ADB

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Mongolia: Updating the Energy Sector Development Plan

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

For Ministry of Energy, Mongolia

Asian Development Bank

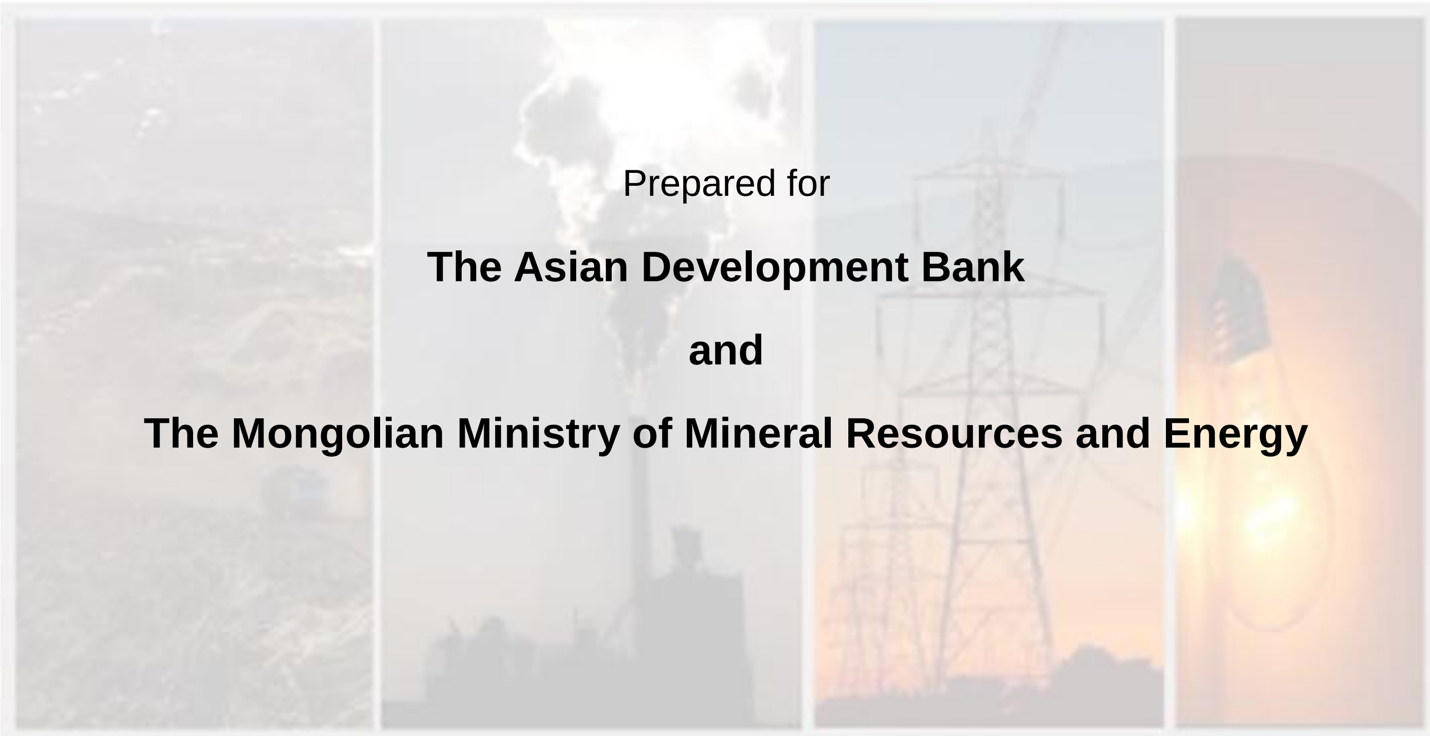
Updating Energy Sector Development Plan

Project Number: TA No. 7619-MON

FINAL REPORT

PART C: Volume - VI of X

CES ELECTRICITY EXPANSION PLAN



Prepared for

The Asian Development Bank

and

The Mongolian Ministry of Mineral Resources and Energy

Prepared by

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empowering people

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in association with

MONENERGY CONSULT

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ABBREVIATIONS

ADB	–	Asian Development Bank
AuES	–	Altai-Uliastai Energy System
CES	–	Central Energy System
CFB	–	Circulating Fluidized Bed
CHP	–	Combined Heat Power
CO_2	–	Carbon Dioxide
CPI	–	Consumer Price Index
EA	–	Energy Authority
EHV	–	Extra High Voltage
ERES	–	Eastern Energy System
EUR	–	European currency unit EURO
GHG	–	Greenhouse Gases
HOB	–	Heat Only Boilers
IDC	–	Interest during construction
LCOE	–	Levelized Cost of Energy
MoE	–	Ministry of Energy
MNT	–	Mongolian Tugrik
NOx	–	Nitrogen Oxides
O&M	–	Operation and Maintenance
PPA	–	Power Purchase Agreement
PV	–	Photovoltaic
SOx	–	Sulfur Oxides
USD	–	United States Dollars
VAT	–	Value Added Tax
WACC	–	Weighted Average Cost of Capital
WRES	–	Western Energy System

UNITS OF MEASURE

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. SUMMARY

A. Introduction

1. In CES, heat demand and heat supply have reached a critical level in terms of reserves. As is well known and accepted by all stakeholders, there is an urgent need to increase heat capacity.

2. Electricity demand is expected to grow at a rate of 7 to 10% over the next five years (assuming that Mongolia's economic performance will not be seriously impacted by the ongoing global financial crisis). There is uncertainty regarding demand growth beyond five years with timing of growth dependent on the manner and rate at which industrialization may occur; based on the current macro-economic outlook an electricity growth rate assumption of 8% is a prudent long-term forecast assumption.

3. This growth rate has been used to determine the likely investment needs for the period 2013 to 2025, for the Central Energy System heat and power sectors, comprising both the large CHP / DHN systems and the dispersed HOB / DH network heating systems.

B. Central Energy System (CES)

4. The Central Energy System is by far the largest Energy System. It is also by far the most complex of the current energy systems. As a consequence the Consultants have expended considerable effort to model the CES system accurately, on year-to-year basis for the planning horizon 2013 to 2025.

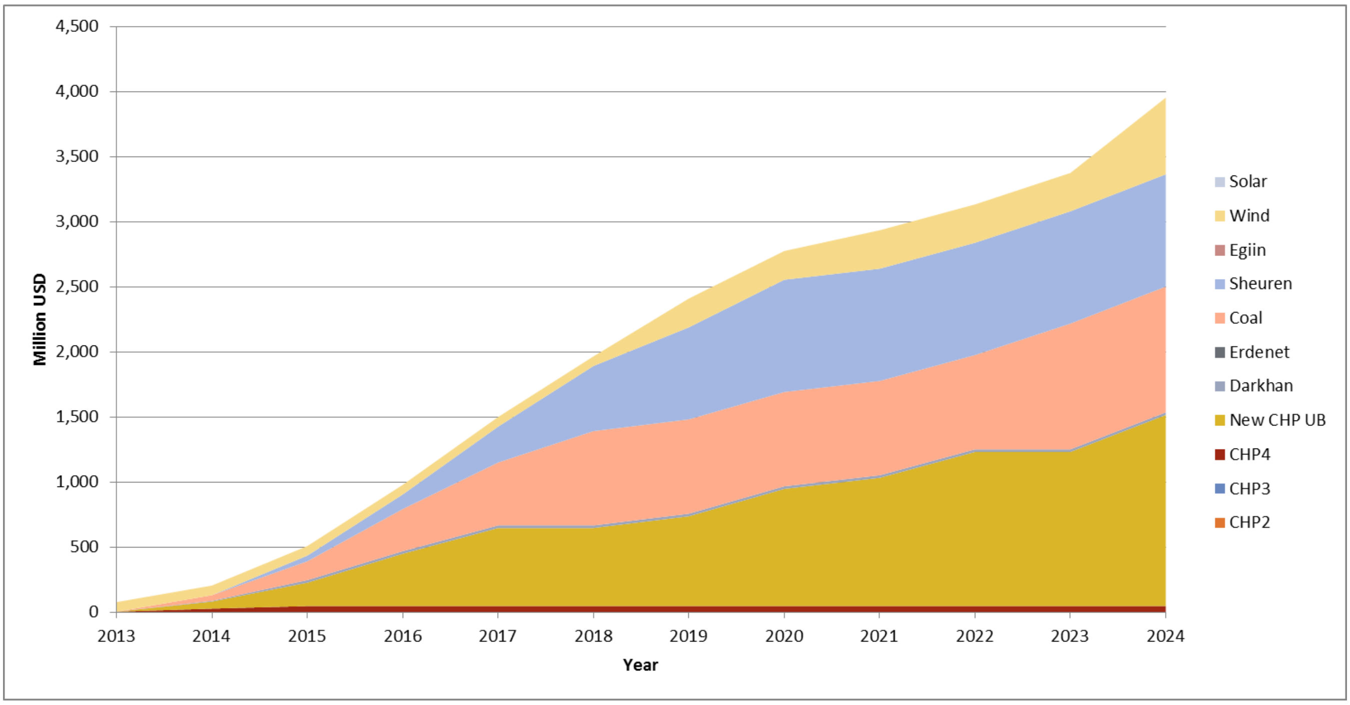
5. **It has been determined that for the period 2013 to 2025 the Central Energy System requires a capital investment of USD$300M for UB heat supply expansion, and USD$4B for electricity supply expansion.**

6. This requirement is based on specific investment plan selected using a balanced portfolio evaluation (the proposed investment plan is named as Scenario 2c). The investment plan has been formulated against a low or 'organic' electricity compound annual growth rate of 8%, but incremental expansion plans have also been developed for medium and high forecast growth rates to determine the Long Run Marginal Cost of the electricity system expansion.

7. The investment plan includes committed plants, namely CHP5, expansion of PP#4, refurbishment of PP#3, expansion of the Darkhan TPP and the 50MW Newcom wind farm. It is proposed that new capacity needs are met as follows – addition of 750MW of new CHP power by 2025, Sheuren Hydropower plant (design capacity of 390MW, operated year round at 170MW on energy basis) commencing operation in 2021, coal-fired condensing power plants starting at 300MW in 2018 and increasing to 600MW by 2025, and grid connected wind power commencing at 50MW in 2014 and increasing to 400MW by 2025.

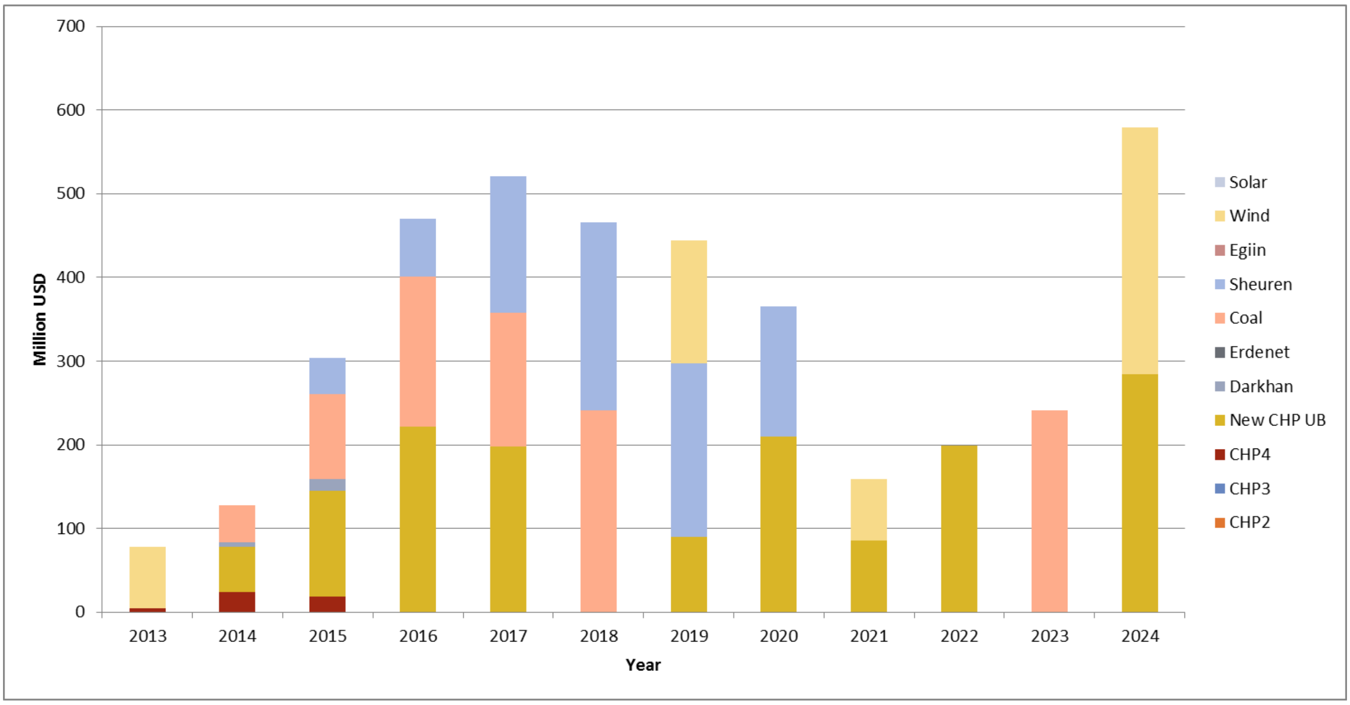
8. The annual capital investment profiles for this plan are shown in the figures that follow.

Figure I-1: Cumulative Capex Requirement of CES Power Sector (Scenario Plan 2c)



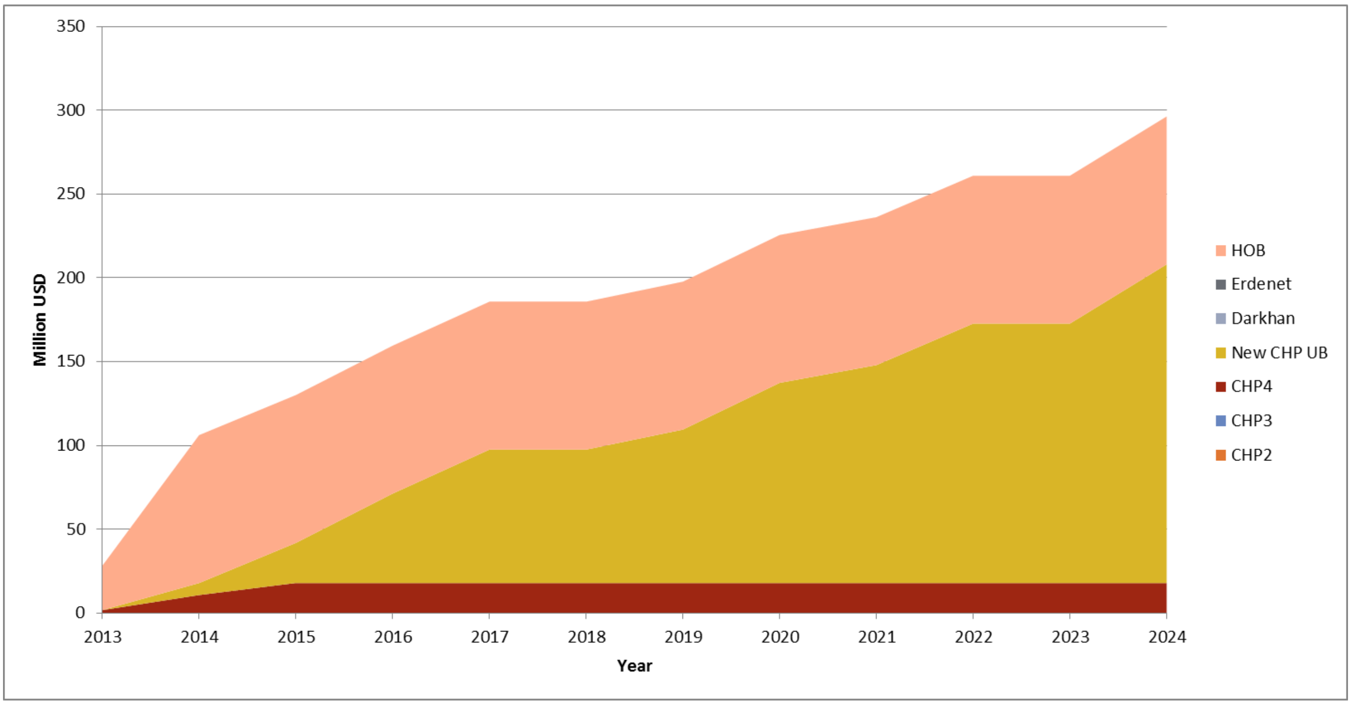
Sources: Consultants' analysis

Figure I-2: Annual Capex Requirement of CES Power Sector (Scenario Plan 2c)



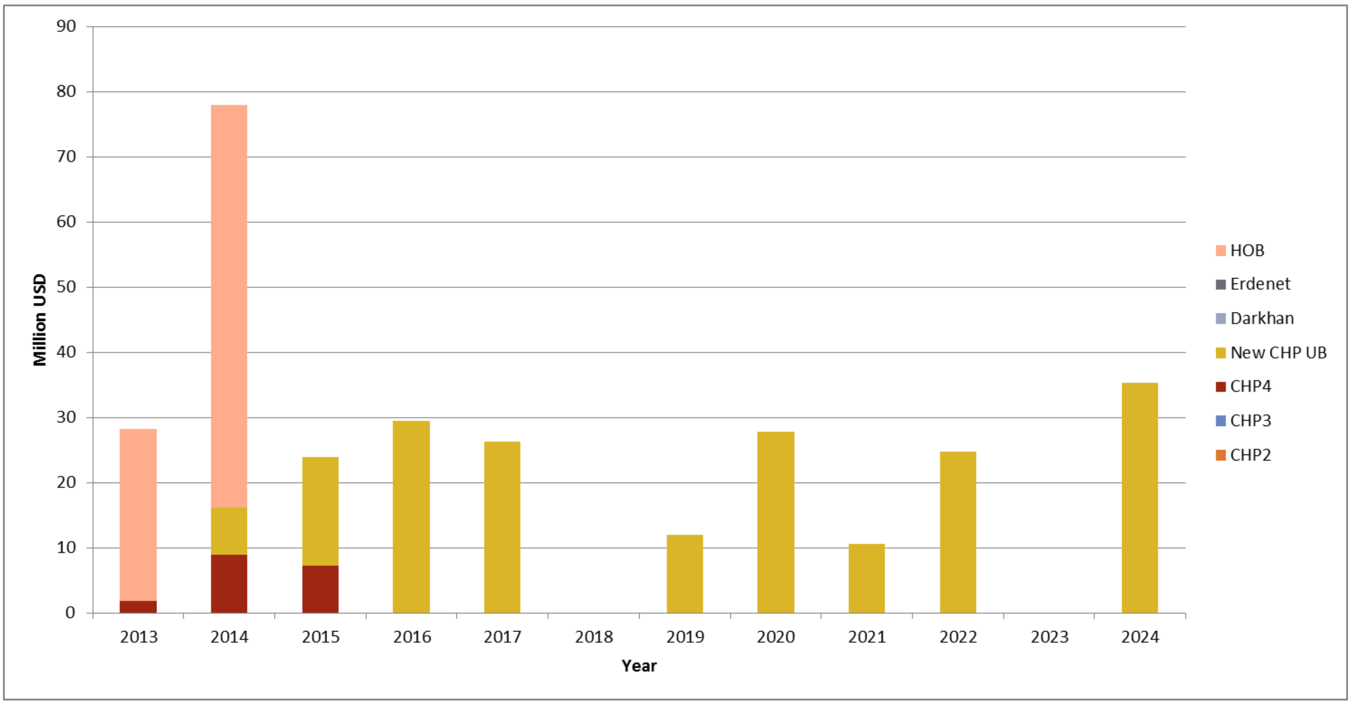
Sources: Consultants' analysis

Figure I-3: Cumulative Capex Requirement of CES Heat Sector (Scenario Plan 2c)



Sources: Consultants' analysis

Figure I-4: Annual Capex Requirement of CES Heat Sector (Scenario Plan 2c)



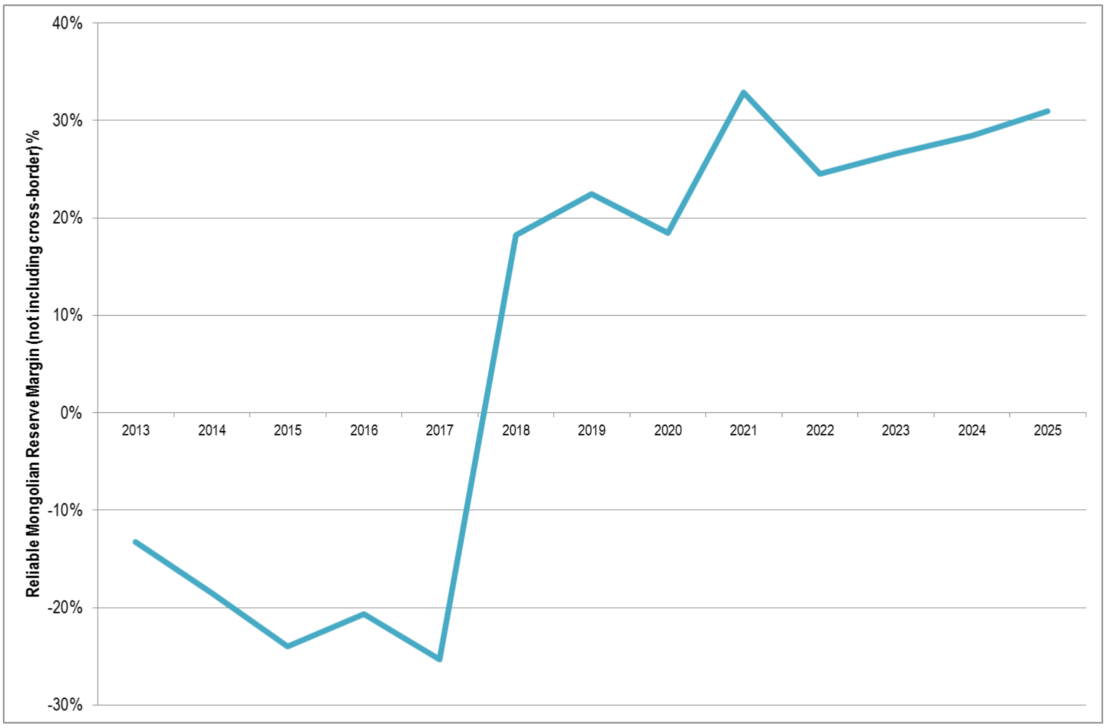
Sources: Consultants' analysis

C. Energy Industry Performance

9. The CES produces and delivers well over 90% of the heat and energy produced in Mongolia. As a consequence the measures of performance of the Mongolian energy industry overall have been very much dominated by the performance of the CES energy plants. The introduction of up to 1200MW of capacity in the Gobi will impact overall performance because the capacity will be one-dimensional, i.e. close to 100% coal-fired capacity. It can be argued that the performance of the industry should exclude the power supplies to TT and OT; at the least performance should be measured with and without TT and OT.

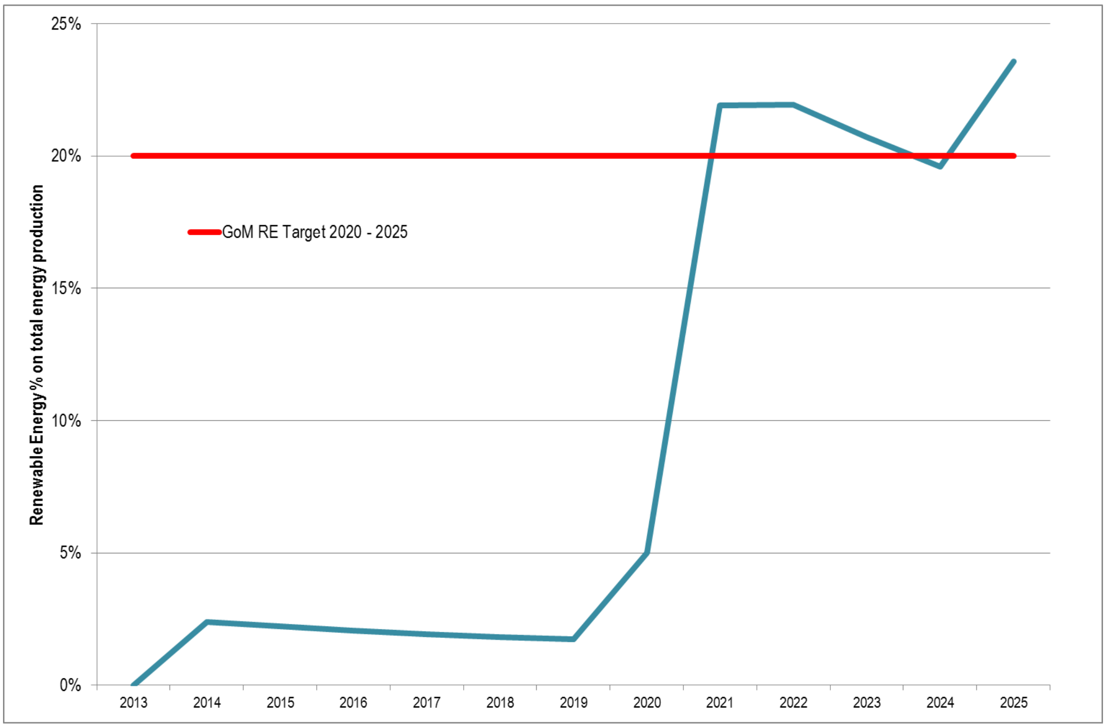
10. The recommended investment plan for the CES will deliver a marked improvement over the recent performance of the energy industry in Mongolia.

Figure I-5: CES Reliable Reserve Margin Under the Proposed Investment Plan



Sources: Consultants' analysis

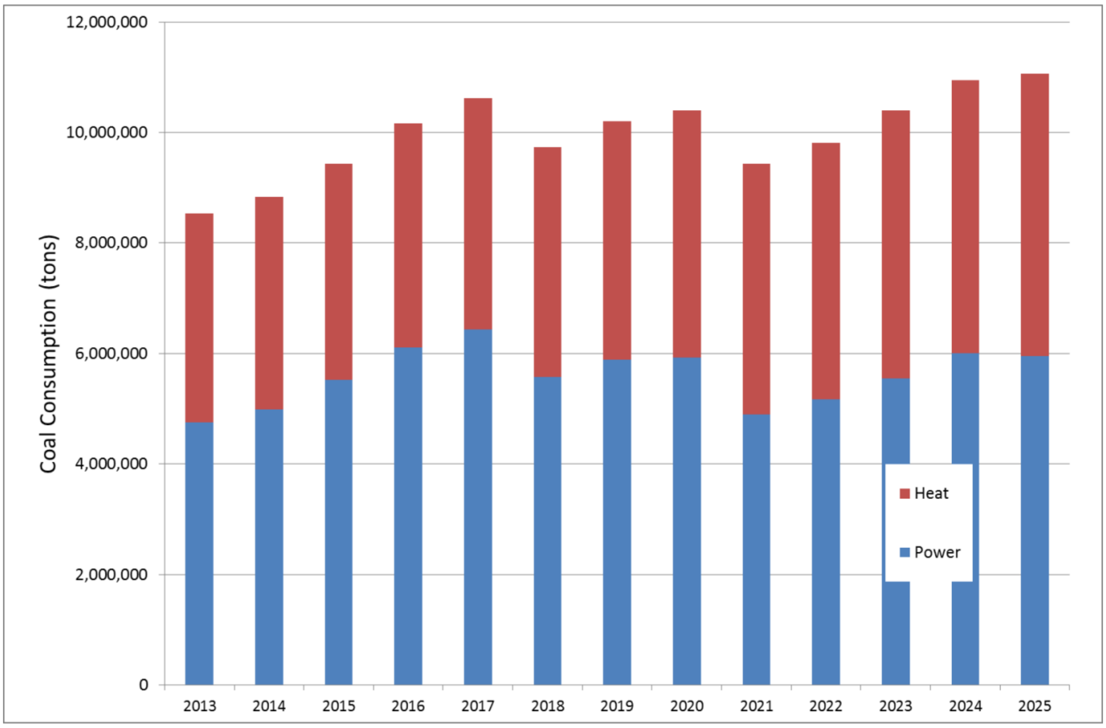
Figure I-6: CES % Renewable Energy on Total Under the Proposed Investment Plan



Sources: Consultants' analysis

11. Grid connected renewable energy achieves the Government of Mongolia's target during the 2020 to 2025 period.

Figure I-7: CES Coal Consumption Under the Proposed Investment Plan



Sources: Consultants' analysis

12. Coal consumption rises marginally and is maintained at a low growth rate due to the impact

of high efficiency coal-fired power plant and the Sheuren hydropower scheme.

D. Energy Industry Policy

13. Performance improvement must by supported by clear and sustained policy direction.

14. The key policies needed to support the recommended investment plan are as follows:-

    1) A unwavering commitment to the selected investment plan for CES;
    2) Tariff strategy to aim for full cost recovery; the target for heat and power tariffs to achieve at least the long-run marginal cost of the selected investment plan (in support of private sector participation);
    3) Coal prices for energy production to be rationalized, targeting the economic value;
    4) Capacity auctions to be used to by plant type, investor support indirectly establishing the viability of the selected investment plan); Power Purchase Agreement to be granted to each successful capacity bidder; fixed and variable costs to be set with reference to the benchmarks determined by this Energy Masterplan;
    5) Grid-connected Renewable Energy targets to be aligned to the selected investment plan; and
    6) Frequent updating of the Energy Masterplan, minor updating of load forecasts and supply expansion timing every year, and major updating of expansion plans according to economization optimization principles at least every 3 years. A Statement of Opportunities to be published annually to provide private sector investors with consistent and transparent information regarding pending investment needs of Mongolia.

II. STRATEGIC IMPERATIVES

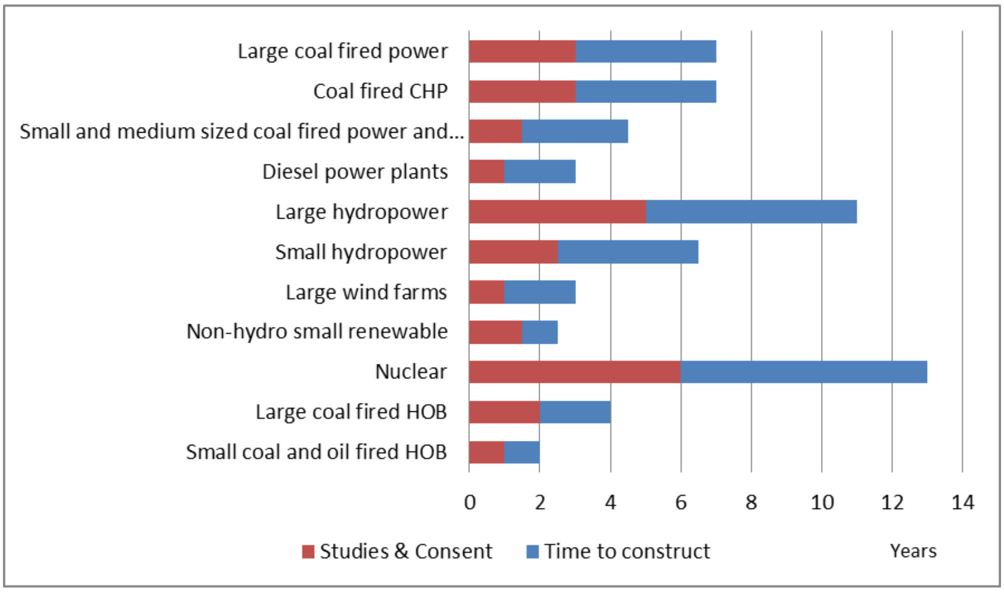
15. In updating the Energy Masterplan, strategic imperatives were firstly synthesized through discussions with Mongolian energy industry leaders and subsequently incorporated in the form of investment plan performance measures.

E. Technical Challenges

16. In 2004 the TA team responsible for updating Mongolia's Energy Masterplan recommended a heavy investment in the replacement of Mongolia's aging energy plant. At that time serious concern was expressed regarding the difficulty in raising adequate counterpart funds. Since 2004 this concern has apparently played out as evidenced by an absence of investment in new heat and power plants.

17. The fleet of thermal power plants have aged almost 10 years since the time of the evaluation leading to the 2004 recommendations, but from an individual plant perspective this has not threatened energy security as the main plants are robust in design and have been operating reliably. From a system perspective there has been significant deterioration in the Mongolian system reserve margin (both in heat and power) and this deterioration raises energy security concerns. The introduction of CHP5 will barely recover the situation and then only for a short period of 1 to 2 years. The situation is serious because it could take up to 5 years to build a new coal-fired power plant to bolster the level of reserves, and during this period the electricity reserve margin will deteriorate further necessitating a heavy reliance on Russian capacity.

Figure II-1: Typical Project Development Lead Times



Sources: Consultants' analysis

F. Environmental Challenges

18. The alternative of supplying heat to Ulaanbaatar city using large HOB's is an unattractive option from an environmental perspective. There should not be a large number of HOBs built in

Ulaanbaatar. There are not so many suitable sites available for heat production. HOB's would need coal yards and coal transportation, creating pollution. A large city should concentrate its energy production in large units in well selected power plant sites, and minimize the transporting of coal.

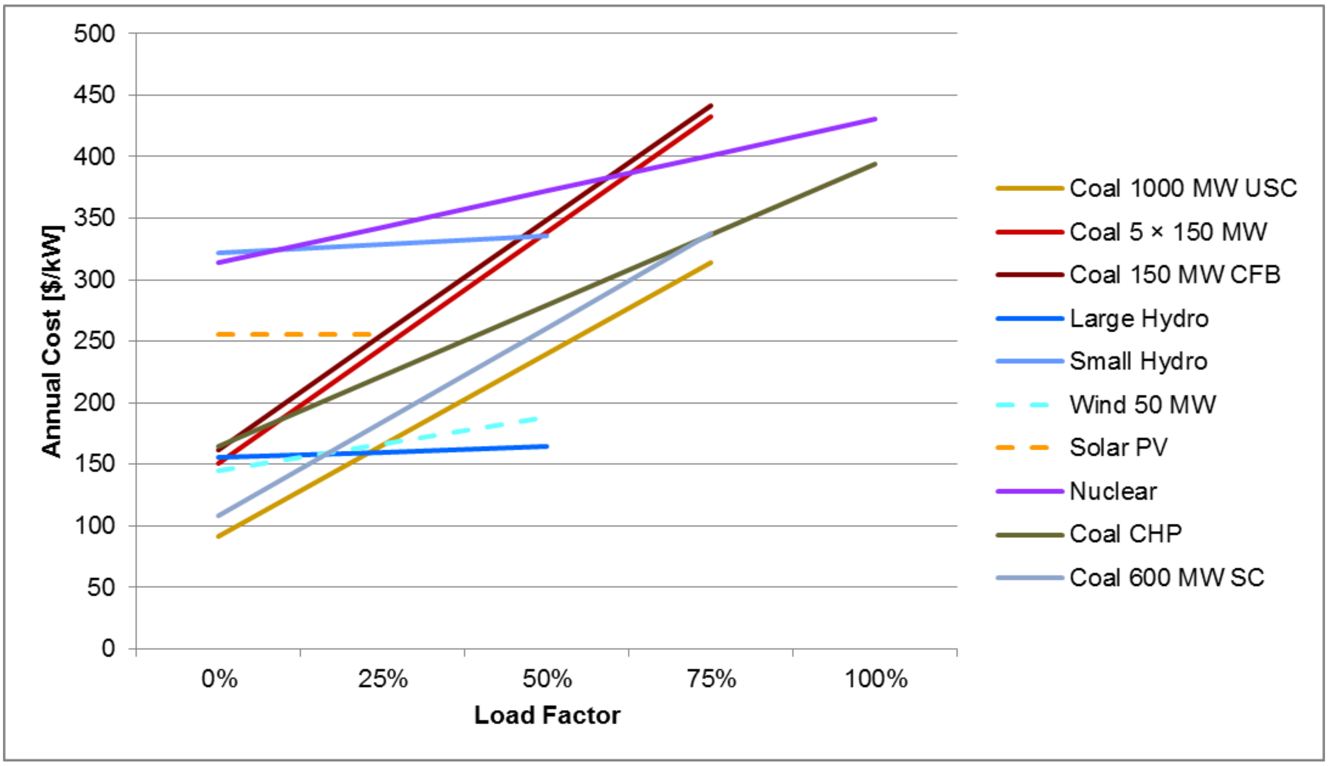
19. CHP technology is widely recognized as state-of-the-art solution for community heating in several developed countries of nearly similar climatic conditions. This includes Germany, Denmark, Finland and Sweden. CHP's are the preferred solution throughout Germany, even though Southern Germany is relatively warm. The importance of CHP even on the small scale can be seen also in the fact that many EU countries have subsidy schemes for small-scale CHP (less 20 MW), which would not be otherwise able to compete with other forms of power generation.

20. Korea has built many CHP plants wherever there is a high heating load. The fact that many countries, including many city areas in Korea, have natural gas distribution networks, explains why some eligible cities lack district heating as buildings are heated with gas. In the absence of natural gas in Mongolia there is clearly a role for coal-fired CHPs, with due attention to minimizing the need for these CHPs to generate in condensing mode.

21. The construction of the CHP5 plant will represent a watershed in the history of the energy industry, proving that Mongolia can attract significant private sector investment proving that the Government is committed to improving the environmental performance of the existing fleet both in terms of total emissions and water consumption.

22. In addition to the introduction of a modern design CHP plant, Mongolia also has an opportunity to diversify its generation mix.

Figure II-2: Economic Screening Cost Curves Determined for Mongolia



Sources: Consultants' analysis

23. The economic screening cost curves in Figure II-2 show that a large hydropower plant can be operated economically provided that load factors are in the range of 25% to 50%, followed thereafter by wind farms. In practice the capacity factor of wind is unlikely to exceed 20%. The screening curve for large hydropower In Mongolia, is based on an optimization of the design of the

dam and reservoir, trading off cost against capacity and energy production to find the optimal design point. A peaking hydropower plant would operate at a capacity factor of 5% which would render the plant uneconomic compared to moderate to large capacity coal plants. This is atypical of the situation in most other countries, largely an effect of the low price of coal in Mongolia. Nevertheless there is a place for hydropower, offering benefits in terms of cost, CO_2 reduction, and support for the greater use of grid-connected wind farms by responding to intermittent generation by wind. After large hydropower and at higher load factors, coal-fired power is justified, first CHP and then coal-fired condensing power.

24. There are risks associated with heavy dependence on hydropower and wind farms. In the case of hydropower the prospect of dry years must be taken into account. In any case for hydropower plant it is typical to assume that reliable capacity is 80% of full capacity, but this assumption does not account for a particularly dry period of several years wherein capacity is severely constrained. With climate change known to be affecting Mongolia, the availability of water in the catchment areas of a proposed hydropower plant must obviously be carefully studied.

25. In the case of wind farms it is typical to assume that reliable capacity is 5% of full capacity due to the intermittency of the wind. In Mongolia it is reasonable to assume that wind speeds are mostly below an acceptable threshold of 6 m/s during the winter months when electricity demand is at a maximum. This assumption is modelled so that wind farms make no firm contribution to reserve margin in winter during the peak demand, i.e. energy security benefits. As clean energy producers, wind farms do of course offer CO_2 reduction benefits. A further difficulty relates to the challenge of grid operation; stability and voltage control difficulties arise during periods of light loading if large wind farms are operating. To mitigate against this risk the percentage of wind power modelled in the Mongolian system has been constrained to no more than 15% on full capacity basis. As improved forecasting and despatch systems are introduced, and system operators gain experience operating hydropower and wind in combination with thermal plant, this constraint might be challenged .. up or down. Hence operating experience with the Newcom 50MW wind farm will be crucial.

III. POLICY CONSIDERATIONS

G. Electricity Demand

26. In CES, electricity demand is expected to grow at a compound rate of around 7 to 10% per annum over the next five years on the grounds that Mongolia's recent economic performance will be sustained during this period. There is some uncertainty regarding the demand growth beyond five years with timing of growth dependent on the manner and rate at which industrialization will occur – on the one hand a 'minerals and mineral processing' boom could be anticipated while on the other hand 'livestock-based industries' would see a more modest growth rate in electricity consumption.

27. The demand growth due to minerals and mineral processing is not expected to taper off over a 20 to 30 year planning horizon. The spurt from industrial growth will likely gradually dissipate after 2030, after which efficiency improvements and a general shift from energy-intensive industries to a more diversified economy over time will see economic growth continue with reduced electricity demand growth.

28. The decision whether to plan for expansion based on a low, medium or high growth outlook is a matter of Government energy policy. For the Energy Masterplan update the low forecast has been adopted as the forecast common to all scenario plans. This low growth rate is 8% and would be considered as high in the developed world. Medium and High growth forecasts have been modelled for a Reference Plan, to establish an estimate of the long run marginal cost of energy supply. This understanding allows for adjustment of financing strategy as load develops. The marginal cost difference of investment plans needed for the Low, Medium and High forecasts was found to be not very steep which further justifies the choice of the Low growth rate for the evaluation of alternative scenario plans.

29. The impact of electricity price increases are not included in the electricity demand forecasts; an increase in efficiency might be expected if medium-term increases were high and impacted on industrial and other consumption patterns. Demand-side management programs could also potentially reduce the overall demand growth marginally over this period but are also not included in the demand forecasts. Taking these factors into account, there may be scope to adjust the timing of supply expansion but in terms of a relative comparison the impact will be common between plans, and in any case is likely not to be material in terms of investment needs.

30. In summary a traditional planning policy has been adopted whereby expansion plans have been costed against Low, Medium and High electricity growth forecasts based on best information to hand in second quarter 2013.

H. Least cost

31. Expansion plans are developed on the basis that a country builds capacity to meet expected growth at minimum economic cost (inclusive of externality impacts such as CO2 mitigation). While the internalization of externalities such as environmental costs is a critical issue in ascertaining the true cost of capacity expansion and in evaluating alternatives, the current lack of capacity reserves and the need to maintain economic growth means that externalities are of secondary importance at this time in Mongolia's. Nevertheless a carbon tax scenario has been evaluated to see the impact that such externalities would have on the cost of an expansion plan if they were introduced as a matter of policy. The Consultant's analysis shows that a US$3 carbon tax applied as a shadow price to the generator's cost of production would add 4% to the cost of a

coal-based expansion program.

32. An alternative to building capacity to meet expected growth at minimum cost is for the country to build in order to attract growth (i.e. to provide excess capacity in order to ensure sufficient reserves to cater for large new consumers without delay). The cost difference between the two approaches will not be significant if the additional cost of excess capacity per MW is not steep, and as mentioned above this is the case in Mongolia.

I. Energy Security

33. As a general principle the inherent uncertainty in demand forecasting, and the uncertainties around expectations of power plant performance require that an amount of reserves is provided to avoid supply interruptions. Building additional generation capacity to provide these reserves adds extra cost to the system which needs to be weighed against the economic cost of supply interruptions.

34. The level of reserves can be determined by incorporating a cost of un-served energy to internalize this trade-off in the optimization of the expansion plan. However in the next three to five years, Mongolia's Central Energy System reserve margin is expected to fall to a chronically low level. Add to this the prospect of industrial growth and it is reasonable to adopt reserve margin criterion as the key planning criterion. The Mongolian power system reserve margin target of minimum 18% and average of 25% was adopted for the period 2013 to 2025.

35. The Central Energy System is by far the most complex, requiring a sophisticated planning approach that involves economic optimization modelling of the integrated heat and power system.

J. Environmental Policy

36. Mongolia is subject to international climate change obligations that encourage shifts from high-emitting fossil fuels to renewable or alternative energy sources. This emphasizes the need to internalize specific externalities such as the environmental impact of fossil fuels.

37. The Government policy on greenhouse gas emissions is specific in terms of a firm target of renewable energy production of 20% on energy base by 2020 to 2025, but falls short of imposing a fossil fuel impost. The Renewable Energy Feed-in Tariff program (REFIT) is expected to support the provision of additional capacity in the medium term.

38. Economic screening curves suggest a limited role for grid connected solar PV farms in the near term. Given the vastness and remoteness of some communities in Mongolia, the use of solar PV seems more suited to remote area power supplies. Demand-side programs such as the 100,000 solar homes target set by the Government are commendable examples of the use of solar energy.

39. The Energy Masterplan does not account for the impact of individual solar PV installations but it does examine the impact of a carbon tax, and of differing levels of renewable energy production in terms of the investment plan portfolio.

40. The Energy Masterplan does not fully address concerns regarding long-term water usage for power generation. Coal-fired generators are intensive water users, and while regional imbalances can be alleviated through water infrastructure development, the long term impact on overall water balances in the country is usually studied during the feasibility stage of specific power plant developments, beyond the scope of an Energy Masterplan.

K. Diversity

41. The Government's renewable energy target indicates indirectly a preference for decreased reliance on coal as the only fuel source for electricity. It has been assumed in the Energy Masterplan that Government policy, as well as Ministry directives, will support the promotion of

greater diversity of the energy mix, through inclusion of hydropower and other renewable options.

42. However, there is the concern with hydropower in particular that the local environmental impacts of a large run-of-river hydropower scheme may attract international criticism, delaying or even suspending such projects. In Mongolia's case this will have a serious impact on diversification as alternatives are limited.

L. Financing Rates

43. The policy objective of increased private participation in the electricity generation sector has been modelled by including cost of capital sensitivity testing of the investment plans.

44. Discount rates are based on the calculations of Mongolia's weighted average cost of capital (WACC) determined by the TA team consultants. The approach is drawn from the generally accepted methodology of determining the required returns to overcome risks to lenders of corporate debt and equity. It has been assumed that the cost of capital (pre-tax, real) in Mongolia is 4% for Government-funded projects, 8% for private sector projects and 6% when Government and the private sector take an equal share of the risks in a project.

45. The discount rate is an important factor in determining an optimal expansion plan due to the manner in which costs are reflected in the modelling. Capital-intensive projects would be penalised under a high discount rate (relative to less capital-intensive projects) as the capital costs are incurred upfront and operating and fuel costs incurred during the life-time of the projects. Heavy discounting of these future costs relative to the capital would result in the model favoring low capital projects with higher operating and fuel costs.

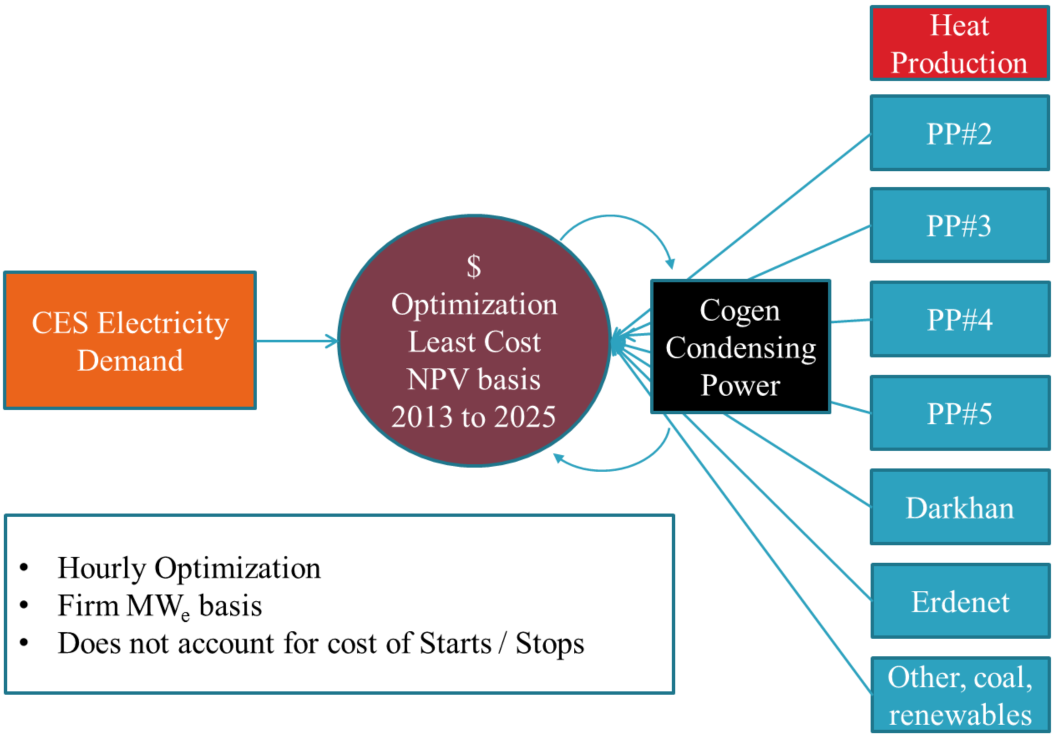
46. The Energy Masterplan is based on an assumption that there are no constraints with regard to affordability. Implicit in this assumption is that price increases in subsequent years will bring the heat and electricity sectors into "balance", i.e. to the financial viability demanded by the private sector given the capacity requirement. If this is the case a reference (or least direct cost) plan provides a suitable benchmark for the costs of the alternatives. Thus the normalized increase in costs (relative to a reference plan) is important in determining the increased costs required in excess of a least cost reference plan.

IV. ECONOMIC DISPATCH

M. Economic Dispatch Optimization

47. The optimization of the energy mix of the CES is based on an economic despatch model built to accommodate the economic dispatch of Mongolia's CHPs as well as other future technologies such as wind, coal-fired power, etc. The model is represented in Figure IV-1.

Figure IV-1: Economic Optimization Model



48. The accuracy of the model depends on the assumed efficiencies of power plants. The efficiencies of conventional power plants are well known and in general masterplans share similar assumptions. In the case of CHP plants the 'turbine characteristic curves' determine the efficiency of the CHP under different operating conditions. In effect there are two characteristics corresponding to whether heat is produced near to the plant design rating in a cogeneration mode, or at much lower levels in a condensing mode. A further complication is the need to allocate the marginal operating cost between heat and power.

N. Efficiency Characteristics of Main CHP Plants

1. Efficiency of CHP4

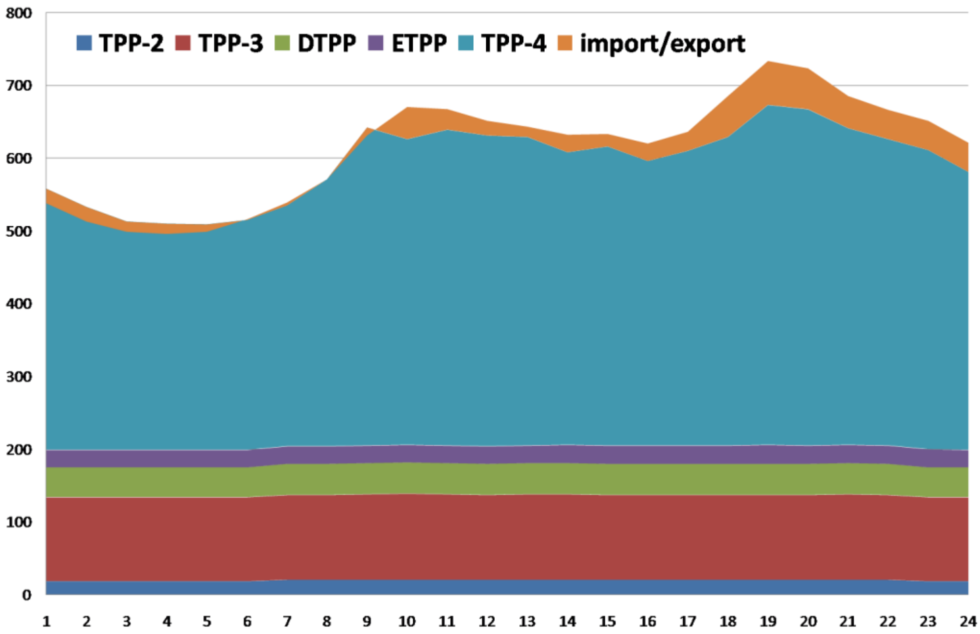
49. CHP4 is an existing plant but it plays an important role in the electricity system as being the plant that primarily follows load. This role is expected to continue several years to the future until new capacity, which is capable of load following, comes on-line. Thereafter its ranking in the

dispatch order will depend on its relative unit cost of electricity generation, which again partially depends on how much district heating load it will serve. CHP4 plant has a technical capacity of producing electricity without underlying heat load, i.e. even after part or all of heat demand has been allocated to new greenfield plants, and therefore its cost structure in various possible future operating modes needs to be analysed.

50. Russian electricity imports also follow load variations of CES, and participate in controlling system frequency, but the capacity of the import link is limited. Therefore, CHP4 (TPP-4) needs to take care of major part of daily load variation whilst the import/export link provides for the crucial margin and frequency control as shown in Graph I-1 in the following.

51. Figure IV-2 illustrates situation on a typical winter peak day in January 2011. CHP plants No 1, 2 and 3 run at almost constant loads. CHP4 took care of the load following up to its maximum capacity. At the evening peak, the needed balance, approximately 80 MW of electricity was imported from Russia to gather for the peak.

Figure IV-2: Peak load of CES on January 28, 2011



Sources: Consultants' analysis

52. First unit of CHP4 was put into operation already in 1983 and in 1990 the plant reached its full capacity of 540 MW. The plant has since then been subject to many renovation projects through which the plant technology has been partially but to a large extend modernized resulting in improved efficiency, higher available capacity and extended life. The current nominal capacity of the plant is 580 MW of electricity and 1145 GCal/h of heat. Overall on annual basis, the plant provides for about 75% of the electricity supply to CES and 60% of the heat demand of Ulaanbaatar.

53. There are eight pulverized coal boilers in CHP4 each having steam raising capacity of 420 t/hat superheated steam pressure of 140 kg/cm2 and temperature of 560°C. The plant has six turbogenerator units connected to common high pressure steam supply. There were originally three turbines with installed capacity of 80 MW and another three of 100 MW capacity, but two have recently been refurbished increasing their capacity by 20 MW each, so that today there are five turbines of 100 MW capacity and one 80 MW turbine. The design inlet steam values are pressure of 130 kg/cm2 and temperature of 555°C.

54. The turbines are of extraction condensing type. This means that at all times part of steam generated by boilers needs to be led to the low pressure parts of the turbines generating 'condensing power' and enabling load following also at times, when the steam flow corresponding to district heating demand of the plant is not sufficient for the required electricity demand. Condensers are of cooling tower type.

55. CHP4 is equipped with two pressure reduction stations, which enable extracting steam from the common high pressure steam header down to medium pressure heat exchange stations for district heating hence making heat supply independent from turbine operation.

56. Coal is supplied from Baganuur and Shivee-Ovoo coal mines. The coal quality varies substantially, which sets high demands for the plant operation. The boilers have been designed for the heat value of 3,500 kcal/kg that corresponds to Baganuur coal. Baganuur coal has a heat value of 3,400 kcal/kg on average, and the moisture content can vary from 26% to 33%, ash content is 9.5% and above, and sulphur 0.36%. Shivee-Ovoo coal has heat value of 2900 kcal/kg, can reach moisture content of even 45%, has ash content of 7.1-11% and sulphur content of 0.9%.

57. The performance of CHP4 is analysed here on basis of operational data from the plant of year 2011. The data consists of daily averages of all key process parameters from coal supply and feed water to boiler steam and electricity and heat supply.

58. Based on the data set, the daily gross and net electricity generation values were used to calculate daily average values for electricity output. On average, the difference of gross and net output of electricity, i.e. plant own use of electricity was 13.5%. The daily values for hot water and process steam production (t/h) were used to calculate daily average output values in megawatts. For hot water also water flow and return and supply temperature were given, and they were used to calculate the hot water production for verification. The calculated hot water production was noted to be some 5 % lower than measured hot water production. The measured hot water production was selected to be used in the performance evaluation.

59. Measured data for boiler steam parameters and feed water temperature was used to calculate boiler steam output. With an estimated boiler fuel efficiency of 88 %, the corresponding boiler fuel input was calculated. The calculated fuel consumption was compared with measured data of coal supply from the two coal mines. The coal production data was converted to energy by using mine specific heating values. The difference between the fuel consumption data obtained with the alternative method of deriving fuel consumption from boiler energy was 7.3 %. The difference is not substantial considering the simplifications made and uncertainty related to the heat value of coal. Even on annual basis, the heat value of coal has varied 7%, LHV of coal having been 3,253 kcal/kg in 2010 and 3,503 kcal/kg in 2007. The fuel consumption data calculated from boiler steam output was used in the performance evaluation. The plant also uses heavy fuel oil (Mazut) as support fuel, but its share of total fuel use is minor, only 0.1%.

60. The key input and output values of CHP4 have been summarized in the following Table I-2. The fact that the efficiency rate varies from 30% to 76% illustrates well how the efficiency is dependent on the operating mode of the plant. At times, when district heat load is low, the efficiency is correspondingly low, whereas during the peak heating seasons the plant reaches efficiency rates which are typical for a CHP plant. It should be noted, however, that the out-dated technology and poor quality of coal lead also to some inherent technical inefficiency manifested in the high station use of energy. During 2011, the use of pressure reduction valves was limited to 17 days and had not a major impact on the efficiency.

Table IV-3: Summary of Key Input/Output Parameters of CHP4 in 2011

	Electricity output		Heat output	Fuel input based on…		Plant net efficiency based on…	
	Gross	Net	Net	Boiler steam	Coal supply	Boiler steam	Coal supply
	MW	MW	MW	MW	MW	%	%
Minimum	142	119	44	540	502	30.0	30.2
Maximum	478	416	779	1897	1743	75.8	68.9
Average	354	306	416	1327	1230	57.4	53.2

Sources: Consultants' analysis

61. The analysis of the plant was continued by combining operational data from year 2011 to other technical data about the plant including a simplified process diagram and capacity data sheets on some main equipment. Based on this information a process model was created to simulate the performance of CHP4. In this process model the whole set of eight boilers and six turbo-generator sets was reduced to a plant consisting of a boiler, extraction-condensing steam turbine, DH heat exchangers and process steam consumer as well as necessary pumps and other auxiliary equipment. The parameters of the process model were carefully calibrated in such way that the model corresponds to the measured operational data as accurately as possible.

62. The process model was used to calculate the characteristics of the power plant. These characteristics included power-to-heat ratio for cogeneration, specific fuel consumption for cogeneration and condensing power and gross and net power yield for DH and process steam production. Using these characteristics and capacity information of the main equipment, the performance of CHP4 power plant in different operation conditions can be estimated.

63. Once the process model was built, it could be tested in various operational situations. From the operational data, operational situations typical for a winter day, summer day and an average operational situation were identified. Once this was done, the marginal heat rates could be calculated for both cogenerated electricity as well as condensing power by analysing the marginal changes in fuel consumption, when one of the other was kept constant. An example of such analysis is in Table I-3 below.

64. Marginal heat rate of cogenerated power could be established by reducing heat load of the typical winter day situation whilst keeping the steam flow to the low pressure part, thus condensing power generation constant. This is the situation in Case 1 of Table I-3. On the other hand, the marginal heat rate of condensing power could be estimated by keeping the heat load and electricity cogeneration constant whilst increasing condensing power by letting more steam to low pressure part of the turbine (Case 2).

65. The boiler fuel-to-steam efficiency was estimated above at 88%. From this the heat rate of district heat and process steam was set at 1.17 (85.5%) allowing 2.5% for steam and heat losses. With these parameters fixed, the four cases provided mathematical basis to derive heat-to-power ratio and marginal electricity heat rates. The power-to-heat ratio is 0.29 and the heat rate for cogeneration 1.36 (73%) and for condensing power 3.85 (26%).

66. The four operational points and the consequent testing of the model and calculated efficiency parameters are given in Table IV-4.

Table IV-4: Calibrating Process Model (2011)

All units in MW	Winter	Summer	Case 1	Case 2
- District heat	718,0	156,0	501,6	501,6
- Steam	17,4	18,6	17,4	17,3
Heat total	735,4	174,6	519,0	518,9
- cogeneration	210,6	50,0	143,5	143,5
- condensing	134,3	209,9	134,3	211,5
Electricity total	344,9	259,9	277,8	355,0
Boiler	1463,0	957,0	1175,1	1409,2
Fuel	**1662,7**	**1087,4**	**1335,3**	**1601,4**
Total efficiency	**65 %**	**40 %**	**60 %**	**55 %**
Testing variables:				
Fuel consumption by output by applying simulated power to heat ratio and heat rates				
DH	840,1	182,5	586,9	586,9
Steam	20,4	21,8	20,4	20,2
Cogen power	286,5	68,0	195,2	195,2
Condens power	517,3	808,4	517,3	814,6
Total	**1664,3**	**1080,7**	**1319,8**	**1616,9**
Total efficiency	**65 %**	**40 %**	**60 %**	**54 %**
Error (MW of fuel)	1,6	-6,7	-15,5	15,5

Sources: Consultants' analysis

67. The process model is accurate and fits well to the operational data. However, the plant system parameters calculated are marginal values and may not be completely representative averages over the whole year and in all possible operational situations, because, for example, electricity heat rate is not linear over the capacity range. Therefore, the performance parameters were also tested against the 365 daily operational data. Overall the fit to the operational data seemed also good indicating high reliability of the model. The fitting of parameters derived by the model to the daily data over the year suggested only minor change to the heat rate of condensing power, as summarized below.

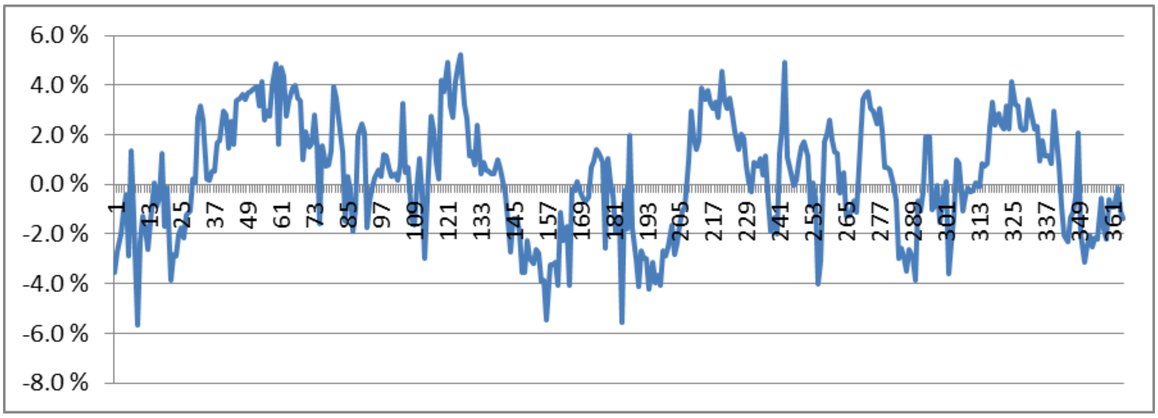
Table IV-5: Performance Parameters of CHP4

Heat rates	MW to MW	%
Heat		
- District heat	1.17	85.5
- Steam	1.17	85.5
Electricity		
- cogeneration	1.36	73.5
- condensing	3.66 - 3.85	26.0 - 27.3
Power-to-Heat Ratio for Cogeneration	0.29	

Sources: Consultants' analysis

68. Testing parameters against the measured boiler fuel consumption at 88% fuel-to-steam ratio, the daily error curve over the 365 days of 2011 is as follows.

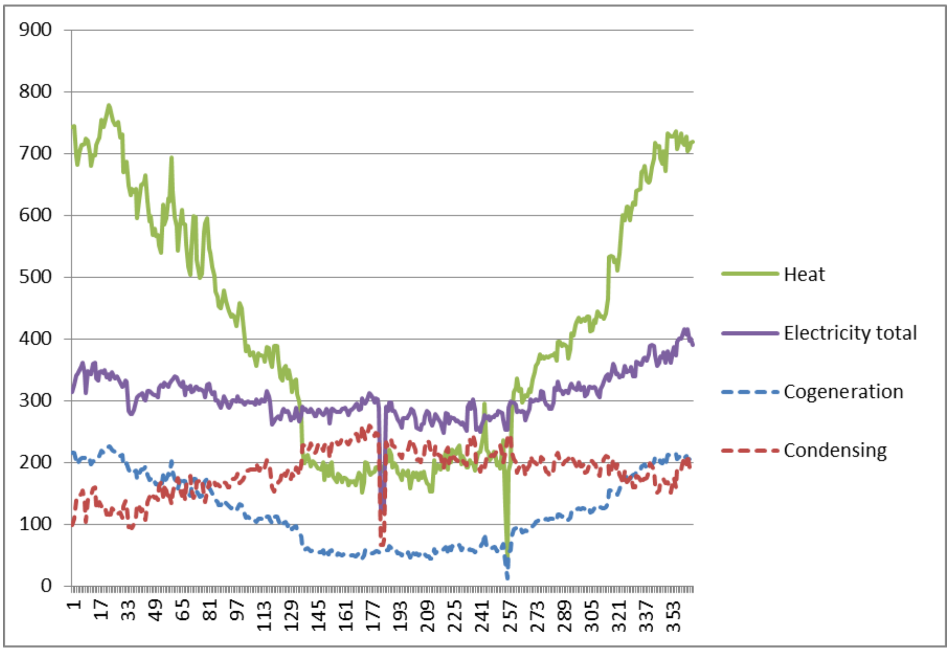
Figure IV-6: Simulation Error % (of Fuel Consumption)



Sources: Consultants' analysis

69. The resulting breakdown of total electricity supply to cogeneration and condensing power is shown in the following Figure IV-7 together with total heat and electricity supply.

Figure IV-7: Heat and Electricity Production of CHP4 in 2011



Sources: Consultants' analysis

2. Efficiency of CHP5

70. The CHP5, Phase I plant is considered as 'committed' in the analysis and assumed to be built during the period of the plan. Technical data pertaining to the plant in the following is taken from the feasibility study of the plant issued in October 2011. The analysis here produces power-to-heat ratio, heat rates for heat, cogenerated electricity and condensing power as well as a method for allocating plant investment, fixed and variable O&M costs to the mentioned three forms of energy output. The parameters and cost allocation rules are then applied in the optimization process of capacity expansion planning.

71. According to the feasibility study, CHP5 will have maximum heating capacity of 1,281 MW and electrical capacity of 820 MW when completed in two phases. This is achieved by having five turbogenerator units of 150 MW each and one 70 MW back-pressure turbine. Under Phase I, which is analysed here, three equal 150 MW condensing extraction turbine units will be implemented with a total electrical capacity of 450 MW and 587 MW heat (505 Gcal/h).

72. The planned plant will represent state-of-the-art technology with high efficiency and good environmental performance. The plan calls for three circulating fluidized bed (CFB) boilers to be built, each having steam raising capacity of 525 t/h, at 13.7 MPa(g) and 540°C. Turbines will have main extraction points at 0.98 MPa(a) and 0.19 MPa(a), two high-pressure pre-heaters, four low-pressure preheaters and one daerator.

73. According to the feasibility study, the plant will consume 3,62 million tons of coal from Baganuur and Shivee Ovoo, of which 73% of tons supplied will be of lower quality coal from Shivee Ovoo.

74. A process model was built of CHP5 on basis of key parameters of the feasibility study. The available information consisted of simplified process diagram and capacity information on the main equipment. Based on this high level technical data of the feasibility study, the process model reduced the three units into one system of a boiler, extraction-condensing steam turbine, heat exchangers for district heating as well as all necessary balance-of-plant equipment such as pumps, condenser and other auxiliary equipment in line with the key process parameters (450 MW, 587 MJ/s, 137 bar(a), 540/540 °C, as quoted above).

75. The turbine process consists of:

- DH water heating in two stages using steam from turbine bleeds;
- Four low pressure condensate preheaters; and
- Two high pressure feed water preheaters and a separate de-superheater.

76. The sizing of the low pressure turbine in the process model was made so that full condensing operation is possible. In all aspects, the model represents latest commercial technology for such CHP capacity.

77. The process model is necessary for the purpose of estimating the characteristics of the power plant. These characteristics include specific fuel consumption for condensing power and gross power yield for district heat production. Using these characteristics and capacity information of the main equipment, the performance of CHP5 power plant in different operation conditions can be estimated.

78. Using the process model five various operational points of CHP5 were analysed.

a) Maximum district heating supply with minimum condensing power generation;
b) Normal winter condition (baseline);
c) Operating the plant for only condensing power production (with no heat load);
d) Operating point with same amount of steam to turbine LP unit (condensing power) as in baseline (b), but with lower heat load; and
e) Similar to (d) as to heat load but with higher electricity output (condensing).

Table IV-8: Sample Operational Points of CHP5

All units in MW	(a)	(b)	(c)	(d)	(e)
Heat total	587,2	423,6	0,0	300,2	300,2
- cogeneration	276,0	199,1	0,0	141,1	141,1
- condensing	56,3	169,6	450,0	169,6	251,8
Electricity (gross)	332,3	368,7	450,0	310,7	392,9
Fuel	1120,5	1120,2	1118,7	923,5	1119,6
Total efficiency	**82 %**	**71 %**	**40 %**	**66 %**	**62 %**

Values on rows shown on grey background stem from the process model.

Sources: Consultants' analysis

79. The purpose of selecting these operating points is to analyse the changes in fuel consumption when certain kind of output fraction (heat, cogenerated electricity, condensing power) is varied. With the resulting changes in other key parameters, the required indices can be established as follows:

80. Case (b) has equal steam flow to LP turbine as Case (d), hence the difference in power output divided by the difference of heat load tells the power-to-heat ratio of the simulated plant. The resulting power-to-heat ratio is 0.48.

81. Heat rate can be estimated in two ways. Case (c) reveals immediately the heat rate in a situation, in which there is no steam extraction at all, resulting in heat rate of 2.49 (40.2%) on gross electricity production. Furthermore, comparison of cases (e) and (d) also provides an opportunity to derive the marginal heat rate of condensing power with a result of 2.39 (41.8%) on gross electricity basis. Considering these two operational points, the value of 2.46 (40.7%) was selected for further analysis.

82. By deducting fuel consumed by condensing power in operating points (a), (b), (d) and (e), the heat rates of district heating and cogenerated electricity can be established at 1.13 (88.5%)

and 1.15 (87.0%) on gross electricity, respectively.

83. Because all steam generation, regardless it is used for heating or electricity production, contributes to the station losses of the CHP plant, all heat rates, including that of district heating, need to be adjusted to net electricity output. The station own use of electricity varies from 32 to 37 MW corresponding to 9.2 to 10.3% of gross electricity in the process model. This amount was allocated to heat and electricity in proportion to their contribution to fuel use, and the fuel use breakdown was re-adjusted accordingly so that the fuel use of heat production was increased to gather for its portion of the station use. The electricity consumption for condenser cooling estimated at 3.65 MW was allocated exclusively condensing power. Thereafter the net electricity was re-adjusted for cogeneration and condensing power, and heat rates were calculated on net basis

Table IV-9: Performance Parameters of CHP

Heat rates	MW to MW	%
Heat		
- District heat	1.19	84,0
Electricity		
- cogeneration	1.19	83.7
- condensing	2.69	37.1
Power-to-Heat Ratio for Cogeneration	0.47	

Sources: Consultants' analysis

O. Cost Allocation of CHP Plants

84. The capacity planning exercise requires that for each producer of electricity and heat the following parameters can be established:

- Capacity limitations (maximum and minimum available capacity, dependencies such as how electricity co-generation is dependent of heat demand through the power-to-heat ratio);
- Availability;
- Life;
- Efficiency (expressed for thermal energy also in the form of heat rates);
- Fixed costs, which include annualized capital costs of the initial investment and costs of insurance, long-term outsourced services, management and permanent operation and maintenance staff; and
- Variable operating cost, which includes costs of fuel, lubricants, electricity, water, spare parts, and salaries and costs of temporary O&M staff and outsourced services.

85. As a single CHP plant may produce heat, co-generated electricity and condensing power, 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 and common facility as compared to an alternative, in which power and heat is generated in separate facilities. 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.

86. In this study, the cost allocation issue concerns only CHP5, which is a greenfield plant, and is among the committed capacity for the planning period. It's fixed and variable costs need to be determined for capacity planning and optimization purposes. It is not necessary to consider the capital costs of CHP4, and regarding other costs it will be a sufficiently fair premise that all costs of its operation are divided in proportions of fuel consumption, i.e. by using the heat rates calculated above.

87. The CHP cost allocation methods can be divided to economic and thermodynamic methods. 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 in a stand-alone mode, and the remainder 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. the most economical way of producing the same amount of heat in HOBs, and allocate the balance of costs to electricity.

88. Without going further in comparing various cost allocation methods, this study chooses to apply the so called benefit distribution method. This method is based on dividing 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 as the CHP plant. Once the total cost is allocated to heat and electricity, the allocation of fixed costs is done by extracting the variable costs by applying the heat rates calculated above, which are based on the physical, thermodynamical reality of the plant. The underlying assumption is therefore that the variable costs are proportional to the coal consumption.

89. It is therefore the first task to establish the total costs of coal fired HOB(s) capable of delivering 587 MW of heat (505 Gcal/h), and a coal fired condensing power plant of 450 MW capacity. The screening study performed during the first phase of this study provides estimates for the capital costs of such plants. The HOB alternative would likely be composed of several coal fired units. Instead of them being steam boilers, the likely alternative would be coal fired hot water boiler, which though needs to operate at a high pressure level due to high temperature of the water of over 120°C.

90. Regarding the variable costs of the 'alternatives', it is necessary to establish the estimates for the annual energy production. This information is retrieved from the Feasibility Study of CHP5 project, which reports annual energy generation of CHP5 simply based on 5,000 operating hours. For Phase I the resulting in annual electricity generation of 2,025 GWh, net (2,250 GWh, gross), and heat production of 1,600 GWh.

91. It is furthermore necessary to estimate the division of co-generated electricity and condensing power. The co-generated power can be derived on basis of heat using the estimated power-to-heat ratio, and the balance of electricity generation is considered as condensing power. The allocation of fixed costs of electricity generation is done in proportions to annual energy ouput of co-generation and condensing power.

92. The following table summarizes all assumptions and gives the resulting cost allocation. The table also reveals the overall benefit of having a CHP plant instead of having electricity generated in condensing power plants and heat in HOBs. In Mongolian conditions, the benefit of CHP is not as substantial as it is in other markets. One of the key reasons is the low price of coal. Consequently the high variable cost of condensing power as compared to co-generation has lesser value in Mongolia. Due to low cost of coal, the variable operating costs have reduced role in the overall cost structure. The fixed costs dominate in the cost structure accounting for 78% of all costs of a CHP plant.

Table IV-10: Cost Allocation of CHP5

	Unit	Condensing Power Plant	HOBs	CHP5
Electrical capacity	MW	450	-	450
Heat capacity	MW	-	587	587
Annual net electricity generation	GWh	2025	-	2025
Power-to-Heat ratio	MWe/MWth	-	-	0,47
- co-generation	GWh	-	-	752
- condensing power	GWh	2025	-	1273
Annual heat production	GWh	-	1600	1600
Cost of coal	$/ton	13	13	13
Cost of coal	$/MWh	3,66	3,66	3,66
Heat rate for district heat	MWf/MW	-	1,17	1,19
Heat rate of co-generation	MWf/MW	-	-	1,19
Heat rate of condensing power	MWf/MW	2,65	-	2,69
Fuel cost	$	19 666 845	6 860 719	22 807 677
Other operating cost	$	6 399 000	2 560 000	6 480 000
Total variable cost	$	26 065 845	9 420 719	29 287 677
Capital cost	$/kW	1 260	350	1 700
Capital cost	$	567 000 000	205 450 000	765 000 000
Annualized capital cost (10%)	$	60 146 934	21 793 982	81 150 625
Fixed operational cost	$	17 010 000	3 081 750	22 950 000
Total fixed cost	$	77 156 934	24 875 732	104 100 625
Total cost per annum	$	103 222 779	34 296 451	133 388 301
Allocating total cost of CHP5	$	(a)	(b)	
Electricity	$		a / (a + b) =	100 122 079
Heat	$		b / (a + b) =	33 266 223
Electricity variable cost	$	Allocation is based on fuel consumption derived with heat rates		20 327 128
- co-generation	$			4 211 458
- condensing power	$			16 115 670
Heat variable cost	$			8 960 549
Total variable cost				29 287 677
Electricity fixed cost	$	Allocation for electricity between co-generated and condensing power is based on annual energy produced		79 794 951
- co-generation	$			29 632 495
- condensing power	$			50 162 456
Heat fixed cost	$			24 305 674
Total fixed cost	$			104 100 625
Total cost per annum	$			133 388 301
Electricity overall cost per unit	$/MWh	50,97		49,44
Co-generation	$/MWh			45,01
Condensing power	$/MWh	50,97		52,06
Heat overall cost per unit	$/MWh		21,44	20,79

P. UB Heat Demand & Production

93. A UB heat demand forecast has been prepared. The methodology and approach has been explained in Volume IV. The heat forecast (sent-out basis) is repeated here for convenience.

Table IV-11: UB Heat Forecast (Sent-Out Basis)

	Low			Medium			High		
	kGcal	Gcal/h	CAGR	kGcal	Gcal/h	CAGR	kGcal	Gcal/h	CAGR
2003	3,920	1,151		3,920	1,151		3,920	1,151	
2004	4,208	1,235	7.3%	4,208	1,235	7.3%	4,208	1,235	7.3%
2005	4,349	1,277	3.4%	4,349	1,277	3.4%	4,349	1,277	3.4%
2006	4,403	1,293	1.2%	4,403	1,293	1.2%	4,403	1,293	1.2%
2007	4,458	1,309	1.2%	4,458	1,309	1.2%	4,458	1,309	1.2%
2008	4,572	1,342	2.6%	4,572	1,342	2.6%	4,572	1,342	2.6%
2009	4,696	1,379	2.7%	4,696	1,379	2.7%	4,696	1,379	2.7%
2010	4,802	1,410	2.3%	4,802	1,410	2.3%	4,802	1,410	2.3%
2011	5,081	1,492	5.8%	5,081	1,492	5.8%	5,081	1,492	5.8%
2012	5,288	1,552	4.1%	5,288	1,552	4.1%	5,288	1,552	4.1%
2013	5,369	1,576	1.5%	5,556	1,631	5.1%	5,743	1,686	8.6%
2014	5,548	1,629	3.3%	5,919	1,738	6.5%	6,290	1,847	9.5%
2015	5,732	1,683	3.3%	6,285	1,845	6.2%	6,839	2,008	8.7%
2016	5,922	1,739	3.3%	6,657	1,954	5.9%	7,392	2,170	8.1%
2017	6,119	1,797	3.3%	7,035	2,065	5.7%	7,950	2,334	7.6%
2018	6,323	1,856	3.3%	7,419	2,178	5.5%	8,515	2,500	7.1%
2019	6,533	1,918	3.3%	7,811	2,293	5.3%	9,088	2,668	6.7%
2020	6,750	1,982	3.3%	8,211	2,411	5.1%	9,671	2,839	6.4%
2021	6,974	2,048	3.3%	8,620	2,531	5.0%	10,265	3,014	6.1%
2022	7,206	2,116	3.3%	9,039	2,654	4.9%	10,871	3,192	5.9%
2023	7,446	2,186	3.3%	9,468	2,780	4.7%	11,490	3,373	5.7%
2024	7,693	2,259	3.3%	9,908	2,909	4.6%	12,122	3,559	5.5%
2025	7,949	2,334	3.3%	10,360	3,041	4.6%	12,770	3,749	5.3%
			3.3%			4.5%			5.5%

Sources: Consultants' analysis

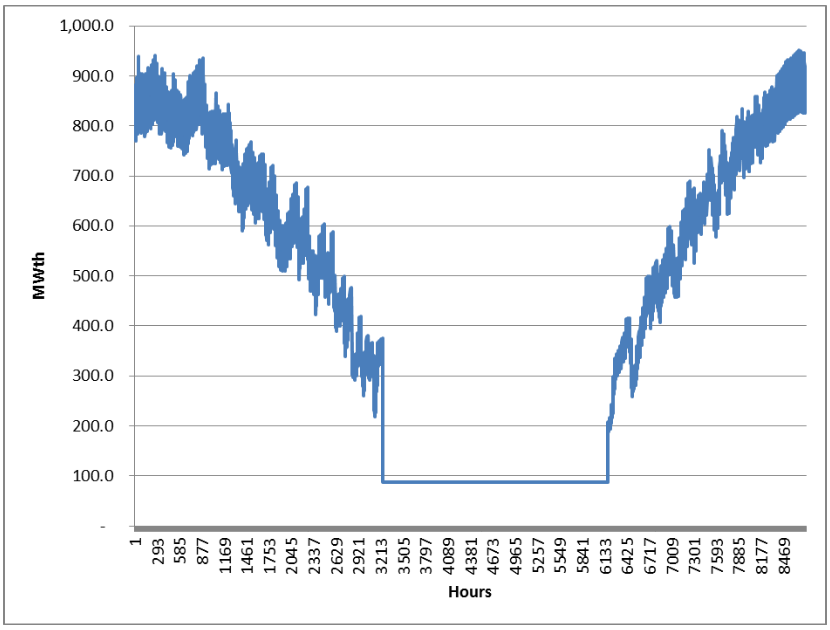
94. Heat production determines the amount of cogeneration and condensing power that can be generated by each power plant. In the case of space heat, the heat production is determined by outdoor temperature relative to a target indoor temperature, accordingly space heat is a variable quantity. Hot tap water is a relatively constant quantity throughout the year. Heat losses are also a relatively constant quantity.

95. The heat production requirement has been modelled based on temperature records, to which has been added hot tap water, steam and heat losses as constant quantities. In the latter case it has been assumed that these quantities grow throughout the planning horizon, according

to the forecast change in drivers, notably the population driver.

96. The variable and constant heat demand can be displayed as a load duration curve for each year of the planning horizon.

Figure IV-12: Total Heat Production – CHP4 – Year 2013



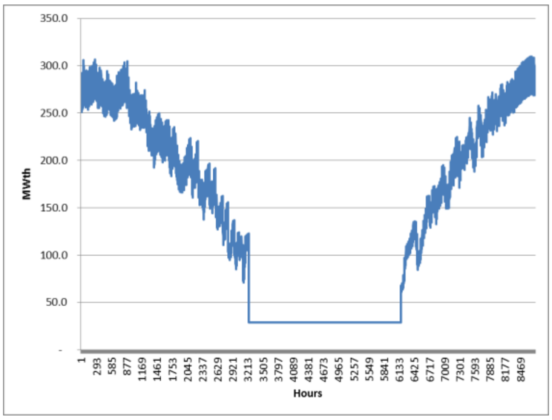
Sources: Consultants' analysis

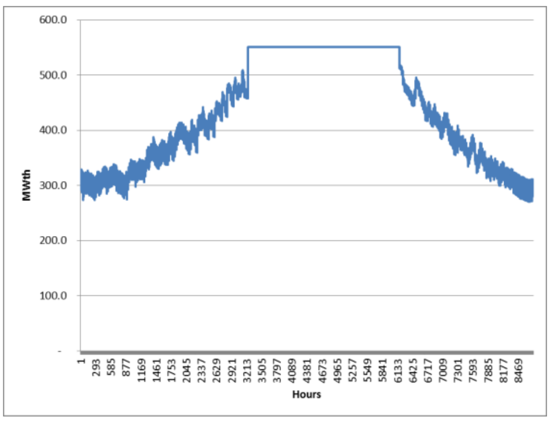
97. The 'must run' cogeneration power and the net available condensing power has been determined according to the 'turbine' curves of each thermal power plant. In the interconnected CES, the available power has been determined separately for CHP2, CHP3, CHP4, Darkhan, Erdenet CHPs and for the future CHP5.

98. Cogeneration power is highest in the winter months, November to February, and lowest in the summer period when the CHPs produce inefficient condensing power. It should be noted that the summer heat and power production reduces the average annual efficiency of the CHPs. The efficiency in the winter months is closer to typical CHP efficiencies observed in other countries.

99. The relationship between the 'available' cogeneration and condensing power is shown in the following charts, to the left and right respectively:-

Figure IV-13: CHP4 – Year 2013





Sources: Consultants' analysis

Q. UB City Heat Capacity Expansion

100. Two heat capacity expansion scenarios are envisaged.

101. Scenario 1 is based on a CHP expansion strategy using standard blocks of capacity of 168 Gcal / hour.

102. The modelled heat capacity expansion is shown in Table IV-14.

Table IV-14: Scenario 1 – Capacity Expansion Plan

	Forecast Deficit	New Capacity	Avail Capacity	New Deficit	Reserve Margin	
	Gcal/hr	Gcal/hr	Gcal/hr	Gcal/hr	%	
2013	9	-	1,585	9	1%	-
2014	(44)	-	1,585	(44)	-3%	-
2015	(98)	300	1,885	202	12%	+HOB300
2016	(154)	180	2,065	326	19%	+PP#4 ext180
2017	(212)	-	2,065	268	15%	-
2018	(271)	336	2,401	545	29%	+CHPX336
2019	(333)	-	2,401	483	25%	-
2020	(397)	-	2,401	419	21%	-
2021	(463)	168	2,569	521	25%	+CHPX168
2022	(531)	-	2,569	453	21%	-
2023	(601)	168	2,737	551	25%	+CHPX168
2024	(674)	-	2,737	478	21%	-
2025	(749)	168	2,905	571	24%	+CHPX168

Sources: Consultants' analysis

103. Scenario 2 is based on a large Heat Only Boiler (HOB) strategy.

104. The modelled heat capacity expansion for Scenario 2 is shown in the following table:-

Table IV-15: Scenario 2 – Capacity Expansion Plan

	Forecast Deficit	New Capacity	Avail Capacity	New Deficit	Reserve Margin	
	Gcal/hr	Gcal/hr	Gcal/hr	Gcal/hr	%	
2013	9	-	1,585	9	1%	-
2014	(44)	-	1,585	(44)	-3%	-
2015	(98)	300	1,885	202	12%	+HOB300
2016	(154)	180	2,065	326	19%	+PP#4 ext180
2017	(212)	-	2,065	268	15%	-
2018	(271)	300	2,365	509	27%	+HOB300
2019	(333)	-	2,365	447	23%	-
2020	(397)	-	2,365	383	19%	-
2021	(463)	300	2,665	617	30%	+HOB300
2022	(531)	-	2,665	549	26%	-
2023	(601)	-	2,665	479	22%	-
2024	(674)	300	2,965	706	31%	+HOB300

	Forecast Deficit	New Capacity	Avail Capacity	New Deficit	Reserve Margin	
	Gcal/hr	Gcal/hr	Gcal/hr	Gcal/hr	%	
2025	(749)	-	2,965	631	27%	-

Sources: Consultants' analysis

105. As HOBs do not produce electrical power, Scenario 2 also requires conventional coal-fired power plants to meet power demand.

R. UB Heat Allocation to Heat Plants

106. In the case of a heat production system, the CHPs and HOBs will produce the heat demanded by the Districts they supply, according to the routing of their associated heat transmission pipelines and location of heat exchangers.

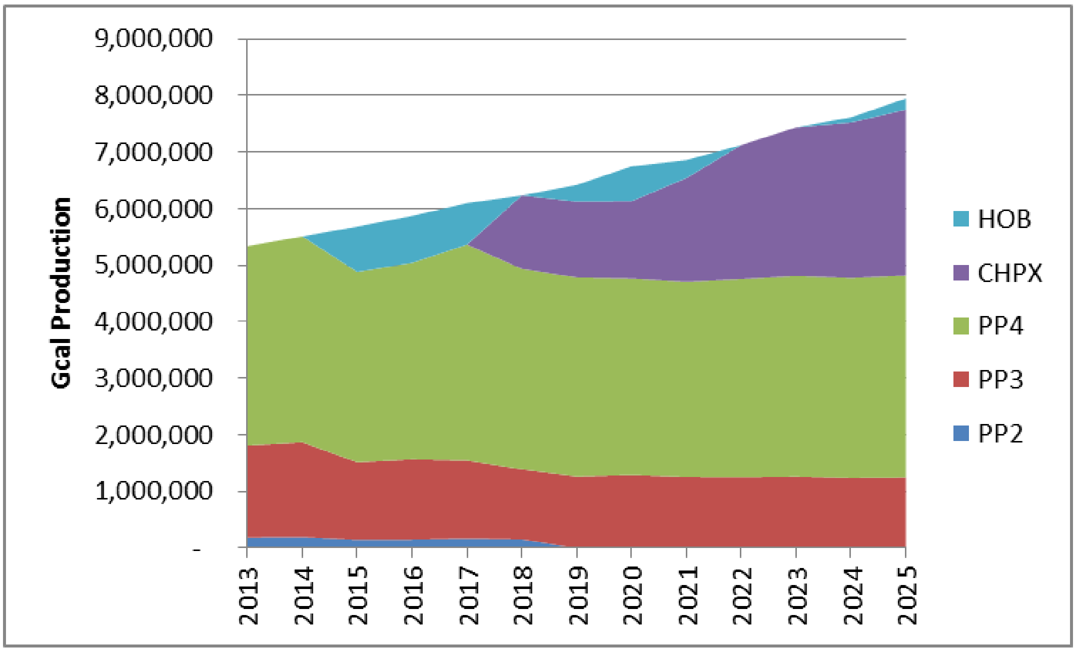
107. In UB, the heat production does not match neatly to Districts or sub-Districts. Over time the share of total heat production of each CHP and HOB will change according to CHP retirements and demographics, the latter measured in terms of new household connections. In addition hydraulic considerations limit the areas that can be served by the heat transmission network.

108. For the purpose of modelling heat capacity expansion it has been assumed that CHP2 will be retired in 2017. It is assumed that a 300GCal/h HOB (Amgalan) will be required and is committed to supply heat demand in the eastern part of UB. These assumptions are common to both scenarios.

109. The modelled heat production is provided in detail in Appendix A.

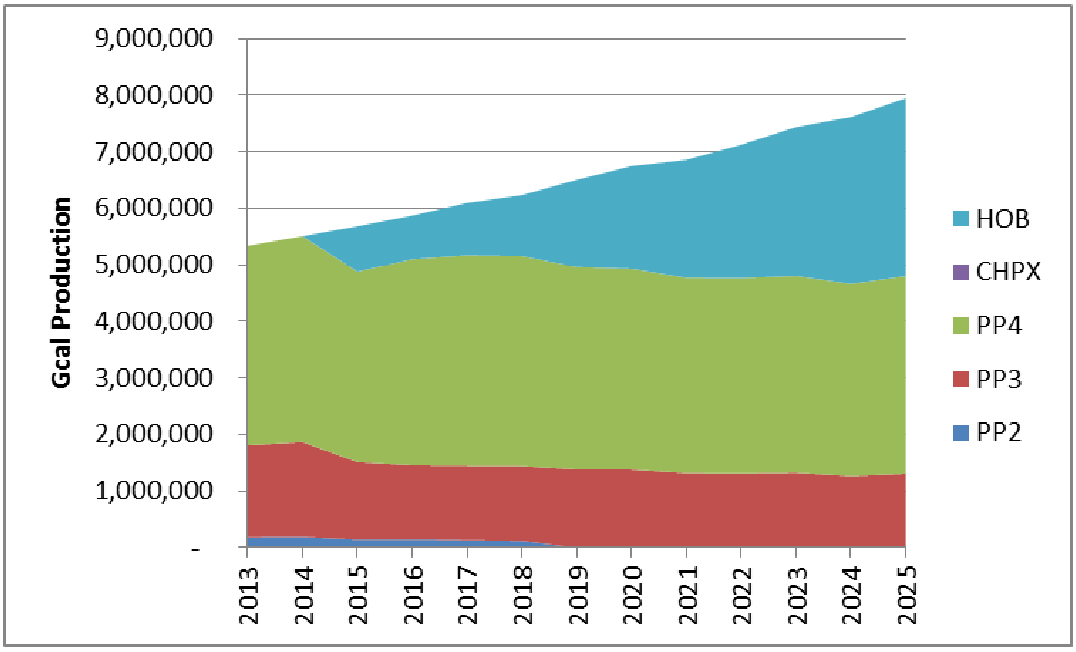
110. The following charts provide the heat production assumptions for Scenarios 1 and 2. The detailed report includes the production assumptions by District.

Figure IV-16: Scenario 1 – Modelled Heat Allocation



Sources: Consultants' analysis

Figure IV-17: Scenario 2 – Modelled Heat Allocation



Sources: Consultants' analysis

S. UB District Heating Network

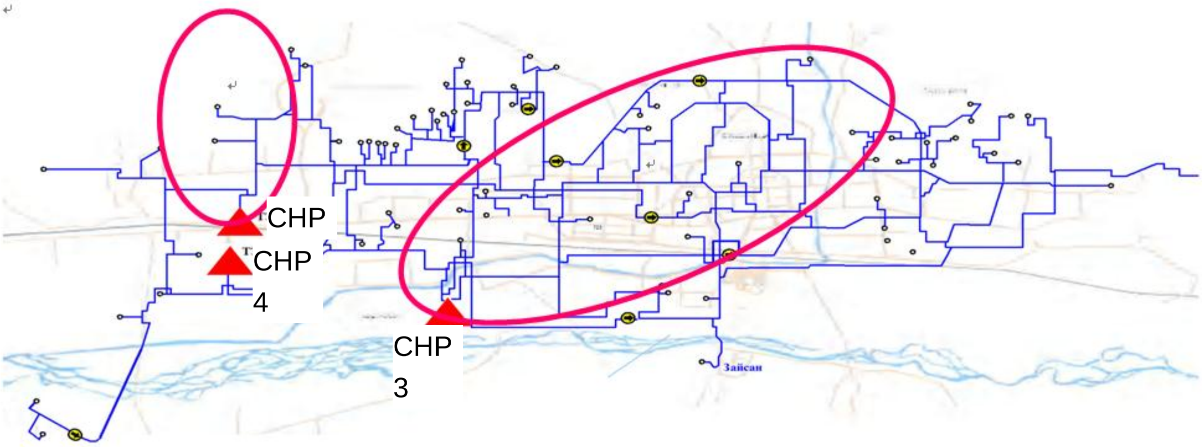
111. The UB District Heating Network must expand to accommodate the increased heat production and transmission.

112. CHP2 and CHP4 are located in the west edge of the urban area of UB, and CHP3 is positioned in south part of the middle urban area. CHP2 covers the west parts of UB as circled by the small ellipse in Figure 1.1 while CHP3 covers the middle urban area as circled by the big ellipse in Figure 1.1, and the remaining network is connected with CHP4. The existing CHPs are located in the west part of UB and the maximum distance between the heat source and customers reaches up to 25 km, and hence the hydraulic balance of the heating system is not ideal. Residents of the far eastern part of the city cannot be served well by the current heating system as they are too far from the heat sources.

113. The UB district heating system uses an indirect connection, employing heat exchange stations between the heat source and consumers. The system has two closed loops – a primary loop and a secondary loop. The loops work independently of each other. The operating temperatures of the supply and return water of the primary heating network is 135°C and 70°C, respectively. The higher temperature difference between the supply and return allow a smaller transmission pipe size, thereby reducing the investment and heat loss in the heat transmission system. The working temperatures of supply and return water of the secondary heating network is 90°C and 65°C, respectively.

114. The determination of the available capacity of the UB District Heating Network begins with an assessment of installed capacity. The available capacity takes into account the reliability of the plant – operating performance statistics indicate historical trends whereas reliability engineering techniques are appropriate for determining future reliability performance and therefore expected available capacity.

Figure IV-18: Heating Coverage of Existing CHP Plants

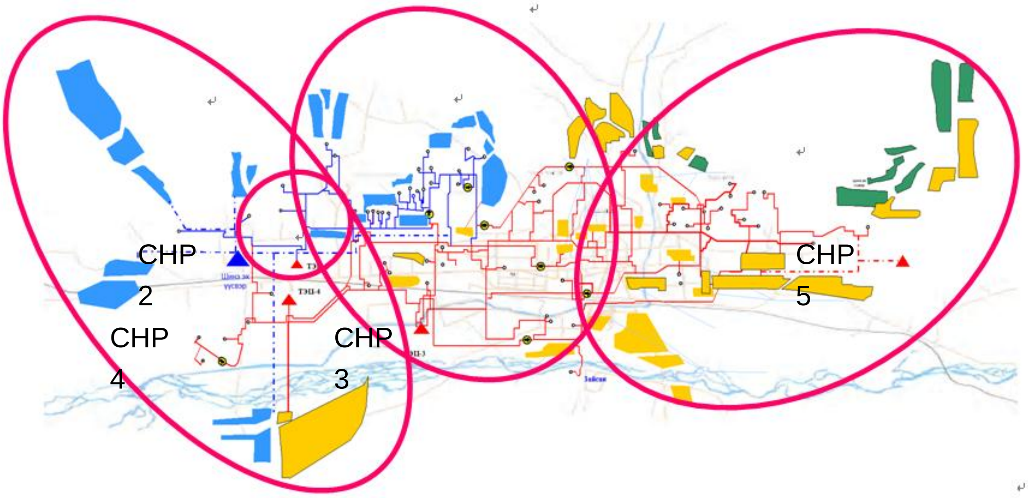


Note: Other than areas circled by the two ellipses, the remaining area is covered by CHP4.

Source: District Heating Company of UB

115. From a technical point of view, the most preferable site for the proposed CHP5 should be at the eastern edge of UB. The existing CHPs can be disconnected from the existing eastern heating area, and connected to the northern and western new development areas. Meanwhile, CHP5 will take over the eastern area, as shown.

Figure IV-19: Proposed Coverage of the CHP Plants



Source: District Heating Company of UB

116. In this case, it will substantially decrease the maximum distance between the heat source and customers. The hydraulic balance of the heating system will be significantly improved and the electricity consumptions of circulating pumps and/or relay pumps will be reduced as well. Thus, energy efficiency will be improved with this arrangement.

117. The District Heating transmission network would need to be strengthened.

Figure IV-20: UB District Heating Network Investment

Strengthening	Timing	Amount $m
Construct new Ø1200 pipe line for heating to increase conductivity of main line No 10 from TPP-4	2012-2014	5.8
Construct new main pipe line for heating from TPP-4 to Yarmag direction	2013-2015	7.7
Improve reliability heat supply for Zaisan consumers, extend capacity of heat pipe lines, construct substation and 2 booster pumps	2013-2014	3.9
Extend capacity of 5a, 10в,10г,10д heat mail pipe lines from TPP-3	2013-2015	23.1
Extend capacity of district heating system in UB.	2013-2014	11.5
		52.0

Sources: Consultants' analysis

T. Sheuren HPP Technical Operating Regime

118. For the purposed of economic dispatch modelling, the operating regime of the Sheuren hydropower plant was modelled in two ways 1) as a baseload plant, that is stored water released on a constant flow basis throughout the year, allowing for a minimum flow in winter to prevent icing problems, and2) as a peaking plant, whereby the plant is despatched to meet peak load in summer time when the reservoir is full, and when the CHP plants are operating in the relatively inefficient condensing mode.

119. The production profiles for each case as shown in the following tables for a 390MW plant:-

Figure IV-21: Sheuren HPP Base-Load Production Profile

MW - hour must run	MW - hour compete
0.0	169.9
0.0	169.9
0.0	169.9
0.0	169.9

MW - hour must run	MW - hour compete
0.0	169.9
0.0	169.9
0.0	169.9
0.0	169.9
0.0	169.9
0.0	169.9
0.0	169.9
0.0	169.9
0.0	2039.0
Total	2039.0

Figure IV-22: Sheuren HPP Peak-Load Production Profile

MW - hour must run	MW - hour compete
83.9	15.6
92.9	15.6
83.9	18.8
86.7	54.1
83.9	153.2
86.7	135.3
83.9	206.8
83.9	171.6
86.7	103.4
83.9	77.4
86.7	39.2
83.9	21.5
1026.6	1012.4
Total	2039.0

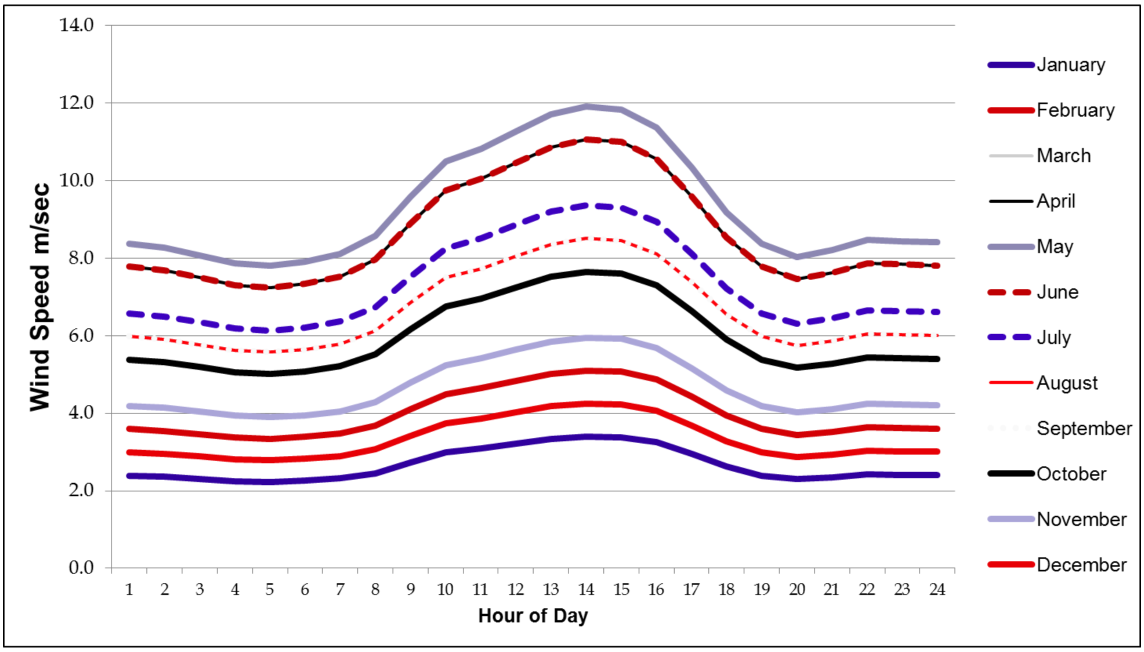
U. Windfarm Operating Regime

120. Windfarm operation is a function of wind speeds and relevant wind turbine generator (WTG) production curves. For the purpose of modelling, a 200MW windfarm comprising 67 x 3MW WTG's was taken as the most economical large scale farm, bearing in mind the Government's ambition to be a large scale wind producer and exporter. In developing the expansion plan for CES, windfarm block of 50MW were assumed, and production was scaled accordingly.

121. The diurnal wind speed profiles were developed from the Mongolian wind atlas, as shown in

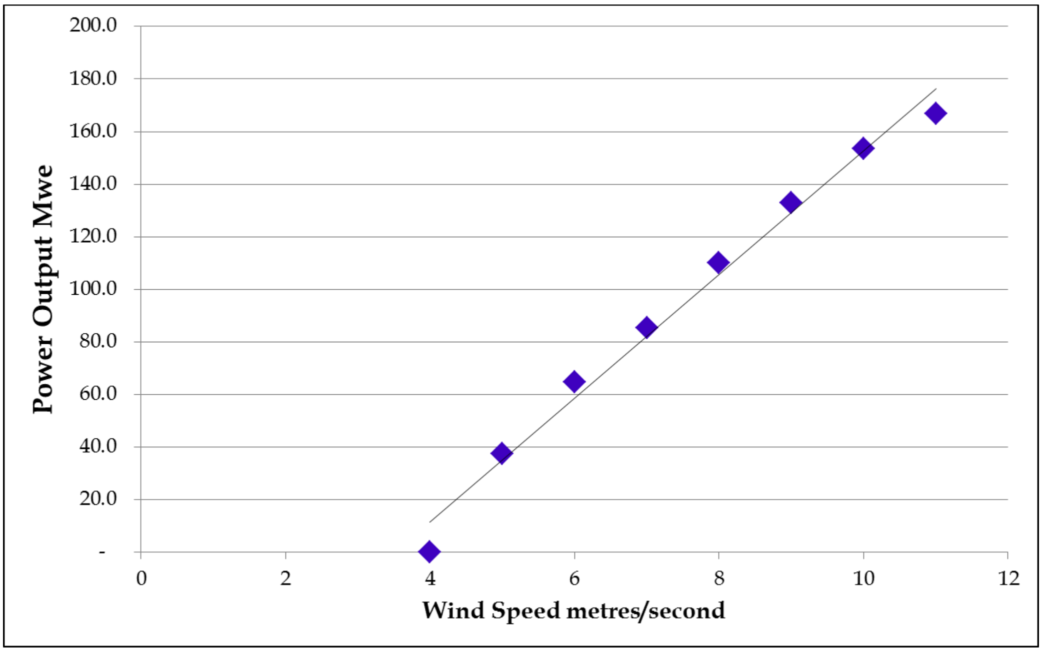
Figure IV-23.

Figure IV-23: Mongolian Wind Speeds (vicinity of UB)



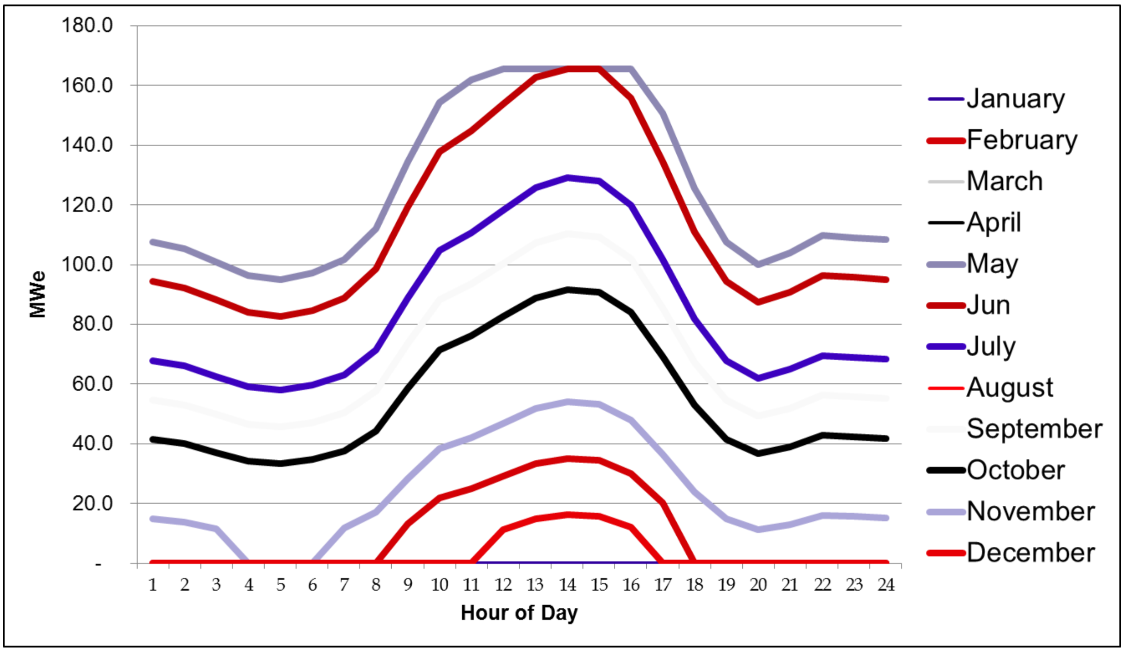
122. An annual energy production versus wind speed characteristic for a 3MW wind turbine (typical manufacturers specification) was used to develop the relationship between power output of the windfarm and wind speed:-

Figure IV-24: Power Output (MWe) vs. Wind Speed



123. And finally an hourly power production profile was developed for the purpose of economic dispatch modelling:-

Figure IV-25: WTG Annual Energy Production vs. Wind Speed



124. The production profile yields a capacity factor of 30%.

V. Solar PV Operating Regime

125. A similar consideration was given to grid-connected solar PV. A capacity of 10MW was assumed, and production profiles developed based on sunlight hours recorded in Mongolia.

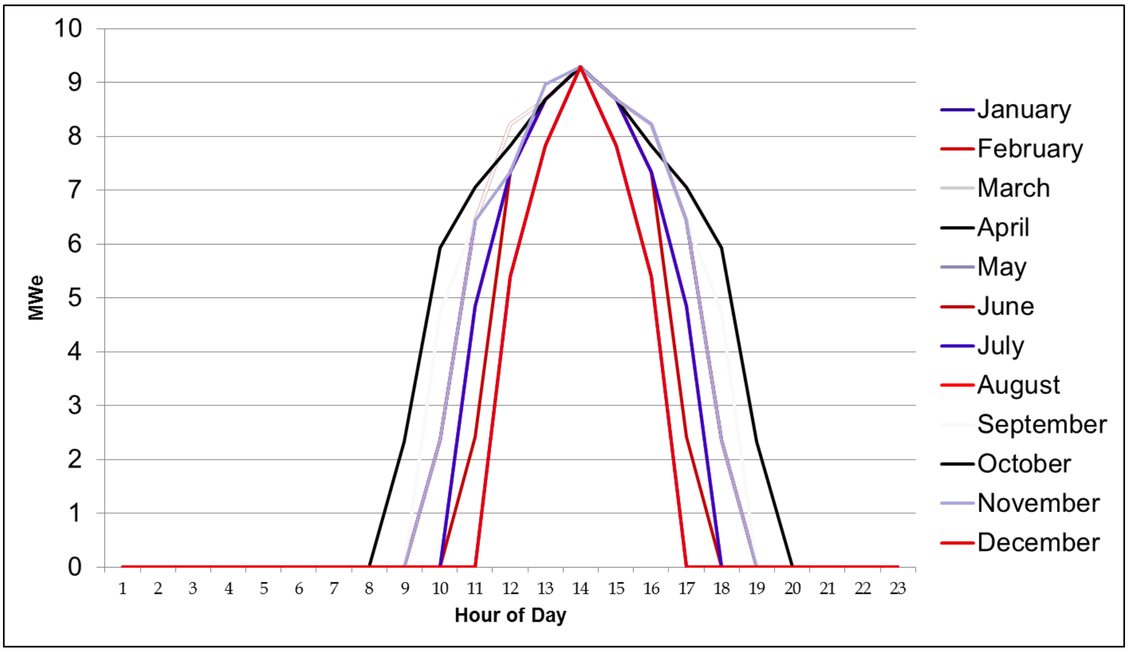
Figure IV-26: Mongolia –Sunshine Hours per day

Hour	7	8	9	10	11	12	13	14	15	16	17
Jan				1	1	1	1	1			
Feb			1	1	1	1	1	1	1		
Mar			1	1	1	1	1	1	1		
Apr		0.5	1	1	1	1	1	1	1	0.5	
May			1	1	1	1	1	1	1		
Jun			0.5	1	1	1	1	1	0.5		
Jul			1	1	1	1	1	1	1		
Aug		0.5	1	1	1	1	1	1	1	0.5	
Sep		1	1	1	1	1	1	1	1	1	

Oct	0.5	1	1	1	1	1	1	1	1	1	0.5
Nov		0.5	1	1	1	1	1	1	1	0.5	
Dec				1	1	1	1	1			

126. A similar consideration was given to grid-connected solar PV. A capacity of 10MW was assumed, and production profiles developed based on sunlight hours recorded in Mongolia.

Figure IV-27: Solar Production Profile –10MW Rated Capacity



127. The capacity factor, based on these production profiles is 24%. Whilst in theory solar PV could be despatched, the screening curve analysis showed that at the present time grid-connected solar PV is uneconomic compared to wind, and so solar PV was omitted in favour of wind in the expansion scenarios developed for the CES.

W. Electricity Demand Growth Scenarios

128. Electricity load forecasts are based on the following scenarios:-

1. A Low or ‘organic’ forecast – this forecast includes growth associated with existing domestic, commercial and industrial consumers. The growth has been modelled using an end-use model applied on individual Aimag and Energy Region basis.
2. A Medium or ‘bear’ industrial forecast – this forecast includes an industrial growth forecast added to the organic forecast; it is assumed that industrial development takes place over a 30 year period (from 2013) centred in three industrial zones – Northern zone (Erdenet / Darkhan), Central zone (Choir / Sainshand) and Southern zone (Dalanzadgad / TT / OT area).
3. A High or ‘bull’ industrial forecast – this forecast assumes that the industrial development described above takes place over a 20 year period in accordance

with mineral and minerals processing expectations.

129. Load forecasts are presented as forecasts of consumer demand, not production of power plants (unless otherwise indicated). Production forecasts have also been prepared incorporating forecasts of station losses and T&D losses.

130. Total losses in the Mongolian power system are currently high, of the order of 35%. New plant will result in a reduction of losses. Production forecasts in 2030 can be estimated by adding 25 - 30%.

131. Load forecasts are based on the assumption that demand is realized when industrial facilities commence operation. This means that in the early years of the industrial zone growth forecast, demand growth is low. It will take some three to four years from today to establish major industrial facilities, e.g. an oil refinery. This explains why demand growth in the early years is forecast to be low.

132. The following electricity forecast is for the CES.

Table IV-28: CES Electricity Forecast

	Central Energy System								
	Low			Medium (Bear)			High (Bull)		
	MW	GWh	AGR MW	MW	GWh	AGR MW	MW	GWh	AGR MW
2011	640	3,243		640	3,243		640	3,243	
2012	697	3,542	8.9%	697	3,542	8.9%	697	3,542	8.9%
2013	718	3,860	3.0%	718	3,860	3.0%	718	3,860	3.0%
2014	815	4,144	13.5%	815	4,144	13.5%	815	4,144	13.5%
2015	871	4,422	6.9%	872	4,427	7.0%	873	4,435	7.2%
2016	948	4,817	8.8%	956	4,807	9.6%	966	4,864	10.6%
2017	1,010	5,131	6.5%	1,032	5,174	7.9%	1,059	5,337	9.6%
2018	1,074	5,452	6.3%	1,117	5,596	8.3%	1,169	5,913	10.4%
2019	1,124	5,704	4.6%	1,194	5,985	6.9%	1,282	6,525	9.7%
2020	1,169	5,932	4.0%	1,275	6,429	6.8%	1,407	7,236	9.7%
2025	1,628	8,189	7.9%	2,016	10,416	11.6%	2,500	13,383	15.5%
2030	2,309	11,516	8.4%	3,161	16,583	11.4%	3,734	20,097	9.9%
CAGR			7.2%			8.6%			9.8%
Average MW added p.a.	88			133			163		

Sources: Consultants' analysis; AGR – annual growth rate

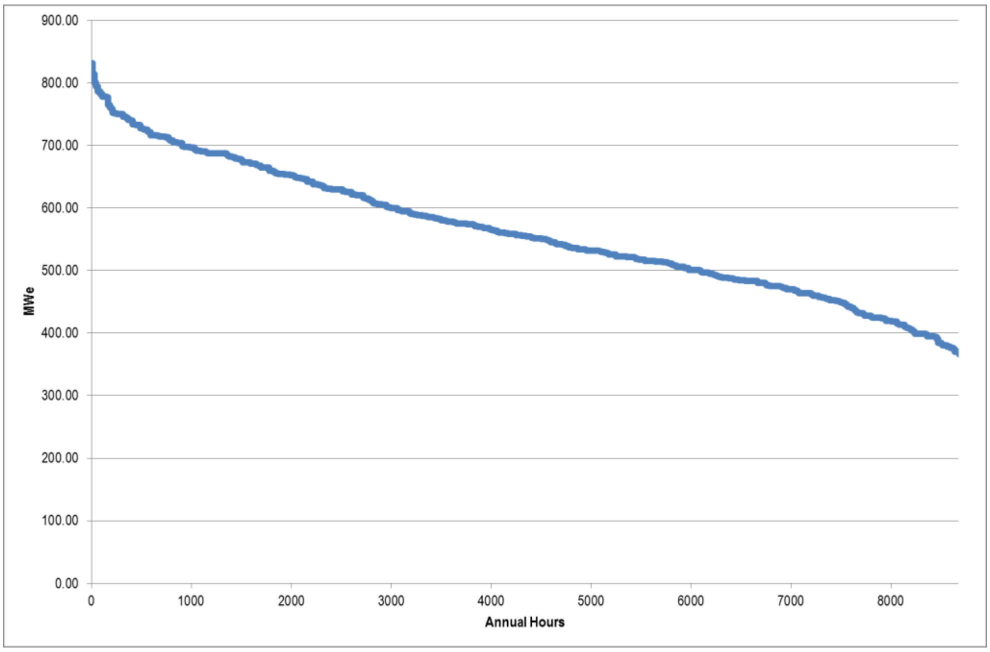
133. The long term growth rates are high by international standards, although consistent with forecasts in developing countries that are pursuing an industrialization strategy and where the industrial base is low.

134. The average MW additions for the medium growth forecasts can be understood as one 150MW block of power every one to two years for the next 20 years.

X. Economic Dispatch of Power

135. The demand forecast has been converted to a sent-out energy / demand forecast, and shaped in the form of a Load Duration Curve for each year of the planning horizon using the data provided in Figure IV-29.

Figure IV-29: CES Load Duration Curve – Year 2013 (Sent-Out basis)



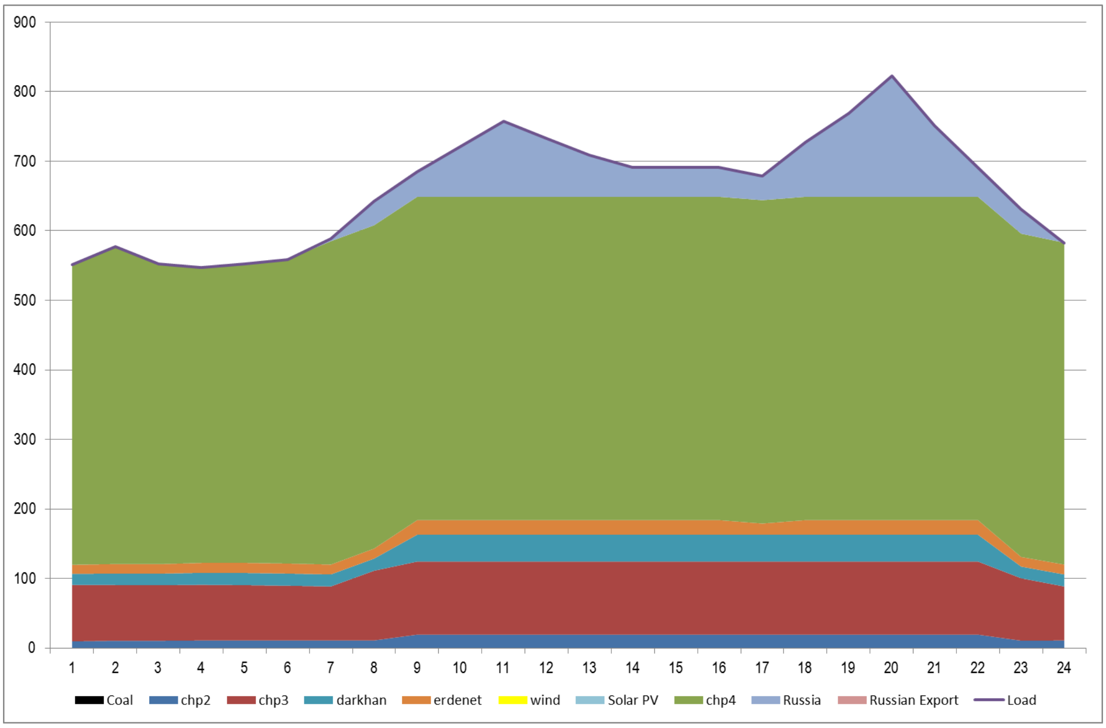
Sources: Consultants' analysis

136. The despatch simulation attempts to despatch the power plants according to available power (cogeneration and condensing), based on the optimal (lowest) operating cost. When Mongolian power is insufficient to meet demand, the balance is made up with Russian import.

137. The simulation also recognizes the technical operating regime. The regime requires that CHP4 is dispatched according to minimum and maximum heat production constraints. The minimum heat production is related to the fourth hour of daily production, representing the minimum electricity production, whereas the maximum is related to the 20th hour of daily production, as the hour of peak load. If the minimum electrical output is less than the capacity available when operating a single boiler, then export takes place. Import is economic if the start-up of a boiler that would operate for less than a couple of hours around the peak can be avoided.

138. The simulation produces monthly production forecasts, which are aggregated into an overall forecast Load Duration Curve that shows the power plant contributions to total energy and demand. The dispatch simulation result for December 2012 is shown in Figure IV-30. Note that the actual dispatch may not have been in accordance with this simulation.

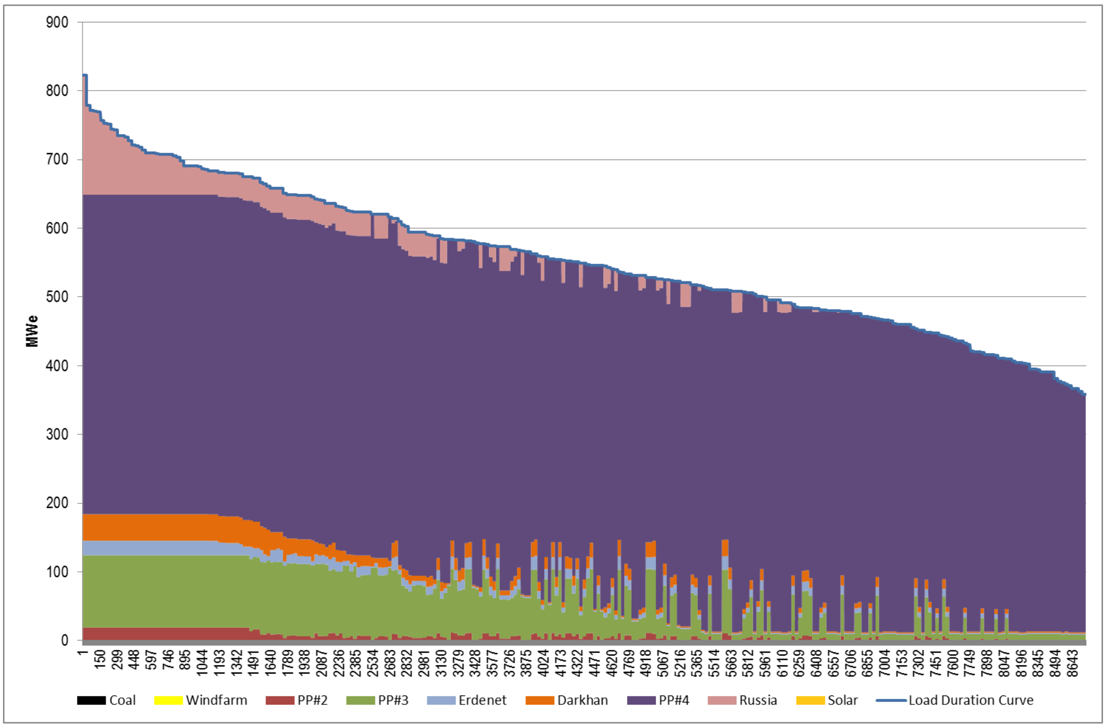
Figure IV-30: Economic Despatch – Dec 2012



Sources: Consultants' analysis

139. The corresponding annual economic dispatch curve is shown in Figure IV-31. The economic dispatch curves for all years are provided as Appendix D.

Figure IV-31: CES Economic Dispatch Curve – Year 2012



Sources: Consultants' analysis

V. CES ELECTRICITY SUPPLY EXPANSION

Y. Expansion Plan Scenarios

140. For the purposes of this Energy Masterplan, it is assumed that the Government will continue with the current build program that includes the Amgalan HOB, the CHP5 power plant, upgrading of PP#4, life extension of PP#3 and extension of the Darkhan power plant. Furthermore it is assumed that the Newcom 50MW wind farm is committed. For the purpose of masterplan development no other power plants have been considered to be committed whether licensed or not.

141. Primary and secondary energy resource considerations were taken into account for expansion modelling purposes in accordance with Volume V.

142. Guided by the technology cost screening, a number of scenarios have been contrived in order to incorporate policy objectives and associated risks into the expansion planning process. The rationale and results from these scenarios are discussed below. The scenarios accommodate policy considerations (distinct from a least-cost reference or a simple supply-demand balance plan).

143. The scenarios are summarized as follows (details are provided in Appendix D – separate volume).

1. Reference Plan

144. A reference plan provides a base comparator against which other plans can be compared.

145. Two reference plans are considered, consistent with the heat supply allocation described in Section 5 above:-

(a) Heat Supply based on CHP Technology - CHP5 is taken to be the core technology for new heat supply.

(b) Heat Supply based on large HOB Strategy - In this scenario condensing coal-fired power plants are included since HOBs do not produce electricity.

2. Greenhouse Gas Emission Targets

146. Given the heightened focus on climate change and the need to address greenhouse gas emissions, of which CO2 is a particular concern for the electricity industry, the Government has established renewable energy targets as a percentage of total energy production. Renewable energy scenarios are based on this policy.

(a) Mandating Target Production of Renewable Energy on Total

Scenarios have been devised targeting average 15%, 20% and 25% of renewable energy production between 2020 and 2025.

(b) Introducing a Carbon Tax

A carbon tax has been modelled. The tax has been modelled at USD$3 per ton of CO2. The carbon tax is modelled as part of the costs of the generators, representing a shadow price for emissions. There is no particular rationale for the choice of carbon tax, the figure has been chosen to assess the impact relative to the reference plan.

(c) Least CO2

A least CO2 scenario has been modelled. This scenario excludes coal-fired condensing power to the extent possible without unduly compromising the reserve margin.

3. Diversification of Resources

147. During 2012 close to 100% of Mongolia's total production came from coal-fired sources. Given the heavy reliance on coal as a source of electricity, Government has seen a need to move to alternatives from an environmental perspective. In countries where coal markets have been liberalized, diversification is also a security of supply imperative that can be mitigated to some extent by diversification.

148. Given that Mongolia has limited opportunity to diversify, to some extent the introduction of hydropower and wind power modelled under the Greenhouse Gas Policy scenario automatically leads to diversification. Accordingly scenarios specifically aimed at diversification have not been modelled, but each scenario is assessed against the 'diversification' of the energy mix that that particular scenario brings to the energy mix.

4. Independent Power Producers

149. The policy direction from the Government is to encourage private participation in the energy sector. The REFIT program encourages private sector participation and the MoE has granted a number of licences to private sector proponents of power plants, and a PPP / BOT approach has been adopted for CHP5. However, there is no specific target set for the percentage of new capacity to be provided or operated by private generators.

150. Three scenarios have been developed to model the involvement of the private sector through a proactive private sector program

(a) Coal Plant Advanced to 2018

A 600MW coal plant is encouraged to be built in advance of load growth curve to take advantage of the current interest of the private sector in coal-fired power generation.

(b) Coal Plant Advanced to 2020

The same scenario as (a) but a 600MW coal plant capacity is advanced to 2020.

(c) Wind Farm Expansion

Under this scenario wind farm capacity is accepted at a rate of 200MW per annum irrespective of demand growth considerations; whilst this leads to a high Mongolian system full reserve margin, the cost difference is offset by the benefits of clean energy and private sector ownership may be less concentrated as more investors can raise finance for investment packages of a modest size.

5. Considerations Regarding Limitations on Imports

151. In recent years imports have grown, although not to a significant portion of the total electricity production in Mongolia. The country is dependent on Russia for the load balancing function in the CES and this dependency represents a risk, albeit an apparently small risk. Nevertheless security of supply considerations point to the need for Mongolia to develop the capability to take over the load balancing function and to depend on Russia only for emergency support, to cover for example black start, dry hydropower years, or catastrophic power plant contingencies.

152. In the past coal plants were operated strictly as base load units. Following market liberalization of coal plants in OECD countries it was soon demonstrated that coal plants could be operated in a highly flexible manner. Modern plants are more capable of following load fluctuations closely. Accordingly the operating regime used in the simulations of the Mongolian power system has assumed minimal import from Russia once condensing coal capacity reaches a

capacity of 450MW.

6. Considerations Regarding Technology Risks

153. Technologies involve different levels or risk. One of the key risks relates to the learning curve associated with the use of a new technology in a new environment. An obvious example is the introduction of large wind farms in Mongolia. Such risks would be further elevated if two technologies were to be introduced at the same time, e.g. wind farms and a large hydropower plant.

154. The following table provides a risk assessment of project risk factors including the scores associated with various technology choices, where the scoring is related to the use of the technology in Mongolia.

Table V-1: Technology Risk Factors (Project Risk Factors)

	FBC	Wind	Small Hydro	Large Hydro	Solar PV Farm	CSP	CHP	HOB
Confidence in Cost Assumptions	2	1	1	3	2	3	0	1
Confidence in Technology	1	2	0	0	3	3	0	1
Confidence in Timing	1	1	1	2	0	2	3	2
Confidence in Reliability	0	3	2	2	1	1	0	0
Safety Concerns	0	0	0	0	0	0	0	2
Resource Concerns	2	1	2	2	2	2	1	1
TOTAL	6	8	6	9	8	11	4	7

Sources: Consultants' analysis

Z. Modelled Scenario Plans

155. The scenarios discussed above are summarized in the following table:-

Table V-2: Expansion Plan Scenarios

Scenario Plan	Name	Conditions
1a	Reference Plan – CHP	Least-cost; direct costs only; limited project options, Government long-term PPAs for new coal-fired condensing power plants.
1b	Reference Plan – HOB	Least-cost; direct costs only; limited project options, Government long-term PPAs for new coal-fired condensing power plants.
2a	Domestic emissions (Emission Target 1)	Hard constraint of average 15% renewable energy production on total
2b	Domestic emissions (Emission Target 2)	Hard constraint of average 15% renewable energy production on total
2c	Domestic emissions	Renewable Energy Policy; target 20% by 2020 to 2025 on

Scenario Plan	Name	Conditions
	(Emission Target 3)	total energy; modelled as hard constraint of average 20% renewable energy production on total
2d	Carbon Tax	Alter input costs of Reference Plan to include carbon tax; carbon tax set at $3 per ton CO2.
3a	IPP alternates 1	As per Reference Plan but force in 600MW coal no later than 2018 with 100% private funding; remaining coal capacity funded by Government.
3b	IPP alternates 2	As per Reference Plan but force in 600MW coal no later than 2020; 100% private funding; remaining expansion funded by Government.
3c	IPP alternates 3	As per Reference Plan but force in 200MW wind per annum from 2020; 100% private funding; remaining expansion funded by Government.
4	Lowest CO2	Force in Egiin run-of-river hydropower plant in 2020; Force in Sheuren run-of-river hydropower plant in 2021; Allowing additional wind farms up to 400MW by 2025; Hard constraint of average 25% renewable energy production on total.

Sources: Consultants' analysis

156. Each Scenario Plan has been modelled with the objective of minimizing the direct costs of the expansion plan (including capital, fuel and operating costs) whilst observing heat production and the reserve margin requirements for heat and power. While certain constraints have been imposed, including emissions constraints for specific scenarios, these are always constraints on the cost optimization objective, i.e. dispatch of the plant during simulation is always based on the marginal operating costs. For the carbon tax scenario the shadow price of emissions was set equal to the carbon tax and entered as an input to the financial evaluation only.

157. For modelling efficiency purposes the calendar year was converted into a load duration curve with time slices representing periods of similar demand. This mechanism has been used for the expansion plan optimization. For robustness a full production optimization has been executed for every chronological calendar year from 2013 to 2025.

158. Planned outage co-ordination is not modelled since the Mongolian energy system has adequate opportunities in summer months to undertake necessary maintenance. Unplanned outages are modelled by assuming a net availability of each power plant according to age, reported performance and industry benchmarks.

AA. Results

159. The detailed optimal expansion plan for each scenario can be found in Appendix D in the form of tables summarizing the salient features of each Scenario Plan. These tables provide indications of the capacity required from each resource at the annual peak.

160. For the purposes of comparison a few indicators from the scenario plans are highlighted in Table V-3. Further discussion of each Scenario Plan is included in the application of the criteria in order to assess the Scenario Plan according to the best fit with the country's objectives.

Table V-3: Scenario Plan Comparators

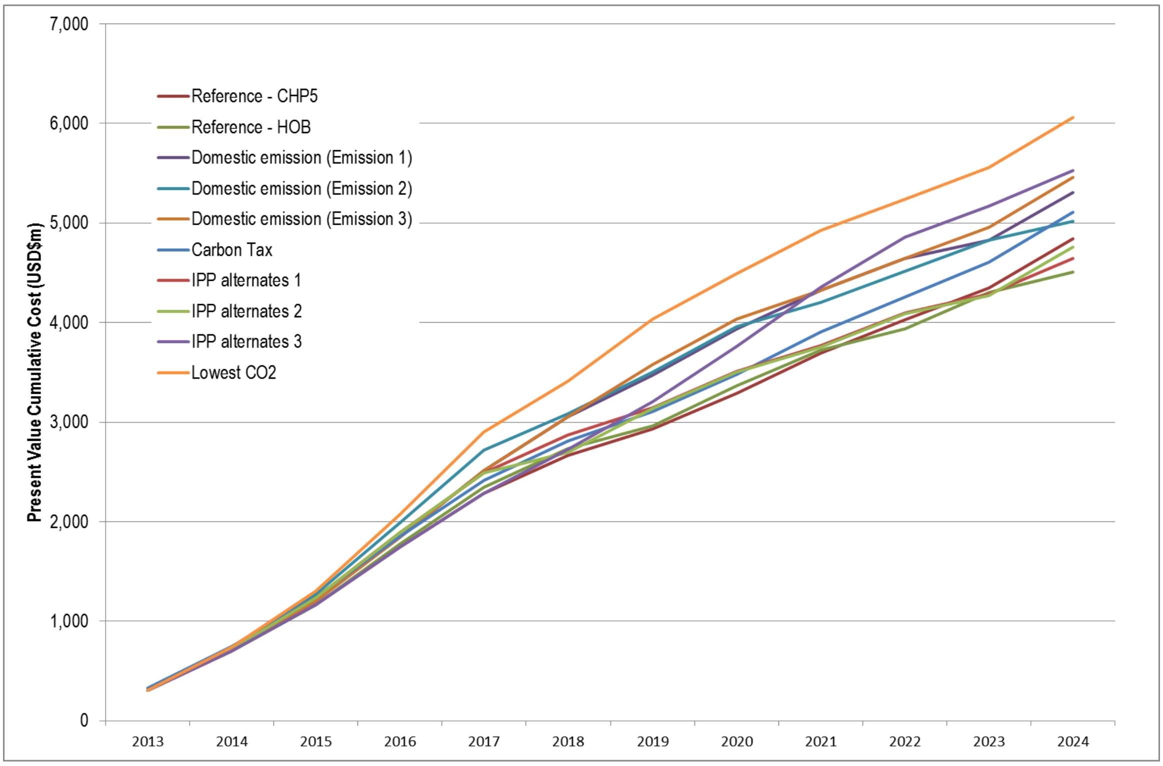
Scenario Plan	Name	Coal 1 start 450MW	Coal 2 start +150MW	Large Hydro start +390MW	Firm Renewable Capacity in 2025 MW	Firm Renewable Capacity in 2025 %
1a	Reference Plan – CHP	2018	2022	-	4.0	1.2%
1b	Reference Plan – HOB	2018	2019	-	4.0	1.2%
2a	Domestic emissions (Emission Target 1)	2019	2022	2021	150	14.9%
2b	Domestic emissions (Emission Target 2)	2018	2024	2021	170	14.9%
2c	Domestic emissions (Emission Target 3)	2019	2024	2021	170	23.6%
2d	Carbon Tax	2018	2023	-	4.0	1.2%
3a	IPP alternates 1	2018	2019	-	4	1.20%
3b	IPP alternates 2	2018	2020	-	4	1.20%
3c	IPP alternates 3	2019	2022	-	100	28.9%
4	Lowest CO2	2022	2024	2020	251	27.6%

Sources: Consultants' analysis

1. Cost of the Plan

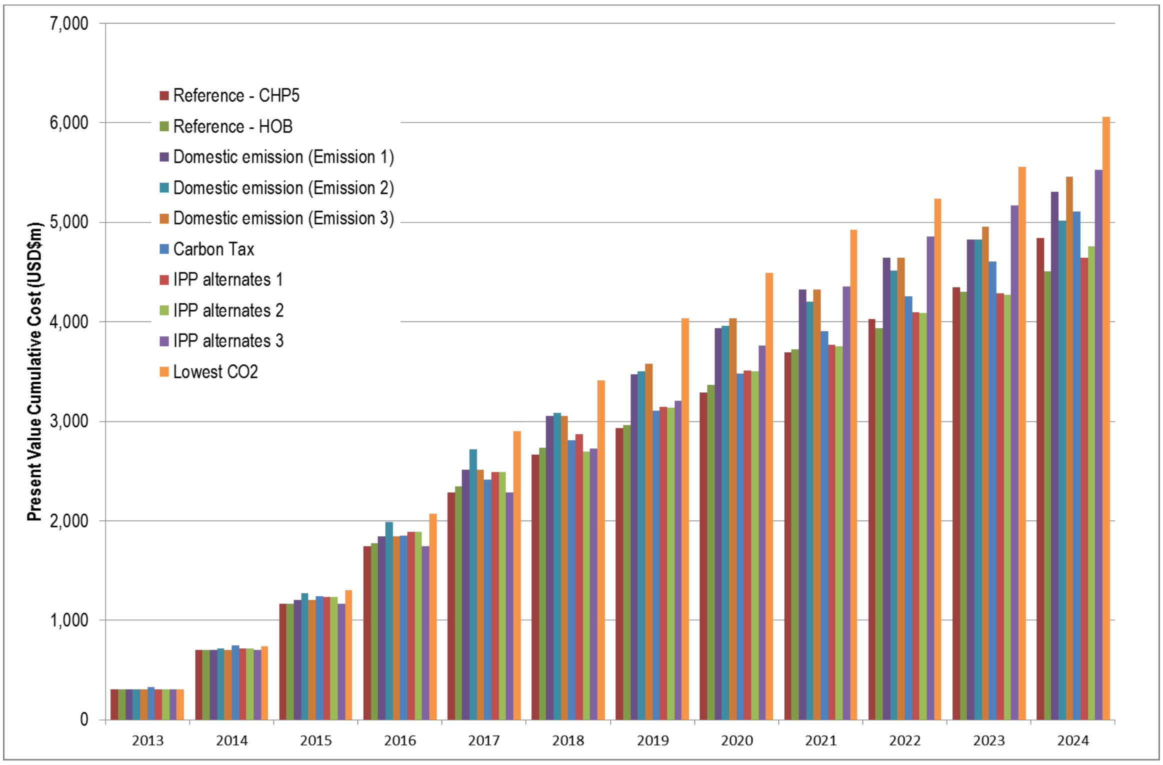
161. Figure V-4 illustrates the cumulative present value of costs associated with each plan. The costs included are the capital costs of new projects (excluding existing plant and committed plant) as well as the operating and fuel costs of all plant. Each of the plans shows a decrease in the last year of the study period due to the effect of adding back a residual capital value representing the yet-to-be value of the plant. Since all of the new plants will be continuing to produce for decades to come an appropriate comparison of the plans should include the full impact of each capacity option. Operating and fuel costs into perpetuity have not been discounted back to the final year and added to the cost of the plan. This approach tends to favour renewable energy over coal in the comparison of PV costs between plans albeit discounting reduces this effect.

Figure V-4: Present Value Cost of the Plan



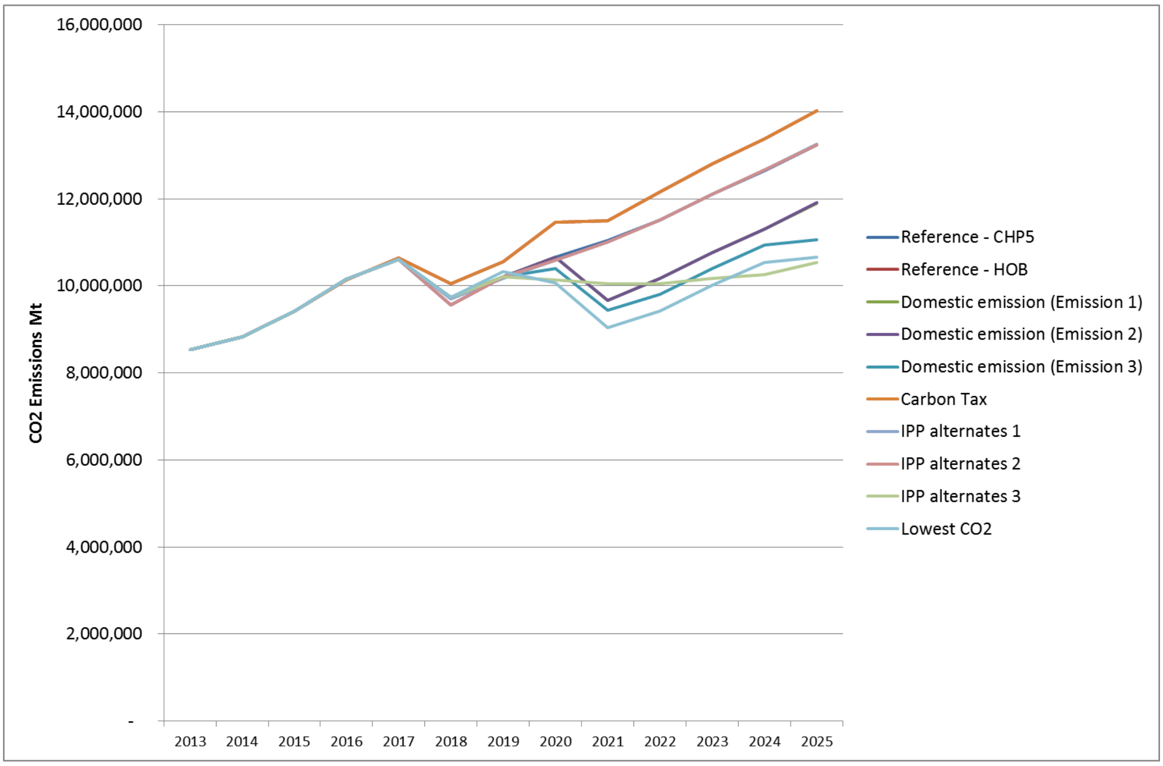
Sources: Consultants' analysis

Figure V-5: Present Value Cost of the Plan



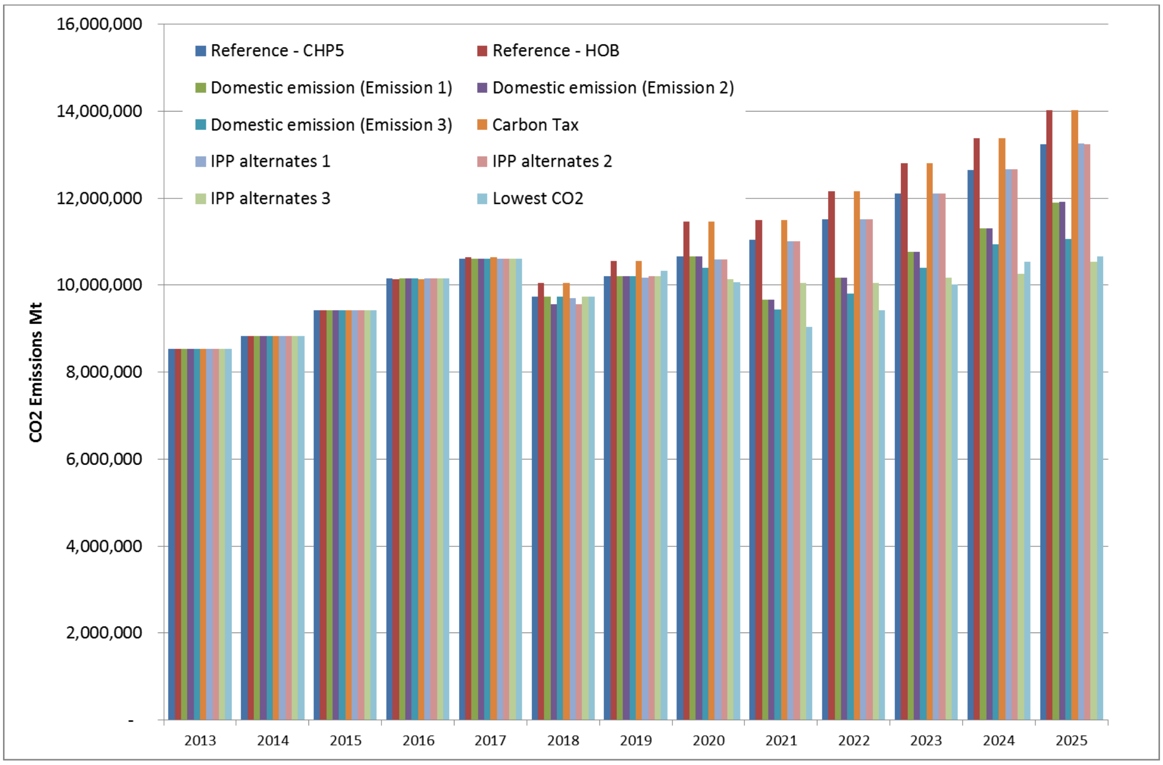
Sources: Consultants' analysis

Figure V-6: CO2 Emissions



Sources: Consultants' analysis

Figure V-7: CO2 Emissions



Sources: Consultants' analysis

2. CO2 Emissions

162. Figure V-6 shows that CO_2 emissions rise for all plans, although in the case of the lowest CO_2 plan the rise is kept very small by excluding coal-fired power plant to the extent possible commensurate with reserve margin considerations.

3. Water Consumption

163. Water consumption shows a dramatic reduction in all plan scenarios because of the impact of CHP5.

Figure V-8: Water Consumption by Scenario Plan

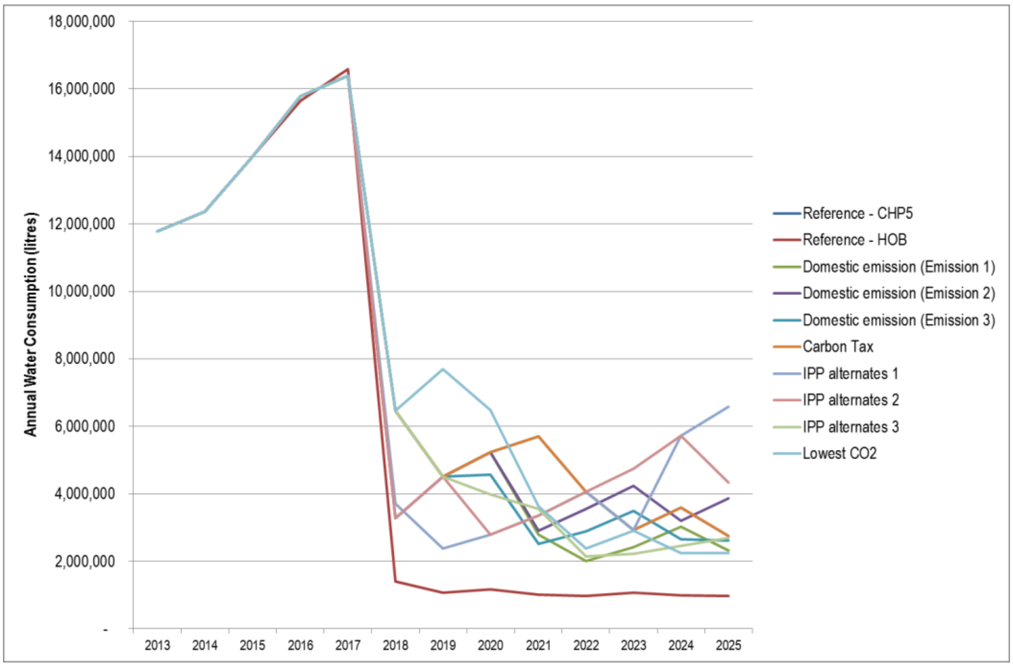
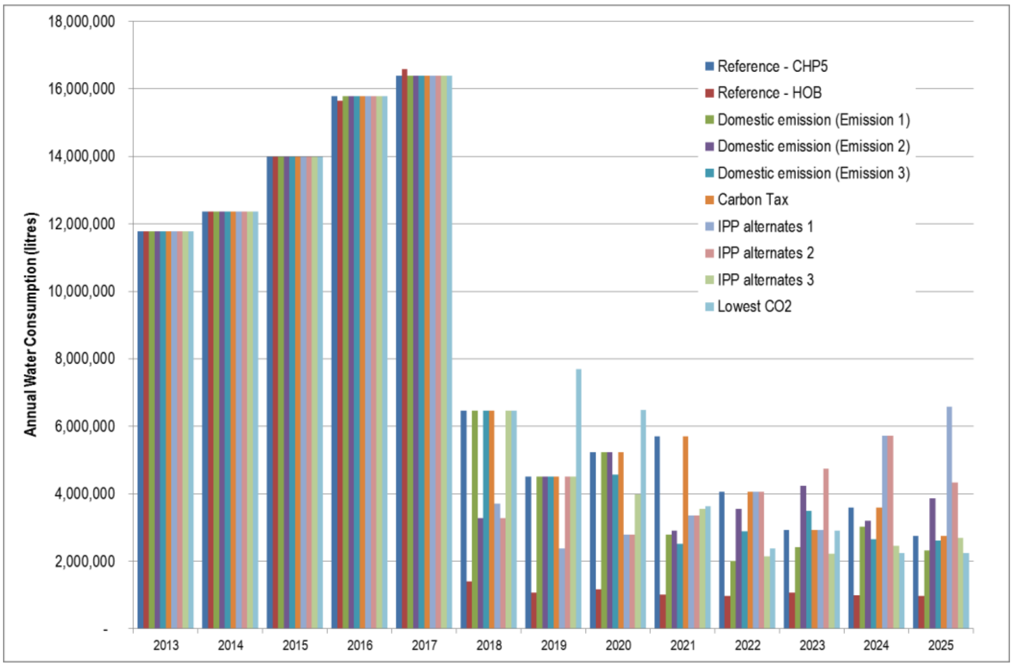


Figure V-9: Water Consumption by Scenario Plan

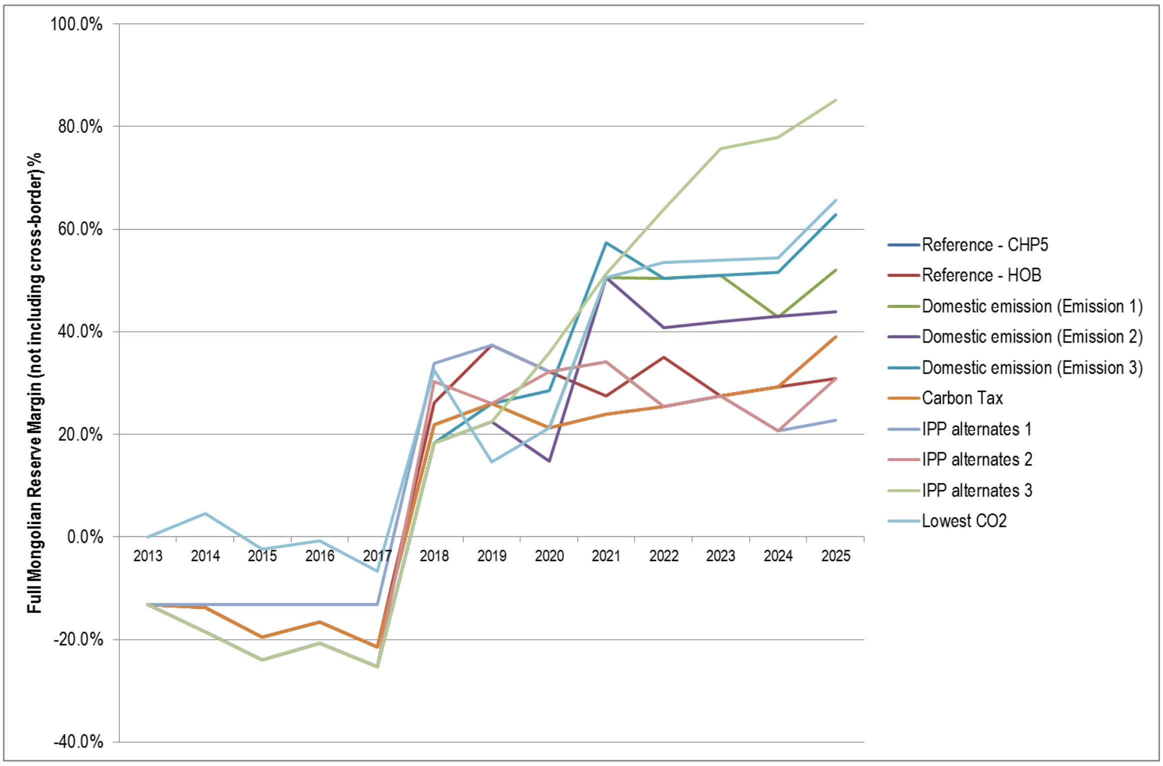


Sources: Consultants' analysis

4. Security of Supply

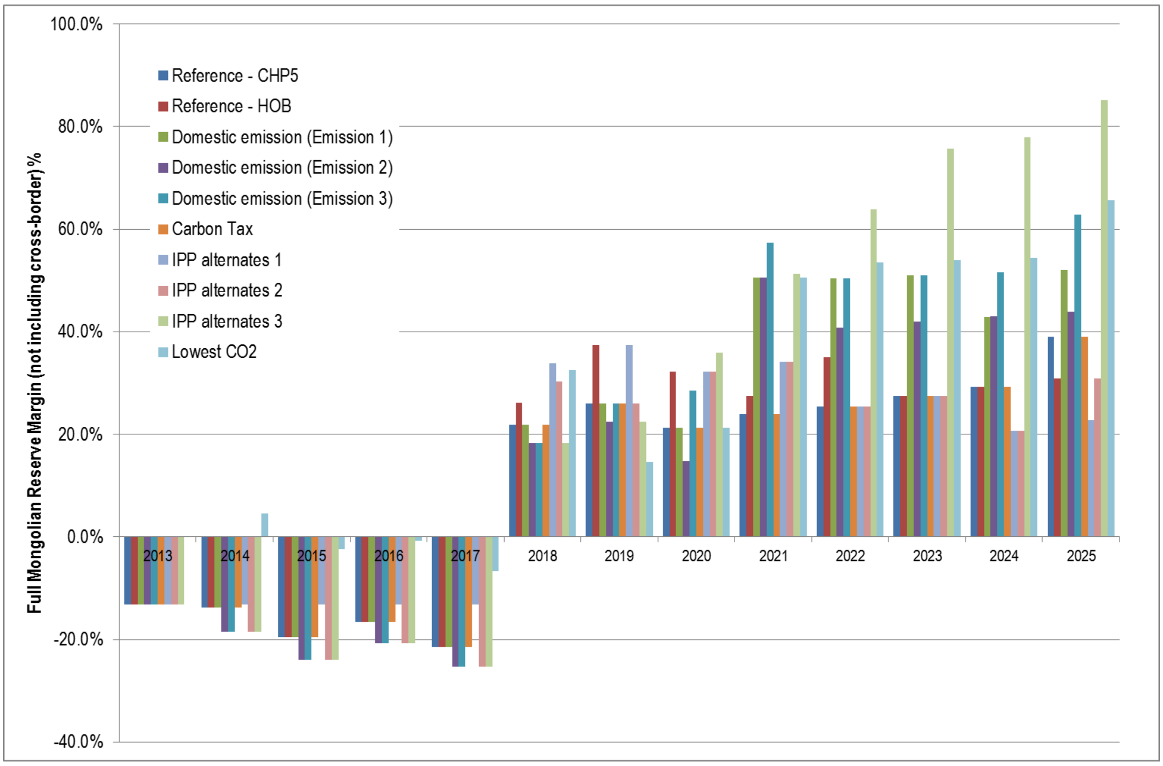
164. Figure V-10 illustrates the annual reserve margin for each of the scenarios based on the full capacity of each project. For a number of potential projects, especially renewable energy sources, the capacity has a low probability of being available for the annual peak (thus unlikely to contribute to the reserve margin). The capacity associated with "non-dispatchable" sources has been de-rated (for wind to 8% of its capacity; and for hydro options to the schemes capacity at time of winter peak). For a more accurate comparison, Figure V-12 demonstrates the reserve margin in each scenario using the de-rated capacity. Each of the scenario plans experiences a maintained or increasing reserve margin (due to the impact of REFIT projects amongst others), while Scenario Plans utilizing more renewable energy have a pronounced reduction in "reliable" reserve margins. The impact of this reduced capacity contribution is captured in the risk factor criterion (described in Appendix B) which provides a means to discount plans which introduce additional risk to the system.

Figure V-10: Full Mongolian Reserve Margin



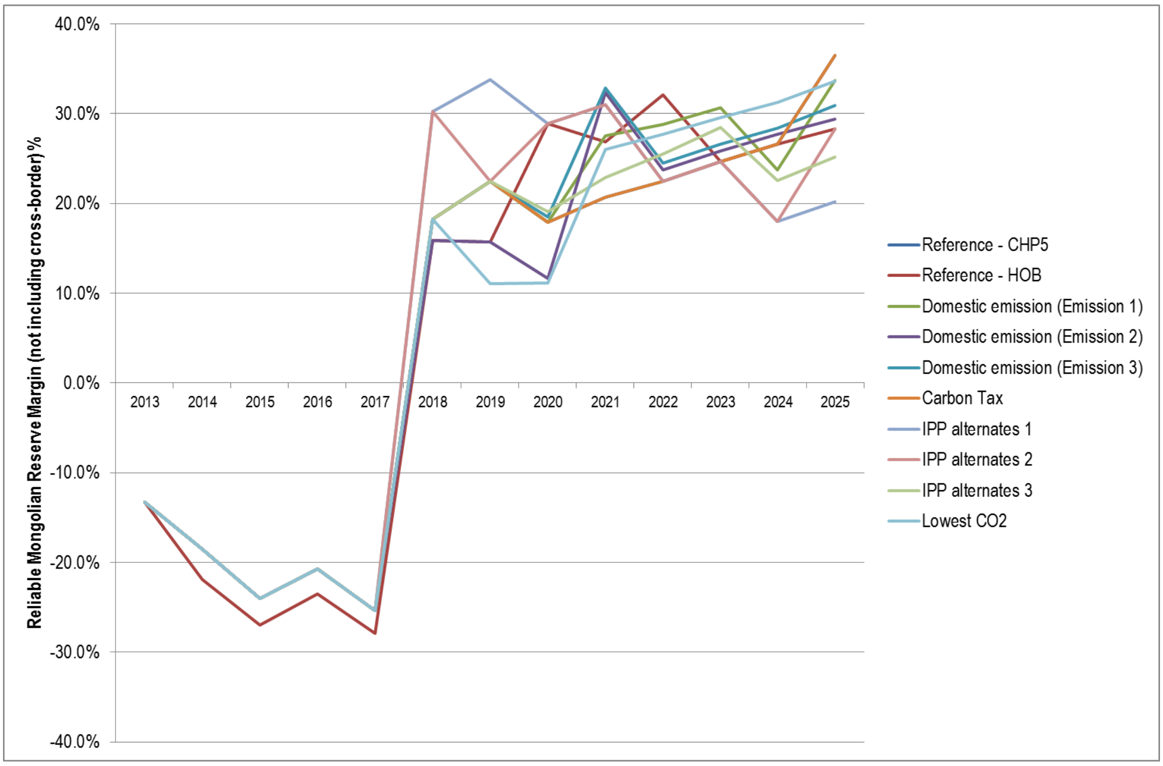
Sources: Consultants' analysis

Figure V-11: Full Mongolian Reserve Margin



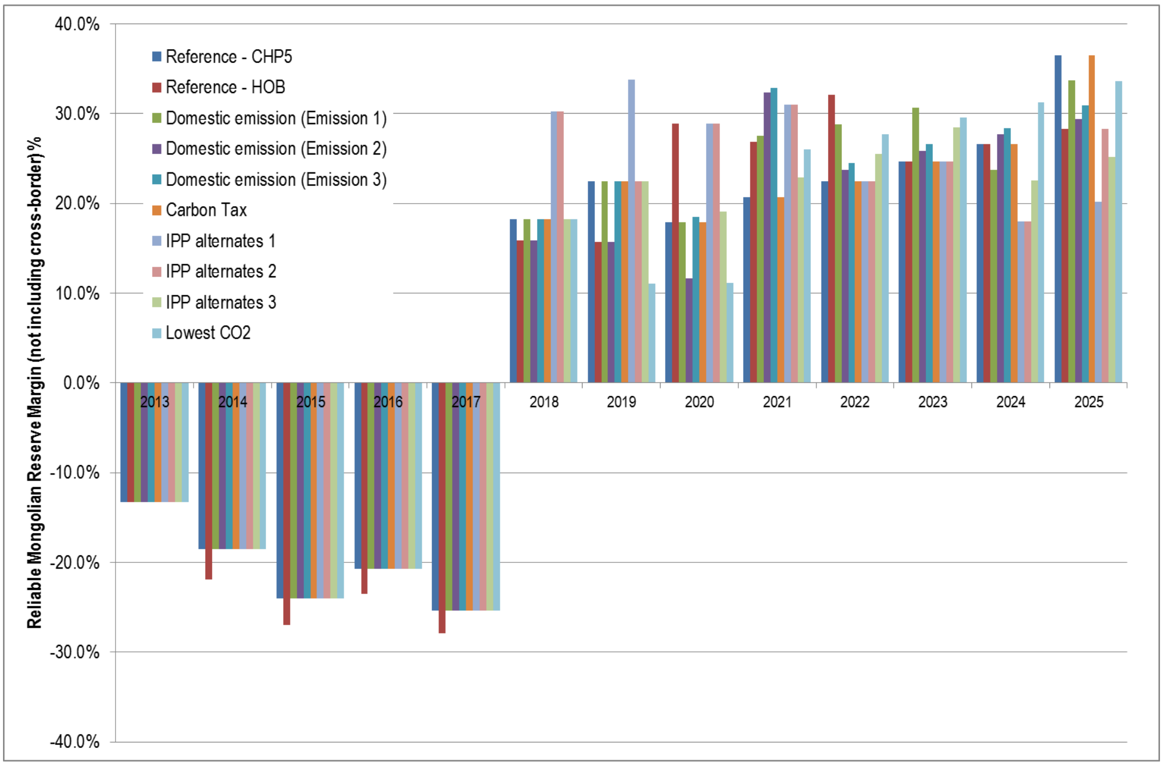
Sources: Consultants' analysis

Figure V-12: Reliable Mongolian Reserve Margin



Sources: Consultants' analysis

Figure V-13: Reliable Mongolian Reserve Margin



Sources: Consultants' analysis

5. Renewable Energy

165. The following charts show the renewable energy contributions of all plans.

Figure V-14: Renewable Energy Production As % on Total

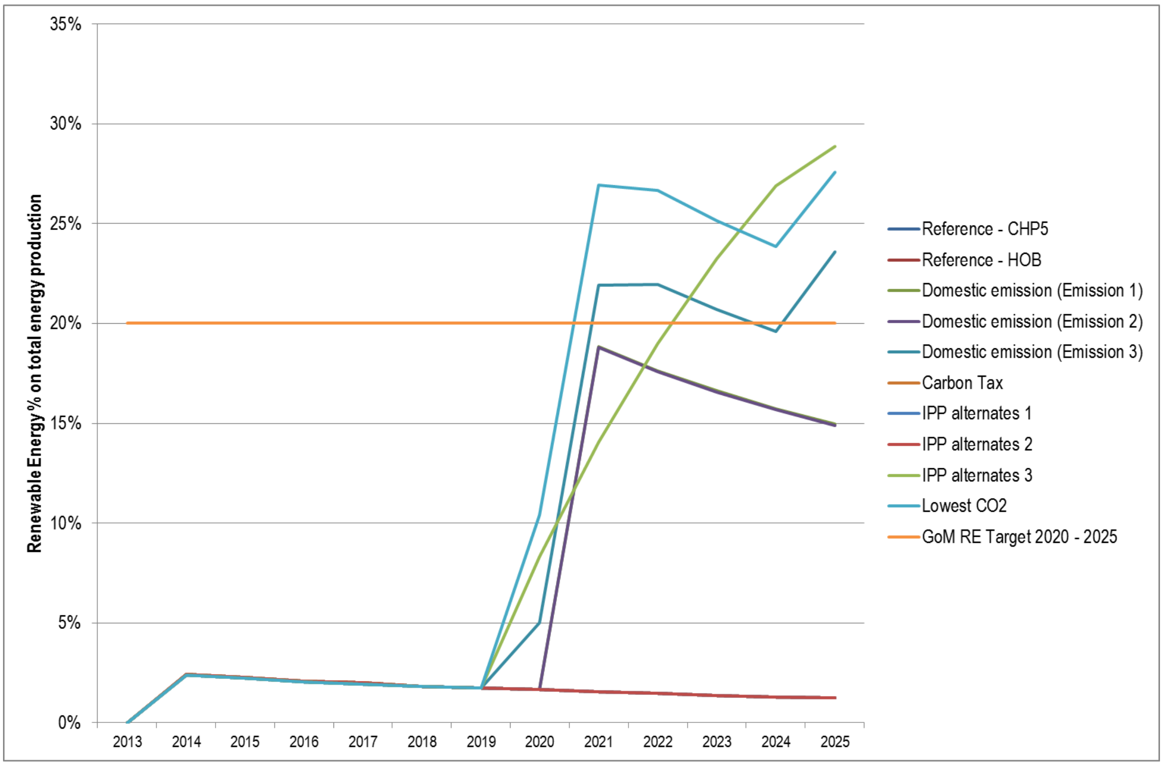
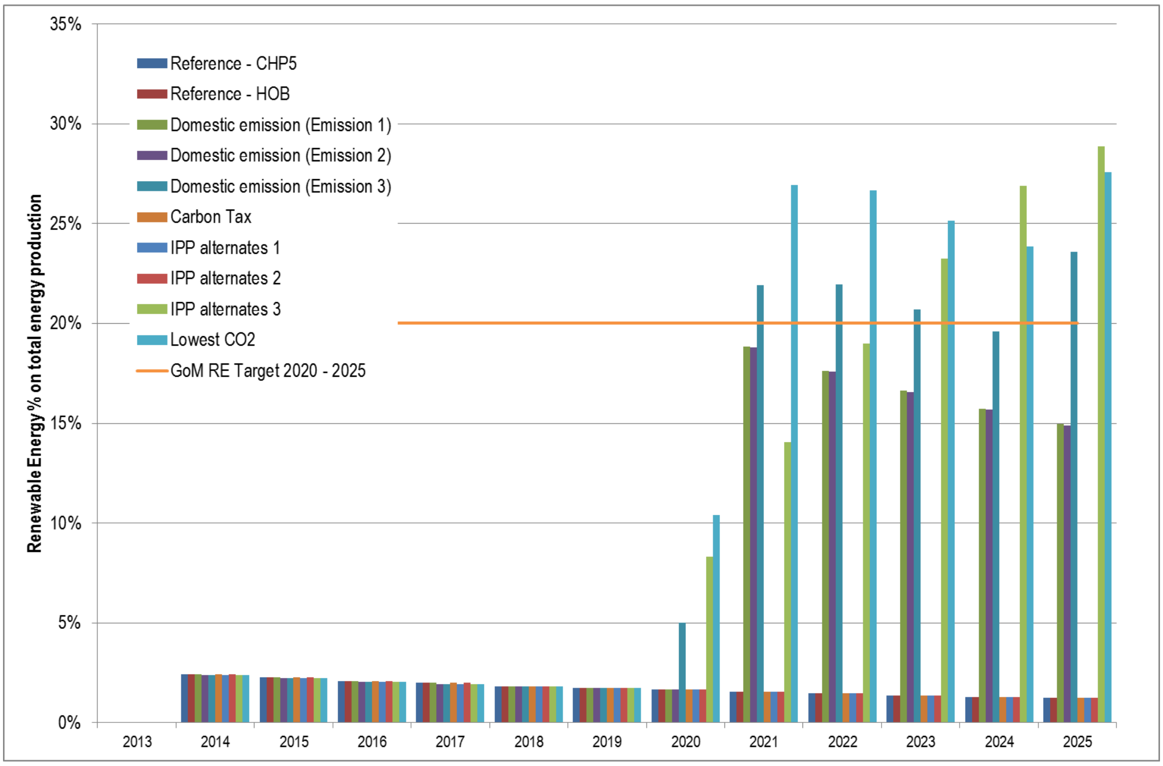


Figure V-15: Renewable Energy Production As % on Total



Sources: Consultants' analysis

Figure V-16: Renewable Energy Production – MWh Sent Out

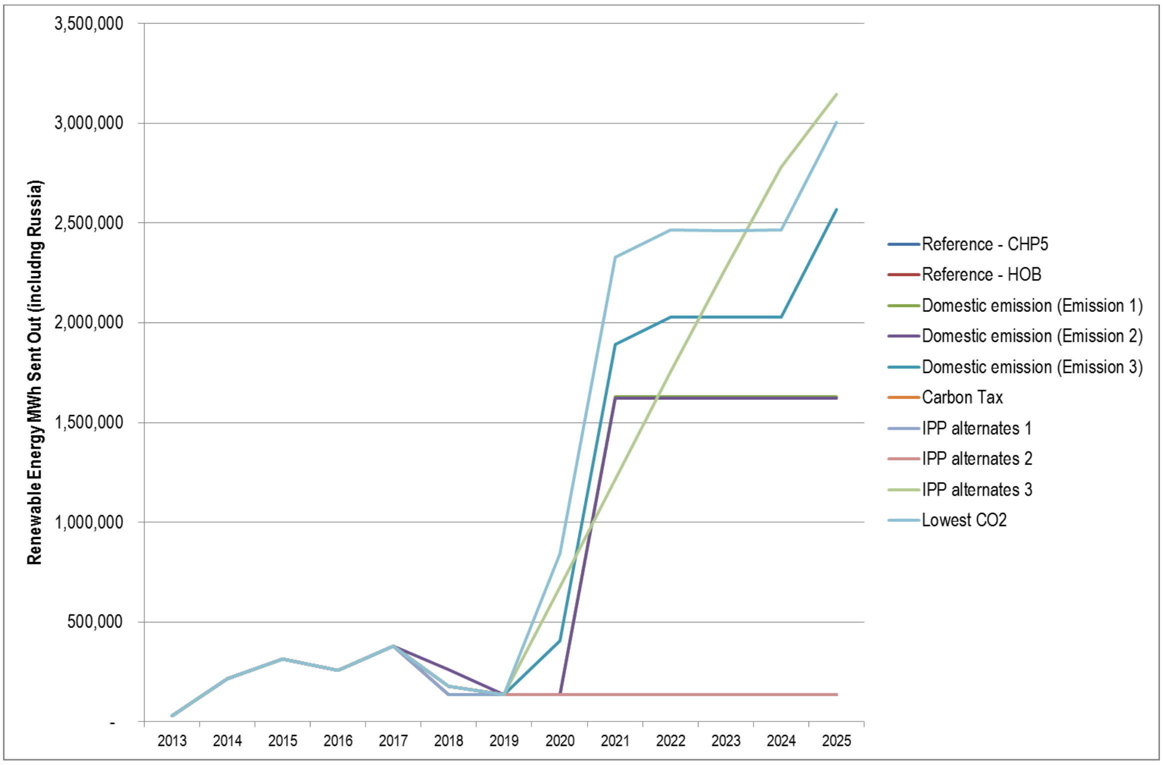
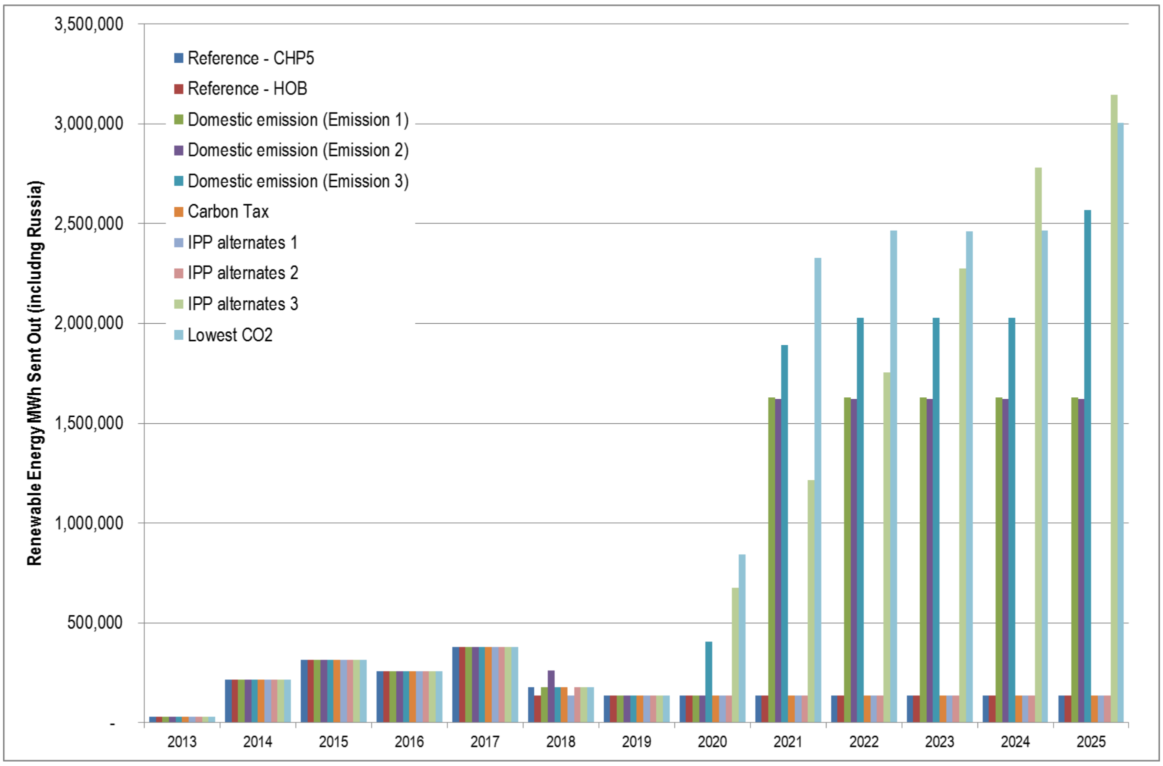


Figure V-17: Renewable Energy Production – MWh Sent Out



BB. Application of Criteria

Goodness of Fit

166. Goodness of fit criterion is described in Appendix B. The criteria describe the dimensions in which the optimal scenario plans can be assessed for "goodness of fit" with Mongolia's policy objectives. The principle is to achieve the best outcome to meet policy objectives, no matter how much in conflict these objectives may seem.

167. By following a rigorous multi-criteria decision making approach it is possible to describe, enumerate and score the preferences and values of the stakeholders with respect to each of the criteria. This provides a solid foundation to choose a single plan as the preferred option. In addition it is possible to identify next-best alternates that can undergo additional stress testing to incorporate concerns regarding robustness to sensitivities.

168. The criteria selected for the evaluation of "goodness of fit" are:-

1) CO_2 emissions, with the average annual CO_2 emissions (in million tonnes) for the study period serving as the metric;
2) Plan cost, with the normalised present value total cost of the plan (indexed to the cheapest plan – the reference plan) as the metric;
3) Diversity, with the coal-fired generation sent-out in 2025 as a percentage of the total generation sent-out in 2025 as the metric;
4) Risk factor, with the index of risk factors associated with constituent projects (weighted according to capacity contribution to the plan) as the metric.

169. Table V-18 provides indications of the results for each scenario. The metrics provided in Table V-18 are normalized, with the best result for each criteria scoring 1.0 and decreasing with worsening results for the specific criteria. For example the Low CO2 scenario, which scores the

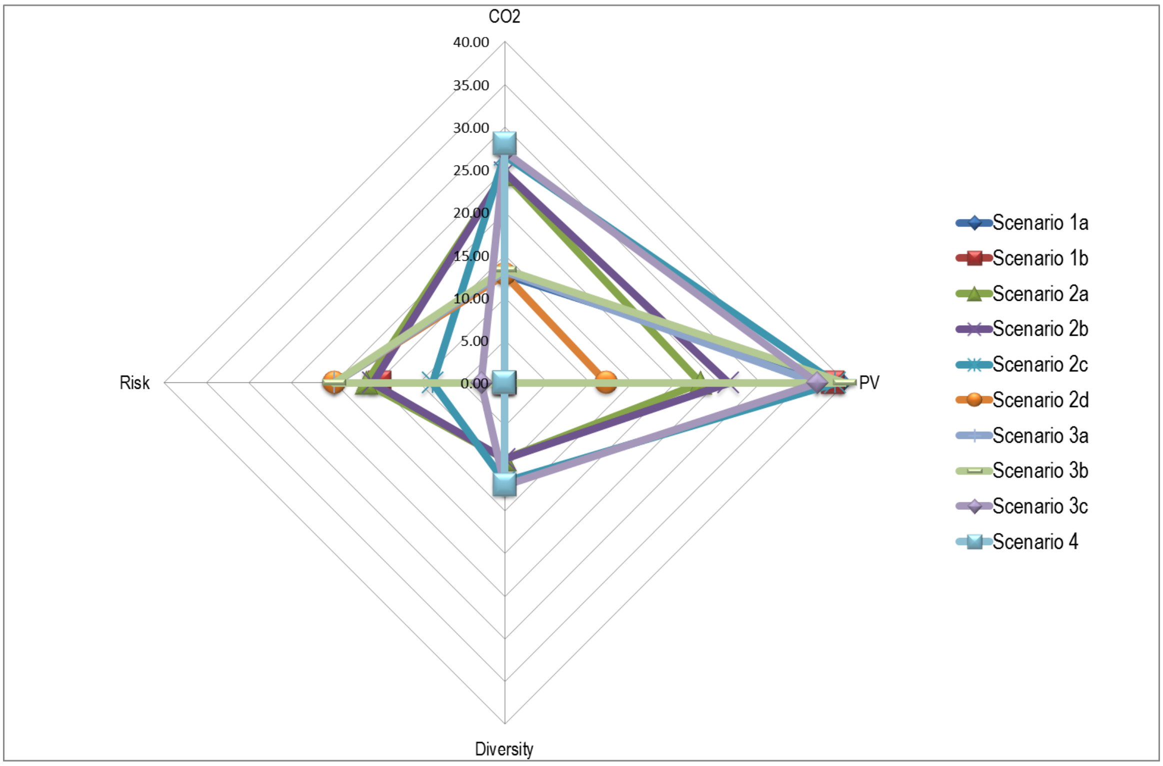
best in terms of emissions and diversity scored worst (by some margin) on both the cost and risk criteria.

Table V-18: Metrics for Criteria (results from economic optimization)

Scenario Plans	Name	Domestic CO2 emissions (Total Mt/a 2013 to 2025)	Normalised PV cost of plan	Coal-fired Generation (% Energy Sent Out on Total in 2025)	Risk factor Associated with Projects
1a	Reference Plan – CHP	138.7	1.003	98.8%	**4.12**
1b	Reference Plan – HOB	143.5	1.006	98.8%	5.27
2a	Domestic emissions (Emission Target 1)	132.0	1.056	85.1%	5.11
2b	Domestic emissions (Emission Target 2)	131.8	1.048	85.1%	5.20
2c	Domestic emissions (Emission Target 3)	129.6	1.005	76.4%	5.66
2d	Carbon Tax	138.7	1.083	98.8%	**4.12**
3a	IPP alternates 1	138.6	1.014	98.8%	4.14
3b	IPP alternates 2	138.5	**1.000**	98.8%	4.13
3c	IPP alternates 3	128.8	1.014	**71.1%**	5.88
4	Lowest CO2	**127.4**	1.115	72.4%	5.97
		Total domestic emissions (2013 to 2025)	*Total PV cost of the plan (2013 to 2025) normalized to the Reference Plan*	*Percentage of Total Energy Production in the Year 2025*	*Weighted Average of Project Risk Factors (by Capacity Contribution)*

Sources: Consultants' analysis

Figure V-19: Normalized Criteria Results for All Plans



Sources: Consultants' analysis

CC. Partial Value Functions

170. Having determined the metric results for each of the potential plans a partial value function is constructed to map these results to a value representing the preferences of decision-makers. The partial value function is important in providing a precise mechanism to rank the outcomes of the different plans in a particular criterion according to the decision-maker preferences. While this process should include a broad range of stakeholders to capture all preferences this requirement could not be fully met for the current iteration and a smaller group of Mongolian experts assisted in determining the criterion and weightings but not the value function.

171. Value functions are provided in Appendix C. For the purposes of the scoring of the plans though, the results are indicated in Table V-20. This shows how each plan has scored according to each criterion (with 100 being the best score, and 0 being the worst).

Table V-20: Partial Value Function Results

Scenario Plans	Name	CO2 Emissions	Cost of Plan	Diversity	Risk Factor
1a	Reference Plan - CHP	45	98	0	100
1b	Reference Plan - HOB	0	96	0	73
2a	Domestic emissions (Emission Target 1)	88	58	74	81
2b	Domestic emissions (Emission Target 2)	88	66	74	77
2c	Domestic emissions	95	97	97	42

	(Emission Target 3)				
2d	Carbon Tax	45	30	0	100
3a	IPP alternates 1	47	92	0	100
3b	IPP alternates 2	47	100	0	100
3c	IPP alternates 3	97	92	100	14
4	Lowest CO2	100	0	100	0

Sources: Consultants' analysis

DD. Swing Weighting

172. A critical component of the Multi-criteria Decision Making process is to determine weightings for each of the criterion. This provides the mechanism to score the plans across the different criteria.

173. In order to determine the weighting for the criteria a series of hypothetical cases are evaluated in which a plan scores best on each of the criteria and worst on all the others. Taking each of these hypothetical plans a preference ranking can be determined to indicate the extent to which one criterion is more important than others and how the other criteria relate in importance to one another. The highest priority gets an arbitrary weighting of 10 and the others are ranked in relation to the top score of 10.

174. Typical weightings for an Energy Masterplan follow:-

- Cost of plan – Weighting 10;
- Emissions – Weighting 7;
- Risk factor – Weighting 5; and
- Diversity – Weighting 3.

EE. Scoring

175. Having calculated the importance weighting between the criteria and the partial value functions within each criterion a final value associated with each plan was produced. This result, indicated in Table V-21 is determined by multiplying the partial value result for each criterion by the weighting (as a percentage of the total weighting for all criteria). Thus the CHP Reference Plan 1a, having scored 50 on the emissions criteria, achieves a score of 14 (0.28*50). The CHP Reference Plan achieves no score for diversity.

Table V-21: Final Value Score for Plans

Scenario Plans	Name	CO2 Emissions	Cost of Plan	Diversity	Risk Factor	Total
1a	Reference Plan – CHP	13	39	0	20	72.1
1b	Reference Plan – HOB	-	39	0	15	53.3
2a	Domestic emissions (Emission Target 1)	25	23	9	16	72.7
2b	Domestic emissions (Emission Target 2)	25	26	9	15	75.3

2c	Domestic emissions (Emission Target 3)	27	39	12	8	85.5
2d	Carbon Tax	13	12	0	20	44.7
3a	IPP alternates 1	13	37	0	20	69.7
3b	IPP alternates 2	13	40	0	20	73.3
3c	IPP alternates 3	27	37	12	3	78.6
4	Lowest CO2	28	-	12	0	40.0
		13	39	0	20	72.1
		-	39	0	15	53.3

Sources: Consultants' analysis

176. Thus, from the multi-criteria decision analysis, it would appear that **Scenario 2c Domestic Emission** plan is preferable to the others, followed by the **IPP Alternates 3** plan with its heavy emphasis on renewables.

177. In spite of the low weighting given to Diversification, this factor has a decisive influence on the outcome.

Figure V-22: Normalized Criteria for Top 3 Plans

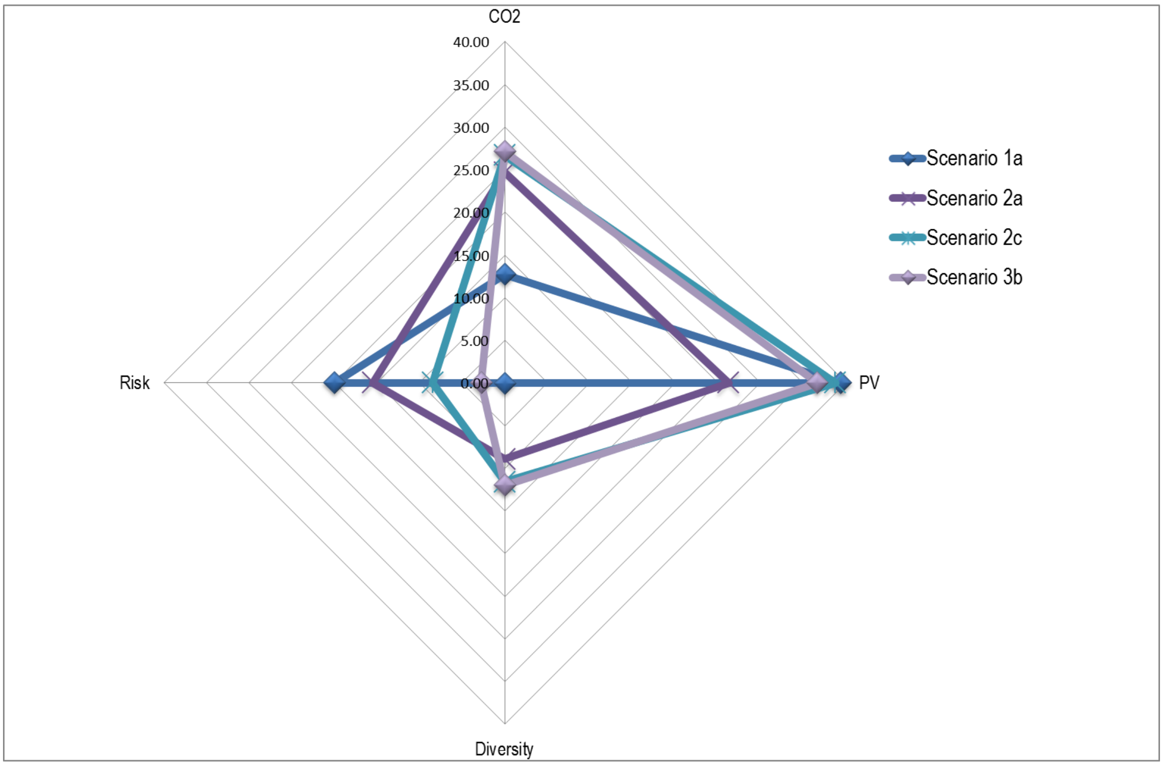


Table V-23: Proposed Expansion Plan – Scenario Plan 2c: Domestic Emissions (Emissions 3)

	Existing CHPs (2013)	New CHP	Coal	Hydro (firm)	Wind (full)	Solar PV	Import	Total New Build	Total System Capacity	Peak Demand (net sent-out) Forecast	Mongolian Reliable Reserve Margin	Mongolian Reliable Capacity Reserve Margin	Annual Exceedence of Import Limit 175MW	Annual Energy (net sent-out) Forecast
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	%	Hours	GWh
2013	775	0	0	0	0	0	119	0	893	893	-119	-13.3%	-	5,283,931
2014	775	0	0	0	50	0	175	50	1,000	956	-177	-18.5%	31	5,655,356
2015	775	0	0	0	50	0	175	50	1,000	1,025	-246	-24.0%	154	6,061,675
2016	879	0	0	0	50	0	175	50	1,104	1,113	-230	-20.7%	31	6,580,960
2017	879	0	0	0	50	0	175	50	1,104	1,183	-300	-25.4%	365	6,993,786
2018	879	300	300	0	50	0	132	650	1,661	1,254	229	18.2%	-	7,416,074
2019	860	300	450	0	50	0	0	800	1,660	1,318	296	22.4%	-	7,793,414
2020	860	300	450	0	150	0	0	900	1,760	1,369	253	18.5%	-	8,093,865
2021	860	450	450	170	150	0	0	1220	2,079	1,461	480	32.9%	-	8,640,948
2022	860	450	450	170	200	0	0	1270	2,129	1,562	383	24.5%	-	9,240,669
2023	860	600	450	170	200	0	0	1420	2,279	1,656	440	26.6%	-	9,791,300
2024	860	600	600	170	200	0	0	1570	2,429	1,749	497	28.4%	-	10,341,340
2025	860	750	600	170	400	0	0	1920	2,779	1,842	570	30.9%	-	10,891,971

Sources: Consultants' analysis

FF. Economic Comparison of Reference 1a and 2c Plans

178. The economic analyses of Scenario 1a.

Table V-24: Scenario 1a: Summary of Financial Analysis

Overall Scenario		WACC 4%	WACC 6%	WACC 8%
NPV, Power Sector	USD	2,777,293,047	2,636,034,193	2,496,658,492
NPV, Heat Sector	USD	1,128,534,274	1,035,522,672	955,054,568
NPV, Total	USD	3,905,827,322	3,671,556,865	3,451,713,060
LCOE, Electricity	USD/MWh	34.93	37.28	39.41
LCOE, Heat	USD/Gcal	12.17	12.45	12.70
LCOE, Total	USD/MWh	45.41	47.99	50.35

Sources: Consultants' analysis

179. The economic analyses of Scenario 2c.

Table V-25: Scenario 2c: Summary of Financial Analysis

Overall Scenario		WACC 4%	WACC 6%	WACC 8%
NPV, Power Sector	USD	2,922,401,235	2,833,512,399	2,728,538,787
NPV, Heat Sector	USD	1,128,534,274	1,035,522,672	955,054,568
NPV, Total	USD	4,050,935,509	3,869,035,072	3,683,593,354
LCOE, Electricity	USD/MWh	36.76	40.07	43.07
LCOE, Heat	USD/Gcal	12.17	12.45	12.70
LCOE, Total	USD/MWh	47.24	50.78	54.01

Sources: Consultants' analysis

180. The financial difference between the two scenarios is summarized in Table V-26. Scenario 1a results are subtracted from the results of Scenario 2c, meaning that the difference represents a cost penalty against Scenario 2c

Table V-26: Financial Difference Between Scenario 1a and Scenario 2c

Overall Scenario		WACC 4%	WACC 6%	WACC 8%
NPV, Power Sector	USD	145,108,188	197,478,207	231,880,294
NPV, Heat Sector	USD	0.00	0.00	0.00
NPV, Total	USD	145,108,188	197,478,207	231,880,294
LCOE, Electricity	USD/MWh	1.83	2.79	3.66
LCOE, Heat	USD/Gcal	0.00	0.00	0.00
LCOE, Total	USD/MWh	1.83	2.79	3.66

Sources: Consultants' analysis

GG. Environmental Performance Comparison of Reference 1a and 2c Plans

181. The technical analyses of the portfolio show that Scenario 2c has a lower environmental impact than Scenario 1a, in terms of CO2 emitted and water consumed for power production.

Table V-27: Scenario 1a: Environmental Performance

		Power Sector	Heat Sector	Total
CO2	Tons	81,959,898	56,768,838	138,728,737
Water Consumption	m³	105,526,455	-	105,526,455

Sources: Consultants' analysis

Table V-28: Scenario 2c: Environmental Performance

		Power Sector	Heat Sector	Total
CO2	Tons	72,788,718	56,768,838	129,557,557
Water Consumption	m³	100,004,675	-	100,004,675

Sources: Consultants' analysis

182. It can be seen that environmental performance is better in the case of Scenario 2c, as expected.

183. Further tests on these plans, especially regarding robustness and price paths, are included in the detailed report. However due to time constraints only the Scenario 1a Reference Plan and the Scenario 2c Emissions portfolio plan have been tested in these dimensions.

HH. Risks & Uncertainties

1. Sensitivity Studies

184. Even with the policy and growth uncertainties to some extent catered for in the scenarios listed above, there are a number of other uncertainties that need to be considered. The models have been tested against changes in the underlying assumptions regarding, in particular:-

- Changes in the energy forecast;
- Plant failure leading to sustained higher than targeted plant outage; and
- Uncertain and prolonged lead times and cost for building new plant.

2. Risk of Changes in the Actual Energy Demand

185. Even with the policy and growth uncertainties to some extent catered for in the scenarios listed above, there are a number of other uncertainties that need to be considered. The models have been tested against changes in the underlying assumptions regarding,

186. In order to test for these uncertainties, the following process was followed on the Reference scenario plan (1a – CHP). It has been assumed that similar responses would be required from the emission portfolio cases as they have similar expansion options in the early period and consequently similar responses would be found in each case. Due to time and resource

constraints the process was not repeated for these and the other plans.

a) For the analyses presented above the Low forecast was used, and all expansion options allowed to be optimised; and
b) For the higher forecast sensitivity, the Moderate and High demand forecast were assessed, allowing coal options only after 2018 (maximum 2 x 150 units per annum).

187. The results indicate that an increase in the actual demand to the medium and high forecast would lead to substantial increase in capacity from coal to fill the capacity gap immediately in 2018; thereafter the base-load coal requirement would need to be met with accelerated coal projects. If the actual demand were to be closer to the Low forecast the rate of increase in coal capacity could be slowed down (as one would expect).

188. To understand the steepness of the marginal cost difference between investment plans needed to meet the Low, Medium and High CES forecasts, it is instructive to compare the following scenario financial summaries against Table V-24 above.

189. The economic analyses of Scenario 1a adjusted to meet the medium (bear) load forecast.

Table V-29: Scenario 1a – Medium Growth: Summary of Financial Analysis

Overall Scenario		WACC 4%	WACC 6%	WACC 8%
NPV, Power Sector	USD	3,180,711,930	3,018,033,807	2,856,853,390
NPV, Heat Sector	USD	1,130,191,210	1,037,029,082	956,426,566
NPV, Total	USD	4,310,903,140	4,055,062,889	3,813,279,956
LCOE, Electricity	USD/MWh	36.34	38.99	41.43
LCOE, Heat	USD/Gcal	12.17	12.44	12.70
LCOE, Total	USD/MWh	46.82	49.70	52.36

Sources: Consultants' analysis

190. The economic analyses of Scenario 1a adjusted to meet the high (bull) load forecast.

Table V-30: Scenario 1a – High Growth: Summary of Financial Analysis

Overall Scenario		WACC 4%	WACC 6%	WACC 8%
NPV, Power Sector	USD	3,690,032,443	3,490,693,613	3,294,612,753
NPV, Heat Sector	USD	1,130,191,210	1,037,029,082	956,426,566
NPV, Total	USD	4,820,223,653	4,527,722,695	4,251,039,319
LCOE, Electricity	USD/MWh	37.51	40.39	43.07
LCOE, Heat	USD/Gcal	12.17	12.44	12.70
LCOE, Total	USD/MWh	47.99	51.10	54.00

Sources: Consultants' analysis

191. According to the financial difference between the Scenario 1a Low Growth and High Growth plans, the Long Run Marginal Cost (LRMC) of supply is around $945 per kW.

3. Other Key Risks in the CES Expansion Plan

192. While the risk factor criterion provides a mechanism to evaluate the potential plans for the inherent risks of each plan, it is worth highlighting the risks to provide focus for possible mitigation.

193. In each of the plans there is a series of common concerns that occur due to the assumptions made up-front. These include:

- Worse performance from the Mongolian base-load CHP fleet. As the stress tests above indicate, if the assumption that the reliability of the existing fleet does not hold for Mongolia's generators the system would be at risk from a reduced reserve margin with limited ability to rectify in the medium term;
- Similarly to the reduced availability of Mongolian power stations, if merchant generators produced less than the assumed capability the expected reserve margin would not materialize;
- Performance and modelling of renewable options - the impact of renewable capacity is highly uncertain given the limited exposure to these technologies in Mongolia. This is partly mitigated by the relatively small volumes expected in the medium term, but with larger and more numerous projects improved modelling techniques and forecasting will be required;
- Load forecast - the actual energy requirement is certain to deviate from the forecast, erring either on the upside or downside. If the forecast is understated the capacity shortfall could be problematic given long lead-time to react. Conversely, an over-estimation would have economic impact of unnecessary capital expenditure;
- Current Mongolian build program - the risks of delays in the current build programme have a significant impact on the ability to meet demand reliably in the medium term, notably any delay to the build of the CHP5 plant; and
- Transmission expansion – all plans assume that the Transmission grid can expand to meet the required energy demand, as well as the geographic spread of new capacity. No allowance is made for the lead times for new Transmission capacity, but significant delays in securing transmission connection or similar limitations would impede on the ability to execute the plan optimally.

194. As indicated in the risk factors there are issues specific to each of the plans. For the purposes of illustration the specific issues for the reference plan and the risk-adjusted emission portfolio plan are discussed further.

a) Reference plan 1a - CHP

- The prime concern for the reference plan, in terms of risk factors, is the limited resources available in terms of water supply. Water supply, especially in the Sainshand area where new coal-fired capacity is expected, is potentially problematic. Additional water infrastructure may be required to meet the water needs for new power projects in the Sainshand area; and
- The availability and transport of sorbent for flue gas desulphurization (FGD) is also a concern, including the waste management for the resulting by-products.

b) Domestic Emissions 2c (Emission 3)

- Chief among the concerns for this plan is the untested nature of the technologies that would contribute to the reduction in greenhouse gas emissions and diversification of the energy mix; in particular large grid-connected wind farms have

not been developed in Mongolia and cost estimates are ball-park at best; and

- Large hydropower projects are subject to dry year operation and suitable management strategies would be needed to ensure that planned capacity is available at all times. This issue has been accounted for in the simulations performed by assuming a low firm capacity during winter peak time, reflecting lower water flows in winter, or assuming a constant low head output at all times with correspondingly low capacity.

VI. CONCLUSIONS

II. CES Energy Masterplan Update

195. The update of the Energy Masterplan for CES is different from previous iterations in that there has been:-

1. The integration of policy objectives, in particular, emissions and diversity;
2. The establishment of criteria and a mechanism to evaluate the plans according to these;
3. Improved transparency from initial steps to offer an energy plan based on rigorous simulations using modelling tools customized for the Mongolian power system; and
4. The testing of robustness and flexibility of the plans.

196. Stakeholder involvement in the planning process has been encouraged through workshops and attendance at Mongolian Energy Conferences, especially Government Departments and industry and consumer groups.

JJ. Recommended Expansion Plan

197. After considering the criteria determined above and undergoing the fairly rigorous decision analysis process based on policy criteria, the Domestic Emissions scenario plan 2c (Emissions 3) is the best of the scenario plans considered.

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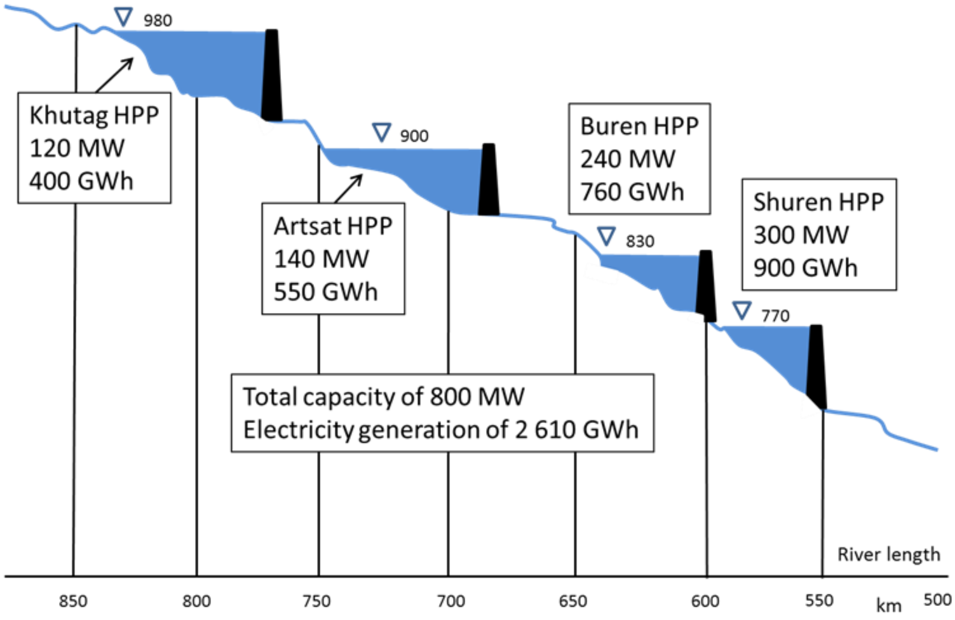
198. Whilst the plan is the best from a balanced policy perspective, the following conditions should be fulfilled to ensure the success of the Energy Masterplan in meeting the needs of the country:-

- Continued investment in the maintenance and refurbishment of existing Mongolian plant to ensure generator performance at assumed levels;
- Continued investigation into coal liquefaction and coal gasification;
- Continued investment in demand side management initiatives to improve energy efficiency and delay additional capacity requirements. This should include investment in off-grid solar PV schemes; and
- Continued investigation into the role of nuclear power to provide low emission base-load alternatives to coal-fired generation; and
- Continued investigation of hydropower potential.

Figure VI-1: Potential for Hydropower



Sources: Ministry of Energy

VII. APPENDIX A: HEAT ALLOCATION BY DISTRICT, CHP & HOB

HEAT PRODUCTION SCENARIO 1 – CHP Expansion (+ Amalgan HOB)

Table VII-1: Allocation of Heat Production by District and Plant in 2013

	PP2	PP3	PP4	CHPX	HOB		PP2	PP3	PP4	CHPX	HOB	Total
Bayangol	0%	38%	62%	0%	0%	26%	-	519,295	859,590	-	-	1,378,886
Bayanzurkh	0%	29%	71%	0%	0%	21%	-	334,896	806,397	-	-	1,141,293
Songinokhairkhan	34%	60%	6%	0%	0%	10%	187,583	336,572	35,093	-	-	559,248
Sukhbaatar	0%	20%	80%	0%	0%	17%	-	179,150	721,572	-	-	900,723
Khan-Uul	0%	18%	82%	0%	0%	15%	-	145,938	661,103	-	-	807,041
Chingeltei	0%	20%	80%	0%	0%	10%	-	109,531	442,826	-	-	552,357
							187,583	1,625,383	3,526,582	-	-	5,339,548

Table VII-2: Allocation of Heat Production by District and Plant in 2014

	PP2	PP3	PP4	CHPX	HOB		PP2	PP3	PP4	CHPX	HOB	Total
Bayangol	0%	38%	62%	0%	0%	25%	-	525,242	869,434	-	-	1,394,676
Bayanzurkh	0%	29%	71%	0%	0%	22%	-	355,648	856,365	-	-	1,212,013
Songinokhairkhan	34%	60%	6%	0%	0%	10%	194,148	348,350	36,321	-	-	578,819
Sukhbaatar	0%	20%	80%	0%	0%	16%	-	178,883	720,496	-	-	899,379
Khan-Uul	0%	18%	82%	0%	0%	16%	-	155,648	705,089	-	-	860,737
Chingeltei	0%	20%	80%	0%	0%	10%	-	111,796	451,980	-	-	563,776
							194,148	1,675,566	3,639,685	-	-	5,509,399

Table VII-3: Allocation of Heat Production by District and Plant in 2015

	PP2	PP3	PP4	CHPX	HOB		PP2	PP3	PP4	CHPX	HOB	Total
Bayangol	0%	35%	65%	0%	0%	25%	-	494,280	915,712	-	-	1,409,992
Bayanzurkh	0%	20%	54%	0%	26%	22%	-	261,036	695,389	-	329,749	1,286,174
Songinokhairkhan	25%	44%	5%	0%	27%	10%	147,111	263,955	27,521	-	160,485	599,072
Sukhbaatar	0%	20%	80%	0%	0%	16%	-	178,400	718,551	-	-	896,951
Khan-Uul	0%	10%	70%	0%	21%	16%	-	89,316	638,912	-	188,881	917,110
Chingeltei	0%	15%	64%	0%	21%	10%	-	83,551	368,589	-	123,204	575,344
							147,111	1,370,537	3,364,675	-	802,318	5,684,642

Table VII-4: Allocation of Heat Production by District and Plant in 2016

	PP2	PP3	PP4	CHPX	HOB		PP2	PP3	PP4	CHPX	HOB	Total
Bayangol	0%	35%	65%	0%	0%	25%	-	510,709	946,149	-	-	1,456,859
Bayanzurkh	0%	20%	54%	0%	26%	22%	-	269,712	718,503	-	340,709	1,328,924
Songinokhairkhan	25%	44%	5%	0%	27%	10%	152,001	272,728	28,436	-	165,819	618,984
Sukhbaatar	0%	20%	80%	0%	0%	16%	-	184,330	742,434	-	-	926,764
Khan-Uul	0%	10%	70%	0%	21%	16%	-	92,285	660,149	-	195,159	947,593
Chingeltei	0%	15%	64%	0%	21%	10%	-	86,328	380,841	-	127,299	594,467
							152,001	1,416,092	3,476,512	-	828,986	5,873,592

Table VII-5: Allocation of Heat Production by District and Plant in 2017

	PP2	PP3	PP4	CHPX	HOB		PP2	PP3	PP4	CHPX	HOB	Total
Bayangol	0%	32%	68%	0%	0%	25%	-	479,796	1,025,486	-	-	1,505,283
Bayanzurkh	0%	19%	59%	0%	21%	21%	-	248,349	760,722	-	275,985	1,285,055
Songinokhairkhan	25%	45%	5%	0%	24%	11%	169,529	305,153	35,507	-	162,935	673,124
Sukhbaatar	0%	18%	82%	0%	0%	15%	-	162,570	755,327	-	-	917,897
Khan-Uul	0%	9%	74%	0%	17%	18%	-	98,401	817,974	-	185,101	1,101,476
Chingeltei	0%	14%	69%	0%	18%	10%	-	83,254	423,107	-	107,865	614,227
							169,529	1,377,524	3,818,122	-	731,886	6,097,061

Table VII-6: Allocation of Heat Production by District and Plant in 2018

	PP2	PP3	PP4	CHPX	HOB		PP2	PP3	PP4	CHPX	HOB	Total
Bayangol	0%	24%	52%	23%	0%	25%	-	379,698	811,541	364,078	-	1,555,316
Bayanzurkh	0%	20%	62%	18%	0%	20%	-	255,461	782,507	226,574	-	1,264,542
Songinokhairkhan	20%	37%	4%	39%	0%	12%	154,558	278,205	32,371	293,591	-	758,725
Sukhbaatar	0%	16%	74%	10%	0%	14%	-	141,386	656,903	86,890	-	885,179
Khan-Uul	0%	9%	73%	18%	0%	18%	-	100,369	834,332	203,386	-	1,138,088
Chingeltei	0%	13%	67%	20%	0%	10%	-	83,900	426,388	124,355	-	634,643
							154,558	1,239,019	3,544,042	1,298,874	-	6,236,492

Table VII-7: Allocation of Heat Production by District and Plant in <u>2019</u>

	PP2	PP3	PP4	CHPX	HOB		PP2	PP3	PP4	CHPX	HOB	Total
Bayangol	0%	24%	52%	23%	0%	25%	-	392,313	838,504	376,196	-	1,607,013
Bayanzurkh	0%	19%	57%	16%	8%	19%	-	230,648	706,502	204,578	99,517	1,241,245
Songinokhairkhan	0%	37%	4%	39%	9%	13%	-	317,407	36,933	334,982	73,449	762,771
Sukhbaatar	0%	16%	74%	10%	0%	13%	-	135,650	630,252	83,370	-	849,273
Khan-Uul	0%	8%	69%	17%	6%	19%	-	102,697	853,682	208,115	76,751	1,241,245
Chingeltei	0%	12%	63%	18%	6%	11%	-	88,960	452,101	131,861	45,694	718,615
							-	1,267,674	3,517,973	1,339,103	295,411	6,420,161

Table VII-8: Allocation of Heat Production by District and Plant in <u>2020</u>

	PP2	PP3	PP4	CHPX	HOB		PP2	PP3	PP4	CHPX	HOB	Total
Bayangol	0%	24%	52%	23%	0%	26%	-	422,377	902,762	405,050	-	1,730,189
Bayanzurkh	0%	17%	52%	15%	16%	19%	-	216,400	662,858	191,953	204,572	1,275,783
Songinokhairkhan	0%	38%	4%	40%	17%	13%	-	342,679	39,873	361,675	155,651	899,879
Sukhbaatar	0%	16%	74%	10%	0%	12%	-	126,232	586,493	77,586	-	790,311
Khan-Uul	0%	8%	64%	16%	12%	19%	-	100,112	832,194	202,890	160,199	1,295,395
Chingeltei	0%	12%	59%	17%	13%	11%	-	87,515	444,758	129,728	96,454	758,454
							-	1,295,314	3,468,938	1,368,882	616,877	6,750,011

Table VII-9: Allocation of Heat Production by District and Plant in 2021

	PP2	PP3	PP4	CHPX	HOB		PP2	PP3	PP4	CHPX	HOB	Total
Bayangol	0%	23%	48%	29%	0%	24%	-	377,448	806,733	489,668	-	1,673,849
Bayanzurkh	0%	17%	53%	21%	8%	19%	-	228,815	700,886	282,801	105,686	1,318,188
Songinokhairkhan	0%	36%	4%	51%	9%	13%	-	332,853	38,730	477,794	80,413	929,790
Sukhbaatar	0%	15%	72%	13%	0%	12%	-	125,849	584,715	106,016	-	816,580
Khan-Uul	0%	8%	64%	22%	6%	19%	-	103,606	861,237	290,848	82,762	1,338,452
Chingeltei	0%	12%	59%	24%	6%	11%	-	90,226	458,538	185,070	49,830	783,664
							-	1,258,797	3,450,839	1,832,196	318,691	6,860,523

Table VII-10: Allocation of Heat Production by District and Plant in 2022

	PP2	PP3	PP4	CHPX	HOB		PP2	PP3	PP4	CHPX	HOB	Total
Bayangol	0%	21%	44%	35%	0%	22%	-	327,967	700,976	556,418	-	1,585,362
Bayanzurkh	0%	18%	54%	28%	0%	20%	-	255,884	783,801	401,553	-	1,441,238
Songinokhairkhan	0%	34%	4%	63%	0%	14%	-	338,141	39,345	631,380	-	1,008,867
Sukhbaatar	0%	15%	69%	16%	0%	12%	-	125,301	582,171	136,250	-	843,722
Khan-Uul	0%	8%	64%	28%	0%	19%	-	107,221	891,290	384,429	-	1,382,941
Chingeltei	0%	11%	58%	30%	0%	12%	-	99,343	504,872	260,527	-	864,743
							-	1,253,858	3,502,456	2,370,557	-	7,126,872

Table VII-11: Allocation of Heat Production by District and Plant in 2023

	PP2	PP3	PP4	CHPX	HOB		PP2	PP3	PP4	CHPX	HOB	Total
Bayangol	0%	20%	43%	37%	0%	20%	-	298,412	636,921	553,809	-	1,489,143
Bayanzurkh	0%	17%	53%	30%	0%	21%	-	270,089	828,540	464,972	-	1,563,600
Songinokhairkhan	0%	32%	4%	65%	0%	15%	-	352,472	41,144	723,241	-	1,116,857
Sukhbaatar	0%	15%	68%	17%	0%	12%	-	127,497	592,398	151,871	-	871,766
Khan-Uul	0%	8%	63%	30%	0%	19%	-	108,884	896,469	423,555	-	1,428,908
Chingeltei	0%	11%	57%	32%	0%	13%	-	107,831	549,501	310,611	-	967,943
							-	1,265,186	3,544,973	2,628,058	-	7,438,216

Table VII-12: Allocation of Heat Production by District and Plant in 2024

	PP2	PP3	PP4	CHPX	HOB		PP2	PP3	PP4	CHPX	HOB	Total
Bayangol	0%	20%	42%	39%	0%	18%	-	271,598	579,350	533,828	-	1,384,776
Bayanzurkh	0%	17%	51%	30%	2%	21%	-	268,735	824,386	489,808	32,642	1,615,572
Songinokhairkhan	0%	30%	3%	65%	2%	15%	-	345,046	40,277	748,842	19,815	1,153,980
Sukhbaatar	0%	14%	67%	18%	0%	11%	-	122,477	569,069	154,706	-	846,252
Khan-Uul	0%	7%	61%	30%	2%	20%	-	113,490	934,399	467,544	23,206	1,538,640
Chingeltei	0%	11%	55%	33%	2%	14%	-	115,954	590,893	353,697	16,504	1,077,048
							-	1,237,300	3,538,376	2,748,424	92,168	7,616,268

Table VII-13: Allocation of Heat Production by District and Plant in 2025

	PP2	PP3	PP4	CHPX	HOB		PP2	PP3	PP4	CHPX	HOB	Total
Bayangol	0%	19%	41%	40%	0%	17%	-	255,562	544,808	531,575	-	1,331,945
Bayanzurkh	0%	16%	49%	31%	4%	22%	-	275,832	846,157	532,857	69,688	1,724,534
Songinokhairkhan	0%	28%	3%	65%	3%	16%	-	353,665	41,283	814,323	43,006	1,252,277
Sukhbaatar	0%	14%	67%	19%	0%	11%	-	127,487	592,350	170,407	-	890,244
Khan-Uul	0%	7%	59%	31%	3%	20%	-	112,881	929,384	492,738	47,743	1,582,746
Chingeltei	0%	10%	53%	34%	3%	15%	-	121,286	618,068	392,041	35,770	1,167,164
							-	1,246,714	3,572,050	2,933,941	196,207	7,948,911

HEAT PRODUCTION SCENARIO 2 – HOB Expansion

Table VII-14: Allocation of Heat Production by District and Plant in 2013

	PP2	PP3	PP4	CHPX	HOB	Total	PP2	PP3	PP4	CHPX	HOB	Total
Bayangol	0%	38%	62%	0%	0%	26%	-	519,295	859,590	-	-	1,378,886
Bayanzurkh	0%	29%	71%	0%	0%	21%	-	334,896	806,397	-	-	1,141,293
Songinokhairkhan	34%	60%	6%	0%	0%	10%	187,583	336,572	35,093	-	-	559,248
Sukhbaatar	0%	20%	80%	0%	0%	17%	-	179,150	721,572	-	-	900,723
Khan-Uul	0%	18%	82%	0%	0%	15%	-	145,938	661,103	-	-	807,041
Chingeltei	0%	20%	80%	0%	0%	10%	-	109,531	442,826	-	-	552,357
							187,583	1,625,383	3,526,582	-	-	5,339,548

Table VII-15: Allocation of Heat Production by District and Plant in 2014

	PP2	PP3	PP4	CHPX	HOB	Total	PP2	PP3	PP4	CHPX	HOB	Total
Bayangol	0%	38%	62%	0%	0%	25%	-	525,242	869,434	-	-	1,394,676
Bayanzurkh	0%	29%	71%	0%	0%	22%	-	355,648	856,365	-	-	1,212,013
Songinokhairkhan	34%	60%	6%	0%	0%	10%	194,148	348,350	36,321	-	-	578,819
Sukhbaatar	0%	20%	80%	0%	0%	16%	-	178,883	720,496	-	-	899,379
Khan-Uul	0%	18%	82%	0%	0%	16%	-	155,648	705,089	-	-	860,737
Chingeltei	0%	20%	80%	0%	0%	10%	-	111,796	451,980	-	-	563,776
							194,148	1,675,566	3,639,685	-	-	5,509,399

Table VII-16: Allocation of Heat Production by District and Plant in 2015

	PP2	PP3	PP4	CHPX	HOB	Total	PP2	PP3	PP4	CHPX	HOB	Total
Bayangol	0%	35%	65%	0%	0%	25%	-	494,280	915,712	-	-	1,409,992
Bayanzurkh	0%	20%	54%	0%	26%	22%	-	261,036	695,389	-	329,749	1,286,174
Songinokhairkhan	25%	44%	5%	0%	27%	10%	147,111	263,955	27,521	-	160,485	599,072
Sukhbaatar	0%	20%	80%	0%	0%	16%	-	178,400	718,551	-	-	896,951
Khan-Uul	0%	10%	70%	0%	21%	16%	-	89,316	638,912	-	188,881	917,110
Chingeltei	0%	15%	64%	0%	21%	10%	-	83,551	368,589	-	123,204	575,344
							147,111	1,370,537	3,364,675	-	802,318	5,684,642

Table VII-17: Allocation of Heat Production by District and Plant in 2016

	PP2	PP3	PP4	CHPX	HOB	Total	PP2	PP3	PP4	CHPX	HOB	Total
Bayangol	0%	32%	68%	0%	0%	25%	-	464,802	992,057	-	-	1,456,859
Bayanzurkh	0%	19%	58%	0%	24%	22%	-	249,288	764,728	-	314,908	1,328,924
Songinokhairkhan	24%	44%	5%	0%	27%	10%	151,171	271,238	31,662	-	164,914	618,984
Sukhbaatar	0%	18%	82%	0%	0%	16%	-	164,135	762,629	-	-	926,764
Khan-Uul	0%	9%	73%	0%	19%	16%	-	83,503	687,503	-	176,588	947,593
Chingeltei	0%	13%	67%	0%	19%	10%	-	78,524	400,153	-	115,791	594,467
							151,171	1,311,489	3,638,731	-	772,200	5,873,592

Table VII-18: Allocation of Heat Production by District and Plant in 2017

	PP2	PP3	PP4	CHPX	HOB	Total	PP2	PP3	PP4	CHPX	HOB	Total
Bayangol	0%	31%	69%	0%	0%	25%	-	472,345	1,032,937	-	-	1,505,283
Bayanzurkh	0%	18%	56%	0%	27%	21%	-	227,459	715,314	-	342,282	1,285,055
Songinokhairkhan	20%	43%	5%	0%	32%	11%	136,844	288,653	34,311	-	213,317	673,124
Sukhbaatar	0%	17%	83%	0%	0%	15%	-	159,231	758,666	-	-	917,897
Khan-Uul	0%	8%	70%	0%	21%	18%	-	91,895	775,905	-	233,676	1,101,476
Chingeltei	0%	13%	65%	0%	22%	10%	-	76,792	401,502	-	135,932	614,227
							136,844	1,316,376	3,718,636	-	925,206	6,097,061

Table VII-19: Allocation of Heat Production by District and Plant in 2018

	PP2	PP3	PP4	CHPX	HOB	Total	PP2	PP3	PP4	CHPX	HOB	Total
Bayangol	0%	31%	69%	0%	0%	25%	-	479,877	1,075,439	-	-	1,555,316
Bayanzurkh	0%	17%	54%	0%	30%	20%	-	210,446	680,111	-	373,984	1,264,542
Songinokhairkhan	16%	42%	5%	0%	37%	12%	123,193	318,249	38,538	-	278,744	758,725
Sukhbaatar	0%	17%	83%	0%	0%	14%	-	150,341	734,839	-	-	885,179
Khan-Uul	0%	8%	68%	0%	24%	18%	-	89,610	777,680	-	270,798	1,138,088
Chingeltei	0%	12%	63%	0%	25%	10%	-	74,859	402,500	-	157,284	634,643
							123,193	1,323,382	3,709,107	-	1,080,811	6,236,492

Table VII-20: Allocation of Heat Production by District and Plant in 2019

	PP2	PP3	PP4	CHPX	HOB	Total	PP2	PP3	PP4	CHPX	HOB	Total
Bayangol	0%	32%	68%	0%	0%	25%	-	512,707	1,094,305	-	-	1,607,013
Bayanzurkh	0%	15%	47%	0%	38%	19%	-	188,235	577,440	-	475,570	1,241,245
Songinokhairkhan	0%	43%	5%	0%	52%	13%	-	364,067	42,498	-	442,708	849,273
Sukhbaatar	0%	18%	82%	0%	0%	13%	-	150,411	698,862	-	-	849,273
Khan-Uul	0%	7%	61%	0%	31%	19%	-	92,198	759,094	-	389,952	1,241,245
Chingeltei	0%	11%	56%	0%	33%	11%	-	79,448	404,861	-	234,307	718,615
							-	1,387,067	3,577,060	-	1,542,536	6,506,663

Table VII-21: Allocation of Heat Production by District and Plant in 2020

	PP2	PP3	PP4	CHPX	HOB	Total	PP2	PP3	PP4	CHPX	HOB	Total
Bayangol	0%	32%	68%	0%	0%	26%	-	552,006	1,178,183	-	-	1,730,189
Bayanzurkh	0%	14%	43%	0%	43%	19%	-	177,920	545,798	-	552,064	1,275,783
Songinokhairkhan	0%	38%	4%	0%	57%	13%	-	345,883	40,375	-	513,621	899,879
Sukhbaatar	0%	18%	82%	0%	0%	12%	-	139,968	650,342	-	-	790,311
Khan-Uul	0%	7%	57%	0%	36%	19%	-	89,689	738,437	-	467,269	1,295,395
Chingeltei	0%	10%	52%	0%	37%	11%	-	77,975	397,357	-	283,122	758,454
							-	1,383,442	3,550,492	-	1,816,076	6,750,011

Table VII-22: Allocation of Heat Production by District and Plant in 2021

	PP2	PP3	PP4	CHPX	HOB	Total	PP2	PP3	PP4	CHPX	HOB	Total
Bayangol	0%	32%	68%	0%	0%	24%	-	534,031	1,139,818	-	-	1,673,849
Bayanzurkh	0%	13%	39%	0%	48%	19%	-	167,765	514,645	-	635,779	1,318,188
Songinokhairkhan	0%	34%	4%	0%	62%	13%	-	316,176	36,907	-	576,706	929,790
Sukhbaatar	0%	18%	82%	0%	0%	12%	-	144,621	671,959	-	-	816,580
Khan-Uul	0%	6%	53%	0%	41%	19%	-	85,922	707,420	-	545,110	1,338,452
Chingeltei	0%	10%	48%	0%	42%	11%	-	74,495	379,621	-	329,549	783,664
							-	1,323,009	3,450,370	-	2,087,144	6,860,523

Table VII-23: Allocation of Heat Production by District and Plant in 2022

	PP2	PP3	PP4	CHPX	HOB	Total	PP2	PP3	PP4	CHPX	HOB	Total
Bayangol	0%	32%	68%	0%	0%	22%	-	505,800	1,079,562	-	-	1,585,362
Bayanzurkh	0%	12%	37%	0%	51%	20%	-	174,957	536,708	-	729,573	1,441,238
Songinokhairkhan	0%	32%	4%	0%	64%	14%	-	323,474	37,759	-	647,634	1,008,867
Sukhbaatar	0%	18%	82%	0%	0%	12%	-	149,428	694,294	-	-	843,722
Khan-Uul	0%	6%	51%	0%	43%	19%	-	85,241	701,811	-	595,889	1,382,941
Chingeltei	0%	9%	46%	0%	44%	12%	-	78,833	401,730	-	384,179	864,743
							-	1,317,732	3,451,864	-	2,357,276	7,126,872

Table VII-24: Allocation of Heat Production by District and Plant in 2023

	PP2	PP3	PP4	CHPX	HOB	Total	PP2	PP3	PP4	CHPX	HOB	Total
Bayangol	0%	32%	68%	0%	0%	20%	-	475,102	1,014,041	-	-	1,489,143
Bayanzurkh	0%	12%	36%	0%	52%	21%	-	183,686	563,485	-	816,428	1,563,600
Songinokhairkhan	0%	31%	4%	0%	66%	15%	-	343,639	40,113	-	733,105	1,116,857
Sukhbaatar	0%	18%	82%	0%	0%	12%	-	154,395	717,371	-	-	871,766
Khan-Uul	0%	6%	49%	0%	45%	19%	-	85,637	705,078	-	638,192	1,428,908
Chingeltei	0%	9%	45%	0%	46%	13%	-	85,728	436,863	-	445,352	967,943
							-	1,328,187	3,476,952	-	2,633,078	7,438,216

Table VII-25: Allocation of Heat Production by District and Plant in 2024

	PP2	PP3	PP4	CHPX	HOB	Total	PP2	PP3	PP4	CHPX	HOB	Total
Bayangol	0%	32%	68%	0%	0%	18%	-	441,804	942,972	-	-	1,384,776
Bayanzurkh	0%	11%	34%	0%	55%	21%	-	177,135	543,388	-	895,049	1,615,572
Songinokhairkhan	0%	28%	3%	0%	69%	15%	-	325,180	37,958	-	790,841	1,153,980
Sukhbaatar	0%	18%	82%	0%	0%	11%	-	149,876	696,376	-	-	846,252
Khan-Uul	0%	6%	47%	0%	48%	20%	-	86,967	716,022	-	735,651	1,538,640
Chingeltei	0%	8%	42%	0%	49%	14%	-	89,797	457,597	-	529,654	1,077,048
							-	1,270,758	3,394,314	-	2,951,196	7,616,268

Table VII-26: Allocation of Heat Production by District and Plant in 2025

	PP2	PP3	PP4	CHPX	HOB	Total	PP2	PP3	PP4	CHPX	HOB	Total
Bayangol	0%	32%	68%	0%	0%	17%	-	424,949	906,996	-	-	1,331,945
Bayanzurkh	0%	11%	34%	0%	55%	22%	-	189,081	580,037	-	955,416	1,724,534
Songinokhairkhan	0%	28%	3%	0%	69%	16%	-	352,880	41,192	-	858,206	1,252,277
Sukhbaatar	0%	18%	82%	0%	0%	11%	-	157,667	732,577	-	-	890,244
Khan-Uul	0%	6%	47%	0%	48%	20%	-	89,460	736,547	-	756,739	1,582,746
Chingeltei	0%	8%	42%	0%	49%	15%	-	97,310	495,885	-	573,970	1,167,164
							-	1,311,346	3,493,233	-	3,144,331	7,948,911

VIII. APPENDIX B: RISK FACTOR METRICS

Criteria for Evaluating Plans

Table VIII-1: Criteria

Policy Area	Criteria Name	Metric	Direction	Weighting
Environmental	CO2 Emissions	Total CO2 Emissions (2013 to 2025)	Minimize	0.28
Financial	Cost of Plan	Total PV Cost of Plan (2013 to 2025), normalized to Reference Plan 1a	Minimize	0.40
Diversification	Installed Coal-Fired Capacity	% of Total Energy Generated by Coal-Fired Power in 2025	Minimize	0.12
Security of Supply	Risk Factor	Weighted Average of Project Risk Factors (by capacity contribution)	Minimize	0.20

Measuring the Risk of the Plans

Table VIII-2: Risk Factor Metrics

Risk rating			
Projects	**R**	**Rationale**	**Scoring**
No risk project	0	High confidence in cost assumptions	
		High confidence in technology	
		High confidence in timing	
		High confidence in reliability	
		Minimal safety concerns	
		No resource concerns	
FBC	6	Moderate confidence in cost assumptions	2
		Moderate confidence in technology	1
		Moderate confidence in timing	1
		High confidence in reliability	0
		Minimal safety concerns	0
		Moderate resource concerns: water	2
Wind	8	Confidence in cost assumptions	1
		Low confidence in technology	2
		Fair confidence in timing	1
		Low confidence in reliability: Mongolian weather	3
		Minimal safety concerns	0

Risk rating			
Projects	**R**	**Rationale**	**Scoring**
		Low resource concerns: wind speed	1
Small Hydro	6	Confidence in cost assumptions	1
		High confidence in technology	0
		Confidence in timing	1
		Poor confidence in reliability: history in Mongolia	2
		Minimal safety concerns	0
		Moderate resource concerns: water	2
Large Hydro	9	Low confidence in cost assumptions	3
		High confidence in technology	0
		Moderate confidence in timing	2
		Moderate confidence in reliability	2
		Minimal safety concerns	0
		Moderate resource concerns: water	2
Solar PV Farm	8	Moderate confidence in cost assumptions	2
		High confidence in technology	3
		Moderate confidence in timing	0
		High confidence in reliability	1
		Minimal safety concerns	0
		No resource concerns	2
CSP	11	Low confidence in cost assumptions	3
		High confidence in technology	3
		Moderate confidence in timing	2
		High confidence in reliability	1
		Minimal safety concerns	0
		Moderate resource concerns: water	2
CHP	4	High confidence in cost assumptions	0
		High confidence in technology	0
		Moderate confidence in timing	3
		High confidence in reliability	0
		Minimal safety concerns	0
		Moderate resource concerns: water	1
HOB	7	High confidence in cost assumptions	1
		High confidence in technology	1
		Moderate confidence in timing	2
		High confidence in reliability	0
		Moderate safety concerns:Ash, Dust	2
		Moderate resource concerns: water	1

Weighting the Risk Factors for Each Scenario

Table VIII-3: Risk Factor Metrics

Scenario Plan	Name	R	Projects	New Capacity by 2025	Scoring
		Risk rating			
1a	Reference - CHP5	4.1	Wind	50	8.0
			FBC	900	4.0
			CHP	750	4.0
1b	Reference - HOB	5.3	Wind	50	8.0
			FBC	1,500	4.0
			HOB	1,028	7.0
2a	Domestic emission (Emission 1)	5.1	Wind	50	8.0
			FBC	750	4.0
			CHP	750	4.0
			Large Hydro	390	9.0
2b	Domestic emission (Emission 2)	5.2	Wind	50	8.0
			FBC	600	4.0
			CHP	750	4.0
			Large Hydro	390	9.0
2c	Domestic emission (Emission 3)	5.7	Wind	400	8.0
			FBC	600	4.0
			CHP	750	4.0
			Large Hydro	390	9.0
2d	Carbon Tax	4.1	Wind	50	8.0
			FBC	600	4.0
			CHP	750	4.0
3a	IPP alternates 1	4.1	Wind	50	8.0
			FBC	600	4.0
			CHP	750	4.0
3b	IPP alternates 2	4.1	Wind	50	8.0
			FBC	750	4.0
			CHP	750	4.0

Risk rating					
Scenario Plan	Name	R	Projects	New Capacity by 2025	Scoring
3c	IPP alternates 3	5.9	Wind	1,200	8.0
			FBC	600	4.0
			CHP	750	4.0
4	Lowest CO2	6.0	Wind	400	8.0
			CHP	750	4.0
			Large Hydro	610	9.0
			FBC	600	4.0

IX. APPENDIX C: PARTIAL VALUE FUNCTIONS

Table IX-1: Cost Value Curve

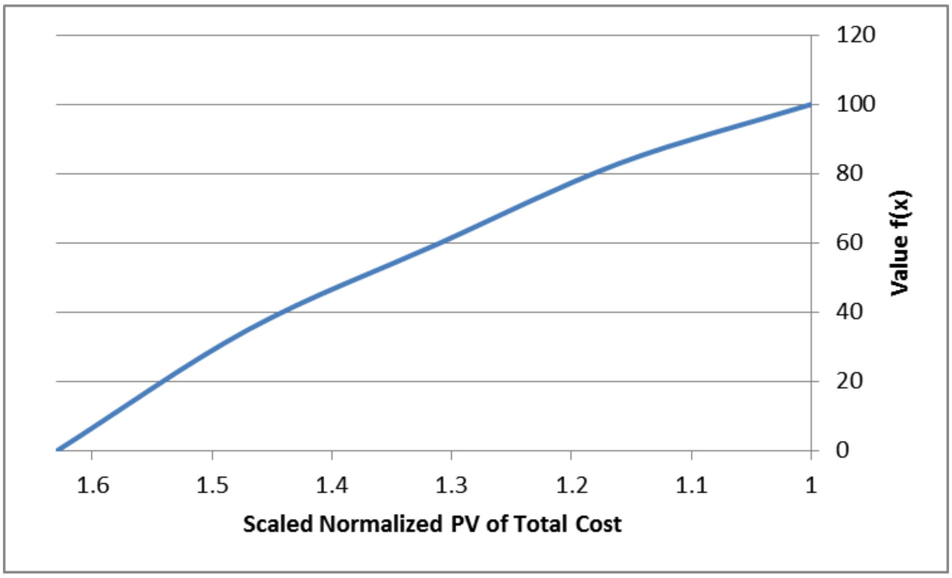


Table I-2: Emissions Value Curve

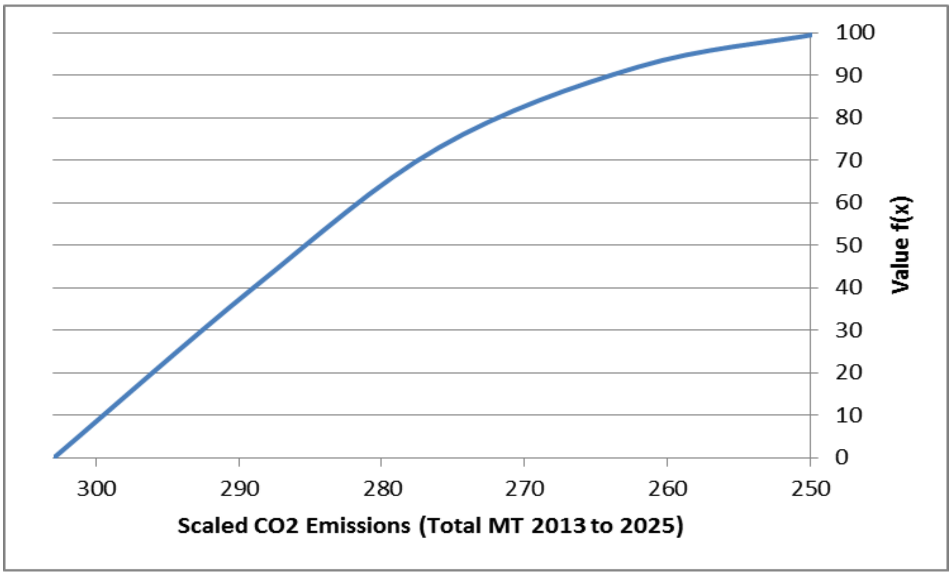


Table I-3: Diversity Value Curve

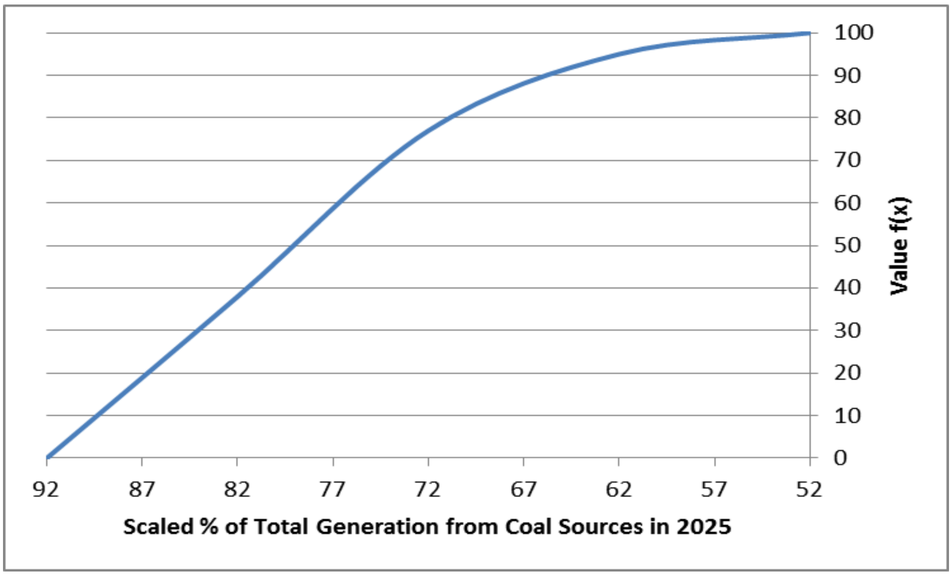


Table I-4: Risk Value Curve