorges Dam hydropower plant, have also offered shares on the markets in Shanghai, Hong Kong, or even New York.

The degree of state ownership in China remains quite high, by some estimates as high as 75 to 80 per cent. There are no wholly privately-owned, electricity generating companies in China with the exception of two Hong Kong (pre-1997 origins) based utilities; even foreign electricity investments have been in joint venture with

SOEs or provincial-owned companies. The state –either central or provincial—dictates electricity prices, the production amount, construction financing, and where to deliver their output leaving very little room for market functioning.

Table 3 - Ownership of the electricity sector, percentage of the total

	Central state	Indirect or regional/state	Free float	Private companies
China	52	18	22	8
India	32	42		27
Ukraine	35		3	62
Uzbekistan	100			
Afghanistan	100			
Kazakhstan *		40		60
Tajikistan	100			
Kyrgyzstan	93			6
Mongolia	80	20		

* Mostly owned by Samruk Energo, a state owned sovereign wealth fund

The major reforms of the electricity sector in Kazakhstan began in laws enacted in 1995 and 1997. These specifically aimed at "de-nationalizing" the generating part of the industry, set up the national transmission monopoly, and began the process of market-based determination of electricity prices. At the time of these reforms, foreign investors, most notably AES, came into the country to repair and restore a suffering industry. Most of the country's power plants were transferred to private companies, many of them foreign. Most of the country's capacity effectively was captive plants that were associated with the large coal mines or large industrial/mining complexes. But not all of the ownership ended in private company hands. State ownership of a fifth of national generation (both thermal and hydropower) as well as utility and distribution assets were consolidated in 2008-2010 into the ownership of an operating company which is a subsidiary of the state national welfare fund (sovereign fund), called Samruk Energo. In 2010, the company bought 50 per cent of the country's largest power plant, Ekibastuz 1, which although now much diminished has a nameplate capacity of 4,000 MW. Samruk Energo, now with 40 per cent ownership of all generating capacity has become the single largest electricity company in the country and is taking the lead in developing new electricity capacity in projects planned through 2030. It is unclear as Samruk Energo develops and launches new generating assets whether it will privatize them in the future. In the past few years, many of the original foreign investors in Kazakh electricity assets have withdrawn from the country.

Ukraine was rather slower at liberalizing its electricity sector. Corporatization occurred in the late 1990s, but did not create profitable or financially sound ventures. The state completely controlled the industry and its profitability until quite recently. A few foreign investors, including AES, entered the country in the late 1990s but found the economic conditions too difficult to justify much investment. Some of these electricity corporations offered very small stakes on the Kiev stock market in the 2000s. Recognizing the desperate need to reform the industry and bring more financial capability into the industry, in 2009 Ukraine announced that it would begin privatization auctions of the leading thermal power companies. The auctions were not well attended—effectively only one bidder participated and the assets were sold at knockdown prices in what appeared to be insider deals—and only one private, closely-held Ukrainian company, DTek, won the largest stakes in four of the principal electricity generators. For all intents and purposes it looks like the electricity sector has moved from a state owned monopoly to a privately owned monopoly, although there are two SOEs left to be auctioned.

The other project countries have not reformed their electricity sectors which are owned and operated by the state. Of these only Mongolia has attracted private foreign investment in generating capacity and this investment has been entirely in captive power plants linked to major mining investments.

Chapter III: Fossil fuels in electricity generation

Resources: Coal

Historically, electricity generating plants were built where fossil fuels were readily available, reliably delivered, cheap and easy to handle. This has over time usually meant coal, although oil was sometimes used (as in the Persian Gulf states), and latterly natural gas in countries having abundant gas reserves. An important, but often unstated criterion in both developed and developing countries was security of energy supply: it is deemed better to rely on domestic resources of fuel for electricity than to use interruptible sources which have to be imported. It has only been in the past three decades that the need to control and reduce pollution and then CO_2 emissions has become an important criterion in building electricity generation plants.

This progression has occurred in the countries cover by the projects well as elsewhere; indeed significant power plants have often been built at or near the coal mines as they were developed. Often the experience has been that it is more economical to build at the mine head and transmit electricity than it has been to build in the urban or industrial centres and build up transport infrastructure to deliver the fuels. Economically this has been by far the least expensive means of building up an electricity sector quickly; cheaper than the alternative power sources such as hydropower or nuclear power generation, and usually cheaper than importing fuels from more expensive world markets.

But to build the foundation of your energy development strategy on the domestic availability of one fuel source requires that there exist an adequate resource base for the long term. In our sample group of countries only five countries have possessed such long term fuel resources and reserves—China, India, Kazakhstan, Mongolia, and Ukraine—and in all cases the "foundation" fuel has been coal. Not surprisingly, coal in these countries has provided and will continue to provide the fuel for current and future baseload electricity.

Table 4 - Coal reserves and production

	Proven reserves billion tons	Annual Production million tons	Year of data, source	Reserves/Production ratio, years
China	114.5	2,445.2	2009, IEA	46
India	60.6	623.7	2009, IEA	97
Ukraine	33.9	51.0	2010	664
Uzbekistan	1.9	3.6	2010	522
Afghanistan	0.06	0.1	2005	60
Kazakhstan*	46.6	104.3	2011	447
Tajikistan	0.3	0.2	2010	nm
Kyrgyzstan*	1.3	0.1	2010	nm
Mongolia*	12.2	4.9	2010	2,490

Sources: For reserves World Energy Council, unless * where national baseline study is the source. For production the national baseline studies are the principal sources, unless indicated differently in the column for year and source.

A key indicator for energy security is the reserves to production ratio, which is expressed in years remaining for production at current levels. But the picture is surprising for our group of countries. China, the world's biggest coal producer and with the world's third biggest reserves, has a R/P ratio of only 46 years—not even two generations for a power plant, not a long future. Mongolia with a small population and an underdeveloped coal mining sector has almost 2,500 years of coal supply, meaning that it has tremendous capacity to mine and export coal. India's coal future looks into the next century.

In the study group the countries with the most secure coal future are those countries of the former Soviet Union primarily in Central Asia; Ukraine, Uzbekistan, and Kazakhstan. But even here there is a misleading situation for in Uzbekistan the coal reserves listed are deep, difficult to mine and have low caloric value so that the industry is underdeveloped by policy. Although mining has steadily been conducted in Uzbekistan at Angren since the 1940s, Uzbek coal reserves were during Soviet times dismissed as an uneconomic resource. At Angren the reserves serve as the basis for the world's longest running underground coal gasification program. In the near future they may be used as fuel for thermal power plants to be converted from natural gas to coal in Angren.

China as the world's largest producer and consumer of coal, most of which goes to electricity generation, has committed to continued development of its electricity industry based on coal. This is primarily for security of energy supply reasons-- and related to this is the lower cost of using domestic coal as opposed to using imported fuels—but also now that the coal industry has grown to the world's largest and a major employer, there is huge political pressure to remain committed to the support and expansion of the coal industry. This latter force is an important policy consideration in the Indian, Ukrainian, and Kazakh coal industries.

China, India, Kazakhstan, Ukraine, and Mongolia have adopted policies where their future electricity development plans rely primarily on the foundation of domestic coal consumption. Uzbekistan has indicated it would like to diversify its fuel use in electricity generation, using more of its locally mined coal in place of natural gas, but it does not have the investment resources to implement this policy.

In China, India, and Ukraine there are specific problems with a "coal first" policy. In all of these countries, the domestic coal industries cannot keep up with demand growth. In China and India, especially, there is a growing deficit between local supplies and the domestic electricity sector demand for thermal coal. In Ukraine and India there are in addition serious problems of low calorific coal resources which are high in ash, moisture, and other impurities. Likewise in Ukraine and India, coal mining is becoming more and more difficult and costly. In Ukraine's case it is the depth of the mines; in India's it is access to mining properties for open cast mining, as well as local opposition to mining. Likewise in India the delivery of prepared coal to power plants is unreliable as the rail system cannot cope; it's an intractable problem that will only get worse in the future. In only the past five years both India and China—despite their official policies—have begun to import coal to compensate for the growing deficit of domestic supplies. The Indian state coal company (CIL) forecasts that in 2012/13 it will need to import 11 per cent of its targeted quota of 392 million tons which it must supply the power industry. Private electricity companies are already importing large volumes outside the state supply quota. Import of coal now exceeds 15 per cent of consumption. Despite the problems with its industry, India projects that its domestic coal use will make it the second largest consumer of coal by 2020 (ahead of the US) as well as the largest importer of coal.

In Tajikistan, Afghanistan, and Uzbekistan there are estimated to be significant unexplored coal resources. In Tajikistan, for example, the government resources department estimates potential resources of up to 5 billion tons, which, if found and developed, would more than suffice the country's electricity needs. There is policy interest in supporting the exploration and development of these resources and developing a coal industry, but investment is lacking in all of these countries, and very little new investment in coal mining is expected in the future. India has expressed an interest in exploring Afghanistan's coal basins.

At the present time only Uzbekistan and China produce synthetic gas (syngas) from their coal resources. Uzbekistan's is the 60 year old project at Angren where an Australian company has recently bought control and may invest in its expansion. China has several coal-to-syngas as well as coal –to-liquids projects, including ones with Australian investors.

China has also made a major commitment to a large scale demonstration project to commercialize the technology called Integrated Coal Gasification Combined Cycle based in Tianjin. This project, called GreenGen continues to get strong support from the Chinese government. It has a pilot 250 MW plant already up and running for the past seven years. It has attracted some foreign investment.

Although there has been much discussion about coalbed methane programs around the world, in our group only China is actively pursuing this technology. China is reputed to have the largest resource base of coalbed methane. One program in particular has begun in Xinjiang led by an Australian investor, the World Bank is supporting another program in Shanxi, and the China National Offshore Oil Corporation (CNOOC) has just this year signed a major contract for exploration for coalbed methane in Shanxi, Shaanxi and seven other provinces of China where coal is plentiful.

Resources: Natural gas

Natural gas in recent decades has become the fossil fuel of choice for electricity generation because of its “cleaning burning” characteristics. Of course it has to be readily available and a delivery infrastructure has to be in place in order to base a power plant on gas. But in countries where natural gas has been available and relatively cheap—such as in Russia, the U.K., Canada, and the United States—it has displaced coal in electricity generation. In the countries cover by the project, natural gas is the primary fuel for electricity generation only in Uzbekistan, although it could supply a significant share of future electricity generation in Kazakhstan as well where most of the country’s reserves are being slated for export. In Ukraine, which has insufficient natural gas reserves and which in the past relied for the overwhelming share of its energy on Russian gas imports, the country’s energy planners have worked to replace gas fired power plants with coal-fired plants because of pressing security of supply issues and the excessive burden on the balance of payments from Russian imports.

Of the nine countries, China has the largest proved reserves of gas with an estimated 3 trillion cubic meters (tcm), but for its voracious energy appetite this volume of reserves is insufficient on which to base electricity development and it is prohibitively expensive to build the needed transport infrastructure is with such a small resource base. Kazakhstan has a relatively large resource of natural gas with proved reserves of 1.9 tcm located primarily in the far west of the country. It should be promoting future electricity development using advanced technology gas turbines, but at the same time it needs to connect the western electricity transmission grid with the rest of the country.

Table 5 - Natural gas reserves and production

	Proven reserves, trillion cubic meters	Annual production, billion cubic meters	Year of data, Source of data	Reserves production ratio, years
China	3.1	102.5	2011, BP Statistical Review	30
India	1.2	46.1	2011, BP Statistical Review	26
Ukraine	0.9	18.2	2011, BP Statistical Review	49
Uzbekistan	1.6	57.0	2011, BP Statistical Review	28
Afghanistan	0.1	0.03	2009, CIA World Fact Book	5
Kazakhstan	1.9*	19.3	2011, BP Statistical Review	98
Tajikistan	0.01	nm	not available	nm
Kyrgyzstan	0.01	nm	na	nm
Mongolia	nm	nm	na	nm

* The baseline study indicates 3.5 tcm of recoverable gas reserves for Kazakhstan which would give an R/P ratio of 181 years.

Only Uzbekistan in our study group has established the policy primacy for natural gas as the main source of future electricity generation. Natural gas fired generators amount to more than 82 per cent of Uzbekistan’s total capacity, with hydropower supplying the bulk of the remaining capacity. But nearly all of the gas turbines are more than 20 years old and are in need of replacement with advanced gas turbines in order to achieve higher efficiencies. Several units (435 MW) of the Navoi power plant are being modernized with Mitsubishi advanced gas turbines.

Although natural gas is not the foundation fossil fuel for China and India both countries have permitted new power plant investment based on advanced natural gas turbines. China in specific is preparing plans to import large volumes natural gas both through pipeline sources and LNG especially for electricity generation as a deliberate policy of reducing CO_2 emissions and other pollutants. Gas will be sourced from Central Asia, LNG, and perhaps from Russia. In India the initiative to develop new gas fired power plants is largely coming from the private developers who are aware that the reliability of coal supply is low and will only get worse in the future. They are planning new advanced gas turbine plants based on imported LNG, but face import restrictions from the Indian government which is already having serious balance of payments difficulties. Current LNG receiving facilities are being expanded and new ones are being planned around the country. Supply issues will remain a constraint on the extensive or rapid development of gas-fired plants in the coming decade.

With regards to proven fossil fuel reserves, Kazakhstan is the one country in our group that could adopt natural gas as a primary source of future electricity generating capacity. It has chosen not to do so in favour of continued reliance on coal. Part of the reason stems from the location of the gas reserves in the far west of the country and that this part of the country is not connected to the national transmission grid. So it is not likely that advanced gas turbines will replace coal-fired plants in Kazakhstan as a means of mitigating CO_2 emissions or in increasing energy efficiency.

In China, the policy has moved in favour of natural gas, even though its reserves position does not suggest a secure energy future based on natural gas. China is replacing coal-fired plant with gas fired plant based on gas imports and it has an aggressive program of seeking out gas and LNG resources from a diversified number of sources including Kazakhstan, Turkmenistan, Russia, east Africa, Australia, and Qatar.

The natural gas situation in China, India, and Ukraine could dramatically change in the coming years as new advanced gas production technologies—specifically shale gas fracturing and coalbed methane production--begin to be applied. Substantial conventional gas reserves could also yet be found in Afghanistan and Tajikistan which are under-explored. In Afghanistan alone there is historical evidence that large resources exist in the north of the country, as up until the 1970s the country was producing 30 bcm a year of natural gas.

Shale gas is a relatively new technology in the world gas market, yet it has scarcely been introduced in any of the nine countries. The U.S. EIA in 2011 released a report which outlined the possible recoverable resources of shale gas in the world outside the U.S. where it is now a well-established technology and a major contributor to U.S. natural gas production. Shale gas is being actively explored for in China, which is forecast to sit on the largest shale gas resource base in the world and expects to be producing 6.5 bcm a year in 2015. Ukraine only this year gave out major exploration contracts, and India has announced that it will aim to award shale gas exploration concessions beginning in December 2013.

China and Ukraine have both acknowledged the need for foreign private investment in the coming decade, especially from those American firms with the greatest technological expertise and experience. In China and Ukraine, the large multinational oil majors, such as Chevron, Shell, and ExxonMobil, have signed up to explore for shale gas and will begin work next year. They have signed up contracts worth billions of dollars a year. But although the resource base in China, India and Ukraine are sizeable, it will be some years before they are turned into proved reserves and significant production begins. This is because it takes many years of trial and error drilling to determine the appropriate combination of hydro fracture liquids, rock matrix, and correct drilling depths and pressures to be able to reliably produce from shale formations. In the U.S. this took more than a decade.

Table 6 - Shale gas resources from U.S. EIA 2011 report

	Estimated resources tcm
U.S.A.	70.2
China	36.0
India	1.8
Ukraine*	1.2

* - Ukraine's geological agency estimates resources of 3.5 tcm

Coalbed methane (cbm) is another advanced fossil fuel that if produced would greatly mitigate the emission of greenhouse gases. Methane is one of the most destructive of greenhouse gases (it is 21 times more effective as a greenhouse gas then CO_2) and whatever methane emissions can be reduced would be greatly beneficial besides adding resources to the availability of natural gas for electricity generation. Although Ukraine had a small program for cbm in the 1990s led by foreign investors along with technical aid from the U.S., its program has mostly stopped. As Ukraine's coal mining is mostly in deep shafts, this method of extraction of hydrocarbons could be eventually the best way to reach deep, hard to extract, and thin coal seams. Ukraine hopes to restart the cbm program with foreign investments as an adjunct to its shale gas program.

Coalbed methane resources in Kazakhstan are estimated by research institutes in that country to be in excess of 1 trillion cubic meters, most of that situated in the Karaganda coal basin. These estimates also project that up to 3 bcm a year of cbm could be reasonably produced from these resources. In recent years, production (and use) of cbm was running at about 25 million cubic metres a year. There have been minor investments by foreign companies in the past decade to exploit this resource.

China has in the past decade launched the most aggressive and extensive program of cbm exploration and exploitation and currently produces 1.5 bcm a year of cbm. Its target for cbm production is 10 bcm a year in 2015 and 60 bcm a year by 2020, but this looks highly ambitious. Foreign investors are stuck in the exploratory phase of cbm here because China does not yet have an adequate regulatory regime for the production and marketing of cbm output. Unlike shale gas which has attracted the largest multinational oil companies, cbm has attracted only small, very entrepreneurial companies from Australia, Hong Kong, and the U.K. In India, Essar Energy, Reliance Energy, GAIL, and ONGC have begun programs and have acquired extensive exploration acreage in several carboniferous states around the country, but there is a minimal commercial production of only 84 million cubic meters a year today. The country's hydrocarbons directorate estimates cbm resources of 4.3 tcm, a level greater than India's current natural gas reserves. But in the coming decade cbm contribution to India's gas balance will remain negligible. The country's coal monopoly now forecasts production of only 1.5 bcm a year by 2016-17; originally targets were for 2.7 bcm by 2015. Foreign investors have shown little interest to date in India's potential.

CO_2 emissions from fossil fuels combustion

Emissions of CO_2 from fossil fuel combustion for electricity generation are the largest single source of manmade CO_2 emissions. Globally according to IEA data, CO_2 attributable to fossil fuel combustion for electricity generation comprises some 28 per cent of total CO_2 emissions of 28,997 million tons from all sources. In the nine countries the electricity output has grown rapidly in the past decade and a half, in China and India especially, but even more so have CO_2 emissions. As of 2009, according to the IEA, China, with over 6.8 billion tons of emissions, was the largest emitter of CO_2 with almost 24 per cent of the total, more even than the US. India with almost 1.6 billion tons was the world's third largest emitter. In our group of countries, it is coal combustion for electricity generation that is the largest source of CO_2, comprising almost 80 per cent of these emissions.

Table 7 - CO_2 emissions from fossil fuel combustion in 2009, million tons per year

	Total CO_2 emissions	CO_2 from fossil fuel combustion	CO_2 from electricity and electric/heat generation
China	6,877	4,476	3,324
India	1,586	889	856
Ukraine	256	165	112
Uzbekistan	112	78	36
Afghanistan*	0.9		0.7
Kazakhstan	189	187	90
Tajikistan	3	1.7	0.5
Kyrgyzstan	7	1.4	1.1
Mongolia	12		7.4

Source: 2011 CO2 Emissions from fossil fuel combustion, IEA. * - Afghanistan data from 2007 from U.S. EIA estimates. China data include Hong Kong

India has the lowest per capita CO_2 emissions of our study group, but it has the highest percentage, 54 per cent, of CO_2 coming from electricity generation in our study group. In the 20 years up to 2009 it had the second highest growth rate of CO_2 from fossil fuel combustion, nearly 172 per cent between 1990 and 2009; however this growth rate has slowed in the past ten years. By far the largest growth has come from fossil fuel combustion used for electricity generation, while transport remains a much smaller contributor.

China on the other hand has seen total CO_2 emissions grow by about 207 per cent between 1990 and 2009, with a strongly accelerating growth in the first decade of the 21st century. China contributes 48 per cent of its total CO_2 from fossil fuel combustion for electricity/heat generation; like India, transport contributes less than electric generation. More than 80 per cent of these CO_2 emissions come from coal use. Because of the especially rapid rate of growth of electricity output and CO_2 emissions from coal burning, China has in quite recent years accelerated its program of both coal substitution and increasing coal combustion efficiency in the electricity sector.

While both China and India have demonstrated rapid growth in CO_2 emissions linked directly to the strong growth in electricity generation in the past two decades, in the remainder of the countries in our group over the twenty year period of 1990 through 2009, there has been an overall decline in CO_2 emissions. This has largely been attributed to an overall decline in electricity generation and fossil fuel combustion in this period. However, in four of these countries –Kazakhstan, Kyrgyzstan, Tajikistan, and Mongolia—the decline in CO_2 emissions was reversed in the past decade as electricity generation began to recover and grow again from its lowest levels achieved in the 1990s. Only in Ukraine and Uzbekistan have CO_2 continued to decline from 1990 levels throughout the ten years 2000 to 2009.

Table 8 - CO_2 emissions per unit of electricity produced, 2009

	grams CO_2/kWh total	grams CO_2/kWh from coal	grams CO_2/kWh from natural gas
China	743	900	431
India	951	1,261°	488
Ukraine	374	1,051	295
Uzbekistan	461	1,121	491
Afghanistan*	932	-	-
Kazakhstan	480	488	574
Tajikistan	29	-	378
Kyrgyzstan	81	439	214
Mongolia	546	541	-
by comparison			
U.S.	508	907	387
E.U. 27	339	814	323
Russia	317	596	315

Source: IEA, 2011 CO2 emissions from fossil fuel combustion. * Afghanistan data from US EIA. °India reported in 2010 that coal and lignite plants emitted 1.1 kg/kWh and some older plants emitted as much as 2 kg/kWh.

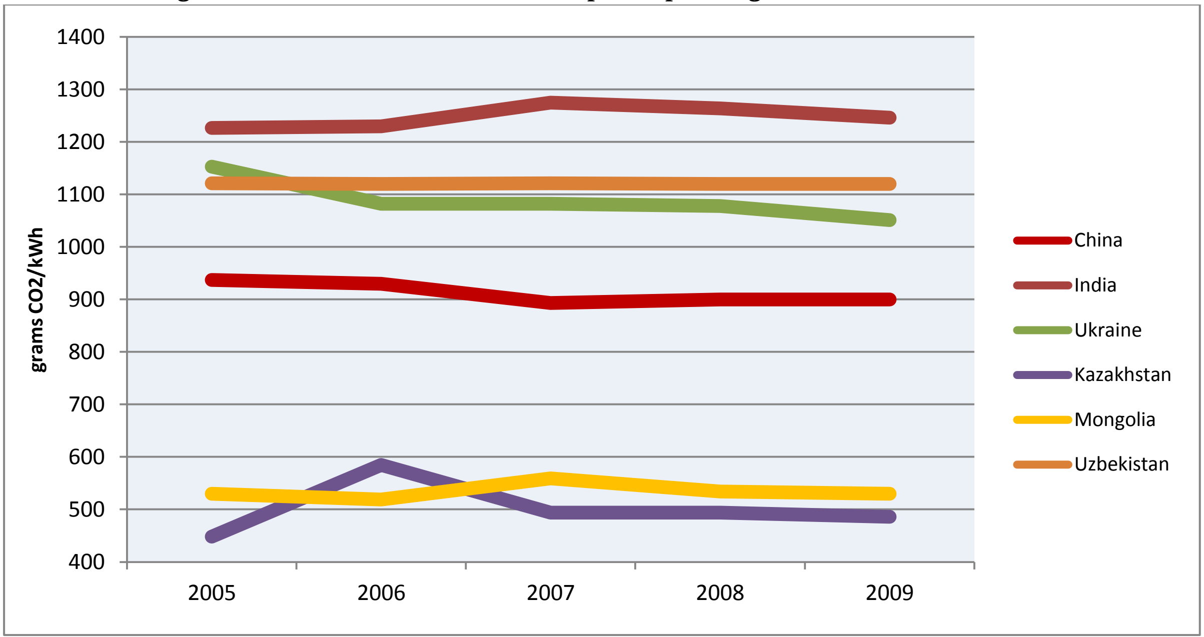
From this table it is clear that India, Ukraine, and Uzbekistan run a "dirtier" generation sector, especially in the coal-fired plants. This is of course due to the low quality coal and lignite used in these countries and the age and condition of the plants themselves; coal that is high in ash, moisture, and other impurities and having low gross calorific content. India's CEA reported that total CO_2 emissions for the electricity generating fleet in 2007-08 were calculated to be 810 grams/kWh, which had been the average for much of that decade. The IEA reports on standards it uses for CO_2 emissions for fossil fuel emissions. The standards are for high calorific coal with minimal amounts of ash and other impurities. Samples of CO_2 emissions it uses based on 2007 and 2009 data are given in the following table:

Table 9 - Implied emission factors for select fossil fuels in power plant combustion

	grams CO_2 per kWh
Brown coal (bituminous)	830
Sub-bituminous	920
Lignite	940
Natural gas	370
Diesel	650

As a result of both the high absolute levels of CO_2 emissions from coal combustion and the rapid growth in coal use and emissions, both China and India have for their latest development programs adopted specific measures to reduce CO_2 emissions. China aims to, by and large, retire its standard, small capacity (<160MW), low efficiency coal burning fleet with much larger (600MW and up to 1,000MW) advanced technology, supercritical and ultra-supercritical power generators. At the same time it aims to increase the share of non-fossil fuel technologies such as nuclear, wind, solar, and hydropower in the total mix of power sources. This program started in the first decade of the 21st century as China quickly adopted supercritical pulverized coal steam generators. It was able to reduce its CO_2 intensity by replacing a small portion of its old coal capacity with the new technologies. And continuing with these policies for future plans, China has announced a program to greatly increase natural gas fired power, especially in the large cities of eastern China, in place of coal burning plants, even if that requires importing LNG. Finally in a bid to reduce CO_2 emissions before combustion, China is highly committed to the ICGCC technology which relies on clean burning syngas. China is also investing in carbon capture and storage as yet another measure to reduce CO_2 emissions, although this is unlikely to yield much improvement in the coming ten years.

Chart 2 - Change in CO_2 emissions from coal-fired power plants, gram CO_2/kWh



Source: IEA: CO_2 emissions from Fossil Fuel Combustion, 2011

India is moving slower along the similar lines. In its latest Five-Year development plant (2012-2017), it has included incentives to power plant developers to build supercritical, large capacity new coal-fired plants. In the next Five-Year plan, all new coal burning plants will have to be either supercritical or ultra-supercritical technologies. But official policy is still trying to promote coal over all other “alternative” fuels or renewable sources. There are some incentives for solar power, but little for wind or none for gas fired plants. India has difficulties in further developing hydropower because of water shortages, and it has long avoided nuclear power development because of the cost and the shortage of domestic uranium resources.

While Ukraine has introduced some incentives for adopting alternative energy sources which produce less CO_2 than coal combustion, none of Ukraine, Kazakhstan, Mongolia, or Uzbekistan has introduced policies, targets, nor specific incentives to convert their coal burning fleets to advanced technology fossil fuel combustion power plants. This means that output of CO_2 in these countries will continue to rise both in absolute volumes and in relative volumes per kWh in the coming decade.

Chapter IV: Advanced fossil fuel technologies for cleaner electricity generation

Advanced technologies for using fossil fuels in electricity generation have evolved over the past decades primarily as a means of achieving higher fuel energy efficiency through burning of these fuels at higher temperatures. An important goal in recent years has also been to reduce CO_2 emissions from power plants, which historically have been the biggest single source of man-made CO_2, as part of the global program of mitigating climate change.

In many developed countries, there have even been calls to entirely abandon fossil fuels, and especially coal, as a source of electricity. But with the abundance of fossil fuel resources (and especially in many countries the abundance of coal resources) and their high energy content and relatively low cost, these calls make no economic sense, either in the immediate or more distant future. Most research has focused on new technologies which either increase energy efficiency of burning fossil fuels and reducing CO_2 emissions, or attempt to capture CO_2 before or after the combustion. There is an inverse correlation between operating a fossil fuel fired power generator at higher efficiency and reducing the generator's CO_2 emissions. The general rule is that for each 1 per cent increase in efficiency of a coal burning power plant there is 2-3 per cent reduction of CO_2 emissions. In general the greater the conversion and capture of heat generated from the fuel burned, the higher the thermal efficiency of the plant. This is why combined cycle and combined heat and power plants regularly generate power at higher efficiencies.

There has been steady technological innovation over the past two decades to increase the efficiency of fossil fuel burning plants. There have been improvements in high pressure, high capacity gas turbines which makes gas the cleanest and most efficient fuel. And there has been intense research in the Clean Coal initiative to increase the efficiency of burning coal and reduce or even eliminate CO_2 emissions.

The advanced technologies for electricity generation from fossil fuels which currently offer the most promise for delivering higher efficiencies and lower carbon emissions are:

- Combined Cycle Gas Turbines, (CCGT) now well understood and widely applied throughout the world and is primarily fuelled by natural gas
- Combined Heat and Power gas turbines, CHP, which have long been in service in many parts of the world and usually are also natural gas fuelled
- Supercritical pulverized coal burning steam generators (SCPC)used to drive power turbines, which are just now being introduced in many countries with rich coal reserves
- Ultra-supercritical pulverized coal burning steam generators (USCPC), a technology that is only beginning to be applied
- Integrated Coal Gasification combined cycle plants (IGCC), is a technology still in the research stage, and which burn synthesis gas, a product of coal gasification

In general, the thermal efficiency of a gas turbine power plant is approximately 52 per cent up to 60 per cent, nearly double the efficiency of standard coal-fired boilers used in most of the world today. By way of reference, the efficiency of the US fleet of coal-fired power plants as of 2010 was about 32 per cent using high heating value coal. The emissions of CO_2 from gas turbine plants is also less than half of the emissions of high grade, clean coal used in these same standard plants (about 435 g of CO_2 per kWh from gas as compared with 1100 grams per kWh from the standard coal plant operating at 30 per cent efficiency).

Combined cycle gas turbines employ the concept of capturing the waste heat of the initial gas combustion to run a second turbine, a heat recovery steam turbine, thus the combined cycle is actually one where two runs or cycles are made from the same combustion where the waste heat (or exhaust) powers a steam turbine after the gas turbine has been powered. These plants can have a single drive shaft for the electric generator or multiple shafts, different ones for the gas turbine and the steam turbines. Just recently the world's most efficient CCGT plant has been opened in Irsching, Germany using Siemens technology. It has achieved efficiency rates of 62 per cent.

The most common capacity size for a CCGT unit is 300 MW or 400 MW. The technology continues to advance as higher and higher gas-inlet temperatures are employing, in turn requiring higher quality steel alloys. Where natural gas is a reliable and available fuel, this technology has increasingly been the preferred one for new plants in recent years. The EIA announced in April that in the US, gas-fired plants using CCGT have now equalled coal-fired plants in electricity generated.

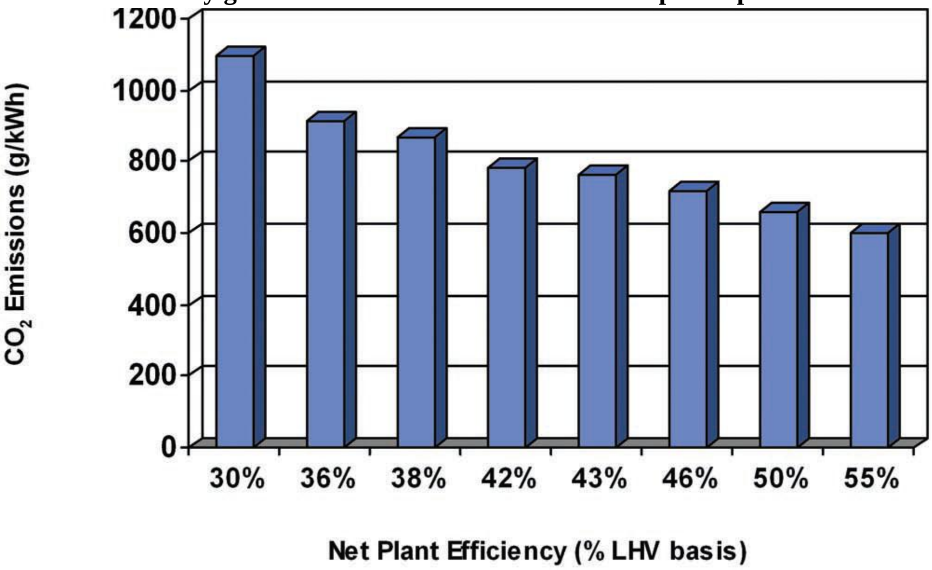
A combined heat and power plant (or cogeneration plants) are ones where the exhaust heat, usually steam or hot water, from power turbines is distributed to users around and near the plant. It actually was the very first type of commercial electricity plant built by Thomas Edison. It is a technology that is widespread in Europe and the former Soviet Union. It can achieve high efficiencies has more of the thermal heat from fuel combustion is captured and used than from conventional power plants. It is a technology that uses many fuels (from coal, to gas, to biofuels, to nuclear) and has even been attached to combined cycle plants. It usually is based on gas or steam turbines. Because the steam has to be transported to the users by insulated pipes usually CHP plants are often located in urban areas or they are built as captive plants next to facilities that consume the heat.

The major technological advance in electricity generation using coal in recent years has been the introduction of steam generators that produce supercritical steam for electric turbines in SCPC and USCPC plants. These require very high temperatures and pressures and special steel alloys and special configurations to achieve the sustained supercritical steam and to control and drive electric generators.

The supercritical steam generator operates at pressures above 24 MPa (the supercritical pressure above which there is no phase state between liquid and gaseous water) and temperatures above 540 degrees Celsius. Since 1990, SCPC units have been steadily introduced throughout Europe, Japan, the United States, and, since 2005, in China there are more than 500 such plants worldwide. They are achieving efficiencies of 38 to 46 per cent and sizeable savings of fuel costs and reductions of CO_2 emissions for their operators. The standard set for these generators have now settled on 600 or 660 MW size. In India, recent plans for SCPC plants call for power plants with 2, 3, and even 4 units of supercritical generators. China has adopted 600 MW units and has even been building units of 1000 MW size. There is now a very substantial track record for this technology, which led to an increased understanding of their operating costs, coal and water treatment, and emissions and waste heat produced.

Continuing the application of higher temperatures and pressures to increase efficiency, research over the past decade has introduced ultra-supercritical steam generators using pulverized coal. At the present time this technology refers to supercritical steam generators run at pressures at or above 29 MPa and temperatures above 590^o C. This sort of plant, of which there are about a dozen operational throughout the world, delivers efficiencies of 44-52 per cent and reduced CO_2 emissions, which are about 40 per cent below the average for global sub-critical coal burning power plants. The most efficient coal burning power plant in the world today is the 411 MW number 3 unit (built in 1998) of the Nordjylland power plant (Vattenfall) in Denmark, which is an ultra-supercritical steam generator that is run as a cogeneration plant delivering both steam heat and hot water to its nearby districts. It has achieved efficiencies of 91 per cent. The standard size for these highly efficient plants is in the range of 800- 1,000 MW, designed larger as a means of capturing economies of scale.

Chart 3: Efficiency gains versus CO2 emissions from coal power plants



China has become the world leader in building and developing USCPC power plants. Currently there are eight such plants in operation in China, and a couple dozen more under development and planning. By taking the lead in design, technology, and engineering China has also managed to drive down the capital costs for such plants. India has just in 2012 ordered the research needed to develop and build its first USCPC power plant-- now scheduled for 2020—but, because they will expand the temperature and pressure criteria, it is calling this technology an Advanced USCPC power plant.

Table 10: Efficiency and emissions intensity of coal-based generating technologies in China, 2008

technology	Capacity, MW	Heat rate, g Coal/kWh	Thermal efficiency, per cent	Emissions, t CO_2/MWh
Ultra-supercritical	1,000	286*	43.03	.73
Ultra-supercritical	600	292	42.09	.75
Supercritical	600	299	41.10	.76
Sub-critical	300	340	36.15	.87
Sub-critical	100	410	29.98	1.05
Sub-critical	50	440	27.93	1.12
Sub-critical	25	500	24.58	1.28
Sub-critical	12	550	22.35	1.41
Sub-critical	6	600+	20.48	1.53

Source: ADB, quoted in Carbon Emissions Policies in Key Economies, Productivity Commission, Australia, 2011.
*Shanghai Electric produced and built a USCPC power plant that used only 278 g/kWh.

The data in Table 10 show the comparative performance of coal-burning generators of different technologies and capacity sizes. These data serve as a basis for calculating the potential abatement of CO_2 achieved by replacing old, small coal-burning plants with the largest, state-of-the-art coal-burning supercritical steam generators. The experience in China in the past six years, showed that it was highly economical to replace the old small (50 MW) plants with large (600 MW), supercritical plants. When it was reported that coal cost $92/ton, the fuel cost savings were $12.48/MWh. The abatement in CO_2 was on the order of 0.33 tons of CO2/MWh. In the 11^{th} Five-Year Plan China replaced 78 GWs of older capacity in small power units with SCPCs plants with 600 MW to 1,000 MW capacity. It was in this program that China was able to reduce by 235 million tons of CO_2 from its yearly electricity generation.

The attraction of Integrated Coal Gasification Combined Cycle power plants is that by preparing synthesis gas (syngas) from coal, the CO_2 can be removed before the combustion cycle, along with a number of other pollutants, especially mercury and sulphur. Syngas can be made from a number of fuels, but the main focus has been on coal. After the syngas is prepared and purified it becomes the fuel stock for a gas turbine with a combined cycle steam turbine for the exhaust heat.

Initial enthusiasm for IGCC technologies has faded in the past decade as a number of research and demonstration projects have run into serious problems including high capital and operating costs, inconsistent quality of input coal, cost overruns, and low efficiencies. So the technology still has not achieved a commercial status for investors. The technology in pilot operation has been able to achieve 42 per cent efficiency. The only profitable plant, which has been in operation since 1993, is the NUON owned plant in Buggenum, Netherlands, which can convert biomass as well as coal to syngas. A number of small Italian IGCC plants use refined oil products and have been operational for a long while.

Nevertheless, there are still a number of initiatives to build new high temperature and pressure IGCC plants. Both India and China have committed to building scale demonstration plants. China's GreenGen project in Tianjin is a commercial scale plant under construction (near completion), while research is still being conducted by India. China's GreenGen project also aims to demonstrate the commercial feasibility of carbon capture and storage.

These advanced fossil fuel technologies have been developed along with the development of specialized steel alloys and engineering breakthroughs that can safely accommodate the much higher temperatures and pressures which delivery the higher efficiencies. This research has been intensive throughout the past twenty years and has engaged the full efforts of the world's leading power engineering companies, has launched materials research, and has garnered much government support in the developed world. In our Group of Nine Eurasian countries, most of these design and engineering capabilities, equipment building, advanced materials, and construction facilities are simply not available. Out of the Group, only over the past decade has China developed the design and engineering capabilities through its own research and development efforts along with contributions of technologies from leading Western power engineering firms such as Hitachi, Alstom, and Mitsubishi Heavy Industries (MHI). China was an early convert to building SCPC power plants and has been building them at a rapid rate, and recently been building USCPC power plants. India, meanwhile, has recognized its deficiencies in the engineering and construction of these advanced power technologies, and, in the past few years, its conventional power engineering firms have begun acquiring the capabilities to build the new technologies by acquiring the technologies or by joint ventures with the established Western power engineering firms. For the other countries, without the engineering and technical capacity, the equipment and materials needed to build these new advanced fossil fuel electricity technologies will have to be imported by the investor.

As is typical with new and innovative advanced designs and technologies, there are still very few firms that have the expertise, experience and know-how to produce them, and usually these are the firms that have lead the research and development of these technologies. In the industrial heavy duty gas turbines which run the combined cycle or cogeneration plants, the leading manufacturers globally are GE, Siemens, Alstom, and MHI. They produce engines of the F through J classes that are 150 to 340 MW in capacity. These high temperatures, high pressure gas turbines typically achieve 55-57 per cent efficiency. When combined with HRSG engines they form the combined cycle block or set. The transfer of advanced gas turbine technology is only just beginning. Shanghai Electric, Harbin Electric, Bharat Heavy Electrical have been the beneficiary of both licensing agreements and joint ventures.

The manufacturers of the steam generators that go into SCPC and USCPC power plants include other specialty engineering firms such as Babcock & Wilcox, Foster Wheeler, Burmeister & Wain Energy, Alstom, Toshiba, and MHI. These firms have in turn transferred their technologies through investments or joint ventures in India –Bharat Forge-Alstom, Toshiba JSW—and in China—Babcock &Wilcox Beijing, Shanghai Electric with MHI, Wuhan Boiler Company with Alstom, and Harbin Electric Power Corporation with GE.

These cases of technology transfer have led to the situation where the Chinese and Indian companies mentioned above not only manufacture and construct the high tech equipment for domestic power plant construction, they are also increasingly competing for engineering, procurement and construction (EPC) contracts for new power plants. Shanghai Electric, for example, one of the world's leading producers of ultra-supercritical steam generating units, provided the equipment and EPC work for a new SCPC plant in western India.

In addition to advanced fossil fuel combustion technologies, there are also new advanced technologies for the exploration, production, or synthesis of advanced fossil fuels which then can go into cleaner combustion generators. Often the end product of the exploration and extraction process is not an advanced fossil fuel as such, but is the same as conventional fuels: shale gas and methane extracted from coal seams are usually identical to conventional natural gas. Underground coal gasification, however, produces a new fuel altogether, syngas. It too goes into specialized power combustion units, but the carbon has been already extracted from the syngas so it is a clean fuel. Such advanced fossil fuels or advanced production technologies include:

- Liquefied natural gas (LNG) allows for easier and cheaper transport over long distances of natural gas which would otherwise not have a market.
- Coalbed Methane (cbm) – methane is pure natural gas but it is a hazardous and waste product of coal mining. Extracting this methane from large coal seams or coalbeds can often be of commercial quantities and this "unconventional" natural gas can be used exactly as gas is. The advanced technology of this fossil fuel is in the specialized methods of extracting the gas from the coal beds or underground coal mines.
- Shale gas—this is also natural gas but in recent decades technologies have been developed to extract it from huge shale beds which are found on almost every continent. This is also a gas that is found and produced by the same processes as oil and gas exploration and development and oil and gas companies dominate its production.
- Coal to liquids, coal to gas technologies—these are advanced technologies but they are not new. They were developed in Germany during the Second World War and later in South Africa where there were abundant coal resources but oil and natural gas imports were embargoed, so the coal was chemically converted into liquid or gaseous fuels. There is underground coal gasification which produces syngas for fuelling electricity generation, or coal to liquids which produce a syn-diesel for transport.

Of all of these advanced technologies only shale gas and LNG appear to be of the scale that has significant climate change mitigation effect. As much as shale gas and LNG can displace coal in electricity generation, it will reduce emissions.

Chapter V: Electricity demand growth and plans for the future

A country's economic growth is directly underpinned by its growth in electricity output. Planners in China and India have both forecast that electricity capacity needs to grow by 8.5-9.5 per cent per year and 8.0 per cent per year, respectively, in order to support the planned annual growth in GDP of 10 per cent and 8 per cent in the coming five years. Between 2010 and 2012—a period when Chinese planners were actively trying to slow the economy—growth in electricity demand was about 7 per cent a year reaching a new high level of consumption of 4.7 Petawatt hours (1,000 billion kWh). Demand already for electricity in both countries is greater than production. In China, there was an implied deficit of 30 GWh of power in 2011, and it is estimated to be 40 GWh this year which means supply and demand are virtually balanced, but many regions of the country are supply constrained or under-supplied. In India, meanwhile, there has been a systemic deficit in electricity supply of about 8 per cent a year over the past decade. Planners expect that 94 GW of new capacity will be needed in the coming five years just to keep up with the growth in demand, but not to close the deficit.

Keeping up with such strong demand growth will mean a major investment in huge amounts of new generating capacity. China expects that between 2011 and 2015, installed capacity will increase by 452 GW, or about 90 GW a year—a yearly amount greater than the total installed capacity of the U.K or in one year equivalent to the total projected capacity additions in India's current Five-Year plan. Continuing the program started in the 11th Five-Year plan, however, China will be trying to dramatically change the composition of its electricity generation by source; aiming both to reduce energy intensity and CO2 emissions per unit of GDP and per kWh. Still the forecast capital investment needed is put at around $445 billion. Although these are huge sums, there does not appear to be any anxiety about financing such a huge construction program.

In India the outlook is rather more daunting. To meet its targets of nearly 8 per cent a year capacity growth, India will have to add 94 GW of net new capacity by 2017 with an expected investment cost of $265 billion. But this target set in the current (12th) Five-Year plan is actually 76 GW of new projects and 19 GW of unachieved projects being carried over from the 11th Five-Year plan. Expectations are that in this ambitious new plan only 49 GW of plant will be completed by 2017. The financing of this very large program are straining India's capacity. Yet still this new power capacity will not satisfy pent-up and unmet demand. It is estimated that around 30 per cent of Indians are without access to electricity.

To understand the relationship between demand growth for energy (or electricity) and the overall growth of the economy (GDP), it is useful to look at the energy intensity of a country. This is an indirect measure of the energy efficiency of the economy; that is, the measure of how much energy input is needed to produce a unit of GDP. It varies over time depending on the stage of a country's economic development, and over space (countries in temperate climates tend to use less energy per unit of GDP than those in very cold or extremely hot climates). Furthermore, countries with a high level of heavy industry will have higher energy intensities than rural, agrarian or services based economies, so that their energy intensities will increase as they adopt industrialization. But as countries adopt more energy efficiency technologies and energy conservation measures their energy intensity tends to fall (as it has in the US over the past 20 years).

Another measure which can illuminate the future demand growth for electricity (or energy) is the absolute number which measures per capita consumption of electricity in country. It is reasonable that as a country develops its economy it will need to supply more energy to its citizens to raise their standards of living. In this regard countries with very large populations have much further to go to deliver economic growth: China and India may have moved far up the development scale in recent decades, but they still have very low consumption of energy per capita.

Table 11 - Energy intensity and electricity consumption per capita, 2009

	Energy intensity, BTU/$ (2005) of GDP	Electricity consumption, (kWh) /capita, 2009
China	10,782	2,631
India	6,389	597
Ukraine	18,033	3,204
Uzbekistan	29,814	1,636
Afghanistan*	772	19
Kazakhstan	13,305	4,506
Tajikistan	18,009	1,937
Kyrgyzstan	15,153	1,402
Mongolia	10,471	1,432
by comparison		
U.S.	8,553	12,884
EU 27	4,920	5,441
Russia	8,889	6,133

Sources: U.S. EIA for Energy Intensity; IEA World Energy Outlook, 2010 for per capita electricity consumption. * Afghanistan data from national baseline report.

It is noticeable from this table that the energy intensities in the countries of the former Soviet Union are significantly higher than in the other countries covered by the project. This implies that in the future investment will need to go more into energy conservation and increasing energy efficiency than into building new electricity generation capacity, that is, that there will not be strong growth in electricity sector expansion in the near future. India's energy intensity could grow, whereas China's needs to decline. But in spite such low energy intensity for India, the data on electricity consumption per capita show just how far India has to go to raise its peoples' standards of living. These data also show that Kazakhstan, alone of our group of countries, is near the European level of electricity consumption, but nevertheless has a very elevated level of energy intensity and so perhaps it does not need much new capacity to be built in the coming decade.

Energy intensity ratio does not give a direct indicator of how much electrical capacity is needed in the near term. It does indirectly indicate the likely rate of power demand growth that is likely to occur in the near term. This growth in electricity demand can be met for example by increasing the efficiency of current plant or the load factor, or by replacing old small power plants with new, larger plants with much more advanced technologies and efficiencies. India, for example, in twenty years to 2007/2008 raised its load factor at its coal-burning power plants from 52 per cent to almost 79 per cent, effectively increasing output dramatically. A more direct indicator of the need for upgrading or replacing power plants is the relative age of plant.

The countries of the former Soviet Union (and including Mongolia) inherited power capacity and infrastructure that had been built prior to 1992 by the centralized Soviet state. In the intervening years, first with a serious economic contraction in the 1990s and then with lack of investment funds, these countries have not invested very much in building new capacity. As a result their power plant is both old and obsolete technologically. By contrast, China has been building new capacity rapaciously in the past 20 years and even accelerated its capacity building –using very high technologies—in the 2000s.

Table 12 - Age structure of electricity generating plants as of 2011, per cent of installed capacity

years	<25	25-30	>30	Idle or retired
China*	90°	3	7	
India*	52°	30	18	
Ukraine	6	40	36	18
Uzbekistan	13	18	68	1
Afghanistan			100	
Kazakhstan	7	34	41	19
Tajikistan	14	12	73	
Kyrgyzstan	17	13	70	
Mongolia			100	

Source: National baseline studies unless indicated. * Source IEA. ° In China 64% of capacity is now 10 years old or less, in India 24 per cent is less than 10 years old, 37 per cent of the coal-fired capacity is less than 10 years old.

In the past three years, recognizing the increasing demand for electricity as well as the aging power plant and low load factors, Mongolia, Kazakhstan, and even Uzbekistan have begun programs of modernization or new-building of power plants, programs which are under way today. Ukraine continues to put off such upgrades or new investment. Nearly 47 per cent of Ukraine total electricity generating fleet, or 75 per cent of its thermal power capacity is more than 40 years old and the thermal power fleet runs at an average load capacity of 31.5 per cent. Now that it has by and large privatized most of its electricity generators, selling them to one private, domestic company, Ukraine is leaving decisions on any new investment in power plant construction or upgrades to that company.

Electricity demand growth projections

Four of the nine countries (Afghanistan, Uzbekistan, Kyrgyzstan, and Tajikistan) do not seem to have formal forecasts or plans of electricity demand growth in the coming five, ten, or twenty years. The remaining five countries –all of which are heavily reliant on coal for their electricity generation—do have formal projections which are prepared alongside extensive projections and planning for national economic growth and development. In India, which is unable to provide access to electricity to almost 400 million of its citizens, the forecast is made in terms of generating capacity additions needed over the forecast period with output projected to support annual GDP growth of 8 per cent. China—where all electricity produced is consumed—the forecasts are based on the optimum output of new capacity leading to forecast consumption levels. Sometimes forecasts for future electricity output include (or maintain) levels of electricity exports, and in some countries they project the end of electricity imports and a switch to exports of surplus output.

Table 13 - Growth rates for electricity output, 2011-2030

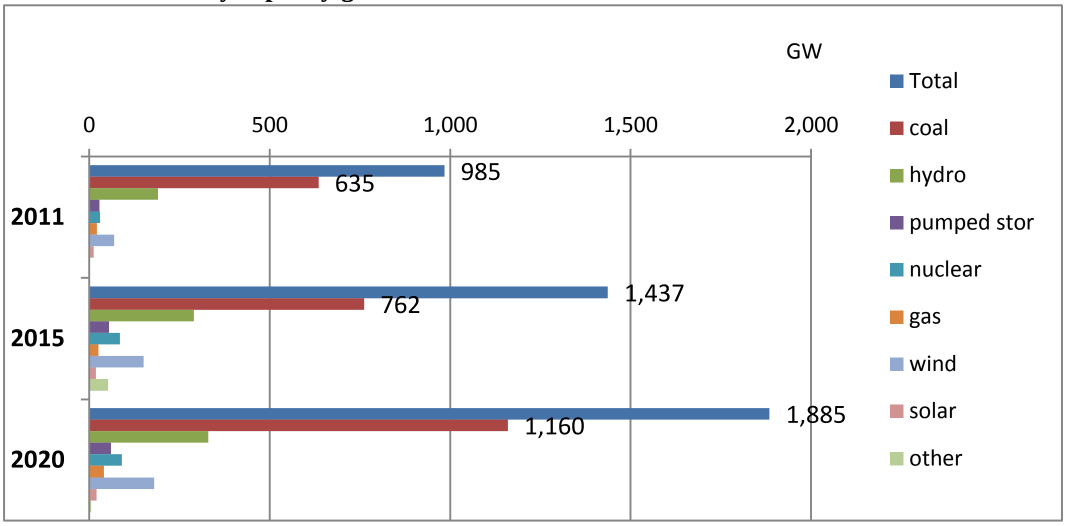
expected yearly capacity growth, %	comments	2011-2015	2015-2020	2020-2030
China	5 yr. plan, capacity expansion	9.2	6.2	
India	capacity expansion 5 year plans 2012-2017, 2017-2022	8.1*	7.6*	
Ukraine	output based, maintains exports through forecast period	1.8	1.8	2.2
Kazakhstan	output based, eliminates regional imports, adds exports	3.8	2.9	2.5
Mongolia	capacity expansion including captive plants, eliminates imports, adds exports	19.7	16.0	4.5°

Source: National baseline studies usually sourced from central governments' energy planning authorities. * Includes spillover capacity construction from 11^{th} Five-Year Plan and from the 12^{th} Five-Year Plan, otherwise these would be 6.5 per cent and 6.1 per cent growth rates. °Through 2025

In China forward energy planning is performed by the China Electricity Council and the Energy Research Institute. It has noted that the peak growth rate in electricity generation capacity addition occurred in 2006 (at 24 per cent year on year) and that growth rates have greatly moderated since then to only 9.4 per cent in the past year 2011/2012. For the period of the 12th Five-Year Plan from 2011 through 2015, the forecast growth in installed generating capacity is expected to increase from the end 2011 level of 984.6 GW to 1,437 GW, this implies a 9.2 per cent annual growth rate for new capacity. This is expected to cost $444 billion dollars in today's dollars. By 2020, installed capacity is expected to grow to 1,885 GW, an annual growth rate of 6.2 per cent in capacity.

This plan shows clearly a continued strong growth in the construction of generating capacity. In absolute terms there will be continued growth in coal-fired power plants—from 635 GW to 1,160 GW by 2020—and so more coal will be burned. But there has been a change in Chinese policy toward coal: its relative share will decline from 70 per cent of capacity to 62 per cent in 2020 as wind, nuclear, and other renewables increase their share. It is anticipated that the output of this new capacity will only just equal demand by that date.

Chart 4 - Electricity capacity growth in China



In India, the Government of India Planning Commission compiles the forecast targets for each Five-Year plan program. The National Energy Strategy is a component of this planning document. The energy targets of the 12th Five-Year Plan were announced in April 2012. It also projects the growth in generating capacity that will be needed to support continued strong economic growth, assuming that whatever additional electricity is produced by that new capacity will be more than consumed. But the projections put out by the energy strategy are targets for the end of the Five-Year Plan period, and in past Five-Year Plans these targets have consistently not been achieved. Construction work under way at the end of the expiring Five-Year Plan is rolled over into the next plan period.

In this way, the 12th Five-Year Plan has set a target of added new capacity of 75 GW from both SOEs and private (captive) power developers. This would be equivalent to a 32 per cent increase in capacity by 2017 to 306 GWs from today's level. The ultimate target in the plan however includes 19 GWs of capacity underway in 2012 from the 11th Plan, so that the target is adjusted upwards to 325 GWs, or an annual growth rate of 8 per cent, which India has never achieved before. In the 13th Five-Year Plan, the target is to build new capacity of 93.5 GW, which implies an annual growth in capacity of 5.7 per cent. But this plan also includes spillover from unachieved construction started in the 12th Plan so that 123 GWs are added which is equivalent to an annual growth rate of 7 per cent, taking India's installed generating capacity to almost 450 GWs by 2022.

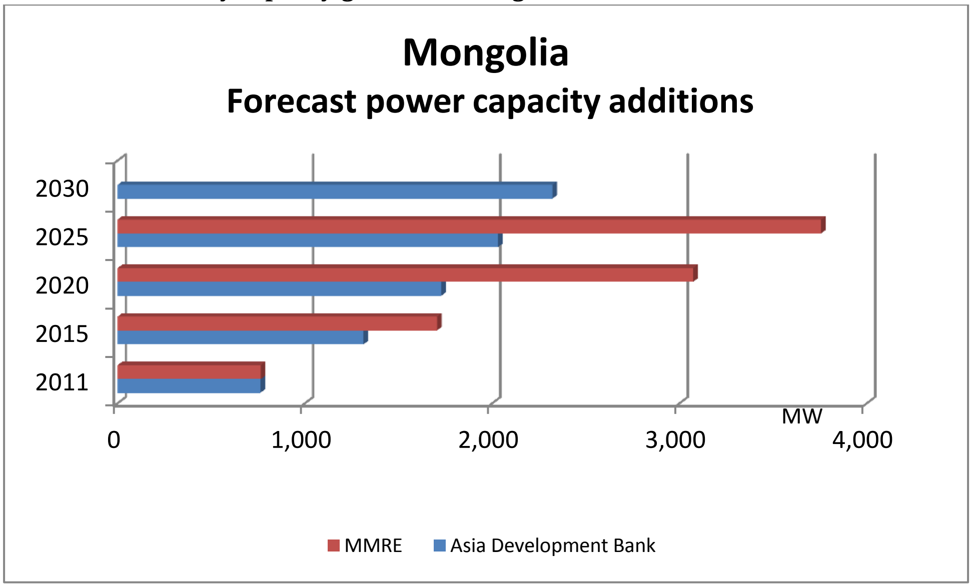
Annual demand growth in India over the past 30 years has been on the order of 3.6 per cent but at no point did supply satisfy total demand, but still these capacity growth targets look very ambitious, even unreachable. In the

11th Five-Year Plan, only 65 per cent of the targeted capacity additions were achieved, and in the Five-Year plans prior to 2007, usually only 50 per cent of target was usually achieved. It appears that energy plans from the National Energy Strategy looks more at political considerations than at economic and technical capabilities. Energy market analysts forecast new added capacity of only 49GW and 60GW in the five year periods through 2022, equivalent to 6.5 per cent and 6.1 per cent annual growth rates during each of the 12th and 13th Plans. These rates are still very high but more realistic.

The forecasts for electricity capacity really appear excessive in Mongolia (as in Table 3). If these projections are to be believed Mongolia will more than double its power capacity within five years, and then increase it again by 80 per cent by 2020. The growth rate of Mongolian economy in the 2000s, with the exception of a recession in 2009, was very strong and averaged 7.7 per cent. Since 2010 it has grown in nominal terms to 15-16 per cent yearly. Demand growth for electricity in this economic growth environment is estimated to be 7 per cent per year about the same as the GDP growth rate, but this does not include the future needs of new mining developments throughout the country.

There is a feasibility study and projection performed by the Ministry of Mineral Resources and Energy, and a forecast plan put together by the Mongolian University of Science and Technology. They both look at the future energy needs of the major new mining investments—both mineral and coal—which are proceeding on a very large scale in the remote parts of the country. Both forecasts look at the energy needs of these mining investments and have included a plan that requires that captive power plants be built at each mining location by the investor. This forecast, including the captive plants, shows installed generating capacity growing from 765 MW in 2011 to 3,000 MW in 2030; an annual growth rate of 19.5 per cent. If even only a few of these new mining operations deliver on the expected scale of new power capacity, Mongolia will have a sizeable excess power supply, but it will need major investments in new transmission facilities and networks in order to export and benefit from this surplus. The Asian Development Bank forecasts much lower growth rates in capacity build up in Mongolia. It forecasts annual growth of 14.5 per cent for 2011-2015, 6.3 per cent for 2016-2020, 3.5 per cent for 2021-2025, and 2.9 per cent for 2026-2030. Such a forecast would still almost triple the size of Mongolia's electricity generating capacity in 20 years.

Chart 5 - Electricity capacity growth in Mongolia



While demand forecasts for Mongolia seem excessive, in Ukraine expectations for electricity demand growth are very low in the coming decade. Ukrainian forecasts are put together by the Ministry of Energy and Coal Industry (MECI) and the National Energy Regulatory Commission (NERC). In its latest draft Energy Strategy from spring 2012, it forecast 1.8 per cent yearly growth in electricity demand through 2020. This would take electricity consumption from 194 Terawatt hours (TWh) in 2010 to 236 TWh in 2020. In the decade from 2021 to 2030, growth is forecast to be somewhat stronger, at 2.2 per cent per year. This forecasts electricity availability of 282 TWh, which includes 8 per cent losses and 2 per cent exports.

This growth in electricity output in Ukraine is expected to come from a decreasing share of coal based capacity between 2011 and 2030. The decline in coal burning capacity will be replaced by increased capacity of nuclear power generation, from 13.8 GW to 17.8 GW, as well as a huge relative increase in renewable energy sources.
In Kazakhstan, it is the Ministry of Industry and New Technologies which is responsible for drafting future development plans and forecasting demand growth for the power industry. It has prepared a detailed short term forecast for demand growth in the Development Program for the Electricity, and a more generalized program for developing the energy industry in all its sub-sectors through 2030. Kazakhstan from 1990 to 1999 had a secular decline in economic activity, GDP, and electricity consumption, the latter which fell from its historic high of 104.7 TWh to a low point of 50.7 TWh. This partly reflected a much overdue reduction of Kazakhstan's very high energy intensity and general inefficient use of energy. Since that low point consumption of electricity, demand has grown back to 84 TWh in 2010 primarily driven by strong economic growth in the first decade of the century which averaged over 7 per cent a year until the financial crisis in 2008-2010. Economic growth has returned and forecasts now are for moderate electricity demand growth to 2014 when the expected consumption will reach 96 TWh. Current projections show the country recovering to its electricity consumption high point only in 2016-2018. By 2030, with less than 3 per cent annual demand growth over the 15 years from 2015, consumption is forecast to 144.7 TWh.

Policy and plans for future development of the thermal electricity sector using advanced fossil fuel technologies

From the national baseline studies it appears that only six of the nine countries have put in place policies and development plans for their thermal power sectors that could possibly use advanced fossil fuels as a means of mitigating CO_2 emissions. The other three—Afghanistan, Tajikistan, and Kyrgyzstan—have development plans that reflect their relative poverty of fossil fuel resources and abundance of hydropower resources. Of the remaining six, only Uzbekistan primarily uses gas to fuel its power plants.

Uzbekistan

We have the least information about Uzbekistan's policies and plans for further electricity sector development. A cornerstone of the energy policy of Uzbekistan is fuel self-sufficiency; it also wants to maintain its role as an energy exporter. It currently exports power to Afghanistan and is looking to further export to Pakistan. There does not appear to be a specific policy to reduce CO_2 emissions, although there are general statements concerning pollution reduction.

The Uzbek Power Engineering Development program was formulated in 2006 and had initial targets of $1 billion of new investment to upgrade the electricity sector. A new program with a planned budget of $3.4 billion, part of the larger industrial development program, was announced in 2011. The original targets were to upgrade and replace power units in three power plants at Navoi, Tashkent, and Mubarek in Qashqardaryo with more advanced gas combined cycle turbines. To date the Navoi project is nearly finishing and should be commissioned shortly. It used Mitsubishi Heavy Industries gas turbines with a capacity of 478MWs and was engineered by a Turkish-Spanish joint venture, at a cost of $460 million. The Tashkent thermal power plant, which is more than 40 years old, has re-launched a program to replace 370 MW of capacity with advanced combined cycle gas turbines. The cost is estimated at $468 million which is being supported by a loan from the Japanese development bank.

As part of the new program, there is a plan to increase coal's share of thermal electricity generation from 4 per cent to 12 per cent. This targets the conversion of five units of gas powered plant at Novo Angren to a coal burning plant at a cost of about $50 million. This will be supported by Chinese Exim Bank. There is no indication what technology will be employed in these new units. This is a step backwards in terms of energy efficiency and CO_2 emissions.

Mongolia

Like Uzbekistan, Mongolia is primarily a centrally-planned, command economy, but it has taken much greater steps and reforms toward establishing a more market friendly economy. Still the electricity sector is state owned and controlled. It has adopted a number of key policy priorities for the coming decade. Among these are: energy self-sufficiency, new electricity generation capacity needed for the major new mining complexes to be built, financed, and operated by the mining developer, introduction of foreign investment in the electricity sector, developing the sector to be financially sustainable, development of renewable non-fossil fuel resources, and the reduction of emissions of greenhouse gases and local pollutants from power plants. Energy self-sufficiency and independence mean complete reliance on coal as the source of electricity in the future. Mongolia is a participant in the Kyoto Protocol, but it has not specifically required power plants as policy to convert to specific advanced coal combustion technologies, such as supercritical steam generators, as a means of reducing CO_2 emissions.

Mongolia's development plan for generating capacity is founded on two different approaches: one is to offer concessions to build new combined heat and power plants near urban areas; the other is to require foreign coal and mineral miners/developers to build and finance "captive" power plants primarily for their own needs. The specific mining projects with planned captive power plants are:

- Chandgana coal mine developer Prophecy Coal of Canada projected size 300-600 MW
- Tsaidam nuur coal mine developer Burkhan Khaldun Group of Mongolia 600 MW
- Mogoingol coal mine developer Mogoin Gol JSC of Mongolia 43 MW
- Tavan Tolgoi coal mine developer Shenhua of China with international consortium 300 MW
- Erdenetsogt coal mine developer Mangreat Group of Hong Kong 600 MW
- Shivee Ovoo coal mine developer Erdenet Mongolia (SOE) 600 up to 4,200 MW
- Oyu Tolgoi copper mine developer Rio Tinto of Australia 300 MW

Not all of these power projects have been approved and it is not clear that the mine developer must finance them. Some of this new capacity will be competing with that of other mines, particularly in exporting the surplus. But with this plan Mongolia's electricity generating capacity would increase by more than 2.5-3.5 times, and there is no plan at the moment of how to connect the surplus from this huge potential electricity output to the national grid (meaning the Central Electric System) or how to transmit electricity to the Chinese grid. All of these projected power projects are seeking equity investors and financing. The developers have claimed that they will build advanced coal burning technologies, but specific characteristics are not known and Mongolian authorities are not requiring SCPC or USCPC plants.

The two power plants in Ulaan Bator and Dornod are both being offered by concession as build-operate-transfer investments. The concession for CHP5 in Ulaan Bator has been preliminarily awarded to a foreign consortium of Japanese, Korean, and French companies. The initial plant is targeted to be a 450MW coal burning plant with the possibility of being expanded to 820 MW. While it was not specifically required to be a SCPC plant, the operating characteristics desired by the Mongolian authorities (efficiency above 40 per cent for the electricity) suggest a SCPC technology. It is reported that the proposal by the foreign consortium is to build 3 circulating fluidized bed boilers of 150 MW each. The Dornod CHP plant, in the far east of the country, is a smaller 100 MW plant. A short-list of bidders for the concession was released in late 2011. China's Harbin Electric was on the short-list. As the size of the plant is small it will most probably not be an advanced coal burning clean technology. It is hoped that both of these CHP projects will be completed by 2016, however it appears that Mongolian authorities are having trouble advancing the awarding and inauguration of the programs.

It appears that Mongolia has laid out plans that are far in excess of demand, even including the incremental new demand for electricity from the major mining investments. This suggests that the country will have difficulty financing all this surplus electricity, especially as all this new capacity will require tremendous investment in new transmission and distribution lines to connect the three network systems with the remote outlying mining centres. This new projected investment in coal-fired plant also will greatly increase Mongolia's CO_2, and it appears likely will not reduce relative CO_2 emissions from the total electricity generating fleet.

Ukraine

Ukraine's policies for the electricity industry are mainly concerned with propping up an old and inefficient fleet of power plants for another decade while at the same time assuring the delivery of sufficient electricity supplies to its people. This policy outlook mainly reflects the reality of a lack of capital for new investment and a system that does not pay the full cost of energy. Ukraine is committed to nuclear power and coal burning as the foundation of its power generation, primarily because it cannot afford the imports of Russian gas, and this makes its politically vulnerable to Russia. The shortage of investment capital however makes the conditions of the industry worse—$C0_2$ emissions from thermal plants are greater than 1,000 grams per kWh due primarily to low efficiency and low load capacity due in turn to old plant and obsolete technologies.

The current policy recognizes these shortcomings: its projections are that more than 30 per cent of total capacity must be modernized and upgraded by 2020 and new capacity amounting to 21 per cent or 11 GW must be built in the period 2021-2030. This will be accomplished by retrofitting with more up to date technologies 14 GW of thermal power plants, replacing 11 GWs of thermal power plants, building 4 GW of new nuclear capacity, and retrofitting and modernizing 5.5 GW of hydropower capacity. In other words fossil fuel capacity relative to clean renewable sources will decline in the coming 20 years. Planning documents estimate that the costs will be about Euros 74 billion ($95 billion in today's dollars) but they cannot see where this capital will come from. So the new investments especially in clean coal technologies are put off until after 2020.

The priority policy until 2012 is to install flue gas scrubbers to reduce pollutants and particulates. But still this is anticipated to total only $1.2 billion in the remaining years of this decade. A secondary priority is the advancement of renewable energy resources. There are incentives to investors in wind, solar, and biomass energy, but the authorities are looking primarily to foreign investors to import and operate those technologies. Finally, the national strategy recognizes that an implementation plan is needed for its treaty acceptance of the Kyoto Protocol. This implementation plan is not expected before 2013; i.e. after scheduled elections in the later part of 2012. The new strategy released earlier in 2012 highlighted the environmental concerns, but still the government does not mandate the development of advanced fossil fuel technologies such as SCPC or USCPC plants to replace the current fleet of obsolete electricity generation technologies.

None of these very limited objectives will be achieved without significant reform of the energy markets in Ukraine and a move to market-determined electricity prices. (Indeed, it is the state control of energy prices that remains its main instrument for implementing its energy policies.) At the end of the day, the Ukrainian consumer does not pay the full cost of electricity or heating delivered. The state run tariff system and Single Buyer Market system is filled with destructive cross subsidies, which move profits back and forth between industrial consumers, generators, residential consumers, utilities, and coal mines. All of these subsidies are determined by political considerations so they will be very difficult to dismantle. Politicians do not believe that Ukrainians can pay the real cost of their energy so they provide heavy subsidies which contribute greatly to the national debt.

Kazakhstan

The development plans for the electricity sector have been formulated out of the conclusions and targets of the National Strategic Development Plan through 2020, that is, electricity needs and growth are viewed in perspective of the amounts needed to support and enable a forecast level of continued strong economic growth. Energy self-sufficiency and independence is an important policy priority but not the overriding one. Like the electric systems of much of the other former Soviet states, Kazakhstan's fleet of generators and its transmission lines are old and running at low load factors; it is critical to update and replace this old infrastructure within the coming decade in order to continue to reliably supply the growing needs of the country. The system is also unbalanced and fragmented because of the large size of the country and the concentration of the coal resources in the northeast and northern regions of Kazakhstan. For this, massive new investment is needed in connecting ultra-high voltage transmission lines between the three networks of the country. Finally it is important to diversify the energy mix to reduce the over-reliance on coal and to improve the environmental friendliness of electricity generation. Use of new renewable resources is given a low priority; new investment in these technologies as planned would take renewables to only 1 per cent of future power output.

There is no explicit policy directive to adopt SCPC or USCPC generating technologies, neither for new-built power plants nor for modernizations of old coal burning plants although there are general policy goals of achieving higher efficiencies and cleaner combustion. However, a new policy directive in 2012 was to be issued which set tough new guidelines for emissions and efficiency for both new and rehabilitated coal and gas fired boilers. How these will be implemented will need to be seen.

Additions to capacity additions have already been identified and started so that they can be brought into operation by the first targeted planning period by end of 2014. The 300 MW Moinak hydropower project was inaugurated earlier this year, as was the 87 MW gas turbine plant in Akshabulak, which reduces flared associated gas from oil production in the Kyzylorda region. A small gas turbine CHP plant was commissioned in Uralsk in Western Kazakhstan in 2010-2011. Some of the major projects have been delayed, however. The large Balkhash thermal power plant with eventual capacity of 2,640 MW was finally launched late this year with the new completion dates pushed back to 2017-2019.

Over the long term, through 2030, new generating capacity of up to 14 GW is forecast to be needed. The forecast baseload capacity is identified as a new nuclear power generator, and a coal burning generator based on the Turgai coal. Both of these large projects are contentious. The Turgai thermal power plant is very dependent on the commitment to full scale development of the Turgai brown coal reserves, something which is still speculative. The expansion of Ekibastuz GRES 2 units 3, 4, and 5, which is currently on-going, is expected to add almost 2 GWs through two phases by 2019.

The main policy directive concerns the rehabilitation and upgrading of current power plants. This program already started in 2006 and is on-going. It aims to provide effectively 7 GWs of new, more up-to-date generating capacities at several of the Kazakhstan's largest power plants.

- Extension of Atyrau cogeneration plant, implementation period: 2006-2010.
- Rehabilitation of units No. 8, 2,1 at Ekibastuz GRES-1, implementation period: 2010-2015;
- Construction of unit No. 3 at Ekibastuz GRES-2, implementation period: 2009-2013;
- Rehabilitation of units 6,5,7,8 at Aksu GRES, implementation period: through 2019;
- Modernization of Shardary hydropower plant, implementation period: 2009-2015;
- Rehabilitation and extension of Almaty cogeneration plant-2 (phase 3, boiler unit No. 8 and boiler room), implementation period: 2009-2013.

The twenty year forecast for these programs, new construction and rehabilitation/modernization, is expected to cost $34 billion. There will plenty of opportunities for outside investors to participate in financing these programs.

China

The policy, planning, and development strategies are put together by the National Development and Reform Commission (NDRC) using an integrated view of the economic development of all the sectors of energy and supporting sectors (transport, industrial growth, transmission, engineering, construction, environmental control). It divides its policies for development into priority categories: highest priority, permitted, restricted, prohibited and ranks development projects in those categories. Since the energy projects have a long-life investment cycle, the policy plans and projections that are normally enclosed in the Five-Year Plans periods are extended over 20 years into the future to see the full cost economics of projects and developments.

The 12th Five Year Plan (2011-2015) starts with a commitment to maintain and further implement strategic policies and targets set in the previous Five Year Plan. The main thrust of this commitment is to continue the highest priority of energy conservation and energy savings measures. Energy self-sufficiency and independence are no longer top priorities, and although coal is still slated as the main source of energy it is already recognized that its share of energy supplied will continue to decline. Access to energy and continuing expansion of electricity service in regions of the country which are energy poor are top priorities but there is a new sensitivity to the need to deliver electricity and energy at a sustainable cost (that is the market cost of energy production and delivery must be borne by the consumers). The other priority measures:

- Carbon mitigation targets will be advanced and be made more rigorous, reduce the growth rate of GHG emissions, continue to reduce energy intensity;
- Large scale thermal power and nuclear projects will be built, investment in improved energy infrastructure, accelerate hydropower construction
- Further optimization of electricity supply and electric grid structures;
- Greater commitment and investment in renewable energy
- Develop research and science centres for domestic energy innovations
- Enhance and reform the pricing system so that energy is properly used and consumers pay the full cost.

After cutting China's energy intensity in the 11th Five-Year Plan by 19 per cent from 2005 levels, the new plan aims for an additional cut in energy intensity by 16 per cent from 2010 levels. Increasing efficiency will also be joined by continuing reduction of targets for CO_2 and GHG emissions. In the 12th Five-Year Plan the target will be to reduce CO_2 per unit of GDP by 17 per cent from 2010 levels. China estimates that it cut out 1.46 billion tons of CO_2 emissions in the last plan period. SOx and NOx emissions will also be scheduled to be reduced by 8 per cent and 10 per cent respectively. The 12th Five-Year Plan and those beyond aim to put a cap on primary energy consumption; trying to limit primary energy consumption at 4.1 billion tons of coal equivalent (tce) in 2015, 5.0 billion tce in 2020, and 5.5 billion tce in 2030.

Specifically in electricity strategies there will be a higher importance put on developing and increasing the contribution from non-fossil fuel electricity generation. This strategy aims over a 20 year period to greatly increase the installed capacity of nuclear power, hydropower, and power from renewable resources. Currently 8.9 GWs of nuclear capacity are being built around China, and nearly 63 GW of new hydropower plants are under construction or approved for construction, as part of the Five-Year Plan. All of these alternative sources in the 12th Five-Year Plan and beyond will take a larger share of electricity generation at the expense of coal's share. The combined share of renewables in generating capacity is targeted to reach 11.4 per cent by 2015, up from 9 per cent. The long term plan for nuclear power is to increase its share from 0.9 per cent of capacity to more than 4 per cent by 2020. This will be achieved by building new nuclear power capacity of 80 GWs by 2020, and another 120 GWs by 2030. Hydropower's share of total capacity—although a strong building program is planned adding 140 GWs by 2020—is expected to fall from its current share of 19.3 per cent to 17.5 per cent in 2020.

The turn away from high carbon intensity since 2006 is also pushing Chinese policy to plan for more gas-fired generating stations, particular in the eastern seaboard cities. And this means a more liberal policy for importing natural gas both by overland pipelines and by LNG. There is currently a flurry of building new LNG importing facilities on the coastline of eastern China, and this will be followed by intensive building of large-scale gas-fired combined cycle power plants near those LNG receiving stations. Foreign investors are involved in the construction of new LNG receiving stations, and Chinese authorities are inviting foreign investors to assist in building the large, advanced combined cycle gas turbine plants that will consume this LNG.

In 2010 China imported 12.2 bcm of gas equivalent (e.g. 9.12 million tons per year (mmtpa)) as LNG through six regasification stations with an import capacity of 25.6 bcm per year (18.8 mmtpa of LNG). In 2011, LNG imports increased to 16.6 bcm, equivalent to 12 per cent of China's total gas supply. In the current plan it is forecast that China will import by 2015 32 to 40 bcm of gas equivalent of LNG (23 to 30 million tons of LNG), expected to be 17.5-20.0 per cent of China's total gas supply. As of the end of 2011, China had already under contract 18.9 mmtpa of LNG for 2015, and 29.5 mmtpa for 2020. Currently 40 per cent of LNG imports are used for electricity generation, but that figure is expected to rise sharply by 2020 as new gas-fired plants are built, that is 50-60 per cent of LNG imports will go to electricity generation in peak shaving plants located in urban areas near the eastern seaboard. This outlook for imports will require 10 to 19 GWs of new gas-fired electrical capacity to be built in the coming 8 years. This makes natural gas in the coming years the fastest growing energy sub-sector, just as growth in coal-fired power continues to slow. But rapid and continued demand growth for imported LNG will require reforms of pricing policies; at a certain point the higher costs of gas from LNG will not be passed along to electricity consumers, and electricity generators will stop buying the gas. PetroChina, the largest gas importer, lost more than $3 billion on LNG and pipeline gas imports last year.

In addition, gas imports from pipeline are beginning to flow into China and with the completion of the West to East Gas pipeline these supplies are flowing to the main consuming regions of eastern China. As of 2011, gas supplies of 14 bcm are coming solely from Turkmenistan, up from 4.3 bcm in 2010. In the current plan these volumes are expected to increase to 30-40 bcm per year as piped gas from Myanmar (10 bcm) and possibly Russia begin to flow into China, and Turkmen supplies reach their designed baseload of 30 bcm per year.

Table 14 - Natural gas imports into China

	LNG mmtpa	LNG bcm equiv.	Piped gas bcm	National production bcm	Total gas supplies bcm	LNG % total gas	Piped % total gas	Imports % total gas
Actual 2010	9.1	12.4	4.3	94.8	111.5	11.1	3.9	15.0
Actual 2011	12.2	16.6	14.3	102.5	133.4	12.4	10.7	23.1
Forecast 2015 low	23.5	32	40	158	230	13.9	17.4	31.3
Forecast 2015 high	29.4	40	50	160	250	16.0	20.0	36.0

The 12th Five-Year Plan projects that China will have gas supplies of 230 to 250 bcm, an amount that includes 10 bcm of unconventional gas (either cbm or shale gas). Imports will comprise 72 to 90 bcm (which does not include LNG or piped gas from Russia), or 31 to 36 per cent of the total gas supply. These amounts would by the end of 2015 make China the second largest consumer of gas after only Russia, and it would become the world's fourth largest importer of gas after only Japan, the U.S., and Germany (currently 10th). It looks likely to become the world's second largest gas importer by 2020. This very much resembles China's very rapid growth in coal use in the first decade of this century.

Coal-burning thermal power plants will continue to be the backbone of Chinese electricity production in the next twenty years, although their relative share of both capacity and total output will decline. In the current Five-Year Plan it is projected that 127 GWs of coal-fired generating plants will be added, and in the next Five-Year Plan through 2020 a huge 398 GWs of new capacity will be added. It is forecast that through 2035 almost 1,000 GWs of new coal-fired power plants will be built in China. China's policy has already committed to employing on a massive scale supercritical steam generators, and it already possesses the world's largest fleet of SCPC power generators. It has achieved this by removing small coal-fired plants with less than 300 MW capacities and replacing them with SCPC plants with 660 or 800 MW capacities. In the 11th Five-Year Plan, 71 GWs of these smaller plants were retired and replaced by SCPC units. It has been estimated that this program, called Larger Substitutes for Smaller, has replaced 110 million tons a year. In 2009, China was building one SCPC power plant per month. In the coming decade it is planned that the country will begin a large program of building mega power plants of 1,000 MW or larger using ultra-supercritical steam technologies.

Ultra-supercritical power generation units have been added quickly since they were first built in China in 2006. Shanghai Electric has built and installed more than 67 GWe of ultra-supercritical power units in the past six years. While the forecast plan for installing USCPC power generators is not available, the totals are likely to be a significant proportion (in excess of 60 per cent) of the nearly 400 GWs of new capacity to be added by 2020. And these additions of high technologies are occurring while the retirement of China's older and smaller, subcritical coal-burning power plants will continue. This program of converting low tech, small capacity coal plants with high tech, mega-sized plants does reduce CO_2 emissions at an acceptable cost: the coal intensity has fallen from 370 grams/kWh to an average of 333 grams/kWh (the average in the EU is 379g/kWh). The newest USCPC technologies have achieved efficiencies of 282 g/kWh. This program of converting the coal-fired fleet has already run a long way: today 75 per cent of China's coal-fired fleet is already less than 20 years old and 80 per cent is more than 300 MWs in size. In order to reduce CO_2 from the Chinese fleet beyond the current replacement program, China will have to investigate how to retrofit carbon capture and storage (CCS) units onto it operating units, while designing new units with CCS already built in.

While China remains committed to rolling out commercial IGCC technology through its large scale demonstration project in Tianjin, this technology does not feature as a high priority target in the 12th Five-Year Plan.

India

The National Energy Strategy has evolved out of the 2006 Integrated Energy Strategy by the Indian Planning Commission. The latest statement of this strategy has as its primary aim is a program that will meet the demand for energy services in all sectors at competitive prices to deliver a sustained growth rate for the economy of 8 per cent through 2032. The 12th Five-Year Plan, which started in April 2012, focuses on expansion of the country's electricity generating capacity. The strategy highlights that coal, because of its low cost advantage and for domestic self-sufficiency reasons, will remain the dominant energy source for the next 20 years. This policy requires a major reform of the coal industry because coal output from domestic mines will need to double by 2020. The strategy also raises the importance of increasing energy efficiency and lays out measures for reducing CO_2 and GHG emissions. These policies are continuations of the National Action Plan on Climate Change which was issued in 2008 and is still being implemented.

The five-year target through 2017 is to add 75 GW of new capacity and complete roughly 19 GWs which were started in the 11th Five-Year Plan. Of this coal-fired capacity is expected to grow by 63.7 GWs. Large hydropower projects are still given importance, but the implementation of a building program is expected to be delayed as resistance in the country remains strong. Since the latest reform of the electricity generating industry in 2003, the government has recognized that the industry needs to develop more on market related foundations. This means that in effect the State can no longer dictate to the electricity companies or developers what they shall develop. This reform also addressed the issue that there are problems with tariffs and cross subsidies, but to date it has not taken measures which fully solve these issues.

The latest development plan recognizes the severe problems with the state-owned and run coal company and it has accordingly liberalized access to imported coal for electricity companies. Most important for power developers, the state has specifically committed to the adoption of clean coal technologies and has provided incentives (in tariffs) for supercritical steam boilers and for ultra-supercritical steam boilers. It has provided a target of 40 per cent of new coal-fired generators to be built in the Five-Year Plan should be SCPC. The incentives (and dis-incentives for subcritical coal plants) are such that 100 per cent of new coal-fired capacity has to be SCPC or USCPC in the 13th Five-Year Plan. In 2010, India had no SCPC plants, now it already has 3 and has another 11 under development. The target is that India will have 50 GW of SCPC power plants by 2020. India has also committed to developing a domestic IGCC program (which admittedly will not be completed until after the current plan period). A demonstration 200 MW IGCC plant is under construction at Vijayawada.

Unlike China, India is not pushing for the retirement of old, small, sub-supercritical coal-fired generating units, although the Five-Year Plan does provide disincentives for any new building of the less efficient technologies. This does not help India reduce its emissions from coal burning. India has much more of its capacity in many, low efficiency, small (<120 MW), technologically backward coal burning plants than China now does. 71 per cent or 72 GW of coal-fired plants in India are smaller than 300 MW with a median age of 21 years. The 12th Five-Year Plan also targets the modernization or rehabilitation for 17 GW of coal-burning power plants (most from the 1980s).

Table 15 - Future coal-fired capacity additions in India: IEA forecast

GW	2011-2015	2016-2020	2021-2025	2026-2030
Gross new additions	74.5	30.6	22.8	52.8
Retirements	1.5	3.2	3.5	6.2

Source: IEA: CCS Retrofit Analysis of Globally Installed Coal-fired power plant fleet, 2012.

One new policy recommendation designed to make more efficient coal-fired plants is the special incentives and approvals procedures for the development of Ultra-Mega Power projects (UMPP). These are power plants with a minimum generating capacity of 4,000 MW that use SCPC technology. There have been four of these UMPPs approved for construction and another eleven are awaiting approval. Tata Energy is the first to begin producing electricity from the first two 800 MW units of its 4,000 MW UMPP in Mundra, in Gujarat. These UMPPs, once approved, also get preferential approvals for coal allotments, or for fuel (either coal or gas) imports.

It is recognized that the coal quality of India's reserves—particularly the very ash and impurities levels—pose certain limits to programs of reducing carbon emissions using higher or more advanced technologies. This partly explains the slow take up of SCPC and IGCC technologies and the inappropriateness of USCPC as it now exists. But it also explains why India increasingly is permitting coal imports for new developments which use these high, cleaner-burning technologies. Coal imports are expected to increase from 100 mt to about 200 mt in 2017, or to about 22 per cent of total coal supply.

The policy and plans for the near term through 2020 do not seem to address the adoption of CCS, either as a requirement of new built coal power plants nor in a program of retrofitting older plants. Presumably this is due to the perceived higher costs as well as the lowered efficiencies when CCS is built onto a new SCPC power plant.

The policy for this plan period includes a loosening of the former restriction on gas imports and this, combined with promotion of advanced combined cycle gas turbine plants, opens up the possibility that more LNG will be imported for general and electricity needs and that more gas-fired capacity power plants will be approved and built in the next decade. There is already a scramble on in the planning and approvals stages to build seven new LNG regasification plants around India's coast to add to the three which are already operating.

The expected share of imported natural gas (which is only envisioned to mean LNG) out of total available supply by 2017 is estimated to grow from 19 per cent to 28 per cent. While there are no targets for natural gas capacity additions, developers are also planning to build on this future prospect. Since 2010, a new 1.15 GW combined cycle gas turbine plant at Sugen has been built and commissioned. Some estimate that new gas-fired capacity will amount to 25 GWs by 2020, more than doubling the current installed gas capacity. Presumably this new capacity will be mostly built at the LNG import hubs or at the terminus of the country's two main gas transmission pipelines. As in China, electricity prices and tariffs will have to be reformed in India in order that gas-fired electricity from LNG can be increasingly sold into the general grid and that the fuel costs can be passed along to end consumers.

The National Energy Strategy calls for increasing the competitiveness of energy markets, and, importantly that prices and resource allocations should be determined by market forces under an effective regulatory system. While this is the policy goal, the implementation of these policies has been lagging: India's electricity market and pricing is in dire need for reform. A huge part of this lack of reform is that the system of prices and market functioning is administered not by the central Indian government but by the federal states, and thus pricing and market functioning are politically manipulated at the local levels. Subsidies and price incentives are awarded for local political gain, and can be changed or transferred with little economic analysis or justification again for political ends. Electricity generating companies are often left footing the bill –huge and unpredictable losses have been recording over the past ten years by many companies in almost all the regions of the country. Probably very little reform will be accomplished in this area before Federal elections in 2014.

The difficulty of financing the planned program in this Five-Year Plan period is a problem that occupies much of the strategy statement. It estimates that roughly $130 billion will be needed in new investment for the electricity generation sector. Of this $75 billion will be needed for the investments in coal-based electricity generation. The State Bank of India estimates this latter figure is more likely to be $110 billion. Over the next ten years, through 2022, it is expected that $105 billion will be needed for investment in only the SCPC power plants that are planned. Where these sources of investment capital are to be found is a serious difficulty for the central government which is already coping with a huge national debt and budgetary deficits. It is foreseen that 50 per cent of the investment in generating capacity will probably come from the private sector.

Chapter VI: The Role for FDI in introducing advanced fossil fuel technologies

It has long been a tenet of economics that foreign direct investment can have a positive effect on the economic development of a country through the introduction of new, advanced technologies and production processes into an economy. Similarly, there has long been the expectation that foreign investment can raise energy efficiency, productivity, as well as to reduce pollution from energy use, reduce the wasteful use of energy, and contribute to reducing carbon emissions from electricity generation. Foreign investment can often be the financial means or catalyst which serves to introduce or to accelerate the development of an economic sector or industry. At its most basic function, foreign direct investment provides capital which otherwise might not be available in the target country.

All nine countries have general policies and laws which invite and promote foreign direct investment in a broad range of economic sectors. Some countries have very active foreign investment promotion offices. China because of its very size and dynamically growing and diversified economy leads the way, receiving more than $670 billion in the past seven years. Nearly all of our countries show some evidence that the world economic slowdown and recessions of Western economies starting in 2008, significantly reduced FDI inflows in the years 2009-2010.

Table 16 - Population, GDP and total FDI in the nine countries

Country	Population, million	GDP, billion $	FDI, billion $						
			2005	2006	2007	2008	2009	2010	2011
Afghanistan	31.4	18.9	0.3	0.2	0.2	0.1	0.1	0.2	0.1
China	1,341.3	7,203.8	72.4	72.7	83.5	108.3	95.0	114.7	124.0
India	1,224.6	1,897.6	7.6	20.3	25.5	43.4	35.6	24.2	31.6
Kazakhstan	16.0	186.4	2.0	6.3	11.1	14.3	13.2	10.8	12.9
Kyrgyzstan	5.3	5.9	0.04	0.2	0.2	0.4	0.2	0.4	0.7
Mongolia	2.8	8.6	0.2	0.2	0.4	0.8	0.6	1.7	9.7
Tajikistan	6.9	6.5	0.1	0.3	0.4	0.4	0.02	-0.02	0.01
Ukraine	45.4	165.2	7.8	5.6	9.9	10.9	4.8	6.5	7.2
Uzbekistan	27.4	45.6	0.2	0.2	0.7	0.7	0.8	1.6	1.4

Source: Population (2010) and GDP (2011) – United Nations Statistics, FDI - UNCTAD

FDI plays a very important role in the economies of China and India; they are the first and third largest destinations for FDI in terms of value, ahead of the U.S. or any other large OECD country. In the seven years since 2005, China received $670 billion and India $189 billion of FDI. Relative to its population and the size of its GDP, India probably receives too little FDI. Its politicians are striving to open the economy more to incoming investment. Ukraine, Uzbekistan, and Afghanistan relative to their populations receive sparse FDI, but each country has its own reasons why so little FDI is received. By the same means Kazakhstan relative to its population receives a disproportionately large share of FDI, although it is very heavily weighted to natural resources extraction, especially hydrocarbons. All of the countries in the table, with the exception of China, show that there was a noticeable impact on their flows of FDI caused by the global financial crisis starting in 2008.

While all the nine countries have promulgated laws which purport to allow, and even promote, FDI, Uzbekistan, Kyrgyzstan, Tajikistan have failed to develop the transparency, rules, and investment procedures to enable much investment at all. As a result these countries have received very little FDI in all sectors over the past seven years. This can be seen in their FDI flows and as well in their investment attractive ratings by international agencies which report on countries' investment climates (such as the World Bank's Ease of Doing Business Index, the Economic Freedom Index of the Wall Street Journal/Heritage Foundation, or the World Economic Forum's Competitiveness Index).

Policies and incentives to permit and encourage foreign direct investment specific to the electricity industry do not exist in Ukraine, Uzbekistan, Afghanistan, Kyrgyzstan, and Tajikistan, where rules and legislation address foreign investments exist in a more general manner that would apply to any private investor. Nevertheless there have been foreign investments made in the electricity sectors in Ukraine and Tajikistan. We estimate that foreign investment in their countries in the electricity sector since 1992, including hydropower, has been in order of $420 million for Ukraine and $280 million for Tajikistan. Uzbekistan claims there has been $200 million in FDI for the electricity sector, but on closer inspection it all appears to be foreign assistance lending. Foreign investments made into the electricity sectors of Afghanistan and even Tajikistan (in its hydropower projects) have been more in the form of foreign development aid grants or loans from developmental banks or foreign governments, which are not considered FDI.

Foreign investments have been made into the electricity generation sectors of the remaining four countries which have specific laws and directives for enabling FDI in the electricity sector, namely, in China since 1985, India since 1991, Kazakhstan since 1994, and Mongolia since 2011. Since 1985, China has received about $16 billion in FDI into its electricity sector, while India since 2000 has received $5.9 billion. We estimate that Kazakhstan has received since 1992 less than $700 million of FDI in its electricity sector and Mongolia has to date not received any but has a commitment for $450 million for the CHP5 power plant.

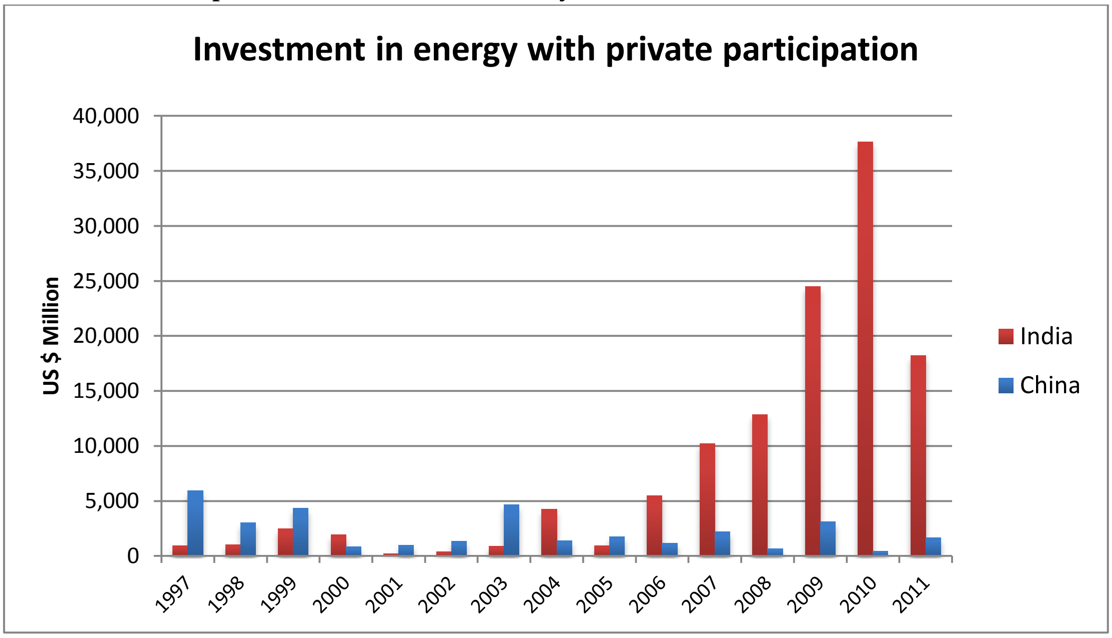
The global IPP industry and FDI

In all nine countries the state operates, owns, and controls the electricity industry from generation through to transmission and sales and distribution. FDI into the sector only became possible as countries liberalized their electricity sectors and allowed for independent power producers (IPP, that is privately owned, non-SOE investments in electricity). This liberalization in some countries included partial privatization of some sectors of the industry, usually only generation, although this privatization has gone farther in some countries than others.

India, which had a private electricity sector which survived nationalization, since the 1991 reforms has developed a significant private electricity sector. Kazakhstan has a privatized electricity generation sector since 1994, although the state retains a big ownership stake through its sovereign wealth fund. Ukraine has mostly privatized its thermal generation sector by 2012. The other countries in our group have not to date privatized their generation sectors and they must rely on special laws, exemptions, and regulations to allow IPPs (whether national investors or foreign) to be able to invest and operate in their countries.

The recent development of public-private partnerships (PPPs) in the electricity sector are simply IPPs in joint venture with SOEs, but still must function as private market operators if they are to attract private investment. Only if IPPs are permitted to function, legally and profitably, can FDI occur in a country. An indicator of how far IPPs are developing and operating is to see the amount of total investment capital. A comparison of the private participation investment in China and India indicates how much more open the Indian economy is to IPPs, and thus to what extent that FDI would be acceptable, than is China's (see Chart 1). These data clearly show the impact of China's promotion of FDI in the late 1990s (and its subsequent sharp decline) and the rise of the private sector in India since 2005, which is bringing large sums of investment capital into the electricity sector (including FDI). For India, with a relatively large domestic private electricity sector, it can be seen that domestic investment in power plants dwarfs FDI in the past seven years. By comparison, since 2005, as Ukraine began its process of privatizing the electricity generation sub-sector, it has received $760 million of private investment in the sector, while before 2006, the sums of private investment, including FDI, were negligible.

Chart 6 - Level of private investment in electricity sector



Source: World Bank Database. Presumably in China most of the funds were from FDI as, unlike India, it does not have a private electricity sector. In India, estimates of FDDI participation are less than one-tenth of the bars shown.

The IPP movement arose out of the de-regulation of the U.S. electricity sector after 1978 and the privatization of the U.K. electricity sector in the late 1980s/early 1990s. A downturn in the industry in the U.S. in the 1980s meant there was accumulated investment capital looking for investment opportunities outside the U.S. At roughly the same, China's reforms in the early 1980s seemed to invite the world in and the first responder was Hong Kong's China Light and Power, which in 1985 signed up the first FDI into China's electricity sector with a nuclear power plant at Dayawan (often called Daya Bay) in Shenzhen, Guangdong. This opening into China occurred at the same time as there was a perceived capital crisis in China and power shortages noticed in many parts of the country. FDI was seen as a solution to these problems. The privatization of the British electricity sector demonstrated to U.S. investors that it was possible to take IPPs overseas and that investment opportunities and returns were quite attractive.

By the late 1980s-early 1990s, the U.S. Government was vigorously promoting the advancement of IPPs and electricity privatization in statist or socialist, developing countries around the world. India made a major reform of its electricity industry in 1991 and all of these movements converged. This was the beginning of the Enron Dabhol natural gas-fired power plant project. There were hundreds of proposals put forward for foreign IPPs in the generating sector, but only 20 eventually came to fruition, but Dabhol was a major political initiative. When it was announced, Dabhol was to be the largest foreign investment ever made in India, and from the very beginning it was confronted with lively political opposition both in New Delhi and on the ground in Maharashtra state. Everything about the agreed project broke all of the political norms, rules and policy structures of the Indian electricity sector: the plant's size and cost, the private power agreement, the American involvement, the import of LNG to fuel the baseload generating units, the fact that it was solely owned by foreigners, the top level political interventions which provoked political disputes between the local state and central government.

Although Dabhol was the first FDI to be signed, there were so many interruptions and disruptions and re-starts in the coming nine years that Dabhol in the end was not to be India's first commissioned and operating FDI power project. That distinction went to another one of the early starters: the Jegurupadu gas-fired combined cycle power plant in Andhra Pradesh which was originally a joint venture between a local private Indian company and another American power developer and which opened in 1997. (The American developer, CMS Power withdrew in 2002 because of difficulties in enforcing the power purchase agreement (PPA).) The second early IPP with FDI was Paguthan gas-fired combined cycle power plant, which was an IPP joint venture between an English developer, PowerGen, and a local private energy firm, Torrent Energy. It opened in 1999 and shortly afterwards PowerGen sold out to China Light and Power (CLP).

The late 1990s and early 2000s was a period of great enthusiasm and gradually dawning disappointment for foreign investors into India. Following the reforms and strong promotion and incentives from India, the country had received 189 offers from IPPs (both domestic and foreign) by August 1995 to develop 75 GW of new power; 95 of these were through MOUs for 48 GW, and 32 were in response to competitive international bidding for 21 GW. Of these 17 projects were approved by late 1996 for "fast track" advancement and approvals, and another 14 by end of 1998. But by 1999, the foreign developers were beginning to experience what has come to be India's biggest obstacle to FDI: hostile litigation, bureaucratic delays and foot-dragging in getting approvals, permits, and negotiations. After five to six years of pushing to advance their projects with no tangible results, by the end of 2001 U.S. firms such as Mirant, Mission Energy, and Cogentrix Energy pulled out of their joint venture projects with Indian or foreign private firms, and as well U.K. firms, PowerGen and National Power withdrew from their projects. The period 1995-2002 proved to be a false start for foreign IPP investors, although it was a time when India's private IPPs began to establish a significant foothold in the Indian electricity sector. Since April 2000, India has received a cumulative investment into all segments of the electricity sector of $5.9 billion, about 3.5 per cent of total investment in the electricity sector.

Meanwhile in China, after CLP broke into China's electricity sector with its nuclear power agreement in 1985, the next IPP investment, and the first to be commissioned also came from Hong Kong. This was the ground breaking 600 MW Shajiao B coal-fired power plant located in Shenzhen which was commissioned and began operations in 1987. It was developed and built by Hopewell Holdings, up to that time a big Hong Kong property and real estate developer, which owned 50 per cent of the project in partnership with Shenzhen Energy, a local state-owned electricity company. After Shajiao B began paying back its investment, Hopewell Holdings began the construction of Shajiao C with 1,980 MW of coal capacity which was completed in 1995. Shajiao B was the first build operate and transfer (BOT) venture to be used in China by IPPs and became a model through the 1990s.

There was a "gold-rush" for foreign IPPs into China in the mid to late 1990s. This was sparked by the success of Hopewell, the decline in the demand for IPPs in the US which released venture capital looking for opportunities in the developing economies, and the some of the liberalized terms for foreign investors contained in China's 9th Five-Year Plan which forecast shortages of electricity and low availability of domestic capital. Foreign IPPs were trolling the opportunities trying to get into the Chinese power generation market. There were 40 IPP companies looking for deals in China in 1994, and 54 in 1995, more than 100 MOUs were signed up for power projects using foreign investment. In late 1995, when China invited bidders for the development and construction of the Laibin B 720 MW coal-fired power plant in Guangxi province, they received more than 42 bids. Electricité de France (EdF), a partner (along with Alstom) in the team that won the bid, stated that it was looking to make China its next market because it had built-out France's electricity sector and there were no further business opportunities there. Laibin B was important as it was the first IPP with 100 per cent foreign ownership and it was the first to try BOT as an investment structure.

Between 1994 and 2000, 54 of the MOUs from IPPs were launched and eventually constructed and commissioned, attracting $10.7 billion of FDI. The estimate at the time (2001) was that foreign investment equalled 13-14 per cent of the assets in electricity generation. Then the door was shut in China and not only did the flow of FDI into IPPs come to a complete stop, many of the original investors and developers withdrew in the years 2000-2004. This retreat was made more sudden as Chinese authorities and electricity boards in many different provinces failed to honour the power purchase agreements (PPAs) either in off-take volumes of electricity or in the promised tariffs. The rules for Rates of Return incentives were changed once again, to the adverse. The Asian financial crisis of 1997-1998 had also gutted investors' bullishness about investing in Asia while alarmingly raising the risk profiles of Asian investments. By the end of 2006, after a promising start in the earlier decade, only an additional $1.4 billion of FDI in the electricity sector had entered the country. It is estimated that China has received $15-$16 billion in FDI in the electricity generating sector since 1985. This is less than 1 per cent of the total investment that has put into the sector over the same time period.

The early IPP developers in China, India, Kazakhstan, and Ukraine have all found that being a foreign investor in the state-run and state-owned electricity industry, which was and remains highly politicized both at the national and local levels, was extremely difficult. There have been all kinds of obstacles and challenges thrown in their way, and profitability, much less a healthy return on capital investment, was constantly difficult to achieve. These challenges, plus aggravated disputes, led most of the early investors to withdraw or sell out; their losses often negatively impacted the profitability of their parent companies back home. Being an early investor did not save many of them. AES of the US was an early entrant in China, India, and Kazakhstan: they have largely withdrawn from China and Kazakhstan, and are near a decision on withdrawing from India. (Ironically, the Chinese have bought a minority stake in AES Corporation in 2010; just as they have in the early entrant in India, Edison Mission Energy.) CLP, Hopewell, and EdF, early entrants in China, still carry on there, all the rest have folded up and withdrawn. Likewise CLP remains active in India, the last of the early entrant investors there.

Table 17 - Arrangements for IPP investments into state-owned electricity sectors

Type	Investment arrangement
CONCESSION	BOT: Build Operate Transfer ROT: Rehabilitate Operate Transfer RLT: Rehabilitate Lease Transfer BROT: Build & ROT
DIVESTITURE	Full or partial privatization sale of state assets, Privatization on shares market
GREENFIELD/ Wholly foreign owned enterprise	Special private legal entity BOT BLT: Build Lease Transfer BOO or BOOT: Build Own and Operate or Transfer
MANAGEMENT AND LEASE	Management contract Lease: fee and operatorship
ACQUISITION	Equity purchase of private or SOE genco
JOINT VENTURE	Equity Joint Venture with Private partner company Contractual Joint Venture with SOE Public-Private Partnership

Out of the initial experience of FDI into IPPs in both India and China, IPP developers understood that there were only a fixed number of arrangements that were allowed for entry into centrally-planned, state-owned electricity industries regardless what the laws said about the freedom for foreign investors to invest in the sector. Countries could offer (or sell) a concession, they could privatize a utility or a power plant, they could buy a power plant or utility company (if the country had corporatized its utilities), the IPPs could take a management contract with investment obligation, or they could enter into a Joint Venture with either a state-owned or private power company. In many cases there were term limits to the concession offered to the investor, i.e. 15-20 years after construction, so that these agreements became Built-Operate-Transfer (BOT) structures. In a few rare cases, Built-Operate-Own-Transfer deals were offered. In China, most deals had limits on foreign ownership; even the Hopewell Holdings investment in Shajiao B was restricted to 50 per cent. Kazakhstan offered term concessions using Rehabilitate-Operate-Transfer terms (AES invested this way in the Ust-Kamenogorsk CHP).

AES also received a term lease to upgrade and operate a hydropower plant in Kazakhstan. Ukraine sold a ROT concession to ContourGlobal to upgrade the CHP at Kramatorsk. In India, with more liberalized electricity generating market and a substantial local private sector, the IPP developer Mission Energy entered a joint venture with Tata Power-- a private energy company that pre-dated India's nationalization of the sector-- to build the Jojobera 1 coal-fired power plant in 1996. In India, there was also one of the very earliest examples of a sale of a SOE power company, still a unique arrangement in India. In 1999, OGDP of Orissa state sold a 49 per cent stake to the U.S. company, AES Corporation (which had first begun investing in India in 1993), for $143 million, a sale which gave the U.S. firm the managerial operatorship of OGDP's principal asset the Ib Valley 420 MW coal-fired power plant. Another example of a sale of the assets of a SOE was Almatyenergo's sale under concession terms to Tractebel in 1996.

As the IPP movement spread its investment arms through the 1990s from the developed economies to throughout the developing world, a consistent cast of investors appeared. Investors in electricity generation were not homogenous entities. Some were contractors, some were utilities or electricity companies, and some were mere special purpose investment funds specializing in risk financing of electricity generation. But many of the large number of participants, for example AES Corporation, were specially established power developers which often had little experience operating electricity generators and which were formed to develop generating units in both the developed and developing world.

Table 18 - Types of companies participating in the IPP market in developing economies of Asia

	Market share 2000	Companies-home country
Power companies/Utilities	42%	PowerGen*-US, Mission Edison*-US,AEP-US, EdF-France, Tractebel*-Belgium, CMS*-US, PSEG Global*-US,CLP-HK, Singapore Power-Singapore, National Power*-UK, HydroQuebec*-Canada, International Power*-UK
IPP Developers	44%	Mirant*-US, AES-US, Cogentrix*-US, InterGen-US, Destec Energy*-US, Panda Energy-US, Peak Pacific Energy*-US, Asia Power-Singapore, CDC Globaleq-UK, GdF-Suez-France
Infrastructure/Engineering companies (EPC contractors)	6%	Hopewell Holdings-HK, POSCO-Korea, Tata Power-India, Cheung Kong Infrastructure-Hong Kong, Doosan Heavy Industry-Korea
Fuel producers	4%	Exxon-US, Conoco-US,BG*-UK, Enron*-US, Total-France
Equipment companies	2%	Alstom-France, ABB*- Swiss, GE Capital-US, Shanghai Electric-China, Mitsubishi Heavy Industries-Japan, Babcock-Hitachi-Japan, Westinghouse-US
Financing funds or other parent conglomerate companies	2%	ContourGlobal-US, Destec Energy*-US, Sojitz-Japan, Hinduja-UK, SembCorp-Singapore, Sithe Global-US

*Indicates companies which no longer exist or which have withdrawn from international IPP development. Market share is from our estimates of the investments these firms made in 1995-2000.

The IPP developers, the biggest group of participants in electricity generation investment in the 1990s, were specially founded to advance IPP investments initially in the US, but then in the UK and worldwide. AES, founded in 1981 shortly after the US electricity de-regulation act of 1978, took the lead and at one time globally was the most active investor, risk taker, and an early entrant and leader in China, India, and later Kazakhstan and then Ukraine. It still has residual holdings in these countries although it is re-organizing and withdrawing from the high risk markets. The big US and then UK utilities in the late 1980s and early 1990s organized operating subsidiaries that sought out international investment opportunities in IPPs relying on their strong credit and abilities to raise finance. EdF sought out international opportunities especially in nuclear power development, taking an early position in China where it has remained involved since 1984. In the early-mid 1990s, many of the large multinational oil and gas companies jumped into power development. Castle Peak Power Company of Hong Kong has been a 60 per cent-40 per cent joint venture of ExxonMobil and CLP for nearly 30 years. But the multinational oil and gas companies did not remain long in the IPP market. Of all of the oil companies that had power development divisions 15 years, only Exxon remains in the business and has a big presence in Hong Kong's electricity generation sector. The engineering firms and equipment manufacturers have not often been investors in building electricity generation stations--almost never lead investors or developers--although they have invested in joint venture equipment manufacturing in both China and India to advance their sales of their power equipment in those countries.

By the first decade of the 21st century, the global IPP movement was beginning to wane, as investors were finding it harder to make strong returns both in high risk markets, such as Asia, and in developed economies. In the US the Enron bankruptcy was accompanied by the collapse of the California wholesale market and the IPPs supporting it--a market structure which had been built and promoted by Enron. In addition to finding financing harder to come by, IPP developers were finding good, profitable investments harder to find, and many of those established as FDI in the 1990s ran into insurmountable problems in the markets of the developed world. The state-owned power generators, in spite of reforms by central governments, did not want competition. Incentives were taken away, pricing agreements and fuel supply contracts were not honoured, and the general environment for foreign investors and operators became quite hostile. Many of the specialist IPP developers also struggled with impossible debt levels and by the middle part of the decade many of them began to seek bankruptcy protection in their home markets. They were followed into oblivion by the IPP development subsidiaries of the large utilities, especially in the US and UK, which found that their parent utility companies did not have the risk appetite, nor the endlessly deep pockets, in order to continue. By the end of the decade—even though there have been new IPP developers to come out of Singapore, India, and even China—the global IPP investment movement was effectively finished, and most of the participants of the 1990s had either disappeared or were shrinking their businesses. The global financial crisis of 2008 has probably been the final death blow to the IPP industry. One of the only survivors from the very beginning of the IPP movement is CLP of Hong Kong which continues to operate its investments and to look for new business opportunities.

Captive power and FDI

Captive power development is that investment made into electricity generating plants which are built primarily to supply an industrial development or mining complex with its own (thus "captive" or "mine-mouth" power plants) and which thus do not primarily rely on sales of electricity to the national or wholesale grid in order to prosper. While these power plants are usually "independent", meaning privately owned, they do not rely on revenues primarily from electricity sales into the national grid and so they are not really IPPs. Sometimes these are sponsored by the industrial company developing the steel mill, coal or minerals mine, or chemicals or industrial park to ensure that these complexes get the uninterrupted, reliable, and affordable electricity that they need to operate. India is well known for these sorts of power plants which represented 15 per cent of India's installed generating capacity as of the beginning of the 12th Five-Year Plan in April 2012. In other cases, an IPP developer is the lead developer, who develops the power plant while looking for investors into a prospective industrial park which will then become the main buyers (and economic justification) for its power plant development. BG Power adopted this business model for IPP projects in S.E. Asia in the early 1990s. In the former case captive power, especially in India, does not attract very much FDI especially if the industrial developer or miner is a local company; in the latter case FDI is usually heavily involved.

India has a number of coal mine-mouth power plants which have been or are being developed by Indian coal mining companies, steel companies, chemicals combines, that are the primarily sponsor and financiers of the plant. Some of them, such as the mine-mouth SKS Ispat & Power Company-sponsored, 1,200 MW Chhattisgarh coal-fired power plant, combines a local steel, coal, construction, and power conglomerate, the primary sponsor and financier, with a U.S. IPP financing company, Sithe Global. But most of the captive power plants in India have been exclusively developed and financed by private Indian firms such as Essar Energy, Torrent Power, or Adani Power and have not entailed much or any FDI.

By contrast, most of the projected mine-mouth power plants in Mongolia will be sponsored by the foreign mining companies which lead the coal or copper mining project. These will undoubtedly be mostly financed by FDI. As another example, SembCorp of Singapore was invited to participate in a sponsored captive gas-fired co-generation plant in Shanghai by the chemicals industrial park which is the lead developer and will be the main owner. It is expected to supply 30 per cent of the financing of the plant's $550 million cost.
The big power plants built at mine-mouths in Kazakhstan were developed in Soviet times and their linked power plants were sold to the industrial companies which had bought the privatized coal or copper mines, such as Kazakmys (copper) or Eurasia Natural Resources (coal). These mine-mouth power plants, Ekibastuz GRES 1 and Aksu power plant respectively, were built with such scale that the "captive" sales represent only a small portion of their electricity output; most of their sales go into the national grid. Neither of these companies has brought much FDI into electricity sector of Kazakhstan. They neither are really captive power nor were they IPP developments.

Obstacles and risks for foreign investors into the power generating sector

Macro risks

Investors who bring FDI into a country have many motives, but foremost among them the investor wants a profit and good return on investment. The more reliable and sooner the investor can get good profits and ROI the better. The more obstacles there are in a recipient country to the investment earning an attractive, reliable return the higher the risks are for the investor whose investment capital is "exposed", and as these risks become greater the less likely the investor will make an investment commitment. The same applies to lenders who support FDI projects. The more obstacles there are to making the investment and getting a return, the higher the risk. Investors have always and everywhere require higher, more assured returns to compensate them for the higher risks (that there will not be any returns), which are perceived to exist in a specific country.

There are many general risks for a foreign investor into any industry of any developing economy; risks which do not have anything to do with the legal or regulatory rules governing industry-specific FDI. These so called macro obstacles can often be the over-riding concerns for potential investors and their presence impedes any further consideration of investment. These macro risk factors which block FDI include:

- **Security**: The presence of civil war or insurrections or other violent civil disturbances prevents the evaluation of all but the most robust investment projects. Investments into IPP electricity generating plants – which are by their nature exposed to high costs, large debt financing components, and long time periods for development and to get a return-on-investment—into countries like Syria (active civil war) or Afghanistan (active violent insurrection)—are at the moment virtually impossible investment destinations. Such places, until they can assure security, can only expect to receive foreign assistance aid for power projects, and not FDI. It has been noted in the past that companies in the extractive industries, particularly oil companies which can get a quick result and can export their production, have been most tolerant of regions with high security risks. Afghanistan may be able to attract mining investments, but it is unlikely to get electricity industry investments under current circumstances.

- **Payments risk**: FDI sends hard currency into a country where the investor earns his profits in the local currency, which may or may not be exchangeable back into the hard currency at the same rates. This can exist in countries where there are high national debt and balance of payments deficits and a history or expectation of depreciation of the national currency (because of inflation or debts). These pose especially high risks for the investor in projects which cost multi-hundreds of millions or even billions of dollars and which extend over a decade or longer. If a country decides to devalue its currency or the markets force it to, this is a risk of loss that is beyond the control of the Ministries with whom a foreign investor has its contracts, authorizations and power purchasing agreements (PPA)

At the present time, India and Ukraine pose these currency devaluation risks. These are macro risks which hit foreign investors in any sector in these countries. India's rupee has fallen from 33.3 to the dollar in September 1995 to 54.4 rupees to the dollar in September 2012, and market expectations are that the rupee will continue to depreciate to 80 to the dollar in just a few years. For the FDI investor in this period that means his rupee returns have lost 38 per cent of their value relative to the dollar, and market participants expect the rupee will lose another 32 per cent in value if as they expect it continues its slide to 80 to the dollar. In Ukraine in the same period, the hryvnia has devalued from 1.5 to the dollar to 8 to the dollar, a loss of 81 per cent of its relative value. Many observers fear that Ukraine's high debt and low credit rating and inability to borrow further will force it to devalue after the next election.

Another element of payment risk is the history of a country's currency convertibility. Many countries have currency exchange restrictions, Uzbekistan for one, where because of the unavailability of hard currency reserves they restrict the amount of domestic currency that can be converted to hard currency and remitted abroad. Even if the country has laws or rules that allow foreign investors to remit their profits abroad, if the country does not have enough freely exchangeable currency or if it does not have enough foreign currency reserves they may simply not comply with the request for profits remittances. This has been the history of foreign investors in Pakistan. Uzbekistan has a regular history of refusing to allow the foreign investor hard currency remittances. This is a very important reason why Uzbekistan receives so little FDI in general.

- **Rule of law**: It has become clearer in recent decades that countries
  - that are governed and administered by enforceable, transparent laws,
  - where the terms of contracts are honoured,
  - where the judicial system can redress grievances promptly, offer restitutions for wrongful damages, and enforce contracts,
  - where a foreign investor's rights and investments are protected (both personal and commercial),
  - where arbitrary or unpredictable laws or rules are not regularly changed nor applied to specific circumstance or for best advantage,
  - where state or provincial authorities cannot flaunt or disregard the national laws or policies and apply their own terms and rulings,
  - where the legal system protects the investor from criminals,
  - where the economy runs according to laws and market rules and conventions, not but by fiat and command,
  - where permits and operations can be obtained by rules and open regular procedures and not solely by connections or personal relationships,

are better destinations for foreign investment. Socialist states and most command economies have very weak rule of law, authoritarian dictatorship also have arbitrary and non-transparent laws and protections for investors. Unfortunately, experience has shown that China has weak rule of law and investors often discover once they are invested how constricted their rights are and how disadvantaged they are in nearly all their dealings and business activities. Uzbekistan repeatedly demonstrated a lack of legal protection for investors. The recent seizures of the foreign investments of MTS and expulsion from the country over commercial disputes are one more demonstration of the perils of investing in the country. Tajikistan, Kyrgyzstan, and Ukraine perform poorly in this regard and in recent years abuses in Kazakhstan have shown that its rule of law has become poorer and more arbitrary than it was in the 1990s when foreign investors first entered the country.

- **Corruption**: This is actually an aspect of the rule of law and it also is a political risk, but corruption can be a problem even in states with an established legal and judicial system. Its presence or extent can block investment projects at almost every turn: land acquisition delayed, rules not enforced until a bribe is paid, protection racketeering, licenses and permits not given or renewed, fuel supply contracts ignored, export rights denied without unofficial payments. And it has a number of costs of course, not just monetary. Delay is one of the biggest risks: the uncertainties of when a project can get the go ahead, can be built or completed, or can be commissioned or expect to receive payments. These can be sizeable risks for foreign investors. India has a poor reputation in this regard, and many foreign investors have discovered that China is periodically risky in this regard. The racketeering and corruption that occur in Uzbekistan are frequently cited by foreigners doing business there. Kyrgyzstan ranked 164th out of the 183 countries for the rampant presence of corruption in Transparency International's Corruption Perception Index. The corruption has ranked as the main political grievance in the country over the past 3 years.

- **Political risk**: The electricity industry and how it develops is underpinned by political policies. Foreign investment in major electricity projects are also made in accordance with political policies and decisions. And there can always be political opposition to those policies, decisions, or investments and where there is opposition there can be resistance and even dramatic political change.

There can often be strong political resentment and opposition to foreign investment in general, or it can be directed to a specific industry or specific project and its locale. Opposition can also be directed against the foreign investor's nationality. (The Indian public in general and many politicians are generally hostile to big American companies seeking to invest—this was especially true after Dow Chemical's Bhopal disaster or Enron's Dabhol fiasco.) This antipathy and opposition can be strong enough that it can muster public, mass demonstrations against a foreign investor's project and its activities (clearing land of forest, using water, digging an open pit coal mine, more recently violent protests by environmental opposition to the planed Jaitapur nuclear power plant). This kind of public opposition or demonstrations can stop an investment project cold, or at least delay it indefinitely. But there are also opposition politicians who can show their opposition to such foreign projects for political advancement and if they gain power they can repudiate the investment project, the contracts, and the enabling legislation. But even if they cannot gain power, their outspoken opposition could force ruling politicians to modify or change the investor's project for political reason. Although politics do not appear to be public, it is clear that some policies in China contain political risk: Chinese do not like foreigners to have complete control of power generators, they do not allow them in to the nuclear sector and restrict foreign investors for political reasons which may only be manifested around the changing of the ruling heads of the Party. China just learned about political risk in energy development when their major investment in a Myanmar hydropower dam project was abruptly cancelled by the new government.

Kyrgyzstan has particular high political risk. It used to be viewed as a foreigner investor friendly country, but after three violent changes of government in the past seven years, those foreign investors have discovered that their investments do not look so assured of success. There have been violent attacks and demonstrations by political opponents of the previous and current regime directed against the country's largest foreign investment, the Kumtor gold mine of Canada's Centerra Gold. Some in the heated opposition are simply angry at the appearance of foreign investors, claiming the politicians have sold off the country to foreigners. The violence of the political actions in Kyrgyzstan, even without a big foreign investment to target, makes the general environment for investment risky and unappealing.

Industry specific obstacles and risks for FDI in electricity generation

With the fall of the global IPP industry and the aftermath of the 2008 world economic crisis, overall investment into the developing economies of the nine countries into electricity generation of all sorts has steadily declined since 2005, most seriously into China and India. This is in spite of recent incentives that have been written into FDI rules for investments into wind and other renewable energy resources. Foreign investors still have profitability as their highest priority when committing to investments in the advanced fossil fuel technologies in developing countries, whether they advance themselves as motivated by climate change concerns or environmentally friendly business targets or whether they seek to transfer technologies which will mitigate CO_2 emissions. The international financial community, including the multinational development aid lenders, also demands profitability. None of them in fact will support the huge amounts of financing needed if the projects will not pay back the interest on debt and pay a return on capital to the investor which will ensure his commitment.

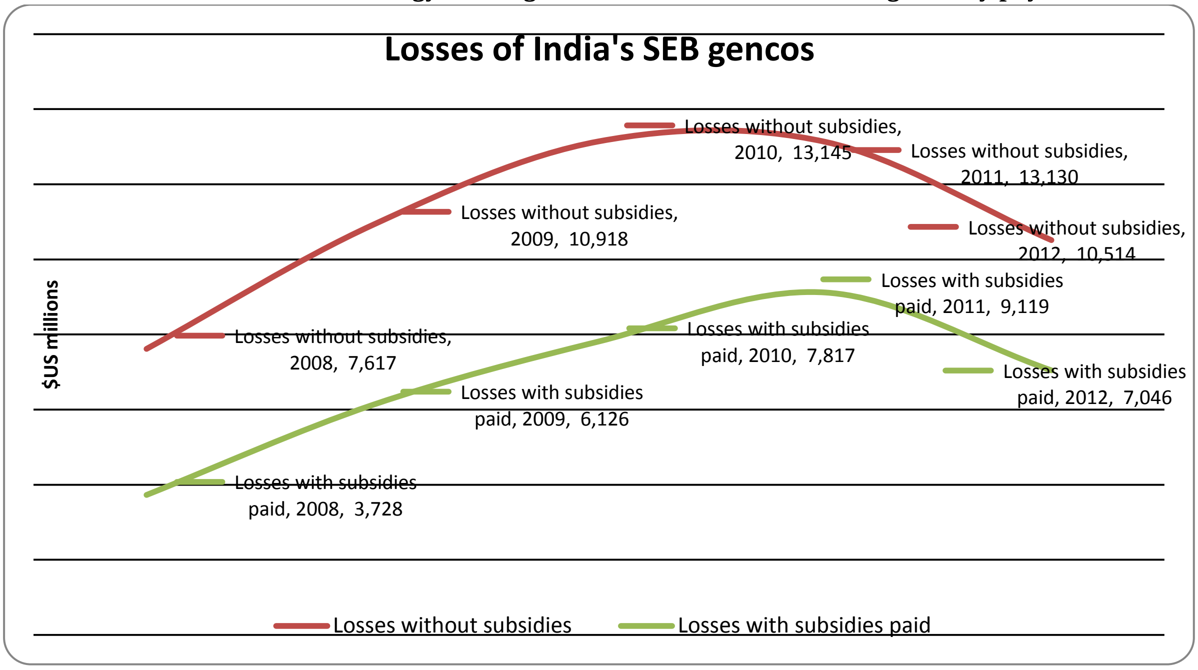
And it is not just profitability: foreign investors have to receive profits rates which are in excess to what they could receive if they made similar investments in Western Europe or Japan. Following the nuclear disaster of

Fukushima in 2011 have now huge demands in excess of $800 billion in the near future to re-build their base-load electricity industries. These are countries with much lower (and much more knowable) investment risks than any of our project countries.

All of the countries in our study group have laws that encourage and enable foreign direct investment; some even have specific terms for the electricity sector. (The problem that remains, as described above, is how efficiently and transparently these laws are applied in practices). These terms have changed over time and countries have gone through stages where they have actively promoted FDI into the electricity generating sector and other stages when they were at best indifferent or even unreceptive. As said earlier, to date China, India, Kazakhstan, and Ukraine have attracted FDI in the electricity generating sector as we have seen above, and Mongolia is about to sign up its first FDI in electricity generation.

The biggest risk that all of the foreign investors have faced and will continue to encounter is building a profitable power plant. This is extremely difficult in both China and India, and the evidence of scope of this difficulty is in the extent to which the domestic electrical utilities have been run at losses, huge losses in fact. But likewise power generators have run at significant losses in Ukraine as well in the past five years and it appears that the power generators in Mongolia do not run at a loss only because the cost of subsidies are passed to the wholesale distributor. It is politically very difficult for local regulators to allow foreigners to sell their electricity so that they can make a healthy return on investment, when the SOE generating companies (gencos) are losing money or have to be heavily subsidized.

Chart 7 - Losses of India State Energy Board gencos before and after receiving subsidy payments



Source: Annual Report, 2011-2012 on the working of State Power Utilities & Electricity Departments

These losses at the local SOE gencos are very heavy indeed, but they are almost contrived deliberately by policy. In India, the largest single segment of electricity generation comprises the State Energy Boards and their utilities, which exist in every state (province) of India. Their losses in the past five years amount to more than $55 billion and they carry on their books arrears of $53 billion.

These high levels of losses have occurred for many years prior to 2008 in the SEBs; their accumulated debts are nearly unsupportable (and in fact are only supported by local political subsidization). Fifty power projects, nearly all SEBs or Central SOEs, are at risk of financial default. A headline in August 2012 showed that the Uttar Pradesh SEB, one of India's largest had financial losses for fiscal year 2011-2012 of 430 billion rupees (or

$8 billion). In the case of the SEBs, losses are mostly attributed to subsidization, theft, non-payment for electricity, and high level of system losses.

In China the situation is similar to India's. The five major electricity companies of China had accumulated losses of 60 billion Renminbi ($8.76 billion) for the period 2008-2010. In 2011, the losses of these five "National Champions" were estimated at a staggering 350 billion Renminbi ($54.2 billion). They have fallen into a classic "spark squeeze" where fuel prices have risen steadily since 2000, but the additional costs have not been allowed to pass-through to end consumers in tariffs. In 2009 for example the average cost of coal to the Chinese utility was $0.039 per kWh, while the average offered tariff was $0.054, a small margin. After an effective "freeze" in coal prices for 2012-2013, they are now earning a paper thin margin of 0.0034 US cents/kWh. Regional sales prices are high enough to ensure profits only in three provinces of China: Jiangsu, Zhejiang, and Guangdong, all on the coast.

These losses in the SOEs all can be put back to the same fundamental risk that has and continues to face foreign investors: price risk, the risk that tariffs are not set to cover rising fuel costs, to allow a capital charge, and to allow for repayment of debt and interest and leave a profit.

- **Price risk:** In all of the countries where foreign investment in electricity has already gone—China, India, Kazakhstan, and Ukraine—the pricing and marketing of electricity have not been liberalized, that is taken out of state control and allowed to function on market principles**.** This has meant that tariff setting has been left to negotiations between the local power authority (provincial in China, SEB in India) and the investor seeking to get a PPA (Power purchasing Agreement). A PPA is one of the key documents which enables a project to attract debt financing. It includes details about:

- volume off-takes of electricity (and take-or-pay arrangements)
- load capacity at which the plant is expected to run
- sometimes rates of Return on Capital (ROC) or Return on Investment (ROI)
- allowable capital charges, interest components (including front loading debt recovery in tariffs)
- tariffs

Foreign investors have insisted that tariffs encompass all fuel costs, capital charges (i.e. depreciation), payments for debt amortization and interest payments, and some reasonable profit component. When China first opened its doors to foreign investment it initially included a 12 per cent ROC in its PPAs, but then it raised this to 15 per cent ROC. Investors of the late 1980s-early 1990s were looking for ROCs of 18-23 per cent. None of China's PPA's offered that. CMS had an investment in India with a local private Indian company in the Jegurupadu coal-fired plant in 1997. It had a PPA that offered a 16 per cent ROR and included a 68.5 per cent load factor. It still exited in 2002 over disputes over the price it received and the volumes it could sell into the wholesale grid. India now offers incentives of 14 per cent ROI for generation projects.

Where tariffs mechanisms failed in China was that they did not offer any pass-through mechanism for the increasing cost of fuel. That is, tariffs could not be adjusted to reflect and capture the higher cost of coal. From 2000 to 2012 coal prices in China have risen by 193 per cent (from Yuan 197/ton to Yuan 600/ton), and most of this price rise was denied recovery in tariffs (the reason for the hefty losses in Chinese SOEs) because they did not have a pass-through mechanism for changes in fuel costs, a situation called a "spark squeeze". This is what led one of the earliest and longest foreign investors in China, AES, to sell out of its power investment in Yancheng in 2011. Peak Pacific also sold out in its seven thermal plants in 2006 for the same problem (unrecoverable rising fuel costs).

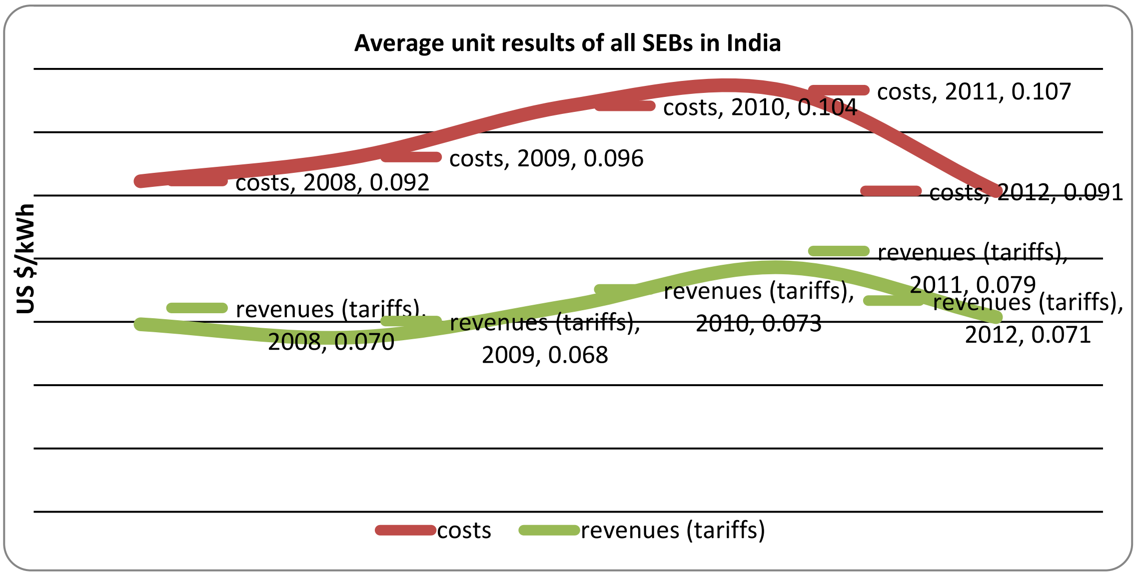
In India as in Ukraine the policy makers and the regulators both believe that the local citizens cannot afford the full price of energy so that electricity prices cannot rise. The problem with tariffs in the PPAs was that they have often resulted in tariffs that were higher than what the SOE gencos are allowed. In this case the SEBs in India and the regulators in Ukraine have often refused to pay the contracted tariff. In certain provinces of China where markets are controlled and regulated by the local power authority, the authority could not face paying more to the foreign investor, regardless of his PPA, than what he paid to his own local SOE genco, so the authority refused to take delivery of the electricity, effectively shutting down the plant.

India has long recognized that its non-market related electricity tariffs were a massive economic problem. They started the first market reform in 2003, but it has been very slow to roll out and its aims have met universal opposition in the SEBs and the states. To press for price reforms or even a move to a market related system for determining prices would be a political struggle that the current government does not have the will or support to undertake. The subsidies issue is a major headache for reformers. Currently the average tariffs for electricity at the generator outlet is 3.8 rupees/kWh ($0.071/kWh), but agricultural consumers pay only 1.53 rupees/kWh ($0.028/kWh) and residential consumers pay 3.2 rupees/kWh while commercial consumers underwrite the subsidies by paying 5.81 rupees/kWh, almost four times more. It is widely reported that generators need at least 5 rupees/kWh to break-even.

The presence of a single buyer model (SBM) in the wholesale market, where the state regulator sets tariffs, distributes, and runs the market, is often the setting where electricity prices are readily manipulated. This can be for profits transferring (downstream) or to run a subsidies program. These SBMs exist in Mongolia and Ukraine and to a certain extent, on a provincial basis, in China. And where they exist they tend to set tariffs too low. The current development to build a CHP in Ulaan Bator has not revealed what its tariff rate would be, but Mongolia imports electricity from Russia for the western grid at $0.08 per kWh, so there is hope that in the capital the foreign investors can get a reasonable tariff that will cover all costs and reward the risks. In the past several years—even as the Ukrainian state was privatizing its generating sector—its main electricity utilities were losing money by the bucket-load. This was primarily due to subsidies to the coal sector where the coal miners (an important political constituency) were given rising rates for coal, but the tariffs of the gencos were not allowed to rise because of the subsidized tariffs for the industrial and residential consumers (another important constituency).

Summarized in its most basic form, politicians in these developing countries do not think the population can afford to pay the full cost of electricity, so they offer tariffs that are too low to pay the fuel costs and returns to the risk taker. In India, these same politicians have even blocked universal metering because they believe that Indians are too poor to pay for electricity at anything close to market rates (and because it is good populist politics). How they expect anyone (other than the consumer) to pay for a program of CO_2 abatement--or even the much more expensive costs of non-fossil fuel electricity generation, or even more expensive CCS—strays into the realm of political wishful thinking.

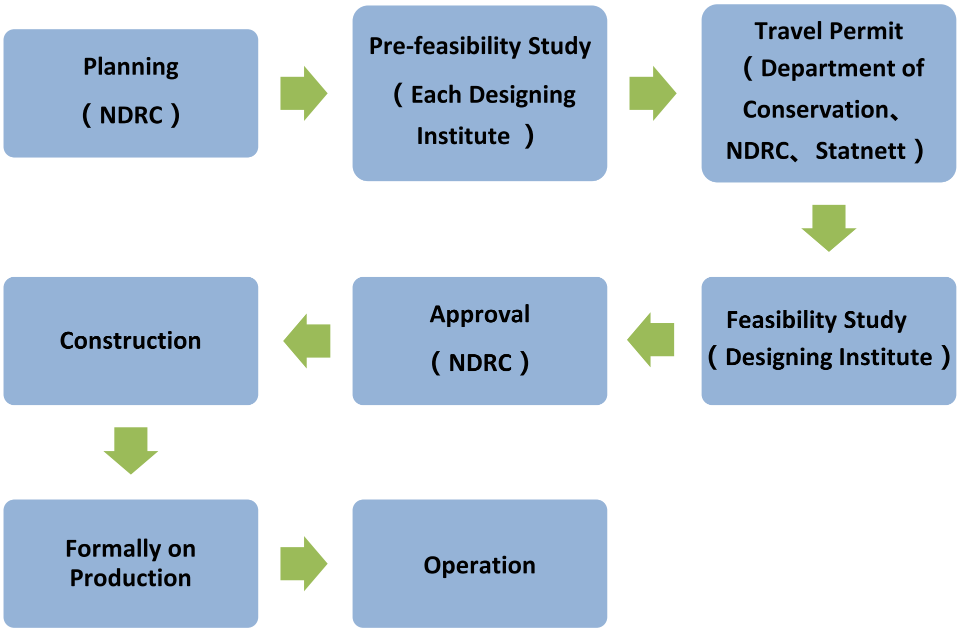
Chart 8 - Reason for losses at Indian SEBs
Source: Annual Report, 2011-2012 on the working of State Power Utilities & Electricity Departments



- **Procedures for making FDI and investing into electricity generation:** Although both China and India make strong protestations that they want to promote FDI into their electricity sector, the interested investor faces a bewildering procedure for locating and getting approvals for a new greenfield project. India has in fact acknowledged that non-transparent approval and inauguration procedures have been a bane of investors (both domestic and foreign) for much of the past two decades. And this is because the procedures cause seemingly interminable and unpredictable long delays. In the past four years India has launched a new "fast track" approvals procedure which it especially directs for its UMPPs and for advanced fossil fuel power plants. Before delays could be up to seven years on getting a project off the ground and construction started. With the fast track some have been developed and launched in less than three years. But India's decentralized governance of the electricity industry still leads to delays imposed by the states or even local authorities. Land acquisition permits have been held up by local and state officials often for more than two years. In the western part of the country water access permits are the issue of delays and unclear procedures.

In China, the procedures have been spelled out a number of times, but the reality is quite different from the official "guidebook". Getting through Chinese procedures for approvals and launching a greenfield power plant are difficult, so the investors from Chinese speaking entities—Hong Kong, Taiwan, or Singapore—have big competitive advantages over all other foreigners as they have consistently demonstrated in the past 35 years. The procedures should be easy as the chart shows:

Chart 9 - Procedures for approvals in China



Source: National baseline study for China

In some extreme cases projects were supposed to get into the fundamental planning document (the Five-Year Plan) in order to be considered. After approvals at the central state level, investors have, just as in India, often had to deal with local or provincial officials who add another layer of procedures and delays. Nevertheless, while procedural obfuscation and delays are a risk for foreign investors in China, historically the FDI projects usually began construction in less than 2 years after raising the issue and then would commission in 2-3 years depending on the scale of the plant, unlike India historically where approvals were 3-4 years and other delays could run 3-5 years on construction.

Project approvals and launching procedures in Kazakhstan, Ukraine, and Mongolia are even less well-established or straight-forward than China's and India's. Such lack of transparency may open the door to corruption. Kazakhstan's Balkhash coal-fired plant development took three years from signing a framework

MOU and signing the agreement to begin construction in September 2012, it was originally planned to be built by 2014, but now it will be in 2018. Ukrainian authorities, because of the poor procedures, can state in the process that they do not need or want any new foreign investment in the electricity sector, at least not for the next 8 years. Mongolia's procedures are not clear cut, but they are inviting foreign investors to bid on planned projects.

Current FDI in advanced fossil fuels technologies

As it has only been since 2004 and since 2010 respectively that first China and then India adopted policies to support and then began building advanced fossil fuel generating technologies—such as SCPC, USCPC, or CCGT power plants which significantly abate CO_2 emissions—it is not surprising that there has been little FDI to date that has gone into these advanced technology plants. To date CLP of Hong Kong is the biggest investor in these advanced technologies and is the longest surviving IPP developer in both India and China.

Table 19 - Current FDI in advanced fossil fuel technologies, power generators

INDIA	Investing company	Power plant	Stake	Type/Capacity	Cost $US mil	Year put into service
	CLP*	Panguthan, Gujarat	100%	CCGT, 655MW	750	1998
	CLP	Jhajjar, Haryana	100%	SCPC, 1,320MW	1,200	2012
under construction	**SembCorp**	Krisnapatnam, Andhra Pradesh	49%	SCPC, 1,320MW	1,280	2013
under construction	**Sithe Global**	SKS Power Generation Chharttisgarh	40%	not clear, 1,200MW	950	2014

*CLP was not the original investor, but bought in its position in two tranches from 2002.

CHINA	Investing Company	Power plant	Stake	Type/Capacity	Cost $US mil	Year put into service
	SembCorp	Cao Jing, Shanghai	30%	Co-generation, 600MW gas	550	2006
	Cheung Kong Infrastructure	Zhuhai, Guangdong	45%	SCPC, 1,320MW units 3 & 4	700	2007
	CLP	Fangchenggang, Guangxi	70%	SCPC, 1,320MW units 1 & 2	665*	2007, 2009
	EdF*	Datang Sanmenxia, Henan	35%	SCPC, 1,260MW	680	2007
	Hopewell Holdings Ltd	Heyuan, Guangdong	35%	USCPC, 1,200MW	815	2007, 2009

*EdF was not the original investor, but bought into its position in 2009

MONGOLIA	Investing Company	Power plant	Stake	Type/Capacity	Cost $US mil	Year put into service
awarded*	**Sojitz, GdF,Posco**	Ulaan Bator #5	100%	CHP/415MW	415	2015

*still under negotiations, delayed by new government

KAZAKHSTAN	Investing Company	Power Plant	Stake	Type/Capacity	Cost $US mil	Year put into service
awarded*	**Samsung C&T, Kepco**	Balkhash	75%	SCPC/1,320MW first module	2,300	2018

From these data it can be seen that FDI has made a contribution to the advanced fossil fuel power technologies in both India and China in the past decade or more. In China it brought in a net \$1.47 billion of new foreign capital since 2006 in support of a net 2.6 GWs of new generating capacity. In India, since 1998, FDI contributed \$1.95 billion which built a net 1.95 GWs of new advanced generating capacity. In India, there are currently underway two projects which could add another net 1.12 GWs of advanced coal-fired power plants or about \$1.0 billion of net new foreign capital. While any amount is encouraging, the sums are at best only very small incremental contributions: over the past decade in China FDI in advanced coal technologies added only 0.2 per cent to its total coal-fired capacity or approximately 1.1 per cent of the total fleet of advanced coal-fired technologies that China has built since 2004. In India, on the other hand, FDI in advanced coal-fired technologies added 0.9 per cent to it total fleet of coal-fired capacity. By comparison to FDI's contribution, India's power developers since 2010 have installed and commissioned about 6.5 GWs of new capacity using advanced fossil fuel technologies, and are embarked on investing in another 21 GWs currently.

To make any kind of noticeable contribution to the abatement of CO_2 emissions from coal burning, FDI would have to invest something on the order of \$30-\$40 billion (45 GWs) for new advanced technologies in India in the coming decade, and something on the order of \$75-\$90 billion (90-95 GWs) in China. In China that is the equivalent to replacing 50 per cent of the remaining small, older sub-critical coal powered fleet that still exist after the completion of the first program China conducted (2006-2010) to replace the small sub-critical fleet with large capacity advanced coal burning power plants.

These levels of investment are not going to come forward from foreign investors even with major reforms in the next few years. We have seen how difficult it has been for both China and India in the past decade to reform their electricity sectors and to make the changes that structure investment incentives and reduce risks to private investors. Huge changes and reforms have already been made, but many of them have been vitiated and other changes and reform initiatives have not been carried out or lasted very long.

Looking forward to the future experience in Mongolia, if the CHP5 power plant moves ahead and the selected foreign investors build it as required (a high efficiency combined heat and power coal-burning plant); it would make a noticeable abatement contribution to Mongolia's CO_2 emissions. What is uncertain up to now are the technical specifications of the planned captive, mine-mouth, coal-burning power capacity that Mongolia wants built at its many developing mining sites. If these are not advanced technologies, the positive impact of CHP5 on Mongolia's CO_2 emissions would be seriously diluted.

Likewise it is uncertain what the experience will be in Kazakhstan. The technical specifications of the newly signed Balkhash thermal power plant are likely going to be advanced coal burning technology. If it is completed with the capacity that has been announced, it would be equivalent to 10 per cent of Kazakhstan's current coal-fired capacity. That is a small abatement contribution, if the power plant is built with SCPC specifications. The important contribution is that it would be a case of FDI introducing new technology into Kazakhstan.
As a contribution to abatement of CO_2 emissions in India, China, and Kazakhstan it is clear that FDI that brings advanced fossil fuel technologies will not in the coming decade make a meaningful contribution or remove a significant amount of CO_2 from their current emissions levels.

New FDI in advanced coal-burning technologies could help abate CO_2 emissions in Ukraine with investments in the range of 10 GWs of new advanced coal or gas fired capacity. Although Ukraine is very much looking forward to attract FDI[5], there seem to be no immediate plans for investing in new greenfield advanced technology plants for at least a decade.

Still, for India, Kazakhstan, Mongolia, and Ukraine, FDI could be an important means for technology transfer in both advanced coal and gas combustion technologies. Perhaps for advanced gas combustion technologies FDI could contribute and be an important means of technology transfer for China's planned expansion of its gas-

[5] An illustration of such efforts is a deal between Shell and Ukraine signed in January 2013. http://www.bbc.co.uk/news/world-europe-21191164

fired capacity. For advanced coal-burning technologies China actually will probably become a significant net exporter of FDI in the coming decade as it has a world leading technological R&D in coal combustion technologies and has the largest fleet of SCPC and USCPC power plants in the world. It has already begun exporting its technological know-how to other coal burning countries, notably India.

Chapter VII: Investment climate

General investment climate, rankings

The general rules, functioning, regulations, and conditions of a country's economy and business activity are the background which makes up the investment climate for both domestic and foreign investors. Elements as diverse as inflation, labour unions, demand growth, currency exchange restrictions, xenophobia, anti-monopoly rules, presence of racketeering, public auction rules, political transparency, and domestic input requirements all are part of the complex fabric of the investment climate.

Countries in our study group range broadly in the openness and attractiveness of their investment climate. And while this is reflected in general domestic investment, the attractiveness of the investment climate is very clearly demonstrated in recent years by the amount of foreign direct investment that countries have attracted in all sectors from foreign investors, both in the nominal amounts of net FDI capital received and the amount of FDI relative to the country's GDP or population (see Chapter V).

Over the years a number of institutions have begun to examine the general business and investment climate in the countries of the world and have constructed ranking indices which make assessments of the many variables of a country's rules and regulations for investment. To demonstrate the relative attractiveness of the investment climate in the nine countries in our study, we look to three such rankings: the Ease of Doing Business Index compiled by the World Bank, the Global Competitiveness Index of the World Economic Forum, and the Economic Freedom Index by the Heritage Foundation along with the Wall Street Journal. The Economic Freedom Index does not measure or rank Afghanistan for reasons related to the continuing insecurity problems there. Likewise Global Competitiveness Index does not measure or rank Afghanistan and Uzbekistan because of lack of data and lack of local observers.

Each of these three institutions applies a slightly different methodology but in all cases they assign scores to the different components that comprise the investment climate. They utilize both surveys of businesses and businessmen working locally as well as in some cases conducting their own empirical or topical studies or specific country studies. From the scores compiled (or averaged) they then make a ranking comparing all countries on a scale of one to 190 (depending on how comprehensive their world view, these ranking range from 144 countries to 190 countries of the world). They annually re-examine the data and make changes as reforms or changes have been made in the countries reviewed. The World Bank, which uses data from more than 800 reports, began its Index in 2001, The World Economic Forum began its report in 1979, and the Heritage Foundation/Wall Street Journal began issuing its Economic Freedom Index in 1995. All three of these indices have attracted critics of their methods, and rankings, and economic assumptions. But all three have attracted faithful users from both the investment community and the multinational aid and lending institutions.

The World Bank Ease of Doing Business index specifically addresses the business and economic conditions facing small and medium sized businesses located in each country that it surveys. It measures and assesses variables in ten basic areas: starting a business, construction permits, getting electricity, registering property, getting credit, protecting investors, paying taxes, trading across borders, enforcing contracts, resolving insolvency. In 2012, the World Bank addressed the correlation between the rankings of Ease of Doing Business and attracting Foreign Direct Investment, and this report found that the better the ranking there was a distinct improvement in the ability of the country to attract FDI, in other words as there was a better investment climate for domestic business there was improved perception of the business climate for foreign investors and more FDI was attracted. Each of the ten basic areas earns a score 0-10, with ten being the best performance and zero the worst. The rankings of countries are inverse to their scores, that is the higher the composite score the lower (or better) the countries' standing in the over-all rankings. In our group of countries in the World Bank Ease of Doing Business Index for 2013 Kazakhstan ranks as the best and Afghanistan as the worst out of 185 countries ranked. With the exception of Kazakhstan, the countries of Central Asia rank poorly relative to most of the rest of the world. On the other hand the Index scores both China and India low in the comparative rankings, even though the World Bank acknowledges that in spite of low scores for ease of doing business, China and India rank first and third in terms of attractive FDI destinations.

In the Global Competitiveness Index for 2012 compiled by the World Economic Forum examines 110 variables classed in twelve pillars (larger classes). It is heavily weighted by the Executive Opinion report, but it also compiles its own reports and uses as well UN data. In the latest Executive Opinion survey the report got more than 13,500 respondents. The Twelve pillars are: public and private institutions, appropriate infrastructure, stable macroeconomic framework, health and primary education, higher education and training, efficient goods markets, efficient labour markets, developed financial markets, ability to harness existing technologies, size of domestic market, production new and different goods using sophisticated technologies, and innovation. These twelve pillars which have many sub-variables are aggregated first and then weighted and aggregated to give an index score of 1-7. The highest score gets a ranking of one and so on down to 144.

Table 20 - Rankings of the general investment climate in the nine countries

	Ease of Doing Business 2013 (out of 185 countries)	Economic Freedom 2012 (out of 184 countries)	Global Competitiveness 2013 (out of 144 countries)	Corruption Perception Index (out of 176 countries)
Afghanistan	168			174
China	91	138	29	80
India	132	123	59	94
Kazakhstan	49	65	51	133
Kyrgyzstan	70	88	127	154
Mongolia	76	81	93	95
Tajikistan	141	129	100	157
Ukraine	137	163	73	144
Uzbekistan	154	164		170

In the Global Competitiveness Index, China and India rank relatively much higher than in the other two Indices. This is likely due to the strong results both of these countries get in the scoring and weightings given for technologies, production capability, education, and research and innovation when compared to the other countries in our group. Likewise Kyrgyzstan ranks relatively lower than it does in the other two indices. Like the World Bank survey, the World Economic Forum's Global Competitiveness Report also gives summary reviews of select countries and as well reports in details reforms to all of the countries changes or reforms.

The Index of Economic Freedoms comes from a more economically liberal point of view. It is thus harsher on socialist, dictatorial, statist and totalitarian economic-political regimes where the state dominates the economy and the rule of law is weak or arbitrary. In our group of countries all score rather relatively poorly because the state does dominate and govern their economies and markets while the rule of law is weak and authoritarian rule is especially prevalent in China and Central Asia. This index evaluates its 10 core freedoms (variables) in four areas: Rule of Law, Limited Government, Regulatory efficiency, and Open Markets. It aggregates scores for each of the ten freedoms on a score of 0-100 where the very best performance scores up to 100 and then applies equal weightings to the four basic freedoms. The higher the total scores the higher the ranking (where 1 is the highest ranking. It then classifies the rankings into classes ranging from countries that are economically free to those that are repressed. Three of the countries in our study group (Tajikistan, China, India) rank in the mostly unfree class (a ranking of 91 or lower), and two (Ukraine and Uzbekistan) as repressed. As in the other two indices, Kazakhstan ranks the highest in our group. In the 2012, the Economic Freedoms index they looked at 184 countries.

As investments into energy production in general and electricity generating stations specifically tend to command large sums of investment capital and are highly visible, they attract a lot of attention. This is why the prevalence of corruption and racketeering in a country is especially damaging for investors in these sectors. Transparency International studies the situation in the world's economies and releases a yearly survey and ranking called the Corruption Perceptions Index. This organization has been monitoring corruption, which is defined as abusing positions of public power for private benefit, since 1995. Its countries are scored on a base of 0 to 100, where 0 is very corrupt and 100 is the very cleanest regime. In its 2012 report, just released, Transparency International surveyed 176 countries. Afghanistan, North Korea, and Somalia score as the worst countries in the world for corruption. Its data for scoring comes from 13 different surveys and studies and 12 multilateral institutions.

Investment climate specific to electricity sector

For investors into electricity generating stations there are a number of criteria that are more specific than the general investment climate and that have the greatest impact on their investment decision. The criteria can be reduced to six: the regulatory system, a market framework, commercial operations, private sector involvement, network access, and electricity tariffs. All of the general conditions of the investment climate as scored in the four surveys cited above still apply in investment decision-making, but these pose less of an immediate risk of causing total investment project failure.

The conditions of the regulatory system that are critical for investors are: the independence of the regulatory from state and political manipulation, the integrity of the regulation system –i.e. that there is a unified regulator and not multiple regulators—the transparency and openness of decision making by the regulator, stability of regulations, and the non-discriminatory nature of regulators' decisions and regulations. For this study we have ranked regulatory systems from 1 to 0 where 1 represents complete independence, high integrity of the system, which makes decision-making transparent, open and non-discriminatory, and where 0 is complete lack of these conditions.

The category of market framework looks at the presence of market mechanisms in determining prices. This includes the presence of open markets for fuels and energy and price discovery is through open markets. Also considered the presence of energy companies traded on public shares markets. Trade barriers to fuel imports are examples of dysfunctional markets. Lack of open markets for land, i.e. state granting of land needs, are also signs of a weak market system. Is there a functioning credit market with enough capacity for costly electricity generating stations? Again a market economy would score 1, which a completely statist economy would rank 0.

The category of commercial operations measures the degree to which business is conducted on principles of mutually beneficial transactions. Are payments made by buyers? Are supplies delivered of purchases inputs? Does the state allow businesses to make profits, are purchase and sales transactions conducted by contracts, are remittances of profits or dividends allowed, are there markets for labour? Are contract honoured and enforced? Procurement is based on public bidding or auctions. What level is there competition for electricity sales and purchases? Or does state ownership or regulation restrict competition? Is taxation based on profits or is taxation primarily excise or punitive? A country where a company's operations are conducted on a commercial basis would be ranked 1 and one where operations were conducted in accordance with state mandates and directives, where non-payments for sales occur, where inputs are acquired only through political determinations and not contracts, would rate a 0.

The level to which the energy sector has been privatized is a very important consideration for electricity generator investors, and especially private foreign investors. This measures the extent to which all the energy sub-sectors have been privatized and have participants from the private sector. This would be private ownership (and control) of electric generating stations, transmission and distribution companies, local utilities, and the fuel extraction and production sub-sectors. Where there is no such privatization, private investors become competitors to SOEs—a competition which they inevitably lose. But the aim of privatization of the electricity sector is to increase competition, so privatizing state owned electricity companies to a private monopoly does not increase competition. Likewise offering only a small stake of an electricity company's shares to private owners does not actually take the company out of state control and convert it to a higher productive, profits seeking firm. The imbalanced competition between private investors and the state-owned and run electricity companies in China and India has consistently been the greatest problems confronting the foreign investor in the past 25 years. This level is measured by a range from 1 where all the energy sectors are privately owned and operated, to 0 is where the state completely owns and operates the sector.

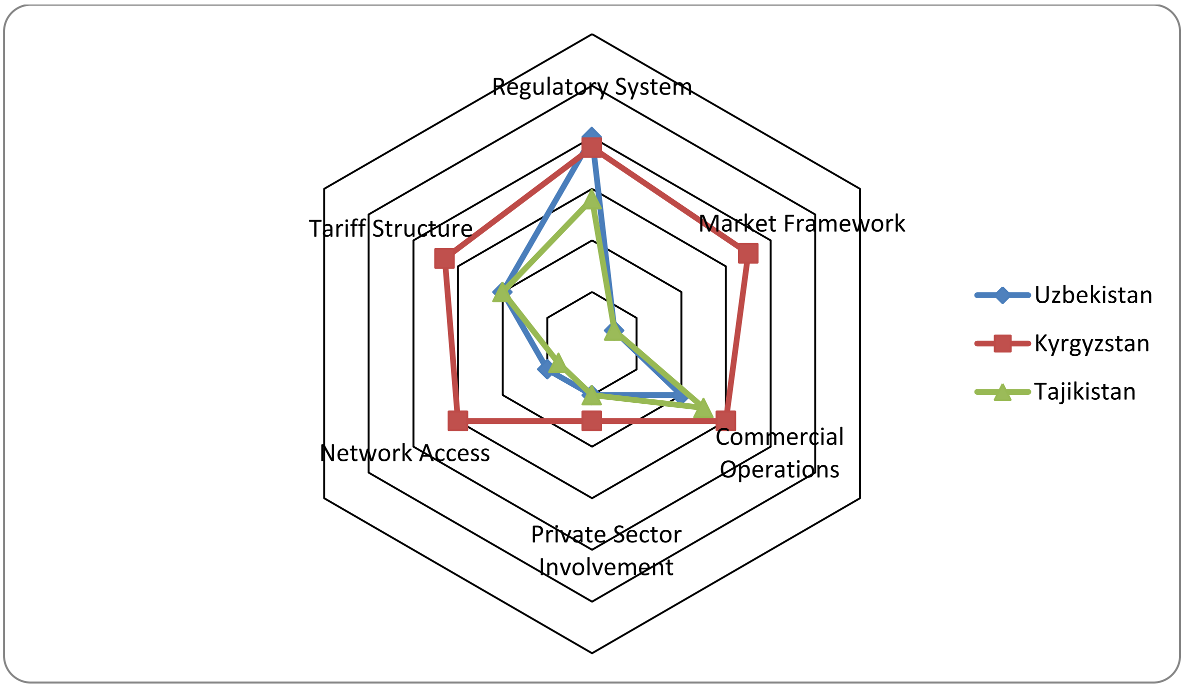
The category of network access looks at the availability of a transmission network, its adequacy and the degree that the country is connected and served in a unified transmission network, or that there would be a connection to the network without too much additional investment or delay at or near the site of the new electricity generating station. Access means also that transmission tariffs are minimal not expropriate. This also looks at non-discriminatory access to the transmission system, that the electricity producer can dispatch electricity to his customer. A good transmission system with fair and open access and reasonably low tariffs rates a 1 in our rankings, while a system that does not function or which has holes in the coverage for the country would rank near a 0.

Always the crucially important factor in the investment decision for an electricity generating plant is the tariff and how tariffs are determined. It is important both in the absolute nominal level of tariffs that the electricity generator can expect to receive for its electricity sales, and in the structure and mechanism of tariff determination. Do tariffs capture all of the investor's costs and hoped for returns? Are they set up by fiat or by formula that aim to capture those costs? Tariff caps and inflexible tariffs which do not respond to changes in fuel costs are harmful. Is the tariff regime predictable and stable—i.e. they are not changed every year? Tariffs that are devised by a regular formula that captures costs and returns, which are flexible, and which are high enough to return a profit to the investor rate a 1, while those tariffs and tariff systems which subsidize other parts of the economy or which do not return the costs and profits of the investor rate nearer to 0.

The EBRD is a major investor and lender to the energy sectors in six of the nine countries in our study group of countries. Their latest assessment published in 2011 of the electricity sectors measures and compares the electricity and gas sectors of the five former Soviet countries and Mongolia in a manner which defines well the investment climate for foreign investors. (*2010 Energy Sector Assessmen*t, EBRD). We can extend their assessment to India and China to demonstrate a comparative assessment of the investment climate for the electric generating sector. Afghanistan is not included because the investment climate at the moment is unattractive because of security concerns.

The assessments by the EBRD demonstrate that the countries of the former Soviet Union plus Mongolia—the so-called transition economies-- with the exception of Kazakhstan, have not advanced or reformed their economies far from their former Soviet structures. This applies equally to their electricity sectors. In almost all of the countries—excepting Kazakhstan—privatization of the sector, liberalization of energy markets, liberal business norms, and independent regulatory systems have not been accomplished. Prices for electricity are everywhere subsidized and the state and politics play the overwhelmingly dominant role in the running of the energy sectors. For this reason the countries Ukraine, Uzbekistan, Tajikistan, and Kyrgyzstan rank very poorly on almost all counts, with the exception that Ukraine has mostly privatized its electricity generating companies. This can be seen in the following chart.

Chart 10 - Comparative measures of the electricity projects investment climate: Uzbekistan, Kyrgyzstan and Tajikistan

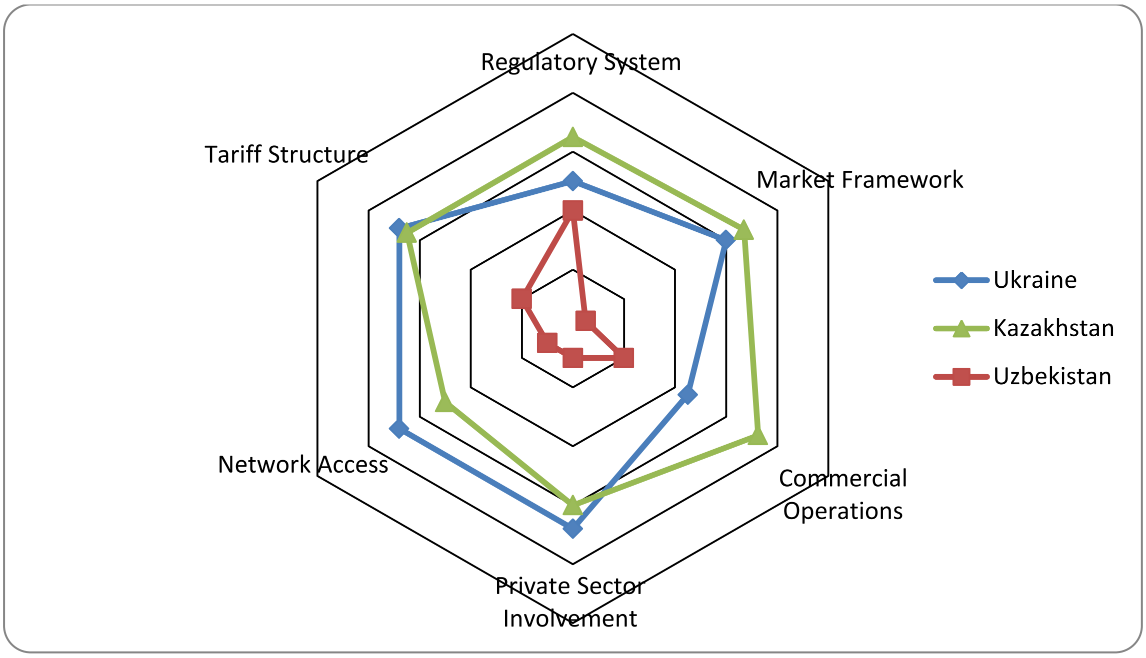


Since 2010, the relatively high markings the EBRD has given to Kazakhstan have been reduced, as over the past three years, moves in the Kazakhi regulatory system have created much more unfavourable investment conditions. First of all the industry, which was nearly 85 per cent in private hands as of 2004, has seen state owned companies buy back a large share so that now, our estimates show that private ownership has fallen to 60 per cent. Since 2010, the regulator has applied tariff caps to each electricity generator, thus effectively ending the open market competitive pricing of electricity sales. What is worse the mechanisms, by which it determines and assigns price caps to each power unit, are opaque—virtually it is tariff formation by fiat. And in the past year, in a further deterioration of its market economy functioning, the state has forbidden the distribution and remittance of dividends by companies. For these reasons we have adjusted downwards the assessments that the EBRD made of Kazakhstan in 2010.

In the same time period, the situation in Ukraine has improved a little, mainly due to the continuing privatization of the electricity generating companies in the country. Unfortunately, to date these privatizations have been snatched up by a private monopoly, one which also has a predominant commanding position in Ukraine's coal production.

The following chart shows the extent to which Ukraine and Kazakhstan have created an investment climate which is much more attractive than the other countries of Central Asia. By these measures Kazakhstan performs slightly better than Ukraine.

Chart 11 - Comparative measures of the electricity project investment climate in the countries with economies in transition



The same analysis used by the EBRD can be applied to China and India. First some adjustments need to be made to the scores that the EBRD gave to Mongolia, which is also a transition economy which was effectively a Soviet economy prior to 1992. The scores given to Mongolia in the 2010 EBRD report are relatively high and reflect a positive outlook of what could be the future situation in Mongolia and not what actually exists. The EBRD gives a 0.6 score to the role of private sector in the electricity sector when in fact there has been no privatization of the industry and there are still no private investors operating independently in the sector, so it gets instead a ranking of 0.05. Likewise the regulatory system is a work in process and has so far changed as politics have changed; most noticeably there was a significant change following the change of government earlier in 2012. Instead of the very score of 0.9, it should get a lower score of 0.4 because it is not very independent of politics and its decisions have not been transparent or stable. The single buyer mechanism is not the best way to structure market based energy transactions; it serves mostly as a distributer of subsidies between different parties. Likewise Mongolia scores lower on the network access primarily because of the lack of a unified transmission system, and access in the remote areas where mining requires new power capacity are totally unserved by the transmission system.

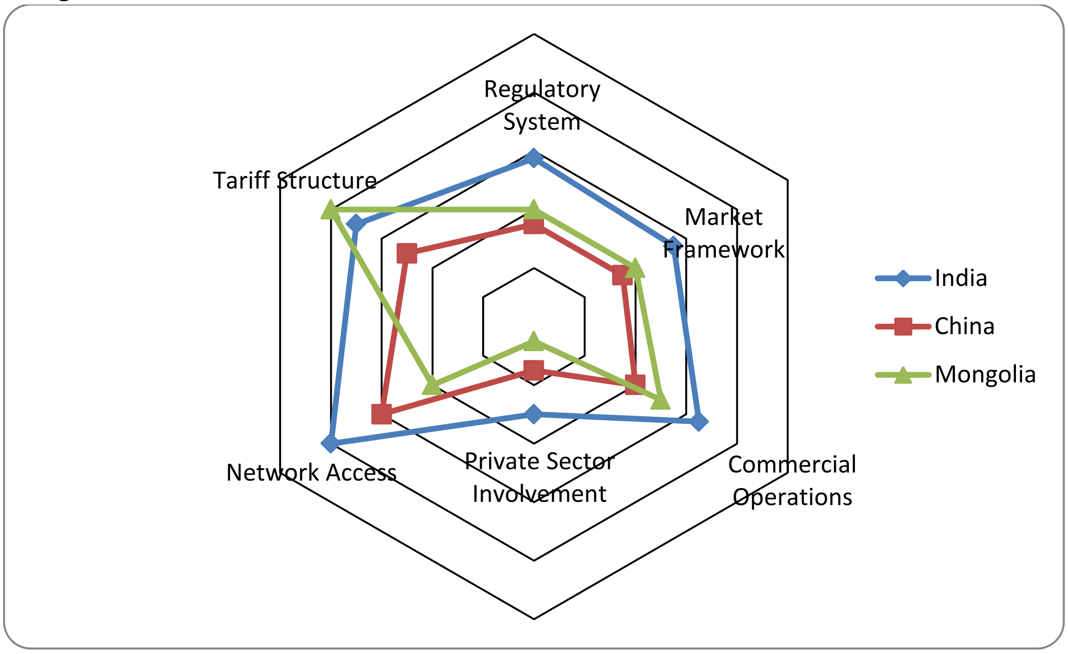
For India, there have consistently been problems with the political interference in its electricity sector. Politicians ride to power promising low prices (or even free electricity to different constituencies). The system is regulated both by Central Government and by the SOEs and effectively the SOEs implement regulation including electricity payments or purchases. In some states of India, electricity generation is not profitable at all because SOEs will not pay tariffs that reflect full cost to the electricity generator. Tariffs have been low, and even if PPAs allow for flexible tariff formation if an SOE does not approve of the resulting price it does not take the electricity from the plant. The rates of non-payments are high, and these reach the generators too. The over structure of the energy industry is not market oriented. The state controls coal and coal pricing, as it also effectively controls imports of fuel. Coal allocations are state, i.e. politically, determined and not market or commercial determined. Permitting for land acquisition is political, and permitting in general is subject to long bureaucratic delays and thus is open to corruption. There are functioning markets for both energy companies and financial institutions. Network access to the transmission system is generally good, but there are regions of the country that are poorly served, and this would make electricity generation investments in those areas challenging. The private sector is now roughly 28 per cent of the electricity generating sub-sector, although this level is expected to rise as a large share of new investment will come from the private sector. And finally, tariffs remain problematical; for many power generators in India, the tariffs they can charge are not profitable, nor are they flexible enough to allow for prices rises when fuel prices rise. Because electricity is so heavily cross-subsidized throughout India, often the off-takers or electricity distribution agencies cannot, and do not, pay for the electricity they receive, regardless of the tariff level.

In China, the investment conditions for power generators are even worse than in India. The fundamental problem is that the electricity sector is still predominately state owned and operated, and is not primarily profit oriented. Private sector involvement is limited to small shareholdings of the big state owned champions and a few private foreign investments. The economy is general is still primarily a state-centric command economy, especially in the energy sector. The rule of law is low so that commercial operations are not based on market determined prices or reliable contracts. The electricity regulatory system is not independent of the state, either at the Central government level or the state levels. The functioning of the regulatory system is opaque and highly dependent on political decisions or local expediency. As a result tariffs are low, and tariff formation is unpredictable. There are many reports of non-payments or refusal to off-take electricity in spite of PPAs with favourable tariffs. Recourse to courts for non-compliance of contracts is rarely successful. This climate is of course the primary reason why there has been so little foreign investment into power plants in the past decade and why there has continued to be a withdrawal of foreign investors from China. In recent years foreign and Chinese companies alike have lost money in China's electricity industry, primarily because of rising coal costs.

In Asia, based on these assessments, India ranks highest for the investment climate it offers to foreign investors. The authorities in India recognize that reforms are needed throughout the energy sector, and especially the electricity sector, they have been steadily working to reform and improve the sector so that all investors can benefit. Reforms are ultimately highly political in India. Although planners recognize they need new investment from foreign investors, they are left with unpalatable and politically difficult choices between accommodating foreign investors and giving them adequate profits or distributing very cheap electricity to the masses with no energy access today.

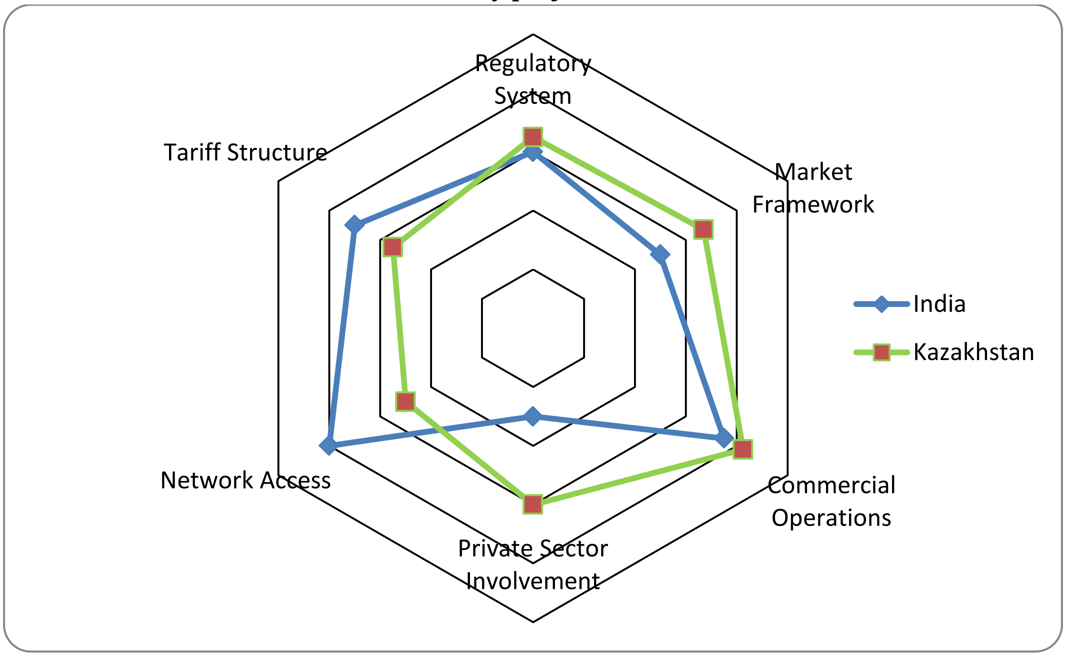
In our group of nine countries there is no regime that provides an especially attractive benchmark for foreign investors into the electricity generating sector. This has been stated most clearly by the chief executive of one of the few foreign investors, CLP, in the electricity generating sector in both China and India. He said in 2010 that future investments would not go any longer into China or India, but likely they would go to Australia, or other countries with better investment conditions and prospective returns.

Chart 12 - Comparative measures of the electricity projects investment climate: China, India and Mongolia



By these assessments, the two countries with the best terms for the electricity projects' investor, foreign or domestic, are India and Kazakhstan. As of 2012, they rank virtually the same, but it would be difficult to say that either country serves as a benchmark for foreign investors. Likewise, in recent years, India has been working very diligently to improve its investment climate –albeit perhaps with little success—while Kazakhstan, which only a few years ago had a rather attractive investment climate for foreign investors in the energy sector, seems to have regressed and has scrapped some of its more attractive conditions for investment and made itself less attractive overall and appears to be committed to making investment more difficult in the near future.

Chart 13 - Investment climate for electricity projects in two best countries: India and Kazakhstan



In the case of Kazakhstan, perhaps authorities there have concluded that since they do not seriously need more investment into new electricity generating capacity, they do not so urgently need to attract foreign investment. While in India, the authorities know that they desperately need new investment from whatever source they can get it, but especially from foreign investments and foreign lending. These are strong incentives for India to continue to improve its investment terms.

Chapter VIII: Findings and conclusions

The Problem: Thermal electricity generation every year emits a substantial share of the world's CO_2. Coal-fired plants are especially large contributors and the rapid growth in capacity of coal-fired power plants in the past 15 years has especially raised alarms about the sudden surge in carbon emissions and their deleterious effect on the climate. China and India have very large coal-burning electricity sectors and are the world's first and third largest CO_2 emitters—and their emissions have shown very strong growth in the past decade.

This project examines the thermal electricity sectors in nine countries of Asia, including Ukraine. The nine countries covered by the project are (by order of population): China, India, Ukraine, Uzbekistan, Afghanistan, Kazakhstan, Tajikistan, Kyrgyzstan, and Mongolia. Five (Ukraine, Kazakhstan, Kyrgyzstan, Uzbekistan and Tajikistan) of these are former component states of the Soviet Union which by and large built their electricity sectors prior to 1992 (as well this was the case with Mongolia). Six countries generate electricity primarily by burning fossil fuels: China, India, Ukraine, Uzbekistan, Kazakhstan, and Mongolia. China and India possess the world's largest and third largest coal-fired electricity generation industries. Three countries—Afghanistan, Tajikistan, Kyrgyzstan—being poor in fossil fuel resources—rely overwhelmingly on hydropower. Only one country, Uzbekistan, generates electricity primarily by using natural gas, which is a much cleaner burning fuel than coal. The other five countries rely on coal for up 80 per cent of their electricity needs primarily because they are endowed with rich coal resources and because coal has been their cheapest available energy source so that energy self-sufficiency mandates that coal be used.

A partial solution: Over the past two decades there has been intensive research and development in making cleaner, more efficient fossil fuel combustion technologies. Of these supercritical pulverized coal (SCPC) and ultra-supercritical pulverized coal (USCPC) steam generators have been shown to be commercial and have been increasingly introduced into the world's coal-burning electricity generation fleet replacing less efficient sub-critical generators. Likewise rapid advances in gas turbines used along with combined cycle generators have increased efficiencies. For the SCPC and USCPC technologies it has been seen that they are more effective in very large capacity plants of 600 MW to 1,000 MW size. Most important, these advanced coal and gas combustion technologies greatly reduce CO_2 emissions, and their adoption can be used as a means of abating CO_2 emissions from large thermal electricity generating industries. Other clean coal technologies, carbon capture and sequestration, and integrated coal gasification combined cycle (IGCC) generation, have not yet been shown to be economically practical, although China and India are both committed to building commercial scale IGCC plants.

These advanced technologies have been adopted by China and India as part of their carbon abatement strategies. China adopted a policy of introducing SCPC and USCPC generators in the 10^{th} Five-Year plan (2000-2005), and since 2004 has been building them rapidly to where, by the end of 2010, SCPC and USCPC power plants represented 54 per cent of China's total coal-burning electricity generation fleet and 38 per cent of its total electricity generating capacity. Since 2006 China has had a program called Large Substitute for Small which has removed smaller, older conventional coal-fired plants and replaced them with these new coal-burning technologies. China plans to add 525 GWs of new advanced coal-burning power plants to its total stock by 2020. A major part of its carbon abatement strategy in that time period, however, is to raise the proportions of natural gas, nuclear, hydro and wind power generation in the total share of electricity generation, thus reducing coal's share. A major program is underway to import more natural gas and direct it to combined cycle gas-turbine power plants in the east of the country.

In India, meanwhile, private electricity companies have built the country's first SCPC only in 2011, although the country began to encourage SCPC adoption since 2006. In the 12^{th} Five-Year Plan, the country laid out a program to advance the adoption of incentive policies to build new SCPC plants to help cut CO_2 emissions. In the plan it mandates that 40 per cent of all new building shall be SCPC, while it has projected that in the 13^{th} Five-Year Plan, 100 per cent of new coal plants must be SCPC or USCPC. India also adopted a program in 2008 to build Ultra Mega Power Plants as an accelerated way to demonstrate the benefits of higher efficiency.

To date only domestic Indian electricity companies participated in this program. Having quickly established a world leading position in SCPC and USCPC technologies, China is sharing its technological progress in clean coal technologies with India. The Indian government is looking to the private electricity sector to take up an important part in developing and financing advanced coal-burning combustion power plants in the next ten years. It is also looking at a greater reliance on renewables as a future source of electricity.

In Kazakhstan, Ukraine, and Mongolia, policy makers have recognized that there are issues with the levels of CO_2 that they emit from their coal based electricity generation sectors. They have not as of yet, however, committed to a policy of adopting the advanced coal combustion technologies or in replacing their older coal-burning fleets with a larger capacity, more efficient SCPC based fleet. Mongolia has specified a high efficiency coal-burning plant be built for the new CHP5 power plant they have offered as a concession to a group of foreign investors earlier this year. But this does not mandate a SCPC be built. From present plans it looks likely that neither Mongolia before 2016, nor Kazakhstan before 2018 will get modern, high efficiency electricity generators added to their present fleets.

Kazakhstan, other than its Balkhash power plant, does not have urgent need for new capacity in the remainder of this decade. Ukraine likewise has no plans for the next ten years for new capacity additions. Instead the policy is to upgrade or rehabilitate old, sub-critical coal-fired power plants and rely more on nuclear power, and perhaps, if it can get outside investors, on more renewable power. Mongolia has an ambitious program to develop new coal-fired power plants as captive power at its many large mining projects which will be developing over the coming decade. Presumably Mongolia will look to the foreign mining developer to finance and build these projected power plants, but there is no information on their likely technological specifications.
In Uzbekistan, policy makers have apparently moved in the wrong direction. Up to quite recently natural gas power capacity amounted to 88 per cent of the country's electricity capacity. Natural gas emits less than half the CO_2 that coal does. But Uzbekistan has decided to convert one of its gas-fired power plants into a coal-burning power plant and it is planning to further increase the share of coal in its electricity generation, policies which will increase CO_2 emissions. It claims that this measure is a step to diversify its energy supply.

Afghanistan, Tajikistan, and Kyrgyzstan all need more electricity than they currently generate. But all three countries are poor in hydrocarbon resources, but rich in hydropower resources. Their current plans are for development of new dams and hydropower plants. Plans for Tajikistan and Kyrgyzstan are far advanced and may have received foreign aid commitments. Afghanistan does not at the present time have concrete power development plans. Afghanistan could only develop thermal power if it were to import natural gas from Turkmenistan or Uzbekistan or if in some far distant date it were to find huge hitherto unknown reserves of gas or coal.

All of the countries have laws and regulations which permit foreign direct investment in principal. But not all of the countries actively promote or want FDI to come into the electric power generating sector. Those countries which have not begun to liberalize or privatize their power sectors are especially unreceptive, countries such as Uzbekistan, Tajikistan, Kyrgyzstan, and to a lesser extent Ukraine. Afghanistan actively promotes FDI into infrastructure but, as is understandable, investors in such large investments (with such long paybacks) as are required for electricity generation are not willing to go to Afghanistan without security guarantees. Mongolia is the only country where the electricity industry has not been liberalized and which is actively promoting large amounts of FDI into its electricity sector and is offering BOT concessions for generation and incentives for investment in new transmission.

China since 1985, India since 1991, Kazakhstan since 1995, and Ukraine since 1999 all have received FDI in the electricity generation sector and all still have foreign investments in it. The overall sums invested have been relatively small in each country and have not made significant or lasting contributions in any country. Total FDI into electricity generation in China from inception to date is estimated to be about $16 billion, for India it has been estimated at $5.9 billion. In Kazakhstan since 1992 it is estimated that FDI has brought $700 million into its electricity generating sector, while in Ukraine the figure is put at $420 million and in Tajikistan we calculate it has totalled $200 million (although we are not certain whether this investment has been foreign aid or FDI).

As a carrier of advanced fossil fuel combustion technologies for cleaner electricity generation, FDI has to date put in an insignificant sum of $3.4 billion in both China and India in seven projects.

The planned development program for new generation capacity for the current Five-Year plan in China is estimated to cost $444 billion. Chinese planners—with an economy nearly four times that of India's and foreign reserves more than 11 times larger than India's—do not think that it will be difficult financing this level of investment. However they have opened up the prospect to foreign investors to make investments and participate in building new nuclear power capacity and they are also trying to promote FDI for CCGT power plants.

In India the current 12th Five-Year Plan calls for $265 billion for the electricity sector. The Indian planners expect that they are short $38 billion for funding this huge bill and are looking for assistance from all directions, including FDI but primarily from India's private sector. They are working hard to promote new FDI for SCPC power plants: currently a net $1 billion is being invested in two projects.

In the near future there are FDI-backed electricity generation projects in Kazakhstan and Mongolia which should get under way soon, but it is not clear whether they will deliver advanced clean coal technologies. In Mongolia terms of the investment are still under negotiation.

Based on past performance, FDI will not deliver enough investment into advanced fossil fuel technologies to make a significant—or even measurable—abatement impact on the CO_2 emissions of either China or India. In the cases of China and India this situation is primarily due to the huge size of their coal-fired electricity sectors and thus their CO_2 emissions levels. It is still possible (but not likely) that Kazakhstan and Mongolia could attract enough foreign investment in the coming decade in new large-scale high efficiency coal-fired electricity generating plants that would make a contribution to the abatement of their CO_2 emissions. Conversely to the situation in China and India, in Kazakhstan and Mongolia, because of the relatively small size of their thermal power sectors, just two or three large investments in new capacity in each country could make a significant impact on their CO_2 emissions.

In the six fossil fuels burning countries the fundamental obstacle to foreign investments is the very low profitability on offer to the thermal power industry coupled with the relatively high risks of investing in each of these countries. The high risks are related to the absence of the rule of law in every country—save in India—which causes arbitrary rulings, project delays, lack of contract enforcement, confiscations, lack of recourse or recompense, and general uncertainties. The very low profitability is tied, in every country, to the lack of a market basis for building up electricity tariffs and ultimately to tariffs offered to investors which are just too low and do not reflect the full costs of fuel, capital, operations, and returns. Payment issues are also a problem especially in China, India, Ukraine, and Uzbekistan.

In none of the countries in this study are there tariffs set by cost build-up and which are flexible enough to allow the pass-through of changing fuel costs. Instead, tariffs are set by fiat, often by local authorities (meaning political considerations determine tariffs), and they most often reflect a political belief that the end consumers cannot afford the full cost of energy, which should therefore be subsidized. Likewise there is everywhere a reluctance to pay higher tariffs to foreign investors than to what is received by state-owned plants, even if the foreign investor has a contract that permits higher tariff rates. Efforts to reform this situation have been, at best, half-hearted and ineffective, or non-existent (put off to a later time). India offers contracts to foreign investors that offer 16 per cent ROI, but investors have learned through hard experience that they cannot hope to earn these rates of return and they have often had difficulty getting the courts to honour and enforce their power purchase agreements.

In India, reforms of the electricity industry, and the coal industry that supports it, have been delayed. Market reforms of electricity prices are something all Indian politicians fear and dread—and so they do not touch, even when they know that reforms are desperately needed. In China, the economists who run the planning system know that deeper reforms are still needed, but the real workings of the electricity industry are in the hands of SOE gencos and local electricity regulators and they resist reforms at every turn.

The pricing of electricity is the fundamental problem causing the non-commerciality of the electricity generating sector for all participants—including SOEs—almost all of our countries. In the past two years, electricity generating companies in China, India, Ukraine, and Kazakhstan have repeatedly reported sizeable losses. Mongolia's gencos are not profitable. Presumably in Uzbekistan the situation in the state monopoly is worse as the tariffs are so low they cannot cover fuel or operating costs.

Finally when planners in any of the nine countries project look to FDI to help grow their electricity industries they do not account for the huge competition they face from alternative investment opportunities located elsewhere in the world in other lower-risk countries. Electricity generating investment funds are looking to invest in lower risk projects with more reliable rules and fewer uncertainties. The leader among the foreign investors in China and India, CLP of Hong Kong, is looking for its incremental electricity generating investments away from China and India and to Australia. In an ironic reversal of roles in the past five years the major SOE Chinese electricity companies have begun to seek out foreign investments in greenfield projects in lower-risk countries outside China and have bought positions in some of the IPP developers who first came to China more than 15 years ago. Furthermore, in the developed countries of the OECD there is a very significant hostility to any investment in electricity generation using coal. New funds are organized every month for investments in renewables technologies—some are even specifically directed at the developing countries of Asia (for example, Terra Firma of the U.K.)—but financing is getting harder everywhere to find for coal-burning electricity generation.

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