Economic Policy Reform and Competitiveness Project

EPRC Proposed Two-Part Tariff for Purchases of Electric Capacity and Energy from Generation Licensees

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ABBREVIATION AND ACRONYMS

CHP	Combined Heat and Power
ERA	Energy Regulatory Authority
EPRC	Economic Policy Reform and Competitiveness Project
NDC	National Dispatch Center
O&M	Operation and Maintenance
USAID	United States Agency for International Development

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SECTION I: EPRC PROPOSED TWO-PART TARIFF FOR PURCHASES OF ELECTRIC CAPACITY AND ENERGY FROM GENERATION LICENSEES

The EPRC Project Team has been requested by the ERA to propose a revised two-part tariff for purchases of electrical capacity and energy from generation licensees. The tariff is to be based on 2010 generating company revenue requirement data. Generation licensees have been recovering their revenue requirement from a two-part tariff approved by the ERA on the basis of cost data submitted by the generation licensees, but NDC has not been practicing economic dispatch.

In March 2010, EPRC submitted a draft report on a proposed two-part tariff methodology for the consideration of the ERA, generation licensees and the dispatch licensee (NDC). The licensees provided written comments, and a roundtable discussion was held at the ERA on May 4, 2010. This report documents and addresses comments received from licensees and presents a two-part tariff methodology for adoption by industry stakeholders to enable NDC to initiate dispatch on the basis of economic merit order during 2010. The tariff is proposed for use in the electricity market currently in place in Mongolia which is, in effect, a vertically-integrated market structure with separate business units.

1. Background

"Economic dispatch" is the practice of operating a coordinated power system such as the CES so that the lowest-cost generators are used as much as possible to meet demand, with more expensive generators brought into production as loads increase (and conversely, more expensive generation eliminated from production as load falls). The U.S. Environmental Protection Act's definition of economic dispatch is: "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities".

Economic dispatch is performed on the basis of an economic optimization process that determines a combination of generators and levels of electricity output to meet demand at the lowest cost, given the operational constraints of the generation fleet and the transmission system. Economic dispatch reduces total variable production costs (i.e., cost of primary fuel, coal in Mongolia, and variable operation and maintenance costs) by serving load using lower-variable-cost generation before using higher-variable cost generation. Economic dispatch can reduce fuel use when it results in greater use of lower variable cost, higher-efficiency generation units than lower-efficiency units consuming the same fuel.

Many factors influence economic dispatch in practice. These include contractual, regulatory, environmental, scheduling, unit commitment, and reliability practices and procedures. In Mongolia's case, heating load is a critical factor in the dispatch process as well. Because economic dispatch requires a balance among economic efficiency, reliability, and other factors, it is best thought of as a constrained cost-minimization process.

Economic dispatch benefits consumers in a number of ways. To minimize costs, economic dispatch typically increases the use of the more efficient generation units, which can lead to better fuel utilization, lower fuel usage, and reduced air emissions than would result from using less-efficient generation. Retail customers benefit from reduced pollution and lower electricity bills when the savings are passed through in retail tariffs. As the geographic and electrical scope integrated under unified economic dispatch increases (i.e., inclusion of Russia in Mongolia's case), additional cost savings result from pooled operating reserves, which allow an area to meet loads reliably using less total generation capacity than would be needed otherwise.

In electricity markets such as that in Mongolia, economic dispatch is promoted through two-part generation purchase tariffs. A two-part tariff recognizes that a generator provides two services: energy and availability, that is, the ability to deliver energy when called upon.[1] Energy relates to the provision of a useful commodity (i.e., electrical energy), while availability relates to the provision of reliable service. The two-part tariff therefore has two components: 1) an energy charge for recovery of the licensee's energy production costs, and 2) a capacity charge for recovery of the licensee's fixed costs; i.e., all costs that are not recovered in the energy charge. A licensee's energy production costs include all variable costs (i.e., costs that vary with changes in energy production), specifically, primary fuel costs and the component of operation and maintenance costs that vary with production.

Improved efficiency and performance is encouraged through the use of benchmarks as opposed to simply passing all costs through directly to the buyer. Benchmarks are established on the basis of historical performance (perhaps averaged over the past three years), and performance of similar generating units, both internal and external to Mongolia, as necessary. In this way, generating licensees can increase profits if they exceed the benchmarks. Conversely, if they fall short of the benchmarks, the generating licensee will absorb the revenue loss rather than consumers. This is consistent with a competitive market where the best performers generally have higher profit margins.

The benchmarks should be established for a period long enough to allow recovery of investment used to improve performance, for example, three years. Otherwise, the licensees will have limited incentive to invest. At the end of the three year period, the benchmarks might be re-set to reflect improvements, thus passing along the benefits to consumers.

2. Revenue Requirement

The first step in the tariff design process is to determine the revenue requirement of the generating licensees. The revenue requirement is allocated to heat and electricity, and tariffs are designed to recover the revenue requirement allocated to each commodity.

The generation licensees have submitted forecast cost and production data for 2010 to the ERA. The ERA has reviewed the submissions, and determined the appropriate revenue requirement on the basis of this data. The generation licensees produce two products: electricity and heat. The total revenue requirement is therefore allocated between heat and electricity on the basis of pre-determined formulas. In 2010, the Government intends to provide a subsidy to the power sector in order to bring generating licensee revenues closer to full cost recovery levels[2]. The intent of the Government subsidy is to reduce the revenue to be recovered in tariffs. The revenue requirement to be collected by heat and electricity tariffs is therefore reduced by the amount of the Government subsidy distributed to each generation licensee. Note that Erdenet is used primarily as a heat plant, so the entire Government subsidy provided to Erdenet is allocated to heat; i.e., none of the subsidy is allocated to electricity. ***It is necessary for the ERA to adjust the revenue requirement for Erdenet accordingly.***

The 2010 revenue requirement allocated to electricity and the forecast energy production delivered to the transmission grid by each generation licensee is provided in Table 1.

[1] A generating licensee can also provide various ancillary services. However, under the current regime in Mongolia, a generating licensee is expected to provide ancillary services within the framework of the current pricing format.

[2] The ERA is on a path to bring tariffs up to full cost recovery levels over a period of years. The current tariff and Government subsidy combined will approach, but not yet attain, full cost recovery for the generating companies. The fact that tariffs do not fully recover costs influences tariff design.

Table 1. 2010 Forecast Revenue Requirement and Electrical Energy Production

	CHP 4	CHP 2	CHP 3	Erdenet	Darkhan
Total Revenue Requirement (Million MNT)	111,000	8065.2	47,644.1	13,111.3	17,035.2
Revenue Allocated to Electricity (Million MNT)	88,512.1	6975.2	34,517.1	9909.8	14,898.4
Electricity Revenue to be Met by Government Subsidy (Million MNT)	4834.0	570.0	2399.0	0	2164.0
Revenue to be Recovered in Electricity Tariffs (Million MNT)	83,678.1	6405.2	32,118.1	9909.8	12,734.4
Electric Energy Delivered to Grid (GWh)	2334.4	100.0	527.4	99.3	204.2

3. Two-Part Generation Purchase Tariff for Electricity

The two-part generation purchase tariff is designed to recover the total revenue requirement allocated to electricity for each generation licensee, less the Government subsidy for electricity allocated to each generation licensee. In order to fairly compensate generation licensees under an economic dispatch regime, it is necessary to design a two-part tariff for purchases of electricity, including an energy component and a capacity component. Owing to the importance of economic dispatch, the design of the energy component takes priority. Following the design of the energy component, the capacity component of the tariff is designed to recover the portion of the revenue requirement allocated to electricity that is not collected by the energy tariff.

3.1 Energy Component

The goal of the energy tariff design is to fairly compensate generation licensees for following NDC dispatch instructions consistent with economic dispatch. The energy tariff is designed to recover all costs that vary with energy production. It should recover all costs of producing electric energy, including the delivered cost of primary fuel, and the variable component of operation and maintenance costs; i.e., water, chemicals, labor, maintenance, etc.

The cost of fuel is relatively straightforward. It includes the total cost of coal (including the cost of coal transport to the plant site), the cost of coal handling and the cost of mazout/diesel fuel for unit start-up. The variable costs of operation and maintenance (O&M) are not as straightforward as they are not tracked separately in Mongolia's system of accounts. While there are separate accounts for fuel, variable water, chemicals and lubricants, there are no separate accounts for variable labor and maintenance. In the absence of this detailed information, they may be approximated using percentages of other costs, and in some instances, are based purely on engineering experience and judgment. For example, in the World Bank Report entitled *Design of Electricity Prices for Generation, Transmission and Distribution for Mongolia*, the consultants estimate variable operation and maintenance costs for each of Mongolia's combined heat and power (CHP) plants at US$ 2.00/MWh (see Table 3.9, page 23). The consultants use the same estimate of variable operation and maintenance costs for a typical coal plant (Table 4.1, page 30). The US$ 2/MWh estimate is consistent with variable O&M cost estimates for various coal technologies quoted in American utility integrated resource plans which generally range from US$ 1 - 2/MWh. As a result, the ERA proposes use of 2.4 MNT/kWh for each generation licensee. Consistently applying a 2.4 MNT/kWh variable O&M charge is a reasonable assumption. It improves the fairness of the energy charge by properly compensating the generation licensees for energy produced without affecting economic merit order and the licensee's overall revenue recovery. ***However, it is recommended that the ERA request the generation licensees to provide detailed estimates of variable operation and maintenance costs for inclusion in future two-part tariff designs.***

In order to encourage generation licensees to maintain and improve production efficiency, the energy tariff design should be based on the average delivered price of fuel to the generation station in MNT/kcal multiplied by the benchmark fuel conversion efficiency, or heat rate, in kcal/kWh[3]. The fuel conversion efficiency is the efficiency at which a generating station converts the energy in coal to useful energy. In this case, we are interested in fairly compensating a generation licensee for electricity delivered to the transmission system. The heat tariff separately compensates generation licensees for heat delivered to the heating network.

The appropriate fuel conversion efficiency, or heat rate, to be used in the two-part tariff development should be based on historical experience and industry standards for similar technologies while taking into consideration changes in the operating pattern of a generating station. By basing the fuel conversion efficiency on historical experience, generation licensees are encouraged to improve their fuel conversion efficiency to increase profits. Further, by basing the energy tariff on energy delivered to the grid, generation licensees are encouraged to reduce internal consumption and losses.

As there have been changes recently in the fuel consumed at the various plants on the CES, EPRC recommends that the fuel conversion efficiency be based on recent actual experience. For the immediate term, EPRC recommends that the fuel conversion efficiency be based on actual experience in 2009. As experience is gained with the new tariff, fuel conversion efficiency benchmarks can be established based on actual experience averaged over a few recent years, and can incorporate industry benchmarks and technical changes in plant operation as desired.

The fuel conversion efficiency for each generation licensee based on actual 2009 experience is shown in Table 2. Note that the data relate to the total coal consumed at each generating station for production of both heat and electricity. This is appropriate for two reasons:

1. Because the generation licensees do not produce heat and electricity separately; and
2. Because there is much less flexibility in meeting heat demand than there is in meting electricity demand, so heat demand represents a constraint.

With regard to point 2, there are three heating networks in Mongolia – Darkhan, Erdenet and Ulaanbaatar. Darkhan CHP is the only CHP connected to the Darkhan heating network, so must meet the heating requirements of the Darkhan area. Similarly, Erdenet CHP is the only CHP connected to the Erdenet heating network, so must meet the heating requirements of the Erdenet area. CHP 2, CHP 3 and CHP 4 are all connected to the Ulaanbaatar heating network, and all three CHPs are used to meet the heating needs of the UB area. However, CHP 3

[3] Mongolia generally speaks in terms of a generator's conditional fuel rate as opposed to a generator's fuel conversion efficiency, or heat rate. The conditional fuel rate is defined as the equivalent fuel used with a heating value of 7000 ccal (or 29.3 Mjoules) per 1 kg of solid or liquid fuel (or 1 cubic meter of gaseous fuel). The terminology was used
extensively in the development of energy balances in the former Soviet Union, and is sometimes referred to as "standard" or "equivalent" fuel. This is another way of presenting a power plant's heat rate, but owing to the complex allocation between heat and electricity, is not appropriate for use in the development of the energy charge component of a two-part generation purchase tariff for electricity.

currently must generate heat at near full capacity. Heating pipe capacity limitations[4] limit the ability of CHP 4 to displace CHP 3 heat production despite CHP 4's capacity to produce additional heat. The portion of the UB heat network supplied by CHP 2 is very small, and as a result, so is its heat production. In summary, it is not unreasonable to dispatch the five CHPs connected to the CES on the basis of lowest cost to produce electricity after meeting heat demand. This approach will fairly compensate generation licensees for electrical energy delivered to the grid.

Note that the fuel conversion efficiency figures for Erdenet and Darkhan may require adjustment for 2011 as both plants are scheduled to begin shifting from Shariin Gol coal, their design coal, to Shivee Ovoo coal owing to depletion of the Shariin Gol coal reserves. Fuel conversion efficiency for these plants will need to be revised to reflect experience gained from operating on the new coal.

Table 2. Fuel Conversion Efficiency Based on 2009 Actual

	CHP 4	CHP 2	CHP 3	Erdenet	Darkhan
Electricity Delivered to Grid (GWh)	2325.0	98.6	513.9	111.6	195.2
Total Coal Consumption (Tons)	2,635,911	179,956.2	973,237.3	288,653	350,742.4
Average Calorific Value (kCal/kg)	3315.0	3429.0	3485.0	3400.7	3473
Total Calories (Gcal)	8,738,045	617,070	3,391,732	981,622	1,218,128
Fuel Conversion Efficiency (kCal/kWh)	3758.3	6258.3	6600.0	8795.9	6240.4
As a Percentage of CHP-4 (%)	100	167	176	234	166

CHP 4 had a much better fuel conversion efficiency in 2009 than the other generation licensees. This is not surprising as CHP 4 has larger, more efficient generating units with more recent technology. Based on the operating pattern in 2009, the fuel conversion efficiency of all other generation licensees was at least 66% greater than that of CHP 4. Overall, CHP 3 was more efficient than CHP 2 in 2009 when both heat and electricity production are taken into account; i.e., CHP 3 produced more useful energy in terms of heat (GCal) and electricity (GWh) per GCal of coal burned. However, when considering electricity production only, CHP 2 was slightly more efficient than CHP 3. This means that on average in 2009, CHP 2 electricity production was better matched to its heat production than was CHP 3. CHP 3 produced heat at maximum output in 2009, while its electricity production was far below maximum (less than 60% of capacity). This implies that CHP 3 is not always being dispatched to maximize overall production efficiency. In fact, as already noted, the entire system is not being dispatched to maximize efficiency and minimize variable costs because:

- Generators are being dispatched to ensure the revenue requirement is met rather than to minimize costs; and
- NDC does not have system simulation software that would enable determination of the optimal dispatch regime under different demand and system constraint scenarios.

It is for these reasons that EPRC is recommending that a two-part tariff regime be implemented, and that system simulation software be procured. The proposed two-part tariff will not solve all problems and result in the most efficient dispatch regime, but it will be a

[4] Last winter was the coldest in recent years, and owing to heating pipe capacity limitations, CHP 3 was forced to produce heat at levels slightly in excess of its maximum capacity.

significant improvement over what is in place today. EPRC continues to recommend that system simulation software be procured as its payback period is expected to be less than one year.

Because the operating pattern is expected to change in 2010 under economic dispatch, and because electricity and heat demand are expected to continue to grow, it is important to monitor fuel conversion efficiencies in the future to ensure generation licensees continue to have a reasonable opportunity to recover their revenue requirement.

Based on ERA forecasts for 2010, the variable production costs including fuel and variable operation and maintenance costs are calculated as shown in Table 3. Fuel costs include the total cost for both heat and electricity production including the cost of: coal, coal transport, coal handling and mazout. The variable operation and maintenance cost is based on the 2.4 MNT/kWh estimate discussed above.

Table 3. Calculation of 2010 Energy Tariff

Plant	CHP 4	CHP 2	CHP 3	Erdenet	Darkhan
Electricity Delivered to Grid (GWh)	2334.4	100.0	527.4	99.3	204.2
Coal Consumption (Tons)	2,653,072	183,000	987,580.3	254,718.2	353,866
Average Calorific Value (kcal/kg)	3250.2	3360.0	3360.0	3400.0	3250.2
Total Calories (Gcal)	8,623,015	614,880	3,318,270	866,042	1,150,135
Cost of Fuel (Million MNT)	60,633.1	4560.3	24,116.8	8320.6	9387.9
Average Cost of Fuel (MNT/kCal)	0.0070	0.0074	0.0073	0.0096	0.0082
Benchmark Fuel Conversion Efficiency (kcal/kWh)	3758.3	6258.3	6600.0	8795.9	6240.4
Variable O&M (MNT/kWh)	2.4	2.4	2.4	2.4	2.4
Energy Tariff (MNT/kWh)	28.8	48.8	50.4	86.9	53.3

As can be seen, CHP 4 has far lower electrical energy production costs than the other generating stations. This is in part due to its greater fuel production efficiency and in part due to its operating pattern – it is used extensively for production of both heat and electricity, while other generating stations are used primarily for heat; i.e., CHP 3 and Erdenet. When a generating station is used primarily for heat production, the incremental cost of electricity production tends to be quite high. Nonetheless, these energy charges are an accurate reflection of the average cost of a generation licensee to produce a kWh of electricity and deliver it to the transmission grid.

At any given time, a generation licensee's cost to produce another kWh will vary from the energy tariff shown above, but averaged over a year, it should be a fairly accurate measure of the cost to produce electrical energy as long as operating patterns remain similar to that forecast. As noted, the tariffs must be reviewed annually to ensure licensees continue to be properly compensated, particularly since operating patterns will change under economic dispatch, and as electricity and heat demand continues to grow.

EPRC understands that the generation licensees pay for coal by the ton. Tests are conducted by the generation licensees to ensure the calorific value, or heat content, meets minimum levels. The generation licensees are in turn responsible for conveying the average heat content of coal deliveries to the ERA. In most international jurisdictions, primary fuel is paid for according to heat content rather than weight. ***EPRC recommends that Mongolia consider revising the current methodology for coal pricing to one where the coal companies are paid according to calorific value. If this is not immediately possible, it is recommended that as a minimum, coal company staff be present when the generation licensees conduct tests on calorific content of coal deliveries, and sign off on the results.***

As explained by EPRC in earlier versions of reports on two-part tariff methodologies, the energy tariff should vary to reflect changes in production costs in the heating and non-heating seasons. The nature of combined heat and power technology is such that fuel conversion efficiency is much different when a plant is used to produce electricity only, versus heat and electricity. The energy tariffs for the heating and non-heating seasons are calculated in the same manner as above, but variable costs and production are summed over the heating and non-heating months, yielding a tariff for each season rather than the entire year. The primary difference in the energy tariff for each season would be the fuel conversion efficiency as the average cost of coal and the variable O&M cost are likely to be constant over the entire year. Therefore, the same analysis is conducted as that shown in Table 2, but the year is split into heating and non-heating seasons to determine the appropriate fuel conversion efficiency in each season.

EPRC recommends that the ERA start collecting the data necessary to enable introduction of a seasonally varying energy tariff in 2011.

3.2 Capacity Component

All other costs of the generating licensee allocated to electricity (less the Government subsidy) that are not recovered in the energy charge are recovered in the capacity charge. Note that the capacity tariff will not fully reflect each generation licensee’s fixed costs because of the interaction between heat and electricity allocation, the Government subsidy, and the fact that tariffs do not fully recover each generator’s cost of supply.

The capacity charge calculation is shown in Table 4. EPRC recommends that the capacity charge be a flat monthly charge that is independent of plant capacity. This is a change from the current two-part tariff methodology used in Mongolia which compensates generation licensees on the basis of average capacity. Compensating generation licensees on this basis is equivalent to an energy payment, thus defeating the purpose of a two-part tariff which is to promote economic dispatch.

As noted earlier, Erdenet is used primarily for heat production and is projected to have very high fuel costs in 2010 because it is switching to a higher cost coal located over 1000 km from the power plant site. Erdenet continues to have value on the CES; in fact, its electrical capacity is becoming more valuable as demand grows and the demand/supply gap tightens.

As noted by EPRC in earlier versions of reports on two-part tariff methodologies, the capacity tariff should be designed to provide incentives to generation licensees to be available, particularly during the winter peak period when reliable capacity is at a premium. Data and information on generation availability has not been tracked by NDC. Further, the capacity payment is quite small at this time, meaning it does not provide a particularly strong price signal As a result, it is recommended that the capacity tariff be a fixed monthly payment until such information can be accumulated. ***EPRC recommends that NDC start collecting availability data for each generating licensee immediately so that improved tariff designs***

can be implemented as early as 2011. Such tariff designs have been explained in a number of documents produced by EPRC in the past, and address not only availability, but also seasonal considerations and potential bonus payments during times when capacity has the greatest value.

Table 4. Calculation of 2010 Capacity Tariff

	CHP 4	CHP 2	CHP 3	Erdenet	Darkhan
Revenue to be Recovered in Electricity Tariffs (Million MNT)	83,678.1	6405.2	32,118.1	9909.8	12,734.4
Revenue Recovered in Energy Tariff (Million MNT)	67,292.9	4881.5	26,564.1	8630.0	10,891.4
Revenue to be Recovered in Capacity Tariff (Million MNT)	16,385.2	1523.7	5554.0	1279.8	1843.0
Monthly Capacity Tariff (Million MNT/Month)	1365.4	127.0	462.8	106.7	153.6

4. Comments from Industry Stakeholders

A roundtable discussion was held on May 4, 2010. It was attended by staff from the ERA, the generation licensees, NDC and the EPRC Energy Team. The purpose was to discuss the EPRC-proposed two-part tariff for purchases of electric generation. Stakeholders also provided written comments on the proposed tariff. Some of the comments are addressed in prior text in this report through the addition of clarifications. Others are addressed below.

At the roundtable discussion it was explained that the proposed tariff is about as simple as can be implemented while still accomplishing the goal of economic dispatch. Economic dispatch has significant benefits in terms of reduced costs (estimated at more than US$ 3 million annually) and reduced pollution. The generation licensees need to embrace economic dispatch as it will reduce costs, thus improving the financial position of licensees. Stakeholder comments and the EPRC responses follow.

- It was suggested that generators should receive a profit margin on the energy tariff (i.e., 5%) to provide incentive to follow dispatch instructions. It was noted that such an “incentive” would promote generation when it is neither needed nor called for by the dispatch center. This is a problem encountered in jurisdictions such as India where generators often produce too much energy in an effort to increase revenues, resulting in system frequency problems. Further, when a generator is dispatched less than forecast, its revenue reduction would exceed its cost reduction, providing a disincentive to follow dispatch instructions as it would lead to deterioration of its financial position. If licensees do not follow dispatch instructions they should be penalized in the form of fines or reduced revenues. The fact that the fuel conversion efficiency built into the tariff is based on historical experience and will be frozen for several years is enough incentive for generators to improve their fuel conversion efficiency and increase profits. Once such improvements are made, the ERA must allow the licensees to keep the profits for a reasonable period of time (i.e., 3 - 5 years), before re-setting the fuel conversion efficiency to return benefits to consumers.
- Generation licensees remain concerned that they will be exposed to revenue risk if they are dispatched less than forecast. They raised a number of abstract scenarios with low probability of occurrence. Even if such scenarios were to occur, the problem would

exist regardless of the tariff design. When such occasions arise, the licensees have the option of filing an application for a tariff increase with the ERA.

- The licensees are concerned that they may be required to produce significantly larger amounts of heat than forecast, and will be unable to recover the costs because all coal costs are recovered in the electric energy tariff. Again, the probability of forecasts for heat production being considerably different than actual is low, and if it does occur, the licensees can respond to the event by filing an application for a tariff increase with the ERA. This would be the situation regardless of the tariff design. Further, an increase in heat production does not necessarily result in a revenue shortfall. Consider historical experience shown in Table 5. As can be seen, CHP 2 and CHP 3 produced significantly more heat in 2009 relative to 2007. In the case of CHP 2, heat production increased 17.5% while there was little change in electricity production (increase of only 0.7%), yet the fuel conversion efficiency in each year was about the same (actually improving by 0.6%). Therefore, CHP 2 electricity revenue would have been about the same in each year, but heat revenue would have increased by about 17.5% with virtually no change in coal costs. In the case of CHP 3, heat production increased 13.9% while electricity production increased by 10.7%. The fuel conversion efficiency remained about the same, deteriorating by less than 0.1%. Therefore, CHP 3 electricity revenue would have increased by about the same amount that its overall fuel costs increased (no net change), but heat revenue would have increased by about 13.9% with no additional cost of fuel beyond what was recovered in the electricity tariff. In both cases, CHP 2 and CHP 3 would have been better off financially as a result of increased heat sales.

Table 5. Historical Production, Coal Consumption and Fuel Conversion Efficiency

Indicators	CHP-4	CHP-2	CHP-3	Erdenet	Darkhan
Electricity Delivered to Grid (GWh)					
2009 Actual	2,325.0	98.6	513.9	111.6	195.2
2008 Actual	2,301.9	98.5	516.1	112.4	202.0
2007 Actual	2,117.5	97.9	464.1	110.0	212.4
Heat Distributed to Network (Gcal)					
2009 Actual	3,052,564.0	147,452.0	1,702,928.0	603,440.4	451,348.0
2008 Actual	2,942,301.0	139,572.0	1,583,457.0	568,485.9	447,221.6
2007 Actual	2,873,092.0	125,520.0	1,494,900.0	597,536.0	441,650.0
Total Coal Consumption (Tons)					
2009 Actual	2,635,911.0	179,956.2	973,237.3	288,653.0	350,742.4
2008 Actual	2,616,962.0	183,580.1	993,883.1	242,476.6	313,001.2
2007 Actual	2,497,296.0	178,987.0	897,263.1	235,176.9	330,714.4
Average Calorific Value (kCal/kg)					
2009 Actual	3,315.0	3,429.0	3,485.0	3,400.7	3,473.0
2008 Actual	3,261.0	3,450.0	3,475.0	3,939.3	3,896.0
2007 Actual	3,503.0	3,443.0	3,411.0	4,015.8	3,833.0
Total Calories (Gcal)					
2009 Actual	8,738,045.0	617,069.8	3,391,732.0	981,622.3	1,218,128.4
2008 Actual	8,533,913.1	633,351.3	3,453,743.8	955,188.1	1,219,452.7
2007 Actual	8,748,027.9	616,252.2	3,060,564.4	944,423.4	1,267,628.3
Fuel Conversion Efficiency (kCal/kWh)					
2009 Actual	3,758.3	6,258.3	6,600.0	8,795.9	6,240.4
2008 Actual	3,707.3	6,430.0	6,692.0	8,498.1	6,036.9
2007 Actual	4,131.3	6,294.7	6,594.6	8,585.7	5,968.1

- There could be a cash-flow issue during the summer months when generators are producing less energy. This is a common issue in all jurisdictions owing to the seasonality of sales. Utility management is expected to understand its business and manage its cash flow accordingly. This is simply a fact of life requiring the power companies to be better business managers.

- The point was made that the cash management system will have monthly surpluses and deficits under the two-part tariff. This is true, but it is a simple matter to manage the cash management system on an annual rather than a monthly basis. Safeguards will be necessary to ensure the cash management system does not run out of funds.

- CHP 3 staff are concerned that their energy tariff is higher than CHP 2, meaning that they will follow CHP 2 in economic merit order. First, the available capacity of CHP 2 is only 20 MW. This compares to an available capacity of 114 MW for CHP 3. Therefore, following CHP 2 in economic merit order is likely to have minimal impact on CHP 3 electricity production. Second, the tariffs are based on actual experience and cost data supplied by CHP 2 and CHP 3. If the energy tariff for CHP 3 were made artificially lower, CHP 3 may not recover its costs, leading to a deterioration of its financial position. CHP 3 can move up the economic merit order list if it improves its fuel conversion efficiency and coal handling and procurement practices.

- Some of the generation licensees asked about implementation of a more complex tariff to reflect different fuel conversion efficiencies in each hour. It was explained that more complex tariffs are certainly more accurate and fair. However, it is important to consider the cost/benefit ratio and the ability of NDC to implement the tariff. NDC currently has neither the tools nor the expertise to implement such a complex tariff, and it would take some time (at least three years) to procure and install the necessary software (i.e., an Energy Management System and a billing and settlement system). It was suggested that they start with the simple tariff proposed, and improve on the design in the future as experience is gained and better tools are procured. It is important to get started with the proposed tariff to ensure there are no further delays in capturing the benefits.

- EPRC recommended that a seasonal tariff be implemented in 2011 once the generation licensees and the ERA have accumulated the necessary cost and production data to design such a tariff. The generation licensees suggested that this be done now rather than later. This would indeed improve the tariff, but to design such a tariff, better cost information is needed which currently is not available. The licensees should start collecting this data as soon as possible. The tariff would be designed following the same process as that outlined in Section 3.1 except cost and production data for each year would be split into the two seasons. The primary difference in the tariff between the two seasons would be the fuel conversion efficiency.

- A number of stakeholders continue to state that the NDC is responsible for ensuring generation licensees recover their revenue requirement. This statement is simply not true. As stated in the Law, NDC is responsible for ensuring the CES is operated efficiently at lowest possible cost consistent with reliability and safety standards. This means that NDC must practice economic dispatch. Dispatching generation to ensure each licensee recovers its revenue requirement is in direct violation of this principle. The ERA is responsible for ensuring licensees have a ***<u>reasonable opportunity</u>*** to recover their revenue requirement. In this sense, the licensees themselves have control over their financial well-being because they control their assets and budgets, and they are responsible for submitting and justifying their revenue requirement data and information before the ERA.

- There was considerable discussion concerning safeguards to ensure the Generation licensees meet their revenue requirement. As has been discussed previously, the ERA provides licensees a ***<u>reasonable opportunity</u>*** to recover their revenue requirement – there are no guarantees because it would take away the incentive for company management to provide services reliably and efficiently. On the other hand, economic dispatch is expected to result in significant changes in operation. It is new and untested, so data upon which to develop tariffs is limited. EPRC is opposed to guaranteeing generator revenues under the new economic dispatch regime for the reasons given above. Consideration might be given to shadow billing generators under the new tariff, but in this case it makes little sense because current and proposed tariffs were developed for completely different operating regimes.[5] Therefore, EPRC recommends that the proposed two-part tariffs be implemented immediately along with economic dispatch. ***The generating licensees, the NDC and the ERA should monitor generator costs and revenues closely (i.e., monthly), and make adjustments as necessary.*** Note that the proposed tariffs are based on averages over the entire calendar year. Therefore, adjustments should not be made too hastily. Preferably, the results should be considered at the end of a complete year of operation (tracked monthly), and if adjustments are necessary, the tariffs should be revised accordingly. If a generator is shown to have made too much or too little revenue relative to forecast without a corresponding change in costs (i.e., greater than 5% change from forecast), the tariff should be adjusted to not only compensate for changes in costs and revenues arising from changes in operating regime, but also to enable recovery/refund of deficits/excesses in revenues in the following year.

5. Recommendations

1) EPRC recommends that the ERA implement immediately in 2010 the two-part tariffs shown in Table 6. The tariffs in Table 6 are based on data forecast by the ERA for 2010 and the actual fuel conversion efficiency of each plant in 2009. The tariffs would apply to electricity purchases from each generation licensee in 2010, or until there is a material change in costs/revenues or coal prices.

Table 6. Proposed Two-Part Tariffs for Generation Purchases

	CHP 4	CHP 2	CHP 3	Erdenet	Darkhan
Energy Tariff (MNT/kWh)	28.8	48.8	50.4	86.9	53.3
Capacity Tariff (Million MNT/Month)	1365.4	127.0	462.8	106.7	153.6

NDC should implement an economic dispatch regime coinciding with implementation of the new two-part tariffs.

2) Revenues and costs should be monitored closely during the first year of operation, and if necessary (revenues differ from forecast by more than 5% without a corresponding change in costs, adjustments should be made in the following year to account for changes in operating regime and to compensate for excess/deficit revenues.

3) The entire Government subsidy provided to Erdenet should be allocated to heat (i.e., none of the subsidy should be allocated to electricity), and the revenue requirement for heat and electricity should be adjusted accordingly.

4) The ERA should start collecting the data necessary to enable introduction of a seasonally varying energy tariff in 2011.

5) The current methodology for coal pricing should be revised so that coal companies are paid according to calorific value. If this is not immediately possible, as a minimum,

[5] Shadow billing means that the generators would be billed under current tariffs, but the bill would show invoice amounts under both current and proposed tariffs. The problem with shadow billing in this case is that the tariffs were developed for completely different operating regimes.

coal company staff should be present when the generation licensees conduct tests on calorific content of coal deliveries, and sign off on the results.

6) The ERA should request the generation licensees to provide detailed estimates of variable operation and maintenance costs for inclusion in future two-part tariff designs.

7) NDC should start collecting availability data for each generating licensee immediately so that improved tariff designs can be implemented as early as 2011.

SECTION II: TARIFF METHODOLOGY FOR CALCULATING ELECTRICITY ENERGY AND CAPACITY TARIFFS OF GENERATING LICENSEES

1. Purpose

The purpose of this methodology is to introduce elements in the generation sector that are consistent with competition in the wholesale market, and that create incentives for generators to improve performance, thus leading to reductions in the overall cost of power. In particular, the goal of this tariff methodology is to fairly compensate generating licensees under economic merit order dispatch.

2. Definitions

1. "Capacity tariff" means a tariff paid to each generating licensee expressed in MNT/Month;
2. "Energy tariff" means a tariff paid for each kWh of electrical energy delivered to the wholesale market by a generating licensee in accordance with the agreements, expressed in MNT/kWh;
3. "Amount of energy" means an amount of electrical energy in kWh supplied to the wholesale market by a generating licensee in compliance with agreements;
4. "Revenue requirement" means the total revenue requirement approved by the ERA for each generating licensee. The total revenue requirement is allocated to heat and electricity in accordance with formulas approved by the ERA. The electricity capacity and energy tariffs are designed to collect the revenue requirement allocated to electricity, expressed in MNT;
5. "Fuel conversion efficiency", or "heat rate" is the average efficiency in the tariff period at which a generating licensee's facility converts the energy in primary fuel to electric energy, expressed in kcal/kWh;
6. "Coal consumption" is the amount of coal delivered to a generating licensee's facility during the tariff period, expressed in tons;
7. "Cost of fuel" is the total cost of fuel including coal, coal transport, coal handling and mazout/diesel fuel, delivered to a generating licensee's facility during the tariff period, expressed in MNT;
8. "Average calorific value" is the average heat content of fuel delivered to a generating licensee's facility during the tariff period, expressed in kcal/kg;
9. "Tariff period" is the period during which the tariff will be in effect.

3. Calculating the Energy Tariff

1. The energy tariff will compensate a generating licensee for the variable costs it incurs generating electrical energy as directed by the dispatch licensee.

2. The ERA, in conjunction with the dispatch licensee and the generating licensees, will determine the "target" fuel conversion efficiency for each generating licensee for the tariff period. The target fuel conversion efficiency will be based on historical performance (i.e., the past three years), and comparison with heat rates of like generators internal to Mongolia, and external to Mongolia, as necessary.

3. The ERA will propose target fuel conversion efficiencies for each generating licensee, and provide each generating licensee with an opportunity to respond in writing if it believes the target fuel conversion efficiency requires further consideration. The generating licensee's response will clearly document why the target fuel conversion efficiency should be adjusted. The ERA will consider all responses filed by generating licensees, and establish firm target fuel conversion efficiencies for each generating licensee prior to the tariff

period. The ERA's published target fuel conversion efficiencies will be final and binding on each generating licensee.

4. The ERA will scrutinize variable operation and maintenance costs and the cost and heat content specified in coal contracts of each generating licensee for the tariff period.
5. The energy tariff for a generating licensee will equal its average cost of fuel purchased during the tariff period multiplied by its target fuel conversion efficiency, plus its variable operation and maintenance cost, as follows:

$$T_i^{energy} = CC_i * FCE_i + VOM_i$$

Where:

T_i^{energy} is the energy tariff for a particular generating licensee in MNT/kWh delivered to the grid,

CC_i is the average cost of fuel including coal, coal delivery, coal handling and mazout/diesel

fuel, during the tariff period for a particular generating licensee in MNT/kcal,

FCE_i is the target fuel conversion efficiency for a particular generating licensee in kcal/kWh, and

VOM_i is the variable operation and maintenance cost for a particular generating licensee in

MNT/kWh

4. Calculating the Capacity Tariff

1. The capacity tariff will compensate a generating licensee for the portion of the generating licensee's revenue requirement assigned to electricity that is not recovered by the energy tariff in the tariff period.

$T_i^{capacity} = RR^{elect}{}_i - (T_i^{energy} * E_i) / N$ where:

$T_i^{capacity}$ is the capacity tariff for a particular generating licensee in MNT/Month,

$RR^{elect}{}_i$ is the total revenue requirement for a particular generating licensee allocated to

electricity in MNT,

T_i^{energy} is the energy tariff for a particular generating licensee in MNT/kWh delivered to the grid

E_i is the number of kWh delivered to the transmission grid in the tariff period in kWh, and

N is the number of months in the tariff period.

Sample Calculation

Consider the following generator (values apply to CHP 4 in 2010):

- Revenue requirement allocated to electricity – 83,678.1 Million MNT
- Electrical energy delivered to transmission grid – 2,334.4 GWh
- Target fuel conversion efficiency – 3758.3 kcal/kWh
- Total coal consumed – 2,653,072.0 Tons
- Average heat content of coal – 3,250.2 kCal/kg

- Total cost of fuel = 60,633.1 Million MNT
- Variable operation & maintenance cost – 2.4 MNT/kWh

Energy Tariff

Average cost of fuel is calculated as:

60,633.1 Million MNT / (2,653,072 tons of coal * 3,250.2 kCal/kg / 1000) = 0.0070 MNT/kCal

The energy tariff is calculated as:

(0.0070 MNT/kWh * 3,758.3 kCal/kWh) + 2.4 MNT/kWh= 28.8 MNT/kWh

The generating licensee will receive 28.8 MNT for each kWh delivered to the grid (i.e., after accounting for station service).

Capacity Tariff

The capacity tariff is set to recover the portion of the revenue requirement allocated to electricity, less the Government subsidy, that is not recovered by the energy tariff. The total revenue requirement allocated to electricity, less the Government subsidy, is 83,678.1 Million MNT. The energy tariff will generate revenues of:

2,334,400,000 kWh * 28.8 MNT/kWh = 67,292.9 Million MNT

The capacity tariff is calculated as:

83,678.1 Million MNT – 67,292.9 Million MNT = 16,385.2 Million MNT

Paid monthly, the capacity tariff is calculated as:

16,385.2 Million MNT / 12 = 1,365.4 MNT/Month

ANNEX A: FUEL CONVERSION EFFICIENCY CALCULATION

ANNEX A: FUEL CONVERSION EFFICIENCY CALCULATION

The fuel conversion efficiency of a generating station is the efficiency at which it converts the energy in the primary fuel, coal in Mongolia’s case, to electrical energy. It requires knowledge of the amount of fuel consumed, the average heat content of the fuel, and the amount of useful electrical energy generated. The amount of useful energy generated is defined as the number of kWh delivered to the transmission grid.

The 2009 actual figures for CHP-4 follow:

- Electrical energy delivered to transmission grid – 2,325.0 GWh
- Total coal consumed – 2,635,911.0 Tons
- Average heat content of coal – 3,315.0 kCal/kg

On the basis of this data, the fuel conversion efficiency is calculated as:

(2,635,911 tons of coal * 3,315 kCal/kg) / 2,325,000,000 kWh= 8,738,044,965,000 kCal / 2,325,000,000 kWh= 3,758.3 kCal/kWh

This fuel conversion efficiency applies to total coal supplied to the generating facility for both heat and electricity production. In this manner, a generation licensee is fairly compensated for electrical energy delivered to the grid. Calculating the fuel conversion efficiency in this manner enables NDC to dispatch generation on the basis of economic merit order. Of course, if a generator can improve its fuel conversion efficiency over 2009 levels, it can reduce its costs and improve its profit margins.

ANNEX B: TWO-PART TARIFF CALCULATION

ANNEX B: TWO-PART TARIFF CALCULATION

The two-part tariff design for purchases of electricity from generation licensees starts with the revenue requirement allocated to electricity, adjusted for subsidies provided by Government. This represents the amount of revenue that is to be recovered from the electricity sales by generation licensees to the single buyer.

The critical component of the two-part tariff is the energy tariff. The goal of the energy tariff is to promote economic dispatch by fairly compensating generation licensees for each kWh delivered to the grid consistent with NDC dispatch instructions. This means that generation licensees should be paid according to an energy tariff that reflects the cost to produce each kWh delivered to the grid. It is not necessary to determine the amount of coal used for heat production versus electricity production.

To develop the energy tariff, it is necessary to have forecasts of the energy delivered to the grid, total plant coal consumption, average calorific value of the coal to be consumed, the total cost of fuel (in this case, coal), coal transport, coal handling and mazout/diesel fuel, and the benchmark fuel conversion efficiency determined in Attachment A. The variable operation and maintenance cost is assumed to be 2.4 MNT/kWh.

The 2010 figures for CHP 4 forecast by the ERA follow:

- Electrical energy delivered to transmission grid – 2,334.4 GWh
- Total coal consumed – 2,653,072.0 Tons
- Average heat content of coal – 3,250.2 kCal/kg
- Total cost of fuel = 60,633.1 Million MNT

On the basis of these data, the energy tariff is calculated in two steps. The first step is to determine the average cost of fuel:

60,633.1 Million MNT / (2,653,072 tons of coal * 3,250.2 kCal/kg / 1000) = 0.0070 MNT/kCal

The second step is to determine the energy tariff:

(0.0070 MNT/kWh * 3,758.3 kCal/kWh) + 2.4 MNT/kWh= 28.8 MNT/kWh

If the CHP 4 delivers 2334.4 GWh to the transmission grid as forecast, it will generate revenues of: 2,334,400,000 kWh * 28.8 MNT/kWh = 67,292.9 Million MNT

If CHP 4 delivers an additional kWh to the transmission grid (or one less kWh to the transmission grid), it will receive an additional 28.8 MNT of revenue (or 28.8 MNT less revenue) which reflects its average cost of producing a kWh (or the average savings from avoiding production of a kWh), so the generation licensee is indifferent to the level of dispatch directed by NDC; i.e., the increase in costs is equal to the increase in revenues. Of course, the tariff will require adjustment in future years as production patterns and costs change. Note that the generation licensee is also compensated for heat production through the heat tariff

The capacity tariff is set to recover the remaining revenue requirement allocated to electricity, less the Government subsidy. In the case of CHP 4, the total revenue requirement allocated to electricity, less the Government subsidy, is 83,678.1 Million MNT. The capacity tariff is calculated as follows:

83,678.1 Million MNT – 67,292.9 Million MNT = 16,385.2 Million MNT

Paid monthly, the capacity tariff is calculated as:

16,385.2 Million MNT / 12 = 1,365.4 MNT/Month