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Mongolia: Updating the Energy Sector Development Plan

(Financed by the Japan Fund for Poverty Reduction)

Prepared by E. Gen Consultants Ltd. Bangladesh in association with MVV decon GmbH, Germany, and Mon-Energy Consult, Mongolia

For Ministry of Energy, Mongolia

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Asian Development Bank

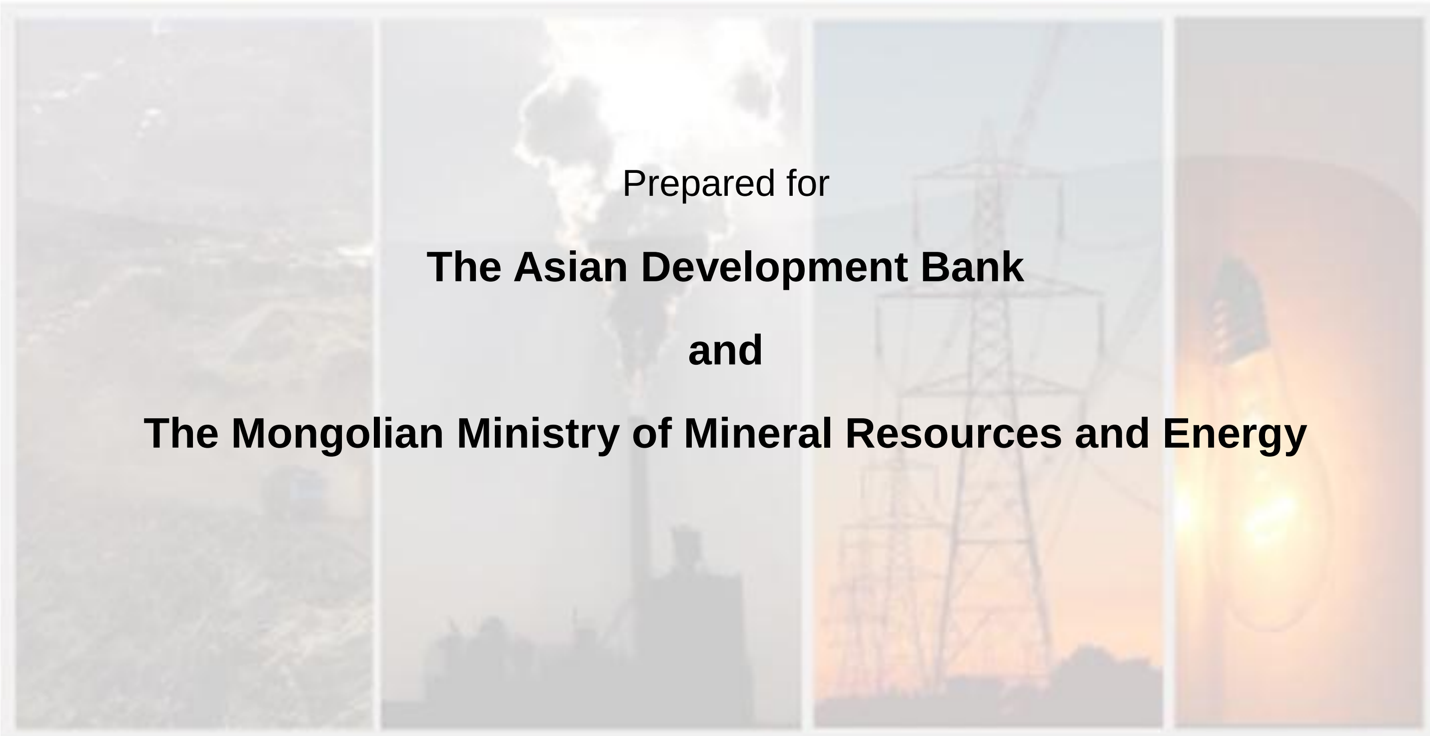
Updating Energy Sector Development Plan

Project Number: TA No. 7619-MON

FINAL REPORT

PART B: Volume - V of X

PRIMARY & SECONDARY ENERGY RESOURCES



Prepared for

The Asian Development Bank

and

The Mongolian Ministry of Mineral Resources and Energy

Prepared by

e.Gen Consultants Ltd.

in association with

15 October 2013

CURRENCY EQUIVALENTS

(As of April 2012)

Currency Unit	–	Togrog (MNT)
USD 1.00	=	1,309 MNT
EUR 1.00	=	1,725 MNT
USD 1.00	=	0.759 EUR

ABBREVIATIONS

ADB	–	Asian Development Bank
AuES	–	Altai-Uliastai Energy System
CBM	–	Coal Bed Methane
CCS	–	Carbon Capture and Storage
CDM	–	Carbon Development Mechanism
CEE	–	Central Eastern Europe
CER	–	Carbon Emission Reduction Unit
CES	–	Central Energy System
CFB	–	Circulating Fluidized Bed
CFBC	–	Circulating Fluidized Bed Combustion
CHP	–	Combine Heat Power
CIF	–	Cost, Insurance and Freight
CO	–	Carbon Monoxide
CO_2	–	Carbon Dioxide
COP	–	Conference of Parties
CPI	–	Consumer Price Index
EA	–	Energy Authority
EC	–	European Commission
ERES	–	Eastern Energy System
ERA	–	Energy Regulatory Authority
EUA	–	European Emission Reduction Unit
EUR	–	European currency unit EURO
GHG	–	Greenhouse Gases
HOB	–	Heat Only Boilers
IA	–	Implementing Agency
IDC	–	Interest during construction
IEA	–	International Energy Agency
IGCC	–	Integrated Coal Gasification and Combined Cycle
IRENA	–	International Renewable Energy Agency
LCOE	–	Levelized Cost of Energy

MMRE	–	Ministry of Mineral Resources and Energy
MNT	–	Mongolian Togrok
MoU	–	Memorandum of Understanding
NOx	–	Nitrogen Oxides
O&M	–	Operation and Maintenance
PPA	–	Power Purchase Agreement
PV	–	Photovoltaic
SOx	–	Sulfur Oxides
TV	–	Television
UHV	–	Ultra High Voltage
USA	–	United States of America
VAT	–	Value Added Tax
WACC	–	Weighted Average Cost of Capital
WRES	–	Western Energy System

UNITS OF MEASURE

BTU	-	British thermal unit
GCal	-	Gigacalorie (one million kilocalories)
GJ	-	Gigajoule (one thousand megajoules)
kJ	-	Kilojoule
kWh	-	Kilowatt-hour
MWh	-	Megawatt-hour
MWel	-	Megawatt electric
MWth	-	Megawatt thermal
PJ	-	Petajoule
TSC (TPU)	-	Tons of standard coal
TJ	-	Terajoule

WEIGHTS AND MEASURES

GW (giga watt)	–	1,000,000,000 calories
GJ (giga joules)	–	1,000,000,000 joules
GW (giga watt)	–	1,000,000,000 watts
kVA (kilovolt-ampere)	–	1,000 volt-amperes
kW (kilowatt)	–	1,000 watts
kWh (kilowatt-hour)	–	1,000 watts-hour
MW (megawatt)	–	1,000,000 watts
W (watt)	–	unit of active power

CONVERSION FACTORS

1 GCal	=	4.19 GJ
1 BTU	=	1.05506 kJ
1 Gcal	=	1.1615 MWh = 4.19 GJ = 1.75 steam tons/hour
1 GJ	=	0.278 MWh = 0.239 Gcal = 0.42 steam tons/hour
1 MW	=	0.86 Gcal/hour = 3.6 GJ = 1.52 steam tons/hour
1 TSC	=	7 Gcal = 29.3 GJ = 8.15 MWh

CONTENTS

I. ENERGY ENDOWMENTS

A. Background

1. Among the most important qualifications of energy system planning are the availability, characteristics and costs of fuels as primary sources of energy, on the one hand, and the various energy conversion technologies, on the other hand, which are needed to convert primary energy to electricity and heat. The purpose of this Section is to provide an overview of the primary energy stocks of Mongolia and its immediate future prospects. The technology options which are suitable for Mongolian conditions, particularly given consideration of the country's primary energy resource endowments and the economic costs of conversion into useful heat and power, will be discussed in Volume III – Energy Supply Options.

2. In the Mongolian context, the country has abundant supplies of thermal coal. Mongolia's existing energy supply system has therefore been built on this premise. Not only the major urban centres are heated by Combined Heat and Power (CHP) plants, during past decades open-pit coal mines were established in most Aimags to supply coal for heating in rural town centres and households.

3. Renewable energy, most notably hydropower, wind and solar energy, is also abundantly available in Mongolia. However, clean energy technology can be three to five times more costly than conventional conversion processes, especially as the traditional coal-based energy system of Mongolia is underpinned by the supply of extremely cheap domestic, and in most cases, local coal. To exploit renewable energy opportunities some form of subsidization for wide-spread adoption is needed. Mongolia has therefore established a feed-in tariff scheme, which has enabled first large-scale investments in non-hydro clean energy. The introduction of significant amounts of non-hydro renewable energy sources also poses operational challenges, particularly when such sources are operated in remote areas.

4. There is a need to recognize the country's investment in existing heat and power systems. In Mongolia, the extreme cold weather conditions have laid a foundation for the provision of heat and power by CHP plants. More than half of the population obtain heat supply from a centralized energy source via a district heating network and have come to depend on centralized heating as an all-important lifeline. However, for the most part, the heat and power assets of Mongolia have reached the end of their useful life with attendant deterioration in efficiency and service performance. The need for replacement is a financial liability but it also offers opportunities to improve efficiency and to save on the energy costs borne by the community.

5. There is significant potential in Mongolia for hydropower generation that is, as of yet, almost entirely untapped. Hydropower is renewable energy but its construction causes changes in the natural and human environment due and consequently there is almost always some opposition to hydropower construction. The future expansion of the Mongolian power system could, however, greatly benefit from hydropower as it not only provides energy to the system but can also contribute to system regulation, and provision of peaking capacity and frequency control, on which aspects Mongolia now depends partially on electricity imports from Russia.

6. The country lacks indigenous natural gas resources, and is landlocked; not only can it be expected that the cost of importing gas will be high, but dependence on neighbouring countries for gas supply involves fuel supply risks that may be very costly to mitigate. There are also other energy resources available, such as shale oil, coal bed methane gas, uranium and geothermal energy. Whether the demand forecast of electricity requires the development of all of these resources within the planning horizon of this study, will be subject of the

study. Overall there are significant challenges in planning for a future sustainable energy system in Mongolia.

B. Coal

7. Mongolia has estimated total coal resources of approximately 173 billion tons found within 15 coal basins. About one third of the resources are in the Gobi region in the south, one third in the eastern region and the balance in the rest of the country, of which the Central Region accounts for about half. Bituminous coal is found in South Gobi and Western basins. Most of the resources in the central, north and western regions are sub-bituminous or lignite. Coal deposits in Mongolia are typically suitable for open cast mining because of their geological condition.

8. Within this resource base there are 85 deposits and over 370 identified occurrences and findings. Reserves established through preliminary and detailed exploration are about 22 billion tons and the number is increasing annually as a result of intensifying exploration activities. The share of high calorific value thermal and coking coal is estimated at 7 to 8 billion tons. The proven reserves are at 12 billion tons including 2 billion tons of coking coal and 10 billion tons of thermal coal.

9. The resource and reserve estimates carried out by the private sector companies in compliance with the Australian JORC or Canadian National Instrument 43-101 are not all publicly available, which results in varying and sometimes conflicting estimates of Mongolia's resources appearing in public media. The quoted resources above (2012) are also not consistent and not adequately reflected in the reports of various international energy sector agencies and other organisations maintaining energy statistics. Therefore, in 2011 Mongolia entered into an MoU with the Committee for Mineral Reserves International Reporting Standards aiming to conform to international reporting standards. This may soon result in better consistency of international estimates of coal resources and reserves in Mongolia.

10. The following figure and table show us the locations of the aforementioned resources as per the Ministry of Mineral Resources and Energy.

Figure I-1: Coal Basins in Mongolia

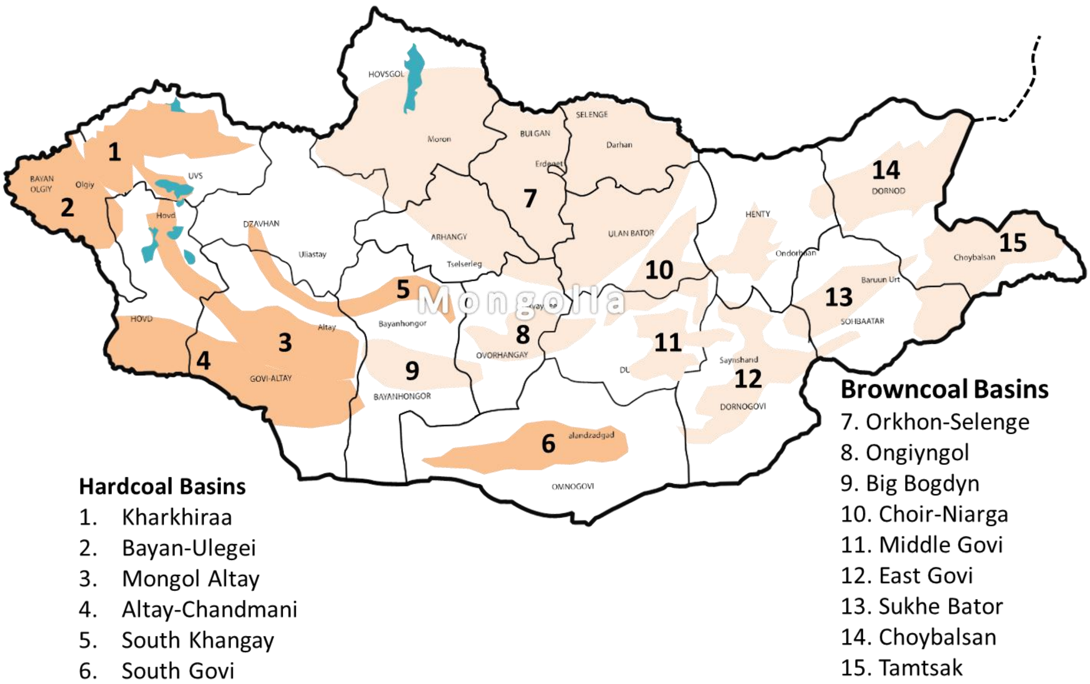


Table I-2: Explored and Forecast Coal Reserves by Major Basin

	Explored	Forecast	Total
1. Kharkhiraa/ 2. Bayan-Ulegey	172.5	4,592.7	4,765.2
3. Mongol Altay Basin	49.0	10,040.6	10,089.6
4. Altayn Chandakh Region	2.1	3,821.4	3,823.5
5. South Changay Basin	4.2	1,221.9	1,226.1
6. South Gobi Basin	15,960.0	10,070.0	26,030.0
7. Orkhon-Selenge Region	408.8	7,295.3	7,704.1
8. Ongiyngol Basin	42.6	1,471.1	1,513.7
9. Big Bogyn Basin	5.2	1,950.9	1,956.1
10. Choir-Nialga Basin	5,932.0	14,401.1	20,333.1
11. Middle Gobi Basin	104.1	13,117.0	13,221.1
12. East Gobi Basin	Na	23,534.0	23,534.0
13. Sukhbaator Basin	68.0	4,190.0	4,258.0
14. Choibalsan Basin	213.2	14,699.0	14,912.2
15. Tamtsag Basin	190.0	31,803.0	31,993.0
Total	**23,151.7**	**142,208.0**	**165,359.7**

Sources: EDRC – Private Sector Opportunities in the Oil, Gas and Coal Sectors of Mongoli;. Frontier Securities 2012: Investment Potential in Mongolian Coal (2012); Figures provided by EEC Consulting and former Ministry of Fuel and Energy of Mongolia, Coal Department (MFEM, Coal Department); Bayan-Ulegay data not separately available.

11. Even though coal resources are abundant, the infrastructure needed for large scale coal production in Mongolia still needs to be further developed. Among the pre-requisites of coal-fired power and heat generation are that (i) there are deposits of sufficient size and scale of operation to support continuous and long-term fuel supply, (ii) the parameters of coal such as calorific value, moisture and ash, among others, are suitable for the planned energy conversion technology, and (iii) the transport distance is not too great so that the transport logistics work well for the plant, for example, coal transport via railway.

12. Coal deposits in and around the CES area produce mostly lignite with calorific value of around 3,000 kcal/kg. The coal supply in the CES area is dominated by three mines, which are Baganuur, Shivee Ovoo and Sharyn Gol. These three mines are all connected to the railway which enables them to supply coal to the capital and other major cities along the Mongolian railway system. Sharyn Gol is managed by a listed company, but in Baganuur and Shivee Ovoo are state-owned companies. There are other mines as well within CES area serving primarily the fuel needs of small boilers, HOBs and the retail market, and new mining development is on-going.

13. **Baganuur** is located about 130 km east of Ulaanbaatar, reachable by railway at a distance of 191 km. It supplies over 70% of the coal of the CES system. It has resources of 600 million tons and is one of the biggest open coal mines in Mongolia, equipped with the world's leading machinery and technology. Its production has risen steadily from 2.8 million tons in 2005 to 3.5 million tons of coal in 2012. Baganuur supplies coal to all five CHP plants in Ulaanbaatar, Darkhan, and Erdenet as well as to the country's main industries and small consumers. The coal moisture content is 33%, ash 9.5%, sulphur 0.4% and volatile matter 43.9%. The heating value is 3,400 kcal/kg.

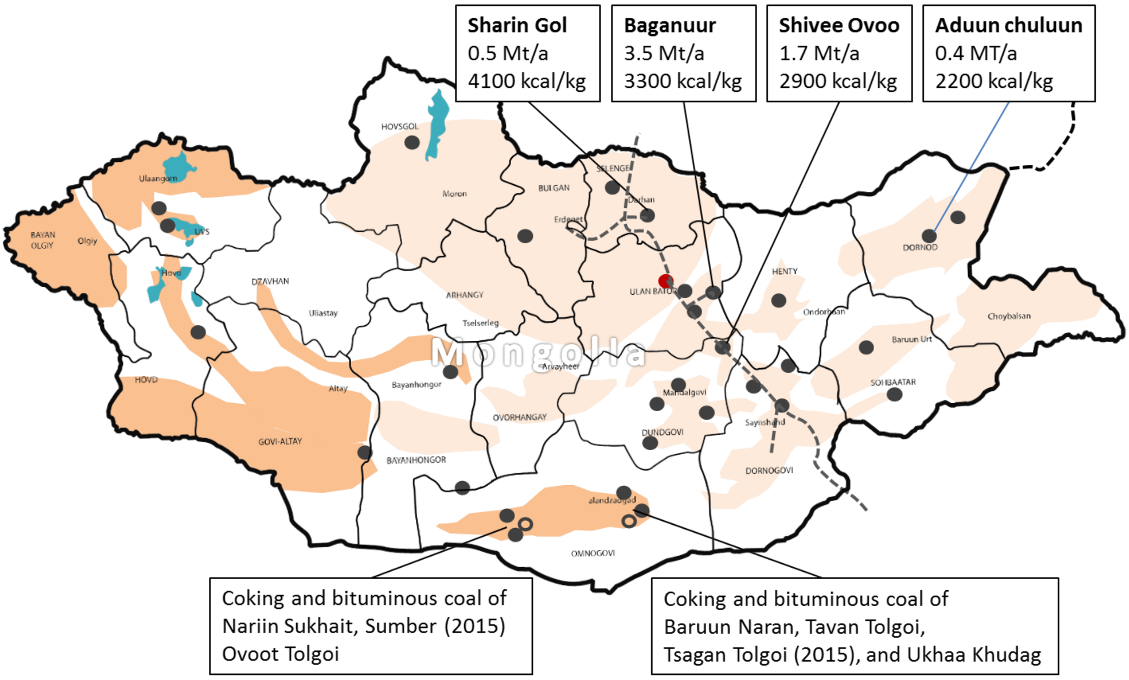
14. **Sharin Gol** is the smallest of the mentioned 'big three' mines but produces the best quality

lignite to the market. It has proven reserves of 146 million tons and produces annually approximately 0.5 million tons. Its production has been on decline, reducing from 0.7 million to less than 0.4 million tons. However, there is a production ramp up project underway, and increased demand, and the company expects to increase its production to at least 0.5 million in the near term. The mine has a long history and has produced 2.5 million tons per annum at its peak. The mine supplies coal to Darkhan and Erdenet cities and CHP plants, as well as to Darkhan, metallurgical plants, a copper mine and other industrial users, as well as to small consumers. Coal moisture content is 14.4%, ash 33.1%, sulphur 1.2% and volatile matter 29.1%. The calorific value of coal is 4,400 kcal/kg.

15. **Shivee Ovoo** is located some 260 km southeast of Ulaanbaatar. It has proven productive reserves of 600 million ton and probable resources of 2.7 billion tons. The annual output of the mine has risen slightly over the last years and is currently about 3.3 million tons. Shivee-Ovoo coal is of rather low quality. The moisture content is 40.7%, ash 8.9%, sulphur 0.9% and volatile matter 42.7%. The coal calorific value is 2,900 kcal/kg. It is one of the newest mines and considered as a strategic resource.

16. Coal from deposits in north and central regions of Mongolia are mostly rather low in ash and sulphur contents but have high moisture content. Since 2010, when Canadian Prophesy Group acquired the mine, **Ulaan Ovoo** mine in northern Selenge started supplying coal to Darkhan and Erdenet in increasing amounts. The most important mine of the Western Region is **Aduunchuluun** which was established as a sub-surface coal mine just 5 km outside Choibalsan city in 1954 by the Mongolian Government. The company has been supplying coal to Choibalsan thermal power plant and local energy users. Aduunchuluun coal is lignite with calorific value of only 2,200 kcal/kg. The mine has resources of 400 million tons, but bringing coal to a wider market would require coal upgrading or briquetting, which have been studied by the company.

Figure I-3: Key Mines



17. Moisture in coal results in efficiency losses in energy conversion. The efficiency of a coal fired power generation drops by about 4 percentage points and 9 percentage points when coal moisture content increases from 10% to 40% and 60% respectively. High moisture content also results in higher capital cost of the plant as the physical size of the boiler and flue gas channels need to be increased in dimension to accommodate the water vapour as a result of high-moisture coal combustion. Coal drying technologies could be applied in the future to

address this issue.

18. Coal properties can be adjusted by selecting a suitable coal mix. The properties do not relate only to handling and combustion, but even the radium equivalent for natural radioactive isotopes in the slag has an impact so that ash from Shivee-Ovoo coal needs to be mixed with that of other coals and materials when used as building material for public and plant buildings. Shivee Ovoo coal is usually mixed with Sharyn Gol or Baganuur coal also for combustion because of its low calorific value.

19. High ash content also has an impact to the efficiency. Key deposits with high ash content coal (over 20%) in Mongolia include Maanit, Nuurst Khotgor, Saikhan Ovoo, Tal Bulag, Tevshiin Gobi, Khar Tarbagatai, Tsakhiurt,Shariin Gol and Alag Tolgoi. High ash content means mostly having rock matter mixed with coal, which causes additional capital and operational costs for extra weight and difficulty in transportation, crushing, conveying and ash disposal. Coal washing to improve coal properties prior combustion is rather standard in Europe, North America, Japan and Australia, but it is increasingly demanded also in China and India.

20. There exists no provision currently for thermal coal preparation at mining sites in Mongolia and there is inadequate quality control in the supply system. Coal quality varies substantially, and occasions of substandard coal feed to the CHP plants have caused emergency situations at the power stations. The Mongolian Government has addressed this issue in the Copenhagen Accord of the Conference of Parties (COP 15) to the United Nations Framework Convention on Climate Change under the nationally appropriate mitigation actions of developing country parties. The option of coal washing at the biggest coal mines in Mongolia, such as Baganuur and Shivee-Ovoi, is also included in the Mongolian Environmental Action Plan.

21. The increasing production of metallurgical coal will give coal washing technologies new impetus in Mongolia. The first coal washing plant was implemented in two stages by Mongolian Mining Corporation (MMC) in 2011 and 2012 at Ukhaa Khudag mine, which is part of Tavan Tolgoi deposit. The capacity of the washing facility is 10 million tons, and it will be expanded to 15 million tons by 2015. More washing facilities are likely to come on line in the near term.

22. Generally, fluidized bed combustion boilers are less sensitive to coal calorific value variation, ash and sulphur content than pulverized coal combustion. At present all boilers in Mongolia use pulverized coal combustion method, but CFB technology has been proposed for CHP5 plant.

23. Recent development has brought and will continue to bring several new mines into operation in the near future. Focus of recent mine development has been primarily in the south of Mongolia, and for metallurgical coal and exports. **Tavan Tolgoi** in South Gobi alone, the largest one, has 7.4 billion tons in resources and 1 billion tons of proven and probable coal reserves. The mine will produce 20 million tons of coal by 2017; 73% of the coal is metallurgical, while 27% is thermal coal that is suitable for power generation. This equals to approximately 5 million tons of sub-bituminous coal in 2017, an amount sufficient for a 1,200 MW base load plant.

24. Many bituminous coal mines are waiting for or under active development in the Southern Mongolia. Table I-4 details some of the existing and new coal mining developments expected in the first half of the decade.

25. Even on the basis of the known reserves at the Tavan Tolgoi fields, Mongolia has the potential to become a major exporter of coking coal. Present infrastructural constraints, not the least of which are the lack of adequate power supplies, lack of access to a railway system, and water supply constraints, pose the main challenges for the mining sector to overcome in releasing the potential.

26. Mining development will cause the need for mine mouth power generation to serve the mining operations and this may provide opportunities for supplying excess power to the grid or for exports. Large mine mouth power plant on this basis have been proposed, among others, to Baganuur coal mine and Chandgana mine (owned by Canadian Prophecy Coal). Currently the

southern mines' electricity demand is fulfilled by a combination of on-site diesel engines and coal fired plants. There is a 220 kV overhead line nearly completed (2012) from Mandalgovi to Tavan Tolgoi region, which would connect the nearby mines to the CES network.

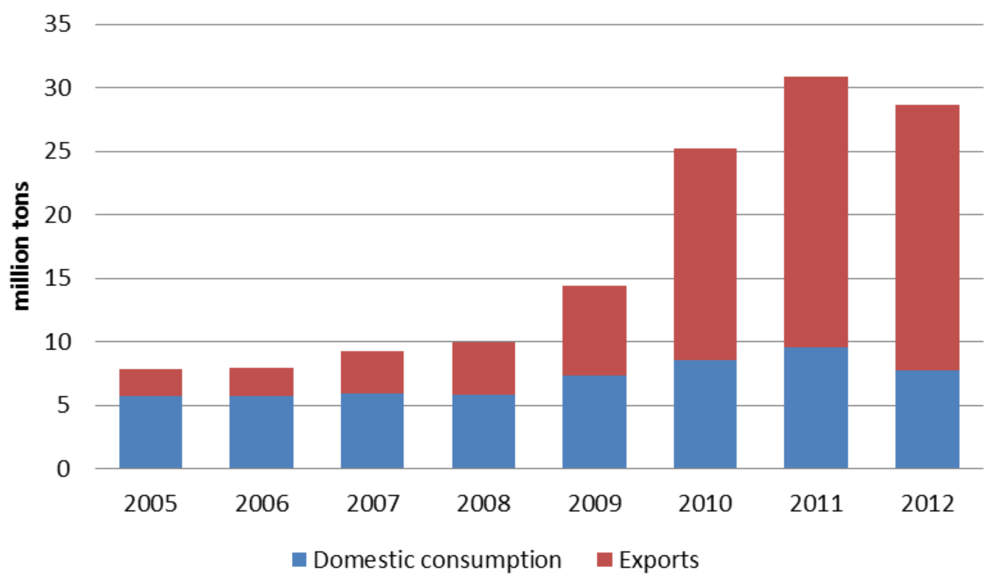
Table I-4: Bituminous Coal Mines

Name	Lifespan (Yrs)	Production (000 tons/p.a.)	Actual and estimated start date
Ukhaakhudag	100	10,000	2009
Baruun Naran	20	6,000	2012
Tsagaan Tolgoi	20	2,000	2015
Nariin Sukhait	40	2,000	2003
Ovoot Tolgoi	50	5,000	2008
Sumber	50	5,000	2015

Sources: Consultants' estimate

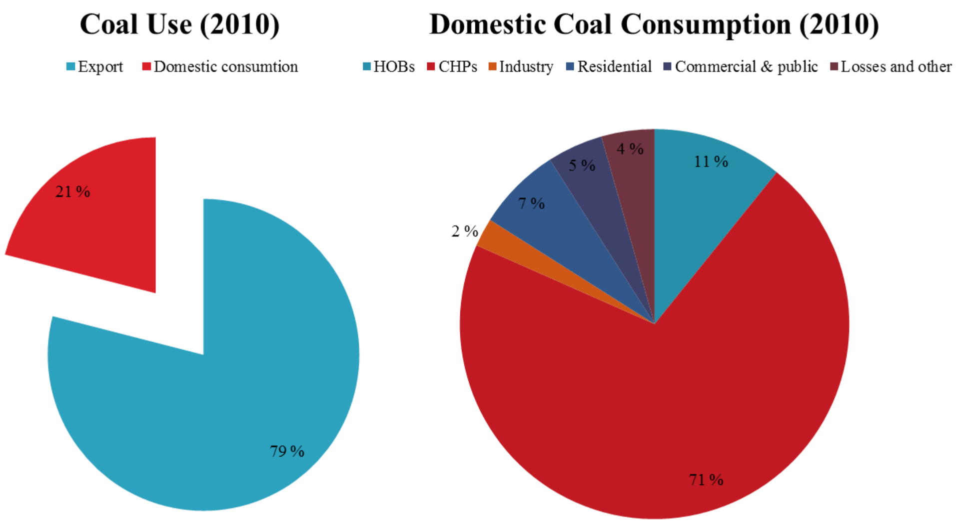
27. **Coal production and export** are of high importance to Mongolia. Coal today provides primary energy for 65% of Mongolia's total energy use, and for over 90% of power and heat generation. Coal represents 40-50 % of Mongolia's export revenues (47% in 2011), and according to the Mongolian Economic Research Institute, over 10% of budget revenues and 80 % of foreign direct investment.

Figure I-5: Coal Production and Export



28. In 2012 Mongolia's coal production reached 29 million tons. Due to weaker demand of China for metallurgical coal than during the previous year, Mongolian coal production decreased. With increasing export of coking coal, the share of domestic consumption has decreased. The breakdown of domestic use by sector is illustrated in Figure I-6.

Figure I-6: Coal Consumption in Mongolia (2010)



Note: The above figures are based on energy statistics (toe) whereby the share of export (79%) is higher than on tonnage basis (66%)

29. With regard to future utilization of Mongolia's thermal coal resources, one can distinguish the following plausible 'scenarios':-

i. Thermal coal is produced to cater primarily for Mongolia's own electricity and heat demand. Metallurgical coal will be extracted for exports.

ii. Thermal coal resources are utilized for on-site electricity production for the purpose of export. The theoretically possible export markets are Russia and China. The possibilities to export electricity to Russia in large scale are limited by the fact that Russia's Central Siberian Plateau region is energy-rich with a substantial surplus of coal, natural gas and hydropower resources. In contrast, China's eastern coastal provinces in general and increasingly also northeastern region are energy-deficient areas, to which the Chinese Government has well formulated "hydro-by-wire" in the south, and "coal-by-wire" in the northpolicies. At present the neighboring Chinese Inner Mongolian electricity market does not provide particularly attractive conditions for electricity sales. However, it is foreseen that the China North Grid, to which Inner Mongolia belongs, will be strongly interconnected to Beijing/Tianjin, China Central Grid and also to China Northeast Grid via a combination of 500 kV, 765 kV and ultra-high voltage (UHV) 1000 kV lines, including both ac and dc connections. This will change the electricity market conditions, and open up a long-term prospect of interconnecting to Korean and Japanese markets as well.

iii. Exporting thermal coal. Again the nearest market of China's Inner Mongolia may not be an attractive market on its own at least in short to medium term. China's Inner Mongolia settlement price of thermal coal Hang Hau was as of June 2012 US$ 45 per ton, and coal of 5,000 kcal/kg is sold at US$ 60-80 per ton. Considering that the transport cost from South Gobi to Inner Mongolia ranges from 12 to 30 US$ per ton, exporting thermal coal to China may not be the preferred option for the excess thermal coal supply. However, the possibility of exporting thermal coal to eastern China, and via China's coal export ports, such as Qinhuangdao, further to China's southern coastal provinces and onwards exports is clearly an alternative. Japan, South-Korea and Chinese Taipei are the world's three largest importers of thermal coal. Tapping the export potential is naturally subject to commercial agreements with Chinese operators as regards to transport, trading and ports.

30. The three coal production "scenarios" described above set different kinds of requirements for the supporting infrastructure. Whilst all of them necessitate a multitude of infrastructure

developments in terms of town development, water supply, electricity transmission and road and railway transportation, alternative (ii) would create onerous requirements for developing high voltage cross-border electricity transmission lines, and alternative (iii) place demands on railway transportation infrastructure.

31. Given the size of the country and the long distances between mines and main urban centres and export points, rail transportation of coal is most feasible. Transportation by railway is more economical than road transportation at annual loads of 2-4 million tons.

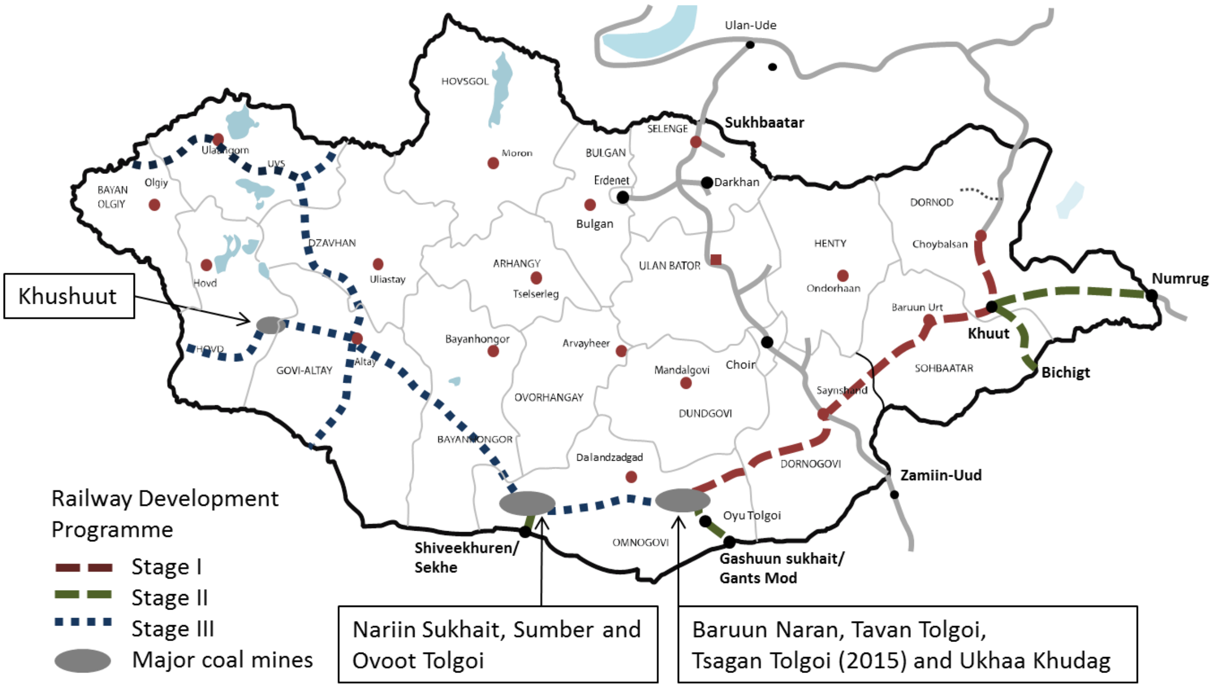
32. Currently the rail infrastructure consists of a Trans-Mongolian main line of 1,110 km from north to south, and Bayantumen Railway in the north-east with a length of 239 km from Russia to Choibalsan. Mongolia's railway system is based on Russian standard of 1520 mm gauge whereas the Chinese use a 1435 mm gauge.

33. Coal transportation accounts for more than 90% of the railway system's current maximum capacity of 9 million tons. Mining activities in Tavan Tolgoi, Baruun Naran, and Nariin Sukhait, Ovot Tolgoi and Sumber are in volumes that call for their own railway development. Other mines may also join to the railway connections to be constructed for these key mines. Studies show that route alternatives to China seem more feasible than those to Vladivostok in Russia.

34. The Parliament of Mongolia has approved a three-phase railway development plan for the construction of 5,683.5 km of railways at a cost of about USD 17 billion. This development would provide better access to the coal mining industry to both China and Russia. The Government has already started respective studies and raised some financing for the first stages of the project.

35. Phase I of the plant calls for the construction of 1,030 km of rail, which will link the Tavan Tolgoi deposit to Sainshand and through Baruun-Urt to Choibalsan; the latter city is already connected to the Russian Trans-Siberian railway. Phase 2 of the plan includes 892.5 km of railway lines, which would connect (i) Nariin Sukhait deposit to Shiveekhuren/Sekhe border crossing to financed by a mining company, (ii) Ukhaa Khudag to Gashuun sukhait/Gants Mod border crossing to be financed by a mining company, (iii) 380 km line from Khuut to Numrug, and (iV) 200 km line from Khuut to Bichigt border crossing. The Phase III expansion includes 3,600 km of westward expansion to be implemented in tandem with the government's regional development policy.

Figure I-7: Future Coal Transport Routes by Railways

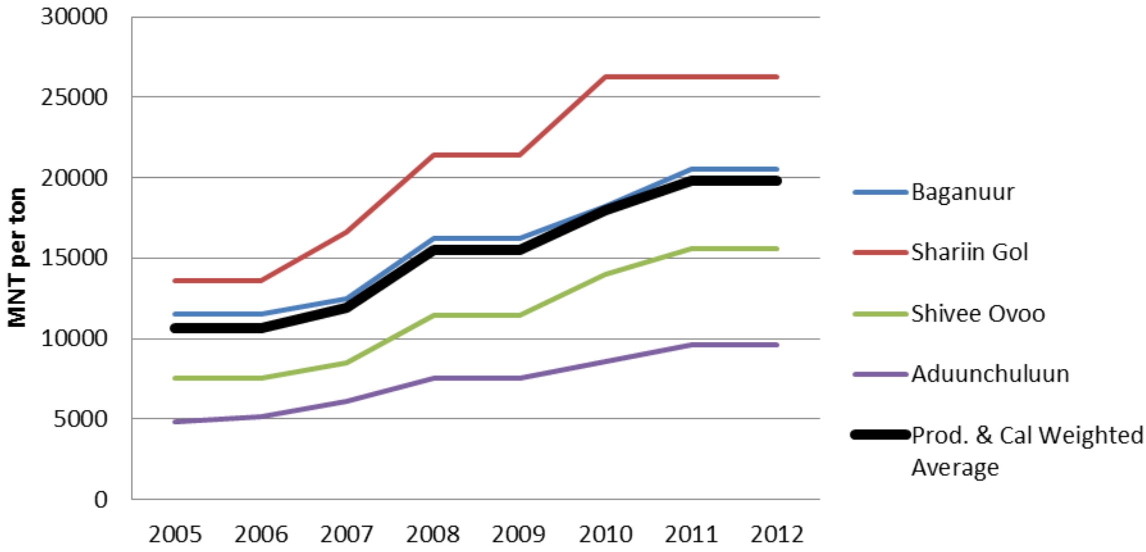


Source: J. Bat-Erdene, State Secretary of MRTCUD at Coal Mongolia Conference, February 2012

36. **Coal prices** for energy production are regulated in Mongolia for the CHP plants and urban heating. These regulated contract prices are negotiated annually. Because coal is the primary cost factor behind the electricity and heat prices, sharp price increases have been avoided and the Government has kept prices close to the break-even cost levels. The mines sell coal also in the open spot market. This coal is typically transported by 1 ton or 5 ton trucks to markets in the urban centers. The spot prices for retail consumers are a multi-fold of the regulated price.

37. The following graph presents the coal overground prices of four key mines that supply fuel to the CHP plants in CES and EES areas. It should be noted that coal from different mines have varying calorific values, which explains a major part of the contract price differences. The graph also shows a line calculated as a weighted average using both the calorific values and production volumes as weights. The graph illustrates clearly that in 2010 there was a notable price increase. The average cost of MNT 20,000 per ton equals to about $ 15 per ton. The calorific value of the 'weighted average coal' is 3,232 kcal/kg.

Figure I-8: Development of Overground Prices of Key Mines



38. Coal price will be one of the most important variables of the analysis comparing various construction programmes for system expansion in Mongolia. The coal price to be used in the economic analysis should be such that it promotes the best use of the country's resources. It should be free of taxes and subsidies. In valuing the economic benefit of an input, such as coal, the most important issue to be considered is its opportunity value. Determining the opportunity value depends on whether or not the commodity is a traded or non-traded one.

39. In the event Mongolian coal would be tradable internationally, its economic value could be established on basis of its FOB border price. However, even though Mongolian thermal coal can theoretically be traded internationally, the de facto situation is that by today coal from the northern mines, which feed coal to the CHP plants, has not been exported.

40. The overground contract prices of 'big three' mines in the CES area are currently (2012) from 23 to 27 USD per ton when expressed in US dollars and adjusted to calorific value of 5500 kcal/kg NAR (net as received). Coal of 5,500kcal/kg is a typically quoted thermal coal in the Asia-Pacific markets. As a reference, estimates of international FOB prices for such coal are about 95 USD in Newcastle Australia and 640 RMB (103 USD) at Qinhuangdao port (QHD) in China in January 2013.

41. A netback analysis of thermal coal would need to consider all the costs associated with bringing one unit of coal to an open, available marketplace such as Qinhuangdao. Such analysis for Mongolian thermal coal at Qinhuangdao port in China should include railway transportation in Mongolia, the cost of border crossing, i.e. border fee and cross-loading, railway transport in China, trader's fees, port handling fee and Chinese taxes (VAT 17%). In addition, the cost of bringing the coal to a comparable level in terms of key combustion properties by coal washing should be added. The railway transportation, if valued at 0.02 $/ton, km on both sides of the border, and considering transport distance of 1,800 km, would already contribute $ 54 per ton to the price.

42. In line with an established assumption, it can be considered for the purpose of this study that with all above mentioned costs included, and considering the initial quality of lignite, there is currently no export market for the coal that is used by the CHP plants in Mongolia. Furthermore, a comparison of Mongolian prices against the mine mouth prices of mines in Chinese Inner-Mongolia, results in similar conclusion. Therefore, the economic value of coal is not established here on basis of a netback analysis. However, this assumption is made in understanding that the coal market conditions may vary over years and that, for example, coal of Sharin Gol, which is of relatively higher calorific value, may have an opportunity in the export markets in the future provided it is washed to the required quality.

43. An economic price of coal should be free of Government direct and indirect subsidies. Currently not all of the key coal mining companies have been able to operate consistently on a profit basis with the regulated prices. Furthermore, it also seems evident that the coal mines have not been able to invest in new mining equipment, improved production efficiency and environmental mitigation to the extent that had been desirable and possible, if the revenue levels had been higher. Therefore, there is an indication that the regulated coal prices have been used as a means to subsidize electricity and heat tariffs to the consumers.

44. Under financial pressure, the state-owned operators in the energy sector have been forced to balance their financing by leaving some payables to other state-owned operators overdue. There has been a stock of payables by the CHP plants to the mining companies, even though the total stock of receivable has reduced since 2009, and also from the key coal mining companies to the Ministry of Finance and Mongolian suppliers. The payables of state-owned energy operators to the four key mines amounted to MNT 8.8 billion in 2012.

45. The financial position of the key mines is as follows:

i. Baganuur coal mine is the largest supplier of coal in the CES area. Since 2007, the mine has operated at a loss except in 2010, when the regulated prices were increased twice. Its turnover of 2012 was about MNT 74 billion. In 2011 and 2012 the losses were -7% and -8% of the turnover, respectively. The total of retained losses in the balance sheet is 70% of the annual revenue in 2011. The company has overdue payables and has not been able to carry out needed rehabilitation works, equipment replacements and exploration as planned.

ii. Shariin Gol supplies coal to Darkhan and Erdenet CHP plants, but has the highest share of coal sold to the open market of the four key mines described here (15-25 %). Its turnover of 2012 was about MNT 16 billion. The premium obtained in the spot market has helped to company to keep up profitable operations over years, which together with lowest state-ownership has also contributed to its highest valuation in the stock market (2012). The company turned a profit in 2007, but its profit levels have been relatively modest, less than 5%, until 2012, when the net profit reached 12%. However, the company has reported some problems such as deferred rehabilitation, lack of modern mining equipment and lorries (which have been borrowed from other companies), and inability to reach soil removal targets.

iii. Shivee Ovoo's production goes primarily to CHP4, but it also supplies coal to regional heat producers and the state railway. Its turnover of 2012 was about MNT 28 billion. Sales at regulated prices account for 97-98% of its revenues. Since 2005, it was marginally profitable only in 2006, and its losses of 2011 and 2012 were -14% and -15% of turnover, respectively. The total of retained losses was nearly 80% of the annual revenue of 2011. Its concerns are similar to Baganuur's, but the company also claims that the salary levels it has been able to offer to its employees are substantially below standards as compared to other similar companies.

iv. Aduunchuluun mine in Dornod Aimag is the smallest of the four key mines with turnover of only 7% of that of Baganuur. The mine has experienced reducing reserves and is in need to explore new mining areas. The company also has plans to develop refined products from its low quality lignite, such as briquettes or liquid fuel. Aduunchuluun returns a healthy profit. Its annual net profits were 12% and15 % of turnover in 2011 and 2012, respectively.

46. The non-subsidized price for 'contract coal' of the four mines is approximated here by assuming that a 12% profit of a mining company would enable it to operate sustainably, distribute returns to its shareholders whilst maintaining adequate level of investments and carrying out needed rehabilitation and exploration over time. Such a non-subsidized shadow price for regulated coal is then calculated by adjusting the year 2012 revenues of mining companies to such level which would return the required profit. The additional sales revenue thus derived represents the needed correction in sales volume and it is divided by the amount of coal supplied

to state-owned companies, to whom coal is sold at regulated prices, to arrive to the needed price increase. The resulting prices are listed in Table I-9 below.

Table I-9: Coal Price Assumptions

Mine	Production	LHV	Weight	Price in 2012	Shadow Price
	Mton/a	kcal/kg	%	MNT/ton	MNT/ton
Baganuur	3	3,300	61 %	20,500	25,170
Shariin Gol	0.5	4,100	13 %	26,275	26,353
Shivee Ovoo	1.3	2,900	23 %	15,560	20,096
Aduunchuluun	0.2	2,200	3 %	9,600	9,600
Weighted Average	5	3,232	100 %	19,783	23,713

47. The weighted average of Table I-9 is calculated on basis of both calorific values and production volumes of the mines. The calculated shadow price implies an average adjustment of +19.9 % to the current average coal price, and this is as a result of raised coal prices of Baganuur and Shivee Ovoo, a marginal change is Shariin Gol coal price, and no change to the coal price of Aduunchuluun mine.

48. Coal prices on as-delivered basis include the transport costs with cost of loading, unloading and the actual transportation. Coal transport from mines already existing in the vicinity of railway connections can be established based on quotations from the railway company. At the moment the transport costs can be as low as 20 MNT/ton,km in Mongolia. However, in estimating transport costs for large amounts of coal, and coal from completely new mining locations, the analysis should factor in the capital cost of a new branch line, or to establish the long term marginal cost of the railway system development. Therefore, estimates for a coal transportation could vary, depending of capital cost assumptions, from 15 MNT/t, km to 60 MNT/t, km.

49. This study estimates, if no specific localized cost estimates are pertinent, a default cost of 25 MNT/ton, km (0.019 $/ton, km) for railways and 250 MNT/ton, km (0.19 $/ton, km) for road transportation. These estimates are slightly higher than the current tariffs but probably less than long term marginal costs of respective infrastructure development.

When no project specific cost estimates are available, the default cost for coal in this study is as follows:

- Overground cost of MNT 23,713 ($18) for coal of 3,232 kcal/kg
- Transport cost of MNT 5,000, equal to 200 km of railway transport at 25 MNT/ton, km

The as-delivered price is:

- MNT 28,713 ($ 22) per ton of coal of 3,232 kcal /kg
- MNT 62,187 ($ 48) per ton of standard coal of 7,000 kcal/kg, equal to
- 8.9 MNT/kcal, 2.12 MNT/kJ, 7.6 MNT/kWh, or 8.83 $/Mcal, 1.63 $/MJ, 5.88 $/MWh

C. Other Coal Based Fuels

50. Other coal based fuels include liquid fuels from coal or oil shale, and gaseous fuel from coal mines (CBM) or by converting coal to gas.

51. Preliminary studies of **Coal Bed Methane (CBM)** have been carried out in Mongolia. Overall the resources seem indicatively substantial but more detailed studies on selected deposits have not confirmed economic feasibility. Most coal production in Mongolia is from surface mines, whereby the potential of extracting CBM relates primarily to the pre-mining drainage prior to surface mining activity. Narin Sukhait mine has been estimated to have CBM resources of 17-34 bcm. Even if the resources are significant, no economic reserves have been identified. Tavan Tolgoi is estimated to hold a potential of 12 bcm of CBM. Nuurst Hotgor mine in western Mongolia has 2.5 bcm of preliminary estimated potential.

52. The technical potential is significant. As a reference for the above mentioned volumes, approximately 2.5 bcm of CBM would be sufficient to fuel a base load combined cycle gas turbine plant of 100 MW for 20 years (52% efficiency, 7 000 h/a).

53. **Coal-to-Gas technologies** can be utilized for (i) the provision of city gas through a piped network to consumers, and (ii) for cleaner electricity production by Integrated Gasification Combined Cycle (IGCC) plant. As there is no natural gas infrastructure in Mongolia, the easiest way of using coal based gas by injecting it directly to an existing gas network, does not exist in the country.

54. Even though there is no detailed analysis of the matter in Mongolia, economic justification of piped coal gas is probably low in Mongolia as cities and towns already have widespread district heating pipeline systems for space heating and hot domestic water. Therefore, gas distribution would provide only marginal value in the residential sector as a fuel for cooking. The cooking fuel, fuel shift prospect together with the remaining open possibilities for gas utilization would probably not be sufficient to cover the capital cost of the associated new gas network infrastructure, which for the heat consumers would run parallel with the existing heat network.

55. The feasibility of piped gas from coal is more likely in towns that will be developed in connection with new mining activities, and in the new greenfield industrial areas which are planned for downstream processing of minerals and metals. In these cases gas could provide the primary source of energy for both heating and cooking.

56. Another way of using coal based gas is IGCC technology, which is considered for the planned Sainshand Industrial Complex. Again, as an emerging technology the capital cost of

IGCC is substantially higher than that of power plants using standard pulverized coal combustion methods at mine mouth locations. Therefore, unless IGCC technology is substantially credited for its better environmental performance, its high capital cost would make it clearly not feasible in the Mongolian context. There are clearly opportunities of diversifying coal use in Mongolia either by applying coal-to-liquid or coal-to-gas technologies. However, the end use requirements and product value lies in liquid fuels and chemicals rather than in electricity.

D. Oil and Gas

57. Oil and gas are widely utilized across the globe for power generation. Despite worldwide effort to give up using oil as a primary fuel for electricity, it continues to have a major role as a secondary fuel to support combustion of solid fuels in large boilers. At the moment in Mongolia, imported oil from Russian (Mazut) is used as the support fuel in CHP plants. Mazut is also used as the main fuel for some HOBs and diesel plants in small towns.

58. Mongolia is a rising oil country with substantial potential to improve its self-sufficiency in liquid fuel supply. At present, crude oil production in eastern Mongolia by Petro China Daqing amounts to about 1 million tons annually. All production is exported for refining in China, and therefore all petroleum products consumed in the country are currently imported.

59. Mongolia has been divided into 25 oil exploration blocks (in total 528 thousand square kilometers). Current investor interest concerns operations in 13 oil basins of which six fields are currently being intensively explored: Tamsag basin, Zuun Bayan, Tsagaan Els basins and Western Mongolia. Mongolia's total oil resources are estimated to amount to 1,600 million tons. Tamsag basin alone has estimated reserves of 600 million tons.

60. The Government has decided to select appropriate technology to process domestic crude oil and to construct a refinery to meet domestic demand for petroleum and petroleum products. With this respect, MMRE is currently studying three project proposals.

61. There are 25 oil shale deposits identified in Mongolia, of which 23 are in Tuv and Dundgobi aimags. Some estimates have assumes that Uvduq Bulag, Khugshingol and Zuunbular deposits hold large-scale resources. Oil shale resources provide an alternative to fuel oil production. Equally there are plans to establish a coal-to-liquid (CTL) plant in Mongolia. Uvdug Khudag deposit is among the best in Mongolia for this purpose. The mine is also favourably located alongside the railway that is planned to Tavan Tolgoi and Oyu Tolgoi deposits.

Cost assumption for mazut in this study is as follows:

- As-delivered price to CHPs in CES area, MNT 1.1 million per ton (850 $/ton)
- Transport cost of 280 MNT/ton, km (0.22 USD/ton, km)

62. Even though these emerging technologies have importance to the industrial strategy of Mongolia, and they provide an opportunity to develop higher value products to serve particularly the country's transport sector with liquid fuel, they have only little bearing to the electricity and heating sectors' primary fuel base.

63. No domestic natural gas resources have been found in Mongolia. There have been plans to construct a natural gas pipeline from Russia to China via Mongolia from the huge Kovykta gas field in Siberia. However, those plans are subject political and economic considerations involving all three governments, and are currently on hold.

64. Oil prices in Mongolia generally follow world market prices. CIF prices are subject to import tariff (10%), VAT, fuel tax and excise tax.

E. Hydropower

65. Another potential source of primary energy that will, most likely, factor into Mongolia's medium term energy mix is hydropower. There is significant potential in Mongolia for hydropower generation that is, as of yet, almost entirely untapped.

66. There are around 3,800 small rivers in Mongolia with a total length of 65,000 km with gross theoretical potential of about 6.2 GW. At present, more than 1 GW of these has been identified.

67. Hydropower resources can be found in the Altai ranges, Tagna and Khan Khukhii ranges, in the mountainous areas of Khuvsgul, Khangai, Khentii and the Khalkh Gol river.

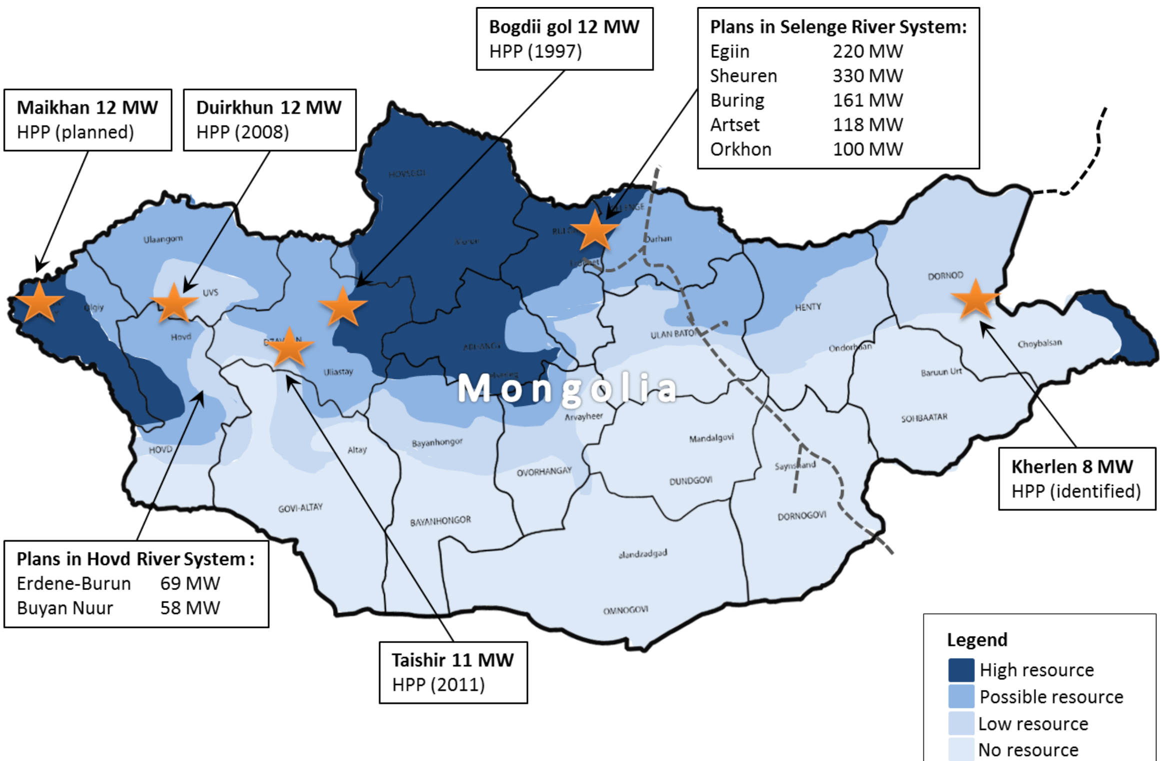
68. There are 13 hydropower stations in Mongolia in operation; most of them are small or medium sized plants. Only four plants are connected to local grids while the rest serve isolated grids of nearby soums. There are three plants larger than 1 MW, namely Durghun (12 MW), Taishir (11 MW) and Bogdiin gol (2 MW).

69. Various studies have identified within CES region prospects to develop five projects in the Selenge river system. These are Sheuren 300 MW, Orkhon 100 MW, Egiin 220 MW, Buring 161 MW, and Artset 118 MW hydropower projects. In addition a 100 MW pumped-storage HPP close to Ulaanbaatar has often been named among the candidates for mid-term implementation.

70. Within WRES there are three projects of 69 MW, 58 MW and 12 MW, and within ERES region one project of 8 MW. Totally in all Mongolia the identified hydropower projects could provide new capacity to about 1,000 MW.

71. Figure I-10 shows the hydropower resources and plants that currently operate in Mongolia.

Figure I-10: Hydropower Resources in Mongolia



Source: Energy authority, Renewable Energy Department

72. The resources of Selenge river, which the biggest river of Mongolia, and its tributaries have drawn most attention and research for hydropower development in Mongolia. Prospects associated with Selenge are not only the largest ones; they are also geographically positioned to

the north of the country, within the area of CES, where the electricity demand is the highest. Out of many projects Shuren, which is located in the main stream of Selenge river, and Egiin, which is a tributary of Selenge, stand out most often. Another large tributary, Orkhon, joins the river close to Sukhbataatar city, nearly 10 km away from the Russian border, and has also been of interest for hydropower development.

73. Water catchment area of the Selenge is 425,200 km^2, of which 282,000 km^2 or 66 percent is located at Mongolian territory. The length of river is 1,095 km, and its average incline is 0.0019. The nominal heads of most important identified dam sites in the Selenge river system vary from 50 to 75 meters.

74. Orkhon rises in the Khangai Mountains of Arkhangai aimag and flows northwards before joining the Selenge River, which then flows north into Russia and Lake Baikal. The Orkhon is longer than the Selenge, making it the longest river in Mongolia. Major tributaries of the Orkhon river are the Tuul River, which passes Ulaanbaatar, and Tamir River. The overall length of Orkhon is 1,124 km and the catchment area is 132,800 km^2.

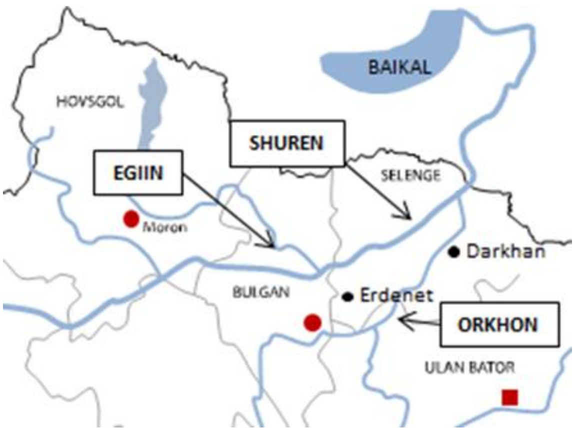
75. Considering the remoteness of the area and harsh climate, raw data of the Selenge river has been collected very conscientiously over the years. Selenge and Orkhon rivers were studied already in the early 20th century by Russian engineers from the point of view of suitability for shipping. Complete long term records since 1941 are available from two sites (Muren and Bulgan), both south of Egiin basin. Since then several gauge stations have been established.

76. The long term average river discharge is 247 m^3/s in Shuren, 241 m^3/s in Zuunburen, and 290 m^3/s in Orkhon-Selenge. Egiin has a mean discharge of 96 m^3/s and Orkhon 65 m^3/s. Selenge river has over-flooded in 1879, 1908, 1932,1952,1971,1974, 1986 and 1993. During extreme floods the river flow has reached 4,000 m^3/s.

77. The maximum flows occur together with the snow smelting and rainfall from May to August. The water flow during these four months represents 71.5 % of the regular (50 %) water flow. About 90 % of the annual precipitation occurs as rainfall from May to September. The flow is smallest in February (0.9 % of annual discharge at regular water flow).

78. Ice formation is another important feature of local hydrology. Freezing starts typically in October and the northern rivers are fully frozen in November. Ice starts breaking in April and is free from ice by the end of the same month.

Figure I-11: Approximate Locations of the Three Key HPP Projects in the Selenge River System



79. The first study for constructing a hydroelectric station at Selenge River was carried out by Russian Gidroproiekt Institute in 1970. Dam sites for hydroelectric stations of Khutag-Undur, Buren, Shar mankhtain were considered in the study. However, dam sites of Khutag-Undur and Buren, which are located upstream from the influent point of Egiin river to the Selenge river, were

excluded from the priority list for construction, because of limited water resources and some negative influences on the environment.

80. For that reason, dam sites around Shar mankhtain became more attractive. Lengidroproikt Institut conducted further research on these sites during 1974-1975. They then emphasized that the dam sites around Shuren are most prospective for developing hydroelectric schemes. However, since then there has been no thorough analysis of the dam sites identified by Gidroprojekt Insitute in the main river of Selenge, for which reason the feasibility study of Shuren dam now stands high in the government priority.

81. Since 1970's, further studies have been carried out in the tributary rivers including feasibility studies for Egeen (1992) and Orkhon (2001) hydropower plants. Both of these plants have been considered by the government in the power sector development plans over the years but for various reasons never advanced to implementation.

F. Wind

82. Mongolia has considerable potential for wind energy. Mongolia's wind resources, which can be classified as excellent for utility scale applications (power density of 400-600 W/ m^2), occupy around 10% of the total land area. There are no resource-based constraints for wind power development. The resources could potentially supply over 1,100 GW of installed capacity. All of the Aimags have at least 6,000 MW of wind potential, three Aimags have at least 20,000 MW and nine Aimags more than 50,000 MW of wind power potential.

83. Existing wind power installations are scattered and report rather poor performance. The largest wind turbines were of 1500 kW capacities before the commissioning of the Salkhit Wind Park of 50 MW about 70 km southeast of Ulaanbaatar, which came on-line in 2013.

84. Theoretically, the Government's renewable energy target of 20 % by year 2020 could be reached by wind power alone. This would require approximately 600 MW in installed wind power capacity producing 1,800 GWh of energy. The intermittent nature of wind power can be smoothened by geographic spread of projects. The wind power capacity of 600 MW would require about 100 MW of fast regulating capacity, such as hydropower or continued import from Russia, to be available.

85. Figure **I-12** is a wind resource map for Mongolia and three licensed utility scale projects, which are currently under development:-

Figure I-12: Wind Resources in Mongolia

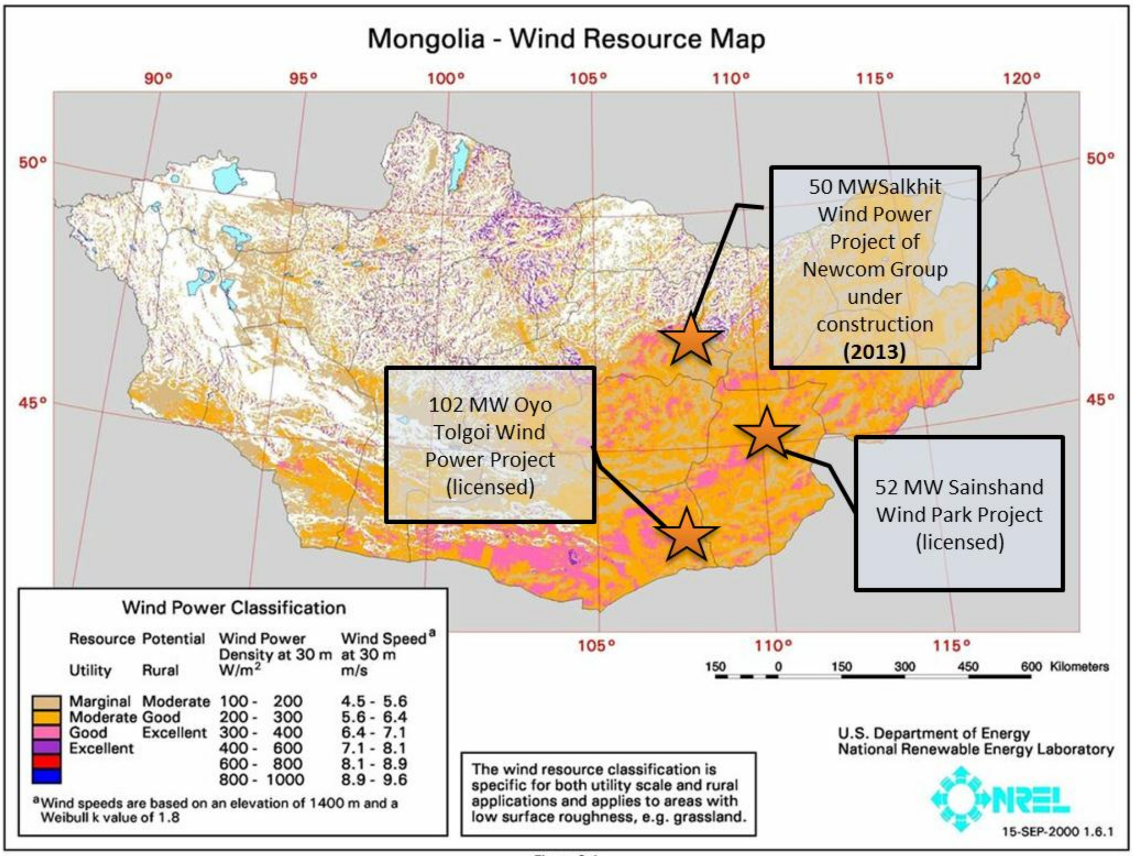


Figure 6.1

G. Solar

86. Mongolia has resource potential for both solar power and solar heating. Solar irradiation ranges from 4.5 kW/m^2 per day in the northern part of the country, where recorded annual sunshine are less than 2,600, to 5.5-6.0 kW/m^2 per day in the Gobi area. Regions with high irradiation account for around 70 % of the country, while those with intermediate levels of solar radiation cover 18 % of Mongolian territory.

87. The National Renewable Energy Program has promoted use of solar home systems for herder houses (100,000 Sun Rays Project) as well as for the use of solar PV for isolated soums to provide electricity for telecommunication, TV repeat stations, border control units and hospitals. At present there are no large-scale grid connected solar PV projects implemented.

88. A large solar PV project is proposed to be studied in the Gobi area similar to China's 200 MW Golmud Solar Park or Indian 600 MW Gujarat project.

89. Solar heating is under-developed in Mongolia. One reason is that hot domestic water is provided by the district heating company. Therefore, there is no consumer level incentive to install individual roof-top solar heaters. Consequently, solar heating potential should be tapped by the district heat distribution companies and possibly housing companies at locations of the nearest heat exchange stations to a block of buildings, i.e. in the secondary networks, where domestic hot water is heated. Cold weather also poses challenges to low pressure water circulated systems and therefore frost-resisting liquids need to be used in the panels. Preliminary studies have been carried out and a proposal for a pilot system has been put forward by the Ministry of Energy.

H. Geothermal

90. There are tens of small hot springs in Mongolia and some of them are used for traditional health resorts and small-scale heating. Their value as a means of supply of commercial energy has so far estimated marginal. Further studies are needed to establish whether or not geothermal energy could provide a feasible local energy source for district heating. Some preliminary studies estimate that the cumulative flows of usable heat (>35 ºC) from hot springs at aimag levels, where there are some, are between 1 to 15 MW_{th}. The impact of this resource to Mongolia's overall energy supply will therefore likely remain limited and very local.

91. Geothermal energy, when available, can be combined with heat pump technology to provide district heating. Even though a ground source heat pump can use the top layer of the earth's crust as a source of heat, thus taking advantage of its seasonally moderated temperature, any heat source that is warmer or more easily accessible can improve the efficiency of the system and lower its capital cost. Therefore also low grade heat sources such as city waste water plants could be explored as potential heat sources for heat pump technology.

92. The potential of geothermal energy remains not fully explored and subject to continuous discussion in Mongolia. Therefore, a case study approach is recommendable for the analysis of the feasibility of geothermal energy. Such analysis on one or few systems should be carried out for locations, which based on already executed preliminary studies demonstrate highest prospects.

93. Hot springs in Arkhangai Aimag have been studied in a pre-feasibility study by Iceland Geosurvey (ISOR), Fjarhitun Geothermal Consultants and Rafnönnun Consulting Engineers. The study concluded that there were highly significant indications that geothermal energy could be economically developed in Tsetserleg and other towns in the Khanghai area. Based on preliminary analysis of this area, there are seven hot springs with surface temperatures ranging from 36 ºC to 86 ºC typically at 17 to 34 km distance from nearest population centres.

94. One of the most prospective ones (including six springs) for development is the Tsenkher hot springs with 86 ºC surface temperature located 25 km southeast from the Aimag center. Tsetserleg has an estimated 13-15 MW (2012-2025) district heating system demand, and would be theoretically suitable for heating by geothermal source. Coal is currently transported from long distance to the town. A full technical and financial feasibility analysis of geothermal based heating, considering needed heat transmission system, is recommended for this single location. Such a suitably selected case study would then expose issues and concerns of future geothermal heating development in the country.

I. Nuclear Energy

95. Mongolia has substantial known uranium resources and geological potential for more. Mongolia's reasonably assured resources are 37,500 tU to the cost level of US$ 130/kg U and inferred conventional resources 11,800 tU, totally 49,300 tU (IAEA, Uranium Resources 2009). Uranium was produced from the Dornod deposit in Mongolia by Russian interests until 1995. Russian, Chinese, Canadian, Japanese and French companies have since then sought Mongolian government consents for their quest after Mongolia's uranium potential. Mongolia joined IAEA in 1993.

96. Since 2008 Russia has re-established its position as a co-operation partner for uranium mining and nuclear energy development. In February 2009 the Government set up MonAtom LLC to undertake uranium exploration and mining on behalf of the state, as well as pursuing nuclear energy proposals. In 2009, Mongolia also signed a nuclear cooperation agreement with India.

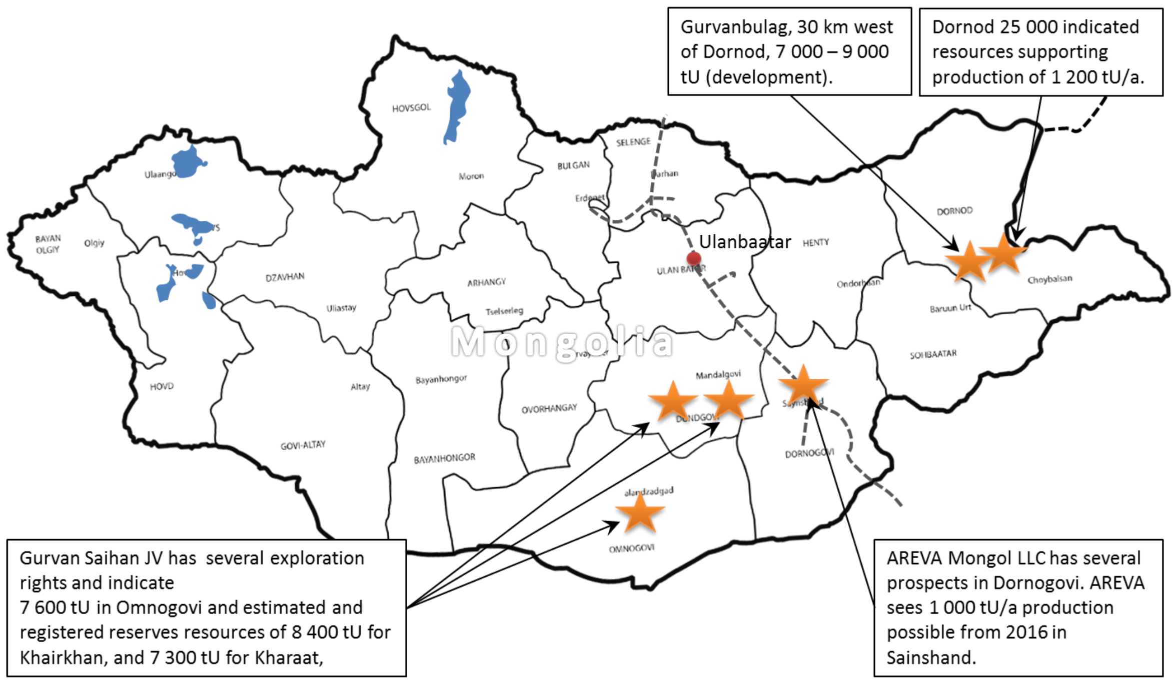
97. In July of 2009 parliament declared all Mongolian radioactive mineral deposits strategically important and other regulation in relation to the nuclear energy industry was formalized in a Nuclear Energy Law. A protocol for establishing a JV by Russian ARMZ and MonAtom was

signed for revitalizing uranium mining at Dornod. Plans for Dornod are not finalized but there is some expectation of production of 1,000-1,200 tU/yr from about 2015.

98. Preliminary ideas for a nuclear power plant in Mongolia have been presented based on Russian, Toshiba 4S and Korean Smart reactor technologies. Ulaanbaatar, Dornod and Western Mongolia have been mentioned as potential locations. However, there are no definite plans for developing nuclear energy as for a domestic source of power and nuclear power does not appear in any approved power sector planning documents.

99. There are 17 ore bodies of different sizes identified. Most of them are in (i) Dornod, (ii) Dornogovi, Dundgovi and Omnogovi, or (iii) in Hovsgol. Figure I-13 shows some of the most notable recent uranium mining development sites in Mongolia:-

Figure I-13: Uranium Resources in Mongolia



II. TECHNOLOGY SCREENING

J. Methodology

1. In this Section, technologies considered later in this study are screened using economic comparative analysis, according to the Levelized Cost of Energy (LCOE). The analyses determine the relative cost of technologies in the Mongolian context.

2. LCOE calculation assumes that the present value of the sum of discounted revenues of a plant is equal to the present value of discounted costs. LCOE thus represents the break-even value for the average energy cost that an investor can shoulder with the given weighted cost of capital (WACC) and other preconditions. The revenues are represented in the calculation by the discounted flow of outputs, namely electricity (MWh) or heat (GCal). The calculation is based on a cash flow on annual basis.

3. Most cost data is based on international references as there is limited experience of recently realized utility sized power projects in Mongolia. Effort has been made to adjust available cost information to Mongolian conditions. Feasibility studies of real projects in Mongolia have been used as a reference whenever possible. Consultant's estimates and data base information as well as international reference data from other markets are adjusted to match local conditions such as fuel properties for coal based power or hydrology for hydropower. Higher reference value is given to cost data from China or Russia than plant costs from Europe or USA. Provisions have been made to consider factors such as land locked location, transport distances of equipment deliveries and market (competition, perceived country risk, etc.).

4. The investment costs ($/kW), which are commonly also called as the overnight cost, i.e. capital cost excluding the financing terms, have been expressed here as per gross capacity of the plant. The costs include all equipment and construction costs but also the so called owner's costs such as for project planning, technical design, project management and construction time interest. However, the resulting capital costs ($/kW) and LCOE ($/MWh) from the cash flow model have been calculated and expressed on the net power and energy produced by the plant (net on sent-out basis), i.e. plant internal use of electricity and heat is deducted from the gross production of the turbine-generators. It is noted that the investment costs are often not reported consistently and there is variation in definitions and therefore inaccuracies in this respect appear in the publicly available cost data.

5. The assumptions and cost items analysed here include the following:-

- Plant construction cost; or EPC cost;
- Capital cost including pre-construction, contingency and other owner's costs such as project management, engineering and construction time interest;
- Construction time;
- Expected life of the plant;
- Decommissioning cost;
- Operation and maintenance cost;
- Unit cost of fuel;
- Calorific value of fuel;

- CO_2 cost;
- Net efficiency;
- Load factor;
- Method for dividing capital and operational costs of a CHP plant to electricity and heat; and
- Weighted Average Cost of Capital (WACC).

6. All costs are estimated at year 2012 level. The exchange rates are the average interbank (± 0%) mid-point of April 2012, i.e. 1000 MNT = 0.764 USD and 1000 MNT = 0.583 EUR.

7. Historical costs expressed in MNT, USD or EUR are brought forward to April 2012 by using MNT, USD and EUR CPI indices in accordance with EC Eurostat statistics (2011-2012 US All Items CPI from Detailed Report of United States Department of Labor).

Table II-1: Cost Correction Factors (MNT, USD and EUR)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011*	2012*
US CPI	91,79	93,88	96,43	100,00	103,17	105,88	110,51	109,60	112,26	113,27	115,15
Euro Area	93,78	95,78	97,87	100,00	102,20	104,39	107,83	108,15	109,90	112,89	112,89

* Interim figures or estimates

8. The lead time from project planning, i.e. preparation of the feasibility study, to signing the equipment supply and construction contracts, or alternatively a single EPC contract, is dependent on the owner' procurement procedures. State-owned entities must follow the public procurement procedures and seek consents and approvals from high government entities at various stages of project development. The procurement process must be subjected to competitive bidding from the feasibility stage onwards. Private sector operators, such as for example the mining companies, can, however, act with or without competitive bidding and proceed directly from selection of suppliers to construction upon receiving government approval for their investment and start construction at the finalized Power Purchase Agreement (PPA). In many cases a private sector operator is though dependent on the public sector entity's actions, for example, for the construction of an interconnecting transmission line. The differences in total project lead times can be substantial, even one to two years. The time element of pre-construction activities is not, however, considered here even though the owner's pre-construction cost is inclusive in the capital cost.

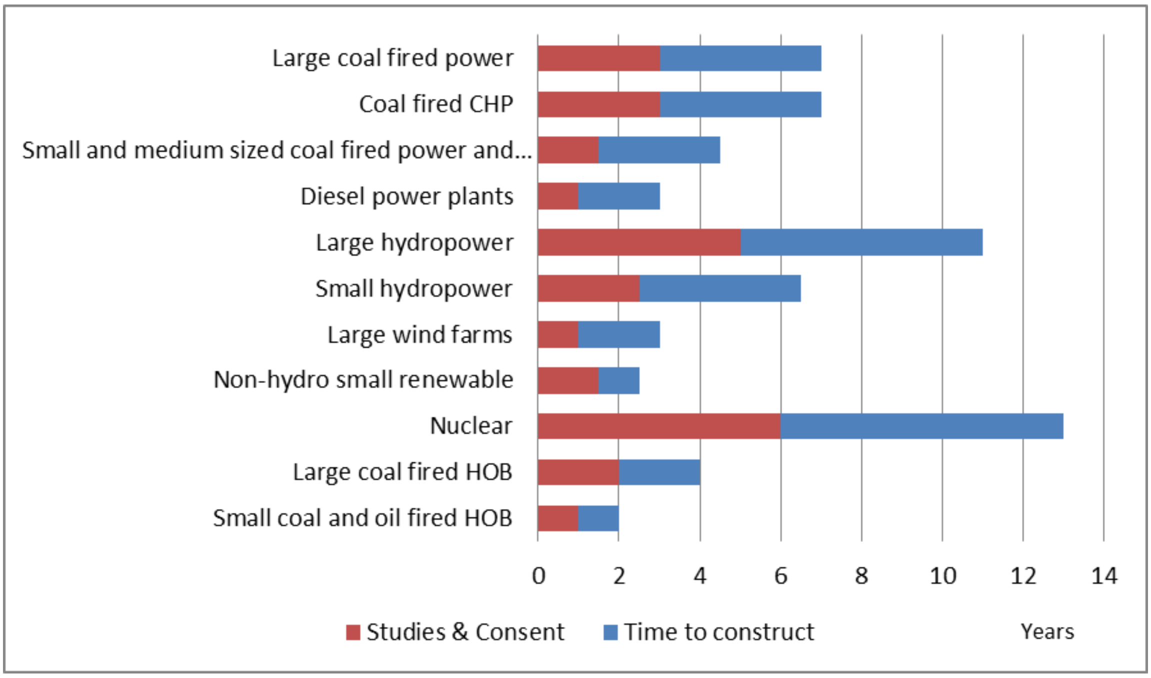
9. The construction phase in Mongolia is influenced by the climatic conditions, which may prevent carrying out certain outdoor construction works during the harshest winter months. The construction period is defined here to start from signing the first contract for equipment delivery or construction. The harmonized estimates are as follows:-

- Large coal fired power (600 MW and above), 4 years;
- CHP5, 4 years;
- Small and medium sized coal fired power and CHP plants, 3 years;
- Small and medium sized oil fired CHP plants, 2 years;
- Diesel power plants, 2 years;
- Large wind farms (50 MW and over), 2 years;
- Other non-hydro small renewable energy, 1 years;

- Large hydropower (50 MW and over), 6 years;
- Small hydropower, 4 years;
- Nuclear, 7 years;
- Coal Fired Heat Only Boilers (HOBs), 2 years; and
- Oil Fired Heat Only Boilers, 1 years.

10. The period to construct is an important factor contributing to LCOE as the discount rate leads to the near costs weighing more than the distant cash flows of project benefits. Also the development period, even though not considered in the following, is de facto a major issue to be allowed for in Mongolia especially in the current situation, where the country is facing diminishing reserve margins and new capacity is needed soon. In city areas, land acquisition, and construction and/or rerouting connecting heat and power transmission lines may delay the project. Hydropower is always subject to public discussion on nature values and resettlement issues associated with large reservoirs. Even though project timing is always project specific and dependent on the level of political unanimity around the project, Table II-2 below illustrates the overall lead times that one should take into account in developing new project initiatives.

Figure II-2: Typical Plant Development & Construction Lead Times



11. The owner's cost during construction is assumed to be distributed in a slightly back-heavy manner typical to EPC contracts. The cost distribution profiles during construction stage are harmonized for all types of power and heat generation as (30%/70%), (10%/50%/40%), (9%/21%/37%/33%), (7%/14%/29%/30%/20%) and (5%/8%/19%/26%/24%/18%), respectively for two to six years of construction period.

12. Construction time interest is calculated in a simplified manner of the total capital cost as accrued during construction with a rate set as 50% of WACC.

13. The expected lifetimes for each technology are harmonized as follows:-

- Large coal fired power (600 MW and above) 40 years;

- Small and medium sized coal fired power, CHP plants and HOBs 30 years;
- Diesel power plants, 25 years;
- Wind, photovoltaic and solar heating plants 25 years;
- Nuclear power plants 50 years; and
- Hydropower 80 years.

14. Decommissioning costs are assumed to be 5% of the plant capital cost except for nuclear power plants for which they are estimated at 15%. Decommissioning cost is assumed here to incur in one year after life of the plant. It is understood that this is not entirely correct for large plants. Especially for nuclear power plants the estimate should rather be in the range of 10 to 15 years. As to lifetimes of hydropower plants, which may extend to over 100 years, there is very little experience of the actual decommissioning cost. Because decommissioning cost, when discounted over the life of the plant, has relatively minor impact to LCOE, the chosen simplification can nevertheless be regarded acceptable.

15. Fuel costs are based on cost levels in Mongolia in April 2012. The cost assumptions have been rationalized in Volume II Section VIII Energy Endowments. Coal cost is set at MNT 28,713 ($ 22) per ton on as-delivered basis, i.e. inclusive of assumed average transport distance. This cost is representative for lignite of 3 232 kcal/kg. For large coal fired power plants, which could potentially be established at mine mouth locations, the coal price and quality could be different. However, harmonized per kcal price is assumed for the purpose comparing the technologies. The price of oil (Mazut) is assumed at MNT 1.1 million ($ 840) per ton as-delivered in Ulaanbaatar. The transport cost of fuel oil is 280 MNT ($ 0.21) per ton

16. CO_2 is calculated in accordance with the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories, as follows:-

- The fuel consumption in energy units (TJ) is 4alculated either from the plant energy output by applying the plant's Net Efficiency or from the actual fuel consumption of the plant by applying Calorific Value of the fuel tonnage on Lower Heat Value (LHV) basis.
- The fuel energy is multiplied by fuel specific Carbon Emission Factors (CEF) expressed as (t C/TJ) to derive Net Carbon Emissions in combustion.
- Net Carbon Emissions are multiplied by Fraction of Carbon Oxidized to derive Actual Carbon Emissions.
- Actual Carbon Emissions are multiplied by 44/12 to find Total Carbon Dioxide (CO_2) emitted from fuel combustion.

17. The cost of emitted CO_2 is an arbitrary figure which will be considered as a factor for sensitivity analysis. It serves as the easiest proxy for the damaging global impact of GHG emissions due to combustion of fossil fuels. It is typical to use the value of the European Emission Reduction Unit (EUA) or Carbon Emission Reduction Unit (CER) as the basis of valuating emission reductions even though it should be understood that this price stands on intergovernmental regulation and political consensus and is by no means representative of all the impacts of climate change. Further, as has been described above, a new fossil fuel fired power plant can be in operation up to 30-40 years, during which period the impacts of climate change are expected to become apparent and critical, and also the value of emission reduction can be assumed to grow significantly.

18. In April 2012, the values of emission reduction units were all time low at levels clearly below the EUR 10 per ton as there was oversupply of CO_2 emission rights in the market largely due to slow economic growth and recession in many parts of Europe. CO_2 futures for 2020 showed variation between EUR 14 and 28. However, the CO_2 prices have then reduced even more, and there is great uncertainty in the market about the future prices under the European Union

Emissions Trading Scheme. Assuming a conservative but still a forward looking estimate, the cost of CO_2 is assumed EUR 20 per ton equalling to USD 26 per ton when CO_2 cost is factored in.

19. The load factor is set at 0.67 for coal fired power. Load factors for renewable energy are dependent on site specific climatic and hydrological conditions, and assumptions are set to be representative for best sites in Mongolia. The load factor for nuclear energy is set at 0.8.

20. The chosen method of dividing the fixed and variable costs of a CHP plant has an impact to the comparative analysis, when CHP technology is compared to electricity-only or heat-only plants. As a single CHP plant may produce heat, co-generated electricity and condensing power, depending on the type of turbine chosen, the challenge is the allocation of the fixed and variable costs of the plant to these three forms of output in a manner that provides for an equitable sharing of the cost benefit of co-generation as compared to its alternative, in which power and heat is generated in separate facilities.

21. The issue of cost allocation of a CHP plant has been long under discussion by energy professionals, but the principal challenge of cost allocation is not unique for power industry. Similar issues are met in other businesses, say, how to allocate costs of a railway system to passenger transport and cargo, or the often quoted example of a refinery environment, where one input, crude oil, is processed in one plant (refinery) to numerous fractions of petroleum and petrochemical products, which each have their unique market conditions and prices.

22. The cost allocation methods can be divided to economic and thermodynamic methods. Thermodynamic methods are often defended as being more ‘scientific’. Advanced methods consider the essential properties of mass and energy flows (temperature, pressure) in the power plant, for example enthalpy or exergy. The underlying principle of, say, exergy method is to value a more useful form of energy (high temperature, high pressure, electricity) higher than a less useful form of energy (low temperature, low pressure, hot water, steam), on basis of thermodynamic values.

23. Whilst the thermodynamic methods answer in a seemingly objective way how to divide the energy inputs (fuel) to the outputs (electricity and heat), these methods do not provide any more objective ground for dividing fixed, non-energy and non-process related costs than other methods. Parameters derived for the purpose of cost allocations by the thermodynamic methods are essentially valid only on one operational point whereas the operational situation and loading of a power plant may vary hour by hour. For the purposes of economic analysis, it would be a too laborious exercise to determine annual averages for all power plants for the thermodynamic parameters that are used for cost allocation. Therefore more practical economic methods are usually favoured.

24. Many methods, whether economic or thermodynamic, fix one form of energy as the primary one, and the other(s) as secondary or side product(s). In these, the primary form of energy carries the costs of all equipment and operation, which is needed by it in a stand-alone situation, and the remainder of cost is allocated to the side product. The same principle is applied when guidance for the ‘value’ of the primary product is taken from the market, and all balance of costs is allocated to the side product. The probably most typical cost allocation method for CHPs is to value produced heat at the cost of its alternative, i.e. production in HOBs, and allocate the balance of costs to electricity.

25. The Mongolian government (ERC) applies pre-set proportions for dividing fixed expenses of CHP plants (70%/30% for electricity and heat) and pre-set heat rates for electricity and heat to allocate fuel and other variable costs. It is justified to assume that heat is generated at a certain fixed efficiency, and allocate all remaining fuel cost to electricity, because the heat rate of electricity is not stable but depends on the proportion of condensing power generated over the period.

26. An alternative would be to divide the total cost of CHP production, including both fixed and variable costs, to heat and power in proportions to the costs of alternatives for both forms of energy. The alternative for heat is a HOB (or rather a number of them), and for electricity it is a

condensing power plant of similar capacity using the same fuel and producing the same amount of energy as a CHP plant. Once the total cost of CHP production is allocated to heat and electricity, in proportions of the total costs of their alternatives, the variable costs are allocated based on fuel consumption calculated using heat rates, which in turn should be established so that their values are in close match with the thermodynamical reality of the plant. The underlying assumption is therefore that all variable costs are proportional to the fuel consumption.

27. The downside of the benefit allocation method is that the risk of error in the reference cost estimates for electricity-only and heat-only production. In Mongolian context coal is of low cost and therefore the cost allocation becomes primarily dependent of capital cost estimates.

28. The cost allocation by benefit allocation method was tested using the design values of the planned CHP5 as an example (Appendix X). The annual electricity generation of the CHP plant (Phase I) was estimated at 2,025 GWh, net (2,250 GWh, gross), and heat production of 1,600 GWh. The fixed costs of coal fired HOB(s) capable of delivering 587 MW of heat (505 Gcal/h), and of a coal fired condensing power plant of 450 MW capacity were estimated differently from the CHP5 feasibility study. Capital costs estimates of 1900 $/kW, 1500 $/kW and 200 $/kWth were used for CHP, condensing power and HOB respectively. The efficiency rates were chosen to represent state-of-the-art technology. The condensing efficiencies were set at 37.7% and 37.2% for the condensing power and CHP plants respectively. The cogeneration efficiency was set at 84%. Heat production efficiency was set at 87% for HOB and 84% for CHP. With these values and discount rate of 6%, the cost allocation exercise results in electricity being accountable for 88% of fixed expenses and 69% of variable expenses of a CHP plant.

29. Realizing that there exists no definite cost allocation method that would universally apply to various kinds of CHP plants in Mongolia, the cost allocation is done in the following by assigning 80% of the fixed costs (including capital costs and fixed O&M costs) to electricity, and 20% to district heating. The variable costs are assigned to electricity and heat in proportion to fuel consumption, which in turn will be calculated using technology specific heat rates.

30. Finally, the weighted cost of capital (WACC), which is used as the discount factor in calculating the whole of life Net Present Value (NPV) operating costs, including operating costs and amortized capital investment, must be determined. WACC is cost of capital in which each category of capital is proportionately weighted, typically composed of the developer's cost of own equity and various types of lending terms to a specific project. As both the credit risk and the cost of own capital vary project by project and developer by developer, the WACC assumed here must reflect a portfolio on energy sector investments in Mongolia with varying capital structures and developer's credit risk ratings. It should be noted that the Government through its state-owned companies is still likely to be the foremost power developer in the near future. On this basis the technology screening uses WACC of 6 % on real pre-tax basis as a harmonized blended finance scenario.

K. Coal-Fired Condensing Power

31. The major coal based technologies that are available today at various stages of development include (i) conventional pulverized coal combustion (PC), (ii) circulating fluidized bed combustion (CFB), (iii) supercritical (SC) and ultra-supercritical (USC) PC combustion, and (iv) integrated gasification combined cycle (IGCC). There are also add-on technologies that can be combined with some or all of the mentioned technologies to improve environmental performance of coal combustion. Among them are carbon capture and storage (CCS) technologies either as a retrofit to running power plants or as part of the new ones. CSS technologies have not yet been commercialized.

32. The coal fired power plants presented here have been selected from the point of view of illustrating the most probable solutions available for Mongolia under the different scenarios contemplated in this study. Options to produce electricity for exports call for highly efficient mine-mouth power plants that have been optimized from the cost point of view. Other equally prioritized considerations are efficiency and environment. Higher efficiency offers reduced CO_2

emission as one percentage-point improvement in overall efficiency can result in up to 3% reduction in CO_2 emissions. Overall, it also results in smaller material flows per output unit and consequently resource preservation, lower capital costs for various transport, handling and auxiliary equipment, and to reduced emissions of other pollutants such as SO_2, NO_x and particulates.

33. The examples presented later will be limited to PC, SC, USC and CFB technologies. IGCC technology, whilst already demonstrated in several plants, is not yet fully commercial and competitive in comparison to PC technology. Not only that the capital cost of IGCC technology is high, the technology is perceived to involve unquantifiable operating risks. Furthermore, the advances in PC combustion through substantial efficiency gains achieved with SC and USC technologies have overall reduced interest in IGCC technology.

34. USC and SC plants are already commercially available, cost effective, and there is rapidly accumulating worldwide operational experience of them. Steam parameters of typical sub-critical power plants are 150 to 180 bar pressure and 540 to 565 ºC temperature; SC plants operate at around 245 bar pressure and 540 to 570 ºC temperatures, and USC plants have temperatures of around 600 ºC or higher. Supercritical pressure is reached at 221 bar, above which level water/steam reaches a state where there is no distinction between liquid and gaseous state. Consequently the boiler does not need to separate steam from water and the substance is heated in a once-through process.

35. The design efficiencies of USC plants are between 39% and 46%. This stands in an apparent contrast with the typical efficiencies of 30% to 37% of the conventional PC and CFBC technologies. However, it should be noted that the SC and USC technologies have not yet been designed for high ash and low grade coal. Therefore, large SC and USC plants can be an option for selected mines only, primarily in South Gobi, where the availability of suitable quality of coal is combined with the possibility of exporting electricity through HV lines to China.

36. CFBC technology is mature and offers many benefits in Mongolian conditions. Compared to traditional PC technology, CFBC can better utilize high-ash content fuels, is less sensitive to coal quality variation, allows mixing various kinds of coals, and provides opportunity to low-cost solution for the reduction of SO_2 and NO_x emissions.

37. Whilst the economy of scale clearly works with respect to plant unit capacity, many mines in Mongolia need to ensure that there is firm capacity available for the mine’s own consumption of electricity. Therefore, a unit size of 150 MW is considered as typical for such purpose. The reliability can be ensured by having multiple units, and cost efficiency can be sought by using exactly similar units in the total capacity up-scaling in the event excess power is planned to be supplied to the grid.

38. The coal fired power plants presented below as examples have therefore been selected to be 1000 MW USC, 600 MW SC, 5x150 MW CFBC and a single unit 1x150 MW CFBC. In assuming the capital costs, the reference data is sought from China. The capital costs assumed here range from 1000 \$/kW to 1700 \$/kW from the largest 1000 MW USC plant to the smallest unit of 150 MW CFBC plant. The plant own use of electricity has been estimated to range from 6% to 9% and plant efficiencies from 45% to 34%, respectively from largest unit to the smallest.

39. It should be noted that the plant capital costs vary significantly country-by-country, and the Chinese cost levels are considerably lower than those in OECD countries including Japan and Korea. IEA data from 2010 collected for SC and USC plants, so called overnight costs, which exclude construction time interest, and were expressed in 2008 US dollars calculated on the net capacities, ranged from 800 \$/kW to 3,500 \$/kW whilst the median cost was at around 2,100 \$/kW. The costs in the Chinese domestic market were between 600 \$/kW and 700 \$/kW.[1]

40. The cost estimates chosen here are clearly higher than the costs in China but lower than the median costs reported by IEA in 2010. The cost drivers in Mongolian conditions are many, as

[1] IEA/NEA Projected Costs of Generating Electricity, 2010 Edition

follows:-

- Local geographic conditions characterized by long and cold winter that sets special requirements for construction.
- Land-locked location with substantial transport distances from some manufacturing bases. On the other hand, large and competitive Chinese, Korean and Japanese OEM manufacturers and contractors are not behind intercontinental transport, and there is a direct railway connection to both European side of Russia and the North-Eastern ports of China.
- Lack of consistency and relatively poor track record of the government in the implementation of approved power sector projects and development plans, which results in perceived risk of delays and cancellations among private project developers and EPC contractors, hence higher risk provisions.
- Party politics inducing politically driven preferences to government procurements with regards to the country of origin of the supply.
- Variations in manufacturers' and contractors' order books affected by economic cycles
- Raw material and component costs in international markets
- No economy of scale in domestic market. Even though some plants would be of standard design and construction in a large market place, Mongolia faces a local first-of-kind phenomenon. Further, with not many large projects to construct annually, there are no major domestic contractors experienced in implementing large subcontracts for power projects.

41. With the above issues in mind, this study assumes gradually reducing unit costs over the planning period. The first power plants in the expansion plan are assumed to have higher specific costs than the later units of the same kind.

42. The plants are assumed to use bituminous coal mine-mouth except for the 150 MW CFB (mine mouth) and CHP plants, which are assumed using lignite.

43. Fixed operating costs of coal fired power plants are estimated at 2.5 to 3.0% of the investment cost and variable O&M costs at 3.1 to 3.3 $/MWh.

L. Coal-Fired CHP

44. Combined Heat and Power (CHP) plants represent currently the main form of electric power production in Mongolia. In this regard reference is made to the preliminary data of the new CHP5 plant planned for Ulaanbaatar. The first phase of the project includes 3x150 MW extraction condensing units with electric gross capacity of 450 MW and heat supply capacity of 587 MW. The overnight cost of the plant is estimated here at 2,000 $/kW.

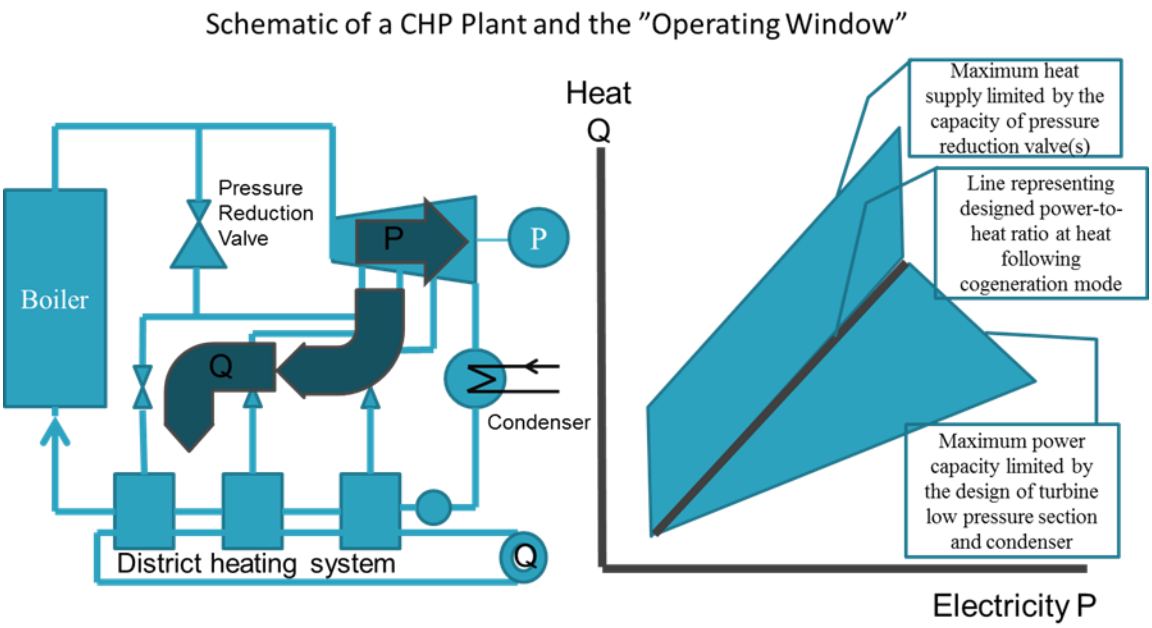
45. Because CHP plants in Mongolia form the backbone of electric power and heat generation systems, they need to be designed to a certain degree to serve both electricity and heat demands individually. This means that the plants are designed to supply electricity even at times, when the heat demand is low and does not support sufficient electricity generation in the turbine's heat-following cogeneration mode. This is realized by selecting such turbine dimensioning in the low-pressure section that allows steam to flow through the turbine to the condenser even when the steam extraction from medium and medium-low pressure extraction points to district heat exchanger stations is at a low level. The design of the condenser must also be sufficient for the large steam amount at such operating point. This kind of operation is typical, when the outdoor temperatures are high (summer, late spring, early autumn) compared to electricity demands.

46. On the other hand, there are operational situations, where there is a proportionally higher heat demand to electricity demand. This is the case during extremely cold weather conditions

(winter, late autumn, early spring) and at times when power demand is low (nights and public holidays). Therefore, CHP plants are designed to have sufficiently large boiler capacity from which steam can be led directly to heat exchange stations for district heating by-passing the turbines. This is realized through having pressure-reduction valves in the main steam pipeline, which enables live steam of high pressure to be led to heating stations at medium or medium-low pressure. Under such operating condition the CHP plant, or part of it, serves as a heat only boiler (HOB).

47. Whilst the efficiency of heat-only production can be estimated at around 89%, the efficiency of electricity generation in co-generation mode can be estimated at 70-75%, and the efficiency of generating marginal electricity in condensing mode at 25-35%, depending on several technical factors such as the live steam and turbine extraction pressure levels. Usually the annual generation of a CHP plant includes all of these forms of production. Therefore, the overall annual thermal efficiency of the plant is formed as a weighted average of efficiencies of various operational modes. For a new CHP plant the total thermal efficiency is estimated here at 59.7%, heat efficiency at 89% and electric power generation efficiency at 46.7%. Whilst a modern CHP plant easily reaches a total thermal efficiency of 85% when it is operated continuously in the cogeneration mode, the CHP plant has a lower average efficiency due to the need to balance electrical demand by generating marginal electricity in condensing mode. The annual Heat to Power ratio of the plant supply is estimated at 0.84.

Figure II-3: CHP Plant Schematic



48. The operating cost assumptions for the CHP plant include 3% of the capital cost as fixed operation and maintenance cost, variable O&M cost of 3.2 US$/MWh, load factor of 67%.

M. Diesel

49. A diesel engine based CHP plant is an option in town centres where there are HOBs for heat production and need for additional electricity, which would anyway be generated using diesel engines or by high-cost electricity transmission connection. Diesel engines have good load following and peaking capacity properties; they start fast, demonstrate good availability and have high part-load efficiency. With these characteristic reciprocating engines are suitable for small, isolated systems. The main disadvantage is that they have relatively high emission levels of NO_x and particulates when using liquid fuels such as mazut.

50. There are four potential sources of heat in a reciprocating engine. Heat can be recovered from flue gases in heat recovery steam generator or heat exchanger; from engine jacket cooling water; from lube oil cooling; and from turbocharger cooling. Only about half of the heat can be recovered from flue gases as medium pressure steam. The rest from the cooling circuits is in the form of hot waters. However, the temperatures are completely sufficient for space heating and domestic hot water purposes. Power to Heat ratios of diesel engine based CHP plants range from 0.6 to 1.1.

51. The following table provides cost estimates for various size of diesel engine based CHP plants.

Table II-4: Cost Estimates for Diesel Engine Based CHP Plants

No of engines		1	2	4	8
Net output	MW	8.6	17.3	34.6	69.4
Net efficiency at step-up transformer outlet	%	42.2 %	42.3 %	42.6 %	42.7 %
EPC cost	$/kW, net	1100	952	775	600
Overnight cost	$/kW	1155	1000	814	630
O&M cost	$/MWh	9	8,5	8	7
Heat output, hot water 60/110 ºC	MW	6.7	13.4	26.8	53.6
Incremental cost of heating capacity	$/kWe	68	63	61	60

52. A single engine 8 MW mazut-fuelled CHP plant is assumed with a total thermal efficiency of 75% in cogeneration, and efficiency is electricity-only mode of 42%. CHP mode can be realized by using both high and low temperature heat sources such as flue gases and jacket oil cooling. Investment cost of such plant is estimated at 1,250 US$/kW in the screening exercise later in this Section

53. The heat loads of Aimag centres are currently 6 - 20 GCal/h and are expected to grow by 2020 so that the range increases to 7 - 35 GCal/h. The electric loads of Aimag's outside CES region are typically less than 10 MW, most often less than 5 MW, if industrial spot loads are excluded. In this connection, diesel engine based cogeneration is an option for covering simultaneously both the electricity demand of the region and heat demand of an urban centre.

54. Considering rural electricity supply to serve primarily residential consumption, a coal fired power or CHP plant faces the difficulties with its limited load following capability. The appropriate configuration for such plant should include not only a backpressure turbine for heat supply but also a condensing extraction turbine for electricity load following. The demand would call for 2x16 MW or 3x16 MW configurations with at least two boilers. This is a rather expensive solution, because a cooling tower is also needed, and not practical, when loads during summer low demand periods do down to just few megawatts and below. In this kind of a situation, the load should either be connected as part of a larger grid (grid connection) or served by a diesel power plant.

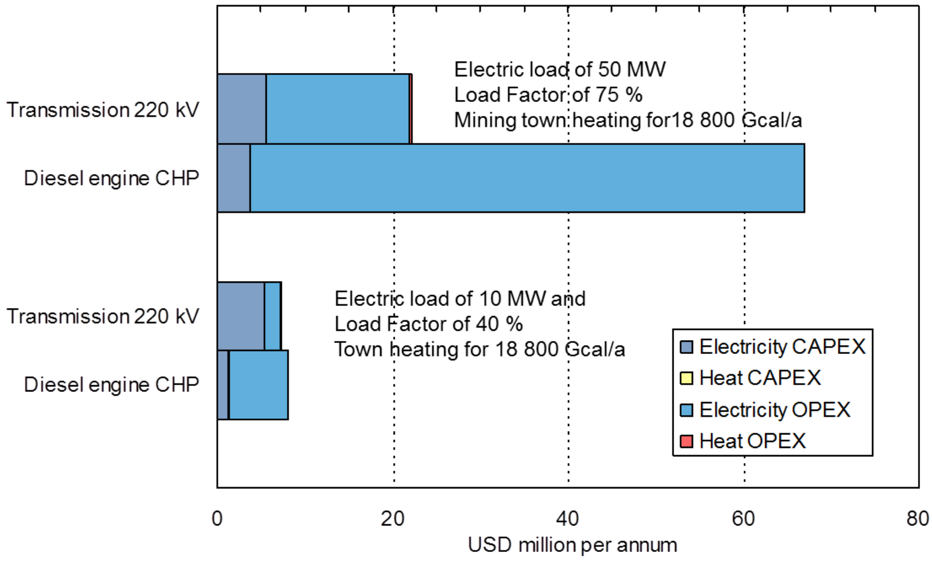
55. The feasibility of diesel based cogeneration was tested in two hypothetical situations. In the first case the township has 800 households and some public buildings connected to a heating system, which together demand 18 800 GCal of heat with peak load of 6.1 Gcal/h. The fuel cost of heating today would be typically around MNT 500 million ($ 0.4million). If such a town together with its surrounding region should be served with electricity with a peak demand of 10 MW and load factor of 40%, the most practical options are either (i) to connect the region to a national grid (AES,CES, DES, EES or WES) or (ii) to build a diesel power or CHP plant.

56. The second case illustrates a situation, where the township is built around an industrial or mining site, which brings about a large and stable electricity demand assumed here at 50 MW in

peak demand and 75 % load factor (three shift operation). The amount of heat demand is assumed the same as in the first case.

57. In both cases a transport distance of 200 km is assumed for coal and mazut, as well as it is assumed that electricity connection to be built on basis of a 220 kV branch line is 200 km of length. As to the transmission option, a substation needs to be built to the receiving end with single bays on both HV and MV sides and a step-down transformer of 35 MVA or 100 MVA, in cases 1 and 2 respectively. In the sending one CB bay expansion to an existing substation is assumed. The line cost is estimated at MNT 100 billion ($ 77 million). Cost of grid electricity is set at 58,500 MNT/MWh (45 $/MWh), transmission losses at 5%, and fuel cost assumptions are as reported elsewhere in this study. The diesel engine CHP plant is dimensioned to gather for 130% of the system peak load. The results are shown in the following graph.

Figure II-5: Cost comparison between diesel engine based CHP plant and 220 kV transmission line in two examples of rural electricity and heat supply



58. The graph illustrates the following:

- Given the assumptions above, grid connection compares well to diesel engine CHP plant for large loads of over 10 MW. At 10 MW, the costs are almost equal. Therefore, for small loads of 10 MW and below detailed studies are needed case by case, as the low capital cost of diesel engines may make them the least-cost option, particularly for loads in the range of 1 to 6 MW typical in Mongolia.

- The cost of heating is very small as compared to the costs required by electrification. In the event diesel engines are chosen for electricity supply, they should be equipped with heat recovery systems for space and water heating, if the surrounding building stock so warrants.

N. Hydropower

59. **Large hydropower plants** have been proposed for Mongolia in several earlier power sector studies. Particular proposals have been put forward for Sheuren 330 MW, Egiin 220 MW and Orkhon 100 MW power plants. Past studies and reports have indicated capital costs from 1,300 US$/kW to 1,600 US$/kW, and load factors of 40%, 25% and 25% for Sheuren, Egiin and Orkhon respectively. There are several ways to optimize the available water flow of a hydro system. For example it has been suggested to have a small unit running as a base load plant in parallel with the large turbine unit which would be dimensioned to capture the seasonally high

water flows, albeit with low load factor. A pumped storage scheme of about 100 MW has also been proposed.

60. References for typical **small hydro power plants** were sought from the CDM documentation of Taishir 11 MW and Durgun 12 MW plants, which were built in 2011 and 2008 respectively, and from the feasibility study of Chargait 24 MW small hydropower plant. The investment cost estimate at current values is set here close to 4,000 US$/kW and the calculation assumes 40% load factor.

61. Hydropower is a capital intensive technology and requires long lead times for development and construction. It is also very engineering and design intensive. Before financing can be secured, substantial effort needs to be put on site surveying, feasibility analysis, planning, preliminary civil engineering design, environmental and social impact analysis, planning of resettlement measures, fish, water quality and biodiversity mitigation, and analysing ways to preserve historical and archaeological sites. Therefore lead times for hydro power schemes can easily vary from three to ten years and even more and the owner's development cost prior to construction may represent up to a quarter of the total cost of a hydropower scheme.

62. The construction costs for new hydropower plants are unique and site specific. The costs can be roughly considered in two major areas. The first area is the civil works, which dominate in the cost structure of a hydropower plant. The works include dam and reservoir construction, tunnelling and canals, powerhouse construction, site infrastructure and grid connection. The second component, electro-mechanical equipment, is mature technology and its cost correlates relatively strictly with the capacity of the hydropower plant. The electro-mechanical equipment account normally not more than 15-25% of the total cost of the scheme.

63. A typical estimation of the construction costs requires detailed physical dimensions of the major civil components, which depend on the hydrological characteristics of the river affecting the dam structure, safety requirements and spill capacities, site and its terrain, and access road and electrical connections. The needs of the power system determine whether the plant is designed for base load supply, middle load, peaking and whether the plant will contribute to system regulation and frequency control. The optimum MW/MWh ratio will be established and the characteristics of electro-mechanical equipment, such as with how many generating units and of which capacity, the plant will be equipped.

64. The usual means of estimating construction costs is a bottom-up approach, where using these physical parameters and "cost of construction" factors, such as specific costs ($/m3) for material volumes – e.g. for building the dam, costs for each main component are estimated separately, and finally summed up.

65. There are no updated, in-depth feasibility and EIA studies with consequent cost estimates available for the Mongolian hydropower prospects, which are ranked here as candidate projects for power system expansion. Feasibility studies for Orkhon and Egiin are older than ten years, and the most recent studies performed of other projects are on conceptual design level. A pre-feasibility study was carried out by Fichtner in 2007 for Chargait small hydropower plant. The most recent study is for the Erdeneburen 64 MW HPP by MCS International, Kyusu Electric Power and West Japan Engineering Consultants. Except for the Erdeneburen feasibility study, the referenced costs from these past studies are clearly outside of the averages that are quoted today by international studies as typical costs of schemes with comparable characteristics.[2]

66. In the context of long-term energy sector development planning, there is no opportunity to carry out a bottom-up cost estimation exercise for each candidate project. However, there is still need for updated cost estimates, which are sufficiently justified to be used for expansion planning but which have to be derived without going to the details of the construction. Therefore the existing estimates, albeit out-dated, can be taken as a basis, which is then challenged by other methods of cost estimation. The two methods of modelling the hydropower costs chosen here

[2] The key characteristics of the mentioned hydropower projects, and other Mongolian hydropower projects, whose names will appear later in this text, are described in Volume IV Energy Planning.

are both empirically based. Firstly ordinary least squares multiple regression analysis is used on basis of a sample that is hoped to be representative enough for the projects in Mongolia. Secondly, the so-called Gordon formula is applied, after calibrating its variables using the same sample of HPP projects that is collected for the regression analysis. In both methods, it would be ideal if the model could be tested against real projects executed in Mongolia, or under similar climatic conditions in the neighbouring countries, but unfortunately no data of such projects is available for the analysis. Both methods are justified and explained in more detail in the following.

1. Regression Analysis

67. The basis of regression modelling is the sample to which the cost model is fitted, and the selection of best parameters to predict the costs.

68. The first criterion for the sample is the newness of the data. As already mentioned, most engineering study based cost information regarding Mongolian hydropower projects is five to 20 years old. Therefore, the sample is selected from projects, which have been completed during the last five years, i.e. from 2008 to 2012. The newness of data reduces risk of error in estimating the evolution of construction costs over the years in real terms when bringing cost data to the level of 2012. The cost data of selected projects is assumed to represent the year, which is three (3) years prior to the year of starting operation. From this year the cost is brought to 2012 simply by using US CPI in accordance with EC Eurostat statistics and for 2011-2012 from US All Items CPI from Detailed Report of United States Department of Labor.

69. Regarding the geography of the projects in the sample, the hydropower construction has intensified during the recent years and at the same time the focus of activity has shifted to the emerging economies. Asia, led by China, and Latin America, led by Brazil, today are the areas where most of hydropower development takes place. So even though there are countries with far higher shares of hydropower production in the system, such as Nordic countries and Canada, the installation of new capacity is keenest elsewhere. In 2010 alone, China added 16 GW of hydropower capacity and Brazil approximately 5 GW whilst approximately 500 MW was put on line in Canada.

70. Newly installed HPPs in China, Brazil, India, Turkey and Vietnam represent 44% of the projects (of less than 300 MW) which were extracted from a database[3] as candidate projects to the sample. These five countries embody such intensity in hydropower construction today that their domestic markets and cost levels are not completely representative to such countries, in which only few, if any, hydropower plants are built annually. Therefore whilst few projects were selected from these markets to the sample, projects from other developing countries, which do not develop new hydropower plants annually, were considered favourably.

71. The key dependent parameter in the analysis is the cost of the project. It is at the same time the biggest hurdle in data collection and possibly the most uncertain. Whilst project technical data is often reliably available, cost data is rarely public and available in the internet. This fact excluded a vast number of projects from ending to the sample. The cost data was searched using, among others, such internet sources as International Water Power and Dam Construction Magazine, Hydroworld.com, the World Bank project database and the PDD and Validation Reports of hydropower projects under the CDM mechanism.

72. The cost data published may not always be reliable and reported in a consistent matter. It is quite customary, that the developers and construction firms announce only the EPC cost of the project, but ignore project development, engineering and financing costs, and sometimes even such project associated costs as for transmission connection, road construction, resettlement and environmental management. In some countries the cost information given to the public must strictly tally with the previously announced engineering cost estimate, which has been the basis of project approval, especially if there is some conditionality associated with the initial project cost

[3] Platts World Electric Power Plants Database, October 2012

estimate, such as for the purpose of a subsidy or a loan. Similar tendency to stick to the planned cost estimates, and to refrain from publishing the posterior realized investment costs is seen in CDM projects, in which the additionality criterion for project return is dependent on the investment cost. With this kind of difficulties in mind, the cost data retrieved from public sources was checked from several sources and best efforts were taken to come up with the latest and accurate investment cost numbers for the selected projects.

73. As there is no opportunity to collect a large sample, care was taken to leave such projects out from the sample, which are clearly not representative for projects in Mongolia. Vast majority of projects in Europe, for example, are re-builds and renovations on existing hydropower sites. The search was focused on finding pure greenfield projects. Projects, in which there was no dam construction, were excluded. Effort was made to exclude hydropower projects to a well-established cascade and mixed multipurpose irrigation and hydropower schemes. The project size was limited to those with an installed capacity from 10 to 300 MW.

74. With these criteria, a sample of 33 hydropower projects from around the world was collected. The sample included initially 36 projects, of which 15 were from Latin America, 4 from Europe, 2 from Africa, 3 from Turkey, 11 from Asia and 1 from Australia. Theoretically, extreme project features are important for a statistical analysis, but in a small sample their weight is sometimes high, which distorts the analysis. Therefore three projects were excluded from the sample, the one with the largest head, Pirris in Costa Rica with a head of 829 meters, and the one with the lowest head, Ashta HPP in Albania with a head of only 5 to 7 meters. Again, Tsanko Kamak project in Bulgaria was left out from the sample for its extremely high investment cost.

75. The costs of hydropower plants and associated transmission systems are to a large extent a function of physical characteristics of the project such as (i) the installed electrical capacity of the plant, (ii) hydraulic head, (iii) type of project (diversion, expansion etc.), (iv) dam type, and (v) remoteness of the location. The cost is also impacted by the competitive situation in the country in terms of civil construction and electro-mechanical equipment, and the same in the international setting especially when large multinational construction firms bid for the project. Cost of labour and the regulatory system (length of permitting project, environmental sensitivity etc.) also have important cost implications.

76. As this sample also shows, there is an evident and strong correlation of cost to the most important parameter, installed capacity of the plant in megawatts. The strong correlation is demonstrated in several studies. An extensive World Bank study on the costs of the hydropower projects from 1990 demonstrated that this single cost predictor accounts for about three-quarters of the variance in cost[4]. Many facilities, such as powerhouse, intake tunnels, tailrace and electrical systems have to be designed to match the number and rating of the turbines. Even though the cost of the dam is not completely in relation to the installed capacity, there is still a notable correlation too. Overall, installed capacity is a good proxy for the overall size of the project, including the civil works.

77. The second important parameter is the nominal hydraulic head of the plant in meters. If the natural conditions permit a high head, it will predict a lower cost in certain proportion, and vice versa. Therefore there should be a negative correlation between the head and cost as the higher head with the same output requires smaller water channels and turbines.

78. With these two parameters, the regression model to be calibrated with the sample is in the following form:

Investment cost in 2012 US$ =

a + b x Installed Capacity in megawatts + c x Nominal Head in meters

79. The formula is tested both with real term figures and with natural logarithms of cost, megawatts and head, as the use of logs may provide a more reliable linear relationship when the

[4] Understanding the Costs and Schedules of World Bank Supported Hydroelectric Projects, July 1990, The World Bank Industry and Energy Department, Energy Series Paper No.31

key variables span over several orders of magnitude.

2. Gordon Approach

80. The other simplified method of estimating hydropower costs is based on the formula of a Canadian hydropower engineer, James Gordon. The method is described in "Black Boxing Hydro Costs", a paper presented at IPA/World Bank seminar in September 1989. The formula is best suited for relatively small power projects, and therefore is worth of testing in the Mongolian conditions.

81. The Gordon formula is:-

Cost (2012 US$) = k x P x S x (MW / H^0.3)^0.82 / (365-F)^0.9

which can be rewritten as:

Cost (US$) = Factors x (MW / H^0.3)^0.82 / F-factor,

where H stands for the head of the hydropower plant and MW for its installed capacity in megawatts.

82. The power factors, a = 0.3 and b = 0.82, are positive but less than 1, to account for the economies of scale that occur in hydropower construction. Thus the cost of constructing a hydropower project depends on the same factors of the design flow, the head of the project and various scheme / site factors as described above.

83. What Gordon calls the "Frost factor", the F factor = (365-F)^0.9, measures actually the difficulty of construction, which in Canadian conditions comes from the fact that construction in remote northern areas, which suffer from frozen earth issues for much of the year, is proven to have a substantial cost impact to the project. This F factor can actually be generalized to other aspects of difficulty in construction, and be calibrated to local conditions so as to act as a dummy to collect for various kinds of difficulty factors to the formula.

84. Whilst the F-factor provides an opportunity to model various difficulties, it is disregarded in the following. It is best suited to relatively even conditions, such as the case when projects in Canada are compared to each other. Our sample includes projects from around the world, and many of them from tropical or subtropical environments. Due to the vast diversity of the projects, other cost factors are expected to vastly override those that can be modelled using the F-factor.

85. The benefit of the Gordon formula is that it also requires limited technical information – only the project design flow and the hydraulic head. It does not require particular engineering dimensions, nor the type of turbine, nor what the major components have been made of – e.g. whether a dam is concrete, earthfill or rockfill. In effect, for projects in the sample, it uses the logic of the Economic Interspersing Approach – i.e. it does not matter what the project is or how the project was built - if it has been built, the designers would have adopted the most economic approach at the time and it is only the fundamental parameters of flow and head (together giving "energy") which matter.

86. Given the basic simplicity, the Gordon formula as well as the regression model both have accuracy limitations, which can be as much as ± 50% on a particular hydro project. This should however be expected – civil costs, particularly geotechnical aspects, are highly site specific and can easily vary by factors of this level, and more, prior to detailed site investigations. But over a number of projects in the sample, it would be expected that the "unders and overs" average out somewhat.

3. Model Calibration

87. It is important to note that this exercise differs from a usual statistical analysis of data in that the model structure for both regression and Gordon formulae is fixed. Unlike in many other analytical problems, we do not seek independent variables to explain and predict a phenomenon, but consider them as already found and grounded in past studies and literature. This exercise merely seeks values for the coefficients that give the best fit of the model to the sample. The calibrated model is then used to predict the current costs of Mongolian HPPs.

88. The sample includes 33 projects with an average cost of 2486 \$/kW. Once the parameters of the above mentioned two models are calibrated to the whole sample, it is noted that the fit is poor (In regression model R^2 = 0,71 with intercept =, a = and b =, in the Gordon formulae the Factors having value of R^2 =0.72). A better fit is found by using simply the average cost of the sample (a = 2486 \$/kW) as the single parameter and Installed Capacity as the predictor. This means that the model should be of the form Cost = a x Installed Capacity, and the impact of Hydraulic Head is ignored. This result obviously contradicts the past experience and would hint at the direction that the Installed Capacity and Hydraulic Head together would not anymore be the best predictive factors, which is counterintuitive.

89. Numerous past studies have shown that the Installed Capacity together with the Hydraulic Head are independent and strong factors behind the cost and their combined influence can be put in the form of the two above mentioned models. Therefore, it is clear that this sample is influenced by a third factor, which is stronger, and which causes more variance in the sample than the two above mentioned factors. This third factor can indeed be identified by analysing the residuals of the Gordon Formulae.

90. The third factor is non-technical and it relates to the market conditions in various countries. The residuals of the fit of the Gordon formula to the sample are shown in Figure II-6. It is observed that where the model predicts too high costs, the projects have been in Brazil, China, India, Turkey or Vietnam. The only project in these countries, whose predicted cost was higher than the realized cost was Serra do Facão 220 MW project in Brazil, but only slightly. Furthermore among these low cost projects are also Kamchai project in Cambodia, Imboulou project in Congo, Asaha project in Indonesia, Nam Lik-1-2 in Laos as well as Taishir and Duirgun in Mongolia, which are not located within the mentioned five countries. Even though seemingly these projects do not belong to the cluster of emerging economies of Brazil, China, India, Turkey and Vietnam, where there is extremely strong hydropower development currently on-going, it appears that in all of these low-cost cases (as evidenced by the model residuals) outside this group the project key contractors had been Chinese. In some cases the project was funded by Chinese agencies and constructed by a Chinese EPC contractor using Chinese labour. This also concerns the projects in Mongolia. In Taishir project the main contractor was Sinohydro Corporation. As to Durgun, China Shanghai (Group) Corporation for Foreign Economic & Technological Cooperation had a role in financing and Hangzhou Asia-Pacific Power-Tech company undertook the construction, and the design and supply of the electro-mechanical and control systems.

91. Therefore, as shown in the graph, three clusters of HPPs can be identified in the sample that need to be considered separately, as follows:

- Cluster A: Projects implemented in countries other than the mentioned emerging economies with installed capacity of 50-300 MW using technology from domestic and international contractors including suppliers also from industrialized countries. The average cost of installed capacity of this cluster in the sample is 3000 \$/kW (N = 14, Average = 3030 \$/kW).

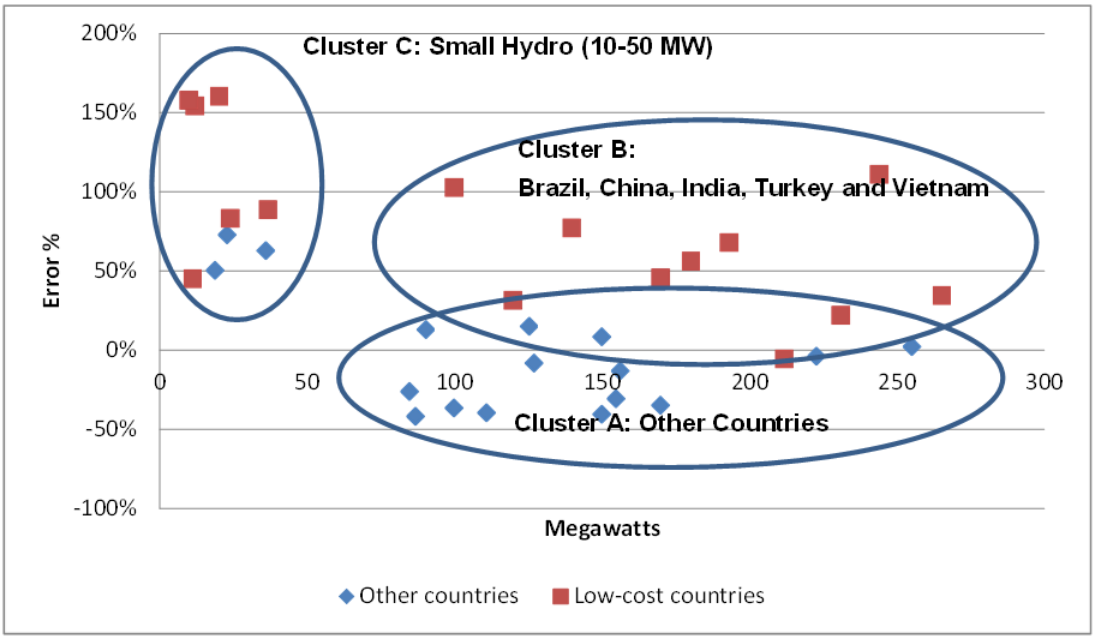
- Cluster B: Projects of the installed capacity of 50-300 MW implemented in Brazil, China, India, Turkey and Vietnam, or by contractors from these countries. The average cost of installed capacity of this cluster in the sample is 2000 \$/kW (N= 10, Average = 1967 \$/kW)

- Cluster C: Small hydropower projects of 10-50 MW. The average cost of installed capacity of the cluster in the sample is 2500 $/kW (N= 9, Average = 2545 $/kW)

92. This clustering is well justified and supported by other studies. Recent international surveys on the costs of power plants clearly indicate that the massive hydropower construction in Brazil, China and India has led to lower investment costs and levelized costs than in other countries, in a manner which is coherent with the average costs of capacity in the above three clusters in the sample.

93. The lower costs of hydropower in emerging economies such as Brazil, China, India, Turkey and Vietnam are due to several factors which are outside the scope of this study. It should be noted briefly, however, that the best hydropower sites have already been developed or they been protected from construction in high-income industrialized countries, hence the most costly sites remain, whereas the mentioned five large emerging economies still have many hydrologically potential sites available for development. As each of these five countries puts tens of power plants (and in China close to one hundred) in operation every year, it means that their domestic market supports a large number of contractors, builders, designers and equipment suppliers tuned to implement hydropower projects efficiently in a very competitive marketplace. Another important competitive advantage is the cost of labour in these countries.

Figure II-6: Plot of Residuals of the Gordon Formula on the Whole Sample vs Installed Capacity



94. The success in domestic market, however, does not automatically translate to commercially successful export of the engineering, EPC and equipment supply to international markets. There are specific challenges in hydropower construction, where large dams and reservoirs have major socio-environmental impacts, and local regulation and mitigation measures differ substantially from those of the supplier's home market. Secondly, the countries' regulation as to receiving foreign labour to the construction sites varies. Some countries require benefit equalization. Despite these challenges, it seem that the Chinese hydropower industry has succeeded in its internationalization effort, and it now dominates the market in Southeast Asia, and exports hydropower construction intensively all over the world including Africa, Middle-East and Latin America. Even though the Chinese labour is low cost, it is also skilled and has developed an impressive track record of implementing projects both in China and overseas.

95. It should be reminded that the choice of contractors and equipment suppliers for a

hydropower project is a function of several issues, in which the first cost and the labor cost in particular are important factors, but represent only one facet of the project.

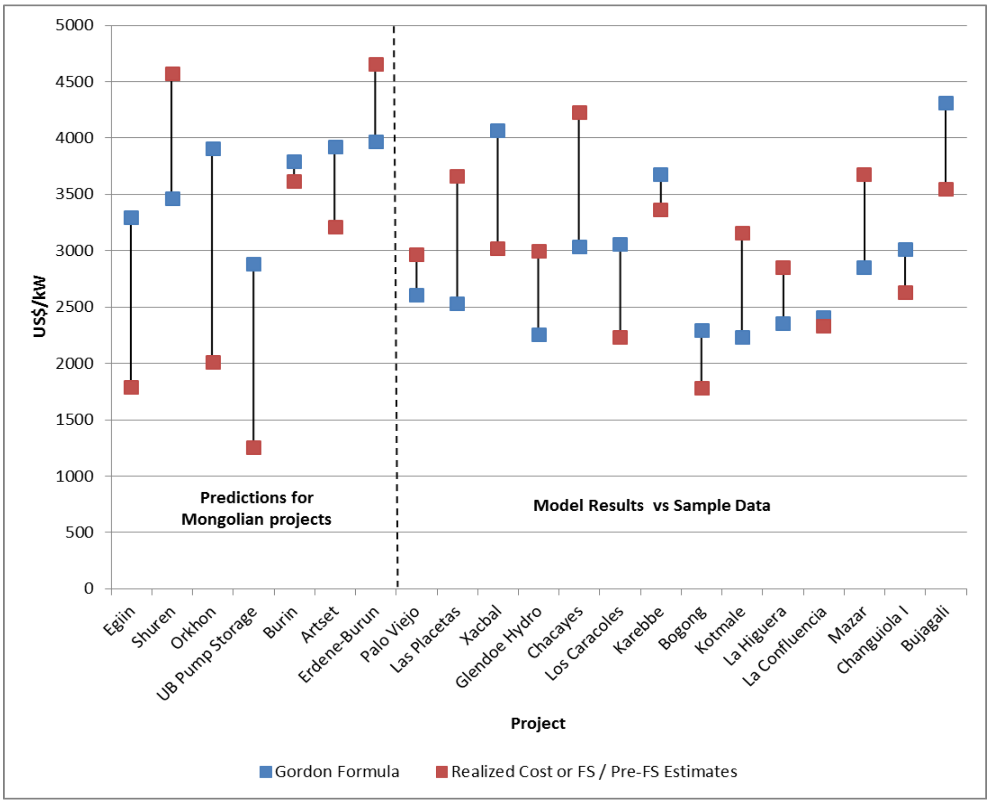
96. The calibration of the parameters to Cluster A results leads to the following formulae, of which the Gordon formula gives a better fit:

Regression model Cost = 75.54 + 2,82 x Megawatts – 0.18 x Head, R^2 = 0.75

Gordon formula Cost = 25 x (Megawatts / Head^0.3)^0.82, R^2 = 0.82

97. The residuals of Gordon model reveal that the predicted costs of 7 of the 10 projects were within ±20%, and three within ±40%. The Gordon model results are shown in the following Figure II-7, and the model parameters have also been used to predict the costs of the Mongolian projects that are in the pipeline as candidate projects for the future.

Figure II-7: Gordon Formula Results vs Sample Cost Data and Model Predictions for the Costs of Mongolian projects using the Higher Cost Cluster A Sample



98. In reviewing the costs of the candidate projects it should be noted that the most recent firm engineering estimate has been carried out for Erdene-Buren by Japanese expert firms, and this estimate is higher than the one predicted by Gordon Formula based on the Cluster A (higher cost) sample. The other one, where Gordon formula gives a lower prediction than the referenced past studies, is the Shuren project. The Shuren project Pre-FS cost estimate is taken from the Masterplan study of 2002. There is a new pre-feasibility study estimate as well, but its cost estimation method is not transparently described in the report and it is founded in too limited data (possibly on the Taishir and Duirkhun experience), and seems in light of modelling results as clearly too low. It is therefore not taken as the reference point for the model.

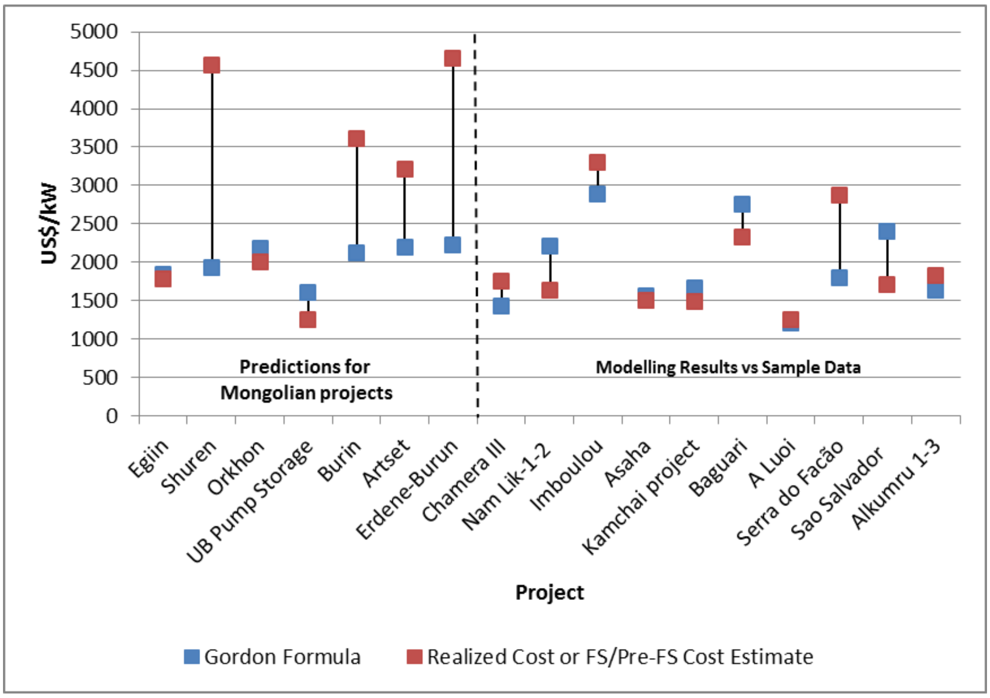
99. The analysis of Cluster B data gives the following formulae:

Regression model Cost = 110.73 + 1.60 x Megawatts – 0.40 x Head, R^2 = 0.56

Gordon formula Cost = 14 x (Megawatts / Head^0.3)^0.82, R^2 = 0.54

100. The Gordon formula gives lowest R^2 at Factors value of 17 (R^2 = 0.57). However, Gordon formula is not linear, and with this value the residuals are biased above zero. Therefore, Factors were adjusted down to the value of 14, which gives close to zero for the average of residuals. Seven of ten observations are predicted within the accuracy limits of ±20%, and three lie within ±40%. The model fit is quite good, but on the other hand, Cluster B has a more narrow window of variation to be explained.

Figure II-8: Gordon Formula Results vs Sample Cost Data and Model Predictions for the Costs of Mongolian projects using the Lower Cost Cluster B Sample



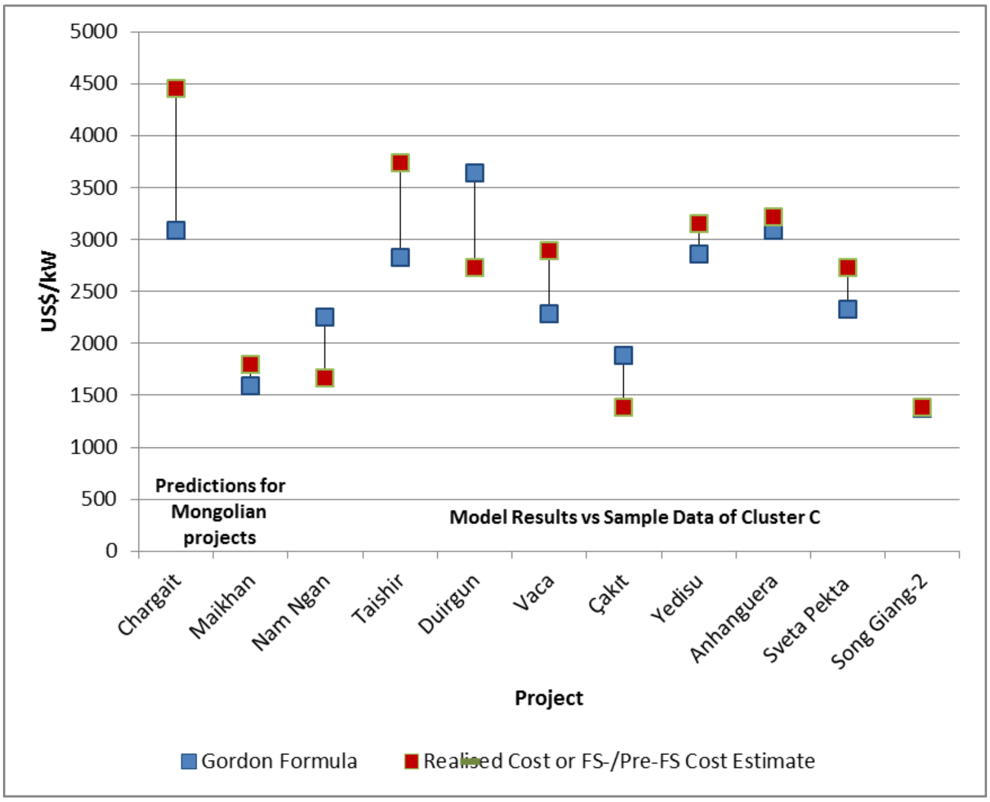
101. The calibration of models to the Cluster C of small hydropower plant of the capacity from 10 to 50 MW

Regression model Cost = e^(1.81 + 1.06 x ln (Megawatts) – 0.29 x(ln Head)), R^2 = 0.89

Gordon formula Cost = 11 x (Megawatts / Head^0.3)^0.82, R^2 = 0.82

102. The linear regression model, not shown above, would seem to fit the sample relatively well. However, is does not predict Mongolia's Maikhan project correctly in any sense, because of its high head of 417 meters. A linear model does not capture the extremities of the few parameters used. The sample of nine projects contains small HPPs with head varying between from 24 m to 338 m. Linear regression formula would give negative costing for Maikhan, and therefore one is led to use again the Gordon formula, which seems to predict Maikhan very close to its pre-feasibility value. It must be noted though that overall the logarithmic model fits best to the sample.

Figure II-9: Gordon Formula Results vs Sample Cost Data and Model Predictions for the Costs of Mongolian projects using the Lower Cost Cluster B Sample



103. Once there are now mathematically derived cost estimates for all key candidate hydropower projects in Mongolia, certain degree of qualitative judgement is finally needed to resolve, which of the cost estimates will be used in the expansion planning.

104. The projects in the range from 50 to 300 MW have already been estimated based on two samples, the first (Cluster A) representing cost levels typical in international contracting and equipment sourcing from developed countries, and the second one (Cluster B) low cost hydropower countries, of which China is the nearest representative to Mongolia and sourcing contracting services, construction and equipment from there.

105. There is an important point to be considered, however, that the hydropower sites in Mongolia represent in many respects a difficult terrain for any contractor to build a hydropower plant. It has been mentioned already, that due to the landlocked location and long distances of Mongolia, transport cost of all electromechanical equipment and imported construction material is high. Secondly, cold weather prevents or makes difficult from carrying out some demanding concrete works. An additional one year will be assumed to the construction time. These difficulties are hard to quantify. A standard +10% cost add-on is therefore assumed for all estimates, which are based on costs of plants in the statistical sample, most of which were built in more favourable climatic environments for hydropower construction.

106. If there is a recent and solid engineering study of the candidate project, such should of course be prioritized over the model based cost estimates presented above. As most of those are quite out-dated, it is chosen here to 'devalue' such estimate the more the older it is, and in a linear manner so that an estimate from year 2012 is given weight (Weight) of 100%, and any older ones are discounted in 10 years so that an original engineering estimate from 2002 or any year earlier is considered here as having no weight.

107. There is a recent engineering estimate available only for the Erdene-Buren project, completed in 2008 and having therefore a weight of 60%. For the small power plants, the pre-feasibility study level estimate of the PDD documents is considered as valid, and therefore

Chargait and Maikhan project cost estimates will have a weight of 30% and 50% respectively. Chargait estimates are further supported by a feasibility study completed in 2005 by international consultants. For all other projects the weight given to past engineering study cost estimates is zero.

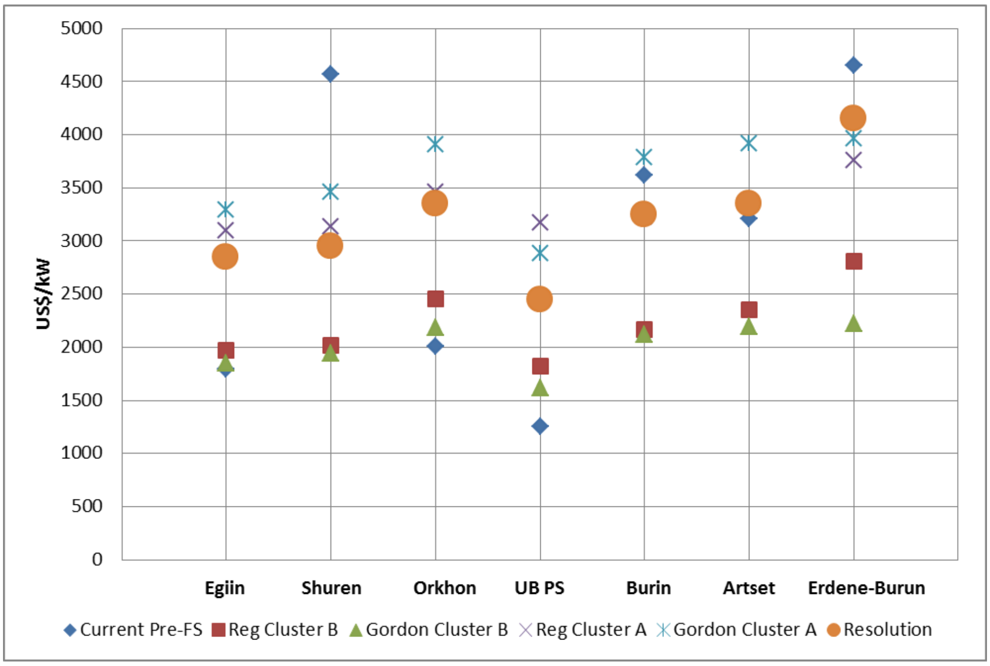
108. In summary, the final cost estimates are resolved as the following:-

Model estimate = 1.1 x (50%x Cluster A based estimate + 50%x Cluster B based estimate)

Final estimate = Engineering Study Estimate x Weight + Model Estimate (1-Weight)

109. The cost estimates and the resolution numbers are shown below for all candidate HPPs.

Figure II-10: Summary of Cost Estimates for Mongolian HPP Projects



110. Cost estimates for the two small hydropower projects in Mongolia are prepared according to the same principles as described above. The estimate that comes as a result of the Gordon formula is increased by 10%. The final estimate is the weighted average of the pre-feasibility level estimate as reported in the CDM documentation and the adjusted Gordon formula result. The cost estimates are reported in the following graph.

111. All candidate projects are summarized in Table II-12.

112. The fixed O&M costs for hydropower will be estimated at 1% of the fixed investment for plants of over 50 MW capacity and 2% small hydro. The variable O&M cost is estimated at 2 $/MWh and 3 $/MWh, respectively.

Figure II-11: Summary of Cost Estimates for Mongolian Small Hydro Projects

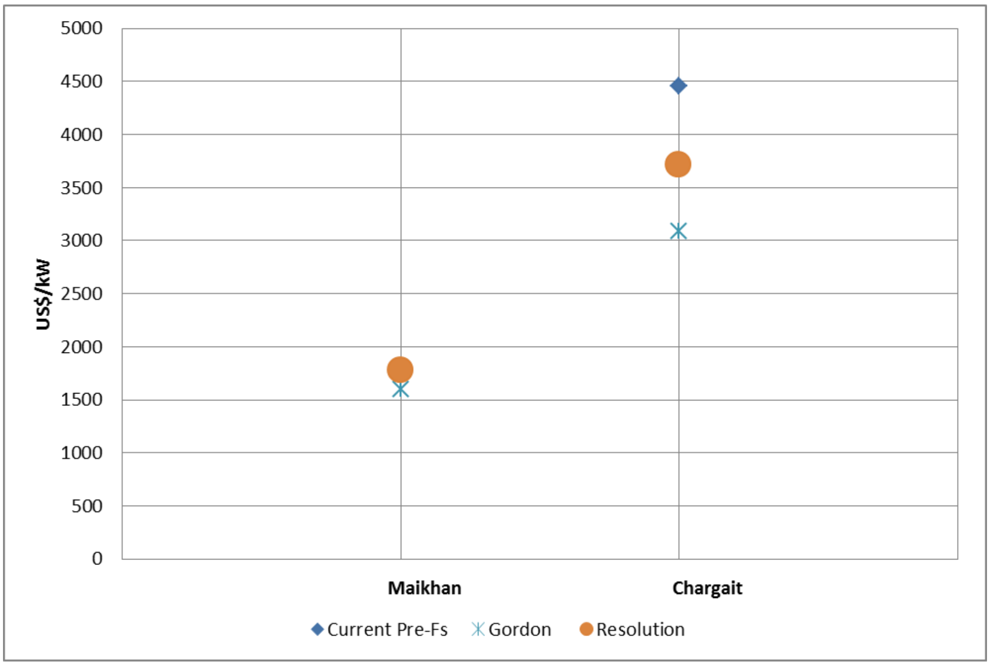


Table II-12: Summary of the Key Characteristics of Mongolian Hydropower Projects

Project	Capacity MW	Production GWh	Hydraulic Head (m)	Crest Length (m)	Cost $/kW
Egiin	220	412	73	710	2827
Shuren	205	957	63	(700) -1200	2969
Burin	161	760	52	1700	3251
Artset	118	553	57	1400	3362
Orkhon	100	219	65	495	3353
Erdene-Burin	64	243	85	-	4154
Chargait	15	68	24	570	3716
Maikhan	12	46	417	no dam	1772
UB PS	100	(102)	224	-	2473

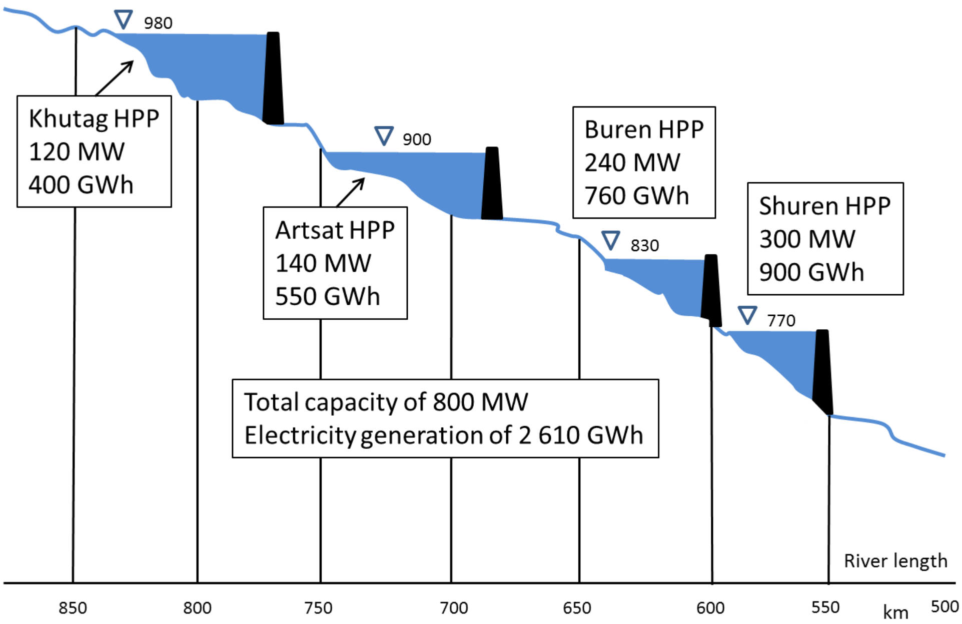
4. Optimization of Dam Height & Installed Capacity for Selected Projects

113. Out of the list of many large hydropower projects, three projects, namely Shuren, Egiin, and Orkhon, stand out as most prospective ones and have already been listed by the Government as candidate projects in the country's electricity supply expansion plans. They are also located in different rivers whereas Shuren, Burin, Artset and Khutag are all different dam sites in the main river of Selenge, initially planned to operate in a cascade. In all past planning, of the four cascaded projects, Shuren has been mentioned as the least-cost and the first priority for construction. Therefore, Burin, Artset, and Khutag are not analysed further. It should be noted, however, that despite small differences, the main hydrological characteristics of these sites are very similar to Shuren (see Figure II-13 below **Figure**).

114. The next step is the search for sufficiently justified planning parameters for the hydropower

plants is the optimization of the design. It involves a very large number of variables including location, layout of different facilities, type and size of dam, type of spillway, type of intake, type of conveyance of water to the powerhouse and type, size and number of turbines. The majority of these variables do not impact directly on the benefits of the project and therefore the selection is made on the basis of cost comparisons. However, there are other variables that impact both the cost and the benefit side and these must be selected by comparing the costs and benefits of the different combinations. Among this last type there are two variables that have the most impact in both the cost and the benefit. These are the dam height and the installed capacity of the turbine and generators.

Figure II-13: Summary of the Key Characteristics of Mongolian Hydropower Projects



115. **Dam Height** creates the hydraulic head, which is the difference in elevation between the upstream and downstream water surface and the energy produced by a given volume of water is directly proportional to the head. In some types of hydroelectric projects the head is not entirely or even primarily developed by a dam but the projects under study in Mongolia are of a type where the head is almost exclusively developed by the dam and therefore the energy produced by the water passing through the turbine is almost directly proportional to the dam height.

116. In addition to creating head the dam also impounds water into a reservoir which has the added advantage that it stores water. The ability to store water is very important because without it water has to be used when it arrives and during the wet season there may be more water arriving than could be handled by the turbines. This excess water needs to be spilled resulting in a loss of potential energy production. Thus the dam height is very important in determining benefits because it is a key determinant of how much energy will be produced.

117. The head created by a dam and its storage reservoir is not constant. It changes as the reservoir storage changes and designers must select a value to specify the turbine design. That value is called nominal head and corresponds to the head that results from a reservoir elevation that is expected to be most frequent.

118. **The installed capacity** is the maximum output that the generator can produce. The turbines can usually produce much more but the generator capacity is the limiting parameter. Having selected the generator capacity and the nominal head the turbine is designed to pass a flow such that at nominal head it will produce exactly a turbine output that matches the capacity of the generator. This is the nominal flow. Since hydropower output is directly proportional to both

head and flow it follows that, for the same generator capacity, the higher the nominal head the lower the nominal flow and vice versa.

119. The significance of installed capacity to the benefits of a hydroelectric project comes from two very different aspects. First, the installed capacity determines what the maximum instantaneous output of the plant is. This is important because it defines how much of the peak demand can be carried by the plant as long as water is available.

120. Second, because capacity is directly proportional to flow, it defines how much water can be used to produce energy at any given time. This is important because if the reservoir is about to spill water then having more capacity means having more nominal flow and therefore more water can be used to produce energy instead of spilling it.

121. There are basically two types of benefits derived from a hydropower project: **energy benefits** and **capacity benefits**.

122. The energy produced by the hydropower plant has two separate uses. One use is to displace energy produced by other plants. Exactly which plants depends on how the hydropower plant will be dispatched. If it is dispatched to produce more or less constant output all the time then it is displacing energy from base load plants. If it is dispatched to meet peak loads during a few hours each day then it will displace energy produced by peak load plants, which is generally much more expensive because such plants have high variable costs.

123. Another use of energy produced by the hydropower plant is to enable a reduction in the capacity needed from other plants. This is called dependable capacity and is related to both the hydropower plant and the shape of the load curve as will be explained below.

124. When a hydropower plant is used to displace peak load capacity, this gives energy a higher value but it is not always possible as it requires that the load curve shape is such that the installed capacity of the hydropower plant is sufficient. When the installed capacity is not sufficient to use all of the energy in the peak then only part of the energy can be dispatched to serve peak loads and the rest must be used in the base.

125. Each of the different dispatch modalities has a different value because in each case the cost of the energy and the capacity displaced is different. Generally speaking the highest overall value is obtained when the hydropower plant is used as much as possible to displace peak generation.

126. In the case of Mongolia this needs to be tested because the peak loads are not supplied entirely by Mongolian thermal plants but by Russian imports and these have a cost of 77 $/MWh that includes both energy and capacity components. On the other hand, if the hydropower plant is used as base load, the lower cost of the displaced coal fired energy, 19 $/MWh, calculated as the variable fuel cost of condensing power, can be compensated by the fact that the displaced capacity will be valued at the cost of a base load plant which, being coal fired plants, will be high, 151,920 $/MW-year.

127. The unit benefit values above are deemed applicable to today conditions. However, in order to compare benefits to the costs over the economic life of the hydropower plant it is necessary to develop unit benefits that reflect likely changes in the real price of the replacement energy and capacity. These values were levelized over a 50 year period using a discount rate of 6%. The price of Russian imports was assumed to experience a real annual growth rate of 0.5%, the cost of baseload capacity was assumed to have no real growth in price and the value of baseload energy was assumed to have a real growth rate of 1% per year.

128. The methodology used in the Assignment of Benefits for optimization considers, for each hydropower plant alternative under consideration, two cases, peak load and base load dispatch. In the first case as much energy is used for peak loads as allowed by the available capacity and that energy is valued at the cost of Russian imports which also includes the value of capacity displaced from such imports. Any remaining energy is then used for base load and valued at the variable cost of a coal plant while the associated capacity is valued at the capital and fixed cost of

a coal plant.

129. In the second case all energy is used in the base and both energy and capacity are valued as the base component of the peak load dispatch.

130. The greater of the two benefits is assigned to the alternative hydropower plant.

131. In order to optimize the dam height and the installed capacity it is necessary to consider the **impact of dam and installed capacity on the total cost of the project**.

132. The height of the dam will of course impact primarily the cost of civil works. This is not limited to civil works related to the dam itself, a higher dam means also a higher head and this means a lower nominal flow for the same installed capacity. Thus, while some costs will increase with dam height, others, such as the cost of intake works, penstock and general water conveyance to the powerhouse, will decrease.

133. The installed capacity will primarily impact the cost of the generation equipment but, for any dam height, the installed capacity is proportional to nominal flow; thus an increase in capacity will also mean increased cost of intake, penstock and general water conveyance to the powerhouse.

134. In order to address the different sensitivities to key design variables the available budget of the plant was distributed into four categories as follows:

1. Cost items that are not sensitive to dam height, installed capacity or nominal flow. This includes, to the extent possible to identify, access roads and construction site preparation, spillway facilities, switchyard and transmission line and administrative and engineering costs.
2. Cost items that are sensitive to dam height before consideration of head effects. This includes mostly the dam itself.
3. Cost items that are sensitive to nominal flow except when installed capacity is the primary cost driver. This includes intake, penstock and conveyance to the powerhouse.
4. Cost items that are sensitive to installed capacity. This includes generation equipment.

135. The information available on each hydropower refers to a particular combination of dam height and installed capacity, and that combination is called here as Reference Alternative. The Reference Alternative is retrieved from the Feasibility Studies of Orkhon and Egiin projects, and from the Pre-Feasibility Study on Shueren. However, the costing of the projects in based on the above analysis. The budget of the Reference Alternative was examined above using the regression analysis and Gordon Formula against typical costs per unit of installed capacity deemed reasonable for similar hydropower plants. These unit costs were selected as 3,360 $/kW for Orkhon and 2,800 $/kW for Egiin and Shuren as rounded figures.

136. Accordingly, all cost components of the Reference Alternative for each hydropower plant were adjusted in the same proportion so that the end unit cost matches the selected values above.

137. The cost of each hydropower plant for combinations of the primary cost drivers (dam height, installed capacity and the resulting nominal flow) different from the Reference Alternative was obtained by adjusting each of the above mentioned four cost components in proportion to the changes in the cost driver relative to the values in the Reference Alternative. Once the total budget for each combination of dam height and installed capacity is calculated, the total cost is annualized using an economic life of 50 years and a discount rate of 6%.

138. For a thorough optimization each combination of dam height and installed capacity must be itself optimized operationally. That means developing an operating regime of the reservoir that maximizes the energy production. This information is available in the case of Egiin where the study shows the energy production as a function of maximum operating level (representative of dam height) and installed capacity.

139. For Shuren and Orkhon this information was not available and therefore a simplified energy estimate was developed. This was done by the following steps:

- Obtain or estimate monthly mean inflows to the reservoir
- Select a constant turbine equal to the mean annual flow
- Calculate monthly reservoir levels starting at maximum operating level and maintaining the level at or above the minimum reservoir level.
- Calculate mean head of every month
- Calculate monthly energy from mean head and turbine discharge
- Estimate total excess water volume from maximum elevation above maximum operating level
- Estimate spilled energy by comparing energy production with unlimited nominal flow to that based on the energy limited by the nominal flow corresponding to installed capacity
- Check that the end reservoir level is equal to the initial reservoir level
- Adjust the minimum reservoir operating elevation to maximize energy production as a compromise between head and spill

140. In the case of Egiin, the calculation was also made as above but, because there is available a detailed chart of energy production for various combinations of operating level and installed capacity, this was used to calibrate the calculated energy production.

141. The **determination of gross benefits** is made using the estimated energy of each combination of dam height and installed capacity and applying that to the dispatch cases described above. First, the energy is dispatched as much as possible at the peak of the load duration curve. In order to estimate the relationship between peak load and energy load the load duration curve show in Figure II-14 was used. That load duration curve, applied to the peak load of the system of 1,128 MW results in the relationship between the peak energy demand and the load factor of that demand shown in Figure II-15.

142. The load factor is used to determine how much capacity would be required to dispatch all of the energy in peak hours. If that requirement is more than the installed capacity of the hydropower plant, only part of the energy can be dispatched in peak hours and the rest is dispatched in off-peak hours. Peak hour energy is valued at the cost of Russian imports, a combined energy ad capacity charge of 77 $/MWh. Off peak energy is valued at the variable cost of a coal fired condensing plant estimated at 19 $/MWh.

143. The final determination of cost is made by using the estimated head to define the nominal flow of each alternative and then using the dam height, installed capacity and nominal flow to adjust the project budget for each combination of installed capacity, dam height and nominal flow.

144. The objective variable is the difference between annual costs and annual benefits and the combination that maximizes this difference is selected.

Figure II-14: Load Duration Curve

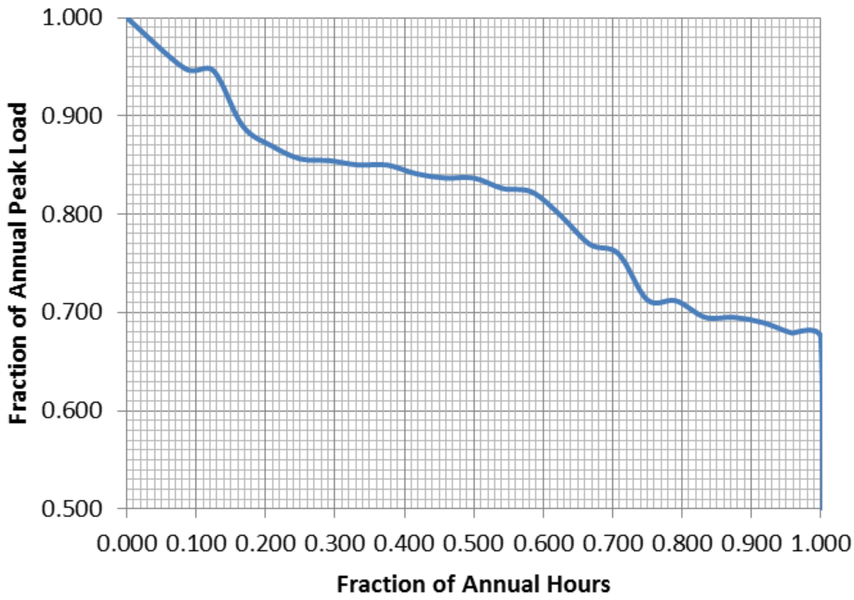
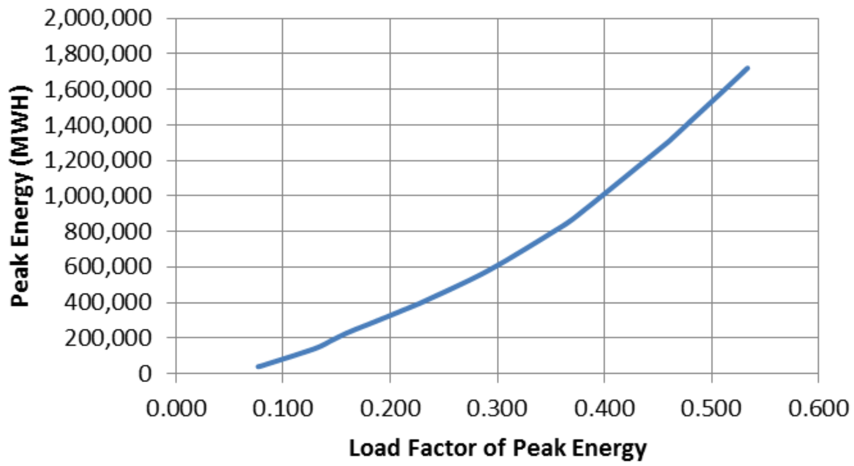


Figure II-15: Load Factor of Peak Energy



145. **Shuren:** Optimization of Shuren scheme started with the Pre-Feasibility Study cost budget with a unit capacity cost of 1,519 $/kW and was increased to 2,800 $/kW. The alternatives analysed for Shuren corresponded to combinations of a range of operating levels between 750 and 770 mamsl and a range of installed capacity between 300 MW and 500 MW. The key results for each combination are listed in Table II-16. The maximum net benefit of 33.48 M$ per year results from the combination of maximum operating level 770 mamsl and installed capacity 390 MW.

146. It is observed that energy production for any of the operating levels analyzed remains constant for installed capacities above 390 MW. Since the peak capacity associated with that energy is less than the installed capacity, there is not additional benefit for capacity above 390 MW and therefore any increase in cost is not justified. It is also observed that for installed capacities below 390 MW the energy produced cannot be entirely placed in peak hours because capacity is insufficient, therefore some of the energy is valued at a lower level and the reduction in cost of lower capacity is greater than the reduction in benefits.

147. The net benefits will continue to increase for operating levels above 770 m. However, there is no indication that it is technically feasible to increase the level beyond that and therefore the optimum operating level is the maximum level considered technically feasible. In fact, after the optimization exercise was carried out it became known that there is a technical limitation regarding the maximum level caused by a number of water pumping stations becoming potentially submerged with this elevation level, and corresponding reservoir size, at the south-western end of the reservoir. This issue can be addressed by building a support dam to protect the pumping stations to the respective side of the reservoir, which would be an additional cost to the project. However, for the purpose of this exercise the issue is taken into account by simply accepting operating level 760 m as the technically feasible maximum.

148. The optimization therefore resulted in the following adjustments to the assumptions of this study for the Shuren hydropower project:-

- Installed capacity of 390 MW;
- Maximum operating level 760 m (93 m);
- Annual production 1,260 GWh (with mean flow), long term average of 1,000 GWh; and
- Cost of installed capacity 2,200 $/kW.

149. The original cost budget for **Orkhon** results in a unit capacity cost of 1,600 $/kW. This was increased to 2,800 $/kW on basis of the results of analysing a sample of international reference projects. However, at that unit capacity cost the project could not be optimized because net benefits were negative by several million dollars per year.

150. The alternatives analyzed for Orkhon corresponded to combinations of a range of operating levels between 905 and 925 mamsl and a range of installed capacity between 60 MW and 200 MW. The project shows maximum net benefits from the combination of maximum operating level 925 mamsl and installed capacity 195 MW.

151. The optimization therefore resulted in the following adjustments to the assumptions of this study for the Orkhon hydropower project:-

- Installed capacity of 90 MW;
- Maximum operating level 760 m as in the Reference Alternative (90 m);
- Annual production 280 GWh; and
- Cost of installed capacity 3,560 $/kW.

152. The alternatives analysed for **Egiin** corresponded to combinations of a range of operating levels between 880 and 910 mamsl and a range of installed capacity between 50 MW and 250 MW. The project shows maximum net benefits from the combination of maximum operating level 895 mamsl and installed capacity 150 MW. The optimization therefore resulted in the following adjustments to the assumptions of this study for the Egiin hydropower project:-

- Installed capacity of 150 MW;
- Maximum operating level 895 m (71 m);
- Annual production 447 GWh; and
- Cost of installed capacity 3,660 $/kW.

Table II-16: Key Results for Shuren Combinations
Reference Unit Capacity Cost is 2,800 $/kW

Maximum Operating Level m.a.m.s.l.	Installed Capacity MW	Unit Capacity Cost $/kW	Annual Energy MWH	Demand Coverage MW	Peak Capacity Credit MW	Base Capacity Credit MW	Base Energy Credit MWH	Base Capacity Benefit M$	Base Energy Benefit M$	Total Annual Benefit M$	Net Annual Benefit M$
770	700	1 522	1 460 362	361,60	361,60	166,71	1 460 362	25,33	33,98	59,31	34,23
765	700	1 500	1 365 616	338,14	338,14	155,89	1 365 616	23,68	31,78	55,46	28,02
760	700	1 479	1 262 721	384,80	384,80	144,15	1 262 721	21,90	29,38	51,28	21,19
755	700	1 458	1 180 630	359,78	359,78	134,78	1 180 630	20,48	27,47	47,95	15,96
750	700	1 437	1 098 027	334,61	334,61	125,35	1 098 027	19,04	25,55	44,59	10,69
770	600	1 681	1 460 362	361,60	361,60	166,71	1 460 362	25,33	33,98	59,31	38,36
765	600	1 657	1 365 616	338,14	338,14	155,89	1 365 616	23,68	31,78	55,46	32,15
760	600	1 632	1 262 721	384,80	384,80	144,15	1 262 721	21,90	29,38	51,28	25,32
755	600	1 607	1 180 630	359,78	359,78	134,78	1 180 630	20,48	27,47	47,95	20,09
750	600	1 582	1 098 027	334,61	334,61	125,35	1 098 027	19,04	25,55	44,59	14,82
770	500	1 905	1 460 362	361,60	361,60	166,71	1 460 362	25,33	33,98	59,31	42,49
765	500	1 875	1 365 616	338,14	338,14	155,89	1 365 616	23,68	31,78	55,46	36,29
760	500	1 846	1 262 721	384,80	384,80	144,15	1 262 721	21,90	29,38	51,28	29,46
755	500	1 816	1 180 630	359,78	359,78	134,78	1 180 630	20,48	27,47	47,95	24,23
750	500	1 786	1 098 027	334,61	334,61	125,35	1 098 027	19,04	25,55	44,59	18,96
770	400	2 241	1 454 785	360,21	360,21	166,07	1 454 785	25,23	33,85	59,08	46,19
765	400	2 204	1 368 723	338,90	338,90	156,25	1 368 723	23,74	31,85	55,59	40,66
760	400	2 166	1 260 078	383,99	383,99	143,84	1 260 078	21,85	29,32	51,18	33,38
755	400	2 129	1 188 193	362,09	362,09	135,64	1 188 193	20,61	27,65	48,26	28,94
750	400	2 092	1 107 501	337,50	337,50	126,43	1 107 501	19,21	25,77	44,98	23,82
770	390	2 284	1 454 355	360,11	360,11	166,02	1 454 355	25,22	33,84	59,07	46,57
765	390	2 246	1 369 390	339,07	339,07	156,32	1 369 390	23,75	31,87	55,62	41,12
760	390	2 207	1 260 050	383,99	383,99	143,84	1 260 050	21,85	29,32	51,17	33,79
755	390	2 169	1 187 175	361,78	361,78	135,52	1 187 175	20,59	27,63	48,21	29,28
750	390	2 131	1 108 054	337,67	337,67	126,49	1 108 054	19,22	25,79	45,00	24,27
770	370	2 377	1 436 623	355,72	355,72	164,00	1 436 623	24,91	33,43	58,35	46,03
765	370	2 337	1 355 737	335,69	335,69	154,76	1 355 737	23,51	31,55	55,06	40,90
760	370	2 296	1 247 947	380,30	370,00	142,46	1 247 947	21,64	29,04	50,68	31,87
755	370	2 256	1 176 324	358,47	358,47	134,28	1 176 324	20,40	27,37	47,77	29,27
750	370	2 216	1 098 280	334,69	334,69	125,37	1 098 280	19,05	25,56	44,60	24,35
770	350	2 480	1 403 123	347,42	347,42	160,17	1 403 123	24,33	32,65	56,99	44,28
765	350	2 438	1 326 474	328,44	328,44	151,42	1 326 474	23,00	30,87	53,87	39,47
760	350	2 395	1 224 629	373,19	350,00	139,80	1 224 629	21,24	28,50	49,74	28,63
755	350	2 353	1 155 212	352,04	350,00	131,87	1 155 212	20,03	26,88	46,92	28,11
750	350	2 311	1 078 275	328,59	328,59	123,09	1 078 275	18,70	25,09	43,79	23,63
770	300	2 800	1 310 932	325,65	300,00	149,65	1 310 932	22,73	30,51	53,24	33,70
765	300	2 750	1 245 763	379,63	300,00	142,21	1 245 763	21,60	28,99	50,59	21,28
760	300	2 701	1 155 078	352,00	300,00	131,86	1 155 078	20,03	26,88	46,91	20,26
755	300	2 651	1 093 875	333,35	300,00	124,87	1 093 875	18,97	25,46	44,43	19,93
750	300	2 602	1 023 227	311,82	300,00	116,81	1 023 227	17,75	23,81	41,56	19,38

Note:

Yellow – Reference Alternative

Orange – Economic Optimum

Green – Technically Feasible Optimum

O. Wind Energy

153. Horizontal axis three-blade on-shore wind power plants have become a commonplace in international power markets. The average unit capacity sold today at the market is between 2 and 3 MW. The cost estimate here will be based on such most typical machine built to a farm total capacity of 10 to 50 MW.

154. Cost estimates for utility scale on-shore wind power plants vary a lot from 1,300 $/kW and 3,500 $/kW. The median cost of IEA 2010 survey was 2,348 $/kW but a recent study of International Renewable Energy Agency (IRENA) reports installed costs in 2010 of 1,300 $/kW to 1,400 US$/kW in China and Denmark but typical costs of 1,800 $/kW to 2,200 $/kW in other markets.

155. The equipment and installation cost dominates in the cost structure of wind power and these are affected by some of Mongolia's specific conditions. They include long transport distances, remote locations with relatively weak power transmission system and short construction period due to climatic conditions available for setting up foundations and erecting towers. In these respects, conditions in China, India, Germany, Spain and USA, which together represent 74% of the world's installed capacity, provide more favourable conditions.

156. Since 2010, the cost of installed capacity has again declined with the rising production of turbines in China and India. With a multitude of cost drivers in mind the baseline cost is set here close to, but higher than the Chinese market at 1,470 US$/kW. Variable O&M cost is estimated at 10 $/MWh and fixed operation costs at 2 % of the overnight cost, which together set the operation and maintenance cost at around 21 $/MWh. Capacity factor of 30% has been assumed.

P. Solar Energy

157. Solar photovoltaic (PV) panels convert sunlight directly to electrical energy. PV is a mature technology, and its application, i.e. accumulated worldwide installed capacity, has grown since 2010 at rates of tens of percentage points annually whilst similar, but decreasing, trend has taken place in the costs of PV modules. The development has been boosted by the feed-in tariff system in main markets that led to explosive growth of manufacturing in China.

158. Due to mass production and fierce competition typical residential PV systems based on crystalline-silicon (c-SI) modules challenge well the amorphous Si thin film modules, which are more common in utility scale applications. According to IRENA study of 2012, residential c-Si PV systems had investment costs of 3,800 $/kW to 5,800 $/kW and efficiencies of about 14% whereas utility-scale amorphous Si thin film system costs were from 3,600 $/kW to 5,000 $/kW with efficiencies from 8% to 9%. However, year 2012 already saw a major reduction in PV module prices.

159. The assumptions made here are 3,000 $/kW for a relatively large scale PV module installation of at least 1 MW and capacity factor of 17%. The O&M cost is assumed as 0.7 % of the fixed investment cost annually. Again, in the absence of experience of a utility-scale system in Mongolia, key technical issues, such as for example the functioning of a tracking system or the feasibility of a battery storage under the cold and icy weather conditions in Mongolia, remain to be studied.

160. Another solar power technology is Concentrated Solar Power (CSP) that uses mirrors to focus sunlight to either vertical pipes (parabolic troughs) or to a single point tank (solar tower), in which heat transfer fluid, typically water or oil, is heated and led further to evaporate steam for an ordinary thermal power process. This technology allows heat storage and scale, which is suitable for utility operations, typically from 50 to 100 MW. The capital cost of CSP is slightly more expensive than PV at the level of 3 400 to 4 600 $/kW without thermal energy storage (TES). However, CSP technology has higher O&M costs but higher capacity factors too, from 20 % to 27 %, resulting in LCOE of 0.19-0.38 $/kWh without TES. With 6 hour TES, LCOE can be decreased

by around 0.02 $/kWh.

161. Solar irradiation in Southern Mongolia is sufficient for CSP by reference to the fact that CSP projects have been implemented under similar irradiation levels, such as in Spain. However, there are many challenges for CSP in Mongolia. A CSP plant has a steam cycle and would need to depend on air cooling as opposed to water cooling in water scarce Gobi area. Due to extreme cold weather of Mongolia the heat transfer fluid needs to be kept heated over the winter nights, when the power plant is not in operation. Natural gas, which is the typical fuel for that purpose, is not available in Gobi area. The Southern area of the country is also very sparsely populated whereby there is only very limited demand-based need to develop CSP capacity there. The massive coal mining operations of the region are likely to bring about associated power production in excess the need of mining sites in the future, which further decreases demand for relatively high cost CSP technology. Considering all these issues CSP technology will not present an interesting option for Mongolia's energy mix by 2025, and will therefore not be considered further in this study. However, CSP technology is developing fast and its foreseen substantial cost reductions may bring it among the feasible options after the planning horizon of this study.

Q. Nuclear Energy

162. Nuclear energy is an alternative that has been occasionally mentioned as a reflection from the fact that Mongolia has substantial uranium resources. Several aspects of nuclear energy production speak, however, against the option. The economy of scale in nuclear power industry supports large units to be constructed, which, on the other hand, are designed to operate as base load plants due to the fact that a nuclear plant is a high-capital-cost and low-operational-cost plant. The current and forecast future loads may not be sufficient for a proportionally very large base load unit. Secondly, even though raw uranium is available in Mongolia, uranium processing and fuel production represent major part in nuclear fuel cost and it should be carried out overseas, such as in Russia. Processing nuclear fuel abroad together with imported power generation equipment would make the import content very high in the levelized cost of electricity despite the availability of domestic raw uranium.

163. The investment costs of nuclear power plants are reported to vary from 1,700 US$/kW to 5,800 US$/kW, again plants in China reporting the lowest costs and those in Europe the highest costs. The following cost screening uses investment cost of 4,000 $/kW whilst other cost assumptions are 1.5% of investment cost for fixed O&M, 4 US$ per produced MWh as variable O&M cost and 9.3 US$/MWh as fuel cost. As Mongolia has no past experience of nuclear power generation, and it would need to establish its education, training and research, inspection and regulation and related institutions to manage the nuclear development, the economic cost of nuclear power development would hugely exceed to pure financial cost of a plant.

164. As a nuclear power plant is very capital intensive, the construction period matters a lot in the levelized cost of electricity. The construction periods have proven to be difficult to estimate, and there are recently several examples of projects, where both the EPC cost estimates and construction periods have been severely underestimated. The nuclear accident of Fukushima Daiichi in Japan has also caused the authorities to intensify inspections and approval processes, which may cause further delay to the projects. There are several examples of projects that have taken over 10 years to complete (in Finland, France, the UK and USA). However, the suppliers continue confirming construction periods of 4 to 6 years, and have also brought in smaller units to the market.

R. Summary of Electricity Generation Technologies

165. The key assumptions and calculated levelized costs of electricity (LCOE) are reported below for various types of coal fired power plants. Generally, coal combustion at foreseen near-term coal prices offers the financially least cost option for power generation in Mongolia, if no externalities such as CO_2 penalties are considered.

Table II-17: LCOE (US$/MWh) of Various Coal Fired Power Plants

		Coal 1000 MW USC	Coal 600 MW SC	Coal 4 ×150 MW	Coal 150 MW CFB
Installed Capacity	(MW)	1000	600	600	150
Total Capital Cost	($/kW)	1000	1155	1470	1575
Efficiency (net, LHV)	(%)	45 %	43 %	34 %	34 %
Load Factor (%)	(%)	67 %	67 %	67 %	67 %
Lead Time	(Yrs)	4	4	4	4
Expected Life	(Yrs)	40	40	30	30
Total Annual Fixed Cost	($/kW)	91	108	151	162
Total Variable Cost	($/MWh)	16.38	17.02	20.69	20.91
LCOE (4 %)	($/MWh)	30.55	33.99	45.51	47.80
LCOE (6 %)	($/MWh)	33.79	37.78	50.09	52.76
LCOE (8 %)	($/MWh)	37.47	42.08	55.28	58.38

166. The LCOE for renewable energy technologies are reported below. Overall, the results are slightly higher than, for example, in China due to some conservative estimates of specific investment costs and construction time. Except for wind energy the LCOE figures are higher than what the Renewable Energy Law states for the acceptable feed-in tariffs. The law allows feed-in prices of 80-90 $/MWh for wind energy connected to the transmission grid, and 100-150 $/MWh, when the plant is connected to an isolated Aimag grid. The former tariff, applicable for large scale wind farms, represents WACC assumption of 9 – 11 % (real, pre-tax) with the cost assumptions reported here. The latter tariff seems highly attractive. However, it should be noted that the below cost estimates are pertinent for a large development. If wind is developed in small scale and in scattered remote locations, the cost assumptions reported below are not pertinent. The highest feed-in tariffs allowed by the law are 100 $/MWh for small hydro (< 0.5 MW) and 300 $/MWh for solar PV, which both are below the LCOE estimates.

Table II-18: LCOE (US$/MWh) of Various Renewable Energy Power Plants

		Large Hydro	Small Hydro	Wind 50 MW	Solar PV
Installed Capacity	(MW)	390	15	50	10
Total Capital Cost	($/kW)	2205	4000	1470	3000
Efficiency (net, LHV)	(%)	100 %	100 %	100 %	100 %
Load Factor (%)	(%)	33 %	33 %	30 %	17 %
Lead Time	(Yrs)	6	4	2	1
Expected Life	(Yrs)	80	80	25	25
Total Annual Fixed Cost	($/kW)	156	322	144	256
Total Variable Cost	($/MWh)	2.01	3.01	10.05	0.00
LCOE (4 %)	($/MWh)	44.24	91.52	66.55	146.10
LCOE (6 %)	($/MWh)	61.61	120.48	66.55	174.28
LCOE (8 %)	($/MWh)	81.06	151.98	66.55	205.11

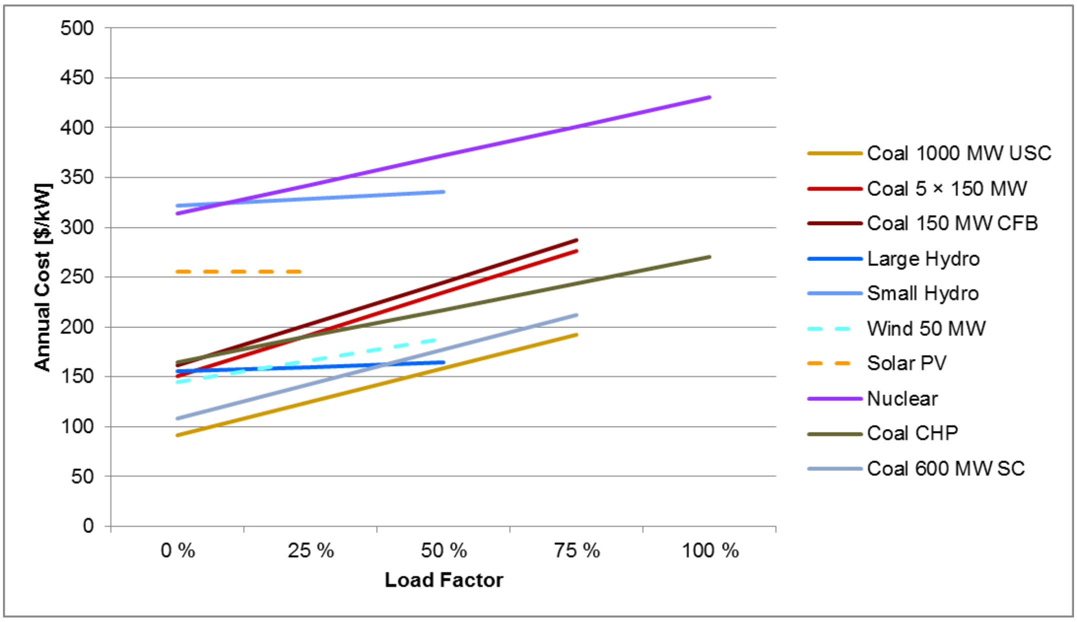
167. The following are cost estimates for other forms of power generation.

Table II-19: LCOE (US$/MWh) of Other Types of Power Generation

		Nuclear	Coal CHP	Engine CHP
Installed Capacity	(MW)	800	450	35
Total Capital Cost	($/kW)	4000	2000	1313
Efficiency (net, LHV)	(%)	100 %	60 %	43 %
Load Factor (%)	(%)	80 %	67 %	67 %
Lead Time	(Yrs)	7	4	2
Expected Life	(Yrs)	50	30	20
Total Annual Fixed Cost	($/kW)	314	164	141
Total Variable Cost	($/MWh)	14.81	13.29	181.09
LCOE (4 %)	($/MWh)	57.53	27.81	203.47
LCOE (6 %)	($/MWh)	71.34	32.84	206.72
LCOE (8 %)	($/MWh)	87.73	38.55	210.28

168. The cost screening curves indicate that the coal fired power generation in large USC and SC units is the lowest-cost form of electricity generation in Mongolia up to the maximum Load Factor level of 40 to 50 %, where hydropower comes in. This Load Factor is possibly reachable by the Shuren project. However, large scale hydro is the lowest cost option if compared to the LCOE of other coal fired power plants, which represent typical technology currently in place or being considered in Mongolia (CHP 450 MW, CCFB 150 MW) when Load Factor exceeds 20%. Wind and solar, shown by dotted lines, are not competitive against the low cost of coal in Mongolia as their Load Factors are limited. Therefore, feed-in-tariff, which are already in place, and possibly other policy instruments are needed to get these technologies properly rooted in Mongolia.

Figure II-20: Screening Curves for Main Technologies



169. The above costs are reported without any consideration of the negative externalities of coal combustion. Setting a price on carbon emissions is one regulatory way to influence anthropogenic global warming. However, the level of such price is a highly controversial issue. There are 14 fundamental studies using Integrated Assessment Models (IAM) which calculate both the positive and negative effects of global warming, and over 300 subsequent studies that draw from their results.[5] There is a high variation in the results concerning the Social Cost of Carbon (SCC), i.e. the societal long-term total cost of each additional ton of CO_2 that is emitted to the atmosphere and contributing to the greenhouse effect. Results from studies using the most scientifically respected IAMs have given prices such as 5, 6, 8, 28, 30, and 85 $/ton.

170. The European Carbon Trading Scheme has been the most liquid and influential price setter for CO_2 emission reduction units over the last ten years. However, the slowdown following the European economic crisis of 2009 has caused energy consumption to reduce in many major markets in Europe, and consequently demand for emission rights to decline. Whilst the long-term CO_2 emission reductions were valued by the market to EUR 20, or even close to 30 per ton before the crisis, the current market conditions do not point to any future level in 2020 or 2025, which would be consistent with the past estimates and therefore be used as a relevant reference in this study.

171. With all uncertainties in mid regarding SCC associated with coal combustion, the following screening curves are made assuming CO_2 price of EUR 20 per ton, equivalent to 26 $ per ton to illustrate the impact of such measure to the least-cost ranking order of various forms of energy.

172. With this carbon penalty, large scale hydropower appears as the least-cost option already when its load factor exceeds 25%. It is also notable that the LCOE of wind energy is below the LCOE of a 150 MW CFB plant, and meets the cost level of large scale coal at Load Factors of around 25 %.

173. The effect of CO_2 pricing is further illustrated in the graph that compares the cost of large scale hydropower to the least-cost option of coal fired electricity generation by USC technology.

[5] Monetary Valuation of the Social Costs of CO2 Emissions:
A Critical Survey, J.C.J.M. van den Bergh ICREA, Barcelona, W.J.W. Botzen, VU University Amsterdam, 2013

Figure II-21: LCOE (US$/MWh) – Assuming CO2 Price of EUR 22 (26 US$) per ton

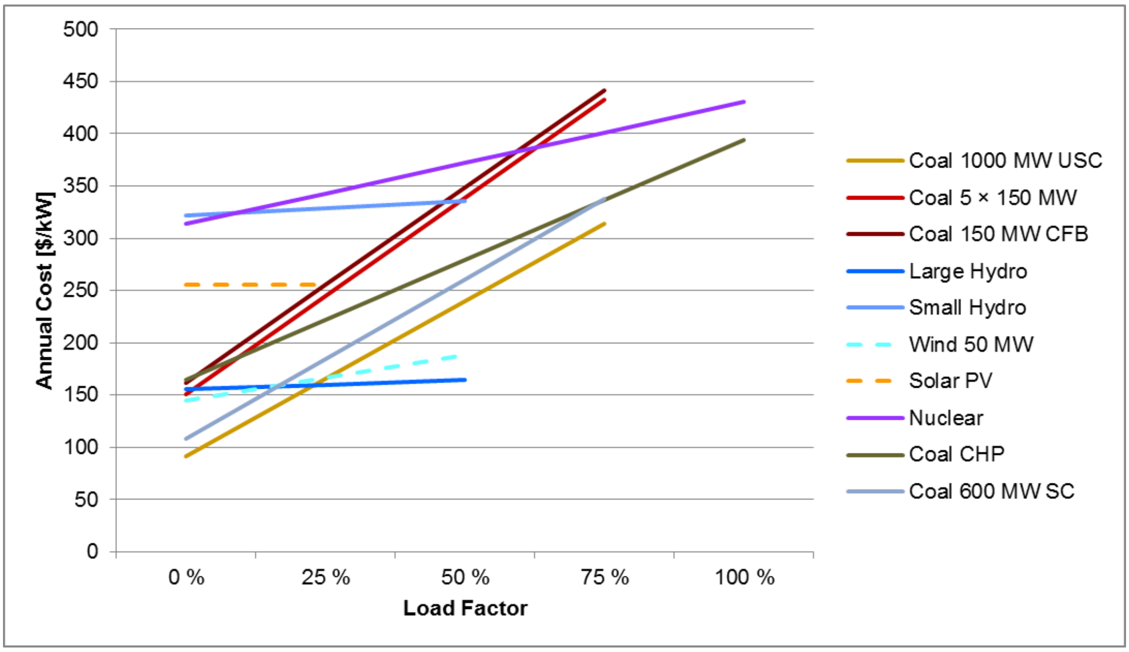
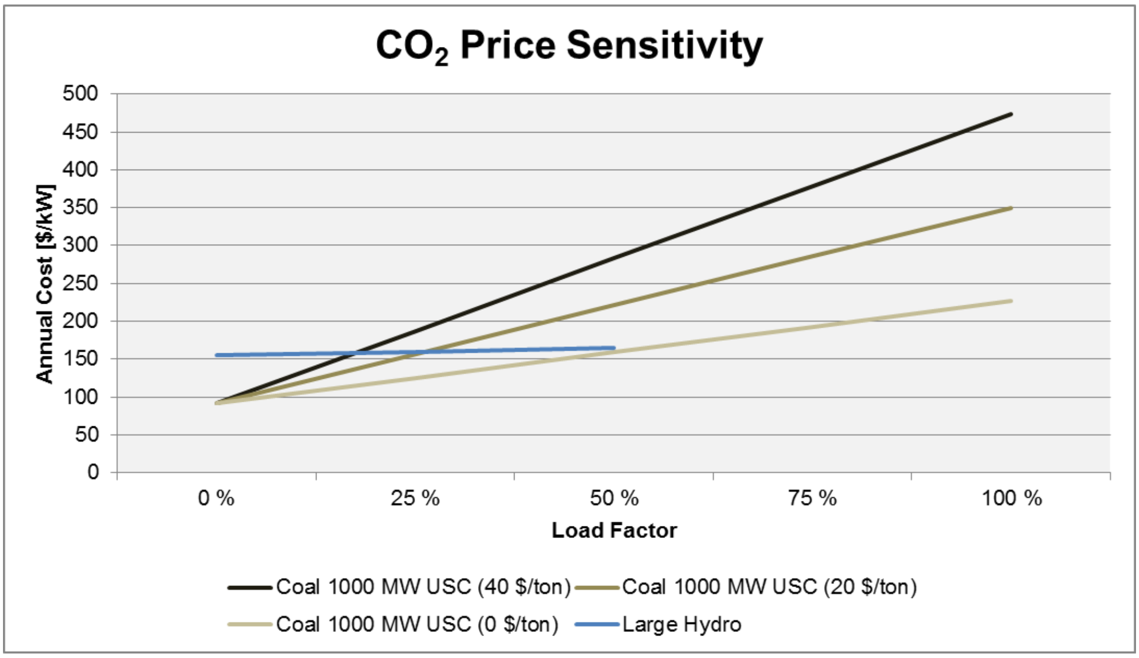


Figure II-22: CO2 Price Sensitivity – Comparing Large Scale Hydro and Coal Fired USC Plant



174. The following charts summarize the levelized costs (solar PV excluded). Nuclear energy and renewable energies are capital intensive, but ± 30% changes in investment costs indicate that the cost ranking order is not very sensitive to investment costs.

Figure II-23: Levelized Costs – Base Case

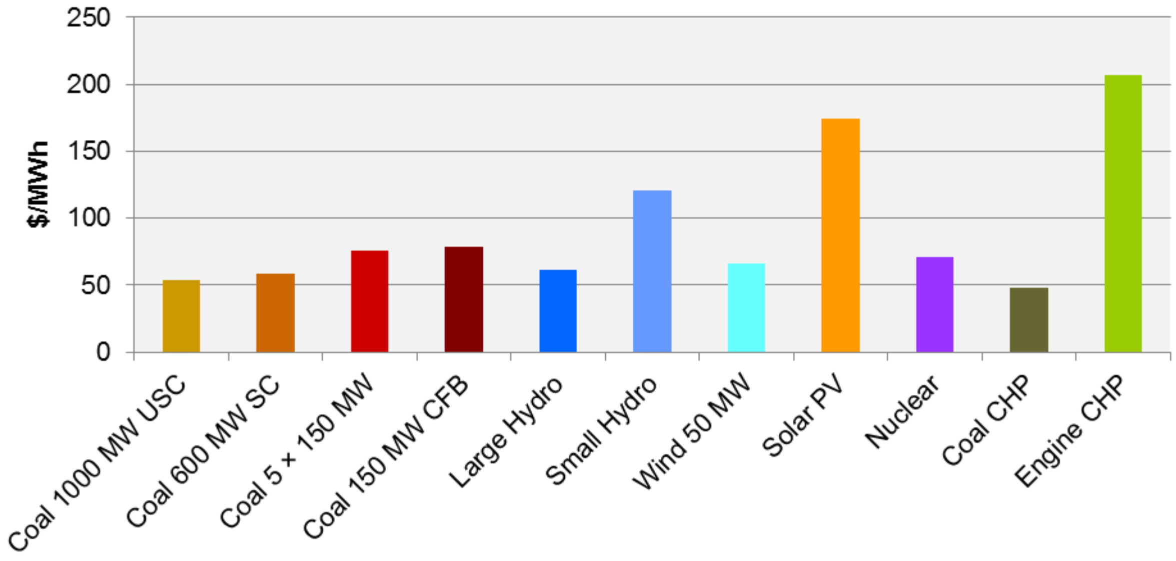
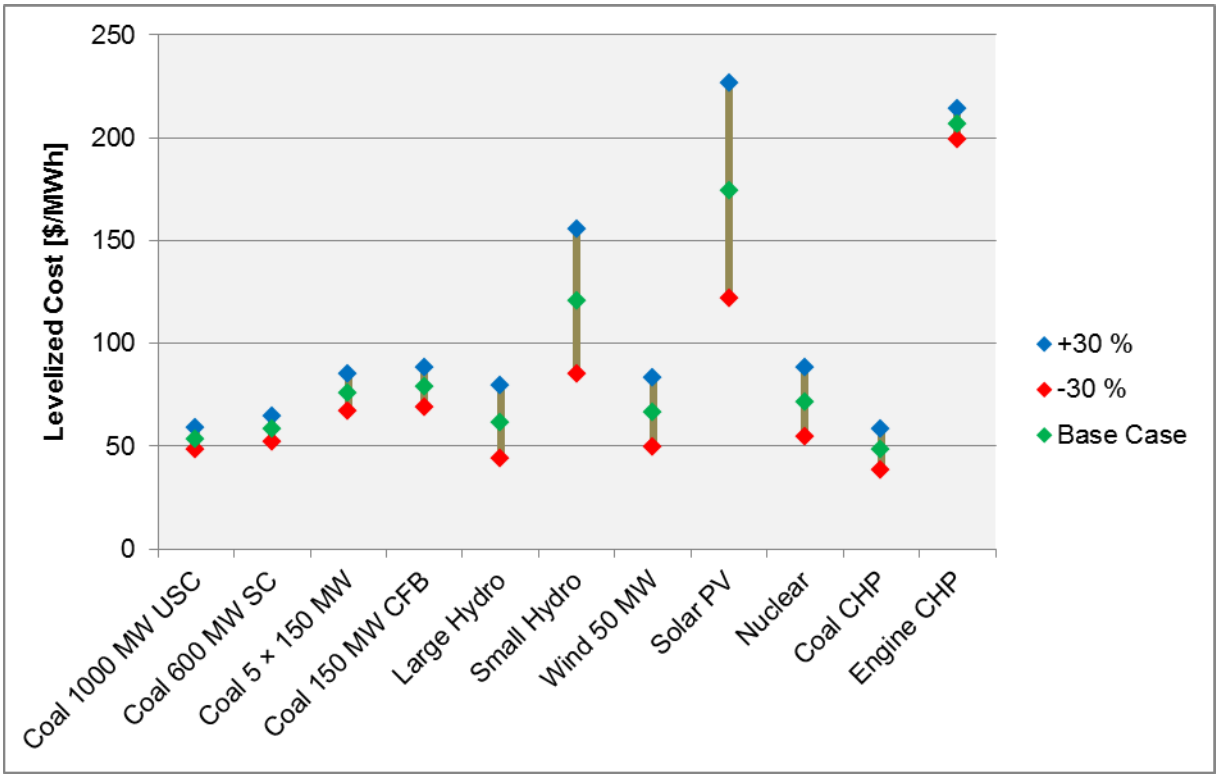


Figure II-24: Capital Cost Sensitivity



S. Heat Supply

175. Small scale coal-fired **Heat Only Boiler (HOB)** plants of 1.7 (2 MW), 5.2 (6 MW) and 8.6 Gcal/h (10 MW) have been selected as representative for typical coal fired heating plants for new

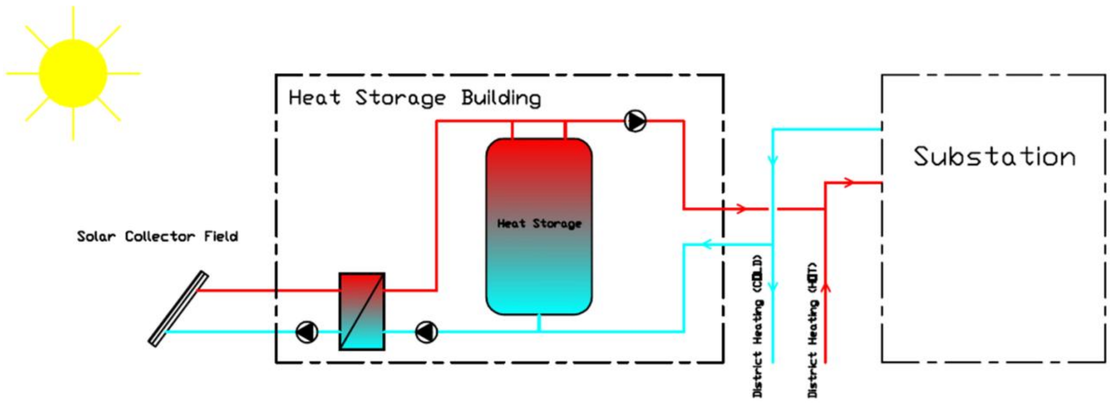
installation in Mongolia.

176. The study on coal fired HOBs of USAID from 2004 noted that the incremental costs of energy efficient HOBs over conventional alternatives are significant. The high first costs usually present a disincentive to facility owners despite the favourable life-cycle economics of a boiler replacement. With this in mind, HOB's modernization options for the 1.7 Gcal/h and 5.2 Gcal/h plants have been included together with new plants for the size categories of 5.2 Gcal/h and 8.6 Gcal/h. Expected lifetime for all plants is assumed to be 20 years with the exception of 1.7 Gcal/h plant with 12 years of expected lifetime. Plant efficiencies are set at 90 % for new ones and 85 % for retrofitted. Load factor is at 80 % in all cases. Construction costs for plant modernization consist mainly of boiler and equipment replacements, boiler transportation and installations. EPCs in different cases are 116 $/Mcal/h for 1.7 Gcal/h retro plant, 112 $/Mcal/h for 5.2 Gcal/h retro plant, 288 $/Mcal/h for 5.2 Gcal/h new plant and 278 $/Mcal/h for 8.6 Gcal/h new plant.

177. **A solar heat collector system** can be realized with flat-plate collectors and a heat accumulator. The system is rated to meet the domestic hot water consumption in summer time, which corresponds to about 25 % of maximum heating load. Two different solar collector plant size categories are studied; 0.25 Gcal/h and 0.1 Gcal/h. Solar collectors' actual capacity is assumed to be 430 kcal/h per collector square meter, which takes into account the conversion efficiency of solar collectors as well as system heat losses.

178. In Mongolia, the solar radiation per square meter per year is estimated to be 1,290 Mcal, of which approximately 40 % can be collected (Load Factor of 13 %). Investment consists mainly of solar collectors and a heat accumulator. The price of solar collectors varies from $600 (0.25 Gcal/h) to $700 (0.1 Gcal/h) within the studied size categories. A heat accumulator is typically dimensioned on basis of 0.7 cubic meters per solar collector square meter; costs vary in a range of 375-500 $/m^3. Total investment costs for solar collector systems are assumed to be 1,620 $/Mcal/h for a 0.25 Gcal/h plant and 1,970 $/Mcal/h for a 0.1 Gcal/h plant.

Figure II-25: Schematic of a Solar Heat Collection System



179. Modern large scale heat pump plant – utilizing thermal energy from waste water – consists of several state-of-the art turbo compressor heat pump units and auxiliary equipment (piping, pumps etc.). Total maximum thermal power of the plant is selected to be 30 MW and it is assumed that the plant serves as a base load plant with the load factor of 85 %. COP (coefficient of performance) of the heat pump (using waste water) is assumed to be 3.0 meaning that one (1) part of electricity is consumed to produce three (3) part of thermal energy. COP is strongly dependent on the temperatures of the heat source and sink. Geothermal energy can be utilized as a heat source instead of waste water; COP might increase significantly using geothermal energy due to its high temperature level. Total construction cost is estimated to be 560 $/Mcal/h;

if geothermal energy is utilized investment costs are higher. 30 years lifetime is assumed for the plant.

180. The following summarizes the costs and assumptions for coal fired boilers.

Table II-26: LCOE (US$/MWh) of Coal Fired Heating Boilers

		Coal HOB 10 MW New	Coal HOB 6 MW New	Coal HOB 6 MW Retro	Coal HOB 2 MW Retro
Installed Capacity	(MW)	10	6	6	2
Total Capital Cost	($/kW)	126	152	101	105
Efficiency (net, LHV)	(%)	85 %	85 %	85 %	85 %
Load Factor (%)	(%)	80 %	80 %	80 %	80 %
Lead Time	(Yrs)	2	2	1	1
Expected Life	(Yrs)	20	20	20	12
Total Annual Fixed C	($/kW)	16,69	20,62	13,86	18,04
Total Variable Cost	($/MWh)	7,24	7,64	8,14	8,64
LCOE (10 %)	($/MWh)	9,75	10,74	10,17	11,30
LCOE (5 %)	($/MWh)	9,02	9,85	9,62	10,77

181. The following summarizes the costs and assumptions of other heat production plants:

Table II-27: LCOE (US$/MWh) of Solar, CHP and Heat Pump Heating Stations

		Medium Solar	Small Solar	Coal CHP	Heat Pump
Installed Capacity	(MW)	0,3	0,12	527	30
Total Capital Cost	($/kW)	1460	1775	112	683
Efficiency (net, LHV)	(%)	100 %	100 %	89 %	300,00 %
Load Factor (%)	(%)	13 %	13 %	85 %	85,00 %
Lead Time	(Yrs)	1	1	4	3
Expected Life	(Yrs)	25	25	40	30
Total Annual Fixed C	($/kW)	165,79	200,49	12,95	86,05
Total Variable Cost	($/MWh)	0,20	0,22	7,79	20,00
LCOE (10 %)	($/MWh)	149,91	181,29	9,71	32,40
LCOE (5 %)	($/MWh)	97,94	118,11	8,92	28,11

182. The levelized cost of heat is from US$ 9.7 to US$ 11.3 for heating technologies using coal as a fuel. Again, low price and good availability of coal throughout Mongolia are the main factors supporting coal based technologies in heating.

T. Summary

183. The above discussion can be summarized as follows:

- Mongolia's primary energy resources do not pose constraints to building up the desired energy future;
- Supply side scenarios, based on technically mature and commercially available power and heat production technologies, needs to include coal-based power and the full range of renewable technologies;
- Large scale hydropower ranks well in cost comparison, and Orkhon, Egiin and Sheuren HPP schemes needs to be considered individually in the expansion planning;
- The availability of coal-based methane and coal gasification is not sufficiently certain, nor does it appear that the prices for these gas fuels will lead to the availability of economic heat and power generation sources prior to 2020; accordingly there is little to be gained by considering these options in further detail;
- The cost comparison of energy conversion technologies hinges on the economic value of coal. Currently coal prices are regulated and prices appear to be lower than their

economic values. The expansion plan production costing needs to model a range of coal prices to demonstrate the impact of coal cost variability on the investment plan; and

- The negative externalities of coal combustion need to be evaluated, estimated and quantified under different scenarios (CO_2 tons & US$, NO_x, SO_x, particulates, others…).

APPENDIX A: HYDROPOWER SCHEMES

U. Introduction

184. In this Appendix, further details are given regarding specific hydropower schemes in Mongolia.

V. Egiin Hydropower Project

185. The feasibility study of the project was carried out in 1992 and final design and tender documents were prepared soon thereafter. The project was proposed to be credited under CDM mechanism in 2006 by Energy Research Development Center (ERDC) of the Ministry of Fuel and Energy and Mitsubishi UFJ Securities acted as CDM advisor. The plan to construct the Egiin Hydropower plant has been included in the Programme of Integrated Power System, issued in 2007 by the Government, for the period 2007-2012 and it tops the list of planned investments of the period.

186. The Egiin River is a tributary of Selenge river, 475 km long and having a basin of 49,100 km^2. The construction site of the planned dam across Egiin valley is just a few kilometres away upstream of the confluence with the Selenge river. The site is approximately 300 km northwest of Ulaanbaatar and about 55 km northwest of Erdenet city.

187. The proposed roller-compacted concrete (RCC) dam is composed of aggregates and cementious material (Portland cement, fly ash from power plants and milled natural pumice). The planned dam has a crest length of 710 m, width of 8 m and height above foundation of 95 m. The planned reservoir capacity is 4,000 million m^3 and it would extend 50 km away from the dam and have a maximum surface area of 125 km^2. As the rated discharge of the plant is 105 m^3/s, the reservoir would enable inter-annual regulation.

188. The power station is planned to have four 55 MW Francis turbines with design head of 59 m and the mentioned discharge of 105 m^3/s. The foreseen annual electricity generation is 412 GWh[6]. The turbines will be fed by embedded steel penstocks passing through the dam. The plant will be connected by a direct, double-circuit 220 kV line to a large sub-station in Erdenet at a distance of approximately 64 km.

W. Sheuren Hydropower Project

189. The Sheuren hydropower project is planned to be constructed to the Selenge River, which is the principal source of Baikal Lake responsible for 50% of its water inflow. Most of Selenge River basin belongs to Mongolia. The river is 992 km long and its basin covers 447,000 km^2. Many other projects reported here belong to the same river system, such as Egiin and Burin. The prospective sites for the plant are located about 250 km northwest from Ulaanbaatar and some 100 km northeast from Erdenet.

190. Sheuren hydropower project has come up in 2012 as a candidate for the next in-line hydropower project of Mongolia. The government has carried out preliminary investigations on the possibilities to have the project financed and has negotiated, among others, with the Kuwait Fund for Arab Development on participation in financing. A pre-feasibility study was carried out by the Energy Authority in 2011, following which the World Bank supported Mining Infrastructure Support Project (MINIS) has continued its development with a target of launching the feasibility study on the project. The plan has raised some environmental and social concerns even before the feasibility study stage, and the World Bank is therefore currently considering its involvement in the further development of the project.

191. The pre-feasibility study is based on early studies available from the Russian Gidroproikt Institute from 1970. Dam sites of Khutag-Undur, Buren, Shar Mankhtain were involved in this study. Since then several continuation studies have been carried out including those of

[6] Plant performance estimates vary depending on the data source.

Lengidroproikt Institute from years 1974-1975. Egiin and Buren sites were omitted as candidate projects in their analysis because of estimated water resource limitations and negative influences on the environment. Four possible candidate sites for dam construction were finally identified.

192. The Pre-feasibility Study refers to five zones where there are totally 10 different sites, which are considered potential for a hydropower plant. The perceived problem of Sheuren has been the crest width of the dam. The ten sites have crest widths from 1,160 m to 2,100 m, and head ranging from 42 m to 87 m. On one site the study concludes that the dam crest length is 1,200 m but, steepness of left river bed is high and right river bed has slope surface. Therefore, the study proposes to build earth fill dam watertight core at the right site, which has slope surface and to reduce the cost of rolled compact concrete dam by reducing its length to 700m. By this the head will be higher and the pre-feasibility study seeks to increase the head and double the originally planned capacity of the plant. .

193. The natural flow of the river is on average 247 m^3/s. The effective net head can be estimated at 60 m. The seasonal peak is in summer and low in winter so that typically January-February monthly average flow is less than 10 % of the monthly average of July. The yearly flow corresponds to annual power generation of approximately 1,000 GWh. The installed capacity of 300 MW or 400 MW, as outlined in the pre-feasibility study, correspond to discharge rates of 618 m^3/s or 824 m^3/s, which cause substantially more intensive regulation in the reservoir and consequently variations of the reservoir surface level and downstream flow. These capacities lead to electric load factors of 38% and 29%, respectively.

194. It is too early to conclude whether hydropower design in Mongolia should address capacity (peaking) needs of the power system or be considered rather from energy demand point of view. However, it is likely that the combined effect of minimizing sharp water flow variations from the environmental point of view and focusing of stable supply of energy, would be more feasible and therefore a lower installed capacity and higher load factor would be preferred. In this context, the Sheuren power plant is considered here as having the design capacity of 205 MW in three equal units of 95 MW, and annual power generation of 957 GWh, hence the load factor of 53%.

195. The plant would have a dam of 83 m height and crest width of 1300 m holding a water reservoir of about 4,600 million m3 covering 90 km^2. The plant can be connected to CES via a 220 kV line of 150 km.

X. Orkhon Hydropower Project

196. Orkhon hydropower scheme has also been long on the planning board. Feasibility study of the project was carried out by the Japanese Chubu Electric Power and Japanese External Trade Organisation (JETRO) in 2001. It was included in the Power System Masterplan of 2002 as the recommended project in its least-cost expansion plan. It is included in the Program of Integrated Power System of 2007. National Renewable Energy Programme from the same year, Section 6 “Near terms tasks”, Item 2 calls for launching construction of 100 MW Orkhon hydropower plant in the Central Region.

197. The proposed dam site Orhon-Ulaan Hunh is located 50 km southeast of Erdenet city and about 200 km northwest of Ulaanbaatar. Orkhon runs from central Mongolia directly to the north where it joins Selenge River. The overall length of Orkhon is 1,124 km with a catchment area of 132,800 km^2.

198. The feasibility study design includes a concrete gravity dam of 90 m height and crest length of 495 m. The rated effective head is 65 m. The maximum discharge is 182 m^2/s.

199. The planned power house includes two vertical shaft Francis turbine, one with a maximum output of 20 MW (36 m^3/s) and another one of 80 MW (146 m^3/s), together 100 MW. The operating regime would be that the smaller unit of 20 MW would run to continuously and produce base energy to the system and ensure constant release of water to the valley downstream of the dam. The larger unit of 100 MW would be run only to generate peak energy, in particular in the

winter. As the annual average flow of the river of 54 m^3/s, corresponds to only about 30 MW on levelized basis, the proposed arrangement seems plausible. The estimated annual electricity production is 219 GWh.

Y. Ulaanbaatar Pumped Storage Power Plant

200. The pumped storage power plant project to Ulaanbaatar (UBPS) has been initiated by a private company Morituimpex Co.Ltd. The plan calls for the plant to be constructed near the capital city and use treated water from the waste water treatment plant in a multipurpose scheme. The source of water is in the wastewater facility. After treatment some 60,000 to 80,000 m^3 per day of water would be led to the thermal power station (on average about 0.8 m^3/s), via an approximately 7 km long water pipeline. The scheme therefore includes a set of sewage-treatment facilities, lower and upper reservoirs with associated dam, penstock, pumps and hydropower turbines, water pipelines and a 2.5 MW generation unit to provide service power for the pump-storage station.

201. From the sewage treatment plant the water would flow through the Tuul flood plain terrace to mountainside of Songino Khairkhan Mountain, where the lower reservoir would be located. The lower reservoir is planned to have a storage capacity of 1,300,000 m^3. The upper reservoir is planned on the Zalaa Mountain and would have a storage capacity of 1,000,000 m^3.

202. The elevation of the overflow land of the lower reservoir is about 1,245.7~1,246.4m. The normal storage water level of the lower reservoir is preliminarily determined at elevation of 1,246 m. Considering the variance of 5.0 m between the highest level and the lowest level, the dead water level is determined is at 1,241 m. The upper storage is planned to the elevation of if 1,490 m with dead water level of 1,460 m. Hence the maximum and minimum net head are 239 m and 209 m and the rated head of the turbines is 224 m.

203. The headrace tunnel is 1,847 m long from the intake to the powerhouse. The powerhouse is likely to be vertical shaft type in a semi-underground powerhouse accommodating two 50 MW turbines with a total installed capacity of 100 MW.

204. The planned operating regime calls for five hours operation daily (weekdays) resulting in the supply of peaking energy to the amount of 120 GWh annually (5 hours daily, 240 days a year). Estimating roughly the combined efficiency (including hydraulic loss, mechanical loss and electrical loss) of both pumping (η~85%) and generation (η~88%) at 75%, the annual energy consumed by the plant can be estimated at 160 GWh.

205. The feasibility analysis of the scheme would need to consider both the service of supplying water to the power stations and the peak shaving service to the power system. In consideration of the latter, an essential factor is the difference in the electricity production cost between the pumping and peak-shaving modes of the plant. With respect of peak shaving benefit, this difference in marginal costs should pay back the annualized cost of the capital expenditure of the pumped storage element of the scheme.

206. If the overnight cost is estimated at 1400 $/kW, the total capital expenditure stands at $ 140 million, which as annualized at 6% WACC gives $ 8.66 million. If the annual fixed O&M cost is estimated at 1.5% of capital expenditure, and variable O&M cost at 1 $/MWh for both pumped and generated energy, the total annual cost of operations amounts to $ 11.0 million ($8.66m + $2.1m +$ 0.28m) .

207. The benefits of the project are in maximum when the generated electricity replaces imports from Russia at the average cost of 77 $/MWh. It should be noted however, that the UBPS will not be able to extract the maximum benefit of replacing imports at all times, because the five hours daily operational period constraints the benefit. Imports from Russia do not distribute evenly for all working days of the year. Secondly, the capacity charge of the import tariff is dependent on the daily peaks of the Russian network, which, albeit somewhat predictable, does not always occur at the same time, and may not always be coincident with the peak in Mongolia. Therefore it

is not likely that the operators of UBPS would always be able to track the optimum daily scheduling for the plant but there should be a contingency for forecasting errors.

208. The cost of pumping energy is lowest in special situations when due to minimum load conditions in CHP4, a boiler and turbine unit is kept in operation to avoid short-term stops and starts, and some excess energy needs to be exported to Russia at very low price for short periods. However, such situations do not occur daily and are more likely in winter than in summer. Because heat driven cogeneration in CHP plants cannot be regulated, and co-generation thus forms a 'must-run base load' element in the Mongolian system, any additional generation on top of it because of UBPS pumping energy demand takes place at marginal cost, which must be determined on basis of condensing power from the most economical unit, currently CHP4 plant. Its heat rate of condensing power of 3.3 translates to an efficiency rate of 1/3.3 = 30.3%, and the pure fuel cost of pumping therefore is 5.87 $/MWh/30.3% = 19.4 $/MWh without including other variable costs (water, chemicals etc.).

209. The annual benefit of UBPS operation can be roughly estimated as the difference of the benefit of peak shaving and cost of pumping as follows:

Annual benefit = 120 000 MWh/a x 77 $/MWh – 160 000 MWh/a x 19.4 $/MWh = $ 6.1 million

210. The annual benefit is clearly lower than the annualized capital expenditure of $ 11.0 million. The breakeven point where the calculated benefit exceeds the annual capital charge occurs at overnight cost of 760 $/kW.

211. The feasibility analysis of the multipurpose scheme may need to consider both the service of supplying water to the power stations and the peak shaving service to the power system. However, the costs and benefits need to be allocated separately for both services. As per the above estimation, other benefits of having the pumped storage with upper reservoir and associated pumping and electricity generation systems, other than peak shaving, should amount to over $ 4.9 million annually. It therefore seems unlikely that expanding the scheme to a pumped storage one would be feasible.

212. A pumped storage scheme can provide the systemic benefits to the Mongolian power system but this is the case only insofar as there is no other similar capacity capable of supplying peaking power. The construction of medium scale hydropower to Selenge river system (Shuren, Egiin, Orkhon) stands high in the government priority, and the realization of any one of these plants would provide opportunity to similar peak shaving services than is planned by the UBPS. Therefore, UBPS should be considered as an option only if there were a firm commitment not to build any other hydropower plants connected to CES in the near or medium future. As this is not the case, and several scenarios of this master plan consider hydropower construction favourably, it is not seen reasonable to include UBPS among the candidate projects for Mongolia by 2025.

Z. Other Projects in CES Area

213. Two other projects in the Selenge river system have been identified as promising.

214. Burin hydropower project is a project that has many similar characteristics than Shueren project. The water flow is high (242 m^3/s) and the required dam is of average height providing gross head of 52 m for power generation, but very big dam with crest length of over 1,700 m. Again, being part of a large river, at installed capacity of 160 MW, the project could potentially provide 760 GWh to the system with 54% plant factor. Despite similarities to Sheuren project, it is considered having more adverse social and environmental impacts. It would lead to resettlement of Egiin Khatai Soum center and Inget Tolgoy farm, and the water reservoir would cover more forest area than Shueren.

215. Artset hydropower project is part of Selenge river system with inflow of 136 m3/s and gross head of 57 m, which have led to the initial estimate of installed capacity of 118 MW and annual energy output of 553 GWh. Similar to Burin site, the location calls for a large dam with crest

width of 1,400 m.

AA. Chargait Small HPP

216. Chargait project is located in Hovsgol province. The location of the site is on the Delgermuren River, approximately 50 km southeast of the provincial capital Moron. The Delgermuren River is a tributary of the Selenge River. The river is 445 km long and has an approximate catchment area of 20 000 km^2.

217. The feasibility study of the project was carried out 2004-2005 under the European Union contract to the joint venture of Irish ESB International and German Fichtner. The plant would have a dam of 35 m height and crest width of 570 m holding a water reservoir. The plant can be connected to CES via a 220 kV line of 150 km. The transmission of electricity is planned via a 30 km long 110 kV transmission line, which would connect to an existing Moron-Erdenet line.

218. The reservoir simulations led to the design capacity of 15 MW and annual power generation of 68.3 GWh. Two Kaplan turbines of 7.5 MW each have been designed with rated head of 24 m.

BB. Erdeneburen Hydropower Project in WES Area

219. The project is located in the Western region of Mongolia on the Khovd River, approximately 30 km from Erdenebured soum of Khovd aimag. The Khovd River on which the dam is planned, originates from the Altai mountain region and reaches to Khar Us Lake. The river is 516 km long and has an approximate catchment area of 58 000 km^2.

220. The feasibility study of the project was issued in 2008 by a joint venture of MSC International, Kyushu Electric Power Co., West Japan Engineering Consultants and Industrial Decisions Inc. The plan of constructing the plant is included in the Program of Energy Intergrated System for the period of 2012-2022. The plan is to connect the plant to the Miyngat substation by 220 kV transmission line.

221. The scheme includes a dam of 90 m height for a water reservoir of 1150 million m^3. The design capacity of the plant is 64.2 MW and the annual electricity generation is 242.7 GWh.

CC. Maikhan Small HPP in WRES Area

222. The Maikhan project is located in Western Mongolia in y Baiyun-Ulgii province about 40 km from the border of China. This small hydropower project is proposed to utilize a high locating Harnuur Lake, which has a maximum depth of 50 m and is fed by spring water and glaciers of the surrounding high mountains. The project does not need construction of a dam or a new reservoir as the lake forms a natural reservoir. The water head drop from the lake to the Hoton River, which runs around 4 km away from the lake, is estimated at around 417 m.

223. The project consists of water collecting canals, which would improve water flow to the lake, an intake tunnel, penstock, powerhouse at the Hoton river and electricity transmission lines. The planned installed capacity of 12 MW would be realized by two Pelton turbines of 6 MW each. The project is estimated to generate 46.4 GWh of electricity annually and supply electricity to Bayan-Ulgii, Khovd and Uvs provinces.