Economic Policy Reform and Competitiveness Project

Proposed competitive electricity market design for Mongolia's Central Electricity System

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Main Author:	Douglas Bowman
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Submitted by:	EPRC Project/Chemonics International Inc., Tavan Bogd Plaza, Second Floor, Eronhii Said Amar Street. Sukhbaatar District, Ulaanbaatar, Mongolia
Telephone and fax:	(976) 11 32 13 75 Fax: (976) 11 32 78 25
Contact:	Fernando Bertoli, Chief of Party
E-mail address:	fbertoli@eprc-chemonics.biz

ABBREVIATION AND ACRONYMS

CES	Central Electricity System
CHP	Combined Heat and Power
EBRD	European Bank for Reconstruction and Development
EPRC	Economic Policy Reform and Competitiveness Project
ERA	Energy Regulatory Authority
GoM	Government of Mongolia
MoF	Ministry of Finance
MoFE	Ministry of Fuel and Energy (now MoMRE)
MoMRE	Ministry of Mineral Resources and Energy (formerly MoFE)
NDC	National Dispatch Center
SCADA	System Control and Data Acquisition
SMO	System and Market Operator
USAID	United States Agency for International Development

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EXECUTIVE SUMMARY

The Economic Policy Reform and Competitiveness Project (EPRC) under USAID Contract No. 438-C-00-03-00021-00 is assisting Mongolia's Energy Regulatory Authority (ERA) with development and implementation of a competitive electricity market. In this regard, EPRC with the support of the ERA has developed this report outlining the rationale for change in the electricity market design, recommending a design that will increase competition while taking into account current technical and financial constraints within Mongolia and advising on next steps for implementation of the new market design. The report has had extensive stakeholder review and input.

In light of current circumstances in Mongolia, it is recommended that an electricity market design with wholesale competition, unbundling of market functions along current lines and a power pool with central dispatch based on costs operating along-side a system of financial bilateral contracts be implemented. As there are numerous financial and technical constraints facing Mongolia's power sector at the current time, it is proposed that this market design be implemented initially with a system of bilateral vesting contracts covering all electricity sales in the Central Electricity System (CES). This will enable early introduction of competitive market principles before financial and technical constraints are fully addressed. Further, the vesting period will provide market participants with valuable training in the principles of competitive markets and the opportunity to demonstrate accountability by honoring contractual obligations and resolving disputes in accordance with regulations.

The tariff in the vesting contracts would be based on costs and would be regulated by the ERA. It is anticipated that the market would be fully-vested for a period of two to three years at which time the vesting contracts would gradually be reduced, forcing wholesale buyers (the distribution companies) to procure a portion of their power needs through negotiated bilateral contracts with generators. The timing and speed at which the vesting contracts are reduced would be determined by the ERA with input from industry stakeholders, but it is anticipated that vesting contracts would be reduced to zero within six years of market commencement.

A high-level summary description of the proposed market design follows:

- The wholesale power market will be based on a system of bilateral contracts for the purchase and sale of electric power and energy. A bilateral contract represents a firm financial commitment by a generator to deliver capacity and energy to the distribution company in the amounts stated in the contract regardless of actual dispatch. Generation output consistent with dispatch orders from the System/Market Operator (SMO) that exceed or fall short of amounts specified in bilateral contracts represent a sale or purchase in the spot market. Bilateral contracts can include contracts between:
    - Distribution Companies and Generating Companies
    - Generating Companies and Exporters
    - Importers and Distribution Companies
- For an initial period of two to three years (to be determined by the ERA with input from industry stakeholders), vesting contracts covering all sales in the market will be assigned between generators and distributors. The vesting contracts will be established by the ERA with tariffs based on costs. Bilateral vesting contracts will be settled monthly and payment will be made directly from buyer to seller. Following the initial vesting period, the vesting contracts will be phased out gradually until each Distributor is allowed to freely negotiate its full supply requirements with any supplier it chooses. The speed at which the vesting contract regime is phased out will likewise be determined by the ERA with input from industry stakeholders.

- Actual delivery amounts can be different from contract quantities so a spot, or balancing, market will be used to settle the differences. All generation will be centrally dispatched by the System/Market Operator (SMO) on the basis of lowest variable cost. The ERA will approve the variable costs used in the spot market for each generator based on information provided by the generators and the SMO. Deviations from contract amounts in both supply and demand will be settled in the spot market at the variable cost of the marginal plant; i.e., the variable cost of the highest cost plant/import dispatched during the period after taking into account constraints.
- The SMO will dispatch all generators under bilateral contracts on the basis of lowest variable cost while honoring heating load requirements, minimizing transmission line losses, maintaining power flows within transmission line limitations, honoring all reliability criteria and respecting generator unit limitations; i.e., minimum load levels, ramp rates, etc.
- The SMO will have the right to demand that Generators provide ancillary services pursuant to license obligations. Compensation for the costs of providing ancillary services will be included in the tariff in the bilateral vesting contracts established by the ERA.
- In the future, market participants may have the opportunity to arrange bilateral contracts for sales over the interconnection with Russia. However, in the near-term vesting period all the needs of Distribution Companies will be met with generation from Mongolian power plants and imports from Russia under the current contract. The contract with Russia will continue to be managed by the Transmission Company and be used principally for ancillary services.
- Distribution Companies will be subject to a transmission tariff based on the revenue requirement of the transmission company spread across sales; i.e., a postage-stamp tariff.
- Distribution Companies will be subject to an SMO service charge based on the revenue requirement of the SMO.
- A transmission system expansion plan will be developed by the SMO on the basis of least cost principles at five-year intervals and updated annually. The SMO will develop the transmission expansion plan in conjunction with market participants and submit the proposed recommended plan to the ERA for review, comment and approval[1]. The transmission company will be responsible for managing construction of ERA-approved transmission facilities.

An extensive stakeholder review process accompanied development of this report. Although concerns were raised by some of the generation licensees concerning their ability to "compete" in the proposed market with their aged assets, the ability of a generator to remain used and useful is ***not*** a function of the market design, but rather the demand/supply balance and the efficiency and operational performance of the assets (see ***Section 4.4.1***). Further, claims that imports from Russia will decimate the domestic generation market are unfounded.

Generally, licensees are supportive of the proposed high-level market design, and none of the issues raised have caused the ERA and EPRC to reconsider the proposed high-level market design. The relevant issues raised by stakeholders are more concerned with detailed market

[1] It is recommended that the ERA approve the system expansion plan consistent with practice in other international jurisdictions with competitive markets. This will require a change in laws and regulations in Mongolia. Until such amendments are made, it will be necessary for the ERA to provide recommendations for system expansion along with justification to the MoMRE (formerly the MoFE) or Cabinet for approval.

design issues that will be addressed during the Market Rules and Grid Code development process.

In summary, if market reform is to be successful, Mongolia must eliminate a number of constraints, in particular, tariffs must be increased as set out in the Tariff Reform Plan to ensure the financial viability of the power companies. At the same time, consumers must be assured that service will improve as a result of the tariff increases. In this regard, the ERA must impose market discipline on the power companies through introduction of the proposed competitive bilateral contracts market in conjunction with incentive regulation that rewards and penalizes power companies in the monopoly components of the market commensurate with performance.

The proposed high-level market design will ultimately increase competition with the attendant incentives for power companies to improve the value of service to consumers, and promote economic dispatch with reduced coal costs and pollution. The proposed market will have a number of other benefits as well, including:

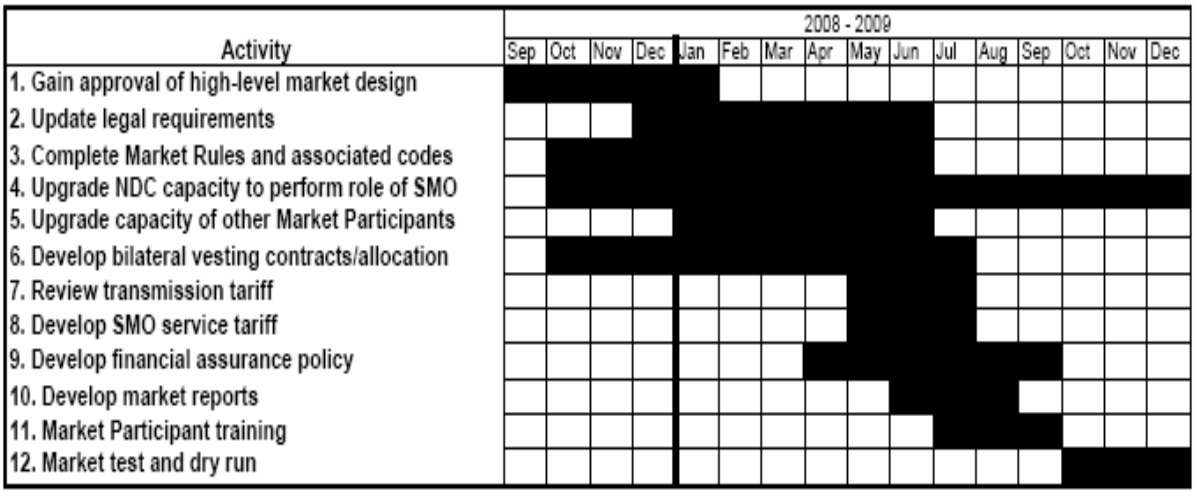
- Elimination of the national uniform retail tariff;
- Replacement of the Cash Management System;
- Improved business relationships among power companies, in particular, distribution licensees and generation licensees;
- NDC development of the system expansion plan with stakeholder input and review, and ERA approval; and
- Potential merger opportunities.

Although there will be costs of up to US$ 2 million associated with implementation of the proposed market for procurement and installation of Energy Management System (EMS) software and a commercial grade billing and settlement system, these procurements should take place regardless of market reform owing to their attendant benefits, and because they are consistent with the Energy Law and market reform objectives, including:

  - Improve value of service to consumers;
  - Reduce the investment and liability burden on the public; and
  - Improve efficiency both in terms of supply and consumption.

The proposed high-level market design can be implemented at reasonable cost and risk. Therefore, the proposed high-level market design is accepted as the basis for market reform and will be used as the model for market governance documents such as the Market Rules and Grid Code, and GoM policy initiatives relating to the electricity sector. The proposed high-level market design is judged to be in the best interests of all of the stakeholders in the electricity sector including consumers.

The steps and proposed schedule for implementation of the proposed market design are shown in the following exhibit. The schedule is based on the assumption that there is a commitment within Mongolia to implement the new market design by January 1, 2010. The implementation steps are described in detail in ***Section 6*** of the report.


Activity
2008 - 2009
Sep
Oct
Nov
Dec
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
1. Gain approval of high-level market design
2. Update legal requirements
3. Complete Market Rules and associated codes
4. Upgrade NDC capacity to perform role of SMO
5. Upgrade capacity of other Market Participants
6. Develop bilateral vesting contracts/allocation
7. Review transmission tariff
8. Develop SMO service tariff
9. Develop financial assurance policy
10. Develop market reports
11. Market Participant training
12. Market test and dry run

SECTION I: BACKGROUND AND PURPOSE OF REPORT

The Economic Policy Reform and Competitiveness Project (EPRC) under USAID Contract No. 438-C-00-03-00021-00 is assisting the Energy Regulatory Authority (ERA) with development of a design for a competitive electricity market. This report outlines the rationale for change in the electricity market design, recommends a design that will increase competition while taking into account current technical and financial constraints and advises on next steps for implementation of the new market design.

The need for reform of the electricity market design is acknowledged in the Memorandum of Understanding (MOU) between the former Ministry of Fuel and Energy (now the Ministry of Mineral Resources and Energy, MoMRE) and the ERA. The purpose of the MOU is to:

> *strengthen collaboration between the Parties on energy sector policy and strategy, regulation of the sector and certain regulatory reform issues and implementation, in particular, on matters including improvement of the financial situation of licensed companies, tariff reform, new bilateral contract power market structure; ERA annual budget preparation and approval; support of the Energy Working Group; certain heat sector issues; and sustained operation of the ERA in accordance with the provisions of the Law of Mongolia on Energy approved on February 1, 2001 (as it may be amended or restated in the future).*

The MOU was signed by the parties on January 29, 2008. The point in the MOU relating specifically to market reform on the Central Electricity System (CES) follows:

> *The Parties shall:*
>
> *3.10.* Submit the following issues to the Fuel and Energy Minister's Council Meeting for discussion:
>
> - Development of the market design,
> - Development of the Market Rules, and
> - Implementation of the new market design.

This report recommends a high-level market design for discussion and approval by industry stakeholders. The second and third bullet points shown above are incorporated in the "next steps" of the market design process and will be addressed once the high-level market design is approved by industry stakeholders.

This report relates to reform of Mongolia's CES. It does not address market reform in other areas of the country (i.e., the Western and Eastern Electricity Systems), and does not address reform of the heat sector. The Western and Eastern Electricity Systems are quite small, so reform is a lower priority. Further, these systems may someday be interconnected to the CES at which time they would be subject to the same market design and governance structure. For the purposes of the electricity market design review, the heat sector is treated as a constraint. Specifically, heat and steam requirements are assumed to be met first before electrical energy is dispatched in accordance with the electricity market rules. It is noted that the World Bank is working with stakeholders in the heat sector in an effort to improve efficiency and performance of suppliers.

This report provides analyses relating to market design. A companion report completed earlier in 2008 addresses retail electricity tariffs for the CES and provides a detailed retail tariff

reform plan[2]. It is imperative that retail tariff reform take place if the electricity market reform is to be successfully implemented.

There have been two reports filed in recent years relating to market reform for Mongolia's CES, including: 1) the December 16, 2004 report entitled *Power Sector Reform in Mongolia – Proposal on a Power Market Structure, Basic Rules and Pricing System*, prepared by SYNEX Consulting Engineers for the World Bank, and 2) the March 31, 2006 Draft report entitled *Rules for the Wholesale Power Market of Mongolia National Power System*, prepared by Chemonics under this EPRC project. As it has been more than two years since these reports were completed, the ERA has requested EPRC to revisit market reform on the basis of today's situation. It is not the intent of this study to duplicate the work in these reports, but rather to draw on the content of these reports and present a high-level market design that accommodates current priorities, technical capabilities and political realities in Mongolia. In this sense, the objective is to review and update data and information in previous reports and put the market reform process back on track.

This report was developed in conjunction with the ERA. It has had extensive stakeholder review and input. The initial draft was presented in September 2008 to key power company staff from Combined Heat and Power Plant 4 (CHP 4), CHP 3, the transmission company (CRETG), the Ulaanbaatar Electric Distribution Company (UBEDN), and the National Dispatch Center (NDC). The final draft of the report included feedback received from these key stakeholders and was presented in early November 2008 at a workshop attended by staff of each power company on the Central Electricity System. Feedback received from the power companies has been incorporated in this final report.

The report is organized as follows:

Section 2 – Current Market
Section 3 – Analysis of Competitive Market Models for Use on Mongolia
Section 4 – Recommended Market Design for Mongolia
Section 5 – NDC Readiness to Perform the Role of SMO
Section 6 – Next Steps

[2] See May 2008 EPRC report entitled *Proposed Retail Tariff Reform Plan for Mongolia's Central Electricity System*.

SECTION II: CURRENT MARKET

2.1 Overview of Mongolia's Electric Power System

2.1.1 General

The electric power system in Mongolia consists of three independent electric power systems: the Central Energy System (CES), the Western Energy System (WES), and the Eastern Energy System (EES). In 2001 the Government of Mongolia (GoM) took major steps toward restructuring the energy sector by passing the 2001 Energy Law, establishing the Energy Regulatory Authority (ERA) and a set of rules and regulations to promote private sector investment in the energy sector. The GoM created 18 Joint Stock Companies (JSC) including generation, transmission and distribution entities and the National Dispatch Center ("NDC") which together comprise the energy sector.

The share entitlements of these companies (except NDC) were distributed as follows:

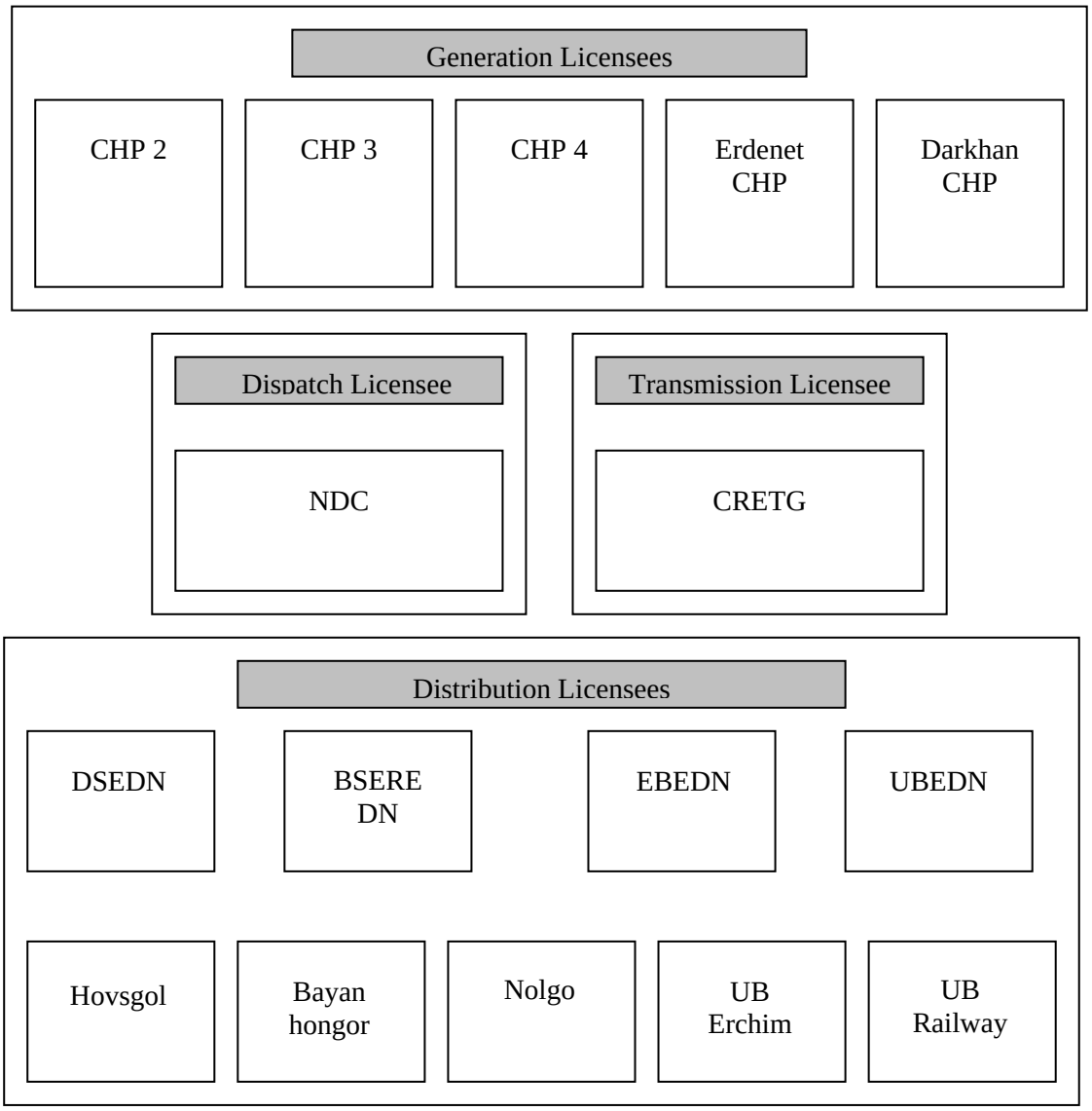
- 41% - to the Ministry of Infrastructure
- 39% - to the State Property Committee
- 20% - to the Ministry of Finance and Economy

The NDC is responsible for dispatch of the CES transmission network. It was created as a Limited Liability Company (LLC) with 51% of its shares distributed to the Ministry of Infrastructure and 49% to the State Property Committee.

The main Mongolian electric system is the Central Energy System (CES) representing 80% of all Mongolian electricity supply. The CES power supply is comprised of five coal burning generating plants and an interconnection to UES of Russia. The other two networks – EES and WES are quite small. WES operates on imports of electricity from Russia, EES has one Combined Heat and Power Plant (CHP) with installed nameplate capacity of 36 MW.

The focus of the evaluation of the market model in Mongolia is on the CES system and its entities shown in ***Exhibit 1***. Total installed nameplate capacity of CES is 782 MW of which 627 MW are available. There is a contract with Inter RAO of Russia to supply up to 120 MW of capacity through a double circuit 220 KV line which is normally operated at 110 kV. The contract is in effect through December 31, 2008. There is also a contract with Inter RAO for the export of power. Exports are utilized to transfer excess power caused by heat demand during the off-peak electricity demand hours. The contract price for exported power is very low because Mongolia is effectively dumping its excess power into Russia.

Exhibit 1. Organization of the CES



2.1.2 Transmission System and NDC

The CES transmission system interconnects three main load centers - Ulaanbaatar, Darkhan and Erdenet and the power plants in these cities by a 220 KV transmission line ring. Transmission voltages are 220 KV and 110 KV, distribution voltages are 35 KV, 10 KV and 6 KV.

The National Dispatch Center is responsible for coordinating daily system operation of all power and heat sector entities including real time coordination of power plant operation, transmission and distribution switching operation, and operation of the heat transmission network in coordination with combined heat and power (CHP) operation. Much of the communications and data acquisition is communicated by telephone and fax.

The NDC is also responsible for providing the information necessary for settlement of spot market transactions within the context of the wholesale electric power market as discussed below.

2.1.3 Adequacy of Resources

The existing capacity of the CHP plants with support from resources in Russia over the interconnection is generally sufficient to meet the electricity needs of Mongolia. With 782 MW of installed generating capacity, 627 MW of which is considered available, and a maximum transfer capacity of 240 MW[3] over the interconnection with Russia, total available capacity exceeds peak demand on the CES of 649 MW established during the winter of 2007/08[4] with a comfortable reserve margin. However, demand is growing steadily at 5 to 7% annually, and power plant equipment is for the most part aged with the newest plant Ulaanbaatar CHP 4 commencing operation in 1981. CHP 4 is the only plant capable of providing ancillary services including limited frequency regulation, load following and operating reserve. Currently, Mongolia must rely on the interconnection with Russia to provide relief during contingencies and for system frequency regulation.

In summary, the demand/supply situation is expected to be adequate in the coming years, but will remain tight until new generation is brought on line; i.e., CHP 5. This is not likely to happen prior to the winter 2012/13. It will be necessary to increase capacity purchases from Russia over and above the 120 MW in the current contract if reserve margins are to be maintained at target levels.

2.2 Transition to the "Single Buyer Market"

Following structural and functional reorganization of the national electric power system, wholesale market transactions were implemented based on the system of vested bilateral obligations between distribution companies and generators. That system was short-lived as distribution companies were plagued with retail revenue collection problems resulting in a situation where the generating companies consistently under-collected revenues needed to maintain equipment and pay fuel suppliers.

Some generating companies complained that the assignments of these bi-lateral obligations were unfair, particularly those assigned the bulk of the contracts with distribution companies with poor collection performance. It is understood that although the bilateral obligations were legally enforceable, it was nearly impossible in practice to obtain relief through the legal system. On average, generators were collecting approximately 60 to 70% of the payments due.

2.3 Description of the "Single Buyer Market"

Faced with these problems, the ERA adopted a market model in 2001 which became known in Mongolia as the "Single Buyer Market". Under this model there are no bilateral obligations between generating and distribution companies. The flow of funds is implemented through a Cash Management System (CMS) shown in ***Exhibit 2*** under which retail customers of state owned distribution companies deposit their payments into the "zero balance" accounts established by each distribution company. These accounts prohibit withdrawals by the distribution companies. At the end of each day, funds from these accounts are transferred into the Main Zero Balance Account ("MZBA") established at the Mongolian Savings Bank. Private distribution companies are not mandated to establish zero balance accounts and are allowed to make direct payments to the "Single Buyer". Cash disbursements are made from the MZBA to generating licensees, the transmission licensee, the dispatch licensee and for imports, while cash disbursements are made to distribution licensees through their zero balance accounts. Cash disbursements are made by the Savings Bank which has signed the respective agreement with the Transmission Company acting as the Single Buyer in

[3] Information provided by NDC at meeting on September 30, 2008.
[4] Information provided by NDC on June 18, 2008.

accordance with the allocation formula approved by licensees at their annual meetings. The CMS ensures that each entity receives a "fair" share of collections. However, only the supplier of imported power receives full payment. Payments to other entities vary in proportion to retail revenue collection.

Exhibit 2. Cash Management System

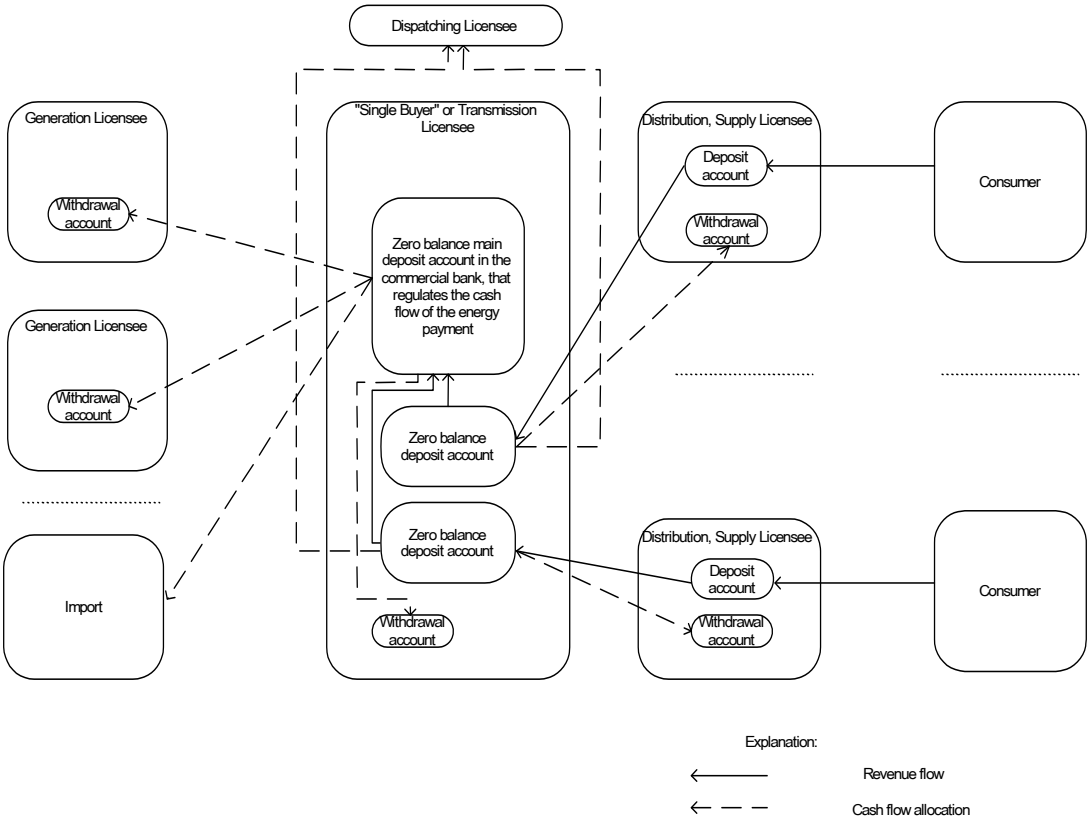


Exhibit taken from Attachment 2 of the Ministerial Decree.

Because the funds allocation formula is based on forecasted levels of consumption and generation, it is also necessary to operate a spot market where generation companies settle deviations from planned output. The spot market rules are developed and approved by the ERA. Settlement between concerned generation companies is performed by adjusting the allocation of revenue due to these companies.

The spot market functions as follows. The Daily Regime Planning Group of the NDC develops generation dispatch schedules for the next "operating" day. During the "operating" day dedicated staff within this group track all deviations from the dispatch schedule, price the energy deviations in accordance with the spot market rules and submit the data to the transmission company to be used for adjustments to funds distributed among generators in the funds allocation process. The spot market rules are somewhat simplistic and vague and do not take into account all possible situations. According to the rules, energy deviations are priced at the combined capacity and energy tariff[5] of the generators. This is not a reasonable approach for valuing capacity and energy transactions. Further, only generation deviations are settled through the spot market - deviations on demand are simply ignored. The current spot market arrangements leave room for improvement.

[5] Effective May 1, 2008, a two-part tariff with separate charges for capacity and energy was introduced on a trial basis.

According to representatives of the ERA, MoFE (now MoMRE) and the generation companies, since the CMS was introduced the collection rate of funds for disbursement by the Single Buyer has improved significantly. According to the ERA's 2007 Annual Report, since introduction of the Single-Buyer Model, collections have improved from 75% in 2001 to 100.3%[6] in 2007. During the 2004 through 2006 period, collections were about 98%.

2.4 Analysis of Current Market Model

Before conducting an analysis of the current market model it must be pointed out that characterization of the market as "Single Buyer" is a misnomer. The transmission company is not taking title to the energy produced by generation companies, and is not legally responsible for paying the generating companies – it simply allocates the funds in the MZBA. Neither can this market be characterized as a power exchange since settlement according to the funds allocation formula does not track payments according to the actual amount of energy produced and consumed. In fact this system is more representative of the operation of a vertically-integrated utility which is functionally unbundled into business units that receive a portion of retail revenues in accordance with the pre-approved formula administered by one of the business units, in this case, the transmission company. As such, this system has the advantages and disadvantages of a market characterized by a vertically integrated utility.

The primary advantages of the current market include:

- Relative simplicity;
- Allows simple balancing of supply and demand and settlement of deviations through the spot market settlement process;
- Reduces misappropriation of retail revenue;
- Provides reasonable financial stability to power sector entities;
- Enables direct pass-through of costs of Government social initiatives to consumers; and
- Contributes to reliable power system operation under difficult conditions.

The primary disadvantages of the current market include:

- It does not foster competition and the resulting discipline imposed on power sector entities to improve performance and efficiency, and increase service offerings to consumers;
- It does not promote commercial relationships, particularly between distribution and generation entities;
- It leads to government intervention and potential hidden subsidies;
- It results in an inappropriate allocation of risk between power companies and consumers;
- It requires that the public sector (i.e., the GoM) raise all capital requirements, or alternatively, commit to inefficient long-term contracts for services[7]; and
- It does not provide distribution companies with sufficient incentives to improve performance in collection of retail revenue.

[6] Performance exceeds 100% owing to payment of receipts from previous years.

[7] Long-term contracts are inefficient in the sense that the GoM will be required to pay for the plant for many years into the future until the contact expires even of new, more efficient and cleaner technology comes along. There is no incentive for the owner/operator of the plant to upgrade to the new technology - he will get paid according to the contract regardless. In a competitive environment, the owner/operator will be required to replace old technology with new technology or forego sales to competitors with new technology, ultimately forcing him out of business. The plant shareholders rather than the GoM and public sector take on technology risk in a competitive market.

As noted above, there is a spot market for energy to settle deviations between planned and actual generation dispatch, but only generators participate in the spot market so there is little incentive for distribution companies to accurately forecast demand. Further, the pricing of transactions in the spot market are suspect as is the consistency of administration. It is unlikely that the current spot market design is meeting its objectives.

Discussion with representatives of the power companies indicates that implementation of the "Single Buyer Market" model played a positive role in the development of the national power system during difficult times. It prevented financial collapse of the power system and helped to maintain reliable operation by introducing financial stability. However, if Mongolia is to experience continued economic expansion in the future and attract the capital necessary to fund this economic expansion and replace aged infrastructure, the reform effort must continue with introduction of increasing levels of competition. The current framework cannot sustain Mongolia through the challenging times ahead.

SECTION III: ANALYSIS OF COMPETITIVE MARKET MODELS FOR USE IN MONGOLIA

3.1 Overview

Competition is introduced in a power sector by providing customers a choice of suppliers and allowing equal and non-discriminatory access to the transmission system. However, customer choice is an entirely new concept in Mongolia, so there are risks involved in moving immediately to a competitive market structure. In addition, there are a number of financial and technical constraints that must be taken into consideration when introducing greater levels of competition in Mongolia.

With this in mind, EPRC has worked with the ERA and key industry stakeholders to develop objectives of the electricity market reform effort and identify the constraints to implementing greater levels of competition. Various market models and design techniques in use around the World are then analyzed on the basis of these objectives while taking into account current constraints culminating in a market design recommendation specific to Mongolia.

3.2 Objectives

Like many jurisdictions around the World, the ERA defines the primary objectives of the electricity market reform effort as follows:

- To improve the value of service to consumers; i.e., quality and reliability of service relative to price, number of service options. etc;
- To reduce the investment and liability burden on the public sector; and
- To improve the efficiency of the electricity sector both in terms of supply and consumption.

The goal is to improve the value of service to customers while reducing risks over which customers have little or no control.

Further, these objectives should be achieved within the context of the following:

- Development of the industry to provide the quantities of energy necessary to meet consumer needs;
- Stimulation of competition while ensuring non-discriminatory and transparent practices;
- Creation of conditions for safe and reliable operation of the supply system;
- Promotion of state-of-the-art technologies;
- Creation of transparent, attractive and stable conditions for investments in infrastructure;
- Stimulation of renewable energy sources;
- Stimulation of environmental protection; and
- Enhancement of energy efficiency in the entire chain of energy activities including consumption.

3.3 Constraints

Mongolia has a number of issues, or constraints, that must be dealt with in order for the reform effort to progress successfully, as follows:

- Retail tariffs are far too low to generate the revenues necessary to recover the cost of supply. The report prepared by EPRC in conjunction with the ERA[8] referenced earlier indicates that the average tariff must roughly double over the next four years if the power companies are to become financially self-sufficient and the Government of Mongolia as principal shareholder is to receive a reasonable return on its investment. Mongolia's residential and industrial retail tariffs are only 26% and 46%, respectively, of international averages.
- There is significant subsidization in the power sector, both to the power and heat sectors as a whole, and between and within customer classes. Subsidies are not targeted to the truly needy, and are not transparent.
- A uniform national retail tariff ensures all classes of customers across the country pay the same tariff regardless of actual cost of supply meaning that there is cross-subsidization between customers of different distribution companies.
- Although there has been significant improvement, collections and receivables remain an issue of concern among industry stakeholders.
- There is limited private sector participation in Mongolia's power sector meaning it will take some time for the private sector to become "comfortable" investing in Mongolia on a sustainable basis.
- With only 782 MW of installed generation capacity on the CES (627 MW of available capacity), Mongolia is a small market. This makes it more difficult to introduce competition and protect consumers against market power abuse by dominant generators. Mongolia's international interconnection with Russia has a maximum transfer capacity of 240 MW, so some limited competition could be introduced from outside Mongolia. Regardless, as noted in the Synex report referenced earlier, the size of the market is not necessarily a deterrent as witnessed in countries such as Bolivia, Panama, Nicaragua and El Salvador that have successfully developed competitive generation markets in electric systems ranging in size from 700 MW to 1000 MW (see page 3 of Synex Report). The small size does however require that the ERA closely monitor the market to guard against market power abuse.
- There are currently a number of technical limitations at the NDC. Although a new SCADA system has recently been installed, budget limitations excluded the addition of an operator training simulator and an Energy Management System (EMS). A training simulator would improve the performance of operators during high-risk events and reduce outage restoration times, thus increasing market participant confidence in the NDC as a system and market operator. The absence of an EMS means that dispatch is not optimal, and that there is little in the way of an audit trail in the event NDC dispatch decisions are challenged by Market Participants. This will become a greater concern in the future as the system increases in size and complexity. Finally, commercial grade metering is not currently installed at each input and off-take point of the grid, and there is no commercial grade billing and settlement system to ensure Market Participants receive and make proper payment.
- Many of the ancillary services necessary to maintain system reliability on the CES are provided by Russia. Although the types and definitions of ancillary services vary around the world, they generally include:

[8] See May 2008 report by EPRC entitled *Proposed Retail Tariff Reform Plan for Mongolia's Central Electricity System*, pages ii and iv.

- *Regulation/load-frequency control:* the adjustment of generator output to correct variations in system frequency;
- *Operating reserve:* Capacity that for any given operating interval is in excess of that required to meet anticipated requirements for energy and is available for dispatch within a specified time period, such as 10 minutes or 30 minutes;
- *Reactive support and voltage control:* The control and maintenance of prescribed voltages on the transmission grid, including, but not limited to, capacitors, static VAR compensators, reactors, synchronous generation facilities, and synchronous condensers; and
- *Black start capability:* The ability of one or more generators to start and provide start-up power to the transmission grid without any dependency on electricity system supply.

The Russian power system is much larger than Mongolia's power system so can help in a variety of ways as allowed under the contract. CHP 4 is the only plant in Mongolia capable of ramping up and down in response to dispatch instructions from NDC, but ramping must be done manually. CHP 4 is used for load following provided changes in demand do not result in reserve margins falling short of target criteria. When reserves fall below target criteria, NDC relies on Russia for support. Russia also provides frequency control, and when severe disturbances occur on the system, Mongolia leans on Russia for support over the interconnection. This reliance of Russia for many of the required ancillary services is not necessarily a deterrent, but must be accommodated in the market design.

- Although significant improvements have been made, there remains a lack of transparency in transactions in the Spot Market and in the establishment of tariffs. It will be necessary to develop clear rules governing the competitive market and tariffs so investors have the information necessary to make sound investment decisions.

Market reform must be staged to allow time for Mongolia to address these constraints, and for Market Participants to gain experience with the new market design in order to manage the risks associated with market implementation.

3.4 Competitive Market Design Considerations

There are many different electricity market designs in use around the world. In order to simplify the discussion of the potential models, the merits of various components of the market design are considered, specifically, the market model, industry structure and market mechanism components. Ownership is another component of market design but is not addressed in this report because there are currently no firm plans to privatize power companies, and because the market design concepts discussed are equally relevant regardless of ownership.[9]

Each component of market design is described briefly below.

- ***Market Model:*** The market model refers to the level of competition introduced. Generally, there are four market models to choose from: monopoly, single-buyer, wholesale competition and retail competition.
  - Monopoly Model: monopoly at all levels. One entity may have responsibility for all functions, or the distribution companies may be separate bodies from the

[9] There is no need to first privatize the power companies before implementing a new market design as witnessed by the success of the Nordic market (NordPool) which has extensive public ownership. Delaying market implementation in Mongolia until the power companies are privatized would unnecessarily delay market implementation, thus delaying, and perhaps foregoing altogether, the benefits of competition.

generation and transmission entity. This model was in common use around the World prior to the introduction of Independent Power Projects (IPPs).

- Single Buyer Model: a single wholesale buyer of electricity can choose from a number of different generators encouraging competition in generation. Access to the transmission system is not permitted for sales to final consumers. The single buyer model was in common use around the World following the introduction of IPPs. Mongolia's current market is referred to as a single buyer, but as noted earlier, is closer to the monopoly model with separate business units within a vertically-integrated utility owned almost entirely by the GoM.
- Wholesale Competition Model: wholesale buyers (distribution companies and in some cases, large customers directly connected to the transmission networks) can choose their supplier, bringing competition into generation and wholesale supply. This requires open access to the transmission system. Distribution companies maintain a monopoly over retail consumers.
- Retail Competition Model: all customers can choose their supplier. This requires open access to the transmission system and distribution systems. The distribution activity can be separated into wires (asset management) and retail, or supply, activities, with the latter being competitive.

- ***Industry Structure:*** There are many possible industry structures with different combinations of the various functions performed by the electricity services industry. The primary functions performed by the industry include: generation (i.e., energy and ancillary services), transmission asset management, system operation and dispatch, market operation, billing and settlement, distribution asset management and retailing (i.e., procurement, customer service and metering/billing). The industry structure refers to the combination of these functions into different entities. There may be several entities within a function; i.e., there may be several generating companies to enhance competition.
- ***Market Mechanism:*** There are two basic market mechanisms to consider: centralized dispatch and self-dispatch. In a centrally dispatched market, generators bid into a centralized market and the System Operator, on the basis of lowest cost determined by the Market Operator, directs the generators when, and at what production levels, to operate. Generating stations are centrally dispatched by the System Operator while complying with its responsibilities related to system reliability. In a self-dispatched market, market participants freely enter into contracts and submit production schedules to the System Operator reflecting their contract positions. As a result, generating stations self-dispatch. They inform the System Operator of their schedules ahead of time. This enables settlement in the balancing market, and helps the System Operator carry out its responsibilities related to system security.

3.5 Market Model

Monopoly Model

Mongolia currently has a monopoly model because all functions are carried out by companies with a single owner, the GoM, without competition in either generation or supply.

The monopoly market model has certain advantages, as follow:

- Simplicity;
- Significant industry experience;
- Low transaction costs; and

- Government social initiatives are easily accommodated.

However, it also has significant disadvantages, including:

- Does not promote competition;
- Discriminatory;
- Limited transparency; and
- High public investment and liability burden.

There is no reason to believe the monopoly model would lead to:

- Improved production or consumption efficiency in the electricity services industry;
- Promotion of “state-of-the-art" technologies;
- The assurance that there will be adequate supply or good quality service;
- Reasonable electricity tariffs; or
- Improved value of service or increased service options for consumers.

This market model is not consistent with promoting greater competition. A key disadvantage is that the public sector would continue to be responsible for raising all capital requirements for the power industry. It is unlikely the GoM can raise the necessary capital, but even if it could, it might be better directed to other social initiatives such as hospitals, schools, roads, etc.
If the GoM continues with tariffs that are far below costs with high levels of cross-subsidization among customer classes this is possibly the best market model. However, it is entirely inconsistent with the objectives of market reform.

Single Buyer Model

Under the single-buyer market model, the Transmission Company would perform much the same function as it does today except that it would actually purchase all generation, and in turn, sell the power to wholesale customers; i.e., the distribution companies and potentially, the customers connected directly to the transmission system. There can be competition in the procurement process for new generation through the issue of a transparent, competitive bid process. A central planning organization determines when new generation is needed on the system, and issues a request for proposals when generation reserves drop below a pre-determined level; i.e., when generation capacity drops below 115% of peak system demand.

The private sector has been successful in reducing construction times and implementing more efficient project management expertise in power plant construction. The private sector has generally been better able to acquire necessary permitting approvals from local Governments owing to the profit motive, and the fact that it is generally unencumbered by the political interference often faced by state-owned entities. Private sector developers are able to construct power plants more cheaply because power plant construction tends to be their only line of business; i.e., business process is less diluted.

The procurement process, when conducted in a transparent and competitive manner results in lower generation costs, both initially, in terms of reduced construction costs, and over the longer term, in terms of reduced operating costs. If any of Mongolia’s existing generating companies were allowed to participate in the bidding process, they should be forced to form an unregulated subsidiary that borrows capital at market rates similar to the private sector. This provides a more fair and level playing field, making the power procurement process more competitive, and putting downward pressure on the overall cost of power.

Under the single buyer market model, the construction risk is transferred from the public sector (i.e., the GoM and retail customers) to the private sector developer, and the Government is not required to raise the necessary capital. In addition, under the single-buyer model,

stranded costs and Government social initiatives such as lifeline tariffs for the poor, a national uniform retail tariff, fuel diversity, promotion of renewable generation, etc., are easily accommodated as the costs of these programs are simply passed through to consumers. Owing to the simplicity of the market arrangements, transaction costs are quite low relative to the wholesale and retail competition market models discussed below. There is a great deal of industry experience with this market model.

However, the single buyer market model has a number of disadvantages as outlined below:

- Although the Government's capital requirements are reduced owing to the successful introduction of private sector capital in the generation sector, the long-term Power Purchase Agreements (PPAs) required under this market structure represent a contingent liability for the Government. As a result, this is not a particularly efficient form of private sector investment in the industry.
- Separation of decision-making and risk for investments means that generators and their shareholders are not subject to risks brought on by technology change and demand forecast errors. This risk remains with the public sector. For example:
    - The costs of generation over-capacity resulting when demand has not grown as rapidly as forecast are borne by consumers. In a competitive market, shareholders of the generating companies would pay for over-capacity rather than the public sector.
    - It would take a long time for improved technology (i.e., reductions in plant equipment costs, advancements in plant efficiency, reductions in plant pollution/emissions, etc.) to be introduced in a market with long-term PPAs.
    - The market provides no signal to the generating plant owners that would prompt efficiency improvement and technological upgrades.
- Prices are determined solely from supply costs with little consideration of consumer surplus and un-served energy values. Incorrect price signals prompt inefficient price response. For example, if demand growth is lower than expected, wholesale tariffs will increase, signaling customers to further reduce consumption resulting in further increases in tariffs. The effect is opposite in a competitive market where surpluses drive costs downward signaling customers to consume more.
- Reliance on an administered algorithm such as economic dispatch is a surrogate for efficient market operations where competition exists, and generators are allowed to compete under economic incentives to cover both short- and long-run marginal costs.
- Government agencies tend to be poor purchasing agents, and long term PPAs are not particularly transparent, prompting accusations of unfairness and corruption.

In summary, the single buyer market model results in only marginal increases in competition and does little to reduce the liability burden on the public sector.

Wholesale Competition Model

Under wholesale competition, wholesale consumers can choose their supplier forcing generating companies to compete for sales, thus putting downward pressure on prices. For this model to function properly there must be open and non-discriminatory access to the transmission system.

The primary advantages of this model are that it promotes competition at the wholesale level putting downward pressure on wholesale prices; it transfers risks from consumers to developers/investors; and decreases the investment and liability burden of the public sector. In addition, the increased competition would be expected to lead to improved efficiency of the electricity services industry while ensuring adequate supply with good quality service at

reasonable prices. It also results in increased transparency, and can be designed to accommodate Government social initiatives such as rural electrification and lifeline tariffs for the poor.

The wholesale competition market model addresses the disadvantages identified under the single-buyer market model:

- Long-term PPAs are not required between the single buyer and generators thus reducing the contingent liability on the public sector and leading to more efficient private sector investment in the industry.
- Decision-making and risk for investments are no longer separated, so generating companies and their shareholders take on risks brought on by technology change and demand forecast errors rather than the public sector.
- Prices are determined by competitive market forces, accounting for consumer surplus and un-served energy values, and prompting correct price signals and efficient price response by consumers.
- There is no need for inefficient and inexperienced Government purchasing agencies and long-term PPAs that are not particularly transparent.

The primary disadvantage of the wholesale competition market model is that it has higher transaction costs than the monopoly and single-buyer market models, and does not necessarily result in increased options for retail consumers to the extent that would be expected under the retail competition model discussed below. There are fewer buyers, so there is less competition than would be experienced under the retail competition model. It is inconsistent with a national uniform tariff.

This model is somewhat unstable as customers who can benefit from competition want choice, putting pressure on the Government to expand the competitive market to include more customers. This model requires significant change in the industry, increasing the risk of failure. In Mongolia there is a need to mitigate many problem areas in the sector before moving to the wholesale competition model.

In summary, this model is consistent with the introduction of increased competition in the sector, although it does not go as far as the retail competition model.

Retail Competition Model

Under retail competition, all customers including wholesale and retail customers are free to choose their supplier, thus forcing generating companies and supply entities to compete for sales, putting downward pressure on prices. For this model to function properly there must be open and non-discriminatory access to both the transmission and distribution networks.

This model best meets the objective of promoting competition. It also reduces the investment and liability burden on the public sector. It is non-discriminatory and transparent, and would be expected to lead to:

- Improved efficiency of the industry, both production and consumption;
- Promotion of "state-of-the-art" technologies; and
- Adequate supply with good quality service and reasonable prices.

It has all of the advantages of the wholesale competition market model, while promoting greater competition and increased options for retail consumers.

The disadvantages are that:

- It has high implementation and transaction costs;

- It is more difficult to accommodate Government social initiatives, although it can make the costs of these programs more transparent;
- It is inconsistent with a national uniform retail tariff;
- It requires significant change, with full reliance on the market to provide consumer benefits, thus increasing the risk of failure;
- In a relatively small market such as Mongolia market power abuse can be an issue; and
- It requires that a number of Mongolia's current problem areas in the sector be mitigated prior to implementation.

So while retail competition is consistent with increased competition, it has certain risks that must be managed, and requires that the current shortcomings in the sector be addressed prior to implementation.

Market Model Summary

The retail competition market model is the ultimate market model in terms of competition. However, as the expected benefits increase so do the inherent risks and the costs of implementation and ongoing administration. It is important that competition be introduced in a way that:

- Has acceptable risk and cost while moving toward long-term policy objectives;
- Is clear, transparent and stable;
- Is relatively simple and quick to implement, with considerable industry experience; and
- Is robust to accommodate changes that arise.

3.6 Industry Structure

There are many possible industry structures with different combinations of the various functions performed in the electricity services industry (see ***Exhibit 3***). There are normally several generators that produce energy and ancillary services for consumption. The transmission component covers several functions including grid ownership, system operations (generation and transmission dispatch), market operations and wholesale settlement administration (i.e., billing). There may be several grid owners providing open access to the transmission system. Generally, there is a single system operator and a single real-time market operator. Management of the transmission functions may be grouped in a number of ways. The distribution component of the business generally includes a number of "wires" businesses and supply businesses. The "wires" businesses provide asset management of the distribution facilities and open access to the distribution system. The supply businesses procure power for sale to retail consumers and provide customer services such as metering and billing, in addition to other value-added services.

A brief discussion of the pros and cons of various combinations of industry functions is provided below.

Combined System Operator and Market Operator Functions

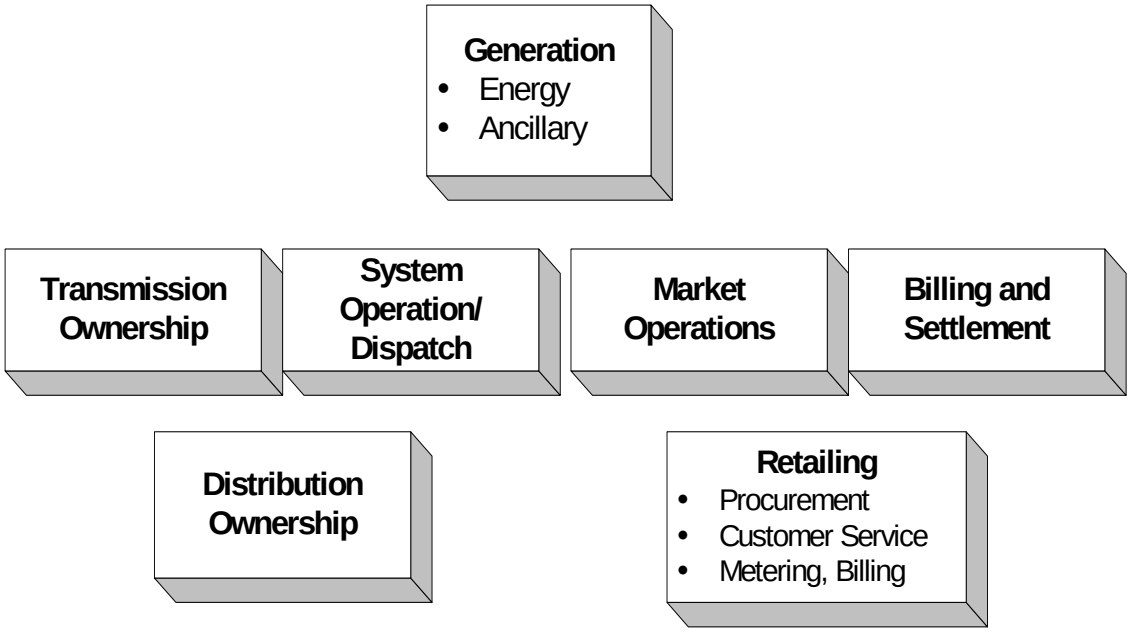
On a real-time basis, the System Operator is forced to intervene in the market owing to sudden changes in demand and generation availability. Independent markets are simply unable to respond quickly enough to provide market solutions to real-time events in electricity markets. As market solutions are the preferred mechanism for encouraging market participants to respond to dispatch instructions, it is logical that System and Market Operator functions be combined into one entity to operate the real-time, or physical, market.

Independent management of the System Operator and Market Operator functions is inconsistent with the goals of the market. The primary goal of the System Operator is to maintain system reliability, with little regard for cost. The primary goal of the Market Operator is to minimize market costs with little regard for reliability. This could lead to conflicts when problems occur on the electricity system. The goal of a combined System and Market Operating entity is to maintain system reliability at reasonable cost, consistent with the overall goals of the market. A combined System/Market Operator entity is consistent with smaller markets such as that in Mongolia; i.e., reduced administration costs.

A combined System/Market Operator entity does not preclude the possibility of introducing an independent power exchange to operate forward markets (i.e., day-ahead). If market participants determine there is a need for forward markets, the System/Market Operator entity might operate such markets in addition to the real-time market, or alternatively, an independent entity such as a power exchange might provide the service.

The discussion that follows assumes that Mongolia will continue with a single entity, the NDC, performing both the System and Market Operating functions.

Exhibit 3. Functions Performed by Electricity Services Industry



Combined System/Market Operator Function with Generator Function

The System/Market Operator entity makes decisions on a day-to-day basis in the competitive market that have significant financial impacts on generators. If the System/Market Operator entity owns generation, management of the combined entity will have a significant incentive to use its position in the market to enhance the financial well-being of its generation affiliate at the expense of other generators; i.e., through the dispatch process, generation maintenance outage scheduling, transmission maintenance outage scheduling, etc. For example, the System/Market Operator entity could schedule generation outages in a manner that maximizes the system marginal price for its generation affiliate. It is very difficult to regulate a System/Market Operator entity that owns generation to ensure against abuse of its market position. Even if it were theoretically possible, other generators would not believe they were being treated fairly.

It is for this reason that the Federal Energy Regulatory Commission (FERC) in the United States promotes the formation of Regional Transmission Organizations whereby transmission assets are turned over to independent System/Market Operator entities to promote greater, and non-discriminatory, competition. Likewise, the EC Directives require as a minimum legal separation of generation, transmission and distribution, and that a transmission system operator be specified whose role is to dispatch plant in a fair and non-discriminatory manner.

Combined Transmission Ownership (GridCo) Function with Generator Function

The GridCo is required to submit schedules of outages for transmission maintenance and upgrades to the System/Market Operator entity on a regular basis. The timing and location of these maintenance outages and upgrades can significantly impact individual generating facilities providing an incentive for the management of a combined GndCo/Genco entity to schedule these events in a manner that favors its own generation over others. As there are numerous such outages, it is difficult for the Regulator and the System/Market Operator entity to ensure the outages are planned in a non-discriminatory manner, and even if it were, there would still be accusations by other generators of unfair treatment.

While GridCo/Genco affiliations are not uncommon in the industry (i.e., United States, France and Germany), most jurisdictions favor separation for the reasons given above. The EU Directives require legal unbundling.

Combined Gridco Function with the System/Market Operator Function (Transco)

There are times when transmission asset owners (GridCos) compete with generators (Gencos) in the market For example, the System/Market Operator entity might request the GridCo to forego an outage or return a facility on outage to service ahead of schedule in order to avoid high-risk situations and the dispatch of expensive generation. In addition, in the planning process, a transmission expansion option might compete against a new generation project for supply to a transmission-constrained area. In these circumstances, management of a combined GridCo/System/Market Operator entity might have incentive to favor the transmission option over the generation option. In the case of outages, it can be difficult for the Regulator to ensure that actions are non-discriminatory. In the case of system expansion, an open public hearing on the system expansion program should for the most part ensure against discriminatory actions.

Prohibiting affiliations between the System/Market Operator and GridCo would ensure against discriminatory behavior. In addition, separating the functions would create smaller, less powerful entities to regulate. However, there are positive aspects of this structure. A separate System/Market Operator entity would own no assets, and would have no capacity to construct new facilities (part of ensuring its independence). It is difficult to ensure that transmission expansion takes place under such a regime - the System/Market Operator does not have the capacity to build, and the GridCo does not have a mandated regulatory requirement making it responsible for transmission expansion. For example in the Province of Ontario in Canada and many United States jurisdictions, the System/Market Operator entity develops an indicative power system plan/report, and awaits proposals from prospective developers to address deficiencies. It is not at all certain that the market will develop the needed transmission capacity under this scenario which can be of particular relevance in markets with high levels of demand growth such as Mongolia.

The TransCo industry structure is the prevailing approach used in Europe including England & Wales, Norway, Sweden, Finland, Netherlands, Belgium, Spain, Poland and the Czech Republic. Under incentive regulation in England and Wales where the National Grid Company serves as the Transco, during the 1990s the cost of transmission was reduced by 37% while the availability of the transmission system was increased by a full percentage point to 99% and the

capacity of the network was increased by 20%. This is the type of improved performance that is envisioned following the introduction of incentive regulation. It is difficult to devise such an incentive regulatory mechanism for an independent System/Market Operator with no assets.

Although there remains a need for documented procedures, transaction costs would be reduced under the Transco structure relative to the System/Market Operator structure as there would be no need for the legal documentation between the independent GridCo and System/Market Operator entities.

Summary of Industry Structure

Mongolia has separated its power sector along functional lines with separate companies carrying out the generation function, separate companies carrying out the distribution function, and a separate company carrying out each of the system/market operator function and the transmission function. This industry structure is conducive to implementation of a competitive and non-discriminatory market. EPRC generally favors combining transmission asset ownership with the system/market operation function in smaller markets such as Mongolia. However, the functions are currently separated and in EPRC's view there are no compelling reasons for merging the two functions. The option for combining the functions into a separate Transco is always open to Mongolia in the future if studies show there are benefits in doing so.

The existence of GoM ownership of companies performing each function will act as a barrier to market entry.

The number of companies in each function, specifically generation and distribution, has not been reviewed in this report except in the sense that the minimum number of companies necessary to promote competition is met. However, the number of distribution companies in particular appears to be excessive, resulting in unnecessarily high administration costs (there are currently nine distribution companies in the CES as shown in ***Exhibit 1***). As such, *it is recommended that the number of companies/licensees in the CES be reviewed to determine if economies of scale can be gained without negatively impacting competition. EPRC is available to assist with such a study if deemed desirable by power industry stakeholders.*

3.7 Market Mechanism

There are two basic market mechanisms to consider: central dispatch and self-dispatch. Central dispatch is sometimes known as a power pool market while self-dispatch is sometimes known as a bilateral contracts market. In a centrally-dispatched market, generators bid into a centralized market and the System/Market Operator directs the generators when, and at what production level, to operate on the basis of lowest cost. Generators are centrally dispatched by the System/Market Operator while complying with its responsibilities related to system reliability.

In a self-dispatched market, market participants freely enter into bilateral contracts and submit production schedules to the System/Market Operator reflecting their contract positions. As a result, generating stations self-dispatch. They inform the System/Market Operator of their schedules ahead of time thus determining settlement in the balancing market and enabling the System/Market Operator to carry out its responsibilities related to system security.

Both market mechanisms require balancing for differences between contracted amounts and actual generation and consumption. Under central dispatch, balancing is carried out by the System/Market Operator as part of the dispatch process. Under self-dispatch, a balancing market operated by the System/Market Operator is needed. In either case, a voluntary power

exchange can be established to offer, for example, day-ahead trading. The two market mechanisms are shown schematically in ***Exhibits 4 and 5***.

There are many variations of these two market mechanisms. For example, the system might include only bilateral contracts, or only a power pool, or it might include both bilateral contracts and a power pool operating alongside one another. The power pool might he cost-based, meaning generators are dispatched on the basis of variable costs, or bid-based, meaning generators are able to bid whatever price they want subject only to market and profitability considerations. In addition, a centrally-dispatched power pool might be mandatory, meaning all generators must participate in the pool, or voluntary, meaning it is each generator's choice whether or not to participate in the pool. A self-dispatched market mechanism might have a bid-based balancing market, or balancing may be handled through bilateral contracts agreements with an administered price. Market mechanisms with central dispatch of generating units are generally related to mandatory pools, and market mechanisms with self-dispatch generally relate to bilateral contracts markets with voluntary pools (i.e., balancing mechanism).

Exhibit 4. Centrally-Dispatched Power Pool

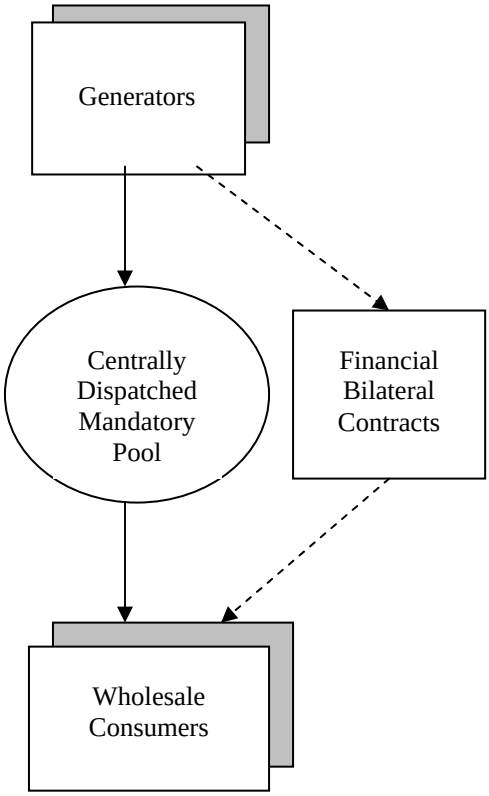
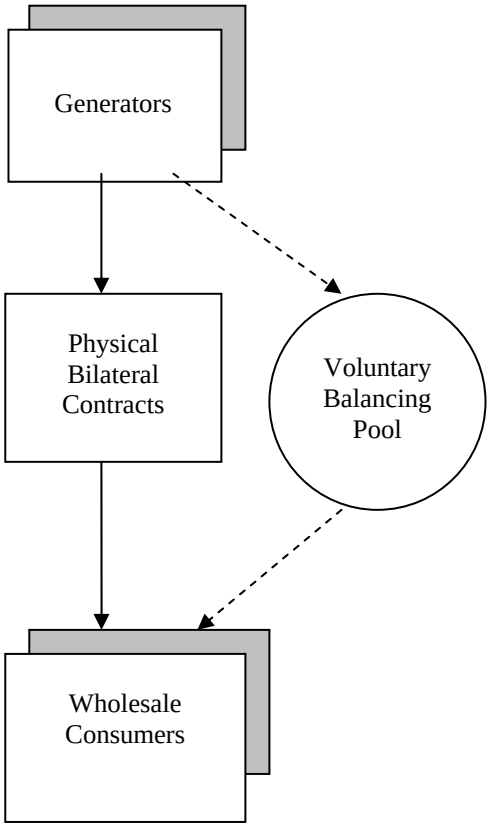


Exhibit 5. Self-Dispatched Bilateral Contracts Market



Bilateral contracts can be physical, meaning that generators self-schedule to fulfill the requirements of their contracts, or financial, meaning generators are dispatched centrally on the basis of costs bid into the pool, and the panties to the bilateral contract settle the price outside the market on the basis of the terms in the contract. Contracts for differences are an example of a financial bilateral contract.

Power Pool/Central Dispatch

In a power pool with central dispatch, generating companies offer price-quantity pairs for the supply of electrical energy for each of their generating units. This forms an industry supply curve. The offered prices are based on predetermined variable costs (i.e., cost-based pools), or the generators can be free to offer any price they like between certain general minimum and maximum prices (i.e., bid-based pools). On the demand side, the system/market operator may forecast demand and dispatch generating units to meet the forecast demand. This is called a one-sided pool. In more sophisticated two-sided pools, the market operator may dispatch on the basis of a demand curve created from price-quantity bids made by the buyers in the market (distribution companies and eligible consumers). The Pool can operate a day-ahead market, a market close to real-time or even a combination of different markets.

Bids and offers are normally firm, meaning that if these bids and offers are matched in the market clearing process, they result in an obligation to receive and deliver the matched volumes at the matched bid price. If the pool only operates a market close to real time, day-

ahead sessions are still conducted, but only as an indicator of forecast prices for the market. The offers and bids in these price-seeking sessions are therefore non-firm.

In parallel to the pool, market participants can enter into bilateral contracts. These contracts can be physical bilateral contracts or financial bilateral contracts. Physical bilateral contracts represent a binding obligation to produce electricity, and the contract parties are required to notify the System/Market Operator of the contract quantities. Transactions are settled at the contract price, and deviations from the contract amounts are settled at the balancing market price. Financial bilateral contracts do not represent a binding obligation to produce electricity, and there is no need for the contract parties to notify the System/Market Operator of the contract quantities - they are settled at the pool price with the contract parties making subsequent adjustments to reflect contract terms.

Bilateral Contracts/Self-Dispatch

In a bilateral contracts market with self-dispatch, buyers and sellers freely enter into contracts for power supply. Sellers will normally be generators, and buyers will normally be distribution companies and eligible consumers. However, generators can also become a buyer (i.e., to cover generation shortages relative to contract commitments); likewise, consumers can become sellers. In other words, each market participant becomes a trader. Brokers can act as an intermediary between buyers and sellers.

There will always be differences between the contracted volumes and the actual metered volumes. The System/Market Operator has to determine and settle these differences, or imbalances. In more advanced markets, the System/Market Operator operates a balancing market (or regulating power market) in order to establish a market based price for the settlement of imbalances.

In parallel with bilateral contracts, a voluntary Power Exchange might be established by market participants. A Power Exchange can offer day-ahead trading with a number of benefits for market participants such as price transparency, anonymous trading and trading portfolio optimization. The Power Exchange could be administered by the System/Market Operator. The Power Exchange itself is not a market participant – it is simply a place where deals between buyers and sellers are arranged. There are never imbalances on the Power Exchange.

Comparison of Central and Self-Dispatched Mechanisms

The two market mechanisms are similar. A centrally-dispatched power pool can have bilateral contracts operating alongside the pool, and in a self-dispatched market, a voluntary power exchange can be implemented to operate alongside the bilateral contracts market. However, there is significant debate concerning the merits of each mechanism.

The two market mechanisms would be similar if there were no transaction costs. The advantage of the centrally-dispatched power pool market is that it provides more optimal outcomes and greater price transparency. The disadvantage of the centrally-dispatched power pool market is that higher costs would be necessary to establish the pool. However this disadvantage should not be over-stated as the self-dispatched bilateral contracts market can likewise have high costs, particularly if a bid-based balancing market is established. NETA in England and Wales is a self-dispatch, bilateral contracts market mechanism with an offer-based balancing market. NETA requires a high level of sophistication by market participants and was costly to implement. The other theoretical disadvantage of the centrally-dispatched pool mechanism, higher price volatility, is really not relevant as financial instruments can be

used for hedging. Moreover, in the case of cost based pools relative to bid/offer-based pools price volatility is quite low.

Advocates of the self-dispatched bilateral contracts market cite the following problems with centrally dispatched power pools:

- Construction of the dispatch schedule can be complicated and lacks transparency. Owing to technical limitations of generating plant (i.e., ramp up/down rates, minimum generations levels, etc.), it is often unclear how the market clearing price is derived from generator offers. This complexity opens the door to potential abuse by generators when submitting their offers, and can lead to less than optimum dispatch.
- Central dispatch requires that the System/Market Operator develop dispatch schedules taking into account plant technical considerations. Arguably, the market participants are in a better position to make these types of decisions because they are best able to gauge their risks. Placing decision-making and risk management on the party best able to make the decisions and manage the risk is likely to result in a more efficient outcome than a central authority with no stake in the outcome.
- Under centrally dispatched bid/offer-based pools all generators receive the market - clearing price represented by the highest priced plant dispatched. A generator with market power has incentive to submit offers different from its marginal cost in an effort to distort the market outcome in its favor. This is one of the problems encountered when the price of a single generator sets the price for all generators dispatched in the trading interval. However, while this may be true of bid/offer-based pools, it is not true of cost-based pools where generators must offer their power at a pre-determined price reflecting marginal cost. In addition, market power abuse has been a concern in most every market in existence, including both centrally-dispatched power pools and self-dispatched bilateral contracts markets.

Central dispatch offers important advantages for Mongolia:

- It provides price transparency;
- It builds on the current practice of central scheduling and dispatch;
- It leads to generation cost minimization;
- It allows for more integrated treatment of generation and transmission plant; and
- There is no requirement for the generating companies to develop scheduling skills.

In Mongolia, the merits of a centrally-dispatched power pool operated along-side a system of financial bilateral contracts introduces competition at the generation level at relatively low cost and risk.

3.8 Summary

Considerations relating to Mongolia's CES follow:

- ***Market Model***: Mongolia must move beyond a single-buyer market model if it is to realize the benefits of competition. Retail competition is far too costly and carries significant risk at this time in Mongolia. Wholesale competition is the favored market model as it provides a reasonable balance of the objectives of the market reform effort with reasonable cost and risk while maintaining the flexibility to move to retail competition if and when desirable in the future.
- ***Industry Structure***: In order for a market to function in a fair and non-discriminatory manner that allows for the free entry and exit of competitive entities, the industry must be unbundled into generation, transmission and distribution components as a minimum. There is considerable debate on whether a market should be further unbundled into

separate market operator and system operator functions, or if they should remain part of the transmission company. Given that the NDC is already separated from the transmission company it is recommended that Mongolia continue with the status quo. The entities can always be combined in future if studies show there are benefits in doing so. Mongolia should undertake a study to identify potential merging opportunities in an effort to gain economies of scale, particularly in the distribution sector.

- ***Market Mechanism***: Generators and distribution companies should be free to negotiate whatever terms they find mutually agreeable for power sales and purchases. Generators should be free to set the price for the energy they deliver to the system provided they are not abusing their market power position. Distribution companies should likewise be free to set the price they are willing to pay, while being protected from market power abuse. A power pool arrangement with central dispatch according to economic merit order based on costs operating along-side a system of financial bilateral contracts has significant advantages in Mongolia at this time. It will result in price transparency, the lowest cost of generation, reasonable implementation and ongoing administration costs, and acceptable risk to implement. It will result in competitive and fair results while instilling competitive discipline between buyers and sellers.

This high-level market design will increase competition, the primary objective of Mongolia's reform effort, and can be implemented within the current constraints facing the electricity sector. It is flexible and robust, has relatively low implementation and ongoing administration costs, and has acceptable risk.

SECTION IV: RECOMMENDED MARKET DESIGN FOR MONGOLIA

4.1 High-level Description of Proposed Market Design

As noted, a market design with wholesale competition, unbundling of market functions along current lines and a power pool with central dispatch operating along-side a system of financial bilateral contracts is favored for Mongolia. However, as noted earlier there are numerous financial and technical constraints facing Mongolia's power sector. In an effort to enable early introduction of competitive market principles before these constraints are fully addressed, it is proposed that this high-level market design be implemented initially with a system of bilateral vesting contracts. In addition to allowing time to address the technical and financial constraints in the sector, the vesting period will provide market participants with:

- Valuable training in the principles of competitive markets, in particular, market pricing and contract negotiation; and
- The opportunity to demonstrate accountability by honoring their contractual obligations and resolving disputes in accordance with the market rules, existing regulations and laws.

The tariff in the vesting contracts would be based on costs and would be regulated by the ERA. It is anticipated that the market would be fully-vested for a period of two to three years at which time the vesting contracts would gradually be reduced, forcing wholesale buyers (the distribution companies) to procure a portion of their power needs through negotiated bilateral contracts with generators. The timing and speed at which the vesting contracts are reduced would be determined by the ERA with input from industry stakeholders, but it is anticipated that vesting contracts would be reduced to zero within six years of market commencement.

With this in mind, a high-level summary description of the proposed market design[10] follows:

- The wholesale power market will be based on a system of bilateral contracts for the purchase and sale of electric power and energy. A bilateral contract represents a firm financial commitment by a generator to deliver capacity and energy to the distribution company in the amounts stated in the contract regardless of actual dispatch. Generation output consistent with dispatch orders from the System/Market Operator (SMO) that exceed or fall short of amounts specified in bilateral contracts represent a sale or purchase in the spot market. Bilateral contracts can include contracts between:
    - Distribution Companies and Generating Companies
    - Generating Companies and Exporters
    - Importers and Distribution Companies
- For an initial period of two to three years (to be determined by the ERA with input from industry stakeholders), vesting contracts covering all sales in the market will be assigned between generators and distributors. The vesting contracts will be established by the ERA with tariffs based on costs. Bilateral vesting contracts will be settled monthly and payment will be made directly from buyer to seller[11]. Following the initial

[10] During the stakeholder process a question was raised concerning the relevance of employing a Central American market design in Mongolia. It is understood that this question was raised as a result of the World Bank study referenced earlier that was completed by Synex Consulting Engineers. The author notes that the design developed in this report is based on the analysis documented in ***Section 3*** which reflects Mongolia's specific objectives and constraints. The content of the World Bank report has been drawn upon in an effort to avoid duplication of work, but the recommendations in this report incorporate design techniques and experience gained around the World culminating in a recommendation specific to Mongolia's objectives and current situation.

[11] Some elements of the current cash management system may be employed as part of contractual arrangements.

vesting period, the vesting contracts will be phased out gradually until each Distributor is allowed to freely negotiate its full supply requirements with any supplier it chooses. The speed at which the vesting contract regime is phased out will likewise be determined by the ERA with input from industry stakeholders, but is expected to be completed within six years of market commencement.

- Actual delivery amounts can be different from contract quantities so a spot, or balancing, market will be used to settle the differences. All generation will be centrally dispatched by the System/Market Operator (SMO) on the basis of lowest variable cost. The ERA will approve the variable costs used in the spot market for each generator based on information provided by the generators and the SMO. Deviations from contract amounts in both supply and demand will be settled in the spot market at the variable cost of the marginal plant; i.e., the variable cost of the highest cost plant/import dispatched during the period after taking into account constraints.
- The SMO will dispatch all generators under bilateral contracts on the basis of lowest variable cost while honoring heating load requirements, minimizing transmission line losses, maintaining power flows within transmission line limitations, honoring all reliability criteria and respecting generator unit limitations; i.e., minimum load levels, ramp up/down rates, etc.
- The SMO has the right to demand that Generators provide ancillary services pursuant to license obligations. Compensation for the costs of providing ancillary services will be included in the tariff in the bilateral vesting contracts established by the ERA.
- In the future, market participants may have the opportunity to arrange bilateral contracts for sales over the interconnection with Russia. However, in the near-term vesting period all the needs of Distribution Companies will be met with generation from Mongolian power plants and imports from Russia under the current contract. The contract with Russia will continue to be managed by the Transmission Company and be used principally for ancillary services. However, depending on the demand/supply balance on the CES, the contract with Russia may be negotiated in the near future to include significant energy purchases in addition to capacity.
- Distribution Companies will be subject to a transmission tariff based on the revenue requirement of the transmission company spread across sales; i.e., a postage-stamp tariff.
- A transmission system expansion plan will be developed by the SMO on the basis of least cost principles at five-year intervals and updated annually. The SMO will develop the transmission expansion plan in conjunction with market participants and submit the recommended plan to the ERA for review, comment and approval[12]. The transmission company will be responsible for managing construction of ERA-approved transmission facilities.
- Distribution Companies will be subject to an SMO service charge based on the revenue requirement of the SMO.

[12] It is recommended that the ERA approve the system expansion plan consistent with practice in other international jurisdictions with competitive markets. This will require a change in laws and regulations in Mongolia. Until such amendments are made, it will be necessary for the ERA to provide recommendations for system expansion along with justification to the MoMRE or Cabinet for approval.

4.2 Bilateral Contracts and Spot Market Operation

As noted, initially the market will be governed by a system of regulated vesting contracts between generators and distributors. The vesting contracts will be designed and approved by the ERA with tariffs based on costs. The vesting contracts will be consistent with freely negotiated bilateral contracts which will replace vesting contracts as they are gradually phased out to introduce greater competition. The freely negotiated bilateral contracts will be consistent with a pro forma contract approved by the ERA.

Bilateral vesting contracts will be established annually and will allow monthly adjustments to contract volumes for capacity and energy. The bilateral contracts will be settled monthly and payment will be made directly from buyer to seller. The SMO will conduct technical reviews of bilateral contracts to ensure system requirements can be met with adequate levels of reliability. During the initial vesting period, all generation capacity will be included in the vesting contracts with the Distribution Companies.

All bilateral contracts will be subject to central economic dispatch directed by the SMO. The tariff in the vesting contracts will include two parts including a capacity component and an energy component. The energy component will reflect each generator's variable production costs (i.e., costs that vary with energy production) including fuel and variable operation and maintenance (i.e., water, chemicals, etc.). The capacity component will reflect each generator's fixed costs (i.e., costs that do not vary with energy production) and include capital (i.e., depreciation), fixed operation and maintenance, taxes, insurance and profit. Payments for energy will be based on energy (kWh) delivered to the transmission grid and payments for capacity will be based on available capacity, that is, the ability of a generator to produce energy when called upon by NDC. In effect, the capacity payment relates to the reliability of the generating station. Capacity payments are made independently of actual energy production with bonuses/penalties for exceeding/shorting the "target" availability.

The objective of the two-part tariff is to promote economic dispatch by making generators indifferent to levels of dispatch. In addition, by indexing payments to historical performance and industry standards generators have the incentive to improve performance. A description of two-part generation purchase tariff design is provided in a June 7, 2006 report entitled *ERA Proposed Two-Part Tariff – EPRC Project Team Comments*. It is noted that a two-part generation purchase tariff was implemented by the ERA on a trial basis on May 1, 2008. This initial tariff represents a simplified form of that developed in the June 7, 2006 EPRC report which was necessitated by the fact that retail tariffs are currently too low to enable full recovery of power company costs. For example, most risk remains with the consumers rather than the generators, and there is only a single fuel conversion efficiency (heat rate) used for the entire year, ignoring the fact that plant efficiencies are much higher during the winter season when there is significant heating demand. Further improvement will be made to the two-part tariff design following the trial period as retail tariffs are increased. It should be possible to import the two-part tariff design directly into bilateral vesting contracts.

The two-part tariffs approved by the ERA will include the costs of ancillary services. The SMO has the right to demand that market participants provide ancillary services within plant capabilities.

At the conclusion of the initial vesting period, Distribution Companies will be allowed to procure their remaining power requirements through freely-negotiated bilateral contracts with generators or through the purchase of balancing power on the spot market.

The energy entitlement of Distribution Companies in their bilateral contracts with generators is the pro-rata share of the given Distribution Company in the capacity of the given generating

company, or may be directly specified in bilateral contracts. The energy payments by the Distribution Companies under bilateral contracts will be calculated as the product of its energy entitlement specified in the contract or computed as a percentage of contractual capacity entitlement expressed in MWh and the energy component of the two part tariff for the generation company.

Capacity payments under bilateral contracts are calculated each month as a product of the amount of capacity specified in the contract expressed in MW, the capacity component of the two part tariff of the given generator expressed in $/MW-month, and a number between 0 and 1 reflecting the availability of the given generating company. Until a procedure for determining the availability factors is approved by the ERA, all availability factors will be set equal to 1 as they are in today's two-part tariff. The ERA, with input from industry stakeholders, will approve guidelines relating to verification of available capacity including a procedure for conducting availability tests and calculation of availability factors.

All deviations of actual production and/or consumption from contract amounts will be settled in the spot market. The SMO will dispatch generation on the basis of lowest variable cost; i.e., the generator with the lowest variable cost will be dispatched first, the generator with the second lowest variable cost will be dispatched second, and so on and so forth until the load is fully met. This merit order dispatch will be subject to satisfying all constraints including heating load requirements, transmission constraints, physical constraints of generators, etc.

Distribution companies will pay generators for energy according to the energy price in the vesting contract. Deviations from contract amounts will be settled in the spot market according to the price of the highest cost generator dispatched in the hour of the deviation. This charge will be applied to distributors whose energy demand is not fully covered by energy in its bilateral contracts and by generators whose energy delivered to the grid is less than energy committed in its bilateral contracts.

The Distribution Companies are responsible for developing their energy consumption and peak load forecasts. By October 1 of each year, the Distribution Companies will submit their peak load and energy demand forecasts to the ERA and the SMO for development and evaluation of their vesting contracts. An indicative forecast of total consumption and hourly loads for the Distribution Companies will be developed by the SMO for the entire year. Distribution Companies may adjust their annual forecast on a monthly basis by submitting adjustments to the SMO no later than 5 days before the beginning of each month.

If a generation company deviates from a dispatch instruction by generating more energy than directed, the energy produced in excess of what would be produced if the dispatch instructions had been followed is paid for according to the energy component of the approved two-part tariff of the least expensive energy producer currently on line whose energy was displaced as a result of the non-compliance with dispatch instruction.

It will be necessary to allocate bilateral vesting contracts between generation and distribution companies. In an effort to mitigate concerns relating to fairness, it is recommended that contracts be allocated in a manner that minimizes cost transfers between the retail customers of each distribution company. More specifically, vesting contracts should be allocated in one of two manners, as follows:

- To maintain retail tariffs more or less uniform across the CES; i.e., households will continue to pay the same tariff across the CES regardless of their distribution company. This national uniform tariff will of course be abandoned once the initial vesting period expires when the retail customers of each distribution company will be subject to tariffs

reflecting the costs of bilateral contracts negotiated by the Distribution Company with its suppliers; or

- To maintain wholesale tariffs as close as possible to current levels. This will result in non-uniform national tariffs (i.e., the retail customers of each Distribution Company will have different tariffs), and will eliminate cross-subsidization among retail customers of different distribution companies.

4.3 Roles and Responsibilities of the Market Entities

4.3.1 Roles and Responsibilities of the SMO

A summary of the responsibilities of the SMO follows. The NDC will perform the function of the SMO.

The main responsibility of the SMO is to ensure the safe, reliable and efficient operation of the interconnected electric power system while administering the power market. In the process of fulfilling its dispatch function, the SMO will require that market participants comply with requirements associated with maintaining power system security and stability in order to assure the reliable supply of power to consumers. These requirements will be based on criteria and reliability rules adopted for the power system as documented in the Grid Code and associated rules and procedures.

The SMO's influence on commercial relations between market participants will be confined to power system planning and real time operation, and to the technical evaluation of bilateral contracts. Based on the results of the technical evaluations, the SMO will have the authority to terminate or limit the execution of contracts and/or require changes in the amount of capacity specified under the bilateral contract.

The specific responsibilities of the SMO will include:

1. Plan the system
    a. Near-term – conduct system simulations to minimize the cost of supply including transmission losses based on the load forecast and load shape, heating load requirements, outage schedules/unit availability, imports/exports, transmission constraints and ancillary services needs
    b. Medium/long-term – conduct system simulations to determine system expansion needs for generation and transmission both from adequacy and cost minimization perspectives; i.e., minimize the cost of generation and transmission taking into account transmission losses and the costs to re-dispatch generation owing to transmission constraints
2. Pre-dispatch
    a. Conduct system simulations to minimize supply costs including transmission losses based on the load forecast including load shape, heating load requirements, outage schedules/unit availability, imports/exports, transmission constraints and the need for ancillary services; conduct additional system simulations until a feasible solution is obtained; communicate the pre-dispatch schedule to generators
3. Real-time dispatch
    a. When there is a change from the pre-dispatch schedule (i.e., sudden loss of generator), re-simulate the system to minimize supply costs including transmission losses based on the load forecast including load shape, heating load requirements, outage schedules/unit availability, imports/exports, transmission constraints and the need for ancillary services taking into account

the changes in system status from the pre-dispatch schedule; communicate the re-dispatch schedule in real-time to generators

4. Billing and settlement
    a. Meter production/consumption with commercial-grade accuracy and redundancy
    b. Acquire production/consumption data and compare actual to scheduled production
    c. Apply production/consumption data to determine transmission charges
    d. Produce bills on basis of contracts, balancing, ancillary services, transmission use and SMO service charges
    e. Collection and disbursement
5. Market information
    a. Maintain a website with market information
    b. Publish relevant market-related reports
    c. Archive market information for at least 5 years; i.e., for billing purposes, for market monitoring, etc.
    d. Collect information associated with market activities, such us details of bi-lateral contracts, proposed outage schedules, etc. from market participants
    e. Maintain confidentiality with regard to market related information
    f. Collect information relating to forced outages and unsanctioned generation deviations
    g. Monitor and record market participant performance data
    h. Maintain a data base of market related data
    i. Provide explanations to market participants and relevant authorities relating to decisions undertaken in the course of system operation and market administration
6. Training
    a. Provide training to market participants on market rules and procedures

The SMO will perform all responsibilities listed above in strict compliance with the approved Market Rules, the Grid Code, associated regulations and its license.

4.3.2 Roles and Responsibilities of the Transmission Company

The role of the transmission company is to provide reliable, stable and efficient electricity transmission with due regard to security of supply and the environment. The transmission company must be independent of all market participants.

The transmission company is obligated to comply with, observe and perform the duties and obligations imposed on it by the Market Rules, the Grid Code, associated regulations and its license. The transmission company is obligated to operate and maintain its transmission facilities and equipment in a manner that is consistent with the reliable operation of the transmission grid as specified in the Market Rules, the Grid Code, associated regulations and its license. More specifically, the transmission company has the following responsibilities:

- Maintain and develop the transmission system;
- Prepare and propose transmission and connection tariffs to the ERA;
- Administer the contracts for power purchases to and from Russia;
- Coordinate transmission asset maintenance and operation with the SMO;
- Conform with quality of service standards and penalties for breaking the provisions of the Market Rules, the Grid Code, associated regulations and its license;
- Coordinate protection systems with the SMO;

- Maintain metering and communication facilities, including remote terminals, as established by the Market Rules, the Grid Code, associated regulations and its license;
- Install compensation equipment meeting the minimum requirements for voltage regulation consistent with the Grid Code;
- Liaise with other bodies having regulatory functions with respect to the transmission grid such as the ERA in accordance with the Market Rules, the Grid Code, associated regulations and its license;
- Participate in the development of reliability standards and criteria for the transmission system; and
- Work with authorities outside Mongolia to co-ordinate activities in accordance with the Market Rules, the Grid Code, associated regulations and its license.

4.3.3 Roles and Responsibilities of the Generators

Licensed Generators sell their energy and capacity through bilateral contracts to wholesalers which during the early stages of the market will be distribution companies. The role of the Generators is to provide capacity, energy and ancillary services to the market. The responsibilities of the Generators include:

- Maintain facilities in good operating condition to ensure commitments are met except during periods of maintenance and force majeure;
- Install and maintain metering systems to measure and record electricity output delivered to the transmission grid consistent with the Market Rules, the Grid Code, associated regulations and its license;
- Install and maintain communications and control equipment consistent with the requirements of the Market Rules, the Grid Code, associated regulations and its license;
- Propose technically feasible ancillary services to the SMO (prices to be covered in bilateral contracts);
- Submit variable costs to the SMO and the ERA in accordance with the Market Rules;
- Provide prompt payment of charges for services due to the market, the SMO and the ERA in accordance with the Market Rules;
- Grant access to its installations for inspections by representatives designated by the SMO or the ERA as provided for in the Market Rules, the Grid Code, associated regulations and its license;
- Maintain levels of credit required by the Market Rules; and
- Make payment for penalties or compensation imposed by the SMO or the ERA, per the Market Rules, following evidentiary and appeal procedures.

The ERA in conjunction with the SMO will ensure that Generators do not abuse market power in the competitive market.

4.3.4 Roles and Responsibilities of the Distribution Companies

Licensed Distributors perform distribution asset management and retailing activities in the franchise areas specified in their licenses according to the requirements specified in the Market Rules, the Grid Code, associated regulations and their licenses. Distributors purchase energy and capacity through bilateral contracts from Generators. The specific responsibilities of the Distributors include:

- Prepare distribution investment plans for new distribution facilities;
- Construct, operate, enhance, repair and maintain distribution facilities in compliance with the Market Rules, the Grid Code, associated regulations and their licenses;

- Provide distribution services on a non-discriminatory basis;
- Meet retail customer demands for connection to their distribution systems;
- Keep an updated database of consumers in their regions;
- Prepare demand forecasts and make them available to the SMO in accordance with the Market Rules;
- Prepare and propose distribution and connection tariffs to the ERA;
- Install and maintain metering systems capable of measuring and recording output received from the transmission grid consistent with the Market Rules, Grid Code and associated regulations;
- Install and maintain communications and control equipment consistent with the requirements of the Market Rules, the Grid Code, associated regulations and their licenses;
- Provide prompt payment of charges for services due to the SMO and the ERA resulting from the Market Rules;
- Allow access to its installations for inspections by representatives designated by the SMO or the ERA as provided in the Market Rules, the Grid Code, associated regulations and their licenses;
- Maintain levels of credit support required by the Market Rules; and
- Pay the penalties or compensation imposed by the SMO or the ERA, provided for in the Market Rules, following evidentiary and appeal procedures.

4.3.5 The ERA

The ERA does not participate directly in the market and is not a market participant. The ERA has the following responsibilities related to the markets:

- Ensure compliance with the Market Rules, the Grid Code, associated regulations and licenses;
- Facilitate development of the market;
- Monitor the market and its operation;
- Promote competition;
- Regulate transmission, distribution and system/market operation activities including charges for services;
- Develop and approve bilateral vesting contracts;
- Develop and approve pro forma bilateral contract;
- Approve variable costs of each generator for use in the balancing/spot market;
- Impose penalties established in the Market Rules and Grid Code in cases of non-compliance;
- Approve the long-range system plan including the authorization and construction of new generation and transmission facilities;
- Approve modifications to the Market Rules and Grid Code, and associated standards and regulations;
- Grant licenses authorizing market participants;
- When requested, mediate and resolve disputes between market participants; and
- Implement the market consistent with Government policy.

The Cabinet is responsible for approving the ERA's budget.

4.3.6 Ministry of Mineral Resources and Energy (MoMRE)

The MoMRE does not participate in the market, nor is there a need for it to participate in the development of the market. The MoMRE sets electricity policy and develops and approves the

market reform plan. The ERA is responsible for interpreting and implementing the MoMRE's policy as well as implementing the market consistent with the market reform plan.

4.4 Stakeholder Issues

As noted, a number of stakeholder workshops were conducted by the ERA and EPRC with power company staff during development of this report. The most relevant of the questions and issues raised during these workshops are addressed in this section of the report.

As noted earlier, the purpose of this report is to gain stakeholder agreement on a high-level market design before proceeding with design of the more specific market components. This is judged to be the most expeditious approach to market design and implementation. Market design components beyond those addressed in this report will be dealt with in the Market Rules and Grid Code development process.

4.4.1 Competitiveness of Domestic Generators

Some of the generators expressed concern that they will be unable to compete in the market and will be forced into bankruptcy. Such concerns are common among generating companies when jurisdictions contemplate power sector reforms.

In fact, it is not the market design that determines when a generation asset is no longer used and useful, but rather the demand/supply balance and the efficiency and performance of the generation asset. If supply exceeds demand by amounts greater than planning reserve margins there is excess generation capacity on the system. In such situations, it is necessary to review the technical and economic performance of generation assets to determine if they remain used and useful, and if not, they will be retired to bring demand and supply back into balance. It is unfair and unethical to impose the costs of generation assets on consumers through retail tariffs when the asset is no longer considered to be used and useful. It is also contrary to Mongolia's Energy Law. Generally in such situations the older, less efficient and poorer performing assets are candidates for retirement.

This describes the process followed in a fully-regulated market. The process is much the same in a competitive market except the market, rather than the regulatory authority, determines when an asset is no longer used and useful. In such cases, the asset owner will be unable to cover its costs through sales of its capacity and energy in the market thus forcing it into retirement. As noted, it is not the introduction of competition to a market that determines if the asset remains used and useful. There has been discussion over the past several years in Mongolia about retiring CHP2[13] while the fully-regulated SBM (single-buyer market) has been in place with little or no competition.

There was concern expressed during the stakeholder workshops that low-cost imports from Russia could put domestic power plants out of business. This concern fails to recognize the following:

- The demand and supply situation is tightening, so all domestic generators are likely to remain used and useful at least until a major new generation source comes into service (i.e., CHP5), and even then they may remain used and useful if demand growth remains strong;
- The transfer capacity of the interconnection with Russia is limited to 240MW and a significant portion of this capacity will be reserved for the provision of ancillary

13 Most recently, consideration is being given to converting CHP2 to a briquette factory.

services. Therefore, the amount of potential energy imports from Russia that would displace generation in Mongolia is relatively small; and

- The ERA will determine how quickly the market will be opened to competition. It is anticipated that imports from Russia will not be allowed until well into the future owing to the importance of the interconnection for delivery of ancillary services. If in the future the ERA were of the opinion that Russian imports would negatively impact the domestic market, it would simply limit imports to levels that would ensure the sustainability of domestic generators.

4.4.2 Cash Management System

As described in ***Section 2.3***, settlement in the current market is implemented through a Cash Management System (see ***Exhibit 2)*** under which retail customers of state owned distribution companies deposit their payments into the zero balance accounts established by each distribution company. These accounts prohibit any withdrawals by the distribution companies. At the end of each day, funds from these accounts are transferred into the Main Zero Balance Account established at the Mongolian Savings Bank. Cash disbursements are made from the Main Zero Balance Account to generating licensees, the transmission licensee, the dispatch licensee and for imports, while cash disbursements are made to distribution licensees through their zero balance accounts. Cash disbursements are made by the Savings Bank which has signed the respective agreement with the Transmission Company acting as the Single Buyer in accordance with the allocation formula approved by licensees at their annual meetings. The Cash Management System ensures that each entity receives a “fair” share of collections; only the supplier of imported power receives full payment. Payments to other entities vary in proportion to retail revenue collection.

There are two primary problems with the Cash Management System, as follows:

- It does not promote commercial relationships, particularly between distribution and generation entities; and
- It does not provide distribution companies with sufficient incentives to improve performance in collection of retail revenue.

Resolution of these two problems is a principle driver for moving to a market with freely negotiated bilateral contracts between distribution and generation entities, instilling payment discipline on the distribution companies and providing incentives to improve collection performance.

While the new market might include a bank account managed by the SMO for payment and disbursement of charges for transmission service, the SMO service charge and transactions in the spot market, consumers of these services will be expected to pay in full. The significant portion of payments in the market will be made between distributors and generators for transactions in the bilateral contracts market. Generators will expect payment for services delivered in accordance with the contract terms and conditions. Otherwise, they will sell their power elsewhere. Therefore, the Cash Management System will cease to exist in its current form under the new market structure.

An element of the market implementation plan presented in ***Exhibit 7*** relates to development of a financial assurance policy. This is of particular interest to the generators who want to avoid non-payment issues experienced under previous market regimes. As such, development of this policy will include direct participation of generators and distributors. It is too early to comment of what this policy will entail, but one potential scenario could include a cash management account similar to that in place today, but managed by a bank for each individual

distribution company. The account might accept direct deposits from the distributor's retail customers and disburse payments to generators according to terms in the bilateral contracts.

Payments would be made to generators in full as opposed to the current prorated payment methodology based on percentage of collections. It might be desirable to set up such accounts during the 100% vesting period as a means for assuring payment to generators while providing the opportunity for distributors to prove they can manage payment and act as responsible commercial entities.

4.4.3 Uniform National Retail Tariff

As discussed in ***Section 3.3***, Mongolia's uniform national retail tariff ensures all classes of customers across the CES pay the same tariff even though the supply costs of each distribution company may vary (i.e., owing to differences in customer density, customer mix, etc.). This means that the customers of one distribution company are either paying or receiving a cross subsidy from the customers of another distribution company. It can also reduce incentives for distribution companies to improve efficiency and performance because retail tariffs are the same for each company, meaning performance is not transparent to consumers.[14]

With the introduction of the bilateral contracts market, it will be necessary to eliminate the uniform national retail tariff. One of the objectives of the new market design is to improve the efficiency of the electricity sector both in terms of supply and consumption. In order to promote efficient consumption, retail tariffs must reflect the costs of each distribution company. Otherwise, customers will consume too much (tariffs below costs) or too little (tariffs above costs). Further, in order to promote efficient supply, distribution companies must have the incentive to negotiate the best bilateral contracts possible. If all distribution companies receive the same revenues under uniform national retail tariffs the incentive to negotiate the best bilateral supply contracts possible is reduced; i.e., there is less incentive to pressure generators to improve efficiency and performance. Therefore, the national uniform retail tariff is contrary to this objective of the market reform effort.

Jurisdictions around the World with wholesale competition have different retail tariffs for each distribution/supply company; i.e., United States, Western Europe, Eastern Australia, etc. Even jurisdictions that do not have wholesale competition may have different retail tariffs in different jurisdictions. For example, prior to the introduction of competition in the Province of Ontario in Canada there were 325 municipal utilities each with its own retail tariffs. Even countries with developing economies such as Pakistan have different retail tariffs in each Province. Abandonment of the uniform national retail tariff is an essential component of the market reform effort in Mongolia. Tariffs that vary with geographic location are allowed under Mongolia's Energy Law.[15]

4.4.4 Transmission Losses

There has been considerable discussion both past and present about making the transmission company responsible for transmission losses including internal consumption at sub-stations. It is understood that transmission losses are currently about 3.5% which is comparable to levels in other international jurisdictions.

[14] If consumers in one area of the country see that their tariffs are higher than those in another area of the country, they will exert peer pressure on their distribution company to improve efficiency and reduce costs. In Mongolia, this disincentive is alleviated to some extent because the ERA establishes distribution company revenue requirements and tariffs on a company-specific basis. The ERA is also considering implementation of incentive regulation and performance agreements at the distribution level on a company-specific basis. This would further mitigate the disincentive to improve efficiency provided appropriate performance targets are established.

[15] See Article 27.6.4.

The transmission company will have limited control over transmission losses in the proposed bilateral contracts market. For example, the direction and lines used for power flows will be determined by the SMO without input from the transmission company. It will be the SMO's responsibility to minimize transmission losses as part of the dispatch process. Even the transmission company's maintenance plans will require the approval of the SMO. Further, the transmission company is not responsible for transmission expansion planning – the SMO produces the plan with stakeholder input and the ERA (or Cabinet) approves it. Finally, the transmission company can submit proposals for transmission upgrades that may reduce losses, but the ERA has ultimate approval authority by determining whether or not to allow recovery of the costs for such plans in the transmission company's tariff. In summary, the transmission company has little control over transmission losses so it would be unfair and unproductive to hold it directly responsible. Further, it is undesirable for the transmission company to become a commercial market participant by forcing it to "compete" with distribution companies for energy in the competitive market to supply transmission losses.

The preferred method for controlling transmission losses is: 1) ensure that transmission losses are factored into the SMO's dispatch decisions, 2) ensure the transmission company is an active participant in the transmission expansion plan development process, and 3) make the transmission company responsible for identifying the impact on losses of proposed transmission upgrades submitted to the ERA as part of the tariff review process. If the ERA accepts the upgrades and allows cost recovery in the transmission tariff, it would hold the transmission company responsible for the associated transmission loss reduction. For example, if the upgrades fail to result in the projected loss reduction, the ERA would require the transmission company to provide an explanation, and if not satisfied, would disallow recovery of the cost of the upgrades in the transmission tariff. Another means for controlling losses through the regulatory process would be to subject the transmission company to an incentive regulatory mechanism that would reward it for reducing losses with bonus payments, thus providing incentive to invest in upgrades.

4.4.5 Market Trial in Select Areas of CES

A question was posed concerning the value and practicality of conducting a pilot test of the market in pre-selected areas of the CES. It is understood that one or two of the distribution licensees have expressed an interest in negotiating their own bilateral contracts, so might be used as a testing ground for the new market design before expanding to cover the remaining distribution companies and all wholesale sales in the CES.

It is first important to point out that the market implementation plan proposed in this report is flexible, including:

- Sixteen months for design and implementation of a market that was first proposed for implementation back in 2006;
- A three-month market test and dry run;
- A two or three year vesting period during which all generation and purchases will be fully regulated; and
- Gradual opening of the market to competition over a number of years through reductions in the vesting contract sales quantities.

Further, the schedule can be delayed or accelerated to allow for unforeseen events as determined by the ERA.

Two approaches to the conduct of a pilot test of the market in pre-selected areas of the CES might be considered. Under the first approach, a pilot test might be incorporated as an additional component to the proposed implementation plan. For example, following a two-year

vesting period the market might be opened to only one or two distribution companies while the other distribution companies remain fully vested. It is EPRC's view that the proposed market implementation plan is already flexible enough and adding an additional component such as this would result in unnecessary and unproductive delays to market implementation.

Under the second approach, the market might be opened immediately to one or two distribution companies (i.e., Darkhan and Erdenet), and the remaining distribution companies would be fully vested. Over time the market would be opened to the other distribution companies. Staged openings such as this are quite common in markets where retail competition is being introduced. For example, the European Union first opened its retail markets to competition for the largest customers (i.e., those served directly from the transmission system), and gradually opened it to smaller customers served at lower voltage levels.

The key consideration here is that the staged approach was used to open the market to retail, as opposed to wholesale, competition. It is very difficult to devise a similar plan at the wholesale level because the number of wholesale customers is so few to begin with. Opening the market to wholesale competition with only one or two customers will not result in competition. There would be a number of other problems as well:

- It would be difficult to determine which generators would compete for sales to unregulated distribution companies and which would be obligated to sell to regulated distribution companies;
- There would be accusations of preferential treatment, either the distribution companies and their customers who are forced to compete or those who were not allowed to compete (likewise for the generators);
- It would not likely result in economic dispatch, a primary objective of the new market. The absence of an economic dispatch regime in the past has resulted in significantly higher primary fuel costs (i.e., coal) and pollution; and
- The market is not yet ready to open to competition for the reasons outlined in ***Section 3.3***. The vesting period under the proposed implementation plan allows time to address the constraints increasing the probability of success of the new market.

As noted earlier, the objective of this report is to gain stakeholder agreement on the high-level market design. The proposed market implementation plan is flexible; the ERA and EPRC expect market implementation to be a fluid process.

4.4.6 Transition from Vesting to Freely-negotiated Bilateral Contracts

There are numerous ways to transition from the period when contracts and sales are fully vested to the period when the wholesale market is opened to competition. The actual path followed will be shaped by significant events (i.e., the construction of CHP 5, plant retirements, the addition of a significant new load such as a mine, etc.), progress on addressing the constraints identified in ***Section 3.3*** (i.e., raising tariffs to levels that reflect costs, reducing cross-subsidies, etc.) and market participant readiness It is for these reasons that the schedule for market opening is left open and in the hands of the ERA with input from industry stakeholders.

The typical method followed when opening markets to wholesale competition is to gradually reduce the sales to distribution companies covered by vesting contracts. During the initial two to three year period, 100% of a distribution company's power needs will be covered by vesting contracts with prices based on costs approved by the ERA. During this period, both the power purchase costs of the distribution companies and the revenues of the generators are "protected"

from market volatility. Following the 100% vesting period, vesting contract quantities are reduced. For example in year 3, perhaps only 80% of each distribution company's energy requirement will be covered by vesting contracts. The energy sales by each generator covered in vesting contracts would likewise be reduced by 20%, forcing each distribution company and generator to negotiate sales and purchases for the outstanding 20% of the market. Year 4 might further reduce the sales covered by vesting contracts to 50% of the wholesale market, and year 5 might open 100% of the market to open competition.

Again, the actual schedule for market opening will be influenced by the events described above. It would be unproductive to define a schedule this far in advance because following a schedule blindly without considering the potential consequences would increase the risk of market failure.

4.4.7 Market Power

As noted, the ERA will need to closely monitor the competitive market to guard against market power abuse. The fact that an entity may have market power is not the concern; many markets around the world have entities with market power. The concern is that an entity with market power abuses its market power position. In response to a question from an industry stakeholder, this section of the report has been incorporated to provide a description of the types of market power that the ERA will need to monitor in order to guard against abuse.

Market participants with market power have the ability to raise prices above competitive levels by physically withholding power, or by economically withholding power through inflated offers. There are a number of factors that can put a generator in position to exercise market power, as follows:

- A generator might control a significant share of the total generating capacity in the market putting it in a dominant position with the potential to influence the market price; i.e., through horizontal market power.
- A generator can have a dominant market position in a localized area owing to transmission limitations.
- A generator might be in a position to exercise market power if it has a concentration of generation at a critical point of the market's load curve. For example, if a market participant has a significant amount of peaking generation it might be able to influence prices when market demands are high.
- A generator might be able to influence market prices if it also owns transmission and/or distribution assets; i.e., through vertical market power. For example, a single vertically integrated utility owning both transmission and generation assets could strategically schedule outages on key transmission facilities thus gaining an advantage for its own generating facilities.

Mongolia has taken steps to safeguard against vertical market power by fully unbundling the power sector.

4.4.8 Renewable Energy Resources

The GoM has shown interest in development of renewable sources of energy as witnessed by the Renewable Energy Law. Therefore, it is necessary to ensure that the new market design accommodates renewable energy projects.

As the law currently stands, contracts for renewable energy are between the seller and the transmission company. This is inconsistent with the proposed market design in that bilateral contracts are to be between sellers and distribution companies. This can be accommodated by

transferring the contract to the distribution companies while leaving responsibility for payment under the contract terms and conditions with the transmission company.[16] In order to reduce transmission company risk, the ERA and the GoM would need to ensure through the retail tariff review and approval process that the distribution companies have the cash necessary to make payment under the terms and conditions of the contract with the renewable generators. Alternatively, the ERA and GoM would need to ensure the transmission company has enough cash to pay the renewable generators in the event of default by one or more distribution companies.

Further, a concern was raised about the variability of the fuel supply for wind projects and the impact of the variable cost on dispatch given that variable costs are essentially zero while payment to renewable generators under contract is based on the combined fixed and variable costs of the project. These issues are readily addressed in the Market Rules by ensuring renewables are treated fairly and consistent with Government policy. For example, wind projects have low variable costs so whenever available would be dispatched first ahead of the CHP generators regardless of the price in the contract. Further, while generators with conventional primary fuel supplies are required to follow the SMO's dispatch instructions, wind generators would not be required to do so. Instead, they would submit a representative schedule of expected production on a day-ahead basis, but would not be bound by it. While this may appear to favor renewable over conventional generators, in reality, it is recognizing the characteristics of renewable generators much the same as minimum loadings and ramp up/down rates of conventional generators are recognized in dispatch.

The European Bank for Reconstruction and Development (EBRD) is currently funding a project with the objective of producing a renewable energy roadmap that is expected to lay the foundation for resolution of these issues. It is important that recommendations from the EBRD study be taken into consideration in the development of the Market Rules

4.4.9 Customers Directly Connected to the Transmission System

There are a number of large retail customers in the CES who are directly connected to the transmission system. It is understood that although these customers do not use the assets and services of the distribution companies, they are treated as customers of the distribution companies because the distribution companies need the revenues.

During the stakeholder meetings, it was inferred that the transmission company should be granted a supply license to serve these customers. Allowing the transmission company to supply retail customers is contrary to Mongolia's Energy Law[17]. It is also contrary to open access. It is for this reason that transmission companies in markets around the world are forbidden to be commercial market participants.[18]

At some point in the future it may be desirable to allow customers supplied directly from the transmission system to become active participants in the market; i.e., by designating them as wholesale customers, or alternatively, by opening the market to retail competition. Although this will increase administrative complexity and cost, it will also increase the number of buyers in the market, leading to increased competition. The decision to open the market to these customers should be left with the ERA with input from industry stakeholders.

[16] This step would not be necessary if the seller agreed to transfer responsibility for the contract from the transmission company to one or more distribution companies.
[17] See Article 14.3.
[18] This is also a good reason against requiring the transmission company to compete for energy in the market to supply transmission losses (see ***Section 4.4.3***).

4.4.10 Capacity

There was a considerable discussion of generation capacity during the stakeholder process. Relying on the market to provide the incentives necessary to ensure adequate generation capacity and reliable supply going forward is a concern in Mongolia as well as other jurisdictions with pool-type markets with central dispatch. It is also a concern in some jurisdictions that have bilateral contracts type markets with self-dispatch.

In the market design proposed in this report valuing and ensuring the availability of capacity will not be a concern during the initial 100% vesting period because all generation capacity will be "assigned" to the distribution companies. All generators will receive their fixed costs plus profit, so will have the incentive to remain operational. Further, because the capacity payment under the two-part tariff will be made on the basis of availability, all generators will have the incentive to maintain their facilities in a manner that ensures continued reliable service. It is desirable to maintain these incentives following the initial 100% vesting period when competition is introduced, particularly in light of the tightening demand/supply situation,

There are a number of ways to accomplish this as described in the two reports discussed earlier (the December 2004 World Bank-funded report by Synex and the March 2006 draft Market Rules developed by EPRC). The Synex approach (pages 8 and 9) is summarized below.

- Each year, the NDC computes the total maximum demand committed by each generator in its supply contracts. The maximum demand is determined during system peak hours and is compared to the firm capacity of the generator defined as the maximum net effective capacity that can be produced based on the average availability of the generator. Generators with excess firm capacity in relation to the maximum demand in its contracts sells the excess to those generators that are short capacity with payment based on the annualized fixed cost of the least cost capacity expansion option; i.e., a gas turbine. The firm capacity of each generator is adjusted proportionally so that the total firm capacity of all generators combined equals the system annual peak demand. This ensures that payments made by generators with deficits match the amount due generators that have excess firm capacity.
- There is also a capacity component in the spot market price similarly based on the annualized fixed cost of the least cost capacity expansion option. Including a capacity component in the spot price ensures that distribution companies do not forego bilateral contracts in favor of purchases in the spot market.

The EPRC's draft Market Rules (pages 5, 10, 11 and 12) treat capacity payment slightly different, as follows (as described in ***Section 4.2*** of this report).

- Capacity payments under bilateral contracts are calculated each month as a product of amount of capacity specified in the contract and expressed in MW, the capacity component of the two part tariff of the given generator, expressed in $/MW-month, and a number between 0 and 1, reflecting the availability of the given generator (scaled proportionally to the average availability of all power system generation). The procedure for determining the availability factors will be approved by the ERA. The system operator is responsible for ensuring that there is sufficient capacity under bilateral contracts to provide adequate levels of system reliability; i.e., to meet system peak demand plus a reserve margin.
- There is no explicit capacity component in the spot market. However, there is an implicit capacity component because purchases in the spot market are priced at the variable cost of the marginal plant. For example, a generator selling power in the spot market whose variable cost is 20 MNT/kWh might receive payment reflecting the

variable cost of the marginal plant at 25 MNT/kWh. The 5 MNT/kWh premium goes toward payment of the generator's fixed costs. Note that this implicit capacity payment also applies in the methodology proposed in the Synex report.

A third method that effectively creates the equivalent of a capacity market is to place a requirement on the distribution companies to have under contract enough generating capacity to meet 100% of its peak annual demand plus a reserve margin, for example, 115% of its peak demand. This methodology is in common use in markets in the mid-western United States.

The important point to consider is that the market design should provide the incentives necessary to ensure there is enough capacity in place to guarantee reliable supply. As noted, during the initial years of the proposed market with 100% vesting contracts, capacity is dealt with adequately. However, once competition is introduced it will be necessary to pursue one of the options described above to ensure supply reliability going forward. The approach chosen will be described in the Market Rules.

4.4.11 Coal Supply

In order for Mongolia's electricity market to be competitive there must be open and equal access to the coal supply. Further, the coal supply must be economic, and deliver in a reliable manner the quantities of coal needed by generation licensees consistent with amounts stated in contracts.

The GoM recognizes the importance of the coal supply industry and is taking steps to ensure its economic viability. The GoM approved an average coal price increase of about 30% in July 2008. There are also plans to expand the capacity of existing coal mines and implement additional reforms to unbundle the various services provided by coal companies. These actions in conjunction with the introduction of competition in the electricity sector should improve the economic viability of the coal companies, increase the quantity of available coal, enhance competition among coal suppliers and improve the reliability of coal supply. GoM reform efforts in the coal sector should have the full support of the electricity sector.

4.4.12 Summary of Stakeholder Issues

Although concerns were raised by some of the generation licensees about their ability to "compete" in the proposed market, as noted in ***Section 4.4.1*** the ability of a generator to remain used and useful is ***not*** a function of the market design, but rather the demand/supply balance and the efficiency and operational performance of the assets. Further, claims that imports from Russia will decimate the domestic generation market are unfounded.

Generally, the licensees are supportive of the proposed high-level market design, and none of the issues raised have caused the ERA and EPRC to reconsider the proposed high-level market design. The relevant issues raised by stakeholders are more concerned with detailed market design issues that will be addressed during the Market Rules and Grid Code development process.

4.5 Conclusions

If market reform is to be successful, Mongolia must make progress eliminating the constraints identified in ***Section 3.3***. In particular, tariffs must be increased as set out in the Tariff Reform Plan to ensure the financial viability of the power companies. At the same time, consumers must be assured that service will improve as a result of the tariff increases. In this regard, the ERA must impose market discipline on the power companies through introduction of the proposed competitive bilateral contracts market in conjunction with incentive regulation that

rewards and penalizes power companies in the monopoly components of the market commensurate with performance.

The proposed high-level market design can be implemented at low cost with minimal risk. It will ultimately result in:

- Increased competition with the attendant incentives for power companies to improve the value of service to consumers; and
- Economic dispatch with reduced coal costs and pollution.

The proposed market will have a number of other benefits as well. It will result in:

- Elimination of the national uniform retail tariff;
- Replacement of the Cash Management System;
- Improved business relationships among power companies, in particular, distribution licensees and generation licensees;
- NDC development of the system expansion plan with stakeholder input and review, and ERA approval; and
- Potential merger opportunities.

Although there will be costs of up to US$ 2 million associated with implementation of the proposed market for procurement and installation of Energy Management System (EMS) software and a commercial grade billing and settlement system, these procurements should take place regardless of market reform owing to their attendant benefits, and because they are consistent with:

- The Energy Law; and
- The market reform objectives including:
    - Improve value of service to consumers;
    - Reduce the investment and liability burden on the public; and
    - Improve efficiency both in terms of supply and consumption.

The proposed high-level market design can be implemented at reasonable cost and risk. Therefore, the proposed high-level market design is accepted as the basis for market reform and will be used as the model for market governance documents such as the Market Rules and Grid Code, and GoM policy initiatives relating to the electricity sector. The proposed high-level market design is judged to be in the best interests of all stakeholders in the electricity sector including consumers.

SECTION V: NDC READINESS TO PERFORM THE ROLE OF SMO

A key consideration in any electricity market implementation plan relates to the ability of the dispatch authority, in this case the NDC, to perform the function of the System and Market Operator (SMO). The introduction of competition in an electricity market increases the complexity of the market and its administration, so it is wise to assess the needs of the incumbent dispatch authority and ensure that the market implementation plan takes into consideration these needs.

The purpose of this section of the report is to identify the needs and the readiness of the NDC to carry out the responsibilities of the SMO. There have been three reports completed in recent years relating to the NDC's readiness to perform the function of the SMO, as follows:

- Final Draft report completed for World Bank entitled *Preliminary Assessment of Necessary Measures to Enhance the National Dispatching Center of the Power System, Mongolia*. This report is dated June 1, 2006. To the author's knowledge, the report has never been submitted in final format;
- January 2006 EPRC report entitled *Evaluation of the NDC's Technical Capacity to Perform the Function of the Independent Market Operator*; and
- March 2006 EPRC report entitled *Assessment of NDC Readiness to Function as a System Operator and Preliminary Schedule and Cost Estimate of Market Implementation.*

This section of the report provides an updated summary of these reports and the NDC's readiness to perform the function of the SMO.

5.1 Current Organization of the NDC

The organizational structure of the NDC is shown in ***Exhibit 6***. The NDC's core business departments include the Dispatching/Technological Management Department and the Regimes Department. These departments are supported by the Communication and Information Department.

The NDC's Executive Director is responsible for the day-to-day operation of the organization. The Administrative, Legal and Marketing Support Department reports directly to the Executive Director. All other departments report to the Vice Director/General Dispatcher who in turn reports to the Executive Director. The total number of the NDC staff is 42.

Current market support activities are concentrated in the Dispatching and Regimes Department. The Regimes Department consists of two teams – 1) Relay Protection and Automatics, and 2) Regime Planning. The Regime Planning team is responsible for calculation of electrical and thermal energy and for development of dispatch schedules. In addition, this team is responsible for tracking generating plant performance, deviations from the dispatch schedule, pricing of the generation deviations in accordance with the spot market rules and submission of the information to the transmission company for settlement purposes. This team is also responsible for administering the competitive auction. The team consists of seven persons; one person is dedicated to the tasks of tracing deviations and preparation of spot market data to be submitted to the transmission company. Compilation of dispatch schedules is performed using a load flow software program. Other calculations are either performed manually or by using spreadsheet based programs with manual data entry.

The Dispatching/Technological Control Department consists of 12 persons, mostly dispatchers. Communications with the licensees regarding dispatch control are conducted by

telephone and fax. A significant part of the power system is not continually monitored from the control room.

Dispatch instructions and related information are recorded in a logbook with data entry performed manually.

5.2 Description and Status of Recent NDC Projects

NDC has recently installed a new SCADA system that has significantly enhanced its ability to perform the SMO function. Further, plans are in place to establish a new Automatic Meter Reading (AMR) System on the CES.

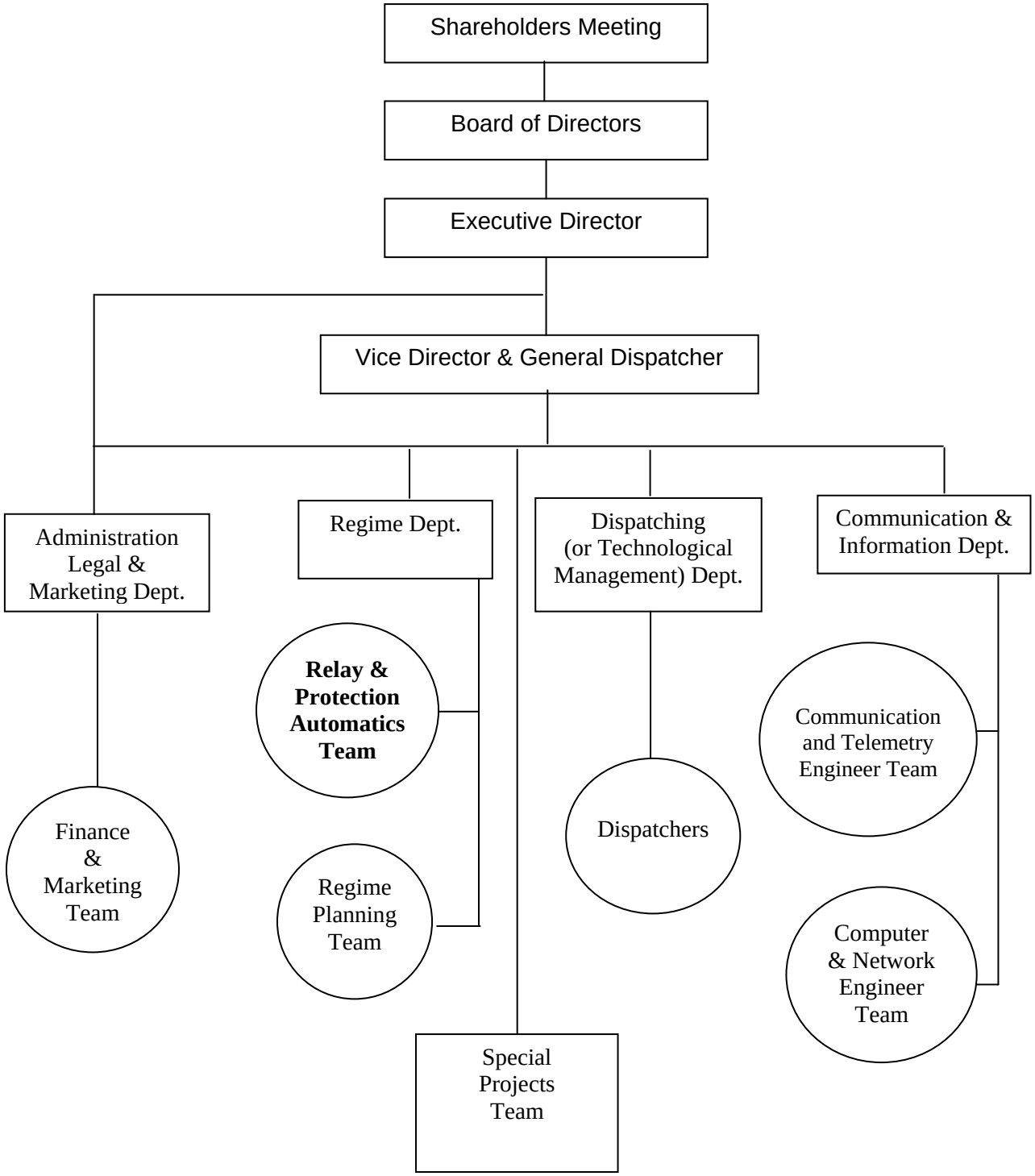
The new Supervisory Control and Data Acquisition (SCADA) system is the Siemens SINAUT Spectrum 4.4 system. The SINAUT system has the capability to cover the entire performance range of electricity system dispatch. It is a modular system enabling users to select only those components that are needed for their particular system design. NDC has chosen a system that best meets its system configuration while taking into account budget limitations.

The SINAUT system enables the NDC to monitor in real-time the configuration of 13 sub-stations, including all five generating stations, the interconnection with Russia and seven other key sub-stations on the system. Each of the 13 substations is linked to the NDC through a new fiber optic cable. The SCADA system accumulates and stores these data for up to two years internally before downloading to tape where the data can be stored indefinitely. NDC staff have been fully trained on the use of the SCADA system.

The information that can be monitored includes energy flows, current, voltage, reactive power, generator output, status of switchgear (i.e., breaker and disconnect switch positions), etc., thus alerting NDC operators to problems in real-time; i.e., energy flows exceeding transmission line thermal limits, breaker trips forcing generating units out of service, etc. The SCADA system enables real-time monitoring and data acquisition and storage, but does not enable remote control of facilities. There is no automatic control equipment on generators or substations, so control is done through person-to-person communications. Dedicated phone lines between the NDC and the critical sub-stations improve the reliability of the communications network. All telephone conversations between NDC and power companies are recorded both at NDC and the power company. Communications are stored internally for 45 days before being downloaded to more permanent media; i.e., tapes.

The automatic metering system has not yet been awarded to a contractor. A request for proposals issued last year by the NDC failed because none of the bidders came in under the allocated budget. A modified metering project request for proposals was issued earlier this year, but again appears likely to fail owing to inadequacy of the budget. NDC expects to enter into one-on-one negotiations with a supplier if the current request for proposals fails as expected. At this point in time, it appears the new meters will not be installed for at least another two years.

Exhibit 6. Current Organization of NDC



It is anticipated that once the AMR project is installed, it will enable measurement and data storage of consumption by the Distribution Companies and delivery by the Generators. The AMR central station will be located at the NDC site (5th floor) and will include all modems and interfaces to the meters at substations and generating stations. The AMR system will utilize a mix of GSM, power line carrier and fiber optic communications equipment (provided under the SCADA project). The technology to be used will be a function of what is available at the site. GSM will be used only if there is no communication infrastructure at a site. The metering system will include meters, interfaces between the meters and the central station and metering data collection (communications) facilities.

The AMR will include up to 880 electronic meters enabling measurement and data storage for every delivery and off-take point on the transmission system. Roughly 400 of these meters are already installed on the system. Up to an additional 480 meters will be procured under the project (subject to budget limitations), and will be installed by the Transmission Company. Under the project, all meters will be linked to the central station and will measure, as a minimum:

- Active and reactive energy
- Exchanges on interconnection links with Russia
- Losses on the transmission network
- Consumption of auxiliary services within the substations

The meters will have data storage for at least three months, and have a measuring frequency of 15 minutes integrated hourly. The AMR will verify and validate the data. The meters will be of commercial quality without duplication.[19]

The project is expected to include an extensive training program structured as follows:

- System administrator — one week for three persons
- Administrator Database — two weeks for three persons
- Modems/IEDs[20]/System Operator — one week for three persons
- Basic User/Advanced User — one week for three persons

Training will be provided during all project phases, including during commissioning and following installation.

In summary, upon completion of this project, the NDC is expected to have a state-of-the-art metering system enabling it to meet the metering requirements of most any wholesale market structure.

5.3 Assessment of NDC Readiness to Perform SMO Function

The NDC's readiness to perform the function of the SMO has been evaluated from both workforce/organization and technical perspectives.

5.3.1 Workforce/Organization

To carry out the responsibilities of the SMO under the new market structure the NDC requires significant enhancements in the areas of workforce and organizational structure. The following measures should be implemented to bring the capacity of the NDC to the level necessary to satisfy the responsibilities of the SMO.

- Form an adequately staffed department within the NDC dedicated to market administration. The department must have adequate trained staff and be equipped with

[19] Back-up will be provided by existing metering installations.
[20] Intelligent electronic device (IED).

modern computer tools to perform such tasks as load forecasting, load flow and production cost simulation analyses, development of dispatch schedules, generating settlement statements and invoices, etc.

- Develop the necessary software to perform market administration functions. The software must be consistent with the market rules and procedures
- Provide comprehensive training to NDC staff on their responsibilities under the new market structure
- Implement necessary "code of conduct" rules

5.3.2 Technical

The initial market design includes a system of vesting contracts that will be designed by the ERA with NDC input, and assigned between Generation and Distribution Companies. Generators will be centrally dispatched by the NDC on the basis of lowest variable cost. Differences between bilateral contract amounts and actual delivery/consumption amounts will be priced at the marginal cost of supply. Therefore, the SMO must be capable of tracking amounts consumed and delivered at every delivery point on the grid on an hourly basis. The SMO must also be able to plan the system, assemble pre-dispatch schedules, dispatch in real-time, do billing and settlement and produce and publish market information.

The NDC can do a number of these things today. For example, the NDC currently conducts planning, develops preliminary dispatch schedules and performs real-time dispatch. There are dedicated telephone lines with recording capability between the NDC and each generating station to communicate dispatch instructions and enable verification. The NDC currently bills customers monthly, and would be in position to operate as the SMO today if monthly settlement were acceptable. However, balancing requires that settlement be done hourly, meaning the AMR and a billing and settlement system that interfaces with the AMR is a pre-requisite for the NDC to perform the SMO function in the new market.

Once the AMR project is completed, the NDC's ability to perform the functions of the SMO will be much improved. The NDC will have a complete set of data on all of its critical substations in real-time, thus improving its ability to dispatch and maintain system reliability, and a complete set of consumption and delivery data for each market participant, thus enabling it to produce market information reports and conduct the billing and settlement process.

The NDC will have all of the hardware and software necessary to perform the role of the SMO envisioned in the market design with the exception of a commercial-grade wholesale billing and settlement system. Billing and settlement consists of processing the AMR data, calculating and producing the bills, issuing the bills and collecting receivables and disbursing payments. Although the market proposed for Mongolia is relatively simple and straightforward, hourly metering and settlement is complex, requiring a fair amount of data manipulation. Mongolia's market will evolve as increasing levels of competition are introduced in the future. Therefore, a commercial-grade billing and settlement system that is flexible, and readily adaptable to changes in the market is recommended. A commercial-grade billing and settlement system will provide the SMO with a proven software package that can withstand the challenges posed by market participants with regard to their settlement statements. NDC will need comprehensive training on the new billing and settlement system, and will need a dedicated staff to administer the system.

The NDC has filed for approval a number of projects related to the functions of the SMO, including:

- A training simulator that simulates operation of the power system. Such simulators are used to train new staff, and maintain/upgrade the skills of existing staff. Training simulators often include facilities for building training scenarios and monitoring progress of trainees.
- Additional training on PSS/E software provided to NDC by PTI-Siemens. Apparently, NDC staff are not comfortable using this software and feel they would benefit from additional training. PSS/E is a system analysis software package that enables control center staff to analyze, and therefore prepare, for various system scenarios that may arise, thus making them better system operators.
- Addition of an Energy Management System (EMS) to the SCADA system. An EMS package enables NDC staff to dispatch plant on the basis of least cost. It provides a merit order stack of generating units based on variable cost, thus enabling least cost dispatch and minimization of fuel costs.
- A billing and settlement system for taking data from the AMR system, applying appropriate tariffs, and producing an invoice. In fact, billing and settlement was originally a component of the AMR project, but has been cut owing to budget limitations.

The approval process for power projects is as follows. During the summer of each year, the line ministry, in this case the MoFE, collects a "wish list" of projects from the power companies, develops an integrated draft proposal for the energy sector, and submits the list to the Ministry of Finance. The Ministry of Finance in turn reviews the proposals from each line ministry and prepares the draft state budget including the public investment program and submits it to Cabinet for review. Following its review, Cabinet submits the draft budget to the fall session of Parliament beginning October 2. Therefore, even if the MoFE is successful in persuading the Ministry of Finance to support its projects, as not all projects in the draft budget are approved by Parliament, there is little chance the projects submitted by NDC have a chance of being approved by Parliament for 2009 implementation.

Although each of the projects submitted to the Ministry will aid the NDC in doing a better job, only the billing and settlement system is required in order for the NDC to carry out the functions of the SMO. Economic merit order dispatch is certainly critical to cost minimization on the power system. However, when there are only five power plants on the system as there is today, economic merit order dispatch is not a complicated process.[21] Likewise, a training simulator and system analysis software would certainly improve operator performance, but the NDC is getting by adequately without these aids today, so they are not considered critical to performing the function of the SMO in the new market.

A commercial-grade billing and settlement system will ultimately be necessary for the SMO to perform the billing and settlement function under the new market structure. The new billing and settlement system will interface with the AMR system, and calculate and produce invoices on the basis of consumption and delivery data provided by the AMR system, and tariffs/prices provided by the SMO. Installation of a commercial-grade billing and settlement system includes two principal components:

- The "product" consisting of various software packages that perform the billing and settlement function; and

[21] An EMS would enable NDC to optimize dispatch, thus reducing coal requirements and associated pollution, so although not a requirement to perform the SMO function, should nonetheless be given high priority.

- System integration including definition, design and development of the product, and project management activities such as implementation assistance, integration, testing, training and documentation.

Vendors for billing and settlement systems are reluctant to provide cost and schedule information without a formal definition of the system requirements. However, vendors have provided a high-level cost estimate of US$ 1 million and a schedule for product installation and system integration of six months from the time of contract award. The "product" accounts for about 80% of the total cost.

SECTION VI: NEXT STEPS

The next steps necessary to implement the proposed market design are described below. A market implementation schedule is included in ***Exhibit 7***. The schedule is based on the assumption that there is a commitment within Mongolia to implement the new market design by January 1, 2010. [22]

6.1 Gain Approval of Proposed High-Level Market Design

A proposed market design is documented in this report. It has been prepared with input from the ERA and industry stakeholders. The next phase of the approval process includes circulating the report to all industry stakeholders including the MoMRE.

It is anticipated that the review and approval process will be completed in five months, by the end of January 2009.

6.2 Update Legal Requirements

It is necessary to examine existing legal arrangements such as the Energy Law and the Renewable Energy Law to determine if they enable implementation and are consistent with the objectives of the new market design. Review of Mongolia's legal arrangements has been an ongoing process. The Energy Law was most recently amended on January 11, 2007. As noted earlier, EBRD is funding a project with the objective of producing a renewable energy roadmap that is expected to lay the foundation for resolution of issues related to renewable energy development.

Once there is approval of the new market design, the legal arrangements will be reviewed for consistency and updated as necessary. It is anticipated that review and updating of legal documentation relating to implementation of the market under the initial 100% vesting period will be relatively minor with completion possible in six months, by mid-year 2009. However, this will depend on GoM priorities. Promulgation of legal documentation is likely to take longer, as are amendments necessary to implement the competitive market expected two to three years following the 100% vesting period.

6.3 Complete Market Rules

Market Rules were drafted early in 2006 and submitted to industry stakeholders for comment. The draft of the Market Rules will be modified as necessary to reflect the approved high-level market design in this report and issued to stakeholders for review and comment. Associated market documents such as the Grid Code will likewise be reviewed and updated to be consistent with the new market design.

It is anticipated that a task group will be formed with representation from the ERA and power companies to review and comment on the Market Rules and Grid Code as drafted by consultants. Market Rules can be developed at the same time the high-level market design is being reviewed and approved, with finalization of the Market Rules and associated governance documents such as the Grid Code expected by mid-year 2009.

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[22] During the stakeholder process, a question was raised about the desirability of implementing the new market on January 1 as opposed to a date that coincides with the start of a new season. With regard to the initial market with 100% fully-regulated vesting contracts, the commencement date is of little relevance. However, it may be desirable to introduce the competitive phase of the market at the end of the heating season (i.e., May 1) when demand and, presumably, prices are lower than at other times of the year. The schedule for market opening will be determined by the ERA with input from industry stakeholders.

6.4 Upgrade NDC Capacity to Perform Role of SMO

As discussed in ***Section 5***, NDC is not currently ready to perform the roles and responsibilities of the SMO. NDC will require re-organization and training, and would benefit from the addition of a number of software tools to help it better perform the functions of the SMO.

Market participants must have confidence in the SMO's ability to perform the role of the system/market operator if the new market is to be a success. However, initially the market will be dominated by Government-owned power supply companies and regulated vesting contracts. The market will for all intents and purposes be fully regulated, so it is not critical that the NDC have all of the tools in place at market commencement. The NDC will have the opportunity to "grow" into the position during this initial vesting period.

In any regard, it is paramount that there be a clear understanding among market participants of how the NDC will carry out its duties at market commencement and until such time the necessary tools are in place to enhance performance. In order to avoid delays in market implementation, it is recommended that international consultants work with the NDC and market participants to develop procedures to be followed for each of the SMO responsibilities at market commencement. These procedures will be continually updated following market commencement to reflect the addition of software tools that enhance the NDC's ability to perform the role of the SMO. This continual updating can best be performed through formation of a Technical Advisory Group with representation from each of the principle market participant groups as well as the ERA.

This task will begin in October 2008 and is anticipated to continue through to market testing and dry run, In fact, the task will continue beyond market commencement with the Technical Advisory Group meeting monthly on an ongoing basis.

6.5 Upgrade Capacity of Other Market Participants to Perform Their Roles

Although not as extensive as the NDC, the needs of the other Market Participants including the generators, the transmission company and the distribution companies must be assessed with the intent to improve their capacity to perform successfully in the new market. It is expected that the needs of these companies will be relatively minor for the initial 100% vesting period, but will increase prior to implementation of competition two to three years following market commencement.

This task will begin by January 1, 2009 and is anticipated to continue through to market testing and dry run, In fact, the task will likewise continue beyond market commencement with the Technical Advisory Group meeting monthly on an ongoing basis.

6.6 Develop Bilateral Vesting Contracts and Allocation Methodology

Bilateral vesting contracts will govern transactions between generators and distributors. These contracts must reflect the costs of each generator, and be allocated/assigned to distributors proportionally while matching the needs of the distributor's customers. The contracts will include a two-part tariff with the energy charge recovering the generator's variable costs (i.e., fuel and variable operation and maintenance), and the capacity charge recovering the generator's fixed costs. In addition, the contracts must include the usual contract clauses and financial assurances. As a two-part tariff is currently in place, much of the tariff design data has already been accumulated.

It is anticipated that development of the vesting contracts and allocation methodology can be carried out coincidentally with the market design and Market Rules approval processes. The additional time beyond the approval process is judged to be one month.

6.7 Review Transmission Tariff

A transmission tariff already exists and is designed to recover the revenue requirement of the transmission company. The current tariff is a uniform per kWh charge applied to sales to all wholesale customers; i.e., the distribution companies. This is commonly referred to in the industry as a postage stamp tariff.

No changes are anticipated to the type of tariff, particularly since there appears to be minimal congestion on the CES transmission grid. Regardless, the tariff will be reviewed to determine if an alternative tariff may be warranted for fairness and efficiency reasons. This evaluation can also be carried out coincidentally with the market design and Market Rules approval processes. It is judged that the tariff review can be finalized during the summer of 2009.

6.8 Develop SMO Service Charge

An SMO service charge, or tariff, will be developed to recover the revenue requirement of the system/market operator. There is already a tariff in place that is designed to recover the NDC's revenue requirement. Nonetheless, this tariff will be reconsidered to determine if it the revenue requirement needs adjustment given the increased responsibilities of the NDC as an SMO, and to determine if it might be better designed to provide a more efficient and/or desirable price signal.

The evaluation of the SMO service charge will be carried out coincidentally with the market design and Market Rules approval processes. It is judged that the service charge can be finalized during the summer of 2009.

6.9 Develop Financial Assurance Policy

A system of financial guaranties for commercial market participants must be developed to provide the SMO with assurance that it will be able to perform the market settlement function and suppliers including the generators, the transmission company and the SMO with assurance that they will be paid for services provided. A financial assurance policy will ensure a viable and liquid market by providing reasonable assurance of uninterrupted payments while being fair to market participants.

Development of this policy should include representatives of the SMO, the commercial market participants, financial and legal institutions and consultants. The policy will be developed following approval of the market design and during completion of the Market Rules, and completed prior to the market test and dry run.

6.10 Develop Market Reports

One of the responsibilities of the SMO is to produce and publish various market related reports in order to improve the transparency and fairness of the market. Market data and information are vital to the successful operation of the market.

The development of the market reports will be carried out following approval of the market design and Market Rules. It is anticipated that the market reports can be developed over a three month period prior to the market test and dry run. This task will dovetail with Task 6.4 – Upgrade NDC Capacity to Perform Role of SMO.

6.11 Market Participant Training

The Market Rules will require that the SMO provide training to market participants on the new market. The market participants will need training on the overall operation of the market, and on their roles, responsibilities and obligations in the new market.

The market participant training will take place just prior to the market test and dry run. It is anticipated that market participant training will take about three months.

6.12 Market Test and Dry Run

Prior to market commencement, it is necessary to conduct a market test to ensure that the SMO and all market participants are fully prepared and aware of their responsibilities in the new market. The market trial ensures the inter-operability of the systems and procedures of the SMO and the market participants and ensures the SMO is capable of directing the operations of market participants. It identifies any deficiencies and the extent to which they require rectification prior to commencement of market operation.

The market test and dry run will be conducted following market participant training and prior to market commencement. It is anticipated that the market test and dry run will take three months and will be completed by year-end 2009.
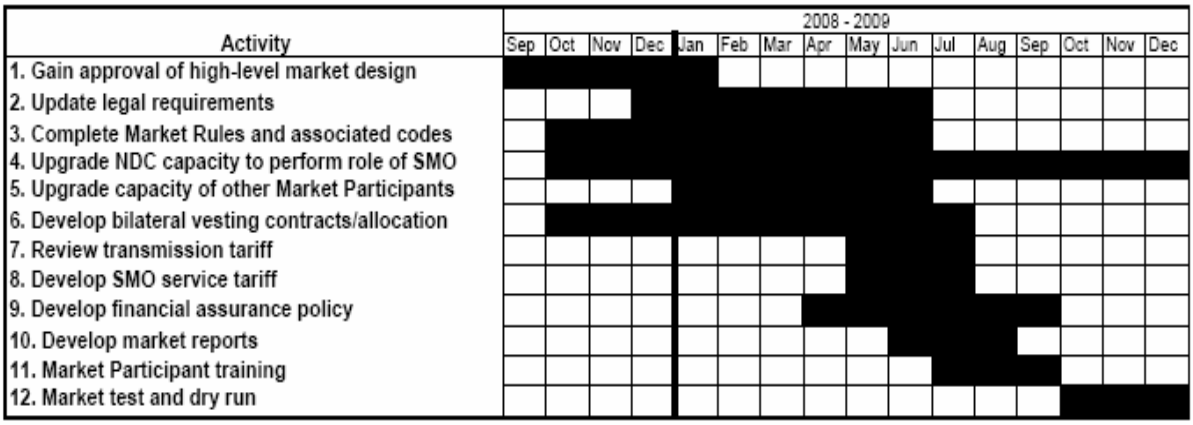
Exhibit 7. Schedule of Bilateral Contracts Market Implementation Activities